OIL

SCARCITY OR SECURITY?

Barbara Sparrow, M.P.
Chairman
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Eighth Report
Standing Committee on
Energy, Mines and Resources

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Chairman: Barbara Sparrow

Minutes of Proceedings and Evidence of the Standing Committee on

ENERGY, MINES AND RESOURCES

RESPECTING:

Pursuant to Standing Order 96(2), matters relating to the Department of Energy, Mines and Resources, specifically Canada's oil reserves and resources.

INCLUDING:

The Eighth Report to the House

CHAMBRE DES COMMUNES

Fascicule nº 28

Le mardi 29 septembre 1987

Président: Barbara Sparrow

Procès-verbaux et témoignages du Comité permanent

DE L'ÉNERGIE, DES MINES ET DES RESSOURCES

CONCERNANT:

Conformément à l'article 96(2) du Règlement, questions relatives au Ministère de l'Énergie, des Mines et des Ressources, spécialement sur les réserves et ressources pétrolières du Canada.

Y COMPRIS:

Le huitième rapport à la Chambre

STANDING COMMITTEE ON ENERGY, MINES AND RESOURCES

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HOUSE OF COMMONS
CHAMBRE DES COMMUNES
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The Standing Committee on Energy, Mines and Resources has the honour to present its

EIGHTH REPORT

Pursuant to Standing Order 96(2), the Standing Committee on Energy, Mines and Resources undertook a study of Canada's oil reserves and resources. After hearing evidence, the Committee has agreed to report to the House as follows.

OIL

SCARCITY OR SECURITY?

ABBREVIATIONS USED IN THIS REPORT

ANWR	Arctic National Wildlife Refuge (Alaska)
API	American Petroleum Institute
CHIP	Canadian Home Insulation Program
COSP	Canada Oil Substitution Program
CPA	Canadian Petroleum Association
CNG	compressed natural gas
CPEs	centrally planned economies (Communist countries)
DOE	Department of Energy (United States)
EMR	Energy, Mines and Resources
EOR	enhanced oil recovery
ERCB	Energy Resources Conservation Board (Alberta)
FERC	Federal Energy Regulatory Commission (United States)
GSC	Geological Survey of Canada
IEA	International Energy Agency
IPL	Interprovincial Pipe Line
LDCs	less developed countries
LPG	liquefied petroleum gases
NEB	National Energy Board
NEP	National Energy Program
NGL	natural gas liquids
NPC	National Petroleum Council (United States)
OAPEC	Organization of Arab Petroleum Exporting Countries
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
R,D&D	research, development and demonstration
SPR	Strategic Petroleum Reserve (United States)
TAPS	Trans Alaska Pipeline System
UAE	United Arab Emirates
WTI	West Texas Intermediate (crude oil)

COUNTRY GROUPINGS USED IN THIS REPORT

Northern America: Canada and United States (excluding Puerto Rico).

Latin America: Mexico, the Caribbean (excluding Cuba), Central and South America.

Western Europe: European members of the OECD.

Middle East: Arabian Peninsula, Iran, Iraq, Israel, Jordan, Lebanon and Syria.

Western Hemisphere: North and South America, their islands and surrounding waters.

Eastern Hemisphere: Africa, Asia, Australia and Europe, their islands and surrounding waters.

Centrally Planned Economies (CPEs): Albania, Bulgaria, China, Cuba, Czechoslovakia, East Germany, Hungary, Kampuchea, Laos, Mongolia, North Korea, Poland, Romania, U.S.S.R., Vietnam and Yugoslavia.

Organization for Economic Co-operation and Development (OECD): Members of the European Economic Community – Belgium, Denmark, France, Greece, Ireland, Italy, Luxembourg, the Netherlands, United Kingdom and West Germany – plus Australia, Austria, Canada, Finland, Iceland, Japan, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey and United States.

Less Developed Countries (LDCs): Non-Communist (including OPEC) countries outside of the OECD. This group includes the majority of the countries in Africa, Asia and Latin America.

Organization of Petroleum Exporting Countries (OPEC): Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. (Neutral Zone output is shared equally by Saudi Arabia and Kuwait.)

Organization of Arab Petroleum Exporting Countries (OAPEC): Abu Dhabi, Algeria, Bahrain, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, Syria and Tunisia. (Neutral Zone output is shared equally by Saudi Arabia and Kuwait.)

International Energy Agency (IEA): Australia, Austria, Belgium, Canada, Denmark, Greece, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States and West Germany.

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FOREWORD

The Standing Committee on Energy, Mines and Resources initiated this study of future oil availability in Canada to dispel the complacency brought about by global oil oversupply and depressed petroleum prices. Almost 60% of the world's reserves of conventional crude oil lie in the politically volatile Middle East, where the Iran-Iraq War is now engaging military forces of the major powers. More than 330 attacks by Iraq and Iran on merchant shipping in the Persian Gulf have led to the convergence of American, French, British and Soviet naval forces in the region. The possibility of an expanded military confrontation in the Gulf poses a growing threat to international oil trade. Of potentially greater consequence is the continuing attempt by Iran to intimidate and destabilize moderate Arab regimes in the Gulf.

This report considers Canada's future availability of domestic light crude oil and the likelihood of a re-emerging dependence on foreign supplies of petroleum. Canada holds less than 1% of the world's proved reserves of conventional crude oil and, for most of the postwar period, has been a net importer of oil. The Committee therefore opens its report with a broad look at world patterns of oil availability and use. Thereafter the study focusses on oil supply and demand in the United States, our principal trading partner in energy, and then on the situation in Canada. In the concluding section, the report discusses the notion of "security of oil supply" and considers, in the context of long-term energy planning, policy options available to the federal government.

The Committee presents 12 recommendations arising from its study. These recommendations are included in the Summary which follows on page 4. The report also contains information which should help Canadians become better informed about domestic and international energy affairs.

The adequacy of Canada's future oil supply cannot be discussed in isolation from other aspects of our domestic energy system. In particular, energy conservation and the potential for substituting other energy forms for oil bear on the future oil supply/demand balance. Therefore the Committee's remarks encompass some of these related matters. The central role of the provincial governments in determining the character of Canadian energy development must also be acknowledged.

The testimony received by the Committee has revealed wide divergence of opinion on what role, if any, the Government of Canada should play in influencing the evolution of Canada's energy system and the petroleum sector in particular. We have revisited a continuing debate: is oil just a commodity traded like any other, or has it a strategic dimension which compels the attention of government?

Most members of this Committee are disposed to advocate minimal intervention by government in the economy. Nevertheless, the Committee is led by the evidence to conclude that oil – indeed energy in general – is more than an economic commodity;

the federal government must maintain influence over the course of Canadian petroleum development. We do believe, however, that government should intervene sparingly and on the basis of long-term energy planning, not in the day-to-day workings of the energy marketplace.

Two premises are integral to this study. First, the petroleum industry must recognize that oil is a strategic commodity and hence government policy will continue to be directed at the energy sector. Second, government must acknowledge the high risk of exploiting a diminishing resource. The petroleum industry has the right to operate within a stable and predictable fiscal regime.

The Committee had to address several practical problems in preparing this report. There is an abundance of confusing terminology and systems of measurement in the energy field. For example, oil statistics may be reported by volume (barrels or cubic metres), by weight (metric tons), or by energy content (joules or British thermal units). Most readers still seem more familiar with English units; thus we have chosen to present the data in barrels, cubic feet, etc. for ease of understanding. We acknowledge that the SI (Système International) scheme of measurement is more logical and ultimately better to work with; in most cases the SI equivalent is also presented. Common energy units, conversion factors and SI prefixes are gathered into Appendix C for ease of reference.

There are also problems of definition, as certain energy terms are not consistently used in the literature. Most of the definitions and concepts which the Committee has adopted are presented on pages 9 through 15 of the report. All monetary values are assumed to be in current Canadian dollars unless otherwise specified.

One final note on energy statistics: data from different sources are not always consistent. Sometimes the variance results from definitional differences. For example, one statistical compilation of "oil production" may include natural gas liquids with crude oil output whereas another may not; some sources report hydro-electric generation by the energy content of the electricity itself (that is, the electric energy is valued at 1 kilowatt-hour equals 3,412 British thermal units) while others report the equivalent energy content of the coal or oil that would be required to generate the same amount of electricity at a modern fossil-fueled power station (the electricity is valued at approximately 1 kWh equals 10,000 Btu). In other cases, sources disagree for unaccounted reasons.

The Committee has endeavoured to be consistent in its use of data which originate from a variety of sources. Where inconsistencies could not be resolved, the Committee has noted this.

Numerous individuals and organizations have assisted the Committee in this study. The names of the witnesses who testified before the Committee are presented in Appendix B. To those who provided additional documentation for our consideration the

Committee is also indebted and thanks in particular Joseph Riva Jr. of the Congressional Research Service in Washington, Frank Mink and other officials of the Energy Resources Conservation Board in Calgary, and officials of the Department of Energy, Mines and Resources in Ottawa.

The Committee also records its appreciation for the work of its staff: to its advisers Dean Clay and Lawrence Harris of Dean Clay Associates; to Ellen Savage, Clerk of the Committee; to Lise Tierney, manuscript typist; and to the Translation Bureau, Secretary of State.

SUMMARY AND RECOMMENDATIONS

The 1986 collapse in crude oil prices left its mark around the world. Demand for oil has increased in most countries as consumers respond to the lower cost of petroleum products. OPEC's 1986 revenue from crude oil exports fell to little more than half of its 1985 level. Spending on petroleum exploration and development is down, which means lower reserve additions in the future. This is especially the case in areas where the cost of finding and developing reserves is high, as in Canada's frontier regions, Alaska and the North Sea. Although Canada now enjoys an aggregate self-sufficiency in oil, we are a net importer of light gravity oils and our production of these will fall in coming years. Low oil prices will accelerate this decline.

The lighter petroleum fuels (light-medium crude oils and natural gas), which are more easily produced and processed, are found predominantly in the Eastern Hemisphere. The heavier, less easily produced and processed petroleum fuels (heavy oil, bitumen and shale oil) lie principally in the Western Hemisphere. An estimated 58% of the world's proved reserves of conventional crude oil is located in the Middle East, yet that region produced only 22% of the world's oil in 1986. The Western Hemisphere, with only 17% of conventional world reserves, produced 29% of the 55.9 million barrels/day lifted last year. This unbalanced output, measured against the share of reserves held, almost guarantees that the Middle East will eventually dominate the production of conventional crude oil once again. Over 90% of the world's current surplus capacity to produce oil – an excess capacity of roughly 10 million barrels/day – lies within OPEC, and most of that in turn is found in the Persian Gulf.

Outside the Middle East, the supply of conventional light oil will decline and oil-importing nations will turn increasingly to the Persian Gulf to satisfy their requirements. As control of petroleum markets reverts to the oil-rich Middle Eastern countries, they will be more able to manipulate price. Given the political instability in this part of the world, further disruptions in the international supply of oil are a possibility for which oil-importing nations should prepare.

Canada faces a shrinking availability of domestic conventional light crude oil but possesses large and technically recoverable resources of bitumen. This resource requires costly upgrading to yield the light petroleum products required by Canadian consumers. Canada also holds substantial quantities of conventional heavy oil and has established modest reserves of light oil in the East Coast offshore and the north. These oil deposits are not generally producible, however, at the reduced oil prices which we have recently experienced.

In the near term, Canada will be forced to import larger quantities of light crude oil. This will increase our vulnerability to any curtailment in offshore supplies. A mechanism is required to offset this rising dependence until longer-term changes can be made to rectify Canada's light oil supply/demand imbalance.

1. The Committee recommends that the federal government establish a government-owned strategic oil reserve, equal to 90 days of net light crude oil imports, with the cost of filling and maintaining the reserve to be recovered through a tax on oil products at the refinery level.

A strategic oil stockpile provides some protection against short-term disruptions in the supply of imported oil, but it does not address the underlying issue of Canada's deteriorating availability of domestic light crude oil. To reduce the imbalance between domestic supply and demand, initiatives to increase the indigenous supply of light oil (or at least to minimize the rate of decline) and to restrain demand for petroleum products should be pursued simultaneously.

On the supply side, Canada has two options for augmenting the output of conventional light crude oil. One option is to develop conventional light crude reserves in Canada's frontier regions, such as those discovered at Amauligak in the Beaufort Sea and at Hibernia on the continental shelf offshore of Newfoundland. The other is to produce Canada's far more extensive deposits of bitumen and heavy oil and to upgrade these heavy hydrocarbons into usable light petroleum products. Actually, some combination of these two approaches will be pursued, but both have been held back because the price of oil fell too low in 1986 to support such high-cost projects, and the threat of widely fluctuating prices constitutes an unacceptable risk to many oil companies.

The Committee does not believe in subsidizing uneconomic oil development. Rising oil prices should provide the economic incentive for frontier and nonconventional oil development to proceed. A partial recovery in the price of oil – to US$22 per barrel recently for West Texas Intermediate crude (WTI, the benchmark crude oil stream in North America) – has prompted the Canadian oil industry to resume several heavy oil projects deferred when the price fell as low as US$10 per barrel in 1986. With regard to oil supply then, the federal government should direct its primary effort to creating a more stable fiscal environment for petroleum activity. The Committee makes the following recommendations to improve the domestic supply of light oil.

2. The Committee recommends that the federal government establish a stable corporate tax regime so that investment in domestic petroleum exploration and development will not be restricted due to uncertainty regarding government policy.

The petroleum industry faces enough uncertainty in the international oil arena without having to contend with unpredictability in the domestic fiscal regime.

3. The Committee recommends that the federal and provincial governments, as owners of Canada's mineral rights, encourage petroleum development by keeping royalties low in the initial years of petroleum production.

Frontier petroleum projects, nonconventional oil development and the enhanced recovery of conventional oil require large initial capital investments. Many years may pass before that investment is recovered. Lower royalties in the early years of production would improve the pattern of cash flow, and allow some projects to proceed sooner than would otherwise be the case. We acknowledge that royalty issues lie principally within provincial jurisdiction and initiatives to influence the rate of petroleum development, apart from Canada Lands, are foremost a matter of provincial control.

Facilitating petroleum development by removing administrative lags is an important task for government. Establishing a pipeline right-of-way is frequently a time-consuming and contentious process, as the United States discovered in building the Trans Alaska Pipeline System (TAPS). In the north, where there is particular concern about the environmental impact of petroleum development, we believe that route selection should proceed in advance of the need, to allow resolution of the issues that interested parties will raise.

4. **The Committee recommends that the federal government complete the planning for a transportation corridor along the Mackenzie Valley in anticipation of pipeline construction and to provide a surface transportation link with the Mackenzie Delta, taking into account native land claims and environmental impact.**

5. **The Committee recommends that the federal government plan a transportation corridor from the Mackenzie Valley to the Alaska border in anticipation that an oil and/or natural gas pipeline may be required to transport Alaska's petroleum production overland, subject to native and environmental concerns being resolved satisfactorily.**

It is in Canada's interest that reserves of light crude oil in the non-OPEC world be maximized. More oil would thereby be available to importing countries in the event of another embargo or other disruption in OPEC supply. It is particularly important that the United States solve its worsening oil supply problem, given its central position in the world economy and its pivotal role in Western security.

6. **The Committee recommends that the federal government encourage the United States to explore for and develop petroleum resources in Alaska's Arctic National Wildlife Refuge, provided that environmental and aboriginal concerns can be satisfactorily resolved.**

7. **The Committee recommends that the role of Canada's foreign assistance agencies be continued in promoting the exploration for and development of conventional petroleum resources in developing regions of the world and especially in the Western Hemisphere.**

A higher level of exploration and development activity will lead to a larger fraction of the Western Hemisphere's light crude oil resources being discovered and used. Also, it is in the developing world where future rates of growth in the demand for oil will be greatest. If the petroleum potential of oil-importing developing countries can be better exploited, the international supply situation will be improved and foreign debt problems afflicting many of these nations may be diminished. As well, Canada's oil service industry benefits when new markets develop for its expertise and equipment.

Better extraction and processing technology can lower the cost of oil production while promoting more efficient exploitation of our petroleum resources.

8. The Committee recommends that the federal government increase its financial support for research, development and demonstration directed to increasing the domestic supply of oil, with particular emphasis on the extraction and upgrading of bitumen and heavy oil and on frontier petroleum development, but also including conventional light oil development through such means as enhanced oil recovery.

The other side of the light oil supply/demand imbalance is policy to reduce the demand for oil. As the use of oil has declined in Canada for purposes such as space heating and electrical generation, the transportation sector has assumed more importance as the core user of petroleum products. Any policy to decrease demand must address the fact that more than 60% of Canada's end-use requirement for oil now arises in the transportation sector and 80% of that amount in turn is consumed in road transport; the principal need is to reduce the consumption of motor vehicle fuel.

9. The Committee recommends that the federal and provincial governments forego taxing natural gas, propane, methanol and ethanol when used as motor vehicle fuels or as blending agents in conventional fuels.

Compressed natural gas (CNG), propane and methanol are economically competitive today as vehicle fuels or blending agents. The principal impediments to their broader use are the infrastructure costs of distribution systems and any need for engine modifications. There have been provincial initiatives to support the introduction of alcohols as blending agents in motor gasoline, most notably in Manitoba. The Committee supports such actions.

10. The Committee recommends that federal incentives for engine modifications to use compressed natural gas and propane as motor vehicle fuels be continued.

The five-year federal incentive program for vehicle conversion to compressed natural gas fueling has been extended for a year because the target of 35,000 CNG-powered vehicles was not attained. The bulk of the financing for this extension is coming from Alberta gas producers in funds remaining from the former Market Development Incentive Payments (MDIP). The five-year incentive program for propane conversion was successful in surpassing the 90,000-vehicle target and terminated on schedule. The Committee believes that federal support for both types of vehicle conversion should be maintained.

The federal government should underwrite part of the cost of research and development designed to ensure that a range of energy options is available in the future, options which the private sector may view as requiring too long a payback period to warrant significant investment today. The federal government has reduced its research, development and demonstration (R,D&D) spending too severely on new energy technologies, alternative energy development and energy conservation.

11. The Committee recommends that the federal government increase its financial support for research, development and demonstration directed to increasing the efficiency of energy use.

It is apparent that the opportunities to pursue energy conservation, even at reduced energy prices, are far from fully exploited. Conservation remains one of the most cost-effective approaches to balancing energy supply and demand. Yet current federal spending is much more channeled to the supply side of the energy budget than to the demand side.

Over the years, the federal and provincial governments have extensively supported the development of Canada's conventional energy system – that is, the use of oil, natural gas, coal, hydro-electricity and nuclear-electricity. In the future, Canada should increasingly incorporate nonconventional energy forms such as biomass, wind energy, direct solar radiation, tidal energy and geothermal energy into its energy supply. New technologies will be required to allow this exploitation and to increase the scope for fuel substitution.

12. The Committee recommends that the federal government increase its financial support for research, development and demonstration to promote the availability of nonconventional energy forms, and for R,D&D to promote the substitution of both conventional and nonconventional energy forms for oil.

Some of the energy alternatives will require many years of development before their exploitation is feasible. Government support of R,D&D will help to ensure that these new energy options are available for our future needs. Canada will also benefit from the export opportunities afforded by these new technologies, particularly in the developing world.

A NOTE ABOUT OIL

Oil is a combustible liquid generally considered to have been formed by geochemical processes acting on the remains of organisms buried in the geologic past. Although oil basically consists of only two elements, carbon and hydrogen, it is characterized by an enormously complex variety of molecular structures – no two crude oils from different sources are identical. Despite this almost unlimited complexity, most crude oils contain 84% to 87% carbon by weight and 11% to 14% hydrogen.

In addition to carbon and hydrogen, there are small amounts of other elements present, typically in amounts aggregating less than 3% by weight of the oil. Sulphur, nitrogen and oxygen are the principal "contaminants", although traces of sodium chloride, phosphorus and heavy metals such as vanadium and nickel are common. Heavy oils and natural asphalt may have a sulphur content of 5% or more.

The conversion of organic material contained in sediments into petroleum is a function of temperature (in turn related to depth of burial) and time.

> Deeper burial by continuing sedimentation, increasing temperatures, and advancing geologic age result in the mature stage of petroleum formation during which the full range of petroleum compounds is produced from kerogen and other precursors by thermal degradation and cracking (the process by which heavy hydrocarbon molecules are broken up into lighter molecules). Depending on the amount and type of organic matter, oil generation occurs during the mature stage at depths of about 760 to 4,880 metres (2,500 to 16,000 feet) at temperatures between 65° and 150°C. This special environment is called the "oil window". In areas of higher than normal geothermal gradient (increase in temperature with depth), the oil window exists at shallower depths in younger sediments but is narrower. Maximum oil generation occurs from depths of 2,000 to 2,900 metres. Below 2,900 metres primarily wet gas, a type of gas containing liquid hydrocarbons known as natural gas liquids, is formed. (Riva, 1987a, p. 590)

At the end of the mature stage and at depths greater than about 4,900 metres (16,075 feet), depending on the geothermal gradient, crude oil becomes unstable and the main hydrocarbon product is dry gas (methane). At sediment temperatures greater than about 250°C (482°F), hydrocarbons cease to be generated from organic matter. Depending on its geologic history then, a sedimentary formation may be oil prone, gas prone, both or neither.

Oils are usually characterized by their API gravity, on a scale adopted by the American Petroleum Institute to measure the specific gravity of crude oils. This scale arbitrarily assigns an API gravity of 10° to pure water. Oils lighter than water have an API gravity greater than 10°; those heavier than water have a value less than 10°.

Unfortunately, there is no standardized definition of what constitutes a "light", "medium" or "heavy" oil on the API scale. The World Energy Conference uses the following classification (WEC, 1986, p. 160).

heavy oil	density: 1,000 to 920 kg/m^3	API gravity 10°-22.3°
medium oil	density: 920 to 870 kg/m^3	API gravity 22.3°-31.1°
light oil	density: less than 870 kg/m^3	API gravity more than 31.1°

An oil with an API gravity of less than 10° (that is, with a density of more than 1,000 kilograms/cubic metre) is commonly referred to as **bitumen**.

The Alberta Energy Resources Conservation Board (ERCB) does not usually differentiate between light and medium oils. It defines heavy oil as having a density greater than 900 kg/m^3 (an API gravity less than 25.7°) and light-medium oil as having a density less than 900 kg/m^3 (an API gravity more than 25.7°) (ERCB, 1987, p. 1-2). Many American oilmen consider a heavy oil to be one with an API gravity below 20°, a medium oil to have an API gravity between 20° and 25°, and a light oil to be one above 25°.

In this report, the boundary between light-medium and heavy oils will be understood to be 20° with respect to U.S. data and about 26° in the case of Canadian data, unless otherwise indicated.

Many other terms used in the oil industry also lack a standardized meaning or usage. To avoid ambiguity in this report, the following definitions of commonly used terms will apply.

Hydrocarbons: any organic compounds – solid, liquid or gaseous – consisting only of the elements carbon and hydrogen. Crude oil, natural gas and coal are essentially mixtures of hydrocarbons of varying degrees of complexity and containing varying amounts of impurities such as sulphur, nitrogen, oxygen, helium and metallic elements.

Fossil fuels: combustible geologic deposits of biogenic hydrocarbons. These deposits include crude oil, natural gas, oil shales, oil sands and coal.

Kerogen: fossilized, insoluble organic material found in sedimentary rocks, usually shales, which can be converted by distillation into petroleum products. Kerogen is considered to be a precursor of petroleum.

Petroleum: a Latin derivative literally meaning "rock oil" and often defined as naturally occurring liquid hydrocarbons. Sometimes the definition is extended to include refined products in the liquid state. In common industry usage, petroleum has come to mean any hydrocarbon mixture that can be produced through a drill pipe, including natural gas, condensate and crude oil. This report follows the common usage of the term.

Liquid Hydrocarbons

(Conventional) crude oil: a mixture mainly of pentanes and heavier hydrocarbons that is recoverable at a well from an underground reservoir, and which is liquid at atmospheric pressure and temperature.

Synthetic crude oil (syncrude): as commonly understood in Canada, a mixture mainly of pentanes and heavier hydrocarbons that is derived from crude bitumen through the addition of hydrogen or the deletion of carbon, and which is liquid at atmospheric pressure and temperature. Syncrude also includes oil obtained from oil shale or coal.

Condensate: a mixture mainly of pentanes and heavier hydrocarbons that is recoverable at a well from an underground reservoir, and which is gaseous in its reservoir state but which condenses to a liquid at atmospheric pressure and temperature. Condensate is often included with "crude oil", a practice followed in this report.

Pentanes plus: a mixture mainly of pentanes and heavier hydrocarbons that is obtained from the processing of raw gas, condensate or crude oil.

Crude bitumen: a naturally occurring viscous mixture, mainly of hydrocarbons much heavier than pentane, that in its natural state will not flow to a well. Bitumen, once produced, may be diluted with pentanes plus so that it can be transported by pipeline without the need for prior upgrading.

Shale oil: oil obtained from the treatment of kerogen contained in oil shale. No shale oil is produced in Canada at the present time, although oil shales are found in various regions of the country.

In this report, the term **oil** includes conventional and synthetic crude, condensate, pentanes plus and bitumen. This grouping is sometimes also referred to as **crude oil and equivalent**. If we wish to exclude synthetic crude oil and bitumen from this group, we denote the remaining three components as **conventional oil**.

Oil sands: sand and other rock materials containing crude bitumen, or the crude bitumen contained within those sands or other rock materials.

Tar sands: sands impregnated with a heavy crude oil, tar-like in consistency, that is too viscous to permit recovery by natural flowage into wells. This term used to be applied to the bitumen deposits of Alberta but has largely been supplanted by "oil sands" in Canadian usage. In the United States and elsewhere, the term "tar sands" is still in common use.

Oil shale: a kerogen-bearing, brown or black shale that will yield gaseous or liquid hydrocarbons on distillation.

Natural gas liquids (NGL): propane, butanes and pentanes plus obtained from the processing of raw gas or condensate (as defined by the ERCB, 1987a, p. 1-4). Some authorities extend the definition to include ethane (for example, EMR, 1987c, p. 75).

Liquefied petroleum gases (LPG): a subgroup of the natural gas liquids, consisting principally of propane and butanes, which can be liquefied under pressure at room temperature. These are familiar as "bottled gas".

Conventional crude, synthetic crude, condensate, bitumen and natural gas liquids may be referred to collectively as **liquid hydrocarbons**.

Gaseous Hydrocarbons

Raw gas: natural gas in its natural state, existing in a reservoir or as produced from a reservoir and prior to processing. Natural gas at the wellhead usually consists of methane with decreasing amounts of heavier hydrocarbons. Raw gas may contain such nonhydrocarbon gases as carbon dioxide, hydrogen sulphide, nitrogen, hydrogen and helium.

Marketable gas: raw gas from which natural gas liquids and nonhydrocarbon gases have been removed or partially removed by processing. Marketable gas is also known as "pipeline quality gas" or "sales gas", and is composed primarily of methane.

Associated gas: natural gas in a free state in a reservoir and found in association with crude oil, under initial reservoir conditions.

Non-associated gas: natural gas in a free state in a reservoir, but not found in association with crude oil under initial reservoir conditions.

Solution gas: natural gas that is dissolved in crude oil under reservoir conditions and that comes out of solution at atmospheric pressure and temperature.

Dry gas: natural gas composed predominantly of methane and ethane.

Wet gas: natural gas containing propane and butanes, sometimes in amounts as high as 50% or more.

Petroleum Resources and Reserves

Resource: all oil and gas accumulations either **known** or **inferred** to exist. That portion of the resource base which has been found is referred to as **discovered resources** or **reserves**. That portion of the resource which is inferred to exist but not yet discovered is known as **undiscovered resources** or **potential resources**.

Reserves: that portion of the resource that has been discovered, of which part is recoverable in current economic and technical circumstances and part is not.

Established reserves: those reserves recoverable under current technology and under present and anticipated economic conditions, specifically proved by drilling, testing or production; plus that portion of contiguous recoverable reserves judged with reasonable certainty to exist based upon geological, geophysical and similar information.

Initial volume in place: the gross volume of crude oil, crude bitumen or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.

Initial established reserves: established reserves prior to the deduction of any production.

Remaining established reserves: initial established reserves less cumulative production.

Ultimate potential: an estimate of the initial established reserves that will have been developed in an area by the time all petroleum exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions to reserves through extensions and revisions to existing pools and the discovery of new pools.

The term "established" to describe reserves has been adopted in Canada, and replaced the combined categories of **proved** and **probable reserves** previously defined by the Canadian Petroleum Association (CPA). Most other countries continue to use the expression **proved reserves** (or **proven reserves**). The proved (or established) reserves category may be subdivided in various ways, with two pairings given below.

Developed reserves: proved reserves considered recoverable through existing wells.

Undeveloped reserves: economically recoverable reserves considered to exist in proved reservoirs and which will be recovered from wells drilled in the future.

Connected reserves: oil reserves connected by an unbroken series of gathering and trunk pipelines to a refinery, or natural gas reserves connected to a pipeline.

Unconnected reserves: oil and gas reserves which are not connected to the market.

Petroleum Deposits

Reservoir: a porous, permeable sedimentary rock containing commercial quantities of oil and/or natural gas.

Pool: a natural underground reservoir containing an accumulation of oil and/or natural gas separated, or appearing to be separated, from any other such accumulation.

Field: may refer to a certain geographical area from which petroleum is produced or to a particular underground producing zone. A field may contain one or more pools linked by some common element, such as their lying along the same trend or their being a product of a common geographical disturbance.

Petroleum Production

Maximum efficient rate (MER): the maximum rate at which oil can be produced without damaging the reservoir and causing avoidable underground waste.

Good production practice: production of crude oil or raw natural gas at a rate limited to what can be produced without adversely affecting resource conservation or the opportunity of each owner in the pool to obtain his share of production.

Under favourable conditions, roughly 10% of the oil remaining in a reservoir can be produced over a year, but the rate can be considerably lower if the oil is viscous, if reservoir permeability is low or if the rate of production must be restricted to prevent damage to the reservoir (for example, by water penetration).

Not all of the oil or gas initially present in a reservoir can be "recovered" or extracted in the production process. Although the **recovery factor** can vary markedly from one reservoir to another, a rough guideline is that one-third of the oil initially in place in a conventional oil reservoir is recoverable and about three-quarters of the gas in place in a natural gas reservoir is recoverable. These factors have been gradually improving as production technology advances.

To increase the recovery factor, **natural recovery mechanisms** may be augmented by sophisticated methods of **enhanced recovery**. This introduces a final group of definitions.

Drive: the displacement of crude oil and natural gas through the pore spaces of a reservoir rock towards a well bore, as a result of the expansion of reservoir fluids or movements of fluids under pressure towards areas of lower pressure. This drive may be caused by the influx of underground water as the oil or gas is produced (water drive), by gas coming out of solution in the oil (solution gas drive), or by the expansion of free gas in a gas cap (gas-cap drive).

Primary recovery: Oil or gas produced as a result of natural drive in the reservoir. The flow of oil to the surface may occur naturally (flowing well) or may be accomplished by mechanical pumping (pumping well).

Pressure maintenance: The injection of a fluid, most commonly water or natural gas, to maintain reservoir pressure which would otherwise be depleted during production.

Water flooding, the most extensively used and least costly form of pressure maintenance, involves injecting water into a reservoir through intake wells to drive the oil towards production wells.

Gas injection is frequently used because natural gas is soluble in oil, increasing its volume, decreasing its viscosity, reducing its surface tension and lessening its specific gravity – all desirable effects in boosting recovery.

Enhanced oil recovery (EOR): advanced methods for recovering oil from a reservoir, which increase the recovery factor and which allow a broader range of reservoirs to be exploited. These techniques may include the injection of miscible solvents such as LPG and carbon dioxide into the reservoir, the addition of heat through steam injection or in situ combustion, and the addition of chemicals to act as wetting agents. EOR techniques are expensive and sensitive to the price of oil.

Components of a typical natural gas

Hydrocarbon and % by Weight	
Methane (CH_4)	70-98%
Ethane (C_2H_6)	1-10%
Propane (C_3H_8)	trace-5%
Butane (C_4H_{10})	trace-2%
Pentane (C_5H_{12})	trace-1%
Hexane (C_6H_{14})	trace-1/2%
Heptane + (C_7H_{16}+)	none-trace
Nonhydrocarbon and % by Weight	
Nitrogen	trace-15%
Carbon dioxide*	trace-1%
Hydrogen sulphide*	occ. trace
Helium	none-5%

* Natural gases are occasionally found which are predominantly carbon dioxide or hydrogen sulphide.

Source: McCain, 1973, p. 4.

Composition of a typical 35° API crude

Molecular Size and % by Volume	
Gasoline (C_5 to C_{10})	27%
Kerosine (C_{11} to C_{13})	13%
Diesel fuel (C_{14} to C_{18})	12%
Heavy gas oil (C_{19} to C_{25})	10%
Lubricating oil (C_{26} to C_{40})	20%
Residuum (more than C_{40})	18%
Total	**100%**

Source: Hunt, 1979, p. 43.

A GLOBAL PERSPECTIVE

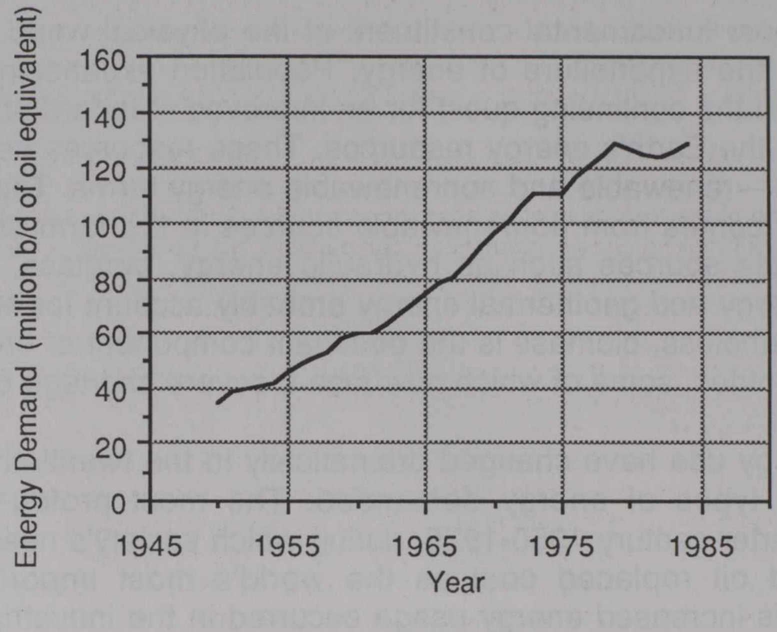
A. International Patterns of Energy Supply and Demand

Energy is the most fundamental constituent of the physical world. No activity can take place without the expenditure of energy. Population expansion, the global trend to urbanization and the continuing quest for an improved standard of living place increasing demands on the Earth's energy resources. These resources belong to one of two broad categories – renewable and nonrenewable energy forms. Today, most of society's energy supply comes from nonrenewable sources in the form of fossil fuels and uranium. Renewable sources such as hydraulic energy, biomass, direct solar radiation, wind, tidal energy and geothermal energy probably account for about 20% of world energy use. Nonetheless, biomass is the dominant component of energy supply in many developing countries, some of which now face a severe shortage of fuelwood.

