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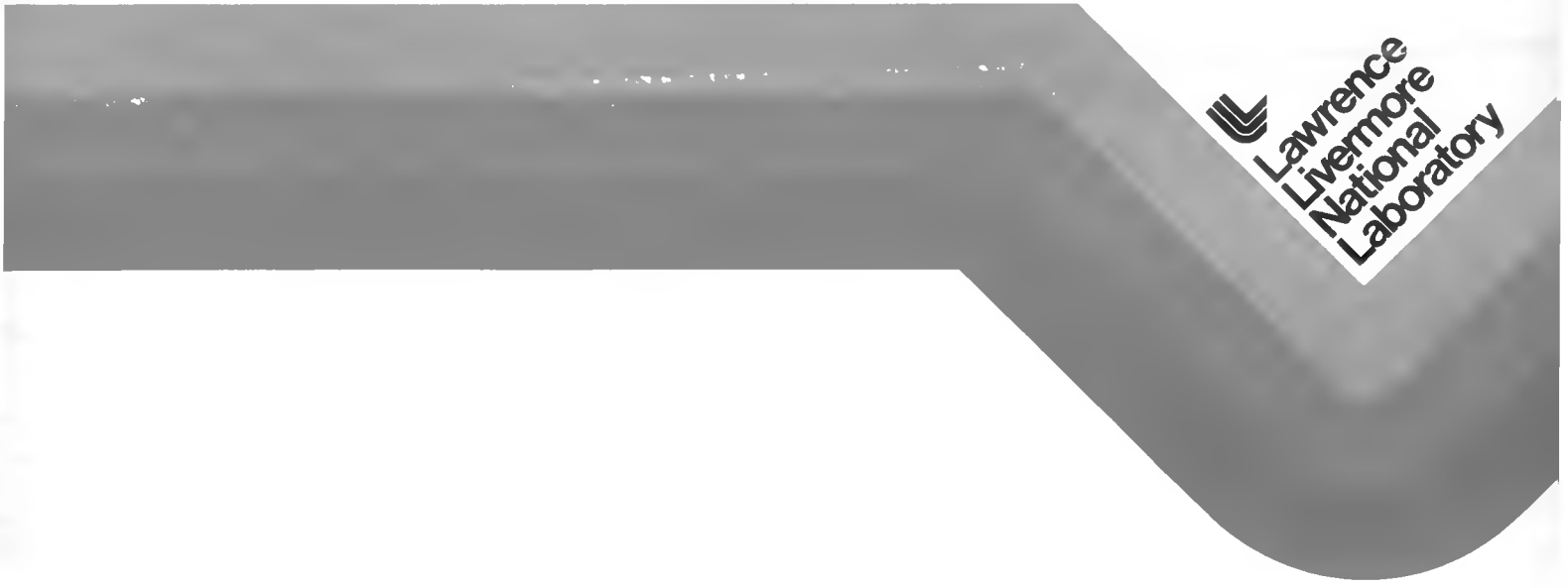
Non-OPEC Oil Production—The Key to the Future

I. Y. Borg

May 11 , 1990



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Abstract

The dramatic increase in non-OPEC oil production that has occurred since the fuel crises of the seventies was accelerated by the subsequent increases in oil prices on world markets. Current moderate world prices are attributable to increased supply in the last decade from these countries. Among those nations whose production has more than doubled since 1973 are China, Mexico, the U.K., Norway, Egypt, India, Oman, Brazil, Colombia, Angola, and Syria. In this context, non-OPEC nations include the Communist oil-producing countries, since their ability to meet their own domestic demand has forestalled the day when they will compete for supplies on world markets.

The prospect for continued growth in non-OPEC oil production is good. Prospects for additions to reserves continue to be bright in virgin exploration areas and semimature oil-producing provinces. Non-OPEC oil production may reach peak levels in the 1995–2000 time frame. However, production will be increasingly countered by growing demand, especially in South and Central America and Asia. It is almost certain that by the mid-nineties, competition for oil supplies in world markets will elevate the price of oil available from the well endowed OPEC nations. Supply disruptions as well may be in the offing by the turn of the century as surpluses on world markets disappear.

Introduction

The current complacency of the general public regarding the adequacy of U.S. energy supplies owes its origins to the return of prices to levels commensurate with those prevailing before the first of the two "crises" of the seventies. Prices at the gasoline pump are conspicuously displayed and are often used as a guide to oil prices and energy costs in general. Judgments based on oil prices alone are in fact defensible since some 34 percent of the energy consumed in the U.S. is in the form of oil, and the prices of oil, natural gas, and coal have historically risen and fallen together (Fig. 1).

The reasons for the precipitous fall in oil prices at the end of 1986 lie in the world marketplace, where supplies became more than adequate to meet demand. This situation evolved from (1) lowered demand, which came about through fuel switching and curtailment of use in response to earlier high prices, and (2) new supplies becoming available on world markets. The artificially high prices charged by OPEC members following the 1973 embargo and the 1979 Iraqi-Iranian war could not be maintained despite a system of country production quotas designed to curtail supply.

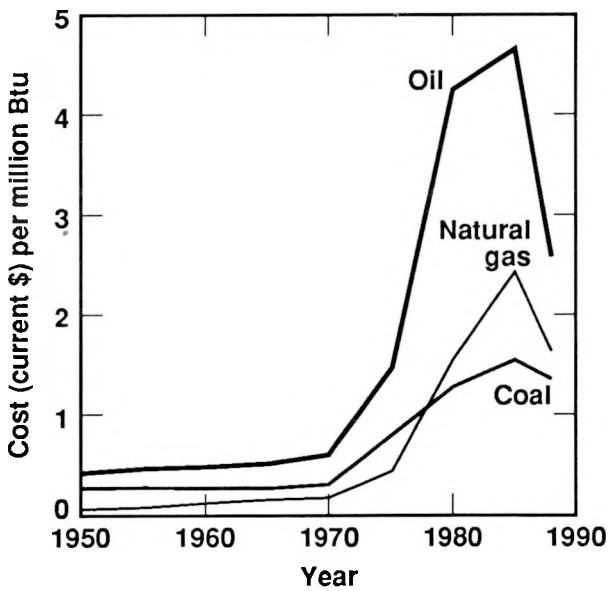

Figure 1. Comparative fuel prices based on Btu content. Crude oil: refiner acquisition cost for domestic oil; natural gas: wellhead price; coal: domestic coal, utility plants. Source: *Annual Energy Review 1988*, U.S. Department of Energy, Washington, D.C., DOE/EIA-0384(88) (1989).

On review, the new oil supplies are seen to have come from non-OPEC countries that prior to 1973 had made small contributions to total world production. Many of these sources of oil have continued to grow over the decade of the eighties. But eventually, they too will suffer the depletion associated with mature oil provinces such as those in the 48 states. The question is: how long will their growth phase last? At some point, countries that are contributing to the new source of world oil will be forced to turn to world markets to satisfy an increasing proportion of their own demand. At that time, it is likely that the large OPEC producers in the Middle East, holding the largest share of the world's reserves and resources, will regain control of world markets, presaging a return to the high oil prices of the seventies.

The Role of Non-OPEC Countries

Prior to 1986, OPEC had enjoyed many years of sustained high prices ($28–34/bbl). In mid-1986, however, the price of oil plummeted to $6 to 9/bbl and finally stabilized at $18/bbl at the end of the year. As stated above, the reason for the price collapse was simply that there was more oil on world markets than demand could absorb. OPEC countries had seen world demand for oil fall for many years in response to the high prices. This factor, together with OPEC members' de facto abandonment of a fixed price system in search of larger market shares, and an ever increasing amount of non-OPEC oil on world markets, led to the precipitous decline in prices.[1]

High crude oil prices, which had prevailed for seven years prior to 1986, had provided the impetus for a search for new sources of petroleum in almost every country in the world. The high prices accelerated the development of earlier discoveries, including ones that theretofore had been uneconomical to produce. The result was that new supplies grew steadily. Although the new sources included major petroleum provinces such as in the North Sea and Mexico, by 1986 the total included contributions from many small regions and countries that had produced little or no petroleum prior to the oil crises of the seventies.

The U.S.S.R. and China accelerated their exploration programs as well, since success promised to stave off the day when they would be forced to meet domestic demand with imports. In the case of the U.S.S.R., petroleum exports became an important source of hard currency. This increased self-sufficiency indirectly affected the world marketplace, and oil production in these countries is an important part of the non-OPEC production that impacted world prices in 1986.

Figure 2 shows the growth of non-OPEC oil production. Between 1973 and 1989, successful exploration and accelerated development doubled and tripled oil production in many countries. Examples of countries that showed large growth are given in Table 1.

Table 1. Non-OPEC countries that had large increases in production between 1973 and 1989.