Patterns of energy use have changed dramatically in the twentieth century, in both the quantity and types of energy demanded. The most profound changes occurred during the quarter-century 1950-1975, during which society's need for energy more than tripled and oil replaced coal as the world's most important energy commodity. Much of this increased energy usage occurred in the industrialized world and global inequalities in per capita energy consumption have widened in the postwar period to extraordinary levels. Per capita consumption of commercial energy in Canada stands slightly higher than that of the United States, 1.8 times that of West Germany, twice that of the United Kingdom, 2.5 times that of France or Japan, 15 times that of Brazil or mainland China, and 480 times that of Chad or Ethiopia (United Nations, 1986).

Figure 1 shows the growth in global demand for commercial primary energy since 1950, based on United Nations statistics and expressed in millions of barrels/day of oil equivalent. "Commercial energy" refers to energy which is commercially traded, and includes crude oil, natural gas, coal and primary electricity (hydro-, nuclear- and geothermal-electricity). Excluded from Figure 1 is the exploitation of biomass – fuelwood, peat, agricultural wastes and dung – as an energy source. Reliable statistics on biomass consumption are not available because much of it is collected by users and not commercially traded. Rudimentary data suggest that biomass may contribute an additional 15% to the commercial use of energy pictured in Figure 1. "Primary energy" refers to energy as extracted or produced at the wellhead, mine or hydro-electric station; that is, energy measured at the point of production. The term "oil equivalent" indicates that energy forms such as natural gas and electricity have been expressed as equivalent quantities of oil, based upon their energy content. By this measure, world demand for commercial primary energy had grown to about 130 million barrels/day of oil equivalent by 1984, according to the U.N. If all of the Earth's population consumed energy at the same per capita rate as Canadians, the total demand for commercial primary energy would have stood at approximately 685 million barrels/day of oil equivalent in 1984.

Figure 1: The Global Demand for Commercial Primary Energy



Notes: 1. Recent U.N. data are given in millions of tonnes of oil equivalent and are here converted to millions of barrels of oil equivalent, using the approximate conversion factor 1 tonne of oil = 7.33 barrels. Older U.N. data are given only in millions of tonnes of coal equivalent and have been converted to oil equivalent using 1 tonne of coal equivalent x 0.687623 = 1 tonne of oil equivalent.

2. U.N. data include unallocated energy use – which primarily refers to data that cannot be attributed to one of the solid, liquid, gaseous or electrical energy categories – and the non-energy use of petroleum. Consumption also includes international aviation and marine bunkers.

Source: United Nations, 1986, p. 33; 1984, p. 51; 1983, p. 93; 1981, p. 39; and 1976, p. 2-3.

Global energy demand rose throughout the postwar era until the second oil price shock of 1979-80, which temporarily reduced demand and caused a substantial drop in oil consumption in the industrialized world. It remains to be seen how much the exponential rate of growth in energy consumption, which characterized the 1950-1973 period, has been permanently modified. The World Commission on Environment and Development (1987, p. 172) has observed that the continuation of these earlier high rates of growth in energy use would magnify four particularly disturbing environmental concerns:

- the likelihood of climatic change generated by the "greenhouse effect" of gases emitted to the atmosphere, the most important of which is carbon dioxide produced from the combustion of fossil fuels;

Valuing Electricity in Reporting Energy Supply and Demand

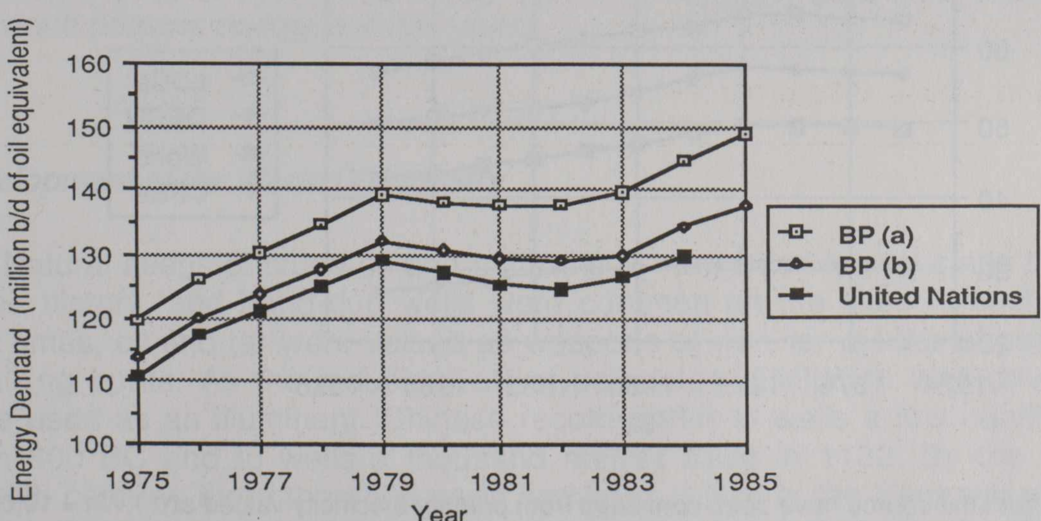
With the exception of countries like Canada and Norway, where the electrical system is primarily based on hydro-electric generation, nations produce most of their electricity by thermal generation using coal, oil, natural gas or uranium as fuel. For thermodynamic reasons, thermal power plants release about two units of heat for each unit of electricity produced. Should thermal electricity be valued in terms of the three units of energy needed in its manufacture (its "fossil fuel equivalence") or the one unit of electricity produced (its "energy output")?

Many agencies have adopted the convention of reporting all electricity – including hydropower – as if it were thermal electricity valued in terms of the fossil fuel that would be required to produce it (about 10,000 Btu/kWh or 10,550 kilojoules/kWh), instead of the true value of its energy content (3,412 Btu/kWh or 3,600 kJ/kWh). This statistical convention is useful for making certain international comparisons but it overstates energy demand in Canada and it inflates the role of hydro-electricity. Hydropower satisfied 12.1% of Canada's primary energy demand in 1985 measured by its energy output value, but 27.5% measured by its fossil fuel equivalence value.

This distinction is important because of the apparent discrepancies introduced in statistical reporting. Comparing per capita energy consumption between Canada and the United States, for example, the values are approximately equal when hydro-electricity is measured by its energy output, but Canada is significantly higher when hydropower is valued at its fossil fuel equivalence. EMR usually reports hydro-electricity by its fossil fuel equivalence; Statistics Canada uses the energy output value. Further complicating matters, both EMR and the NEB have begun reporting nuclear-electricity at a value of 12,100 kJ per kWh (approximately 11,480 Btu/kWh), reflecting the fact that Canadian nuclear reactors are about 30% efficient in producing electricity. This report adopts the energy output approach – valuing all electricity production at 3,412 Btu/kWh – because the Committee believes that this gives a clearer picture of energy supply and demand.

International statistics show the same divergence. United Nations data, for example, report electricity at 3,412 Btu per kWh while British Petroleum, in its *Statistical Review of World Energy*, reports electric energy at 10,000 Btu per kWh. The following illustration shows how this affects a compilation of world energy use. The difference between U.N. and BP reporting was roughly 15 million barrels/day of oil equivalent in 1984. Note that the two data sets do not fully correspond, even after conversion to a common basis for reporting primary electricity.

The Global Demand for Commercial Primary Energy, as Reported by BP and by the United Nations



BP (a): British Petroleum data with primary electricity valued at 1 kWh = 10,000 Btu.
BP (b): British Petroleum data converted to value primary electricity at 1 kWh = 3,412 Btu.

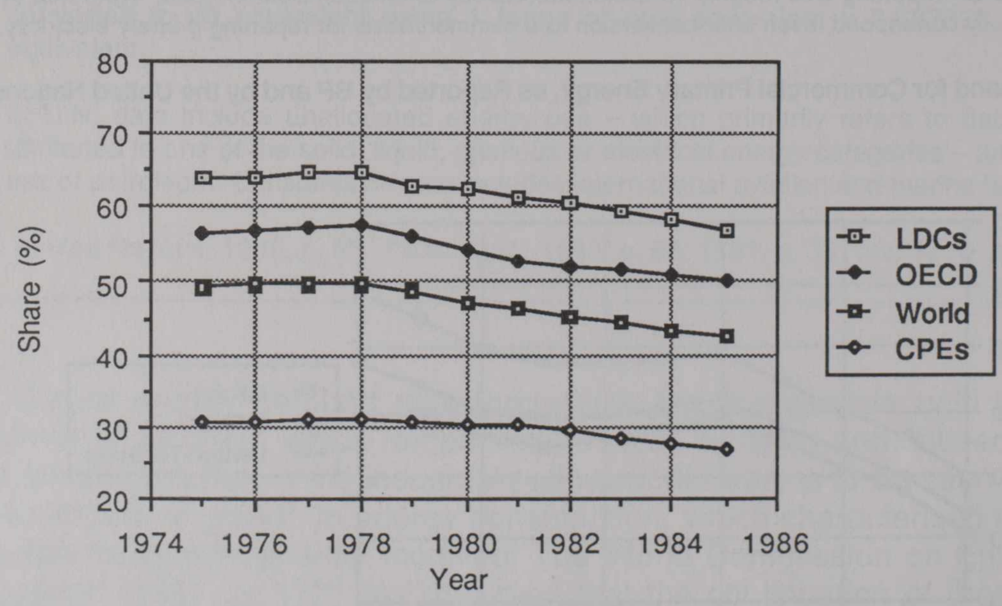
- urban-industrial air pollution caused by atmospheric pollutants from the combustion of fossil fuels;

- acidification of the environment arising from the combustion of fossil fuels; and

- risks of nuclear reactor accidents, problems of radioactive waste disposal and dismantling reactors at the end of their service life, and the dangers of nuclear weapons proliferation associated with the use of fission energy.

Oil is thought of as the energy commodity that fuels the industrialized world, and it is true that Western industrialized countries today consume nearly 60% of global oil output. It is less commonly recognized that, in the developing world, oil accounts for a larger share of commercial energy demand on average than it does in the more diversified energy systems of the industrialized nations or in the more coal-oriented Communist countries. Figure 2 tracks the change in oil's share of primary energy demand since 1975, both globally and as subdivided into three component parts: the Organization for Economic Co-operation and Development (OECD), the less developed countries (LDCs, including OPEC) and the centrally planned economies (CPEs or Communist countries).

Figure 2: The Share of Oil in OECD, LDC, CPE and World Primary Energy Demand



Note: Data from the source have been converted from primary electricity valued at 1 kWh = 10,000 Btu to 1 kWh = 3,412 Btu.

Source: British Petroleum, 1986, p. 7-8, 28, 30, 33-34.

Figure 2 reveals that oil's share of world commercial energy use fell from 49% in 1975 to 42% in 1985. Viewed by region, oil's share of LDC primary energy demand declined over the same period from 64% to 57%; of OECD energy demand from 56% to 50%; and of CPE energy demand from 31% to 27%. In each region, the decline began in 1979 and continued through 1985.

Although oil's share of energy use has fallen around the world, the consumption of oil actually increased throughout this period in the LDCs. In the OECD (and to a minor extent in the CPEs which are essentially self-sufficient as a bloc), oil consumption dropped in response to high prices and concern about security of supply. The nations of the developing world, however, have not all displayed similar behaviour. Demand for oil fell in Latin America after the second price shock, but not in the Middle East, Far East or Africa. Figure 3 illustrates these differences.

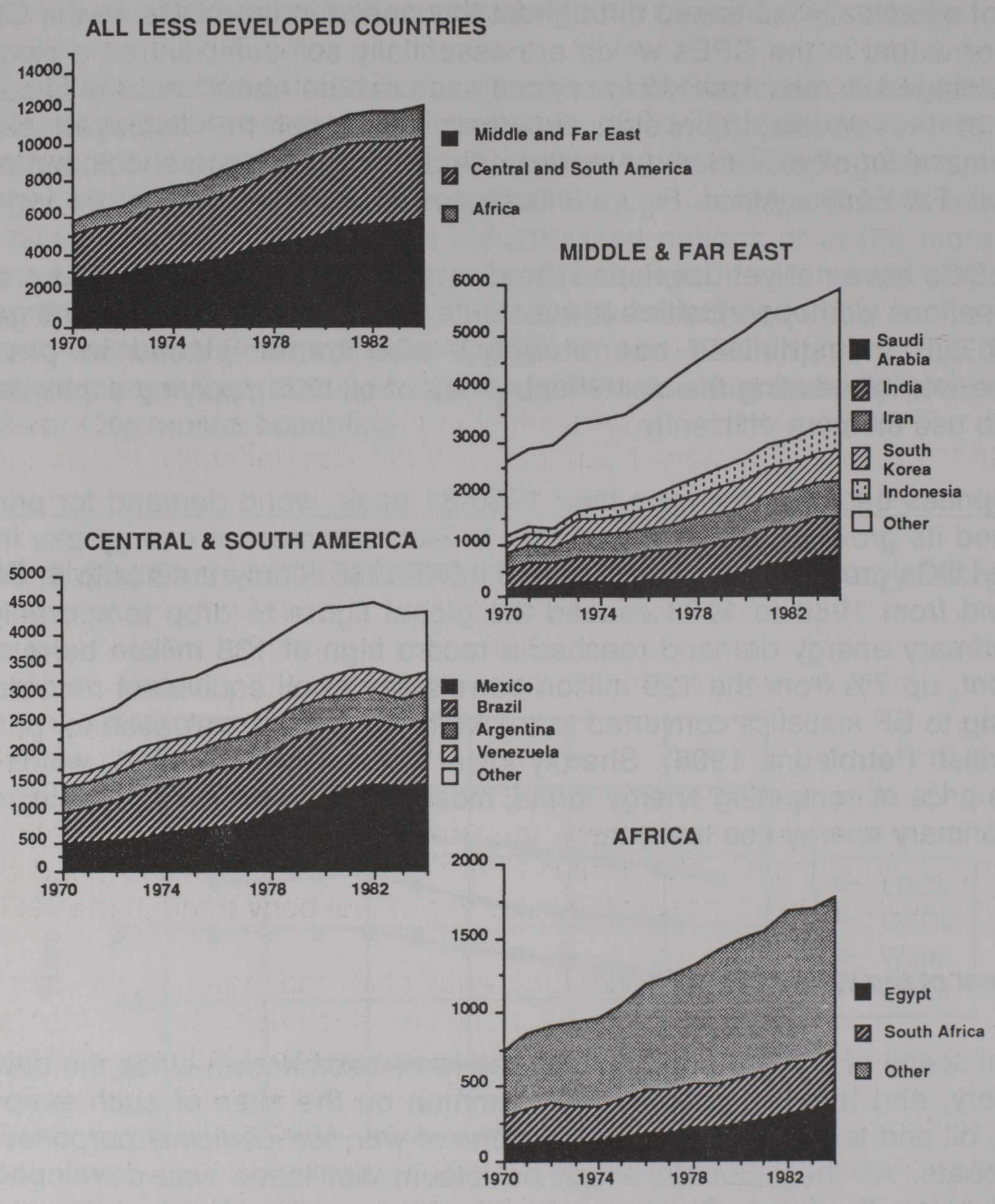
Most LDCs have not yet developed the diversified energy systems that provide industrialized nations with opportunities to substitute other fuels such as natural gas or electricity for oil. Industrialized countries are also better placed to practice conservation, either in reducing the discretionary use of oil or in applying sophisticated technologies to use oil more efficiently.

As oil prices began to fall from their 1980-81 peak, world demand for primary energy resumed its growth, beginning in 1983. In fact, commercial energy use in the CPEs and the LDCs grew throughout the period 1975-1985 – only the slump in OECD energy demand from 1980 to 1983 caused the global figure to drop temporarily. In 1985, world primary energy demand reached a record high of 138 million barrels/day of oil equivalent, up 7% from the 129 million barrels/day of oil equivalent recorded in 1982 (according to BP statistics converted to a 1 kWh = 3,412 Btu valuation for primary electricity) (British Petroleum, 1986). Sharply lower prices for oil in 1986, which also depressed the price of competing energy forms, most probably led to a further increase in total world primary energy use last year.

B. Development of the World Oil Industry

Natural seeps of crude oil and natural gas have been known since the dawn of recorded history, and hand-dug wells were common on the sites of such seeps. In ancient times, oil and tar were valued as weapons of war, for medicinal purposes and for caulking boats. As the industrial art of petroleum distillation was developed, oil became used as an illuminant. Chinese records refer to wells a few hundred metres deep in 600 BC and to wells a thousand metres deep in 1132. By the end of the eighteenth century, more than 500 wells had been drilled in the Yenangyuang oil field in Burma. There was early development of the petroleum industry in the Soviet Union when the oil and gas deposits of the Baku fields were exploited in the latter part of the nineteenth century. (Hunt, 1979; Riva, 1987a)

Figure 3: Oil Consumption in the Less Developed Countries (thousands of barrels per day)



Source: U.S. Department of Energy, 1987, p. A-7.

Although North America's first oil well was reportedly completed in Enniskillen Township in Ontario in 1858, it was Edwin Drake's well drilled at the Titusville, Pennsylvania seep in 1859 that is credited with launching the North American petroleum industry. This event also marks the beginning of the modern petroleum era – by 1871, more than 90% of the world's oil output was centred in the Pennsylvania fields opened by Drake's well. (Hunt, 1979)

The world's first 200 billion barrels of crude oil were produced in the 109 years between Drake's 1859 well and the year 1968. The next 200 billion barrels were extracted in a single decade, 1969-1978. With the stabilization of world oil output in the 1980s, it appears that the 1979-1988 decade will see the production of roughly another 200 billion barrels. This cumulative 600-billion-barrel output is estimated to represent more than one-third of the world's total original endowment of conventional crude oil.

For much of the 130-year modern history of the petroleum industry, the governments of producing countries had comparatively little influence over the development and management of the international oil business. As the industry grew, it was the major oil companies (the "majors") that controlled it, partly in their own right and partly with the help of their parent countries in what was generally perceived to be a loose alliance of interests.

Louis Turner, in his analysis of the international oil industry, suggests that the period 1954-1970 was the "golden age" of the industry, at least from the perspective of the multinational oil companies (Turner, 1983). The companies successfully coped with two major supply disruptions during these years – the Suez War of 1956-57, which saw the closure of the Suez Canal and Iraq Petroleum Company (IPC) pipelines, and the June 1967 Arab-Israeli War, during which the Suez Canal, the Trans-Arabian Pipeline (Tapline) and the IPC pipeline system were shut down. Generally the petroleum companies were free from restraint in their operations by either host or parent countries. The formation of OPEC in 1960 was a cloud on the horizon but the majors resisted most of the initiatives of that body through the 1960s.

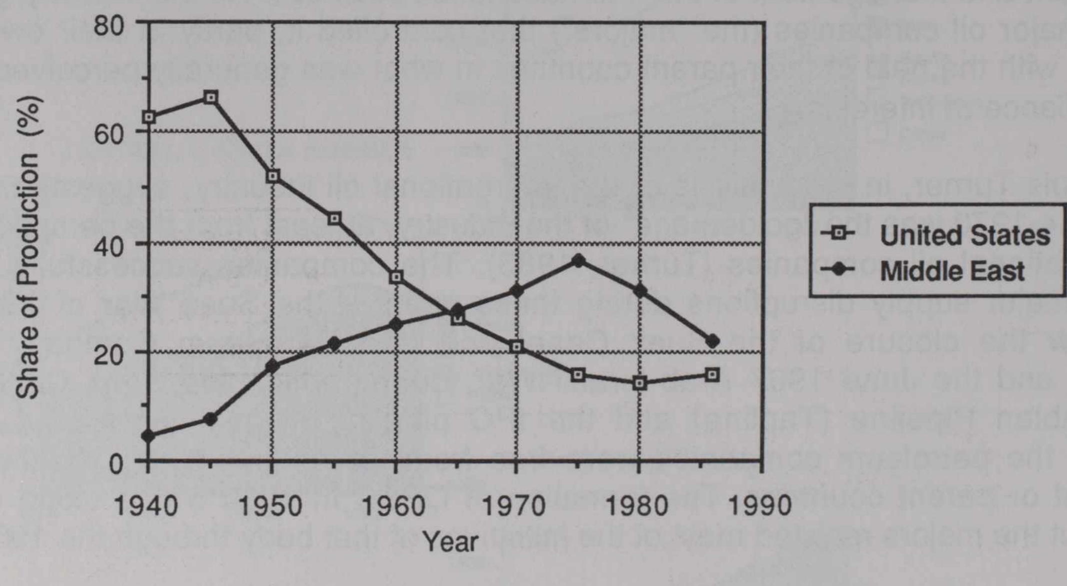
Oil became in the twentieth century what coal had been to the Industrial Revolution. Oil fueled the internal combustion engine, which ushered in a new age of mobility. The development of refining spawned a new chemical industry. Oil became the leading commodity in international trade and commercial empires of enormous wealth were created. American oil companies were established early in this period and became among the most prominent on the world oil scene. Much has been written about the multinational oil companies – Exxon, Royal-Dutch/Shell, Mobil, Texaco, Standard Oil of California, Gulf and British Petroleum – the "Seven Sisters", which held dominion over the business for so long.

Less often considered are the national oil companies, some of which have been industry participants for many years, including Compagnie Française de Pétroles (CFP) and Société Nationale Elf-Aquitaine (SNEA) of France and Ente Nationale

Idrocarburi (ENI) of Italy. Other national oil companies were creations of the turbulent 1970s: Veba in West Germany, STATOIL in Norway, the British National Oil Company (BNOC) and Petro-Canada.

The United States dominated oil production throughout most of the modern petroleum era. At the close of World War II, the U.S. was not only the world's largest producer but its output exceeded that of all other producers combined. As recently as 1963, the United States still accounted for more than half of all the crude oil that had ever been lifted. Figure 4 indicates the extent to which the United States has relinquished its share of world oil production since World War II. The growing importance of Middle East crude in world supplies is also shown.

Figure 4: The U.S. and Middle East Shares of World Crude Oil Production since 1940



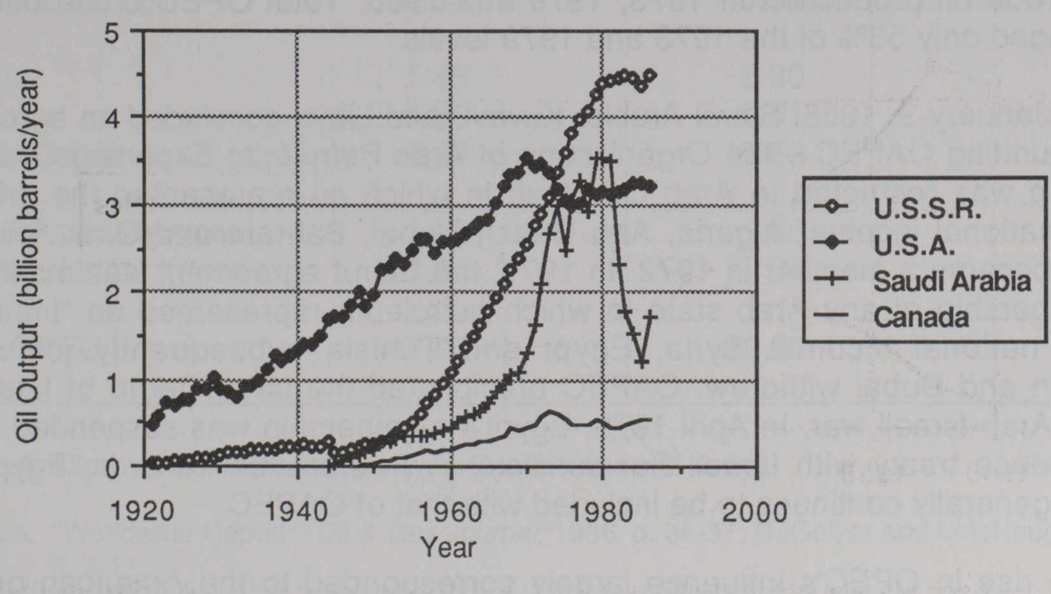
Sources: DeGolyer and MacNaughton, 1985, p. 3-5 and 9; "Worldwide Report", *Oil & Gas Journal*, 1986, p. 36-37.

U.S. crude oil liftings peaked in 1970; even the development of the supergiant Prudhoe Bay oilfield in Alaska has not allowed the United States to reclaim that height of production. World crude output attained a rate of 22.7 billion barrels annually in 1979, at the time of the second price shock, and has not regained that level since.

Although the United States stands second in oil output – at 8.8 million barrels/day on average in 1986, behind the Soviet Union at 12.3 million barrels/day – it is straining its productive capacity and appears to be entering a decline exacerbated by the fall in world oil prices. Middle East output, at about 12.3 million barrels/day in 1986, equalled Soviet production but this region had been lifting 18.2 million barrels/day in 1980.

Figure 5 compares the oil production of the United States, the U.S.S.R., Saudi Arabia and Canada. Soviet output has risen almost continually since early in the century. The small decline in Soviet production in 1984 and 1985 was turned around in 1986 and Soviet output is expected to show a further increase during 1987. Nonetheless, the Soviet Union is considered to be approaching the peak in its capacity to produce conventional crude oil. U.S. liftings, after peaking in 1970, showed a secondary rise when Prudhoe Bay oil entered the market in 1977. American production is expected to show a continuing decline in the future.

Figure 5: Soviet, U.S., Saudi Arabian and Canadian Oil Production since 1920



Sources: DeGolyer and MacNaughton, 1985, p. 5, 7, 9; "Worldwide Report", *Oil & Gas Journal*, 1986, p. 36-37.

The huge drop in Saudi Arabian output following the second price shock was not caused by any physical constraint in productive capacity. It reflects a reduction in demand overall for oil and recent Saudi policy to voluntarily restrict its own output. The subsequent upturn in Saudi Arabian production reflects the current intent to regain market share. Canada's annual output is also presented in Figure 5. In recent years, Canada has typically stood in about tenth position in world crude oil production.

The Organization of Petroleum Exporting Countries was formed in 1960. Prior to its creation, control of the world petroleum business lay primarily in the hands of the major oil companies. Prices were established through a distributors' cartel. With the aim of gaining a better price for their oil and improving their negotiating position with the majors, a number of oil-producing countries held discussions concerning a united pricing and production policy, culminating in the formation of OPEC on September 10, 1960, in Baghdad. The five founding countries were Saudi Arabia, Kuwait, Iran, Iraq and Venezuela.

A decade was to pass before OPEC would be able to exert much influence on the world oil scene. Throughout most of the 1960s, the price of Saudi Arabian light crude oil, the world benchmark crude, remained fixed by the oil companies at US$1.80 per barrel.

Today, OPEC membership stands at 13: Saudi Arabia, Kuwait, Iran, Iraq, the United Arab Emirates (UAE, with the principal oil-producing members being Abu Dhabi, Dubai and Sharjah), Qatar, Libya, Algeria, Nigeria, Gabon, Venezuela, Ecuador and Indonesia. Table 1 shows the 13 member states of OPEC and their estimated levels of crude oil production in 1973, 1979 and 1986. Total OPEC crude output in 1986 averaged only 58% of the 1973 and 1979 levels.

On January 9, 1968, Saudi Arabia, Kuwait, and Libya concluded an agreement in Beirut founding OAPEC – the Organization of Arab Petroleum Exporting Countries. Membership was restricted to Arab countries in which oil represented the principal source of national income. Algeria, Abu Dhabi, Dubai, Bahrain and Qatar joined in 1970; Iraq became a member in 1972. In 1971, the Beirut agreement was modified to allow membership of any Arab state in which petroleum represented an "important" source of national income. Syria, Egypt and Tunisia subsequently joined the organization and Dubai withdrew. OAPEC precipitated the oil embargo of late 1973 during the Arab-Israeli war. In April 1979, Egypt's membership was suspended after it signed a peace treaty with Israel. For consistency in statistical records, Egypt's oil production generally continues to be included with that of OAPEC.

The rise in OPEC's influence largely corresponded to the American decline. U.S. crude oil output reached its highest level in 1970, when production totalled 3.52 billion barrels (equivalent to an average output over the year of 9.64 million barrels/day). American production of all oils, including natural gas liquids, totalled 4.13 billion barrels in 1970, or 11.31 million barrels/day on average. At the time of the Arab oil embargo, the United States was importing more than 35% of its oil requirements.

The income which OPEC has derived from the export of oil since 1965 is displayed in Figure 6. Values are expressed in billions of current U.S. dollars. Over the period 1973 through 1986, oil exports earned OPEC more than US$2.1 trillion. This enormous transfer of wealth has been one of the factors contributing to the current external debt load of US$1.1 trillion burdening the developing countries and stressing the world banking system.

Table 1: OPEC Member States and Their Crude Oil Production in Selected Years

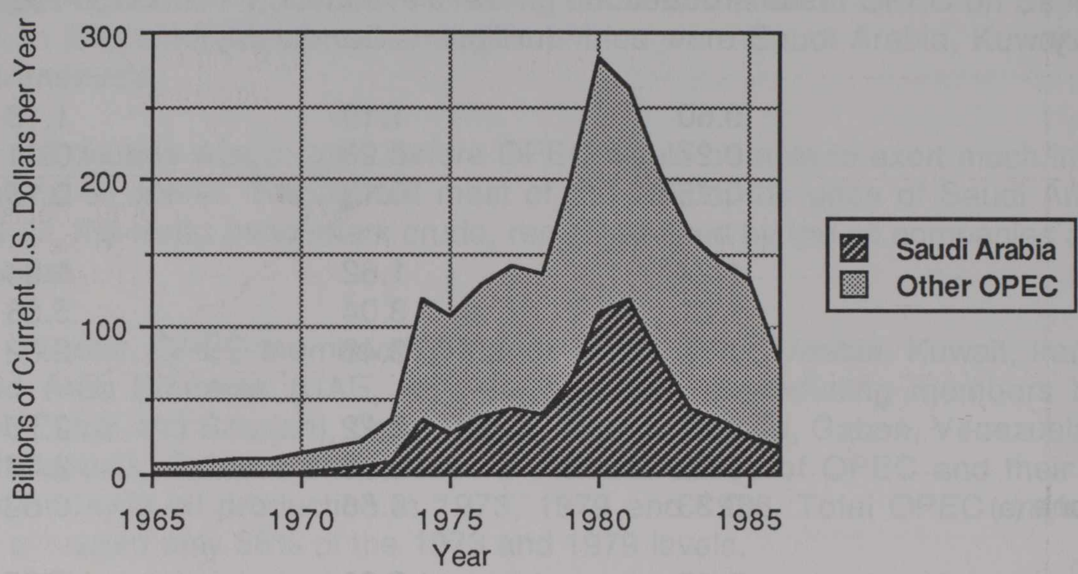
Country	1986 Production	1979 Production (millions of barrels/day)	1973 Production
Algeria	0.60	1.19	1.10
Ecuador	0.27	0.20	0.21
Gabon	0.15	0.19	0.15
Indonesia	1.24	1.62	1.34
Iran	1.81	3.04	5.86
Iraq	1.79	3.48	2.02
Kuwait	1.20	2.22	2.76
Libya	1.03	2.08	2.17
Neutral Zone (a)	0.33	0.56	0.52
Nigeria	1.46	2.30	2.05
Qatar	0.33	0.51	0.57
Saudi Arabia	4.72	9.63	7.33
United Arab Emirates	1.38	1.53	1.53
Venezuela	1.66	2.36	3.37
Total OPEC	**17.97**	**30.91**	**30.98**

(a) Neutral Zone output is shared equally by Saudi Arabia and Kuwait.

Sources: "Worldwide Report", *Oil & Gas Journal*, 1986, p. 36-37; DeGolyer and MacNaughton, 1985, p. 6, 9-11.

The export of crude oil earned OPEC almost US$8 billion in 1965. In 1973, those exports earned US$37 billion, a figure which jumped to US$119 billion the following year. The second price shock caused OPEC revenues to surge from US$135 billion in 1978 to US$282 billion in 1980. By 1985, oil revenue had sagged to US$132 billion, as prices eroded in the face of growing non-OPEC output and reduced demand in the industrial world, forcing OPEC members to discount the price of their oil. OPEC revenues are estimated at US$75 billion in 1986, driven down by the unprecedented price plunge. At an average selling price of US$18 per barrel, the current OPEC target, and assuming that 1987 quotas are adhered to by member states, OPEC projects 1987 oil export revenue at US$86 billion. If the higher oil prices of recent months are sustained, however, 1987 revenue could regain the US$100 billion level.

Figure 6: The Rise and Fall of OPEC Crude Oil Export Revenues



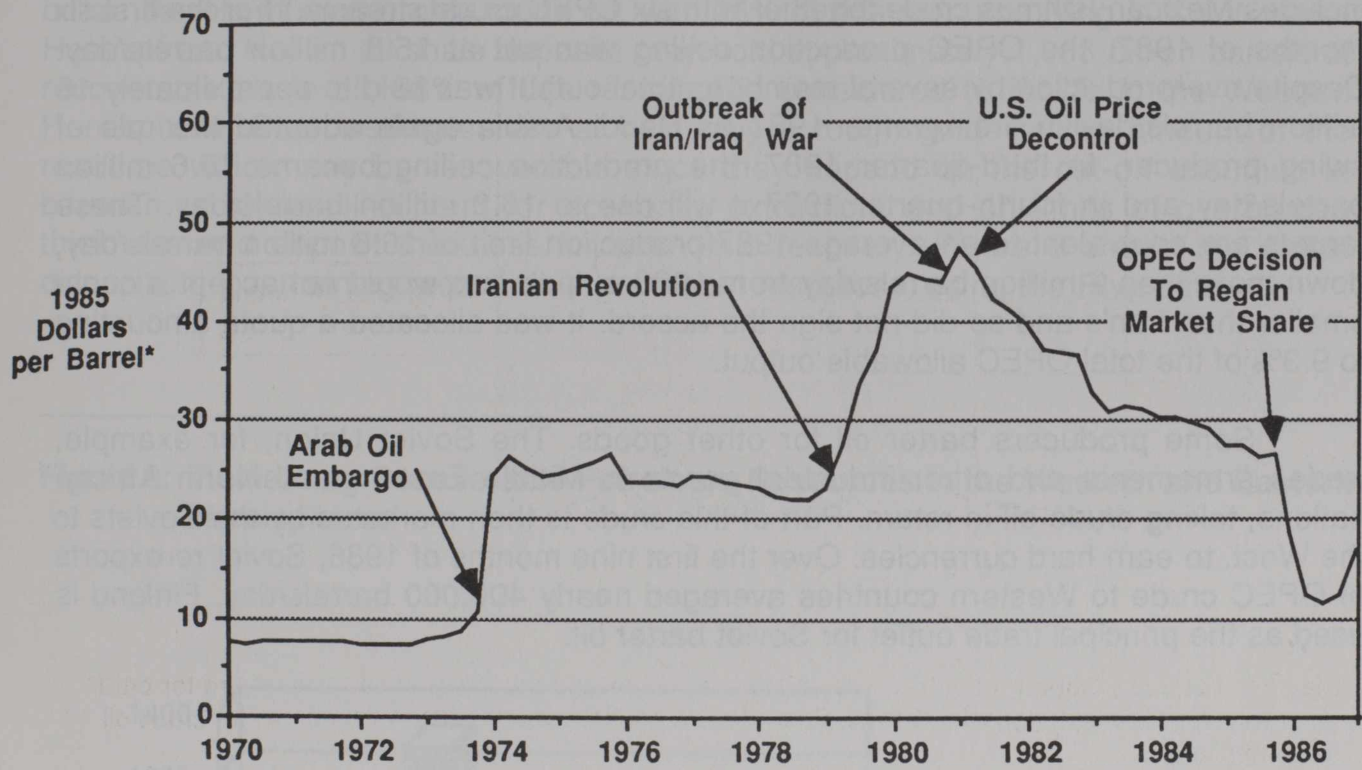
Note: For Ecuador, Gabon, Iran, Iraq, Libya, Nigeria, Qatar and the UAE, export values are for crude oil only; for Algeria, Indonesia, Kuwait, Saudi Arabia and Venezuela, export values are for crude oil and equivalent.

Sources: OPEC, undated, p. 6; "The Tide Turns for OPEC Revenues", *Petroleum Economist*,1987, p. 256.

Figure 7 charts the constant-dollar price of oil since 1970 and shows the price shocks of 1973-74, 1979-80 and 1985-86. Price is defined as the average quarterly cost of oil imported by U.S. refiners and is expressed in constant 1985 US dollars per barrel. At the bottom of the price decline in 1986, crude oil sold for only a few dollars more per barrel, in real terms, than it had in the early 1970s.

Oil pricing has become a complicated matter in recent years. During most of the 1970s, less than 5% of internationally traded crude oil is estimated to have been sold on the spot market. In the first half of the 1980s, however, spot selling proliferated and, over brief periods, as much as 70% of world crude trading took place at spot or spot-related prices. This phenomenon was followed by the collapse of the "fixed" price system late in 1985, as "netback", "formula" and "retrospective" pricing schemes were introduced, led by Saudi Arabia's netback pricing initiative. For much of 1986, netback prices competed with spot prices in the market. Except in a few countries like Canada, the United States, Egypt and Malaysia, "official" or company "posted" prices virtually disappeared.

Figure 7: World Crude Oil Prices Since 1970, Measured in Constant 1985 US Dollars



Note: Price is defined as the average quarterly cost of crude oil imported by U.S. refiners, expressed in 1985 dollars.

Source: U.S. Department of Energy, 1987, p. 15.

Crude Oil Pricing

A **netback** price for crude oil is based on the spot value at the refinery gate of the slate of products derived from the crude, minus transportation, insurance, financing and processing costs. The guaranteed margin to refiners drew more oil into the market, helping OPEC to regain some of its former market share but contributing to the collapse in oil prices. OPEC abandoned netback pricing to return to a fixed price system in February of 1987.

Formula pricing links the selling price of a crude oil to selected spot market crude quotations, combining reduced market risk with a reasonable return to refiners. For example, Mexico's light Isthmus crude sold into the United States is tied to the spot prices of West Texas Intermediate crude, West Texas Sour crude, Alaskan North Slope crude and heavy fuel oil, with a further price differential per barrel.

In **retrospective** pricing, the seller fixes the price of the crude oil after it reaches its destination, using predetermined links with certain crude spot prices.

Source: EMR, 1987c, p. 37-40.

In December 1986, the members of OPEC (apart from Iraq) agreed to re-establish a fixed price structure, effective February 1, 1987, and to set production quotas for 1987. A price of US$18 per barrel, derived from a basket of seven crude oils, was set as the reference price for crude above 26° API. (Interestingly, this basket includes Mexican Isthmus crude together with six OPEC crude streams.) For the first six months of 1987, the OPEC production ceiling was set at 15.8 million barrels/day. Despite overproduction by several members, total output was held to approximately 16 million barrels/day in first-quarter 1987 as Saudi Arabia again adopted the role of swing producer. In third-quarter 1987, the production ceiling became 16.6 million barrels/day and in fourth-quarter 1987 it will rise to 18.3 million barrels/day. These targets are equivalent to an average 1987 production limit of 16.6 million barrels/day, down more than 2 million barrels/day from 1986 output. Iraq would not accept a quota smaller than Iran's and so did not sign the accord. It was allocated a quota amounting to 9.3% of the total OPEC allowable output.

Some producers barter oil for other goods. The Soviet Union, for example, trades armaments and other industrial goods to Middle Eastern and North African nations, taking crude oil in return. Part of this crude is then marketed by the Soviets to the West, to earn hard currencies. Over the first nine months of 1986, Soviet re-exports of OPEC crude to Western countries averaged nearly 400,000 barrels/day. Finland is used as the principal trade outlet for Soviet barter oil.

C. World Petroleum Resources and Reserves

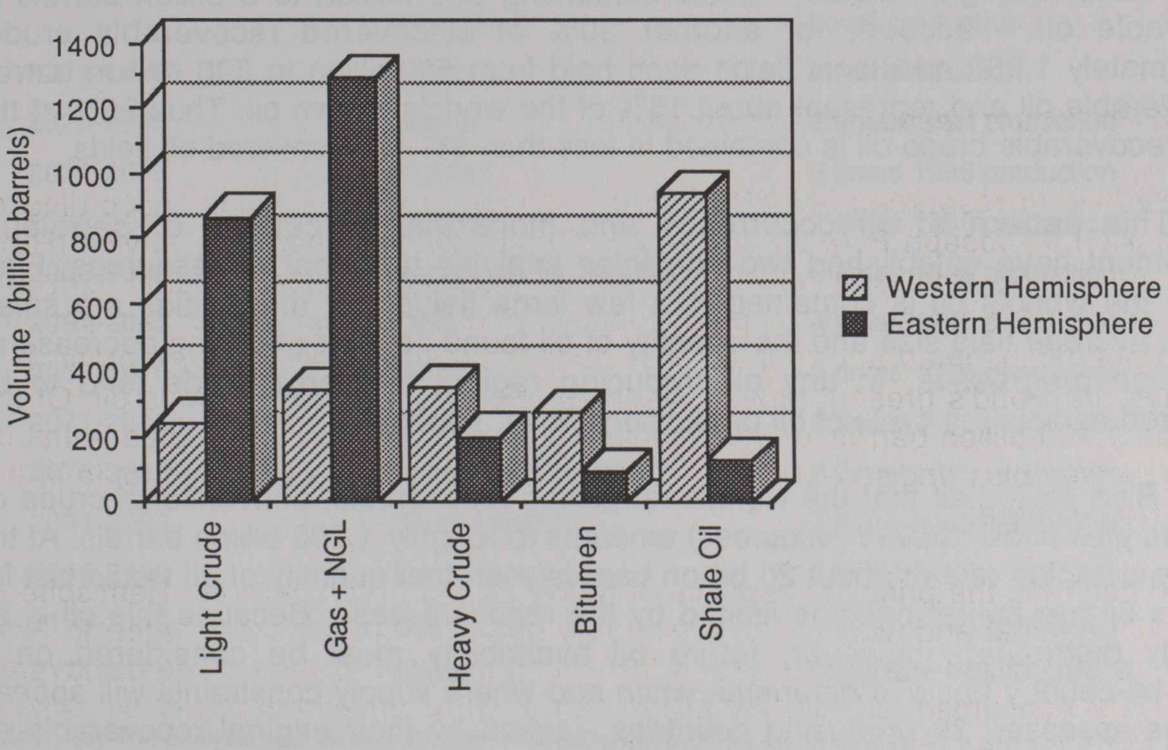
Petroleum resources are distributed irregularly over the globe. According to data compiled by Joseph Riva Jr. of the U.S. Congressional Research Service (Riva, 1987a), the world's total original endowment of recoverable, conventional light and medium crude oil is assessed at approximately 1,635 billion barrels. Of this amount, 32% has been consumed and roughly 30% remains to be discovered. The other 38% constitutes the world's present proved reserves of conventional light crude oil. Of the more than 1,100 billion barrels of light-medium crude oil yet to be consumed – that is, proved reserves plus undiscovered oil – 78% of this amount is calculated to lie in the Eastern Hemisphere.

In contrast, the principal deposits of heavy oils lie in the Western Hemisphere. The world's original endowment of recoverable heavy crude oil is estimated to have been about 608 billion barrels, of which 85% is considered to have been discovered but only 11% consumed. Of the 540 billion barrels of unconsumed heavy oil, 64% is believed to be located in the Western Hemisphere.

The world's total original endowment of recoverable natural gas has been estimated to contain an amount of energy equivalent to 1,897 billion barrels of oil, including a calculated 341 billion barrels of natural gas liquids. Roughly half of this resource is thought to have been discovered and about 14% consumed. Of the remaining gas and gas liquids resource, approximately 79% is believed to be located in the Eastern Hemisphere.

Known bitumen deposits are estimated in the Riva study to contain roughly 354 billion barrels of recoverable crude oil, with 76% of this resource lying in the Western Hemisphere. Known oil shale deposits may hold approximately 1,066 billion barrels of recoverable shale oil; 88% of this resource is considered to reside in the Western Hemisphere. Such estimates are at best only a rough guide to the amount of the resource which may be recoverable since they depend on the cut-off assumed in bitumen or shale oil content for economic extraction, and on limits of overburden thickness and deposit thickness for economic recovery. Figure 8 shows the global disposition of remaining recoverable petroleum resources, using the Riva data.

Figure 8: Remaining Recoverable Petroleum Resources in the Western and Eastern Hemispheres



Source: Riva, 1987a, p. 588.

Riva concludes that the world's total original endowment of recoverable petroleum was roughly equivalent to 5,560 billion barrels of oil. Subtracting the natural gas component, the original "oil" resource – that is, light-medium crude oil, heavy crude oil, natural gas liquids, bitumen and shale oil – was roughly 4,000 billion barrels. The lighter, more desirable petroleum fuels, which are less costly to produce and process, lie predominantly in the Eastern Hemisphere. The heavier, less desirable petroleum fuels, which are more costly to produce and process, lie predominantly in the Western Hemisphere.

Approximately 40,000 oil fields have been discovered worldwide since 1860. The largest class of field is the supergiant, containing more than 5 billion barrels of recoverable oil. Thirty-seven supergiant fields have been found and these fields originally contained an estimated 51% of all the conventional crude oil discovered to date. The Persian Gulf region holds 26 supergiant fields, of which 11 are located in Saudi Arabia. The world's largest field, Ghawar, was found in 1948 and its 86 billion barrels of recoverable oil transformed Saudi Arabia into the world's leading oil nation. Kuwait's Burgan field is the second largest, having originally contained 75 billion barrels of recoverable oil. Two supergiants have been discovered in each of the United States (East Texas and Prudhoe Bay), the Soviet Union, Mexico and Libya. There is one in each of Algeria, Venezuela and China.

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

This pattern of oil occurrence and more than a century of petroleum development have established two principles applying to global oil resources. First, most of the world's oil is contained in a few large fields, but most fields are small. Second, average field size and the quantity of oil found per unit of drilling decrease as exploration progresses. In any oil-producing region, the large fields tend to be discovered early in the cycle of oil production. (Riva, 1987c)

Riva estimates that the world's remaining recoverable, conventional crude oil (reserves plus undiscovered resources) amounts to roughly 1,200 billion barrels. At the current production rate of about 20 billion barrels/year, that quantity of oil would last for 50 years before output became limited by the resource base. Because this oil is so unevenly distributed, however, future oil availability must be considered on a country-by-country basis to determine when and where supply constraints will appear. Riva has assessed 29 producing countries, ranked by their original recoverable oil endowment. Assuming that proved reserves will be established in the future at the statistical rate observed in past development and that the reserves/production ratio will not fall below 9 in any of these countries (a value characteristic of producing regions in their declining years), he calculated the number of years that each country could sustain its 1986 level of oil production. These results are summarized in Table 2.

Table 2: Projections of Future Oil Production Capabilities

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

Notes: (a) The analysis was divided into five-year increments.
(b) For those countries which could increase output in the year 2000, the value given is not a forecast of increased production but only an indication of the level of production that could be achieved if the oil resource base calculated to exist were exploited at the maximum rate.
* Denotes a member of OPEC.

Source: Riva, 1987c, p. 16-17 and 19.

The proved remaining reserves component of the world's conventional crude oil resources is almost 700 billion barrels. The largest share of these proved reserves – nearly 58% – lies in the Middle East. In its year-end 1986 "Worldwide Report", *Oil & Gas Journal* gives the distribution of world oil reserves, as charted by EMR in Figure 9. Reserves are first characterized as OPEC or non-OPEC. The non-OPEC reserves are subdivided onto OECD, LDC and CPE reserves. OPEC holds an estimated 68.5%, or 478 billion barrels, of year-end 1986 world proved reserves of conventional crude oil; the OECD claims just 7.9%, or 55 billion barrels. Only one-fifth of world reserves lie in the non-OPEC, non-Communist world. The United States and Canada together hold less than 5% of world reserves. The North Sea holds a mere 3%, despite its current influence in world oil trade. Of particular note, the OECD countries consumed 57% of the world's oil in 1986 but held less than 8% of proved conventional oil reserves.

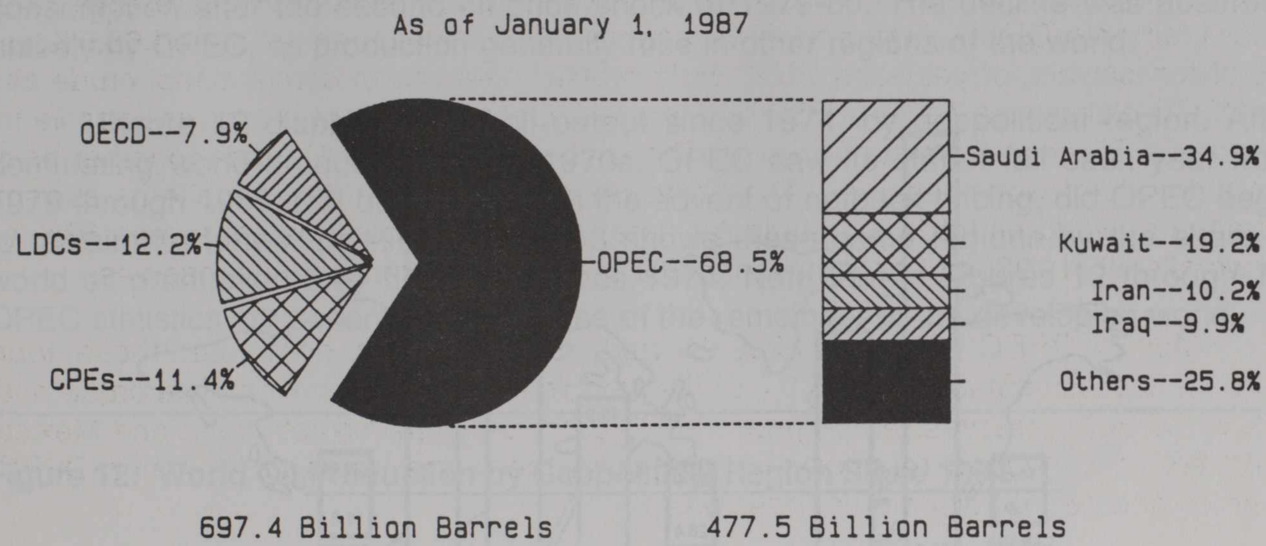
Within OPEC, Saudi Arabia, Kuwait, Iran and Iraq dominate; these four countries are estimated to hold 51% of the world's reserves of conventional crude and 74% of OPEC's reserves. Among non-OPEC producers, the Soviet Union and Mexico stand first and second respectively. Between them, they hold 52% of non-OPEC reserves and 16% of world crude reserves.

The global pattern of reserves does not match the pattern of crude oil production. Some countries are producing their reserves at high rates – notably the U.S.S.R., the United States, the United Kingdom and Canada – and other countries are producing their reserves at comparatively low rates – such as Kuwait, Saudi Arabia, Iraq and Mexico. The ratio of year-end proved reserves to production over the year is known as the reserves/production ratio (R/P ratio) and provides a measure of the longevity of current reserves. To illustrate, year-end 1986 proved reserves of crude oil in China were 18.4 billion barrels and 1986 production averaged 2.59 million barrels/day. Thus the R/P ratio was 18.4 billion ÷ (2.59 million x 365) = 19.5/1 (usually written simply as 19.5). Figure 10 displays reserves/production ratios for the world as a whole; for OPEC, the OECD, the LDCs and the CPEs; and for important producers within each of the country groupings.

Figure 10 reinforces the fact that OPEC is currently underproducing its crude oil reserves relative to the remainder of the world. As a group, OPEC had a reserves/production ratio of 73 at year-end 1986, whereas the OECD nations stood at 10 and the CPEs at 14. Led by Mexico, the LDCs occupy an intermediate position with an R/P ratio of 30. The world's two leading producers – the Soviet Union and the United States – have R/P ratios of 13 and 8 respectively. Saudi Arabia, the third largest producer in 1986, has an R/P ratio of 97.

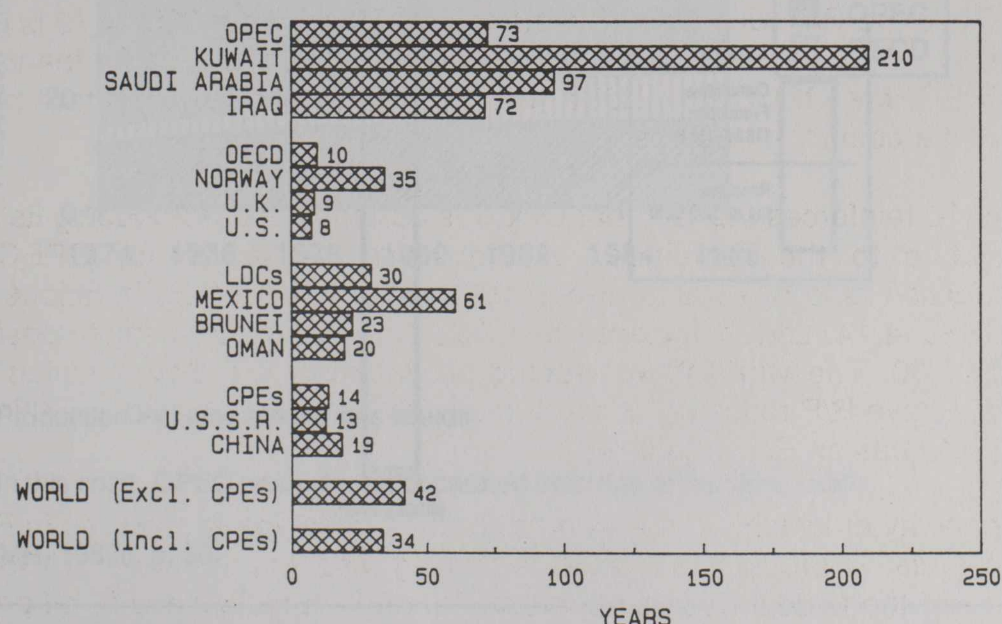
Another way of looking at the world's crude oil reserves is provided in Figure 11 which plots cumulative production against remaining reserves to year-end 1985. Again the dominance of the Middle East is apparent. Although cumulative U.S. oil production still substantially exceeds that of any other country, the reserves base which remains to support future U.S. output is now quite limited.

Figure 9: World Proved Oil Reserves by Geopolitical Distribution



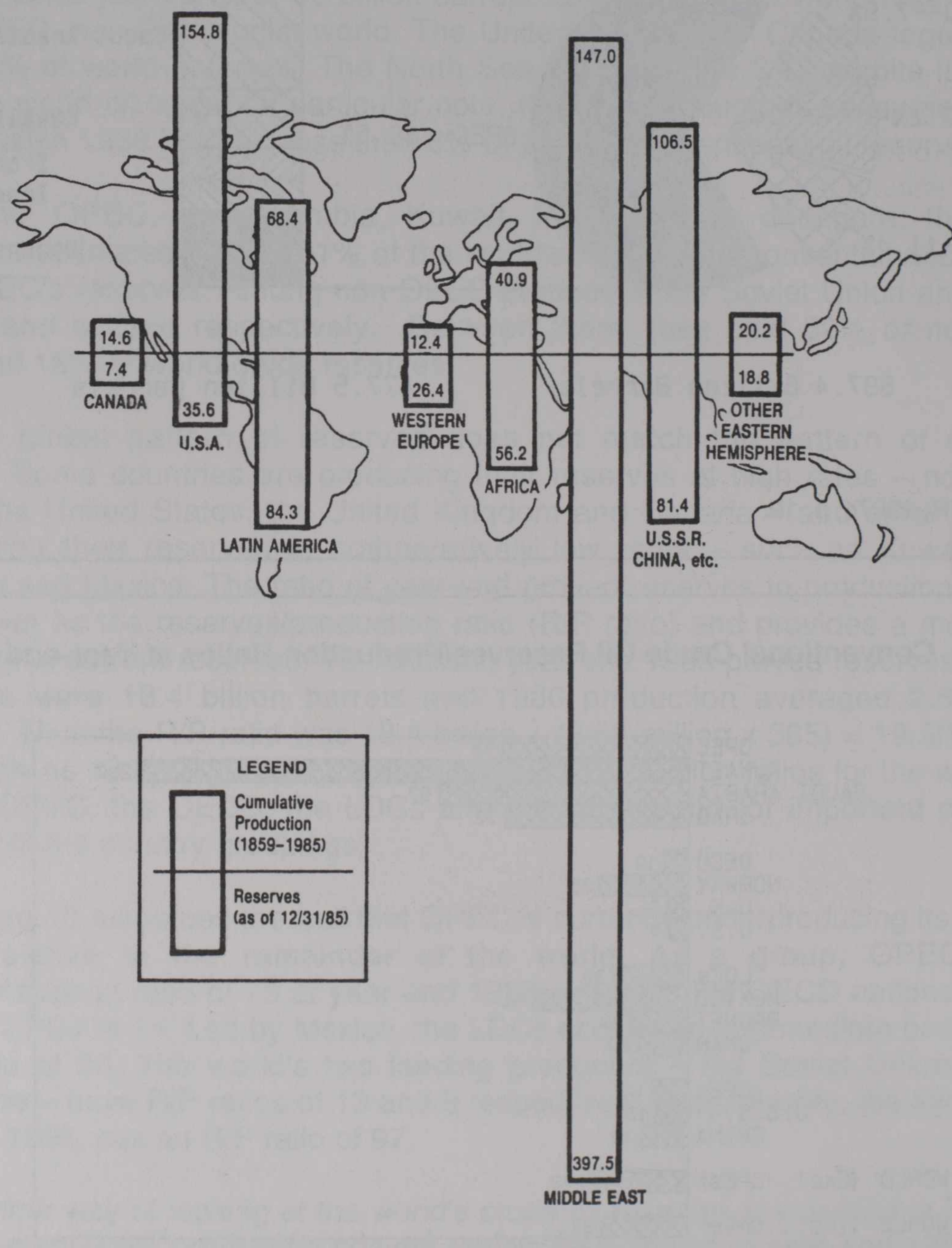
Source: EMR, 1987c, p. 19.

Figure 10: Conventional Crude Oil Reserves/Production Ratios at Year-end 1986



Source: EMR, 1987c, p. 20.

Figure 11: Cumulative Oil Production and Remaining Conventional Crude Oil Reserves by Region at Year-end 1985 (in billions of barrels)



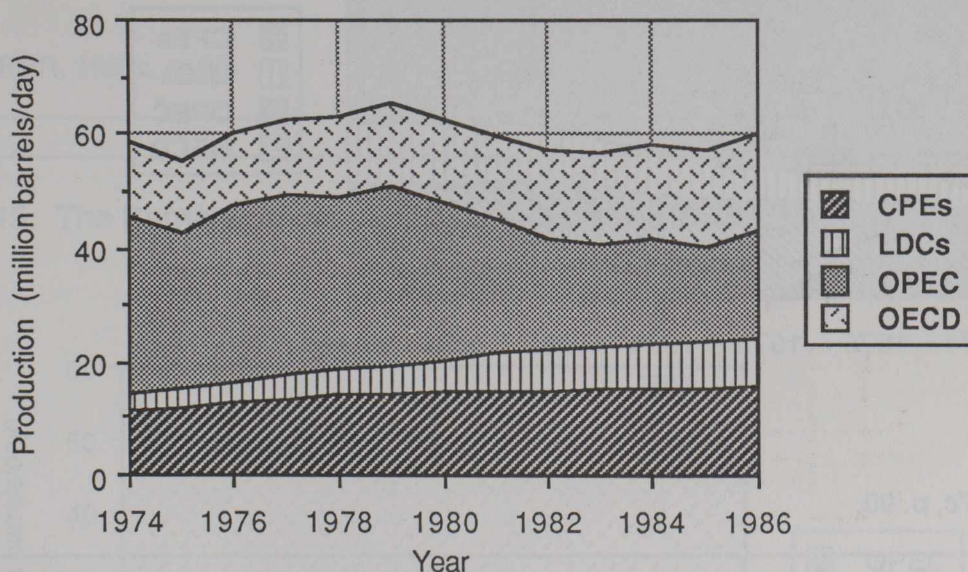
Source: U.S. National Petroleum Council, 1987, p. 9.

D. World Oil Production, Consumption and Trade

After decades of almost uninterrupted year-to-year increases in the production of crude oil, output fell in the early 1980s, as industrialized nations reduced consumption after the second oil price shock of 1979-80. The decline was absorbed entirely by OPEC, as production generally rose in other regions of the world.

Figure 12 displays world oil output since 1974, by geopolitical region. After dominating world production in the 1970s, OPEC saw its output fall each year from 1979 through 1985. Not until 1986, with the advent of netback pricing, did OPEC begin to reclaim its former position. Figure 13 shows these same regions by the share of world oil production they have held since 1974. Note that in Figures 12 through 15, OPEC statistics are separated from those of the remainder of the developing world.

Figure 12: World Oil Production by Geopolitical Region Since 1974



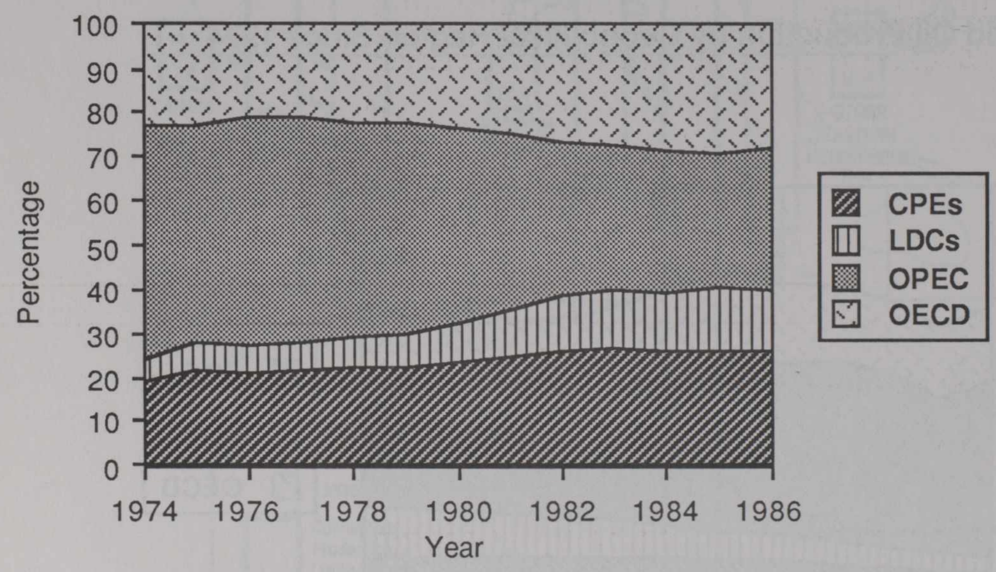
Notes: 1. Production includes natural gas liquids.

2. In this chart, OPEC production is separated from that of the other LDCs.

Source: EMR, 1987c, p. 90.

Non-OPEC sources of supply cannot indefinitely sustain the expansion achieved in the wake of the two oil price shocks. In 1973, non-OPEC/non-Communist oil output averaged 14.7 million barrels/day. By 1979, it had expanded to 17.7 million barrels/day. The second price shock further spurred non-OPEC output, which grew to 22.7 million barrels/day. But non-OPEC/non-Communist production may be nearing its peak. Low prices have compounded the problem of diminishing returns from petroleum exploration outside the Middle East. The situation is made clearer in comparing the distribution of oil production by geopolitical region, shown in Figure 13, with the distribution of conventional crude oil reserves, presented in Figure 14.

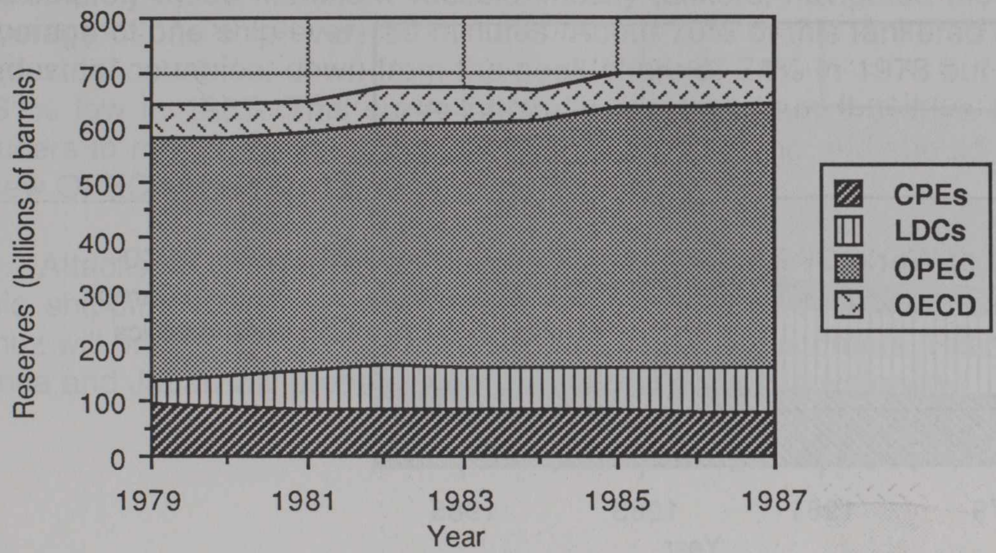
Figure 13: Share of World Oil Production by Geopolitical Region



Source: EMR, 1987c, p. 90.

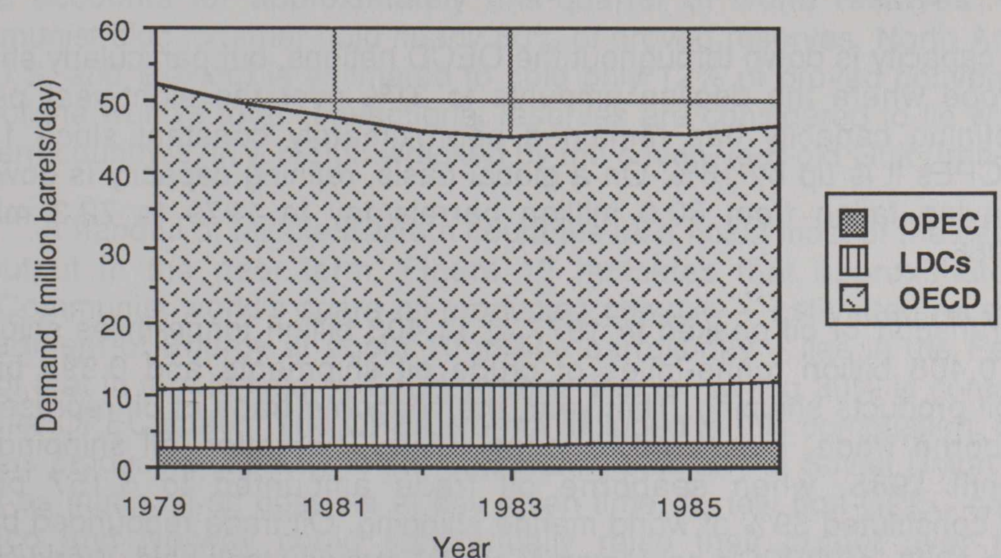
Figure 15 illustrates oil consumption in the non-Communist world since 1979. Although demand fell substantially in the industrialized nations from 1979 to 1983, it remained virtually constant in the non-OPEC developing countries and increased slowly in the OPEC states. Over this same period, there has also been a shift away from the consumption of heavy oil products towards light oil products. These trends have caused a rationalization of world refining capacity, leading to a reduction in capacity in the industrialized world and to an increase in refining complexity. Figure 16 illustrates recent trends in refining capacity by region of the world. The OECD data are subdivided into North American, Western European and Pacific components.