	Production (10^3 bbl/d)[a]		
Country	1973	1989	Change
U.S.S.R.	8420	12,140	1.5×
China	1140	2751	2×
Mexico	450	2613	4×
U.K.	8	1773	222×
Norway	30	1474	48×
Egypt	165	852	3×
India	150	676	3×
Oman	295	613	2×
Brazil	165	596	3×
Malaysia	320	563	1.5×
Angola	160	453	2×
Colombia	200	404	2×
Syria	105	340	3×

[a] Sources: for 1973, *International Energy Statistical Review*, Central Intelligence Agency, Washington, D.C., ER IESR 81-001, 1 (January 27, 1981); for 1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

Prospects for Sustained Oil Production in Non-OPEC Countries

In the next few years, the key to moderate world oil prices lies in the ability of non-OPEC countries to collectively maintain oil production at current levels. Increased demand in the nineties, driven in part by population growth, will require continued growth in output. In order to simply sustain total current non-OPEC production levels, it is necessary that declining production in countries with mature oil-producing provinces, such as the U.S., be compensated by increases elsewhere in the non-OPEC world. Some

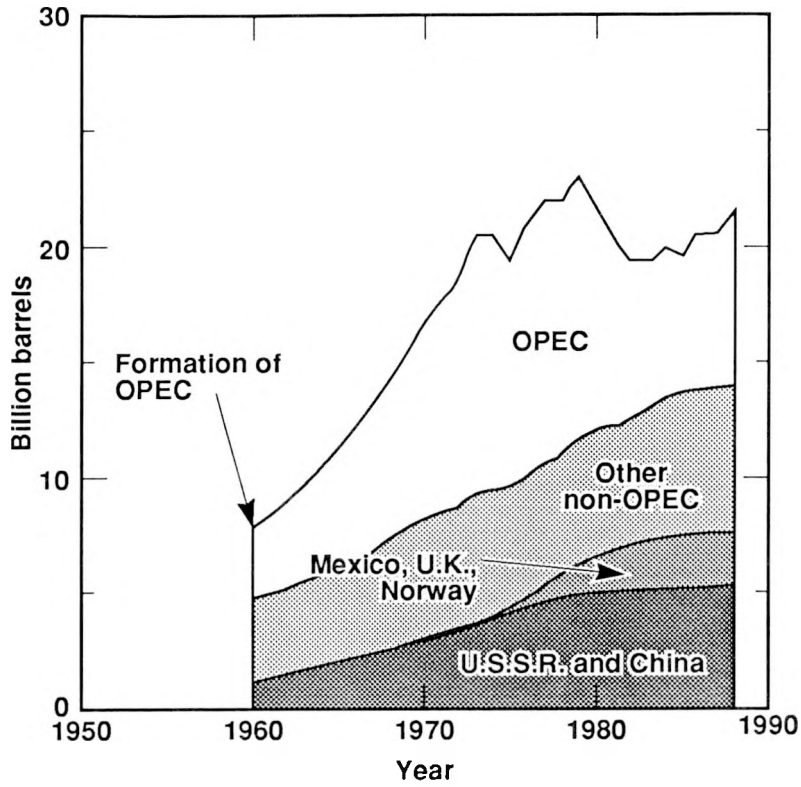

Figure 2. World oil production. Sources: *Annual Energy Review 1988*, U.S. Department of Energy, Washington, D.C., DOE/EIA-0384(88) (1989), Table 105; *Twentieth Century Petroleum Statistics—1989* (DeGolyer and MacNaughton, Dallas, Tex., December 1989), pp. 3–12.

indication of whether this is possible, given that oil prices remain at the $20 to 25/bbl level, can be gained by reviewing the developments within the principal countries that comprise the non-OPEC group.

United States

Until 1974, the U.S. was the largest oil producer in the world. At that time, the U.S. was overtaken by the U.S.S.R.. The production decline that began in 1973 continued until the opening of the Trans-Alaska pipeline in 1977 (Fig. 3). Thirteen years later, total production is well below 1973 levels, and the downward trend is expected to continue even as world crude oil prices trend upward. The Prudhoe Bay field on the North Slope of Alaska entered its production decline in 1988. Planned installation of water and natural gas separation and reinjection facilities may increase production by 400 million barrels over the life of the field[2]; however, that represents less than 1 year's flow through the Trans-Alaska pipeline.

With 3 million exploratory and development wells, the U.S. is one of the most thoroughly explored countries in the world.[3] Onshore additions to reserves within the lower 48 states are expected in the future to come primarily from additional recovery in developed fields through either in-fill drilling or enhanced oil recovery (EOR). Enhanced recovery, two-thirds of which is currently steam flooding, accounted in 1988 for 8 percent of total U.S. production (Fig. 4).

Individual new onshore discoveries in the lower 48 states are expected to continue to be small (less than 1 million barrels); however, these discoveries have been numerous and relatively inexpensive to find and place on production.[4] Major discoveries are only likely in frontier areas—the outer continental shelf (OCS) and Alaska, especially the Arctic National Wildlife Refuge. Table 2 gives the combined potential from all future sources. The portion associated with OCS provinces is about one-third of the total (Table 3).

Federal Offshore Production and Exploration

U.S. oil production in offshore provinces makes an important contribution to total domestic production. It comprised 14 percent of the total in 1988 (Figs. 4 and 5), all but 2 percent of which was from federal offshore tracts. An even larger percentage of domestic gas production (about 25%) comes from federal offshore leases. Annual federal revenues from oil and gas (royalties, bonus payments, rentals, etc.) are currently on the order of $3 billion and reached highs of more than $9 billion in 1981 and 1983.[6]

Gulf of Mexico OCS. Production from the Central Gulf of Mexico, which is offshore of the state of Louisiana, is by far the largest contributor to total

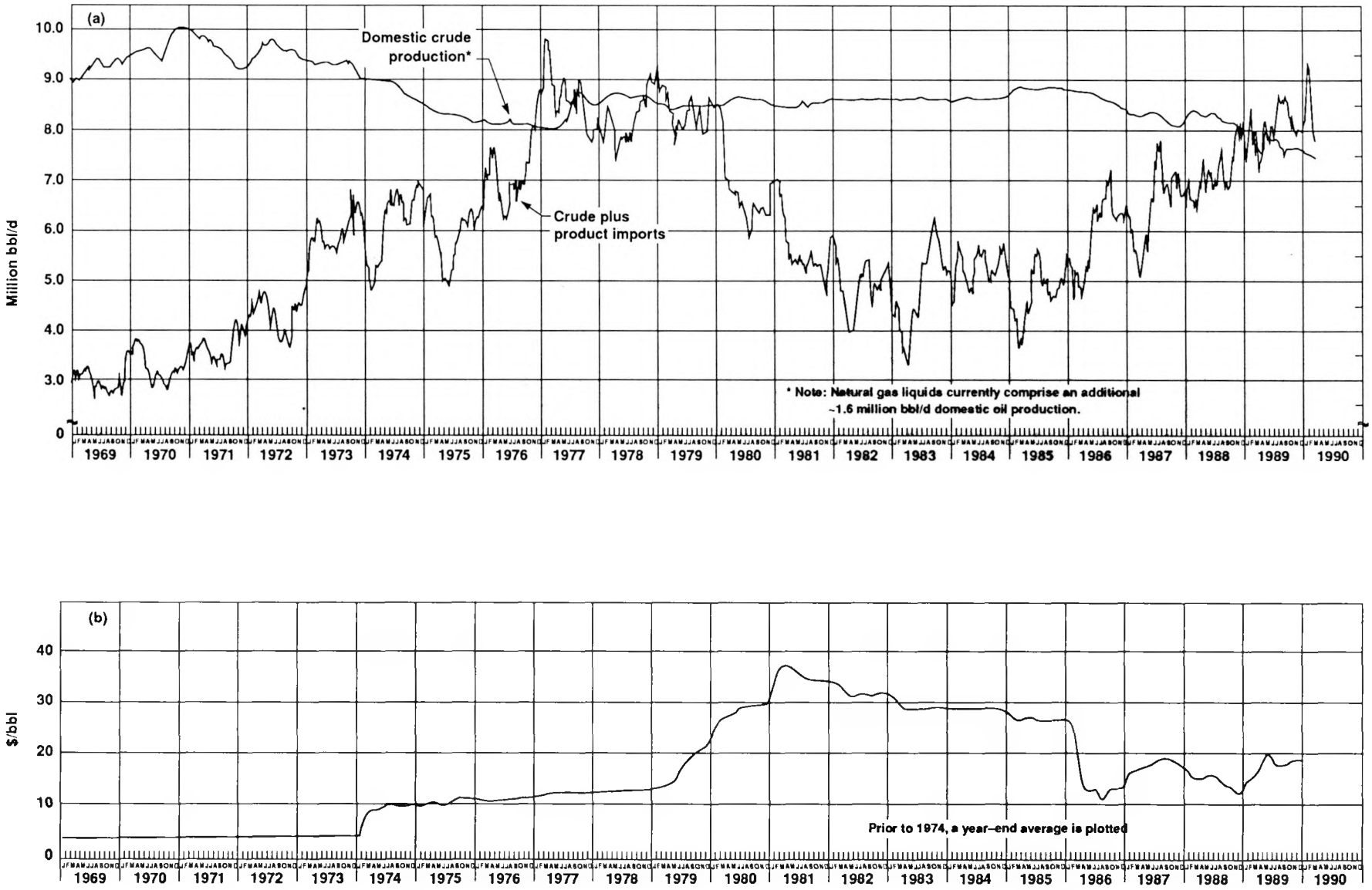

Figure 3. (a) Historical record of U.S. oil imports and domestic production (moving 4-week average). (b) Refiner acquisition cost of crude oil. Shown is a composite of domestic and imported oil. Sources: for imports and production, weekly data from *Oil and Gas J.*; for cost, *Monthly Energy Review*, U.S. Department of Energy, Washington, D.C., DOE/EIA-0035 series.

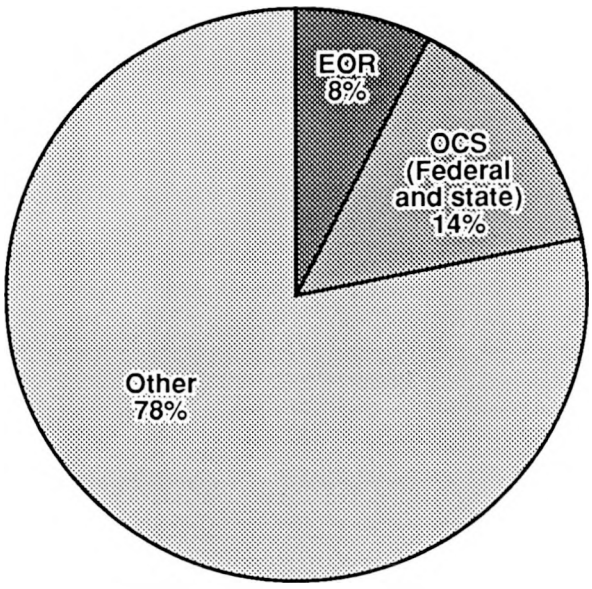

Figure 4. Contributions to U.S. oil production in 1988 (8,140,000 bbl/d). EOR, enhanced oil recovery; OCS, outer continental shelf. Sources: *Annual Energy Review 1988,* U.S. Department of Energy, Washington, D.C., DOE/EIA-00384(88) (1989), Table 49; *Oil and Gas J.,* Vol. 88, p. 31 (March 19, 1990), and Vol. 88, p. 32 (April 23, 1990).