Figure 14: Geopolitical Distribution of Proved Crude Oil Reserves at January 1



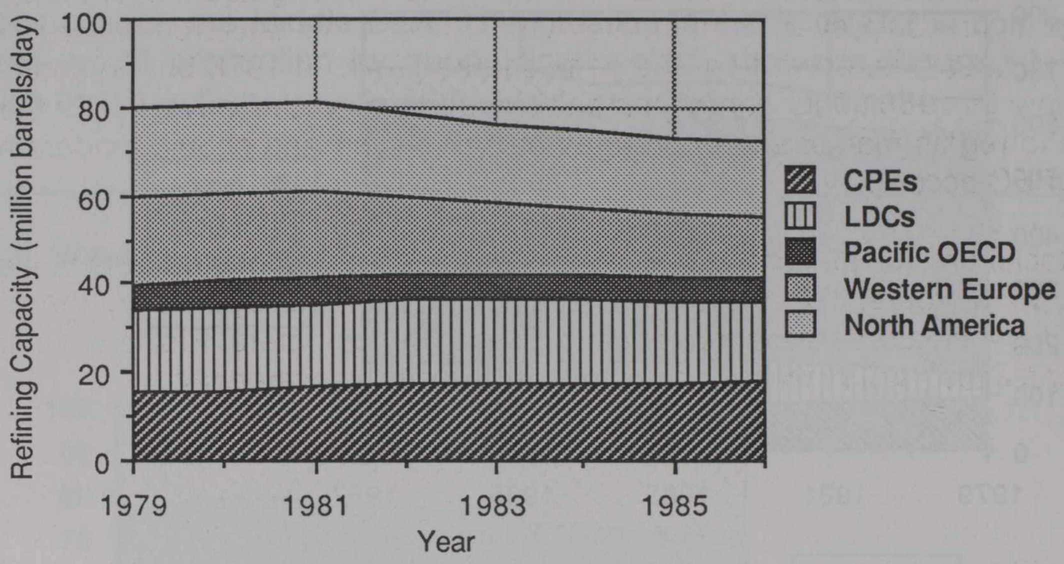
Source: EMR, 1987c, p. 90.

Figure 15: The Demand for Oil in the Non-Communist World since 1979



Source: EMR, 1987c, p. 84.

Figure 16: World Refining Capacity by Region since 1979



Notes: 1. OPEC refining capacity is included with the LDC totals.

2. OECD refining capacity is subdivided into three regional components: North America (the United States and Canada), Western Europe and the Pacific (Japan, Australia and New Zealand).

Source: EMR, 1987c, p. 101.

Refining capacity is down throughout the OECD nations, but particularly sharply in Western Europe where the decline amounts to 31% over the eight-year period shown. LDC refining capacity has remained approximately constant since 1979, whereas in the CPEs it is up by 16%. On a global basis, refining capacity is down by almost 10%, having fallen from 80.0 million barrels/day in 1979 to 72.3 million barrels/day in 1986.

Tanker transport of oil peaked in 1977 at 11.403 billion tonne-miles shipped, comprised of 10.408 billion tonne-miles of crude oil shipments and 0.995 billion tonne-miles of oil products shipping. That year, the seaborne trade of oil represented 65% of all seaborne trade, measured in tonne-miles. Thereafter, oil shipping fell continuously until 1985, when seaborne oil trade amounted to 5.157 billion tonne-miles and constituted 39% of world marine shipping. Oil trade rebounded by an estimated 16% in 1986, as OPEC's new "market share" strategy took hold. World crude oil output rose about 6% but OPEC's production was up by 16% and Middle East (long-haul) production by 25%. Oil tankering rebounded to 44% of all seaborne trade. (Tucker, 1987)

The Strait of Hormuz at the entrance to the Persian Gulf correspondingly regained some of its strategic significance. The volume of oil transiting this narrow waterway had been declining since the late 1970s and reached a low of 29% of all internationally-traded oil in 1985. Recent IEA data indicate that 35% of internationally-traded oil – 7.6 million barrels/day – moved through the Strait in 1986. Approximately 6,500 merchant vessels, mostly tankers, navigated the Strait last year, an average of one ship every 80 minutes. About 70% of this tankered oil was destined for industrial countries, down from the peak share of 74% in 1978 but up sharply from the 61% low in 1985. This surge primarily resulted from the drive by Persian Gulf producers to regain market share through netback pricing and should moderate under the new OPEC accord.

Attacks on Gulf tanker traffic by both Iran and Iraq demonstrate the vulnerability of this shipping route. Expansion of the pipeline systems bypassing the Strait of Hormuz will principally serve larger sales to European customers. Rising sales to North America and Japan will probably continue to move via this waterway.

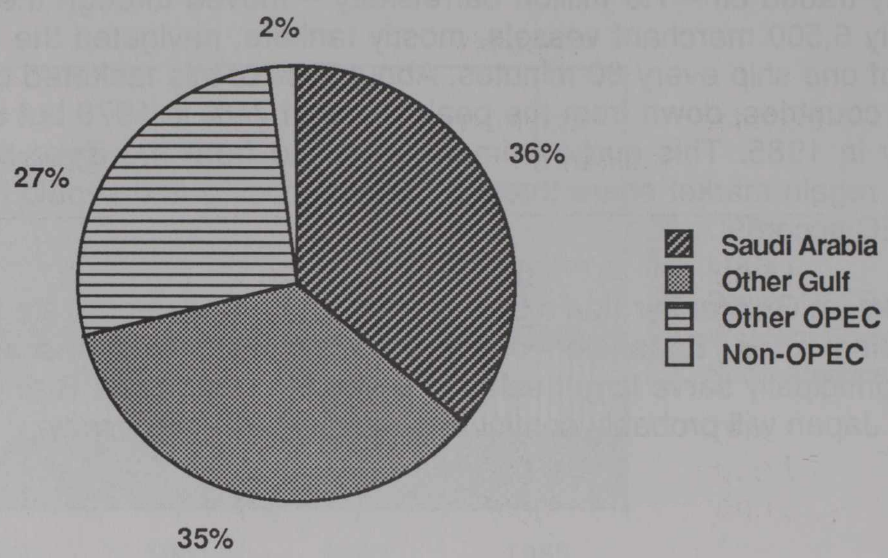
E. Oil as a Strategic Commodity

Oil has a strategic significance because of the dominant position it has attained in satisfying the world's requirements for energy, coupled with its irregular geographic distribution.

The world petroleum market is susceptible to manipulation for various reasons. OPEC controls about 68% of world conventional crude oil reserves; Saudi Arabia alone accounts for approximately one-quarter of world reserves. OPEC and the Communist bloc together hold nearly 80% of proved reserves. North America (Canada, the U.S. and Mexico) is estimated to hold only 12% of proved conventional reserves. Half of the world's total conventional reserves are considered to lie within four Middle Eastern countries, in a region wracked by the seven-year-old Gulf (Iran-Iraq) War.

A handful of Middle Eastern countries also holds most of the capacity to expand oil output in the near term. Figure 17 indicates that approximately 70% of the non-Communist world's spare oil-producing capacity – estimated recently by the U.S. Department of Energy at about 10 million barrels/day – lies in the Persian Gulf, and half of that in turn is held by Saudi Arabia. The remaining 30% is contained principally in other OPEC states. The CPEs are not included in this compilation, but there is little surplus producing capacity in the Communist bloc as the Soviet Union and China tend to lift as much oil as possible at any given time. A few non-OPEC countries such as Mexico and Norway could substantially raise their output over time by further developing their reserves, but the ability to increase production now, using facilities already in place, lies in the Persian Gulf and selected members of OPEC in other parts of the world.

Figure 17: Where the World's Non-Communist Surplus Oil Producing Capacity Lies



Note: "Other Gulf" producers include both OPEC and non-OPEC Persian Gulf states apart from Saudi Arabia. "Other OPEC" covers all OPEC members outside of the Gulf region. "Non-OPEC" includes the OECD and LDCs other than OPEC and the non-OPEC Persian Gulf producers.

Source: U.S. Department of Energy, 1987, p. 18.

The U.S. Central Intelligence Agency (CIA) regularly estimates crude oil productive capacities for each member of OPEC. At the end of 1986, the CIA estimated that OPEC's overall available capacity to produce crude oil stood at 27.2 million barrels/day, with 31% of this capability held by Saudi Arabia and 65% held by OPEC Gulf members in total. The actual OPEC December 1986 production rate was 18.1 million barrels/day, only two-thirds of available capacity. The CIA also calculated that OPEC's maximum sustainable capacity – the highest production rate that could be maintained for a period of several months – was 34.4 million barrels/day at the time. Table 3 shows the CIA estimates for year-end 1986.

In recent years, OPEC has attempted to extend its influence in the international oil business. During the 1970s, host governments nationalized most of OPEC's oil fields, relegating the petroleum companies to the role of operator. In 1970, foreign oil companies accounted for more than 95% of the equity in OPEC oil producing rights. After a decade of nationalization, in 1980, foreign oil companies held less than a 15% equity in OPEC's oil production. Hence the ability of the multinational oil companies to act as a buffer between producing and consuming countries has been reduced.

Table 3: OPEC Crude Oil Productive Capacity at Year-end 1986

Country	Installed	Capacity Maximum (million barrels/day)	Available	Production (December 1986 rate)
Algeria	1,200	900	900	662
Ecuador	300	285	330	285
Gabon	250	150	185	180
Indonesia	1,800	1,650	1,650	1,188
Iran	7,000	5,500	3,400	2,200
Iraq	4,000	3,500	1,750	1,550
Kuwait	2,900	2,000	1,950	1,300
Libya	2,500	2,100	1,600	1,000
Neutral Zone	680	600	600	350
Saudi Arabia	12,500	10,000	8,500	5,000
UAE	2,550	2,415	1,550	1,201
Venezuela	2,600	2,500	2,400	1,585
Totals	**41,430**	**34,400**	**27,215**	**18,134**

Notes: 1. **Installed capacity**, or design capacity, includes all elements of the crude oil production system, including production, processing, transportation and storage. This is usually the highest capacity estimate. **Maximum sustainable capacity**, or operational capacity, is the highest production rate that can be sustained for several months. It does not necessarily reflect the maximum rate that can be maintained without damage to the reservoirs. **Available capacity**, or allowable capacity, reflects current restrictions on output (for example, an announced production ceiling, capacity lost because of the Gulf War, or the March 1987 earthquake in Ecuador which severed the pipeline link from the country's Amazon basin oil fields to a coastal terminal). For limited periods of time, available capacity can exceed sustainable capacity.

2. Neutral Zone output is shared equally by Saudi Arabia and Kuwait.

3. The estimates of maximum sustainable capacity for Iran and Iraq were those made prior to the Gulf War; the loss of capacity due to the conflict is uncertain.

Source: U.S. Central Intelligence Agency, 1987, p. 2.

The Arab oil embargo was not the first attempt to use oil as a political or strategic weapon. Germany's lack of indigenous oil supplies in World War II has been cited as an important factor in its defeat. The fact that the United States embargoed shipments of crude oil and scrap steel to Japan after war commenced in Europe apparently influenced Japan's decision to attack Pearl Harbor. South Africa has established a costly industrial capacity to produce liquid and gaseous fuels from domestic coal deposits, thereby reducing its vulnerability to oil embargos.

Since World War II, there have been six important disruptions in oil supply, three of which have caused significant dislocations in the economies of oil-consuming countries. These six disruptions include:

1. the 1951-53 Iranian Boycott;
2. the 1956-57 Suez Crisis;
3. the 1967 Six-Day War;
4. the 1973 Yom Kippur War;
5. the 1979 Iranian Revolution; and
6. the 1980 invasion of Iran by Iraq, opening the Gulf War which continues today.

The Iranian Boycott, the Suez Crisis and the SIx-Day War had comparatively little effect on world oil supply and the international price of oil, although the Suez Crisis caused some hardship in Europe. In each case, the United States boosted production to help offset any oil shortfall, as did a number of other producers. In contrast, the Yom Kippur War, the Iranian Revolution and the onset of the Gulf War had major repercussions, including huge price increases.

F. The Role of the International Energy Agency

The International Energy Agency (IEA) is an autonomous body established in November 1974 within the framework of the Organization for Economic Co-operation and Development (OECD). Its headquarters are in Paris and its purpose is to implement an International Energy Program. Twenty-one of the OECD's 24 member states collaborate in this effort.

The IEA member countries are Australia, Austria, Belgium, Canada, Denmark, the Federal Republic of Germany, Greece, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The OECD signatories that do not participate in the IEA are France, Iceland and Finland.

The stated aims of the International Energy Agency are:

1) co-operation among IEA participating countries to reduce excessive dependence on oil through energy conservation, development of alternative energy sources and energy research and development;

2) maintain an information system on the international oil market as well as consultation with oil companies;

3) co-operation with oil producing and other oil consuming countries with a view to developing a stable international energy trade as well as the rational management and use of world energy resources in the interest of all countries; and

4) planning to prepare participating countries for the possibility of a major disruption in oil supplies and to share available oil in the event of an emergency.

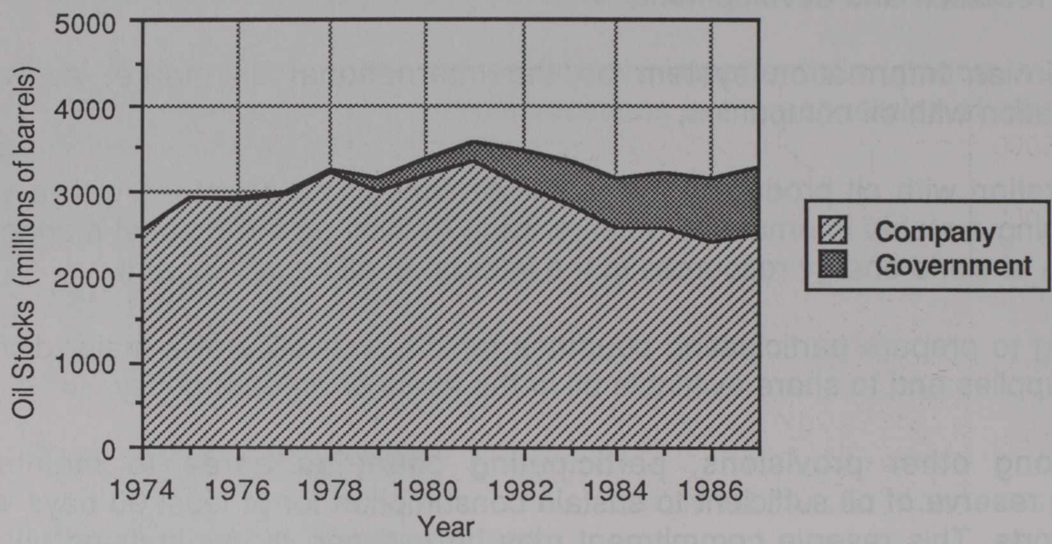
Among other provisions, participating countries agree to maintain an emergency reserve of oil sufficient to sustain consumption for at least 90 days with no net oil imports. This reserve commitment may be satisfied by maintaining oil stocks themselves, fuel switching capacity and stand-by oil production. Total oil stocks maintained by a participating country are defined to include crude oil, major products and unfinished oils held in refinery tanks, bulk terminals, pipeline tankage, barges, intercoastal tankers, oil tankers in port, inland ship bunkers, storage tank bottoms and working stocks; and oil held by large consumers as required by law or otherwise controlled by governments.

In recent years a shift has taken place in the oil stocks held by OECD countries. Since 1981, company-held stocks have generally been declining while government oil stocks have been growing larger. In effect, governments have been assuming a larger share of the burden in maintaining strategic oil stockpiles. Figures 18 and 19 provide more detail on OECD oil inventories. Figure 18 displays OECD annual opening inventories of oil since 1974, subdivided into company and government stocks. Figure 19 shows how these stocks translate into days of forward consumption, again broken down into company and government shares.

Typically about half of the OECD company-held stocks have been crude oil and the remainder petroleum products.

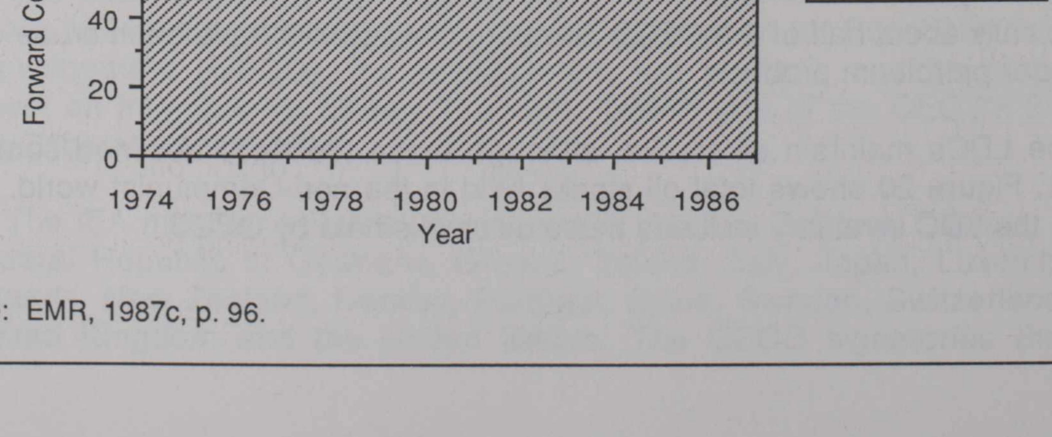
The LDCs maintain oil stocks, although these too have declined somewhat since 1981. Figure 20 shows total oil stocks held in the non-Communist world. In this illustration, the LDC inventory includes those oil stocks held by OPEC.

Figure 18: OECD Opening Annual Oil Inventories since 1974, as recorded each January 1



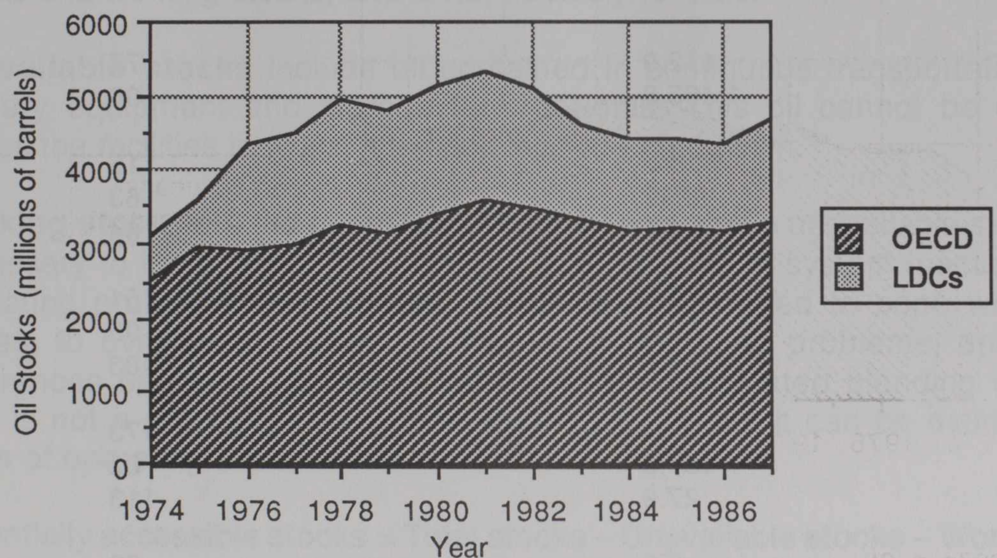
Source: EMR, 1987c, p. 96.

Figure 19: Days of Forward Oil Consumption Represented by OECD Oil Stocks



Source: EMR, 1987c, p. 96.

Figure 20: OECD and LDC Opening Annual Oil Inventories since 1974, as Recorded each January 1



Source: EMR, 1987c, p. 100.

Canada is not required under the IEA stipulations to maintain an emergency reserve because it is a net exporter of oil.

Each quarter, OECD nations report their oil "stock levels" and the number of days of forward consumption that these stocks represent. Table 4 shows an OECD accounting for October 1, 1986.

Although these are spoken of as available stocks – "stock level" equals "total stocks" held minus a 10% adjustment for "unavailable stocks" – the amount that could be drawn down in an emergency is less than suggested. This is because the reported stock levels include "working stocks", which are not normally available for use. Canada's position is especially poor in this regard. Although Table 4 indicates that Canada's stock level was equivalent to 77 days of forward consumption on October 1, 1986, EMR advised the Committee that the quantity of oil actually available for drawdown only amounts to 10-20 days of consumption, depending upon the season.

Table 4: OECD Oil Stocks as of October 1, 1986

Country	Stock Level (millions of barrels)	Days of Forward Consumption
Canada	112.9	77
United States	1,485.8	100
Japan	516.0	115
Australia	35.2	63
New Zealand	6.6	84
Austria	21.3	101
Belgium	39.6	95
Denmark	39.6	183
Finland	37.4	173
France	137.8	82
Greece	27.9	113
Ireland	5.9	63
Italy	167.1	89
Luxembourg	1.5	81
Netherlands	66.0	107
Norway	19.1	107
Portugal	17.6	93
Spain	69.6	82
Sweden	47.6	135
Switzerland	44.0	183
Turkey	14.7	36
United Kingdom	129.7	85
West Germany	269.0	130

Notes: 1. Data for Iceland are not available.

2. Stock data in the source have been converted from tonnes to barrels using the approximate factor 1 tonne of oil = 7.33 barrels of oil.

Source: EMR, personal communication.

Definitions Used in IEA Reporting of Oil Stocks

The **minimum operating requirement** is the level of stocks necessary at a given time to maintain smooth operations and avoid runouts, and below which shortages begin to appear in a defined distribution system. It is composed of unavailable stocks and working stocks, and is not normally for sale.

Unavailable stocks include oil contained in continuous transportation systems, refinery equipment and storage tank bottoms. This oil cannot be drawn down unless the facilities in which it is contained are shut down.

Working stocks are the quantities of oil over and above unavailable stocks that are necessary to keep the primary refining and distribution system functioning without operating problems and runouts. It includes oil needed to cope with operating cycles, to overcome unexpected delays or operating problems, and to smooth differences between production schedules for associated blending components. This is not a precisely measurable quantity of oil but it can be estimated on the basis of operating experience.

Potentially accessible stocks = Total stocks – Unavailable stocks – Working stocks

Potentially available stocks are estimated for the OECD countries but the data are not publicly released.

In the 1973 Arab oil embargo, certain Western nations were targetted because of their support of Israel in the Yom Kippur War. This strategy of "divide and conquer" met with some success as several industrial countries practiced a 1970s version of appeasement to avoid being embargoed by OAPEC. To prevent this happening again, the IEA participating countries have agreed to an oil allocation program activated by a specified reduction in oil supplies. If the group as a whole, or any participating country, sustains or expects to sustain a reduction in its oil supplies equal to at least 7% of its average daily rate of consumption, then each participating country agrees to restrain demand by an amount equal to 7% of its consumption and to allocate oil among the group according to certain provisions. At the present time, Canada is a net oil-exporting nation and would therefore have an obligation under these circumstances to allocate oil, directly or indirectly, to other participating countries having an allocation right.

Doubt has been expressed in some quarters about the willingness of all 21 IEA nations to participate fully in an allocation program if a serious shortfall in international oil supply occurs. During the Iranian Revolution of 1978 and subsequently at the onset of the Iran-Iraq War in 1980, the decline in non-Communist oil supply approached 7%

but did not trigger the IEA oil-sharing provisions. Thus the program remains untested by a supply emergency.

Another area of IEA collaboration is long-term co-operation on energy matters to reduce dependence on imported oil. The Standing Group on Long Term Co-operation considers national and co-operative programs in:

1) conservation of energy;

2) development of alternative sources of energy such as domestic oil, coal, natural gas, nuclear energy and hydro-electric power;

3) energy research and development, including co-operative programs on coal technology, solar energy, radioactive waste management, controlled thermonuclear fusion, the production of hydrogen from water, nuclear safety, waste heat utilization, conservation of energy, municipal and industrial waste utilization, and overall energy system analysis; and

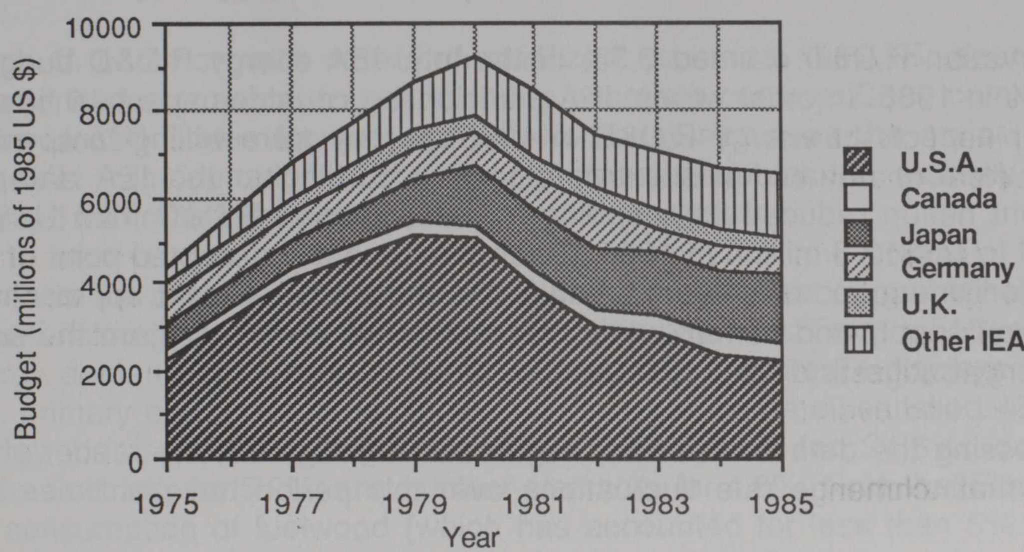
4) uranium enrichment.

Unfortunately, with declining oil prices has come declining interest by most participating countries in the longer-term energy options and in energy conservation. The falling support for energy research, development and demonstration (R,D&D) is apparent in Figures 21 through 23.

Figure 21 displays government energy R,D&D budgets for the IEA countries since 1975, in constant 1985 U.S. dollars. Figure 21 shows that this spending peaked in 1980 at US$9.24 billion and fell to US$6.57 billion by 1985, a decrease of 29%. The U.S. alone accounts for all of this drop; other IEA nations are split in their performance. Spending on energy R,D&D is down from its 1980 values in West Germany and the United Kingdom, but up in Japan, Italy and Canada. Canada's spending on energy R,D&D reached its maximum in 1984.

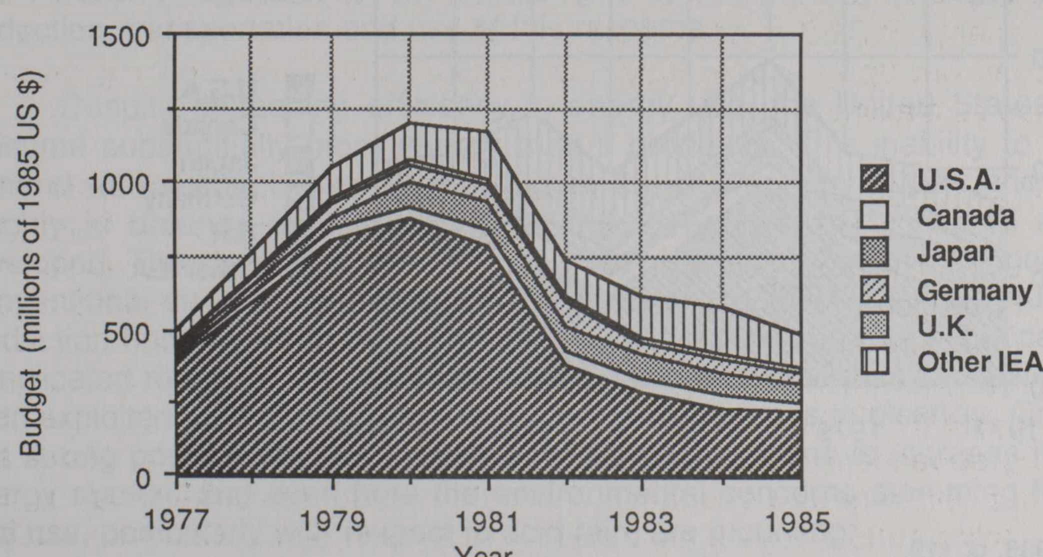
Figure 22 gives the amounts budgeted since 1977 for renewable energy R,D&D. The drop since 1980 in this component of total energy R,D&D is much larger, amounting to 60%. These statistics illustrate the waning interest in renewable energy forms given the reduced price of oil and its ready availability. The United States has dominated this decline and Canada's cutbacks have been prominent, but countries such as Japan and Sweden are also spending less. The 75% plunge in U.S. funding for renewable energy R,D&D since 1980 is particularly perplexing in view of that country's rising dependence on foreign oil. Only Belgium, Italy and the Netherlands budgeted more for renewable energy R,D&D in 1985 than they did in 1980; nevertheless, Italy's 1985 budget was just 35% of its 1984 peak. Canada's budget of US$23.5 million in 1985 stood at only 41% of the US$57.3 million budgeted in 1981. Total 1985 IEA budgeted expenditures for renewable energy R,D&D represented 7.4% of all IEA energy R,D&D planned spending; in 1981, they had accounted for 13.9%.

Figure 21: IEA Government Energy R,D&D Budgets in 1985 US Dollars



Source: IEA, 1986, p. 52.

Figure 22: IEA Government Budgets for Renewable Energy R,D&D in 1985 US Dollars



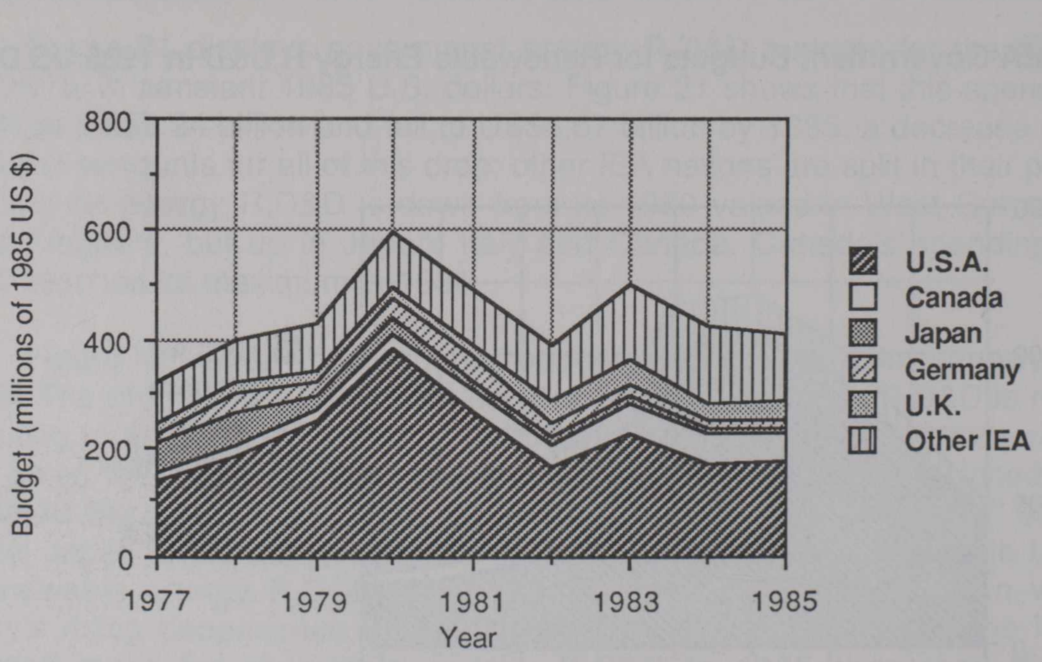
Source: IEA, 1986, p. 125.

Figure 23 shows the decline in IEA budgeted spending on conservation R,D&D. Down 31% since 1980, the reduction is comparable to that in total energy R,D&D. Most of the participating countries have been affected, although Canada, the United Kingdom, Italy and the Netherlands are above their 1980 budget levels. Canada's 1985 conservation R,D&D budget at US$50.4 million was near the 1984 peak of US$54.8 million.

Conservation R,D&D claimed 6.5% of the total IEA energy R,D&D budget in 1980 and 6.2% in 1985. In other words, IEA participating countries spent 16 times as much on other aspects of energy R,D&D in 1985 as they were willing to spend on conservation. Japan's behaviour is extraordinary; according to the IEA data, this energy deficient nation reduced its spending on conservation R,D&D from US$55.9 million in 1977 to US$12.3 million in 1985. Given the generally accepted point of view that spending on energy conservation is one of the most cost-efficient approaches to balancing energy supply and demand, this preponderence of spending on the supply side of the energy budget is difficult to understand.

In assessing the data contained in Figures 21 through 23, the reader should keep in mind that exchange rate fluctuations over this period have at times been considerable.

Figure 23: IEA Government Budgets for Conservation R,D&D in 1985 US Dollars



Source: IEA, 1986, p. 119.

THE UNITED STATES: OIL PRODUCER IN DECLINE

A. U.S. Energy Supply and Demand

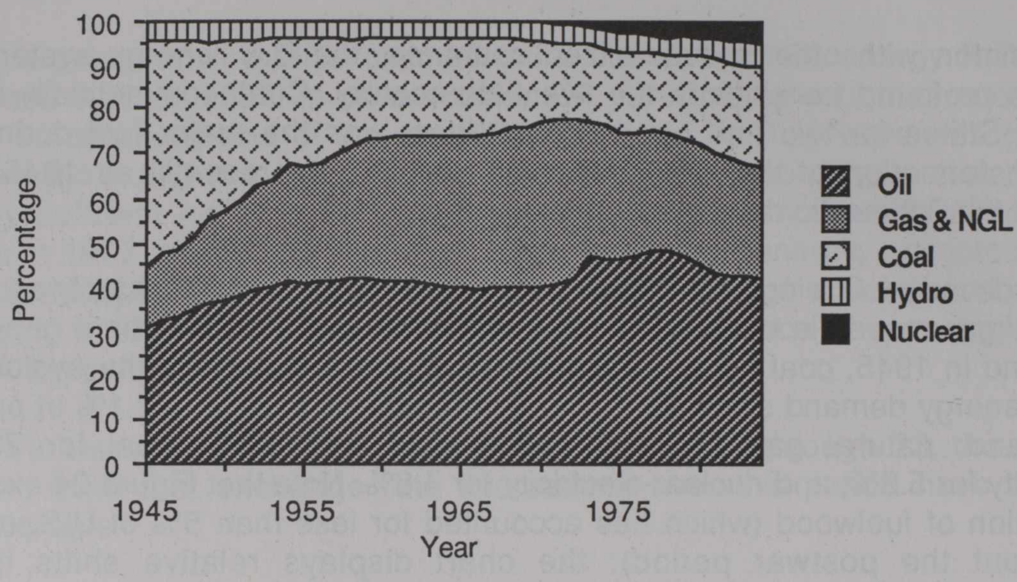
In common with other industrialized countries, the U.S. energy system has experienced a profound transition in the twentieth century. Coal, commercially mined in the United States for two and one-half centuries, was the major fuel during the industrial transformation of the late nineteenth century. As recently as 1945, coal satisfied half of the domestic demand for primary energy.

In the decade following World War II, consumption of coal fell sharply as crude oil and natural gas moved in tandem to supplant its use. From a 51% share of primary energy demand in 1945, coal fell to 29% in 1955. Figure 24 displays the evolution in U.S. primary energy demand since 1945. In 1984, crude oil satisfied 42.1% of primary energy demand; natural gas and NGL accounted for 24.6%; coal for 23.3%; hydro-electricity for 5.2%; and nuclear-electricity for 4.8%. Note that Figure 24 excludes the consumption of fuelwood (which has accounted for less than 5% of U.S. energy use throughout the postwar period); the chart displays relative shifts in the consumption of oil, gas, coal and primary electricity.

Natural gas continues to be the fuel most readily substitutible for oil in the United States. Although U.S. gas resources are considered to be larger than those of conventional oil, the recent collapse in world oil prices reduced petroleum drilling activity and new gas reserves are not being established at a rate commensurate with the anticipated growth in demand for this fuel. The National Petroleum Council claims that excessive regulation of the natural gas sector has worked against the efficient production, transportation and use of this resource.

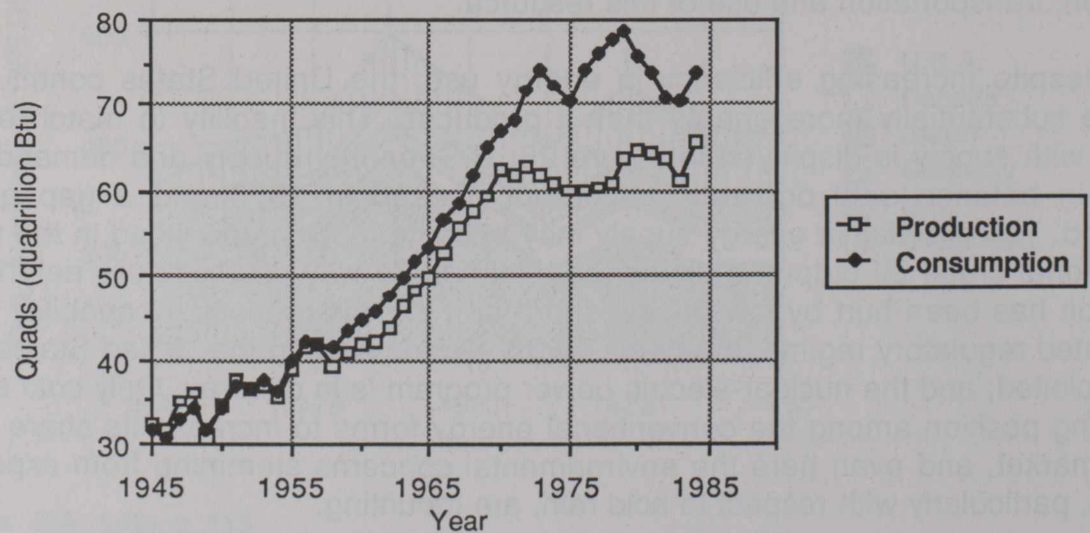
Despite increasing efficiency in energy use, the United States continues to consume substantially more energy than it produces. This inability to match energy demand with supply is displayed in Figure 25. U.S. energy supply and demand were roughly in balance until domestic oil output peaked in 1970 and a gap quickly developed. The shortfall in energy supply may become more pronounced in the future. Conventional crude oil output is almost certainly on its way down; future natural gas production has been hurt by low prices, short-term excess producing capability and a complicated regulatory regime; the prime hydro-electric sites in the United States have been exploited; and the nuclear-electric power program is in disarray. Only coal seems in a strong position among the conventional energy forms to increase its share of the energy market, and even here the environmental concerns stemming from expanded coal use, particularly with respect to acid rain, are mounting.

Figure 24: U.S. Primary Energy Consumption by Fuel Share Since 1945



Source: DeGolyer and MacNaughton, 1985, p. 107.

Figure 25: The Production and Consumption of Primary Energy in the United States



Source: DeGolyer and MacNaughton, 1985, p. 106-107.

There are no easy solutions to present U.S. energy difficulties. A growing unease over American energy prospects is reflected in recent studies. The United States has traditionally been, and will continue to be in the foreseeable future, Canada's principal trading partner, in energy and in other goods. Therefore, energy problems affecting the United States have their repercussions in Canada.

B. U.S. Oil Resources and Reserves

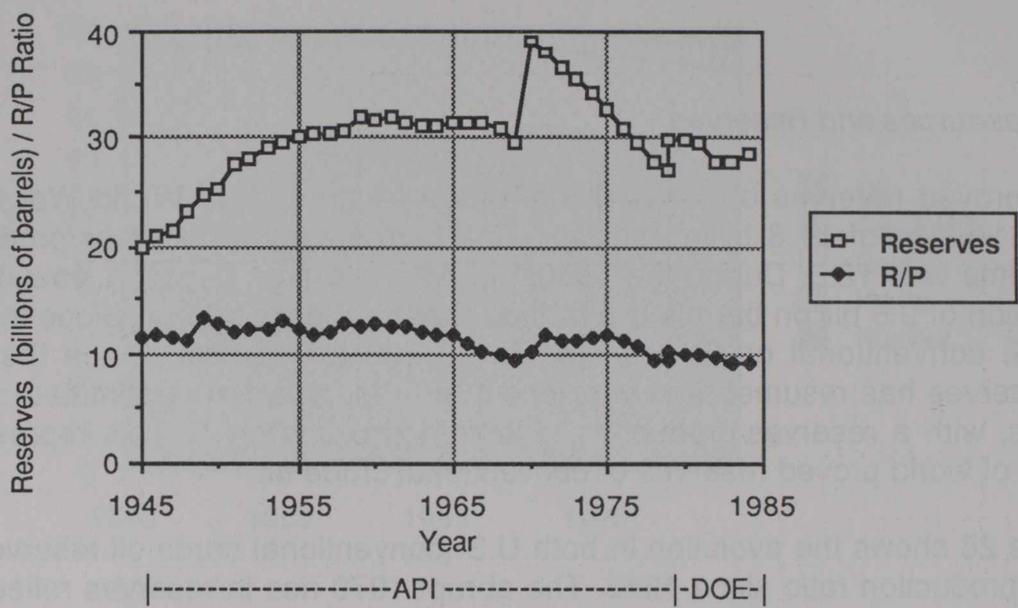
U.S. proved reserves of conventional crude oil grew after World War II to a year-end 1961 value of 31.8 billion barrels. The corresponding reserves/production ratio at that time was 12.6. During the 1960s, proved reserves began a slow decline until the addition of 9.6 billion barrels at Prudhoe Bay on Alaska's North Slope in 1970, boosting U.S. conventional crude reserves to 39.0 billion barrels. Since then, the decline in reserves has resumed and year-end 1986 reserves were estimated at 24.6 billion barrels, with a reserves/production ratio of approximately 8. This represented less than 4% of world proved reserves of conventional crude oil.

Figure 26 shows the evolution in both U.S. conventional crude oil reserves and the reserves/production ratio since 1945. The abrupt 1970 rise in reserves reflects the inclusion of Prudhoe Bay oil. The subsequent decline was temporarily arrested in the early 1980s, as higher prices for oil in the wake of the second price shock prompted increased drilling activity. Four states – Texas, Alaska, California and Louisiana – hold more than 80% of total U.S. reserves. The reserves/production ratio has been slowly falling as the United States moves along the declining side of the conventional oil production curve.

Until 1979, the American Petroleum Institute estimated proved reserves of conventional crude oil. Beginning in 1979, the Department of Energy assumed this function, using a new basis for reserves estimation. The two statistical series overlap for the year 1979: the lower 1979 values on both curves in Figure 26 are API estimates; the upper values are DOE estimates.

Figure 27 compares yearly crude oil output with annual reserve additions in the United States since the end of World War II. Prior to 1960, reserve additions consistently exceeded production and conventional crude oil reserves grew. Thereafter, output typically exceeded reserve additions – with the notable exception of 1970 – and crude oil reserves have been declining. Texas leads in production, supplying more than one-quarter of all U.S. crude oil. Alaska provides one-fifth of domestic supply, Louisiana about one-sixth and California one-eighth. Together they account for 85% of American crude oil output.

Figure 26: U.S. Conventional Crude Oil Reserves and the R/P Ratio since 1945



Notes: 1. Both reserves (in billions of barrels) and the reserves/production ratio are read on the left-hand scale.

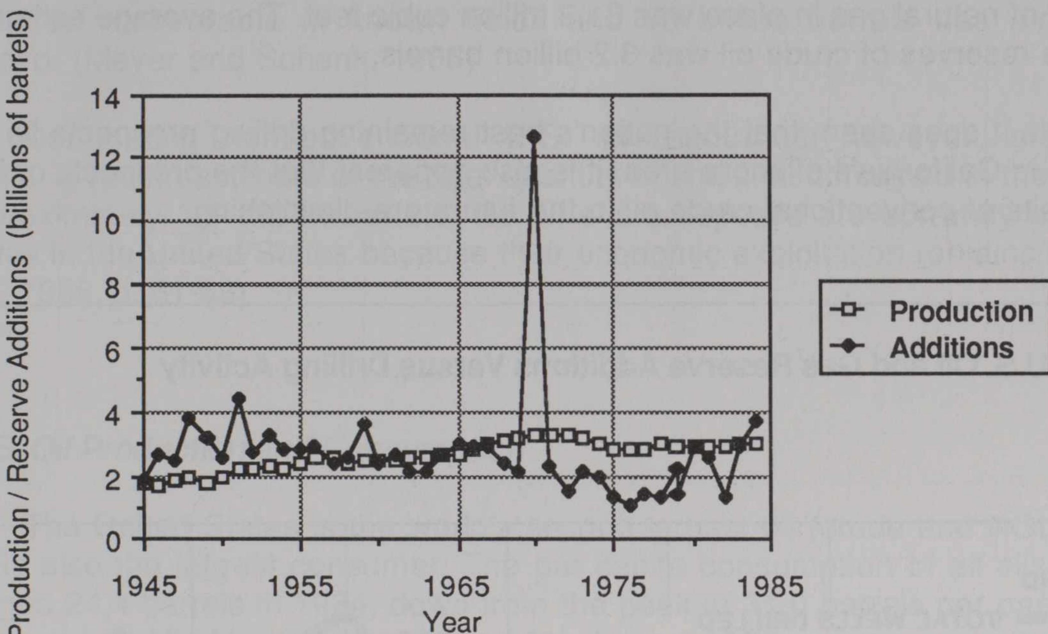
2. The API reserve estimates and corresponding R/P values cover the period 1945 through 1979 (lower value on both curves); the DOE reserve estimates and R/P values cover the period 1979 (upper value on both curves) through 1984.

Source: DeGolyer and MacNaughton, 1985, p. 18.

Over the period 1971-1985, the U.S. petroleum industry added 34.7 billion barrels to conventional crude reserves. During that same span of time, however, production totalled more than 45 billion barrels, leading to a 10-billion-barrel decline in proved reserves. Today's reduced oil prices and diminished drilling activity will result in even lower reserve additions.

The close relationship between petroleum drilling activity and reserve additions of crude oil and natural gas is indicated in Figure 28, which compares total annual reserve additions of oil and gas, expressed in billions of barrels of oil equivalent, with the total number of wells drilled per year. The downturn in 1986 drilling and reserve additions is already being reflected in U.S. crude oil production.

Figure 27: U.S. Annual Crude Oil Production and Reserve Additions since 1945



Notes: 1. Both crude oil production and reserve additions are read on the left-hand scale in billions of barrels.

2. The 1970 spike in reserve additions includes the 9.6 billion barrels booked for Prudhoe Bay.

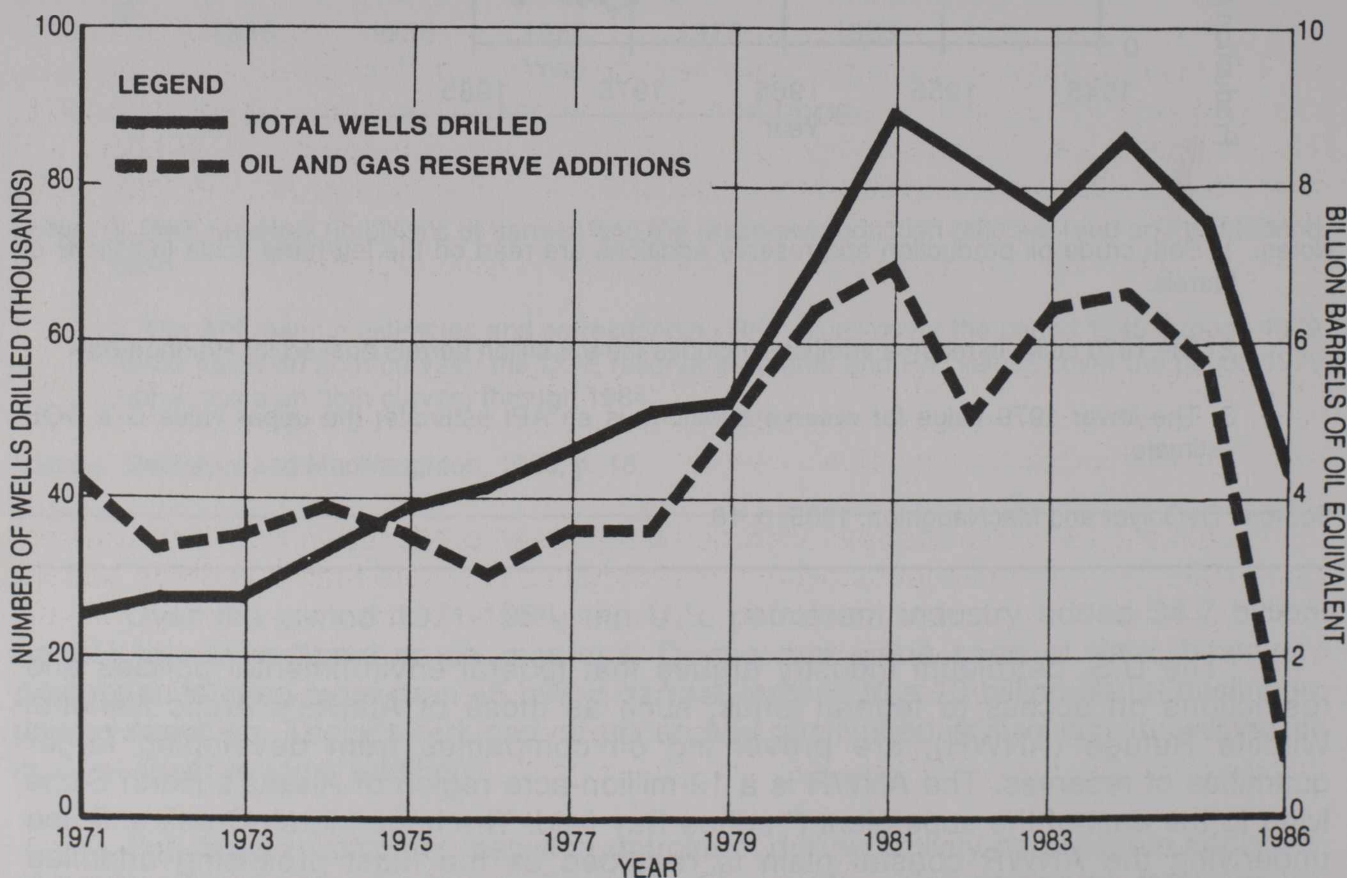
3. The lower 1979 value for reserve additions is an API estimate; the upper value is a DOE estimate.

Source: DeGolyer and MacNaughton, 1985, p. 18.

The U.S. petroleum industry argues that federal environmental policies and restrictions on access to federal lands, such as those of Alaska's Arctic National Wildlife Refuge (ANWR), are preventing oil companies from developing larger quantities of reserves. The ANWR is a 19-million-acre region of Alaska's North Slope lying to the east of the supergiant Prudhoe Bay field. The huge Marsh Creek anticline underlying the ANWR coastal plain is regarded as the most promising undrilled geologic structure remaining within the United States. Environmentalists argue that the migratory Porcupine caribou herd uses the entire ANWR coastal plain as calving grounds. This herd, estimated to contain 180,000 caribou, ranges over almost 100,000 square miles of northeast Alaska and northwest Canada. Industry representatives contend that petroleum development of all prospective regions of the coastal plain would modify less than 1% of this area. The U.S. Fish and Wildlife Service, together with the U.S. Geological Survey and the Bureau of Land Management, conducted a six-year study of the ANWR coastal plain, including an evaluation of the potential impact of petroleum development on the caribou herd. The study concluded that no appreciable decline in caribou population is anticipated as a result of oil development. The study also reported that the average estimate of oil in place was 13.8 billion barrels and of natural gas in place was 31.3 trillion cubic feet. The average estimate for recoverable reserves of crude oil was 3.2 billion barrels.

While it does seem that the nation's best remaining drilling prospects lie in the ANWR and in California's offshore area, it is also apparent that the prospects of finding large deposits of conventional crude oil in the future are diminishing.

Figure 28: U.S. Oil and Gas Reserve Additions Versus Drilling Activity



Source: U.S. National Petroleum Council, 1987, p. 88.

Apart from its reserves of conventional crude oil, the United States contains large deposits of nonconventional oil. An estimated 1.3% of the world's bitumen resource – amounting to about 43 billion barrels of bitumen in place – lies in the U.S. Roughly 10% of the world's nonconventional heavy oil is estimated to reside in the U.S. This resource is set at 90 billion barrels, of which about 18 billion barrels is considered recoverable in known fields and 10 billion barrels has already been produced. (Meyer and Schenk, 1985)

Dominating nonconventional U.S. oil resources, however, are oil shale deposits. A recent estimate of the total quantity of shale oil contained in these deposits is approximately 1.6 trillion barrels. No oil shale deposits are currently classified as reserves in the United States because their economic exploitation remains in question. (WEC, 1986, p. 61-63)

C. U.S. Oil Production and Consumption

The United States is the world's second largest oil (crude and NGL) producer, but it is also the largest consumer. The per capita consumption of all oils in the U.S. averaged 24.4 barrels in 1984, down from the peak of 31.0 barrels per person in 1978 (DeGolyer and MacNaughton, 1986, p.101). During 1986, average output of about 8.8 million barrels/day was derived from almost 640,000 wells. Viewed another way, 72% of the world's oil wells produced 16% of the world's oil last year, indicating the intensity of exploration and the maturity of the oil industry in the United States.

The United States holds only 4% of global conventional crude oil reserves to support this level of output. Although the reserves/production ratio for crude oil has fallen to about 8, the industry has continued to function with a reserves/production ratio less than 15 throughout most of this century.

Almost 150 billion barrels of crude oil has been produced in the United States since 1859, but conventional recovery technology has left more than 300 billion barrels in the ground. This cumulative average recovery of less than one-third of the oil originally in place can be improved upon by employing methods of enhanced oil recovery (EOR) – about 30 billion barrels of this oil remaining in place is estimated to be potentially recoverable using current and advanced EOR technology. However, at today's oil prices, many EOR projects are not profitable.

Table 5 illustrates why low oil prices are so damaging to the U.S. petroleum industry and why Middle East producers can use price, if they choose, to undercut American petroleum development. The United States has drilled more than 85% of the non-Communist world's currently producing oil wells. As Table 5 reveals, the wells of the Middle East are far more prolific producers, averaging about 3,100 barrels of daily output per well versus 14 barrels per day in the U.S. The discrepancy is even more striking in the case of Saudi Arabia. The Ghawar field in Saudi Arabia, the world's

Figure 30 is based on two oil price trends used by the NPC in its analysis of future U.S. oil supply and demand. The upper price trend starts at US$18 per barrel in 1986 and rises at a real rate of 5% per year to US$36 in the year 2000. The lower price trend starts at US$12 per barrel in 1986 and increases at a real rate of 4% annually to US$21 in 2000. The gap between U.S. oil demand and domestic supply was then projected by the NPC for these two pricing cases. In the high price case, the shortfall in domestic oil supply grows from the 1985 actual value of 4.2 million barrels/day to the projected 2000 value of 9.1 million barrels/day. Net imports of crude oil and products as a percentage of domestic oil demand correspondingly rise from 27% in 1985 to 52% in 2000. In the low price case – which promotes demand while inhibiting supply – net imports of crude oil and products rise to 13.6 million barrels/day by the turn of the century; imports grow to a 68% share of domestic use. (U.S. National Petroleum Council, 1987) In 1973, at the time of the Arab oil embargo, net oil imports represented about 35% of U.S. oil consumption.

In 1985, stripper wells (wells producing less than 10 barrels of oil daily) accounted for approximately 17% of U.S. oil output – 1.3 million barrels/day out of a total 7.6 million barrels/day of crude production. Average daily output from each of the 460,000 stripper wells was less than 3 barrels, compared with an average nonstripper well production rate of 45 barrels/day. These low-volume wells tend to have high per-barrel production costs and consequently are particularly vulnerable to falling oil prices.

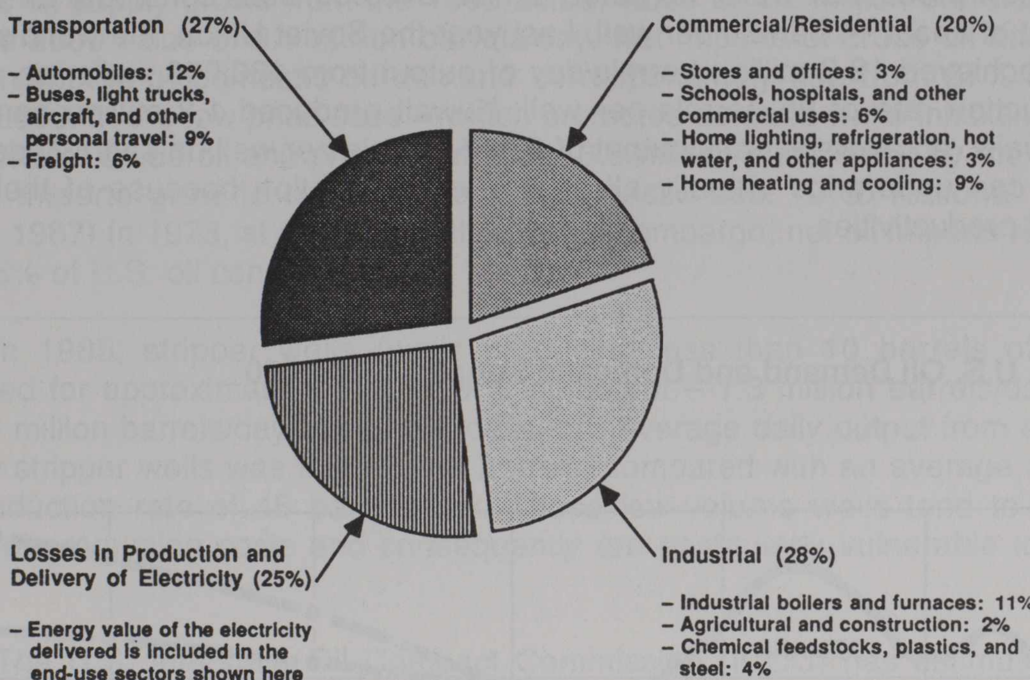
The U.S. Interstate Oil Compact Commission (IOCC) has estimated stripper well production losses at various oil prices. At a price of US$10 per barrel, the IOCC calculates a production loss of 638,000 barrels/day; at US$15 per barrel, 277,000 barrels/day; and at US$20 per barrel, 107,000 barrels/day. Stripper well production is concentrated in Texas, Oklahoma, California and Kansas.

The effect of the price slump on U.S. oil output is evident in production statistics. Figure 31 compares U.S. domestic oil supply (crude oil and NGL) in the first half of 1987 with that of the same period in 1986. Falling oil prices in 1986 forced down supply as uneconomic production was shut in or abandoned. In 1987, a partial price recovery is reflected in a marginal increase in supply. The companion to reduced supply is increased imports. Figure 32 compares imports of crude oil and products in the first half of 1987 with imports during the comparable period of 1986. The increased level of import this year is superimposed on the regular seasonal fluctuation.

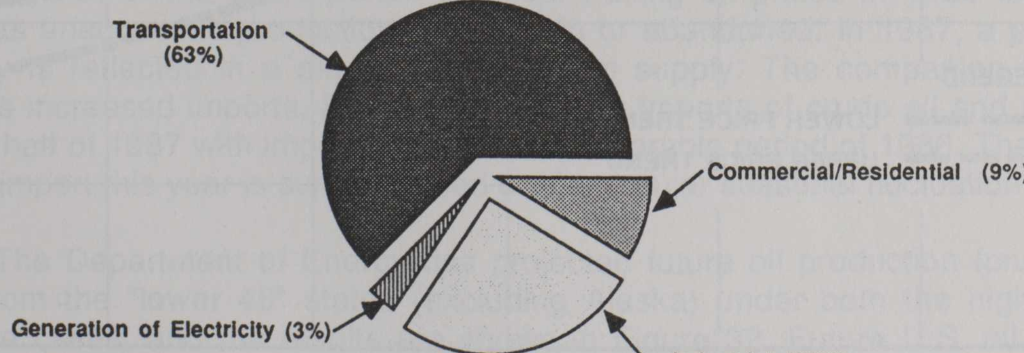
The Department of Energy has projected future oil production (crude oil and NGL) from the "lower 48" states (excluding Alaska) under both the high-price and low-price cases, and the results are shown in Figure 33. Future U.S. oil production drops more rapidly in the low price case as oil exploration and development activity is depressed and future reserve additions are smaller. Even in the high-price case, however, U.S. oil output continues a slow decline.

Figure 29: U.S. Consumption of Primary Energy and of Oil by Sector

Consumption of all U.S. primary energy broke down like this in 1985:



. . . and this is how oil consumption was divided among the major sectors:

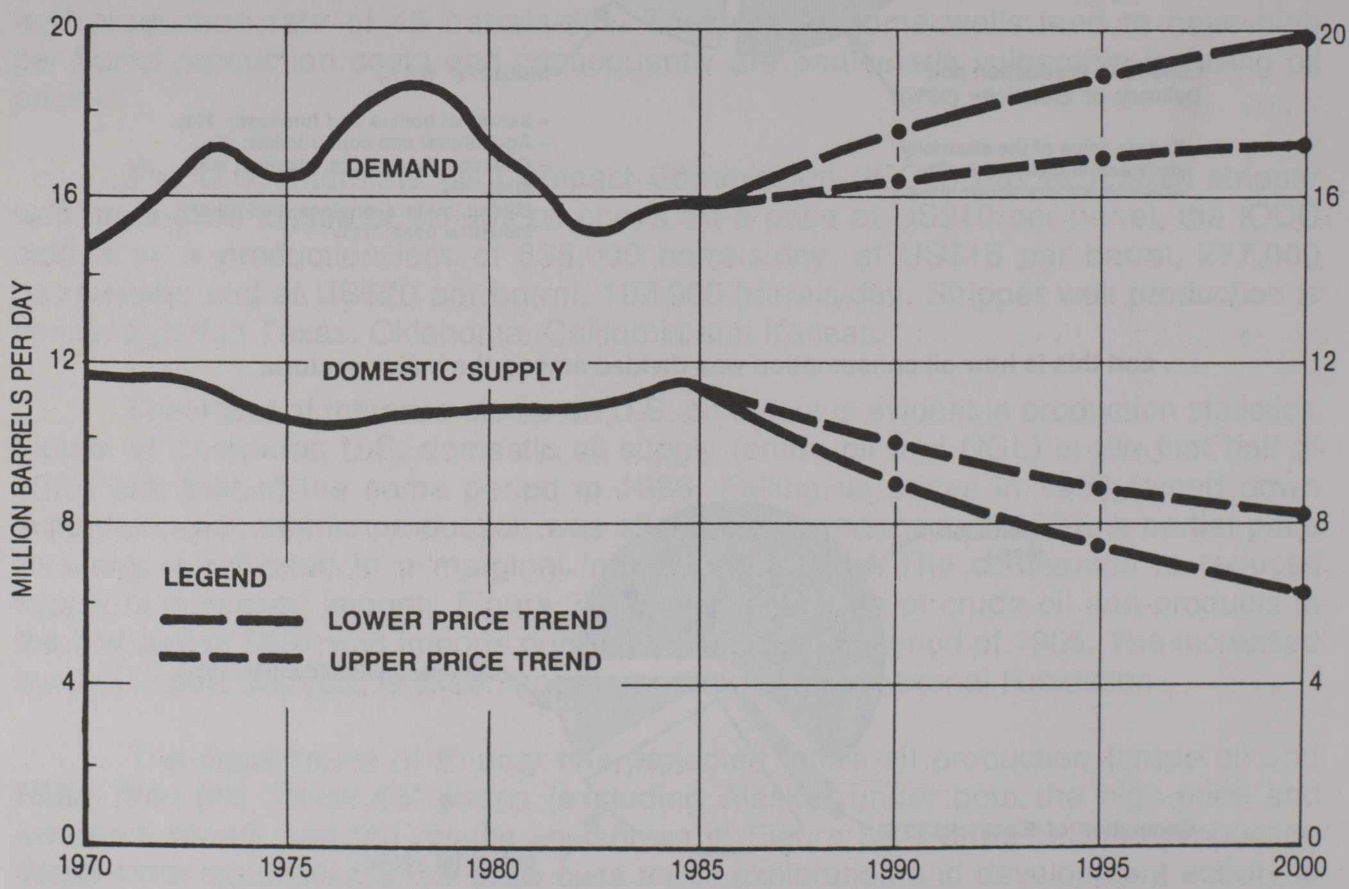


Source: U.S. Department of Energy, 1987, p. 100.

D. Low Prices and Future Oil Availability

Figure 30 illustrates the degree to which the U.S. oil supply-demand situation is predicated on the future price of oil. This price sensitivity is a function of the aging of the American oil industry. Most of the United States has been extensively explored for petroleum and production is currently being sustained from the output of a very large number of low-production wells. As noted earlier, 640,000 wells contribute an average daily output of about 14 barrels per well. Last year the Soviet Union, the world's largest producer, achieved 12.3 million barrels/day of output from 130,000 wells, an average daily production rate of 95 barrels per well. Kuwait produced 1.2 million barrels/day from 363 wells, an average daily output of 3,305 barrels per well. In short, Middle East producers can underprice virtually all of U.S. oil production because of their much higher well productivities.

Figure 30: U.S. Oil Demand and Domestic Supply, 1970-2000



Source: U.S. National Petroleum Council, 1987, p. 6.

Figure 29 is based on two oil price trends used by the NPC in its analysis of future U.S. oil supply and demand. The upper price trend starts at US$18 per barrel in 1986 and rises at a real rate of 5% per year to US$36 in the year 2000. The lower price trend starts at US$12 per barrel in 1986 and increases at a real rate of 4% annually to US$21 in 2000. The gap between U.S. oil demand and domestic supply was then projected by the NPC for these two pricing cases. In the high price case, the shortfall in domestic oil supply grows from the 1985 actual value of 4.2 million barrels/day to the projected 2000 value of 9.1 million barrels/day. Net imports of crude oil and products as a percentage of domestic oil demand correspondingly rise from 27% in 1985 to 52% in 2000. In the low price case – which promotes demand while inhibiting supply – net imports of crude oil and products rise to 13.6 million barrels/day by the turn of the century; imports grow to a 68% share of domestic use. (U.S. National Petroleum Council, 1987) In 1973, at the time of the Arab oil embargo, net oil imports represented about 35% of U.S. oil consumption.

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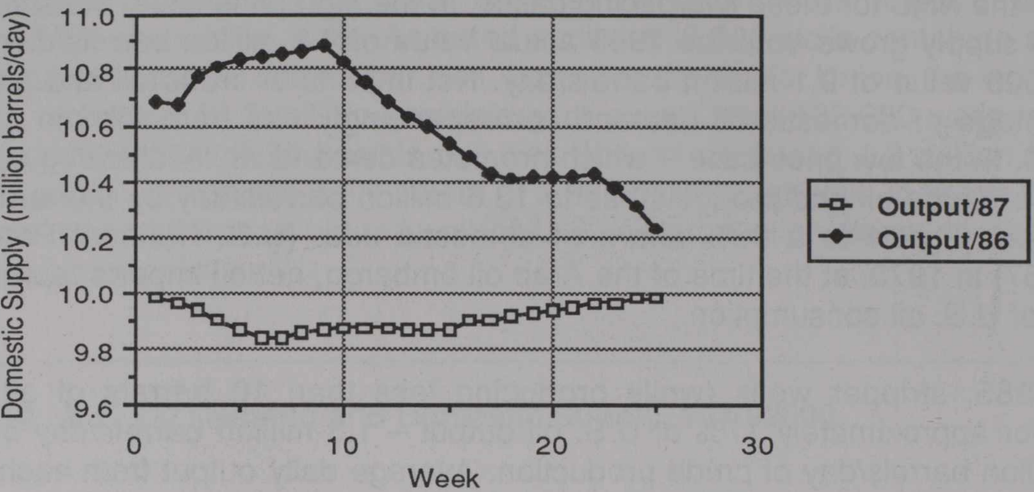
The effect of the price slump on U.S. oil output is evident in production statistics. Figure 30 compares U.S. domestic oil supply (crude oil and NGL) in the first half of 1987 with that of the same period in 1986. Falling oil prices in 1986 forced down supply as uneconomic production was shut in or abandoned. In 1987, a partial price recovery is reflected in a marginal increase in supply. The companion to reduced supply is increased imports. Figure 31 compares imports of crude oil and products in the first half of 1987 with imports during the comparable period of 1986. The increased level of import this year is superimposed on the regular seasonal fluctuation.