Gulf production. Here, crude oil and condensate production has been between 255 and 387 million barrels for the last twenty years and is currently 262 million barrels. Until 1976–1977, additions to reserves, on average, exceeded production in the Gulf. In the interim, the decline in exploration and additions to reserves has been exacerbated by the decline in crude oil prices. Nonetheless, deep-water drilling records in the Gulf have been repeatedly broken in the last five years in the Mississippi and Green Canyon areas; and bids have been received by the government on tracts beneath 10,000 ft of water (OCS Sale 112).

Table 2. Mean estimates of undiscovered, economically recoverable petroleum resources.[a]

Oil (billion bbl)	Gas (Tcf)[b]	Natural gas liquids (billion bbl)
34.8	262.7	6.3

[a] Source: R. F. Mast et al., *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment,* U.S. Department of Interior, U.S. Geological Survey and Mineral Management Service, Washington, D.C., 89-600108 (1989), Table 1.

[b] Tcf, trillion cubic feet.

Table 3. Estimates of federal OCS undiscovered, economically recoverable oil and gas resources, as of January 1987.[a]

Federal OCS area (leased and unleased)	Conditional mean[b] Oil (billion bbl)	Gas (Tcf)
Atlantic	0.32	3.65
Gulf of Mexico	5.64	64.33
Alaska	3.32	0
Pacific	2.10	5.17

[a] Source: G. J. Gould, *OCS National Compendium,* U.S. Department of Interior, Mineral Management Service, Washington, D.C., OCS Information Report MMS 89-0043 (June 1989), Tables I-2, I-4, I-6, and I-8.

[b] A conditional mean is calculated assuming that some hydrocarbons exist in an area, as opposed to a mean, which incorporates the risk that the area may be barren.[5]

The current well completion record in the Gulf is in 3553 ft of water in the Viosca Knoll area.[7] It is just hort of the world record of 3671 ft, set in Brazil's offshore Campos Basin. To be economically feasible, production from discoveries at such depths must be large—20,000 to 40,000 bbl/d—and thus involve 20 to 40 subsea completions.[8] Despite the existing infrastructure for oil and gas production in the Gulf, its deep water is a frontier area for petroleum exploration.

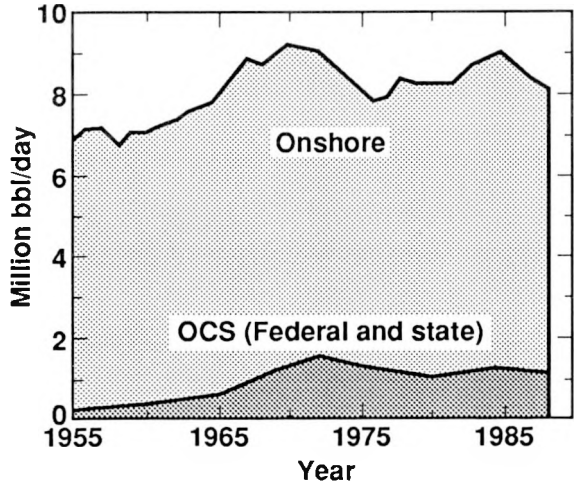

Figure 5. U.S. onshore and offshore production. Source: *Annual Energy Review 1988,* U.S. Department of Energy, Washington, D.C., DOE/EIA-0384(88) (1989), Table 49.

Alaska OCS. Of the four federal OCS regions (Alaska, Pacific, Gulf of Mexico, and Atlantic), Alaska ranks after the Gulf of Mexico in the size of its estimated economically recoverable, undiscovered oil and gas resources.[9] Of the 11 offshore basins assessed, the Chukchi Sea basin, adjacent to the U.S./U.S.S.R. international boundary, is believed to contain the most hydrocarbons (Fig. 1); the risked mean estimate of undiscovered oil is 590 million barrels as of January 1, 1987, according to U.S. Department of Interior estimates. (The risked mean estimate takes into account the degree of uncertainty surrounding the existence of the hydrocarbons.) Response to the first federal lease sale, held in May 1988, was unexpectedly strong despite the fact that it is virgin territory; not even a continental offshore stratigraphic test (COST) well has been drilled in the region. In addition, the area is characterized by some of the most extreme conditions of weather, accessibility, and ice found in northern Alaskan waters.

Subsequent to the 14 federal lease sales held in Alaska through FY1988, 68 exploratory wells were drilled, which resulted in 8 discoveries, all in the Beaufort Sea area north of Prudhoe Bay.[10] No plans for further development have been made public, probably because of the isolation of the federally owned Beaufort area and the requirement that multiple discoveries in nearby leases be made in order to make development economically feasible. The only producing field in either federal or state* areas of the Beaufort Sea is the Endicott field (370 million barrels of oil and 0.8 Tcf of gas). This field was discovered in 1978 in state waters. Costs of developing the field to reach its scheduled 100,000-bbl/day production in 1988 were $1.1 billion.[11]

Pacific OCS. Although offshore areas adjacent to the states of Oregon and Washington are believed to contain small amounts of undiscovered oil and gas, the bulk of the resources in the Pacific area are associated with California. The mature offshore industry in the state contributes approximately 16 percent to total California oil production, almost equally divided between state and federal waters. Proved offshore reserves (state and federal) are 27 percent of total California reserves, the largest portion being in the federal OCS.[12] Estimates of undiscovered OCS resources are on the order of 2 billion barrels, almost all of which is in the southern part of the state. In northern and central California, heated controversy and litigation for the past 5 years between the U.S. Department of Interior and environmental and local groups surrounded the proposed leasing of tracts (OCS Sales 91 and 119) in 1989 and 1990. All of the areas of interest coincide with offshore sedimentary basins, areas where hydrocarbon prospects are normally good. However, in contrast to southern California offshore areas, the sediments are thin and hence are probably not good exploration prospects. Estimates of undiscovered recoverable oil and gas in the two areas are small relative to almost all OCS subregions. Between 1963 and 1967, 20 exploration wells were drilled and abandoned on tracts acquired in an earlier lease sale (OCS P-1).

Atlantic OCS. A total of 46 wells have been drilled in the Atlantic OCS area; however, no new exploratory wells have been spudded since 1984.[9] The province is now primarily considered to be a gas-prone area.

Alaska

By most accounts, the bulk of recoverable oil yet to be discovered in onshore Alaska and in state waters is located on the North Slope, which includes the Arctic plain and the foothill region of the Brooks Range.[10] About half of the oil (3–4 billion barrels) is believed to reside in the Arctic National Wildlife Refuge (ANWR), in the northeastern section of the North Slope; however, the area is not well assessed for lack of drilling information, and estimates vary widely depending on assumptions made by the various estimating agencies.[13] In any event, there is a question as to whether hydrocarbons in ANWR, if discovered, could be exploited at current prices of less than $20 per barrel.[14]

Nonetheless, there is strong interest in the area. Preliminary seismic surveys by the U.S. Department of Interior indicate that there are at least 26 favorable geological trapping structures in the area. Proximity to the supergiant Prudhoe Bay field and the Trans-Alaska pipeline also make the area highly attractive to the oil industry. It will take congressional action to open it for exploration, however. To date, concerns about damage to the environment—in particular, the calving caribou and musk ox herds found seasonably in the area—have caused Congress to move cautiously.

Some indication of what is to be found in ANWR was garnered by Chevron and British Petroleum with the 1986 completion of a 14,530-ft well (the 1 KIC well) near, but not on, one of the major promising structures in the area. No public information was released concerning what was found. The exploratory well was drilled on land owned by native Alaskans, who acquired it in a land swap with the government, which wished to consolidate other wildlife areas in Alaska. The Kaktovik Inpiat Corporation then leased

* Offshore leases within three geographical miles of shore are managed by the State of Alaska.

the land to Chevron. A subsequent exploratory well, "Aurora," drilled by a 12-company consortium, reportedly found oil; like the KIC well, however, it is "tight hole," which means the data were not released.[15] In addition, there have been several exploratory wells drilled offshore of ANWR in state waters. All information released indicates that ANWR is one of the last giant prospects in the U.S. It seems inevitable that it will ultimately be exploited.

Soviet Union

The Soviet Union is the largest oil producer in the world. Its exports [Fig. 6(a)], which equate to about one-third of total production, are critical to the economies of the Comecon countries,[16] and exports to the Free World are an important source of hard currency. From the standpoint of the United States, a self-sufficient Soviet Union and its allies means less competition for world supplies.