The Department of Energy has projected future oil production (crude oil and NGL) from the "lower 48" states (excluding Alaska) under both the high-price and low-price cases, and the results are shown in Figure 32. Future U.S. oil production drops more rapidly in the low price case as oil exploration and development activity is depressed and future reserve additions are smaller. Even in the high-price case, however, U.S. oil output continues a slow decline.

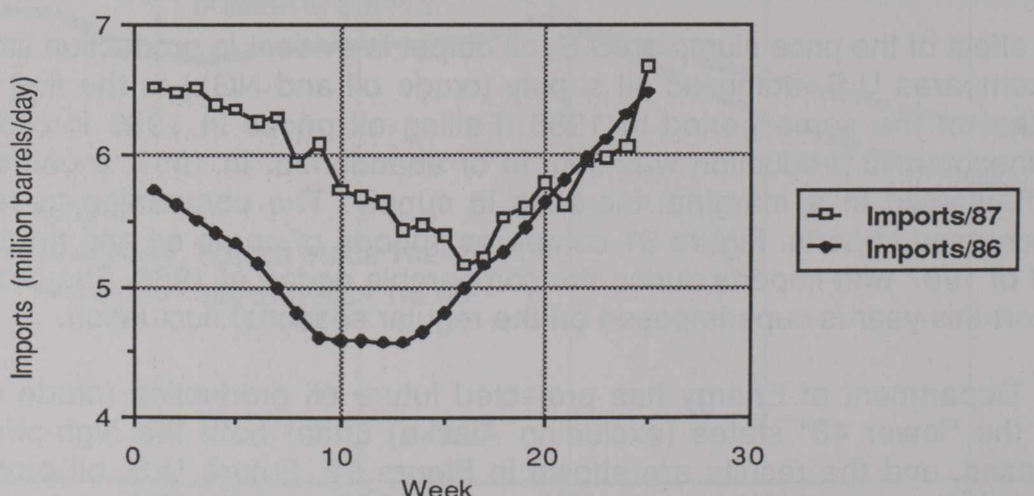
Figure 31: U.S. Domestic Oil Supply in 1987 Compared with 1986



Note: Supply includes both crude oil and NGL.

Source: "Industry Scoreboard", *Oil & Gas Journal*, various issues, 1986 and 1987.

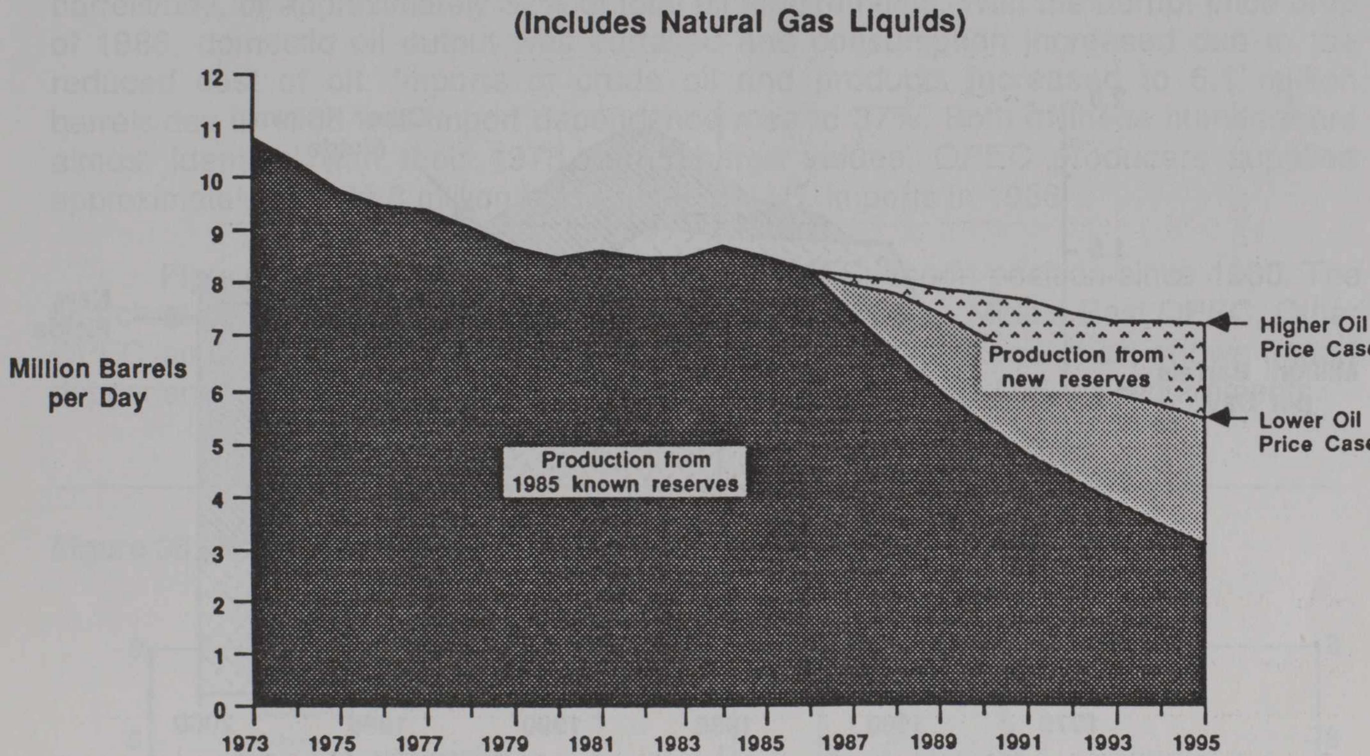
Figure 32: U.S. Oil Imports in 1987 Compared with 1986



Note: Imports include crude oil and products.

Source: "Industry Scoreboard", *Oil & Gas Journal*, various issues, 1986 and 1987.

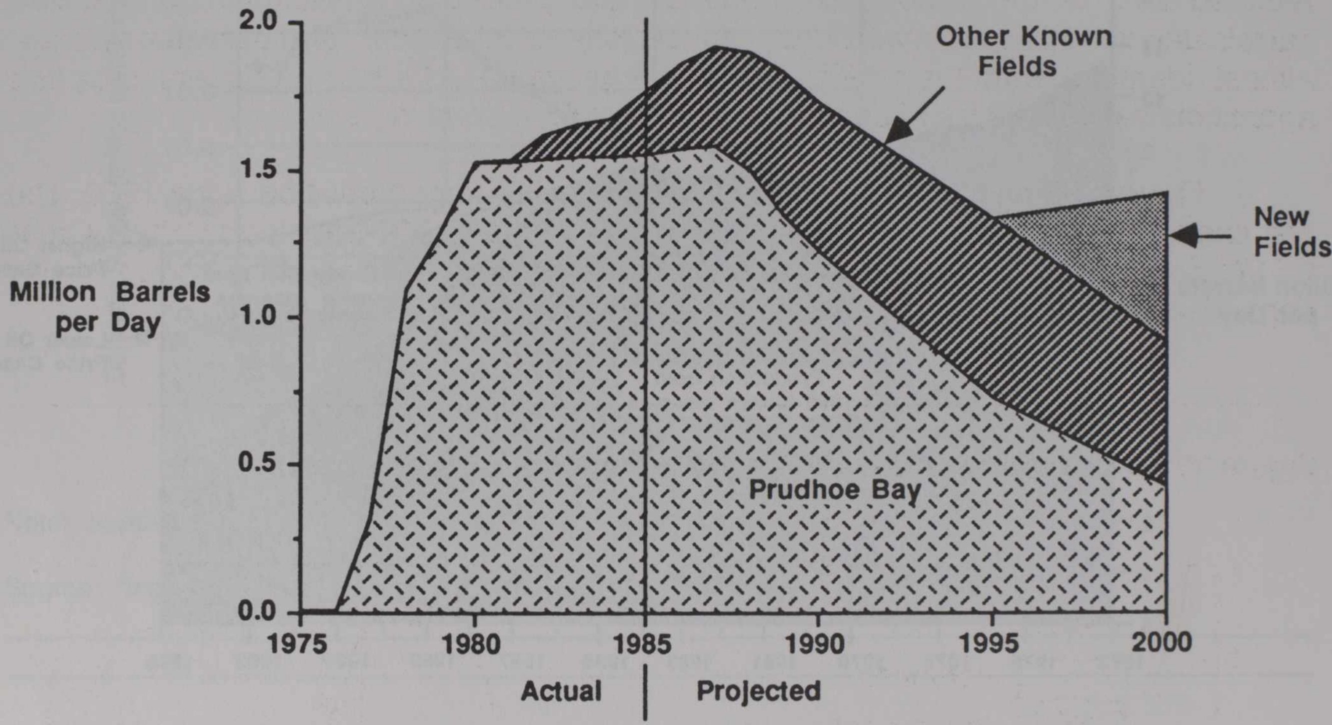
Figure 33: Projected Oil Production in the Lower 48 States



Source: U.S. Department of Energy, 1987, p. 64.

Alaskan North Slope oil output is charted separately in Figure 34, showing the coming drop in Prudhoe Bay production. Mature production at Prudhoe Bay has been about 1.5 million barrels/day but, beginning in 1988, liftings from this supergiant field will begin their decline. By the mid-1990s, Prudhoe Bay oil will be flowing at only half of its present volume; at the end of the century, output is projected to fall below 0.5 million barrels/day. Production from other known fields on the North Slope can offset only a fraction of this loss. If petroleum exploration and development is allowed in the ANWR, there is the possibility of a resurgence in North Slope production by the turn of the century.

Figure 34: Projected Alaskan North Slope Oil Production



Notes: 1. "Other Known Fields" include Kuparuk, Milne Point, NGL Project, Gwydyr Bay, Point Thompson, Seal Island and West Sak.

2. "New Fields" includes potential development of the Arctic National Wildlife Refuge.

Source: U.S. Department of Energy, 1987, p. 65.

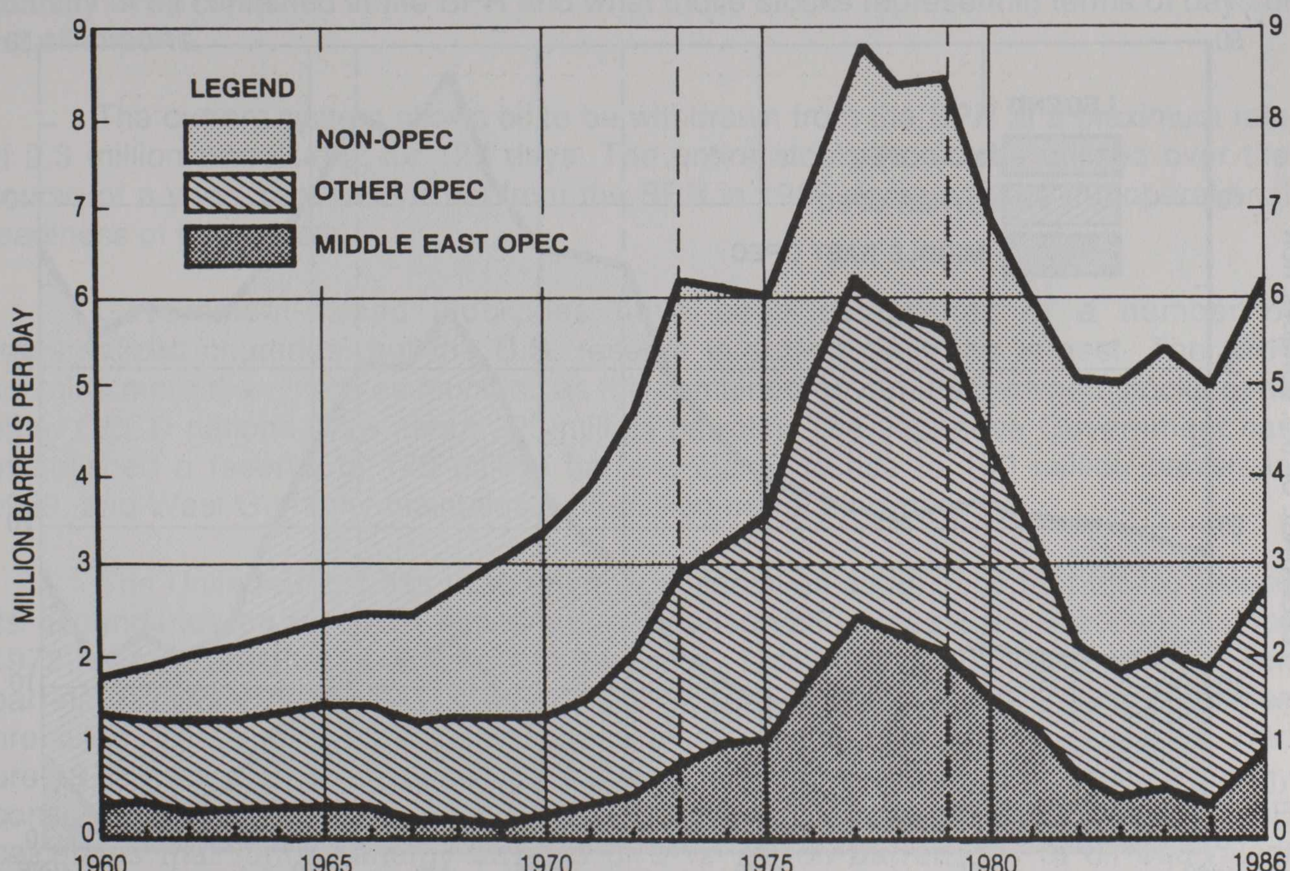
E. The Implications of Rising Imports

At the time of the Arab oil embargo, which began in October 1973, U.S. imports of crude oil and products had risen to more than 6 million barrels/day and represented approximately 37% of U.S. oil consumption. These imports were split about equally between OPEC and non-OPEC sources. Canada was the single largest supplier of oil to the United States and provided more crude in 1973 (about 1 million barrels/day) than all of the Middle East suppliers combined (about 0.8 million barrels/day).

U.S. imports of crude oil and refined products peaked in 1977, at 8.8 million barrels/day or 47% of U.S. requirements. By that time, OPEC was supplying almost 70% of U.S. import needs, equivalent to one-third of total American oil consumption. Imports of crude oil and products subsequently bottomed in 1985 at 5 million barrels/day, or approximately 32% of total oil requirements. With the abrupt price drop of 1986, domestic oil output was curtailed and consumption increased due to the reduced cost of oil. Imports of crude oil and products increased to 6.1 million barrels/day in 1986 and import dependence rose to 37%. Both of these numbers are almost identical with their 1973 pre-embargo values. OPEC producers supplied approximately 45% (2.8 million barrels/day) of U.S. imports in 1986.

Figures 35 and 36 illustrate the fluctuating U.S. import position since 1960. The first chart portrays import dependence by source of the oil – Middle East OPEC, Other OPEC and Non-OPEC – and by quantity imported. The second chart shows import dependence again by source but also as a percentage of total U.S. oil requirements.

Figure 35: U.S. Imports of Crude Oil and Refined Products by Source

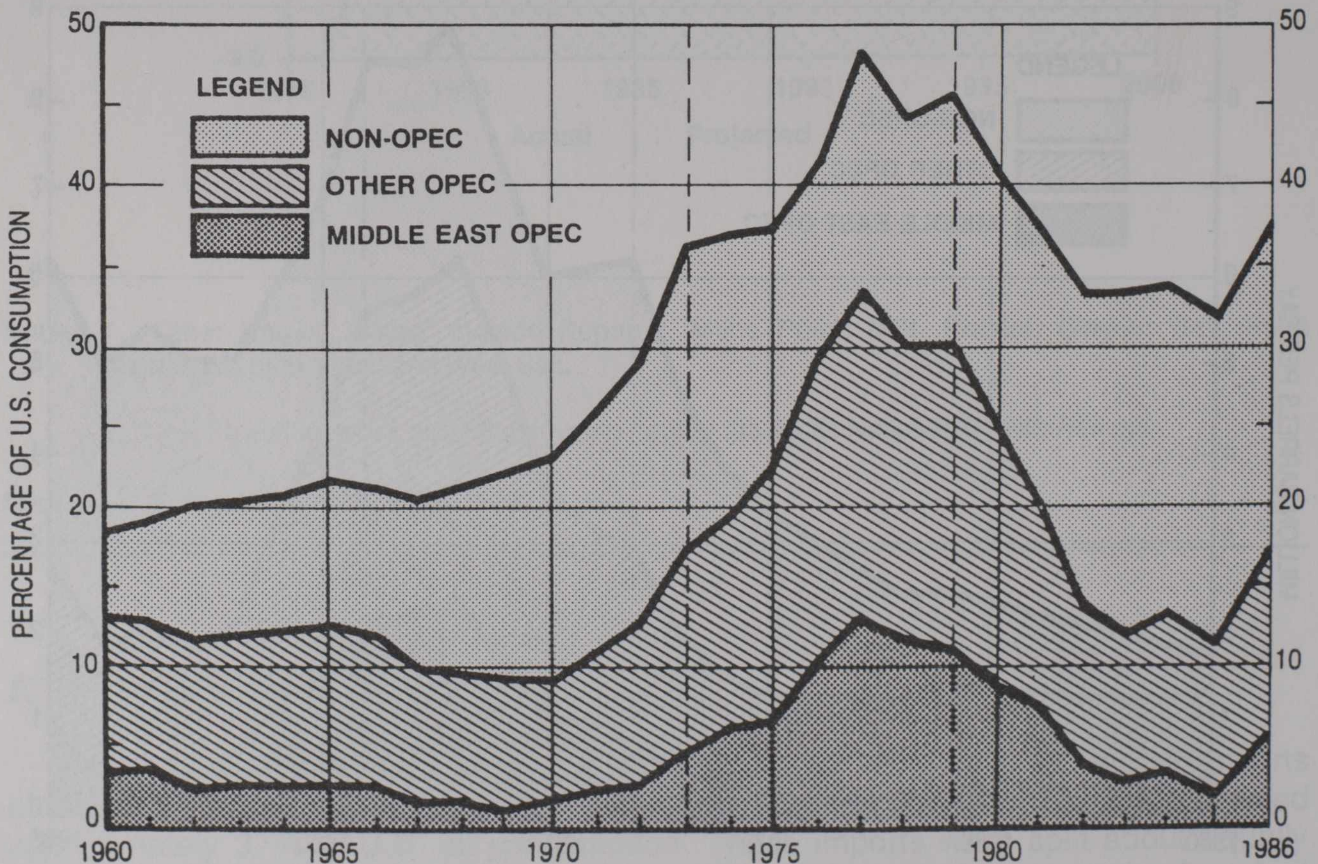


Source: U.S. National Petroleum Council, 1987, p. 36.

During 1986, Mexico and Saudi Arabia were the leading crude oil suppliers to the United States, each satisfying about 15% of American import needs. Canada stood third, providing about 13%. (In the latter part of 1986, Canada was the largest combined supplier of crude oil and products.) Venezuela and Nigeria each provided about 10% of U.S. imports. The United Kingdom was the sixth largest supplier last year, providing 8%, and Indonesia was seventh at 7%.

Thus four of the seven leading exporters to the United States in 1986 were members of OPEC and those four provided 42% of U.S. imports. Of the remaining three, Canada and the United Kingdom face declining production and will recede in importance as U.S. suppliers. Mexico has the reserves base to expand production, perhaps to twice its present rate, but may lack the financial resources as it struggles with its enormous burden of foreign debt. Among other non-OPEC producers, only Norway appears to have the capability to substantially raise its output. Even if Mexico and Norway doubled their current rates of production, however, that increase would cover only about half of the projected decline among other non-OPEC producers.

Figure 36: U.S. Imports of Crude Oil and Refined Products as a Percentage of Use



Source: U.S. National Petroleum Council, 1987, p. 36.

The United States faces increasing imports of foreign oil, with OPEC claiming an increasing share of the imports. Barring some dramatic action, the United States will see its imports of OPEC oil rise to unprecedented levels in the remainder of this century. At present the U.S. energy system is more resilient and less vulnerable to oil supply disruptions than it was in 1973, because of its Strategic Petroleum Reserve (SPR), because of an increased domestic capability for fuel switching, and because of the greater diversity in non-OPEC sources of oil supply. Non-OPEC oil supply will shrink in the future, however, and, as U.S. imports continue their rise, the SPR will have to be filled at a more rapid rate to maintain the same level of import protection (that is, the number of days that the SPR would last if used to replace imports).

F. The Strategic Petroleum Reserve and Other Defences

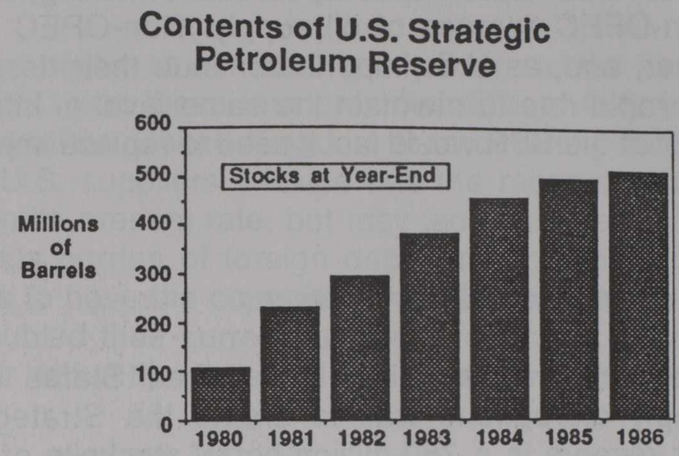
One of the principal actions taken by the United States to reduce its vulnerability to future supply disruptions was to create the Strategic Petroleum Reserve. The target of this reserve is a 750-million-barrel stockpile of crude oil; the actual quantity of oil in the SPR now exceeds 500 million barrels. At current import levels, this corresponds to about 90-100 days of net imports. Figure 37 indicates the quantity of oil contained in the SPR and what those stocks represent in terms of days of net oil imports.

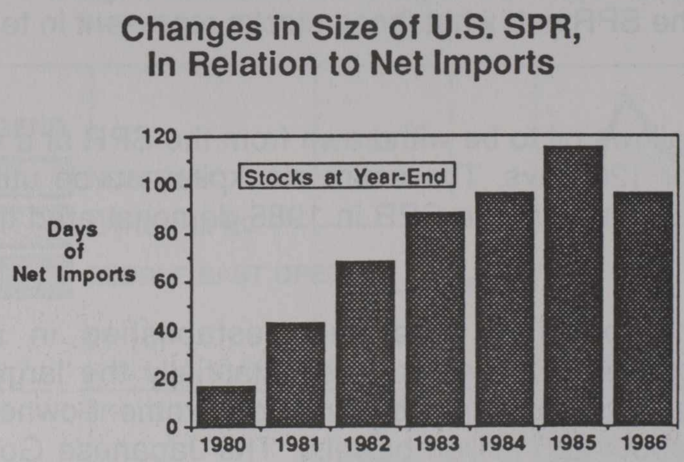
The current system allows oil to be withdrawn from the SPR at a maximum rate of 2.3 million barrels/day for 120 days. The entire stockpile can be utilized over the course of a year. Test production from the SPR in 1986 demonstrated the operational readiness of the system.

Government-owned stockpiles have been established in a number of industrialized countries, but the U.S. reserve is substantially the largest. The SPR contains more than twice as much oil as the combined government-owned stocks of all other OECD nations (now about 225 million barrels). The Japanese Government has established a reserve of 140 million barrels, slated to rise to 190 million barrels in 1989, and West Germany maintains a 55-million-barrel stockpile.

The United States has used energy conservation as an important tool to reduce its dependence on oil. DOE estimates that conservation measures introduced since 1973 have resulted in a U.S. demand for energy today that is equivalent to 14 million barrels of oil/day (29 quads of energy per year) below what would have otherwise prevailed. These gains have been made in all sectors of the U.S. economy. Had pre-1972 trends in energy use continued, it is estimated that U.S. annual energy consumption would be about 40% higher than is actually the case today. DOE calculates that further energy savings of 5-12 million barrels/day of oil equivalent (10-25 quads annually) could be achieved by 2000 if existing cost-effective conservation technologies, together with technologies anticipated from future R&D, were applied fully. (U.S. Department of Energy, 1987)

Figure 37: The U.S. Strategic Petroleum Reserve



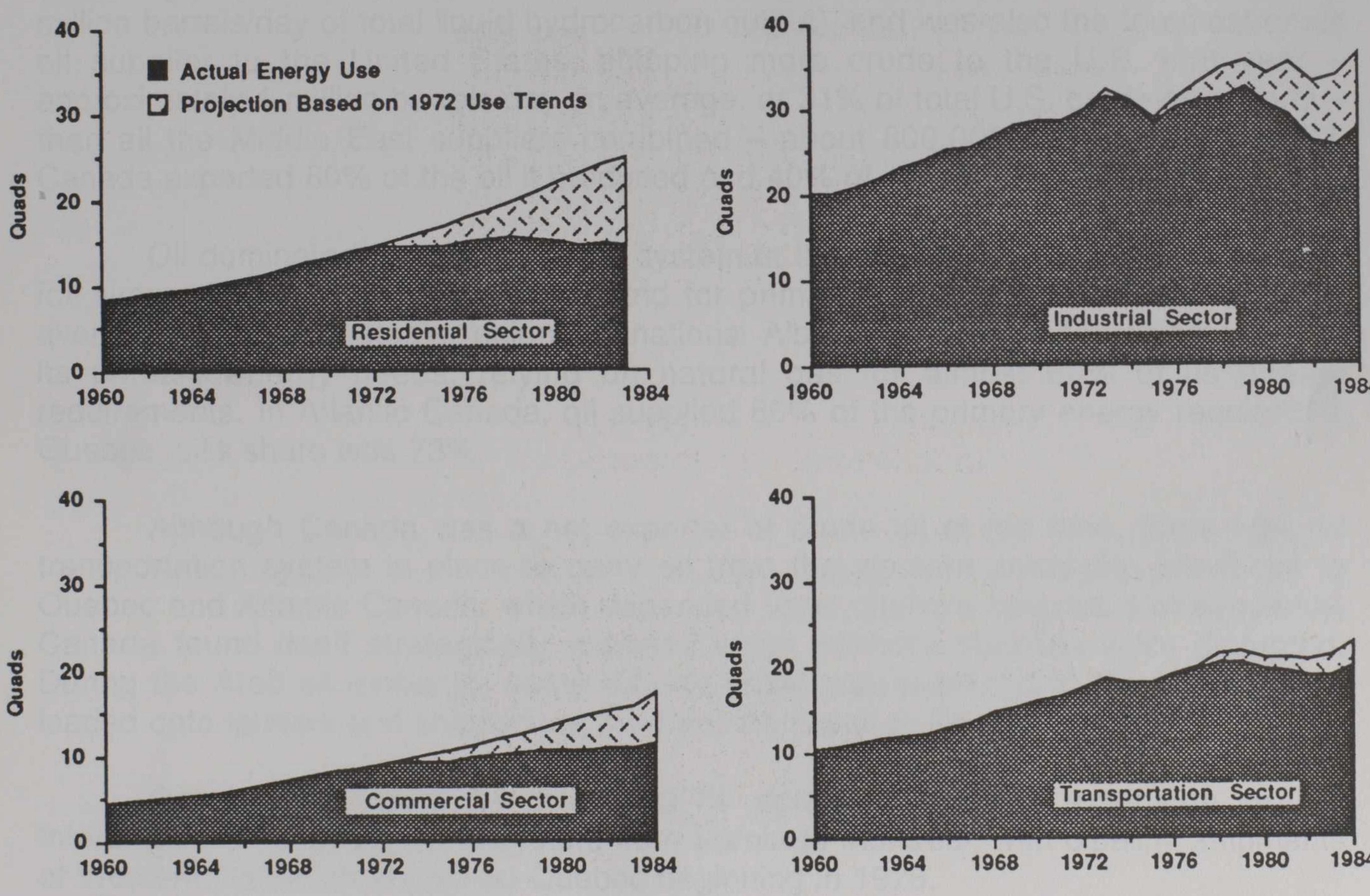


Source: U.S. Department of Energy, 1987, p. 215.

Figure 38 shows estimated energy savings since 1973 in the U.S. economy. It is apparent from Figure 38 that the transportation sector has been the most difficult one in which to achieve greater efficiencies in energy use.

Advances in conservation technology have been credited by the U.S. Government with contributing two-thirds of the energy savings in the industrial sector and three-quarters of those in the transportation sector. This demonstrates the importance of supporting conservation R,D&D. Changes in the structure of the U.S. economy towards the manufacture of less energy-intensive goods have also been a factor, as have the initiatives taken by indivdual consumers.

Figure 38: Energy Savings since 1973 in the U.S. Economy



Source: U.S. Department of Energy, 1987, p. 97.

CANADIAN OIL SUPPLY IN QUESTION

A. Energy Developments Since 1973

At the time of the Arab oil embargo and first price shock in 1973, Canada was experiencing its peak year of crude oil production and export. Canada was the world's tenth largest producer, at 1.74 million barrels/day of conventional crude oil (and 2.12 million barrels/day of total liquid hydrocarbon output), and was also the foremost crude oil supplier to the United States, shipping more crude to the U.S. that year – approximately 1 million barrels/day on average, or 31% of total U.S. crude oil imports – than all the Middle East suppliers combined – about 800,000 barrels/day. In 1973, Canada exported 60% of the oil it produced and 40% of its marketable gas output.

Oil dominated Canada's energy system at the time of the embargo, accounting for almost 55% of the domestic demand for primary energy. However, this national average concealed notable regional variations. Alberta used oil to satisfy only 28% of its primary energy needs, relying on natural gas for almost 60% of its energy requirements. In Atlantic Canada, oil supplied 86% of the primary energy required; in Quebec, oil's share was 73%.

Although Canada was a net exporter of crude oil at the time, there was no transportation system in place to carry oil from the western producing provinces to Quebec and Atlantic Canada, which depended upon offshore sources. Consequently, Canada found itself strategically exposed when offshore supplies were disrupted. During the Arab oil embargo, some Alberta crude was pipelined to the West Coast, loaded onto tankers and shipped via the Panama Canal to Eastern Canada.

One consequence of the 1973-74 episode was the extension of the Interprovincial Pipe Line (IPL) system from Sarnia to Montreal, with pipeline shipments of Western Canadian crude into Quebec beginning in 1976.

At the time of the second price shock in 1979-80, Canada was a net importer of oil. Although crude purchases from OPEC had fallen from 796,000 barrels/day to about 500,000 barrels/day in 1979, domestic output had dropped by 20% over the intervening six years and the demand for oil had risen by 11%. The National Energy Board was continuing to forecast a declining availability of light crude from the conventional producing area of Western Canada. In its 1978 report on Canadian oil supply and demand, the Board estimated that the average rate of production from established reserves would fall by about 8% annually (NEB, 1978).

In contrast, Canada's reserves position for natural gas was much better. Annual reserve additions in Western Canada were consistently exceeding production and significant discoveries had been made in the Mackenzie Delta/Beaufort Sea and in the Arctic Islands. (Approximately one-quarter of Canada's established reserves of natural gas lie in the north and remain unconnected.) The reserves/production ratio for natural gas in 1979 was approximately 28; for conventional crude oil it was less than 12. However, most of Eastern Canada lacked access to western gas supplies because the pipeline system served the domestic market only as far east as the Montreal area.

Canada's National Energy Program (NEP), announced 28 October 1980, was based on two premises: that oil prices would continue to rise (the Program scheduled domestic price increases through 1990, reaching a level of $63.75 per barrel for conventional 38° API crude oil with an "oil sands reference price" of $79.65 per barrel); and that Canadian prices could be shielded from developments in volatile international markets. Import compensation, a system of subsidization introduced in 1974 to maintain a lower-than-international price for crude oil in Canada, continued under the NEP. The National Energy Program marked the first time that the federal government had raised the issue of energy demand to a more even footing with that of supply. The government intended to reduce the share of oil in domestic energy use by more than a third by 1990, corresponding to a decline in forecast oil consumption of 20%, from 1.82 million barrels/day in 1979 to 1.48 million barrels/day in 1990. To achieve this, three approaches were taken to modify energy demand: energy conservation was vigorously promoted, off-oil conversions to other energy forms were encouraged, and renewable energy development was supported. (EMR, 1980)

The Canadian Home Insulation Program (CHIP) was the main component of the conservation program. Under the NEP, the annual CHIP budget was increased from $80 million to $256 million and the target set was insulation upgrading in 70% of Canadian homes by 1987. Conservation initiatives in the industrial and transportation sectors complemented the residential program.

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

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

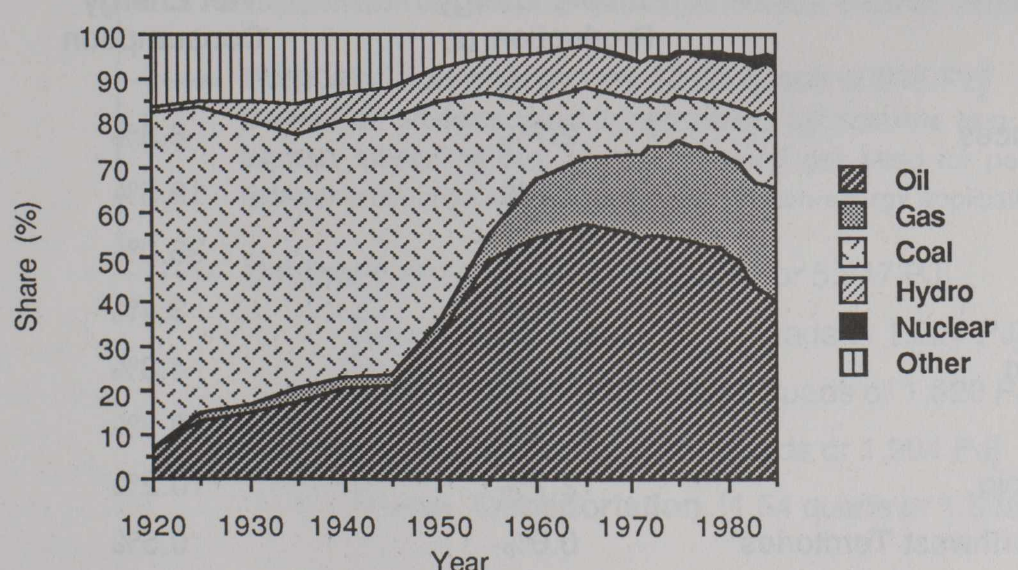
The NEP and higher oil prices combined to produce a remarkable reduction in both the domestic demand for oil and its share of the primary energy mix. Oil substitution, with its additional costs, was achieved despite the severe recession. Over the five-year period 1980-1984, the share of oil in Canada's primary energy demand fell from 50.6% to 41.8%, a 17% drop in relative use. Natural gas increased its share from 21.9% to 24.6% over the same period, primary electricity rose from 11.6% to 13.8% and coal increased from 11.6% to 15.5%. (EMR, undated, p. 2.3A)

B. Canadian Energy Supply and Demand

The way Canadians use energy has changed markedly in recent years. The share commanded by oil in Canada's primary energy consumption ran at about 55% in the late 1960s. Following the first oil price shock, oil's share of the primary energy mix declined slowly to approximately 50% in 1980. The second price shock triggered a more rapid decline which continued through 1985; that year, oil accounted for 40% of primary energy demand. The use of natural gas grew most over this period. Its share of the energy mix increased from 15.2% in 1965 to 22.0% in 1975 and to 25.5% in 1985.