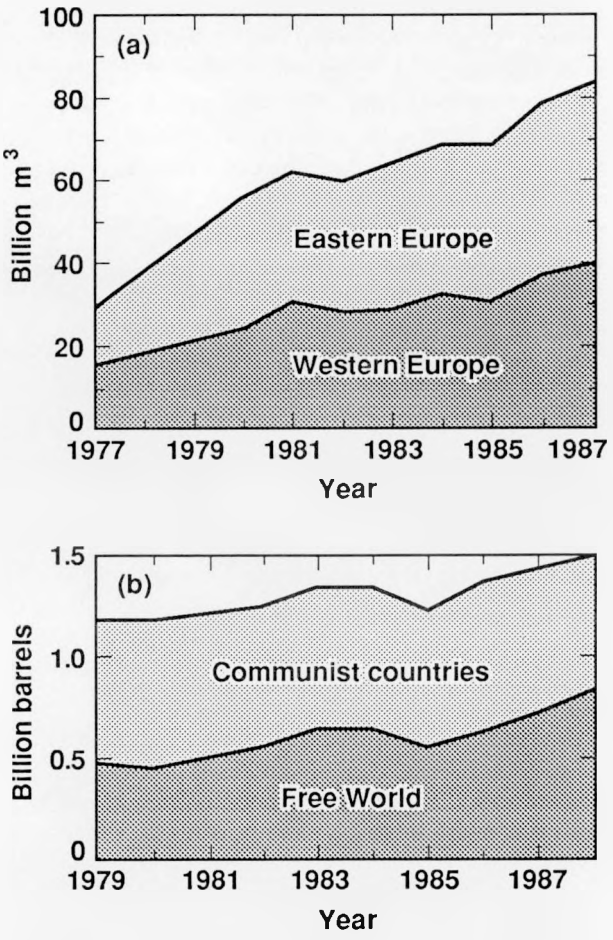

Figure 6. (a) Petroleum exports from the U.S.S.R. (b) Natural gas exports from the U.S.S.R. to Eastern and Western Europe. Source: *International Energy Statistical Review*, U.S. Central Intelligence Agency, Washington, D.C., DI IES 90-002 (February 27, 1990).

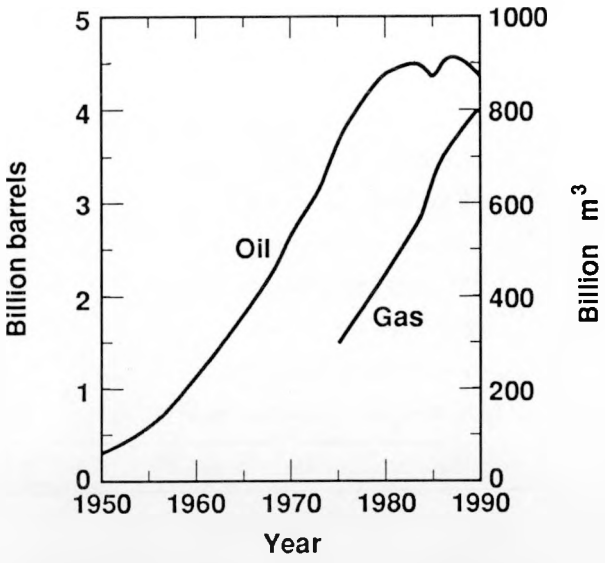

Figure 7. U.S.S.R. oil and gas production. Sources: for 1950–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

From all indications, oil production in the U.S.S.R. has plateaued after three decades of steady growth (Fig. 7). The plateau has occurred despite the large and growing contribution that condensates from natural gas production are making to the total. That contribution is at least 500,000 bbl/d of the total 12.1 million bbl/d.[17]

The single factor that has most affected Soviet oil production is the decline in major West Siberian fields in Tyumen and Tomsk oblasts; these contribute the largest regional share to the country's total production—approximately two-thirds. The supergiant Samotlar in Tyumen reached peak production in 1980 and has been in decline since then. Nonetheless, it has intermittently produced more oil per day than any field in the world, including Saudi Arabia's Ghawar field.[18] The reasons that the Soviets have been unable to maintain production in West Siberia lie in poor development and production practices, which date back to the discovery of the giant fields. There has been enormous waste, and the infrastructure is inadequate to attract and keep qualified technical workers. Production costs exceed those in other parts of the country by 50 percent.[19] But costs of exploring, developing, and producing have climbed throughout the U.S.S.R. as the size of discovered oil deposits has fallen and the terrain has become more hostile and distant from population centers.

Table 4. Supergiant U.S.S.R. gas fields.[a]

Field	Reserves (Tcf)	Status
Urengoi, Tyumen	285.6	Production start, 1978
Yamburg, Tyumen	167.9	Production start, 1986
Zapolyar, Tyumen	94.3	Under development
Medvezhye, Tyumen	54.7	Production start, 1972
Bovanenkov, Komi	146.5	Under development
Kharasavei, Komi	45.3	Under development
Shtomanov (Barents Sea)	105–141	Undeveloped

[a] Source: J. D. Grace and G. F. Hart, "Giant Gas Fields of Northern West Siberia," *Bull. Am. Assoc. Petr. Geol.*, Vol. 70, pp. 830–852 (July 1986); *Oil and Gas J.*, Vol. 88, p. 35 (September 4, 1989).

Four regions are the main foci of long-range planning in the oil industry: West Siberia, the Pre-Caspian Depression and the Caspian Sea, the Barents Sea, and Eastern Siberia. Although all are believed to contain unexploited resources, proving those reserves may be slow. Soviet economic problems, a lack of investment capital, a boundary dispute with Norway in the Barents Sea, and distance from markets in the case of Eastern Siberian prospects suggest that expedience will dictate concentration in West Siberia and the Caspian Sea area. The development of frontier areas such as the Barents Sea may have to wait for the participation of Western firms in joint ventures, which apparently the U.S.S.R. is now prepared to be a party to.[20]

The outmoded refining industry has also failed to meet goals as the demand has increased for light oil products. Demand has declined for heavy residual oils as natural gas has displaced oil at power-generating stations. Without adequate catalytic and hydrocracking units, the strategy for meeting demand is to increase the throughput at the refineries, with a resultant glut of residual oils that are eventually sold on world markets at very low prices.

The gas industry in the U.S.S.R. has outperformed all other energy resource sectors. Many large discoveries made in the sixties and seventies in northern West Siberia have been exploited, and others on the Yamal peninsula (Bovanenkov and Karasavei) are yet to be developed. Table 4 gives the size of some of the larger fields. By comparison, U.S. proved gas reserves as of December 31, 1988, were 168 Tcf (including a 24.6-Tcf downward revision in 1988 attributed to adverse market conditions).[21] These massive gas reserves—perhaps 40 percent of the world's total—will supply gas to the U.S.S.R. and Europe [Fig. 6(b)] well into the next century.

The market for natural gas in Western Europe has not grown as rapidly as anticipated; however, it will continue to grow under the impetus of environmental considerations. Gas is relatively pollution-free as compared with traditional boiler fuels such as coal and fuel oils. Barring major delays in construction of pipelines, and assuming that repair and maintenance of trunk lines are undertaken, gas will also have increasing importance in Eastern Europe, especially if the cost of crude oil creeps upward.

The important contribution that natural gas liquids and condensate are making to overall Soviet oil production will increase as gas production from the supergiant fields comes on-stream. It will offset the almost certain decline in the mature oil fields in West Siberia. Production of natural gas liquids and condensate, together with production of oil from new fields under development, such as Tengiz and Astrakhan (gas condensate) in the Caspian region, means that total Soviet oil production will probably not decline appreciably before the next century.

Canada

Canada is second to Saudi Arabia as a supplier of crude oil and refined petroleum products to the U.S. Exports to the U.S. are about 350 million bbl/yr, which is less than the all-time high of approximately 480 million bbl/yr. After 1973, Canadian governmental policy called for a partial curtailment of exports in order to conserve resources. In the course of compliance, producers shut-in production[22] (Fig. 8). The strong export position that Canada has nonetheless maintained belies the size of its reserves of conventional oil—6.1 billion barrels in producing and nonproducing areas at the end of 1988.[23] (Nonproducing areas included are fields in the Beaufort Sea and the

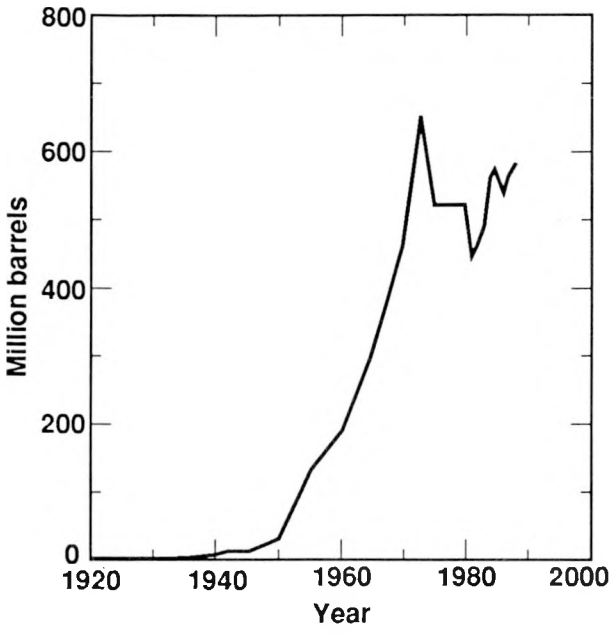

Figure 8. Canadian oil production. Sources: for 1920–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

Terra Nova field in offshore Newfoundland.) To augment the supply of conventional oils, Canada has undertaken the development of its heavy oils and bitumens. In 1988, the production of heavy oil (<22°API gravity in Canada) was estimated at 500,000 bbl/d, and oils from bitumens at about 185,000 bbl/d[24] (210,000 bbl/d capacity), out of a total Canadian output of 1,609,000 bbl/d (Fig. 8). The size of these resources is enormous—1.2 to 1.5 trillion barrels in place—of which perhaps 300 billion barrels are recoverable at some cost.[24] At this juncture, the Canadian Petroleum Association considers 1.8 billion barrels of synthetic crude from the operating Suncor and Syncrude plants in the reserves category, together with an additional 1.4 billion barrels of bitumen under development.[23] Total reserves of all categories of liquid hydrocarbons at the beginning of 1989 are given as 10.2 billion barrels.

Additional conventional oil may be discovered in yet-to-be explored terrains, such as offshore and in western Canada. The offshore areas in eastern Canada remain promising. However, the development of the 0.5- to 1.0-billion barrel Hibernia offshore field near Newfoundland has progressed slowly since its discovery a decade ago, and any additional developments may suffer the same fate owing to the hostile environment and the resulting high associated costs. (Hibernia is in "iceberg alley," not too far from the spot where the *Titanic* sank.)

Thus the future mainstay of the Canadian industry will be its heavy oil and oil-sand deposits. The current focus of the federal and provincial governments is participation in the financing of upgrading plants for both heavy oils and the oil sand's bitumen. Synthetic crude oil now produced at the operating Suncor and Syncrude plants in the Athabasca area is a "bottomless" blend of hydrotreated naphtha and gas oil made using a carbon-rejection technology of delayed and fluid coking. New projects, such as the OSLO upgrading project and one near Lloydminister, will incorporate hydrogen-addition or hydrocracking upgrading technology. Existing operations for producing unconventional and synthetic crude oil are believed to be profitable at oil prices of $10 to $16 per barrel.[25] The new OSLO development, which is expected to be on-line in 1996, was assessed as viable with prices in the range of $20 to $25 per barrel after inflation is taken into account.[23] Nonetheless, price uncertainties are taking their toll of heavy oil and bitumen production plans. Expansion at Cold Lake and Peace River has been postponed because of financial constraints, as have other planned major projects. Whether combined heavy oil and synthetic crude oil production can reach 1 million bbl/d by the early part of the next century is conjectural. Since conventional light oil production is expected to fall to 145,000 bbl/d by 2005,[26] exports to the U.S. are likely to be greatly restricted without the development of Canada's heavy hydrocarbons.

China

China's oil production in 1989 was on a par with Mexico's and the U.K.'s. It has been steadily rising since 1970 as a result of draconian measures to maximize output from known fields and the exploration of offshore tracts through lease agreements with foreign oil companies (Fig. 9). The bulk of China's 2.7 million bbl/d production comes from two large onshore fields (Daqing and Shengli), the oldest parts of which have reached maturity. By developing numerous peripheral reservoirs in both fields, the Chinese National Petroleum Company (CNPC) hopes to maintain production at current levels into the nineties.[27]

In 1989, China exported almost 17 percent of its domestic oil production,[28] which constituted about 20 percent of its foreign exchange earnings.[29] Despite rising production, critical exports have fallen since their high in 1985. The reason is that domestic demand is rising at an estimated 4%/yr.[30] As a consequence, a high priority has been set on developing additional resources.

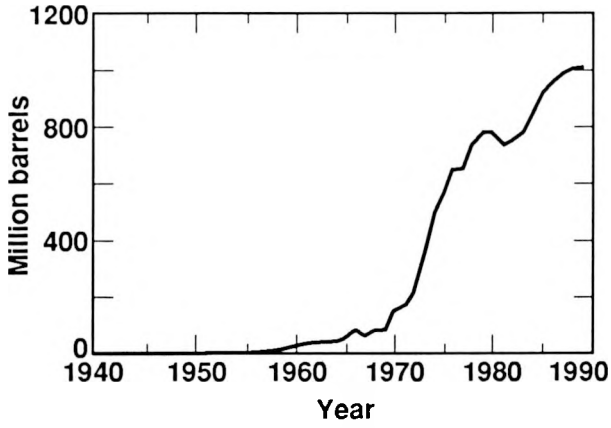

Figure 9. China's oil production. Sources: for 1940–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

Two principal exploration targets are the offshore provinces, which were opened to foreign participation for the first time in 1983, and the Tarim basin in the westernmost region of China, which is being explored by CNPC.

Response to the first round of bidding for tracts in the offshore areas was good. Response to the second round in 1986 was less enthusiastic, and response to the third in 1988 was lukewarm, despite improved terms. In the five years between the first and second round, foreign interests invested $2.5 billion in Chinese offshore ventures,[29] and the results have been disappointing. Many participants bid in the third round because of the widespread belief that participation may confer preferential status should the Chinese open up highly prospective onshore areas in the northwest corner of the country to foreign exploration. By 1992, nine offshore oil fields should be on-stream, as compared with two in 1988,[31] but all nine are expected to reach modest peak production levels: less than 25,000 bbl/d. This new oil will have a small impact on China's petroleum requirements.

The Tarim basin in Xinjiang province, northwestern China, has been the site of CNPC exploration for nearly 10 years. Some 160 exploratory wells have been drilled and 31,000 line miles of seismic surveys have been made within the remote area, which is about the size of the state of Texas.[32] Until 1989, discoveries were modest. The oil and gas discovery made in 1989, however, tended to confirm estimates that the basin holds 5 to 7 billion barrels of oil.[33] Plans are to triple the number of rigs operating in the area by the end of 1990.

Despite concerted efforts to develop new sources of supply, it seems unlikely that under the most optimistic assumptions they will contribute substantially to China's oil production before the turn of the century. On that account, it is possible that China will be forced to look to imports to meet its growing demand before that time.

Mexico

After the U.S. and the Communist countries, Mexico is the largest non-OPEC oil producer. Some 66 percent of its production stems from discoveries made in the Gulf of Campeche in the mid-seventies[34] (Fig. 10). Production from earlier discoveries in the onshore Reforma area has declined substantially. Although exploration has continued throughout the eighties, the bulk has been focused in proven areas, such as offshore Campeche and southeast onshore areas.[35] Crude oil reserves have vacillated around 50 billion barrels after reaching a high of 57 billion barrels in 1982,[36] which puts them on a par with those of Venezuela and the U.S.S.R. and at almost twice the size of those of the U.S. and China. Nonetheless, some of the reserves are heavy oils—probably 11 billion barrels—requiring production procedures not currently in use and not economic at current prices.[37] Development of the country's resources is hampered

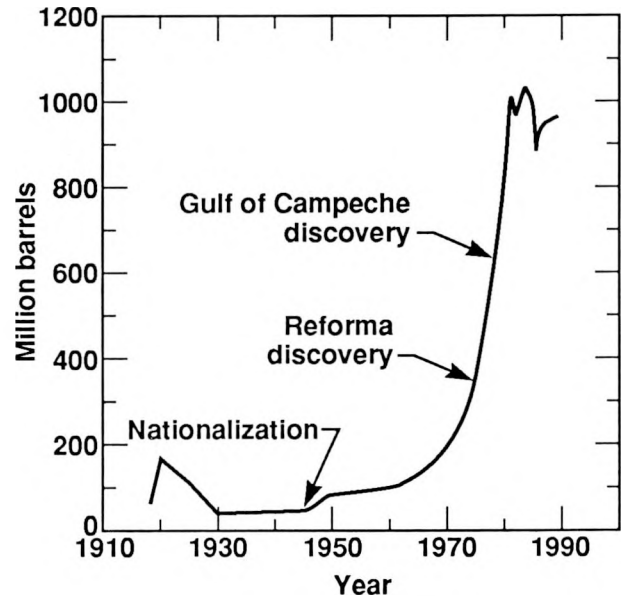

Figure 10. Mexico's oil production history. Sources: for 1920–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

by Mexico's foreign debt, which stood at $106 billion in 1988. In Latin America, this debt is second only to Brazil's, and servicing it takes more than total revenues from oil exports.[37] Maintaining production at the current 2.6 million bbl/d level for any length of time will be difficult because funding of Pemex, the national oil company, is not at optimum levels. An option, heretofore politically unacceptable, is to solicit foreign investment in the oil and gas industry. Investment in any of the so-called "downstream" activities such as refining could free Pemex funds for development of its hydrocarbon resources.

An additional concern is the rising domestic demand, now about 1.5 million bbl/d, which promises to cut into oil exports. Domestic energy consumption is growing at 3 to 4 percent annually and may reach 5 percent/yr by the end of the century.[38] Consequently, there is a good possibility that Mexican oil exports will cease by the year 2000. In 1989, Mexico was among the U.S.'s five principal sources of foreign oil at about 780,000 bbl/d.

Norway

In contrast to the U.K.'s sector in the North Sea oil province, Norway's has potential for substantial growth. There are at least nine Norwegian fields that have already been discovered that could start producing before 1995.[39] All but two of the nine are in the central North Sea area with its well developed infrastructure and pipelines; the two (Heidrun and Draugen) are in the oil-rich Haltenbanken area above the 62nd parallel (Fig. 11). Assuming these fields come on-line in the nineties, production decline in the large Ekofisk area and at the Stratfjord field, which is anticipated to begin in the early nineties, will more than be offset. Production of more than 2 million bbl/d is possible by 1995, up from the current level of about 1.4 million bbl/d. Figure 12 contains projections to 1996 by the *Petroleum Intelligence Weekly*.[39]

Following the fall in the price of crude oil in 1986, Norway voluntarily cut production 7.5 percent below capacity[40] and curtailed development in three of its newly discovered fields (Draugen, Brage, and Heidrun) in order to stabilize prices.[41] Nonetheless, exploration and development in older fields have continued, and the very large Oseberg field came on stream at the end of 1988.[42] In addition, although the stabilization measures extend into 1990, the government has given approval for production startup in the Draugen field and is expected to approve the development of the Brage field.[43]

Norwegian oil reserves doubled between 1981 and 1989.[44] The total is between 11 and 16 billion barrels, depending on the estimator,[45] and is the third largest amongst non-OPEC and non-Communist countries. Only the U.S. and Mexico have larger reserves within that group. In contrast to earlier years in the decade, 1988 was not attended by many large discoveries; however, reserves rose by 532 million barrels owing to revisions in earlier estimates.[42] Upward revisions in many Norwegian fields continued into 1989.[46]

Norwegian natural gas reserves and resources are second only to those of the Netherlands in Western Europe. Their utilization depends on the construction of thousands of kilometers of large-diameter pipe to European customers. In 1986, Norway signed a $64 billion pact with gas companies from West Germany, Belgium, the Netherlands, and France to supply gas from its huge Troll gas field.[47] The agreement, which runs until 2020, calls for deliveries to begin in 1993. It is viewed as a counter to increasing reliance on Soviet gas on the part of Western European nations. Sweden may seek a similar agreement with Norway in order to find substitute fuels as nuclear reactors are phased out; however, Soviet gas transported via Finnish pipelines is geographically more convenient.