Figure 39 shows the share of Canadian primary energy demand that each energy form claimed over the period 1920-1985. Coal fell from 75.0% of primary energy use in 1920 to its low point of 9.3% in 1974, thereafter rising to 14.6% in 1985. Hydro-electricity has slowly raised its share, from 1.5% in 1920 to 12.1% in 1985. Nuclear-electric generation grew from virtually nothing in 1965 to 2.7% in 1985. Other energy forms – including fuelwood, waste wood, spent pulping liquor, primary steam (included since 1973 in EMR statistics) and other unspecified fuels – declined from an estimated 16.3% of demand in 1920 (principally as fuelwood) to a low of 2.5% in 1965, rising to 5.0% of primary energy demand in 1985.

Figure 39: The Mix in Canadian Primary Energy Demand, 1920-1985



Note: "Other" includes fuelwood, waste wood, spent pulping liquor, primary steam (since 1973) and other unspecified fuels. Wood and pulping liquor, forms of biomass, comprise most of this category.

Source: EMR, undated, p. 2.3A.

Canadian primary energy production and net domestic energy consumption slumped in the early 1980s as the effects of higher petroleum prices, energy conservation and the severe recession were reflected in the energy sector. According to Statistics Canada (which values all primary electricity at 3,412 Btu or 3.6 MJ per kWh), primary energy production amounted to 8.12 quads (8.12 quadrillion Btu, equal to 8,559 petajoules) in 1980, declined to 7.88 quads (8,303 PJ) in 1981 and has since grown to 9.42 quads (9,931 PJ) in 1985, a gain of almost 20% over a period of five years. The fall in energy consumption lagged behind and was more pronounced than the drop in primary energy output. Consumption stood at 7.00 quads (7,382 PJ) in 1980 and subsequently fell to 6.34 quads (6,685 PJ) in 1983, a reduction of close to 10%, before recovering to 6.81 quads (7,181 PJ) in 1985. (Statistics Canada, 1986)

An issue which remains largely unremarked is the striking regional imbalances across Canada in energy production and consumption, portrayed in Table 6. One province, Alberta, accounts for two-thirds of Canada's total primary energy production while another province, Ontario, represents more than one-third of net energy consumption. Federal energy policy should address these imbalances.

Table 6: Primary Energy Production and Net Energy Consumption by Region of Canada in 1985

Region	Primary Energy Production (a)	Net Energy Consumption
Atlantic Provinces	2.7%	6.3%
Quebec	5.0%	19.5%
Ontario	3.7%	35.0%
Manitoba	1.1%	3.4%
Saskatchewan	7.0%	4.8%
Alberta	67.0%	20.3%
British Columbia	12.7%	10.2%
Yukon and Northwest Territories	0.6%	0.5%

(a) This column does not total 100.0% because of round-off errors.

Source: Statistics Canada, 1986, p. 2-3.

The relationship between primary energy production and net energy consumption can be seen in Figure 40 which shows the 1985 flow of energy in Canada from primary energy supply to end-use energy demand.

Figure 40: The Flow of Energy in Canada in 1985 (a)

Primary energy production [9.42 quads or 9,931 PJ]

Plus energy imports; minus energy exports; plus/minus energy stock changes. (b)

Gross domestic energy availability [7.46 quads or 7,866 PJ]

Minus conversion losses in thermal-electric generation; minus fuel uses and losses in energy production, conversions and distribution, apart from each energy-producing industry's use of its own produced fuel (e.g., the use of natural gas to upgrade bitumen at an integrated tar sands plant falls into this category).

Net domestic energy consumption [6.81 quads or 7,181 PJ]

- **Producer consumption** [0.69 quads or 726 PJ]
  Use by each energy-producing industry of its own fuel (e.g., the consumption of refined products by the oil refining industry; the use of gas as a fuel for pipeline transportation of gas by the natural gas industry; electrical transmission losses).
- **Domestic non-energy use** [0.58 quads or 615 PJ]
  Refined oil products used in non-energy applications (e.g. petrochemicals, asphalt, lubricating oils, greases); natural gas used for petrochemical and fertilizer production; coal products used in non-energy applications.
- **Domestic energy use** [5.55 quads or 5,847 PJ]
  - **Residential** [1.23 quads or 1,297 PJ] =22%
  - **Commercial** [0.97 quads or 1,020 PJ] =17%
  - **Industrial** [1.81 quads or 1,904 PJ] =33%
  - **Transportation** [1.54 quads or 1,625 PJ] =28%

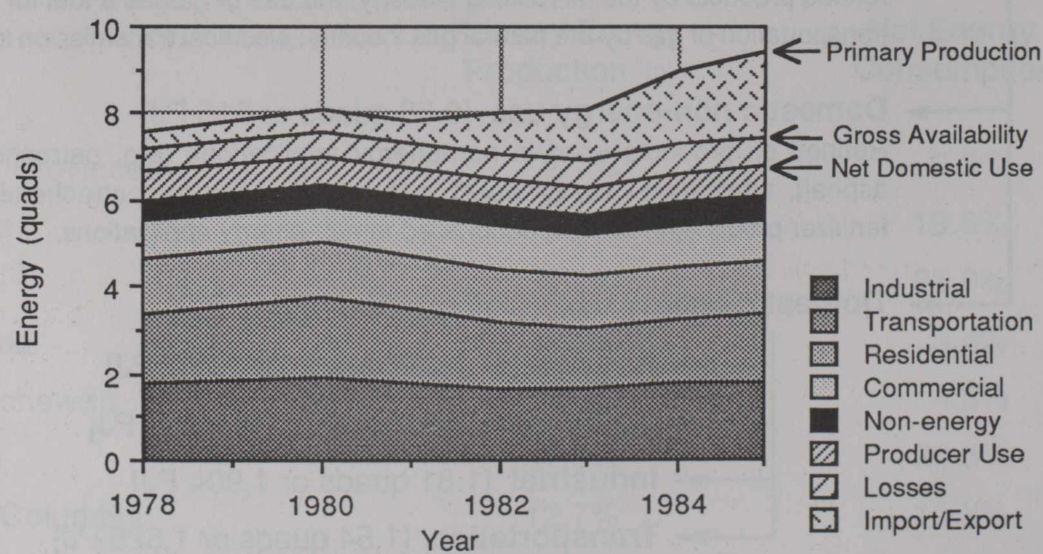
(a) Subcategories may not sum to category totals precisely because of round-off errors.
(b) All imports and exports of electricity are assumed to be from primary sources, so no thermal-electric generating losses are calculated for this category.

Source: Statistics Canada, 1986, p. 1.

The bottom section of Figure 40 provides the distribution of end-use energy demand in Canada for 1985. The industrial sector (most of the goods-producing industries) claims the largest share at 33%, but transportation (energy used in transporting goods, services and people) is not far behind at 28%. Residential energy requirements (energy used in households and farms) account for 22% of demand. Commercial sector (service-producing industries, including government but excluding transportation) energy use accounts for the remaining 17% of end-use energy demand.

Figure 41 shows how Canadian primary energy production and net domestic energy consumption have changed over the period 1978-1985. The top line represents the total production of primary energy in Canada since 1978. Accounting for energy imports and exports and net changes in energy stocks yields the second line, gross energy availability in Canada. Subtracting certain uses and losses of energy in production, conversion and distribution yields the third line, net domestic consumption of energy. Consumption is divided into producer use of energy, non-energy applications, and energy demand in the industrial, transportation, residential and commercial sectors of the economy.

Figure 41: Energy Supply and Demand in Canada, 1978-1985



Source: Statistics Canada, 1986, p. 1.

C. Oil Resources, Reserves and Producibility

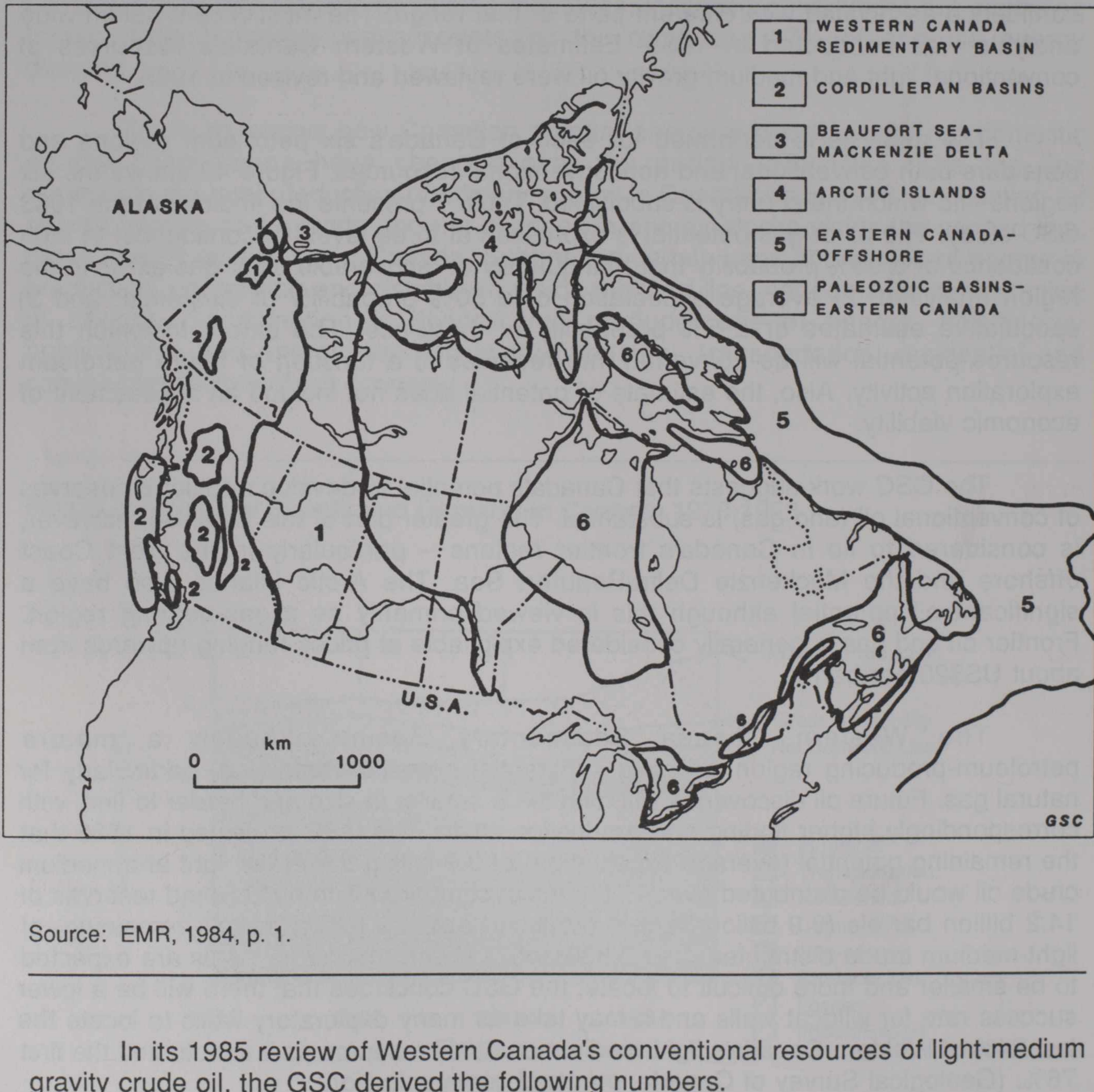
Canada's petroleum resources are periodically and systematically evaluated by the Geological Survey of Canada (GSC). These estimates are prepared using a form of probability analysis which yields a range of values along with a level of confidence associated with different parts of that range. The most recent nation-wide analysis was conducted in 1983. Estimates of Western Canada's resources of conventional light and medium gravity oil were reviewed and revised in 1985.

The analysis is performed for each of Canada's six petroleum regions and considers both conventional and nonconventional resources. Figure 42 shows the six regions into which the country is subdivided. Table 7 presents the findings of the 1983 GSC study. The oil or gas potential is expressed at three levels of confidence: 1) high confidence or a 95% probability that that quantity of recoverable oil or gas exists in the region analysed; 2) average expectation or a 50% probability of existence; and 3) speculative estimates or a 5% probability of existence. The extent to which this resource potential will be converted into reserves is a function of future petroleum exploration activity. Also, the estimate of potential does not include an assessment of economic viability.

The GSC work suggests that Canada's potential to develop additional reserves of conventional oil (and gas) is substantial. The greater part of this potential, however, is considered to lie in Canada's frontier regions – particularly in the East Coast offshore and the Mackenzie Delta/Beaufort Sea. The Arctic Islands also have a significant oil potential although this is viewed primarily as a gas-bearing region. Frontier oil and gas is generally considered exploitable at prices ranging upwards from about US$20 per barrel.

The Western Canada Sedimentary Basin, although a mature petroleum-producing region, still has substantial potential remaining, particularly for natural gas. Future oil discoveries will tend to be smaller in size and harder to find, with correspondingly higher finding and production costs. The GSC projected in 1985 that the remaining potential (average expectation) of 3.7 billion barrels of light and medium crude oil would be distributed over 4,000 pools, compared with established reserves of 14.2 billion barrels (9.9 billion barrels produced and 4.3 billion barrels remaining) of light-medium crude distributed over 3,300 pools. Given that future pools are expected to be smaller and more difficult to locate, the GSC concludes that there will be a lower success rate for wildcat wells and it may take as many exploratory wells to locate the last 24% of Western Canada's light-medium crude oil resource as it took to find the first 76%. (Geological Survey of Canada, personal communication)

Figure 42: Canada's Petroleum Regions



Source: EMR, 1984, p. 1.

In its 1985 review of Western Canada's conventional resources of light-medium gravity crude oil, the GSC derived the following numbers.

Remaining established reserves: 4.3 billion barrels (684 million cubic metres)

Potential: (1) high confidence – 2.9 billion barrels (460 million cubic metres)
(2) average expectation – 3.7 billion barrels (590 million cubic metres)
(3) speculative estimate – 4.8 billion barrels (770 million cubic metres)

Table 7: Canada's Conventional Oil and Natural Gas Resources

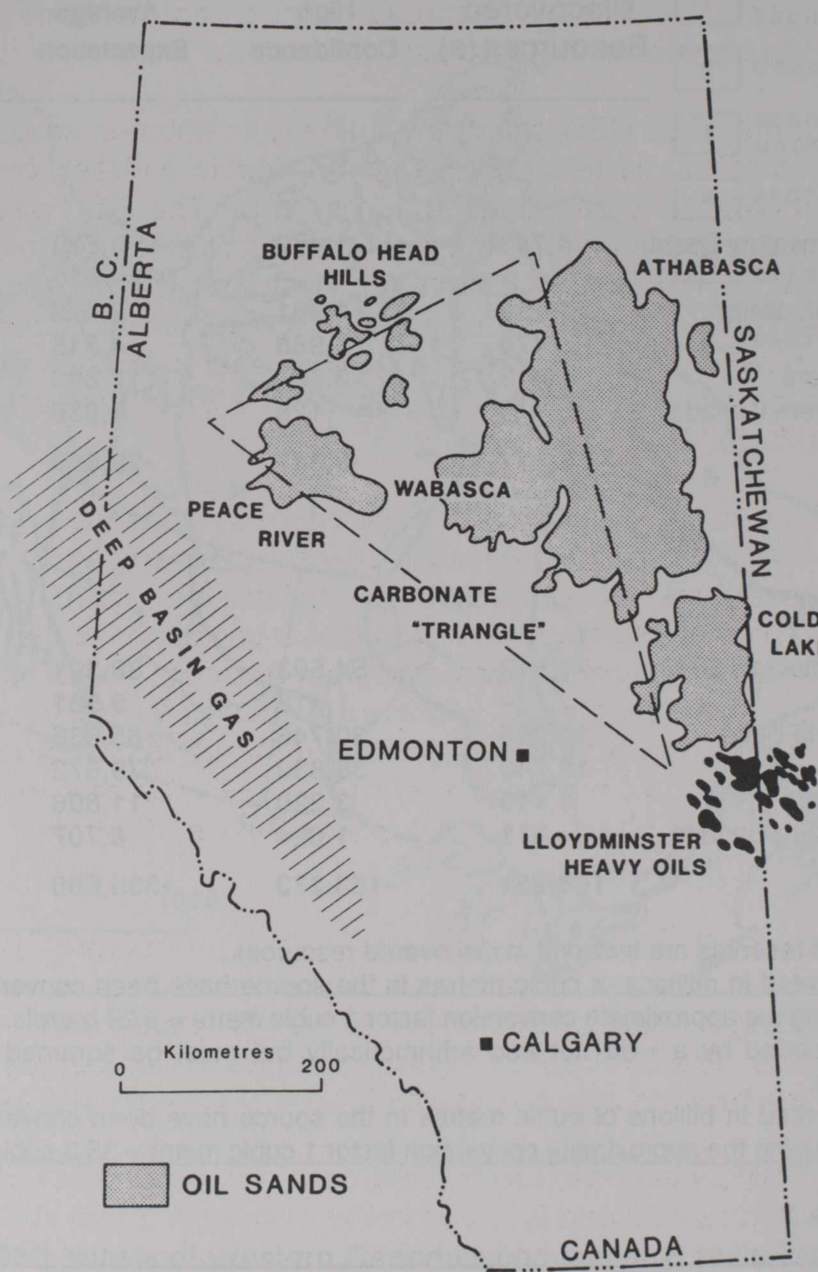
	Reserves and Discovered Resources (a)	Potential High Confidence	Potential Average Expectation	Potential Speculative Estimates
Recoverable Oil				
(millions of barrels) (b)				
Western Canada Sedimentary Basin	4,743	1,472	3,730	7,611
Cordilleran Basins	–	–	315	692
Beaufort Sea/Mackenzie Delta	736	1,931	8,473	16,933
Arctic Islands	478	1,988	4,315	8,208
Eastern Canada Offshore	1,415	3,220	11,806	21,336
Paleozoic Basins–Eastern Canada	5	126	1,050	3,805
Totals (c)	**7,377**	**•9,347**	**•29,689**	**•56,579**
Recoverable Gas				
(billions of cubic feet) (d)				
Western Canada Sedimentary Basin	74,518	54,503	88,391	174,029
Cordilleran Basins	–	1,412	9,531	26,828
Beaufort Sea/Mackenzie Delta	10,096	30,746	65,835	144,836
Arctic Islands	12,743	38,830	79,672	129,269
Eastern Canada Offshore	1,415	3,220	11,806	21,336
Paleozoic Basins–Eastern Canada	311	1,624	6,707	23,298
Totals (c)	**106,359**	**•153,273**	**•335,668**	**•645,461**

Notes: (a) Established reserves are included in discovered resources.
(b) Data presented in millions of cubic metres in the source have been converted to millions of barrels, using the approximate conversion factor 1 cubic metre = 6.29 barrels.
(c) Totals preceded by a • do not add arithmetically but must be summed using statistical techniques.
(d) Data presented in billions of cubic metres in the source have been converted to billions of cubic feet, using the approximate conversion factor 1 cubic metre = 35.3 cubic feet.

Source: EMR, 1984, p. 3.

Canada's nonconventional petroleum resources are large. The Geological Survey of Canada defines nonconventional petroleum as any oil or gas deposits which cannot be produced effectively with normal oilfield techniques. This category includes oil sands, heavy oil, carbonate oil, deep basin gas and oil shale. Most of these deposits are located in Alberta, as shown in Figure 43.

Figure 43: Oil Sands, Deep Basin Gas, Heavy Oil and Carbonate Oil Deposits of Western Canada



Source: EMR, 1984, p. 48.

Canada's deposits of bitumen are by far the largest in the world, and lie almost entirely in Alberta. A recent study of world heavy petroleum resources accords Canada 82% of the bitumen resource – an estimated 2.66 trillion barrels of bitumen in place out of a global total of 3.2 trillion barrels. This compilation includes the combined bitumen resources of the oil sands and the "carbonate triangle", carbonate rocks lying beneath the oil sand deposits (Meyer and Schenk, 1985). Crude bitumen accumulations exist in these carbonate rocks and have become known as carbonate oil. These accumulations are not producible in the foreseeable future.

According to the 1983 GSC study, the quantity of bitumen contained in the oil sands is almost 1.25 trillion barrels (197,590 million cubic metres), but only a small fraction of this is considered to be ultimately recoverable. The GSC also asigned 315 million barrels (50 million cubic metres) of bitumen in place to the Grosmont Formation in the carbonate triangle (GSC, 1984). In its most recent reserves report, the ERCB estimates crude bitumen in place in designated oil sands deposits at 1.69 trillion barrels (268 billion cubic metres). The Alberta Board further calculates that the ultimate volume of crude bitumen in place within the province is 2.52 trillion barrels (400 billion cubic metres) (ERCB, 1987).

Of this 2.52 trillion barrels of bitumen considered to comprise the total resource, the ERCB estimates that 170 billion barrels (27 billion cubic metres) is contained within deposits that may eventually be exploitable by surface mining; the remaining 2.35 trillion barrels (373 billion cubic metres) occurs in deeper deposits the exploitation of which would require in situ recovery or underground mining techniques. The initial mineable volume of crude bitumen in place was established at approximately 75 billion barrels (11.9 billion cubic metres). Allowing for various factors, including a combined mining/extraction recovery factor of 0.79, the ERCB sets initial established mineable reserves of crude bitumen at 33.3 billion barrels (5.3 billion cubic metres) (ERCB, 1987).

The Canadian Petroleum Association (CPA) includes as established developed reserves only the oil contained in the oil sands that is within economic distance of the existing oil sands commercial extraction plants and experimental or demonstration projects. The CPA set this quantity at 860 million barrels (130.5 million cubic metres) of crude bitumen at year-end 1985 (CPA, undated, p. II/15A).

Canada's heavy oil deposits are modest on a global scale but important in the domestic resource picture. Canada is assessed as holding 1.3% of the world's heavy oil resources, a total of 11.3 billion barrels initially in place out of a global estimate of approximately 880 billion barrels. About 750 million barrels is estimated to be initially recoverable, of which 438 million barrels had been produced at the time of the study (Meyer and Schenk, 1985). Even though a limited component of the Lloydminster heavy oil deposits can be produced by conventional means, the GSC regards the overall heavy oil resource as nonconventional. Because of the uncertainties of extracting heavy oil, the 1983 GSC study observed: "Estimates of the total percentage of the resource which will be recoverable are highly cost-price dependent and are not included in this report" (GSC, 1984, p. 49).

Large accumulations of natural gas are known to exist in the deeper, westernmost part of the Western Canada Sedimentary Basin. This gas occurs in "tight" formations – rocks with very low porosity and ultra-low permeability. Production of this tight, deep basin gas would require massive hydraulic fracturing of the reservoir rocks. Where the deep basin gas is in contact with more conventional reservoirs, such as in the Elmworth gas field, there is a better prospect of the gas being economically recoverable. At Elmworth, about 0.35 trillion cubic feet (10 billion cubic metres) of gas is in contact with more permeable conglomerates and has been assigned by the GSC as a reserve. The GSC has not yet evaluated Canada's deep basin gas potential, but industry estimates ranging as high as 30 trillion cubic feet (8,500 billion cubic metres) have been published.

Canada's deposits of oil shales are widely distributed across the country and most have not been investigated in any detail. The best known oil shales are found in New Brunswick and are considered economically exploitable at higher oil prices. Reserve estimates suggest more than 283 million barrels (45 million cubic metres) of shale oil are in place in the New Brunswick deposit.

The overall picture then is one of limited resource potential for light-medium crude oil reserve additions in Western Canada; a substantial potential for conventional oil development in Canada's higher-cost frontier regions; and a very large potential for higher-cost nonconventional oil development, with its requirement for oil upgrading, in Western Canada.

D. Canadian Oil Production and Consumption

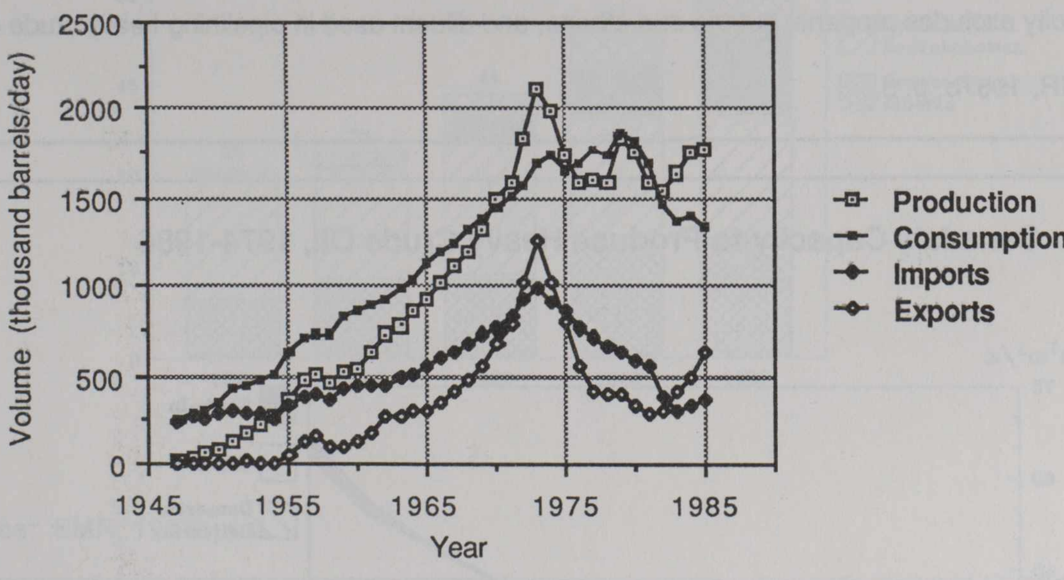
For most of the postwar period, Canada has been a net importer of oil. For two relatively brief periods – in the early 1970s, during which Canada's output of oil reached its peak, and today – Canada has been a net exporter. Light oil is the smaller export component and one which will decline in coming years. In the 1970s and 1980s, Canada has gradually expanded its production of bitumen and heavy oil. Heavy oil and diluted bitumen now comprise the bulk of our oil exports. Canada lacks the market to absorb more than a small part of its domestically-produced heavy oil and crude bitumen and, apart from the integrated Suncor and Syncrude oil sands mining operations, lacks the capability to upgrade these heavy materials into the light products required in this country. Consequently, Canada also imports part of its light crude requirement.

Figure 44 charts Canada's production, consumption, imports and exports of oil. After 1973, it became government policy to phase out the export of light crude oil. Recently, the National Energy Board has eased its control of oil exports. Now light crude exports moving under contracts of less than one year in length are essentially unrestricted apart from reporting requirements. The federal government retains the right, however, to restrict exports if it considers the national interest to require such action. Article 8 in Part I of the Western Accord (signed by the Governments of Canada, Alberta, British Columbia and Saskatchewan in March 1985) states:

> In the event that supplies of crude oil and petroleum products to Canadian consumers are significantly jeopardized, the federal government, after consultation with the producing provinces, may restrict exports to the extent it considers necessary to ensure adequate supplies to Canadians.

In article 5, Part I, the NEB is directed to include force majeure clauses where appropriate in export contracts for terms exceeding one month.

Figure 44: Canada's Production, Consumption, Imports and Exports of Oil



Notes: 1. Production includes all liquid hydrocarbons.

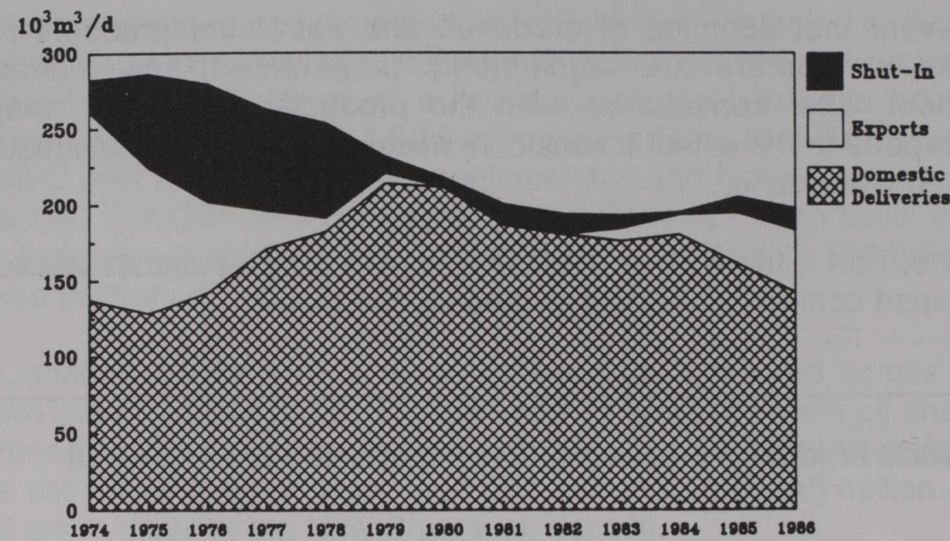
2. Consumption includes refinery crude runs and net product imports.

3. Imports and exports include both crude oil and products.

Source: Canadian Petroleum Association, undated, Table 7, Section III; Table 1, Section VII; Table 2, Section VIII; Table 1, Section XI.

Canada's capacity to produce crude oil since 1974 is broken down into its light and heavy crude oil components in Figures 45 and 46.

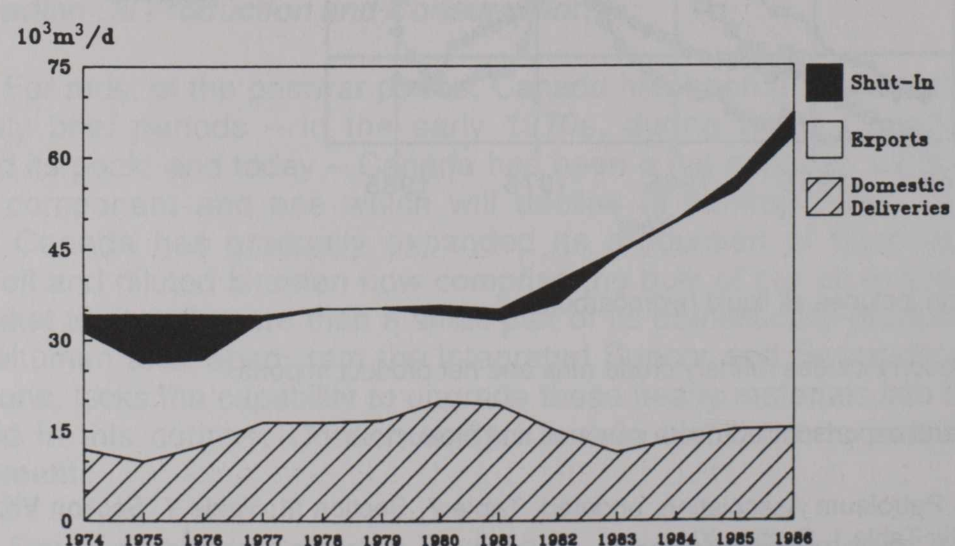
Figure 45: Canada's Capacity to Produce Light Crude Oil, 1974-1986



Note: Capacity excludes propane, butane and ethane, and diluent used in pipelining heavy crude oil.

Source: EMR, 1987b, p. 5.

Figure 46: Canada's Capacity to Produce Heavy Crude Oil, 1974-1986

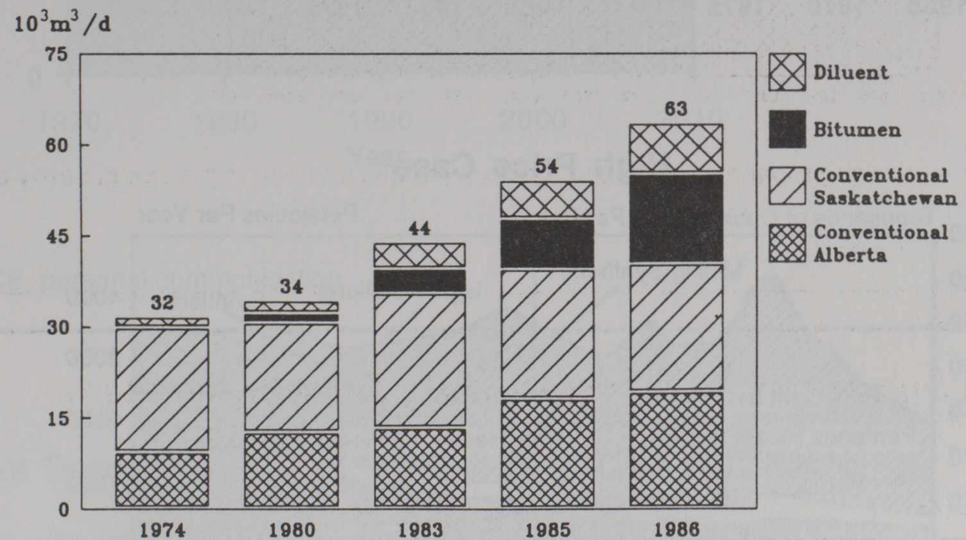


Source: EMR, 1987b, p. 6.