United Kingdom

The likelihood that North Sea production would reach a maximum by 1990 if not sooner has been expressed by many analysts for more than a decade.[48–51] That assessment was based on the expected decline in the largest of the oil fields in the U.K. sector of the North Sea[52,53] (Brent, Forties, Ninian, and Piper), which started up in the 1975–1978 period, and to a lesser extent, on the peaking of oil production in the Norwegian Ekofisk area in 1980.[54] While oil discoveries in the U.K. sector have mitigated declines in older fields, none has been large, and the concensus is that no more giant fields are likely to be found. Production decline in the U.K. sector began in 1986 (Fig. 13) and is expected to continue. Nonetheless, there are 11 fields with reserves of approximately 1 billion barrels that are expected to come into production and peak between 1991 and 1993.[55] Production in 1988 was affected by a series of strikes and accidents affecting the Brent, Forties, Scapa, and Claymore fields.* Thus the drop in production in 1988 and 1989 evident in Fig. 13 is larger than would otherwise be expected. At the end of 1989, production had been partially restored, and 1990 totals may reach 1987 levels, assuming that planned shutdowns associated with maintenance at several of the larger fields prove to be routine.

* The Piper platform gas explosion; loss of the Fulmar floating storage facility in storms; equipment failure at Brent; a gas explosion at the Cormorant Alpha platform which shut down the Brent pipeline system; and the shutdown of the St. Fergus gas treatment plant due to the discovery of plant problems.

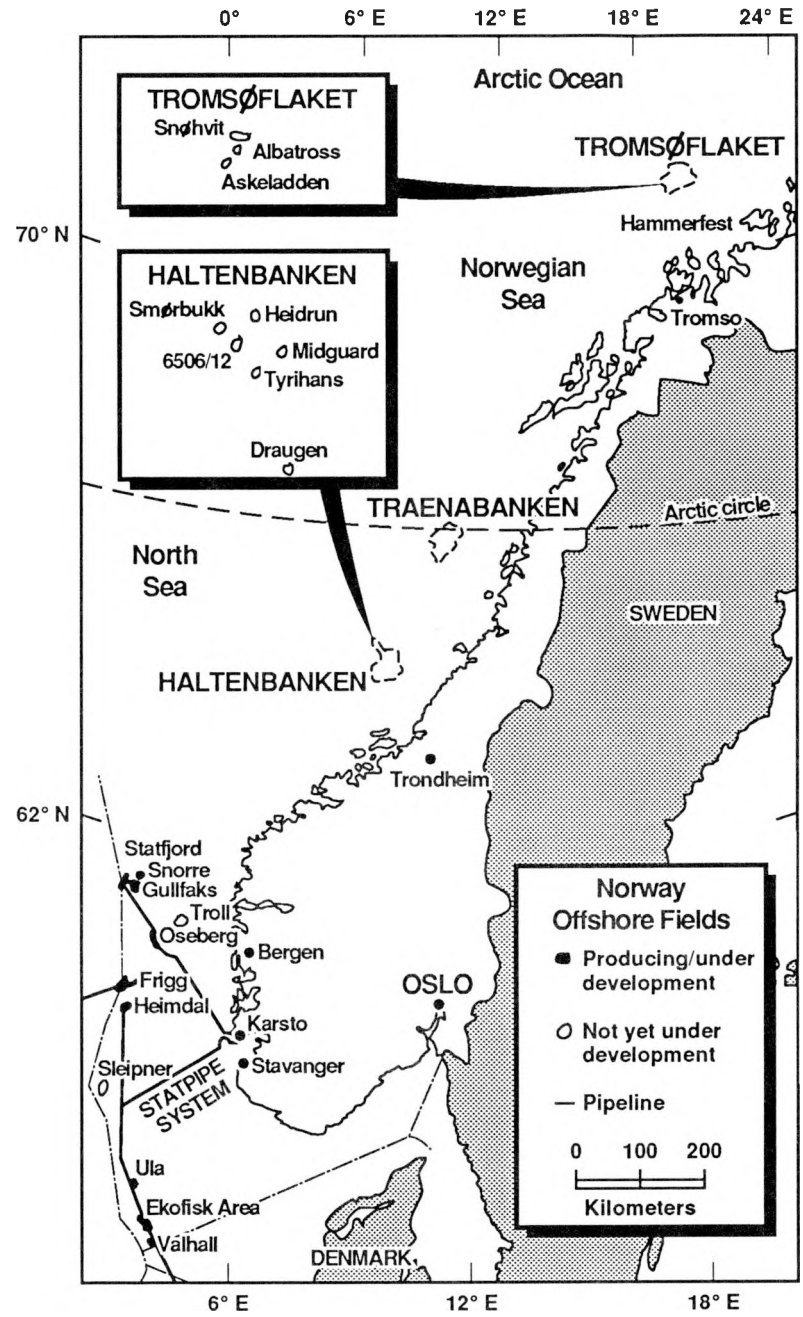

Figure 11. Norway's offshore oil fields. Source: *Petroleum Economist*, Vol. 53, p. 9 (January 1986).

Egypt

Egypt is not generally considered to be a major oil-producing country although its production is steadily approaching the 1 million bbl/d level. The bulk of oil produced in the country (Fig. 14) is from numerous fields in the Gulf of Suez. Until recently, the vast Western Desert was not considered to be fertile ground for oil discoveries such as those forming the basis of Libya's industry farther to the west. However, international oil companies operating on concessions during the past 10 years have made a series of small discoveries that have raised hopes that the area may contain sufficient reserves to help counter the decline in Gulf of Suez fields.[56] Production in the Western Desert is about 50,000 bbl/d, and government planners hope that it will rise to 100,000 bbl/d in the 1990s.[57] A series of pipelines linking the largest of the finds in the Western Desert to the coast at El Alamein ensures a market for small discoveries and continued interest in the Western Desert on the part of international oil companies. Nonetheless, unless major

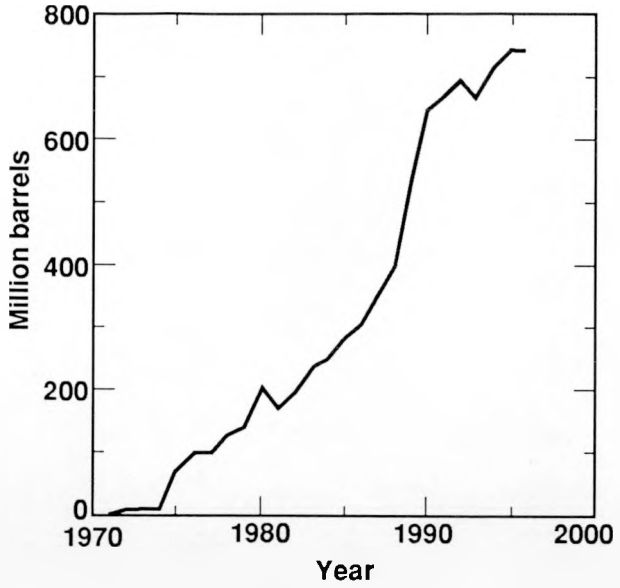

Figure 12. Norwegian oil production in the North Sea. Sources: for 1970–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990); projections for 1989–1996, *Petroleum Intelligence Weekly*, Vol. 28, p. 5 (November 27, 1989).

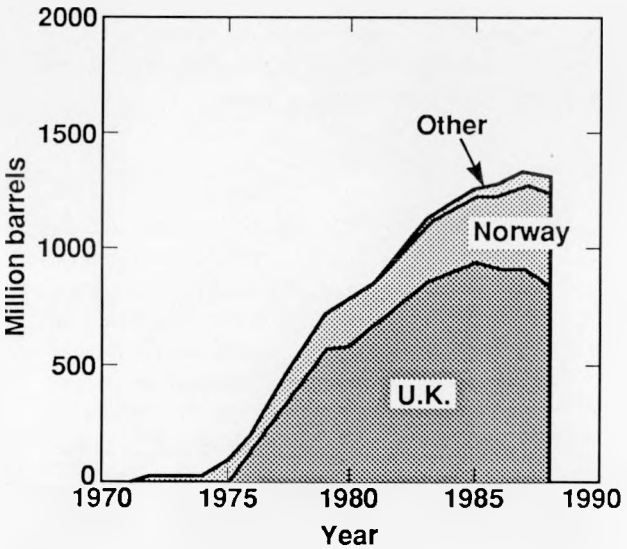

Figure 13. North Sea oil production. "Other" includes the Netherlands, Belgium, and Denmark. Sources: for 1970–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

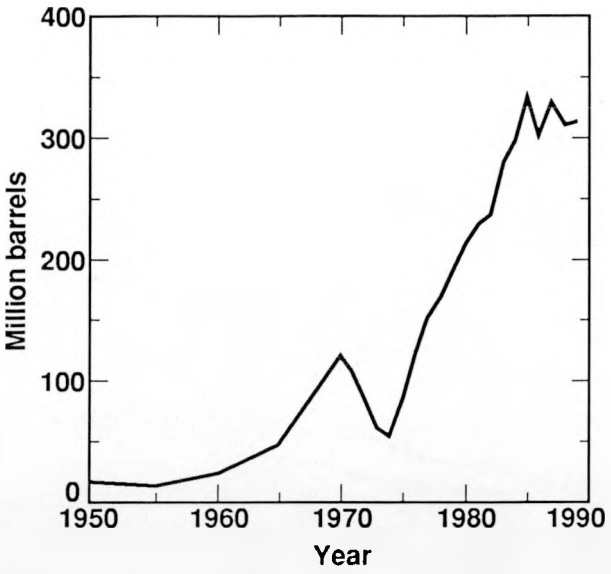

Figure 14. Egyptian oil production. Sources: for 1950–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

discoveries are made in the area in the near future, the Gulf of Suez will continue to be Egypt's principal hydrocarbon province into the next century.

Because the government has reversed earlier decisions and given oil companies rights to develop and sell any gas found on concessions, utilization of the gas that has been discovered is being realized.[57] Depending on timing, these new gas supplies may counter the present unusually high consumption of oil for power generation in Egypt. The central African drought has severely impacted the generating capacity at the Aswan Dam. It is about half of normal, and oil-fired units have made up the difference. The new governmental policy has also encouraged exploration because gas discoveries, which were formerly written off, lessen the risk taken by companies holding concessions.

India

India is among the countries that have more than tripled their domestic oil production since the mid-seventies (Fig. 15), and it is hoping to reach the 1 million bbl/d level by the end of the present decade. At that point, it will be a member of a small group of producers outside of the Middle East that have attained that level. Unfortunately, demand driven by a burgeoning population has steadily increased over the same period, and self-sufficiency has not been attained.

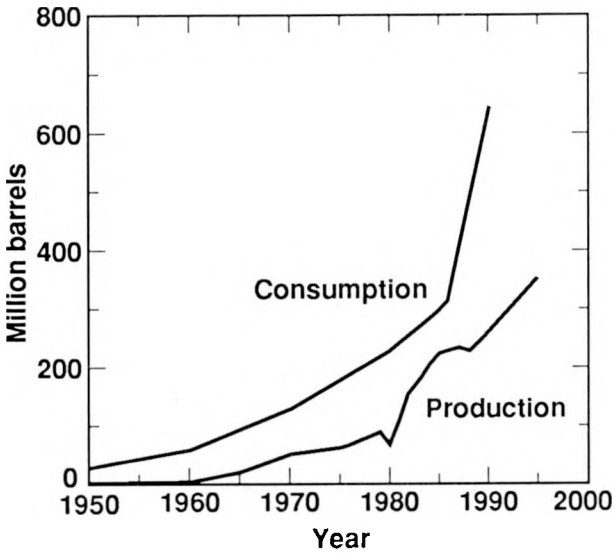

Figure 15. India's oil production and consumption. Production is based on calendar year; consumption data are based on fiscal year. Thus FY1950–1951 is plotted as calendar year 1950. Sources: for 1950–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, 31–32 (March 19, 1990); for 1995 projection of production, *Petroleum Economist*, Vol. 156, No. 12, p. 382 (December 1989); for consumption data and projections for 1990, *Oil and Gas J.*, Vol. 86, p. 25 (January 11, 1988), and *Petroleum Economist*, Vol. 156, No. 12, p. 382 (December 1989).

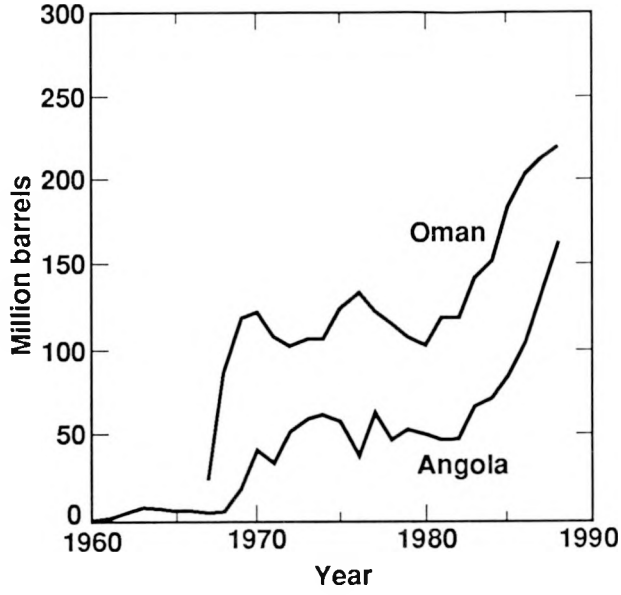

Figure 16. Oil production in Oman and Angola. Sources: for 1960–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

Even with Herculean efforts to increase production, the gap between supply and demand is expected to widen, and increased imports will exacerbate the country's debt problem[58] (Fig. 15).

Two-thirds of India's production comes from northwestern offshore fields, of which the Bombay High is the largest. The two national oil companies are the principal operators. Production at that field, which was discovered in the late 1970s, has reached a plateau,[59] and major exploration efforts have been under way for some years to discover comparable fields. So far, discoveries have not been of comparable size; the largest is the onshore Gandhar field in Gujarat state, which should come into production in 1991[60] and perhaps reach 60,000 bbl/d by 1995. In order to step up exploration, the government has offered offshore acreage to foreign oil companies in three rounds of licensing. India received only one bid in the first round and none in the second. Better terms in the third round led to agreements with six foreign oil companies that are now exploring the southern and eastern areas.

Although the principal target of exploration is liquid hydrocarbons, gas discoveries that have been made have the potential of mitigating the growing need for fuels and forestalling the purchase of larger and larger quantities of oil from foreign sources.

Oman

Oman is one of the undeveloped countries in the Middle East, but in the last 20 years it has moved from a country in which it was against the law to wear spectacles or ride a bicycle to one with all the modern trappings. The impetus for these changes has been its growing oil and gas revenues. It is one of the many small countries that has contributed to the growth of non-OPEC oil production following the crises in the seventies. Since then, oil production has doubled (Fig. 16) as a consequence of active exploration by numerous oil companies holding concessions; and the discovery phase is not over. Although bordered by Saudi Arabia and the Emirates with their large producing oil reservoirs, the discoveries in Oman have been individually small but numerous. Their development has been economically feasible because new fields can be connected to those countries' large oil pipeline system at minimum cost.[61]

One of the curiosities of the oil geology in Oman is that the source rocks and some of the reservoir rocks are Precambrian in age. Apparently the tectonics of the region were such that subsequent burial of the ancient hydrocarbon-rich rocks was not sufficiently deep to subject them to high temperature and pressures, which normally cause the destruction of the hydrocarbon.[62]

There is doubt that oil production can continue to grow at past rates. The government is planning to increase production to 255.5 million barrels in 1990.[63] Its small fields have a limited lifetime and require artificial lifting techniques, and are consequently more costly to produce than is typical elsewhere in the Middle East.[64] Nonetheless, Oman continues to attract foreign investors.

Brazil

Brazil's long-standing goal to be energy sufficient has remained elusive despite the fact that its domestic oil production has more than tripled in the last two decades (Fig. 17). Self-sufficiency has had additional support from Brazil's unique program to produce alcohol fuels for transportation from agricultural products. In 1988, sales of alcohol were 50 percent higher than

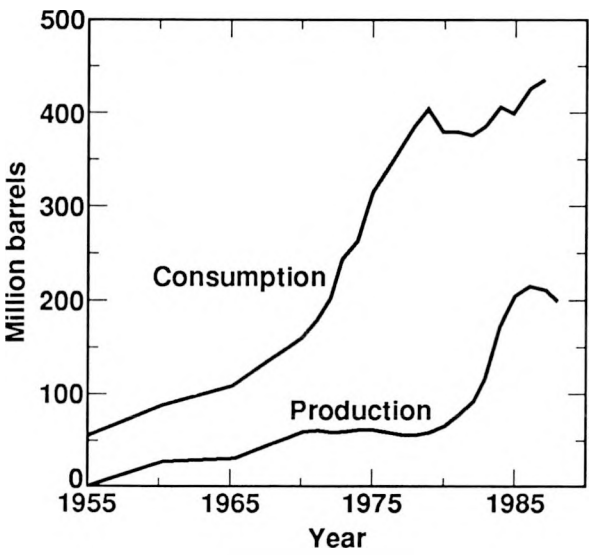

Figure 17. Brazil's oil production and consumption. Sources: for production during 1955–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for production during 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990); for consumption during 1955–1974, *World Energy Supplies 1950–1974,* United Nations, New York (1976), Table 10; for consumption during 1975–1987, annual editions of *Energy Statistics Yearbook*, United Nations, New York.

sales of gasoline.[65] Production amounted to about 190,000 bbl/d; however, the subsidies to the agricultural sector to produce the alcohol have contributed to the nation's financial problems. To cope with the so-called "chicken and egg" problem with respect to fuel and vehicles, Brazil has manufactured alcohol-fueled cars for a decade or more. In 1988, 88 percent of total Brazilian automobile production was of alcohol-fueled cars[66]; however, because of a shortage of ethanol in 1990, production of ethanol-propelled automobiles has been cut back.

Despite a growing demand for liquid fuels, Brazil continues to plan for near self-sufficiency by the end of the century. Assuming adequate funding, Petrobras, the national oil company, forecasts total production of nearly 1.5 million bbl/d in 1997,[65] up from 650 million bbl/d in 1989. The anticipated increase is expected to come from discoveries in the offshore Campos Basin that have yet to come on-line. Although Brazil is the largest country in South America, almost two thirds of oil discovered to date have been in the offshore fields in the Campos and Santos Basins. Two giant fields (Albacora and Marlim), shown in Fig. 18, have yet to be exploited. The discoveries, which are believed to contain about 5 billion barrels of oil, lie in very deep water: the depths are 400 to 2000 m.

As of January 1, 1988, Petrobras stated its proved reserves as about 3 billion barrels, two-thirds of which are in offshore fields. Thus access to the very deep offshore resources would more than double Brazil's reserves. Although Brazil is a leader in deep-water well completions, development of these two reservoirs will be technologically difficult and expensive, at the very least. The record for the deepest completion is in the Gulf of Mexico (Green Canyon satellite well) at 684 m.[65] Petrobras plans a 600-m completion in the Albacora field in 1989, and statements of Petrobras engineers suggest that they can handle depths to 1000 m with current technology. A wildcat well drilled to 800 m discovered a new field in the Campos basin in 1990[67]; however, producing at that depth is an additional challenge. The plan is to use well offsets to drain the oil beneath deep water, and 6 to 8 km of flexible 4-in. lines to produce from the record depths.