The small upturn in light crude oil productive capacity shown for the years 1984 and 1985 in Figure 45 primarily reflects the expansion of Norman Wells production in the Northwest Territories. In 1986, the declining productive capacity in Western Canada again became apparent.

The composition of the heavy crude oil output displayed in Figure 46 is given in Figure 47. Conventional heavy crude oil production in Saskatchewan has remained relatively steady over the period while growing in Alberta. Unrefined bitumen production has been growing most rapidly, together with the need for diluent to allow pipeline transport.

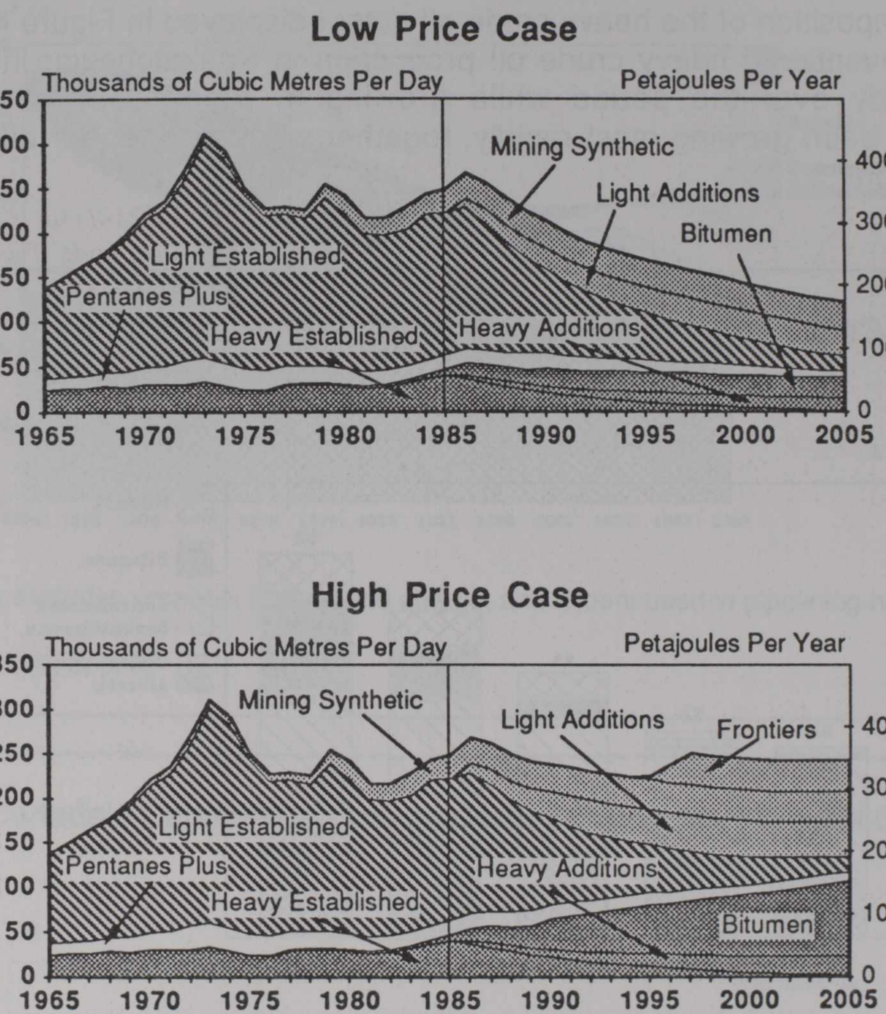
Figure 47: The Composition of Canada's Heavy Crude Oil Production



Source: EMR, 1987b, p.6.

Canada's future capability to produce oil has been assessed by the NEB for two price scenarios extending to the year 2005, which the Board believes will bracket future international prices. Although the NEB acknowledges the possibility of price excursions above or below these limits, it considers the two price cases to encompass the range of sustainable oil prices. The low case has the price of WTI crude at Chicago rising to US$18 per barrel (in constant 1986 U.S. dollars) by 1995 and remaining constant in real terms thereafter. The high case assumes a price of US$27 per barrel from 1995 on. Figure 48 shows the resulting NEB projections of Canadian crude oil supply through 2005 under the two pricing assumptions.

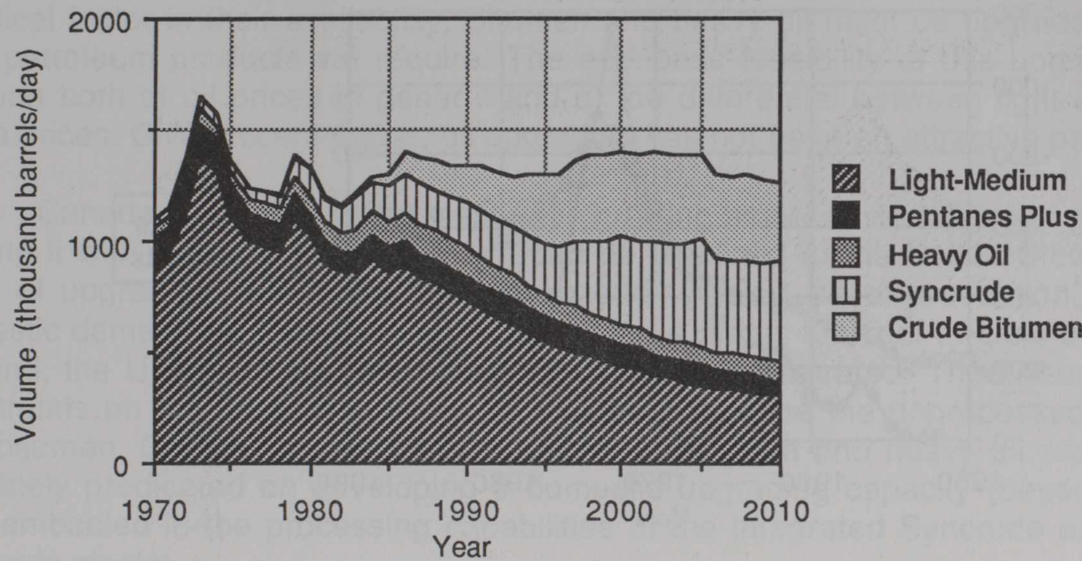
Figure 48: The Future Supply of Domestic Crude Oil under Two Price Assumptions



Source: NEB, 1986, p.87.

In 1986, Alberta accounted for 83% of Canada's conventional oil output and 100% of bitumen and synthetic crude oil output, equivalent to 88% of Canada's total production of oil. The Energy Resources Conservation Board has projected Alberta's oil production to the year 2010, as shown in Figure 49. The ERCB expects conventional crude oil output in 2010 to be at only one-third of the 1986 rate. Bitumen production, in either crude or refined form, will account for the major part of Alberta's oil output beyond the turn of the century.

Figure 49: Alberta's Oil Production Projected to the Year 2010



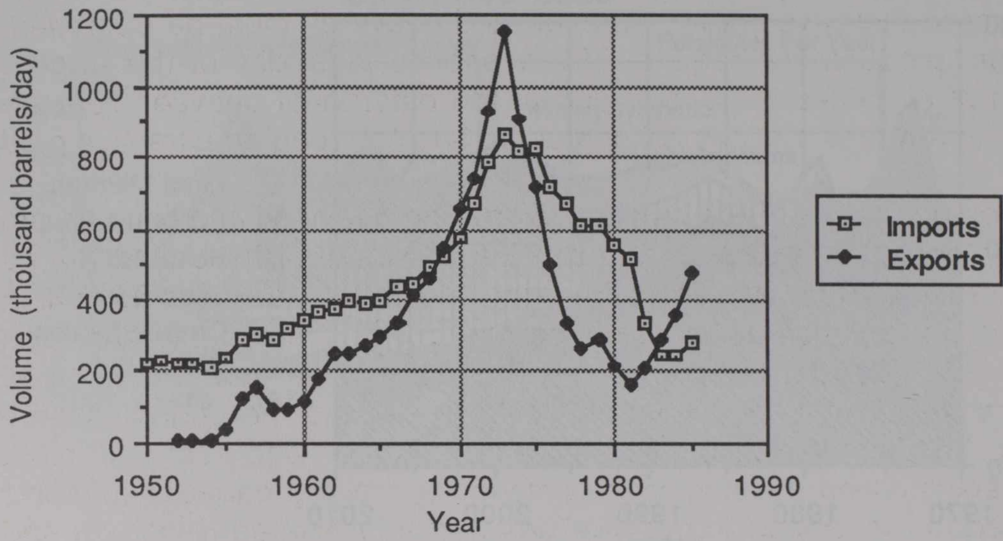
Source: ERCB, personal communication.

E. Canada's Trade in Oil

Canada's petroleum industry has used export sales to the United States to promote its development. A large proportion of Western Canadian crude oil and natural gas production has at times been sold in the United States. Eastern Canada has traditionally imported its oil requirements from offshore. Thus Canada's trade in energy has included crude oil as a major component, even during those periods when we have maintained a rough net self-sufficiency in oil. The prospect in the 1990s is for our imports of light crude oil to climb and to exceed exports of heavier gravity oils to the U.S.

Figure 50 shows the record of Canada's imports and exports of crude oil since 1950. Even when Canada was a large net exporter of crude oil in 1973, it was still a substantial crude oil importer. This pattern of crude oil exports from Western Canada to the United States balanced by crude oil imports into Eastern Canada from overseas has prevailed through much of the postwar period.

Figure 50: Canada's Exports and Imports of Crude Oil since 1950



Source: CPA, undated, Table 2, Section VIII; Table 1, Section XI.

F. Balancing Future Oil Supply and Demand

Canada is fortunate in having more options than many countries in handling the question of light crude oil availability. Both the supply and demand sides of the oil equation must be addressed.

On the supply side, Canada has two means of augmenting light crude oil availability beyond what remains to be recovered in the Western Canada Sedimentary Basin. Conventional light crude supplies can be extended by developing the new reserves which have been established in the East Coast offshore and in the north. These deposits are expensive to exploit and the quantity of recoverable oil discovered to date is not sufficient to sustain a level of production able to offset the projected decline in Western Canadian light crude deliverability. Nonetheless, frontier oil can reduce the rate at which Canada becomes dependent on offshore light crude.

The petroleum industry must achieve the highest recovery rates feasible in extracting our conventional oil resources; this is the role of enhanced recovery techniques which increase the efficiency of resource utilization. Low oil prices make this goal less attainable, however, as enhanced recovery is a higher-cost approach to maximizing the recovery of the crude oil in place. Enhanced recovery adds incrementally to oil output over extended periods of time; again the effect will be to slow the decline in light crude production, not reverse it.

The other way to increase supply is to develop Canada's huge resources of bitumen and substantial deposits of heavy oil. Because these heavy hydrocarbons are more difficult and costly to produce and process than light gravity oils, the price of oil is a critical factor in their availability. Bitumen and heavy oil must be upgraded into the light petroleum products we require. The economic feasibility of this upgrading is a function both of oil prices in general and of the differential between light and heavy crude prices. Given recent prices, oil upgrading has not been an attractive prospect.

Canada currently exports most of its growing heavy oil and bitumen production, diluting it with pentanes plus so that it can be pipelined to the United States without need of upgrading. There are limits to extending this type of production. First, the domestic demand for these heavy oils is not large and is forecast to grow only slowly. Second, the U.S. northern tier market could become saturated. Third, there may be constraints on the amount of diluent available to pipeline the unprocessed heavy oil and bitumen. Continued expansion of Canada's bitumen and heavy oil production is ultimately predicated on developing a domestic upgrading capacity (beyond what is now embodied in the processing capabilities of the integrated Syncrude and Suncor oil sands plants).

If greater domestic capability to process heavy petroleum fuels can be established, then Canada's heavy hydrocarbon resources would be adequate to satisfy our demand for petroleum products for decades.

Turning to the issue of restraining oil demand, Canada is again favoured with a variety of options: conservation, using other conventional energy forms such as natural gas and coal to substitute for oil, and exploiting new forms of energy – principally renewable energy supplies – as replacements for oil. R,D&D support of innovative energy technologies is needed to reduce the costs of these options and to increase the efficiency of energy utilization.

Despite lower petroleum prices, opportunities still remain to conserve oil in cost effective ways. The cumulative benefits of conservation can be very impressive. In the United States, total energy consumption in 1985 was no more than it had been in 1973 and the use of oil was down. This was achieved despite population growth and economic expansion. Conservation remains one of the most effective strategies for modifying oil demand.

Canada has promoted the substitution of other energy forms for oil. Less than 1% of Canada's electricity was generated in 1986 by the combustion of oil; coal-fired and nuclear generation have expanded to displace the use of oil. The extension of the natural gas distribution system in Quebec was an important factor in that province's success in reducing its reliance on petroleum products. The development of the Venture gas field offshore of Nova Scotia or the extension of the gas distribution system on to Atlantic Canada would similarly present opportunities for oil substitution in the region of Canada (apart from the north) still most dependent on oil.

The many possibilities open to Canada in the area of alternative energy development were summarized in the earlier work of the House of Commons Special Committee on Alternative Energy and Oil Substitution (*Energy Alternatives*, 1981). This study demonstrated that there is no lack of options, although there are certainly questions of cost and budget constraints. Some of these alternatives will require many years to assume a significant role in Canada's energy system. Others have been developed to the point where they are technically available today, depending on energy prices. It is particularly important to continue the R,D&D needed to move these alternatives towards commercial use, so that Canada will have a range of energy options open to it in the future.

STRATEGIC ENERGY PLANNING FOR CANADA'S FUTURE

A. What Is Meant by Security of Oil Supply?

The term "security of supply" is frequently used but not so frequently defined. For policy-making purposes, it is important that the meaning of this concept be clear. EMR proposed the following definition in its recent report, *Energy Security in Canada*:

> 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 acceptable 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. (EMR, 1987a, p. ii)

The Committee agrees with this rather technical definition of security of supply, but would extend the description. Oil is not a segregated component of Canada's energy system but rather one aspect of a complex, integrated system. In our view, security of oil supply is enhanced as the relative importance of oil in Canada's energy mix is reduced and as the opportunities for inter-fuel substitution are broadened. Energy conservation, fuel substitution and the exploitation of nonconventional energy forms contribute to security of oil supply because they make the need to import oil less pressing. Conservation and the introduction of renewable energy forms and new energy technologies can be pursued in all regions of the country. In other words, security of oil supply should be considered in the context of a resilient national energy system which over time tends to reduce today's pronounced regional disparities in energy supply.

B. The Role of Government

The options for government policy lie across the spectrum, from a policy of "laissez-faire" to an administered petroleum price with accompanying taxes and compensation programs. Neither extreme seems desirable or realistic. The dismantling of the National Energy Program marked a new approach to Canadian energy policy, one that was much more sensitive to developments in international petroleum markets — an outlook brought about not only by a preference for freer markets but also by the practical impossibility of maintaining an administered price for oil which was rapidly outstripping the international price upon which imports, exports and private transactions ultimately depend.

In the vastly different circumstances of 1987, an administered price system hardly seems tenable. Rather, the Committee seeks solutions which are compatible with both the recent re-orientation of Canadian energy policy and the hard realities of the international petroleum market. This includes the possibility of marked price increases in the early 1990s but current prices below levels that would bring major new Canadian reserves on stream in time to meet the growing shortfall in light crude oil.

For this reason, the "laissez-faire" approach, however appealing to the theorists, falls short of ensuring Canada's light crude oil self-sufficiency in the 1990s and beyond. This is a central concern of the Committee's study.

The Committee has therefore considered a range of "intermediate" policy options, and recommended, where appropriate, that certain actions be taken.

1. A Strategic Petroleum Reserve

The federal government should establish a strategic petroleum reserve. Regardless of what policies are pursued to promote the discovery and development of new reserves, a strategic petroleum reserve which would provide 90 days supply to Eastern Canadian refineries would provide immediate defence against a sudden supply shortage, an eventuality not unlikely given the political volatility of the Arab oil producing states.

Petroleum for the reserve would have to be purchased at current market prices from whatever were the most cost-effective sources of supply.

The Western provinces already have security of oil supply. The reserve should be located to give quick access to refineries in the Atlantic and central regions which now rely, or may rely in the future, on offshore sources. Like other types of insurance, the cost should be borne by those who are protected by the policy — the oil consumer. The strategic petroleum reserve could be established with a 1¢ per litre tax levied at the refinery level. At a 1¢ per litre rate, the reserve would grow at a pace that should roughly match Canada's rising net imports of light crude oil, at least over the near-term.

Even though a strategic petroleum reserve would be used at central and Atlantic Canadian refineries in the event of a disruption in offshore oil supplies, Western Canada would also benefit. There are emergency plans in place to ration oil in Canada if imports are curtailed. To the extent that an oil stockpile makes rationing less stringent, consumers from coast to coast would benefit and Western Canada would have to ship less of its oil east under a national oil allocation plan. Although Canada has a net self-sufficiency in oil today, Western production will wane and total Canadian demand will rise. There will not always be a ready surplus of Western oil to be pipelined to Eastern Canadian markets.

2. Options for Government Policy

Two approaches best avoided are providing investment funds out of the federal purse (because there isn't enough money to pay for all of the requests), and putting the government in a position of choosing winners and losers.

Loan guarantees for large projects eliminate the need for direct cost subsidization. They are relatively safe: a project must become a significant financial disaster before the last resort of foreclosure is taken by the banks (witness the Dome Petroleum epic!), so the likelihood of having to pay out is relatively small. Yet a guarantee is often the only thing that will allow the capital market to advance funds to a plausible but highly risky venture. The government's position can be further strengthened by requiring companies to commit a significant proportion of their own capital to the total cost of a project before granting loan guarantees on the borrowed funds that would be needed to make up the difference.

The next question is what projects would be eligible? The answer is difficult. While the government can and does at times assume the role of underwriter, it is not the government's primary skill to pick winners and losers in a highly technical and unpredictable industry.

There is a broad range of fiscal policy tools available to the government. It has been a tradition of the Canadian political system to attempt to influence economic behaviour through incentives contained in the income tax system. It would be relatively easy and quite consistent to make tax incentives available with the stated intention of establishing new petroleum reserves wherever this could be accomplished in the country.

Stronger tax credits, accelerated depreciation and "superdepletion" are all familiar possibilities. But expanding such measures is fundamentally incompatible with the policy goal of tax reform which is intended to reduce or eliminate many of the preferential tax treatments enjoyed by various sectors of the economy. By recommending stronger tax incentives, the Committee would commit the disservice of adding a steeper grade to the much sought-after "level playing field".

A much clearer and more direct means of influencing behaviour is a cash grant. Subsidies to preferred projects initiated in the private sector definitely allow for a clear accounting of what has been accomplished for the taxpayers' money, as the Auditor General has noted. But current fiscal constraints limit the practicality of this approach. The deficit is already too large. Increased expenditures would have to be financed by new or higher taxes. The last 18 months have seen the dismantling of the Petroleum Incentives Program (PIP) with its grants and the corresponding Petroleum and Gas Revenue Tax (PGRT) which was intended to finance it. It is not practical to introduce a similar program of grants and taxes.

An alternative to grants and subsidies to the private sector is for the government to carry out the work itself through a state agency. This option is not recommended. Not only would it be inconsistent with the general thrust of current government policy and privatization initiatives, but there is also an inherent inefficiency in state enterprise brought about by the lack of accountability; crown corporations never risk a share-holder revolt.

3. The Government as Oil Broker

One of the more innovative suggestions received by the Committee was made during a Committee hearing by a Canadian oil company (Husky Oil, 1987). The firm was presenting the case that Canadian petroleum companies need the certainty of a guaranteed price in order to undertake the mega-projects necessary for the development of new oil reserves.

If the federal government were to enter into petroleum purchase contracts at guaranteed prices, petroleum companies should bid for the sale by offering the lowest possible price. With a contract in hand, the winning firms would undertake their project with the price certainty that would generate private capital market financing.

The government would contract an amount equivalent to 20-30% of projected oil demand, and would be in a position to resell the oil later, and/or keep some of it as a strategic reserve. It was suggested that any losses sustained by the government could be covered by a general cents-per-litre petroleum tax, and the possibility remained of making money were the price of oil to rise above the contracted price.

The main objection with respect to this proposal is that the Committee does not wish to see the Government become a broker of oil.

The Committee also discussed the workings of various potential stabilization programs, and compared the idea in principle and in practice to the assistance given to farmers under present price maintenance programs. After the recent Canadian experience with administered petroleum prices, and wishing to avoid the role of price stabilizer and broker, the Committee does not believe that such programs would be appropriate.

It might be possible, however, to track oil prices with the thought of making loan guarantees available to large projects should the price fall below a stipulated level. This could compensate for the private capital market's reluctance to provide financing for increasing reserves (which is important for the country) during periods when price and profitability are weakening and risk is becoming greater.

APPENDIX A

TWO DISSENTING STATEMENTS

Statement by the Member for Cape Breton - The Sydneys

The Committee has drawn two logical conclusions in view of the evidence collected: there is a growing probability with time of a serious disruption in the international supply of oil; and a laissez-faire approach to economic development will not ensure Canada's future self-sufficiency in light crude oil. Unfortunately, the Committee's recommendations fall well short of addressing the problems which the report acknowledges.

The Committee's emphasis on a government-owned strategic oil reserve is misplaced and diverts attention from the underlying issue – our growing dependence on offshore light-gravity oil which will increasingly be supplied by OPEC as North Sea production declines. Canada, the United States and other industrial nations will be forced to import a progressively larger share of their oil requirements from a politically unstable Middle East. A strategic oil reserve is a short-term mechanism for dealing with an emergency; it is not a policy response to the long-term question of oil supply.

I applaud the Committee's strong support for research and development to foster energy conservation, and both conventional and nonconventional energy technologies. The Committee did not, however, take the next logical step to promote selected energy developments that are clearly in the national interest. Eastern Canada is vulnerable to a disruption in offshore oil supply – why didn't the Committee make a clear statement of support for proceeding now with Hibernia? The Committee has missed two opportunities to effectively promote the use of methanol and ethanol as motor fuel blending agents, which would both extend Canada's stocks of gasoline and provide a ready substitute for lead as an octane enhancer. A modest federal subsidy for a limited period of time is all that is required. The federal government subsidizes the conventional energy system; what is the rationale for withholding similar support for renewable energy development?

The report states that it is not the role of government to pick winners and losers in the energy sector. The federal government picks winners and losers in other areas of Canada's economy – why is this inappropriate in the case of energy, which is vital to our future well-being? The report also concludes that a state agency such as Petro-Canada should not be used to further federal energy objectives because of the "inherent inefficiency in state enterprise". If the alternative is to depend on the petroleum industry to act in Canada's long-term best interest, I prefer to live with a little "inherent inefficiency".

I disagree with recommendation #6 in which the Committee supports petroleum exploration and development in Alaska's Arctic National Wildlife Refuge. If a pipeline link from the Mackenzie Valley to the Alaska border is predicated on developing petroleum resources in the ANWR, then I disagree with recommendation #5 as well.

This report clearly outlines the potential for serious difficulties to arise in Canada's future supply of light oil. The Committee's recommendations do not measure up to the problem.

Statement by the Member for Vancouver - Kingsway

I agree with the Committee's conclusion that energy is more than an economic commodity and that, while the market mechanisms will always be there, the federal government must influence Canadian energy development.

With regard to the legitimate role of the federal government in the development of Canada's energy resources, I draw to the attention of the Committee the following excerpt from the Dissent to the 1986 Report of the Economic Council of Canada, by Diane Bellemare, Pierre Fortin and K. Kaplansky:

> ... surely the history of the past century, the lessons of the great depression and repeated international crises ought to teach us that a democratically based government needs a variety of levers to protect the health of a society and, at the same time, to foster private initiative and individual freedom in the face of potential threats posed by unconstrained and frequently manipulated "market forces".

Like the Committee, I too am concerned with Canada's deteriorating supply of domestic light crude oil and with the fact that Canada will have to plan for the 1990s by developing some of our frontier supplies and/or upgrading our heavy oil. Nevertheless, while a stable corporate tax regime is desirable, governments are entitled to a fair economic rent from these resources since, after all, the Canadian public is the owner of these resources.

I strongly disagree with the Committee's recommendation for planning a transportation corridor from the Mackenzie Valley to the Alaska border. That issue was settled 10 years ago when the National Energy Board – after exhaustive hearings in which they heard from the ranking experts in the field – rejected the idea on environmental grounds.

As well, the Committee recommends that Canada support the ill-advised American policy of developing the Arctic National Wildlife Refuge in Alaska. First, the development of the ANWR will affect the Porcupine caribou herd and thus the interests of Canada's native northerners who partly live on the caribou. Second, the official policy of the Canadian Government opposes the exploitation of the ANWR. There is no commanding reason in Canada's interest to change that policy.

I would add that this report brings together a wealth of useful information on Canada's and the world's supply of and demand for oil.

APPENDIX B
LIST OF WITNESSES

First Session
Thirty-third Parliament

Issue No.	Date	Witnesses
13	03-06-86	**Energy Resources Conservation Board of Alberta**
		Vern Millard Chairman
		Frank Mink Manager Economic
14	05-06-86	**National Energy Board**
		Roland Priddle Chairman
		William Scotland Associate Vice-Chairman
		Dr. Peter Miles Director General Energy Regulation
		Alan Hiles Director Energy Supply Branch
		Ross White Director Oil Branch

First Session
Thirty-third Parliament

Issue No.	Date	Witnesses
17	17-06-86	**Department of Energy, Mines and Resources** **Geological Survey of Canada** **Earth Sciences Sector** Dr. John Fyles Chief Geologist (Ottawa) Dr. Walter Nassichuk Director Institute of Sedimentary and Petroleum Geology (Calgary) Dr. Richard Procter Executive Director Petroleum Resource Assessment Secretariat (Calgary)

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
3	24-11-86	**Department of Energy, Mines and Resources** The Honourable Marcel Masse Minister Martha Musgrove Director General Natural Gas Branch

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
5	02-12-86	**Husky Oil Ltd.** Art Price President Jan DeJong Manager Frontier Engineering
6	21-01-87	**Inter-City Gas Corporation** Wayne Harding Vice-President U.S. Corporate Development **Inter-City Gas Resources** Peter Krenkel Vice-President Operations
6	22-01-87	**TransCanada PipeLines** Gerald J. Maier President and Chief Executive Officer Jim Cameron Executive Vice-President **Western Gas Marketing Limited** Ken Orr President and Chief Operating Officer

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
7	05-02-87	**National Energy Board** Roland Priddle Chairman Dr. Peter Miles Director General Energy Regulation Mark Segal Director Economics Branch Alan Hiles Director Energy Supply Branch Ross White Director Oil Branch Ken Vollman Director General Pipeline Regulation Sandra Fraser General Counsel
8	10-02-87	**Polar Gas Project** John Holding President Ollie Kaustinen Vice-President Engineering

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
8	10-02-87	**Tennessee Gas Transmission** Richard Snyder Director Long Range Planning Jim Keys Vice-President International Energy
9	19-02-87	**Department of Energy, Mines and Resources** Len Good Associate Deputy Minister Energy Program David Oulton Director General Oil Branch Energy Commodities Sector Peter Dyne Director General Office of Energy Research and Development Research and Technology Sector Gavin Currie Director General Energy Emergency Planning Group Energy Commodities Sector

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
9	19-02-87	Maureen Dougan Senior Energy Relations Officer Multilateral and Bilateral Energy Relations Division International Energy Relations Branch Energy Policy, Programs and Conservation Sector
11	05-03-87	**Georgetown Center for Strategic and International Studies** Dr. Henry M. Schuler
12	10-03-87	**Imperial Oil Limited** Robert B. Peterson Executive Vice-President and Chief Operating Officer Jim Hughes Manager Energy and Industry Outlook Operations Planning and Coordination Department
13	24-03-87	**Texaco Canada Resources** Wiliam A Gatenby President and Chief Executive Officer Jack D. Beaton General Manager Finance and Planning

Second Session
Thirty-third Parliament

Issue No.	Date	Witnesses
13	24-03-87	Orville C. Windrem Vice-President
18	30-04-87	**Solar Energy Society of Canada Inc.** Doug Lorriman President Jeff Passmore Vice-President Bill Eggertson Executive Director

APPENDIX C

STANDING COMMITTEE ON ENERGY, MINES AND RESOURCES

Members of Parliament who participated in the Committee's study

Chairman

Barbara Sparrow (Calgary South)

Vice-Chairman

Aurèle Gervais (Timmins - Chapleau)

Paul Gagnon (Calgary North)

Russell MacLellan (Cape Breton - The Sydneys)

Lawrence O'Neil (Cape Breton Highlands - Canso)

Bob Porter (Medicine Hat)

Ian Waddell (Vancouver - Kingsway)

Staff

Dean Clay
Consultant

Lawrence Harris
Consultant

Ellen Savage
Clerk of the Committee

APPENDIX D
ENERGY UNITS AND CONVERSION FACTORS

This discussion is reproduced with some modification from Appendix A and Chapter 2 of the 1981 report *Energy Alternatives*, prepared by the former House of Commons Special Committee on Alternative Energy and Oil Substitution.

The International System of Units

A new system of units has been adopted by most countries in recent years. This system of measure, the most accurate yet devised, is called the International System of Units and officially abbreviated as SI (for *Système International*) in all languages. SI is intended as the basis for a global standardization of measurement.

SI is based on the decimal system with its multiples of 10, but is not synonymous with the metric system since it excludes metric units that have become obsolete and includes a few units, such as the second, which are not metric. There are seven base units in SI, of which three are relevant to this report. There are also derived units in SI, of which five pertain to this study. Table D-1 presents these units.

Table D-1: SI Base and Derived Units Used in this Report

Quantity	Name/Unit	Symbol
Base Units		
Length	metre	m
Mass	kilogram	kg
Time	second	s
Derived Units		
Area	square metre	m^2
Volume	cubic metre	m^3
Density	kilogram per cubic metre	kg/m^3
Energy	joule	J
Power	watt	W

The SI package allows for the continued use of certain non-SI units. The hectare (ha) generally replaces the acre as a measure of land and water areas, with the square metre being preferred for other measures of area. Although the second is the base unit for measuring time in SI, other units such as the hour (h), day (d) and year (a) continue to be used. Degrees Celsius (°C) continues as the common measure of temperature, with Kelvin temperature (K) being essentially relegated to the scientific domain.

Unfortunately, three names exist to describe the same unit of mass, 1,000 kilograms: metric ton (t), tonne (t) and megagram (Mg or one million grams). Megagram is the correct SI expression but it is not widely recognized; "tonne" seems likely to prevail in the literature.

Energy and Power

In the science of mechanics, energy was originally defined in terms of work, which is the product of a force acting through a distance. In SI notation, the unit of energy is the **joule** and is defined as a force of 1 newton acting through a distance of 1 metre, or

1 joule = 1 newton-metre.

Other forms of energy were considered to be independent quantities and thus independent units were defined to quantify them. Man subsequently discovered that energy is conserved – it is neither created nor destroyed in being transformed from one type to another. Thus energy is not really *consumed*, it is *exploited*. An important result of this law of nature – the law of energy conservation – is that one unit of measurement, the joule, can be used to quantify all forms of energy.

In many situations one is interested in the rate at which energy is being delivered or transformed or dissipated. Power is the measure of how fast energy is being delivered or used. Since all types of energy are measurable in joules, it follows that all energy transformations or rates of usage can be measured with a common unit. In SI, that unit is the **watt**. One watt is defined as the delivery of one joule of energy per second, or

1 watt = 1 joule/second.

When power is generated at a constant rate, the amount of energy produced in a given time is

energy = power x time.

Consequently, 1 joule = 1 watt-second.

SI Prefixes

Since the joule and the watt are very small measures of energy and power, one normally works with multiples of these units. To avoid cumbersome quantities, the SI package includes a system of decimal multiples expressed as word prefixes and added to the unit names. Five prefixes cover most of the quantities which arise in a study of this scope. These are presented in Table D-2.

Table D-2: Commonly Used SI Prefixes

SI Prefix	Symbol	Value	Example
kilo	k	10^3 (thousand)	kilovolts (kV)
mega	M	10^6 (million)	megatonnes (Mt)
giga	G	10^9 (billion)	gigawatt-hours (GWh)
tera	T	10^{12} (trillion)	terawatts (TW)
peta	P	10^{15} (quadrillion)	petajoules (PJ)

Conversion Factors

The following conversion factors are either exact or correct to four significant figures.

Distance

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

Area

1 square foot = 0.09290 square metre	1 square metre = 10.76 square feet
1 square mile = 2.590 square kilometres	1 square kilometre = 0.3861 square mile
= 640 acres	= 247.1 acres
= 259.0 hectares	= 100 hectares
1 acre = 0.4047 hectare	1 hectare = 2.471 acres

Volume

1 cubic foot = 0.02832 cubic metre

1 cubic metre = 35.31 cubic feet
= 1,000 litres

1 American barrel = 0.1590 cubic metre

1 cubic metre = 6.290 American barrels

1 American barrel = 42 American gallons
= 34.97 Imperial gallons

1 American gallon = 3.785 litres

1 Imperial gallon = 4.546 litres

Mass

1 short ton = 2,000 pounds = 0.9072 tonne

1 tonne = 2,205 pounds = 1.102 short tons
= 1,000 kilograms

1 pound = 0.4536 kilogram

1 kilogram = 2.205 pounds

Energy

1 British thermal unit = 1,054 joules

1 kilowatt-hour = 3,412 British thermal units
= 3,600,000 joules

1 quad = 1 quadrillion British thermal units
= 10^{15} Btu = 1,054 petajoules = 1,054 x 10^{15} joules

Power

1 kilowatt = 1.341 horsepower
= 3,600,000 joules/hour

1 horsepower = 745.7 watts

1 British thermal unit/hour = 0.2931 watt

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Pursuant to Standing Order 99(2), the Committee requests that the Government table a comprehensive response to its report.

A copy of the relevant *Minutes of Proceedings and Evidence*, (Issues nos. 13, 14 and 17 from the First Session of the Thirty-third Parliament, and Issues nos. 3, 5, 6, 7, 8, 9, 11, 12, 13, 18, 25, 26 and 28 which includes this report, from the Second Session of the Thirty-third Parliament) is tabled.

Respectfully submitted,

BARBARA SPARROW

Chairman