The Amazon basin is also the site of recent exploration activities, but discoveries to date have been modest.[68]

Runaway inflation and government deficits led to cuts in the Petrobras budget in 1989 from $3.2 billion to $1.0 billion.[66] Development of the deep water offshore fields, as well as expansion after full restoration of production at the Enchova platform, which was destroyed by a blowout in 1988, may well be postponed. (The decline in oil production from this incident is apparent in Fig. 17.) While technically possible,

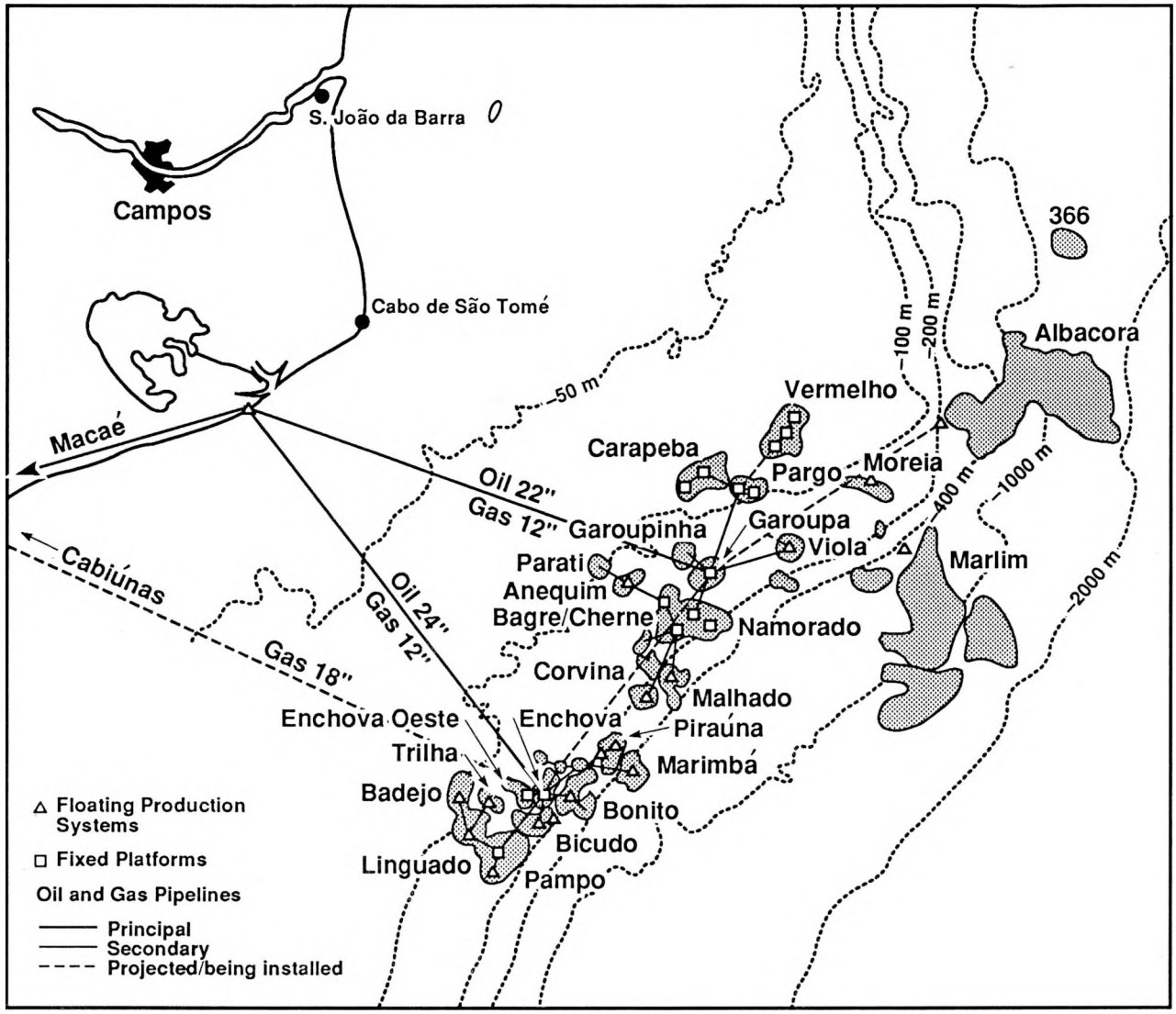

Figure 18. Brazil's offshore fields. Source: *Campos Basin*, Petrobras Public Affairs Service, Brazil (1988).

the time frame projected for further development is believed to be too short as judged by American experience.[69]

Angola

This west African country is one of the most important oil producers on the continent because of early American exploration efforts, which resulted in the discovery and development of the northern offshore Cabinda area. In 1978, the Marxist government formulated a new economic policy designed to encourage additional foreign participation in developing its mineral resources; and in 1989, the last unexplored area of its coastline was opened to foreign investors. Until recently, the largest successes were recorded by Cabgulf, a Chevron subsidiary, and by Texaco, which account for the four-fold increase in production since 1970 (Fig. 16). Discoveries in the last few years by Elf Aquitaine, a subsidiary of the French national oil company, promise to increase production substantially.[70] The civil war between the Marxist government and the U.S.-backed rebels has consumed a large share of the country's oil income and has led the major U.S. operators in the country to sharply reduce their interests.[71] Participation by non-U.S. companies, such as Italy's Aguip and Japan's Mitsubishi, is viewed as an exercise in risk management.

The exploration phase is far from over. Texaco announced two offshore discoveries in 1989–1990.[72]

By all accounts, the tracts offered by the Angolan government have highly favorable geology for additional hydrocarbon discoveries. The onshore areas of the country, which is the size of Texas and California combined, have seen minimal exploration to date because of guerrilla activity, which has made activities hazardous.

Ivory Coast

During the discovery phase of exploration offshore of Ivory Coast in the early eighties, high expectations were held for the development of a major petroleum province on the west coast of Africa. Several major oil fields (Espoir and Belier) discovered at that time remain the only discoveries of note, and both fields are in a state of decline. In fact, Phillips Petroleum Co., operator of the Espoir field with a 57.5 percent stake, announced that it was shutting down its operations owing to the decline in production and low world prices for crude oil.[73] Espoir has yielded 30 million barrels of oil since production began in 1982. Phillips hopes to develop the gas reserves adjacent to the field in order to maintain a presence in the area.[74] Negotiations concerning concessions are under way with the government.

Colombia

In 5 years, Colombia has moved from being an oil importer to being the third largest oil exporter in South and Central America. Only Venezuela and Mexico export more. A series of discoveries starting with the Cano Limon giant field in 1983, together with a relatively generous concession policy toward foreign oil companies, have resulted in a complete turnaround in the country's economy. Ecopetrol, the Colombian national oil company, takes 40 percent of the production and 20 percent royalties. Once a discovery is made, Ecopetrol development costs are shared.[75] Currently, inadequate pipeline capacity limits both production and exports. The Cano Limon field and the neighboring Redondo field near the Rio Arauca, which forms the border between Colombia and Venezuela, could deliver 350,000 bbl/d from existing wells. However, the pipeline to the Caribbean port of Covenas has a nominal capacity of only 225,000 bbl/d.[76] Pipeline construction there and to the south, where smaller fields have been developed, has high priority in the expansion program announced last year.

The rapid rise in production and exports (Fig. 19) is almost miraculous in light of the activities of Colombian rebels, who would like to see cancellation of all contracts with foreign companies and the nationalization of all mineral industries. All told, there are

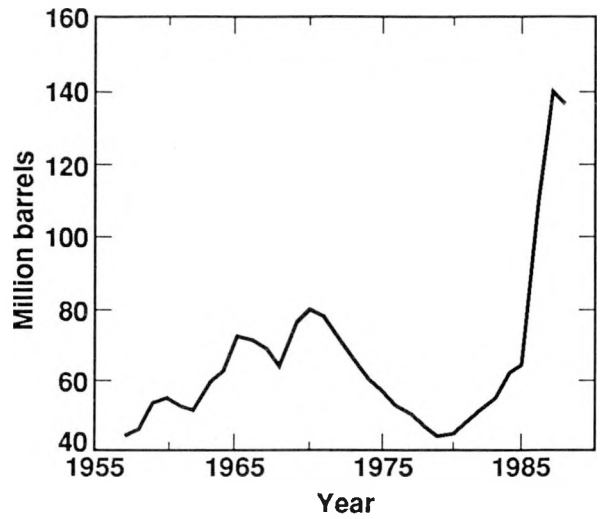

Figure 19. Colombia's oil production. Sources: for 1955–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

about 50 foreign companies operating in Colombia.[77] In 1988 alone, the Cano Limon–Covenas pipeline was reportedly dynamited more than 49 times.[78]

Despite numerous oil discoveries in the east-west trending Magdalena basin that runs the length of the country, the Cano Limon giant field is unique. Its initial crude oil reserves were set at 1 billion barrels,[79] and its continuation into Venezuela, where it is called the Guafita field, is estimated to contain an additional 400 million barrels of recoverable oil.[80] Colombia's total crude oil reserves as of January 1, 1988, are about 2 billion barrels.[81] Ecopetrol hopes to raise production to 637,000 bbl/d by 1993, half of which will be exported.[75] Beyond that, the national company anticipates a production decline, which is also the view of independent observers.[82]

Syria

The discovery of two large fields in 1984 and 1988, the Tayyim and Omar fields, has turned Syria's oil fortunes around (Fig. 20). The first came on-stream in 1987 and the second in 1989. The discoveries and the government's attractive contract terms have stimulated the interest of foreign exploration companies, which has resulted in a spate of new concessions over the past few years.[83] Exploration activity in the country has produced additional, albeit smaller, oil discoveries and some sizable gas finds. Syria aims to use the gas to provide 30 percent of its own energy requirements, which are primarily for electrical generation,

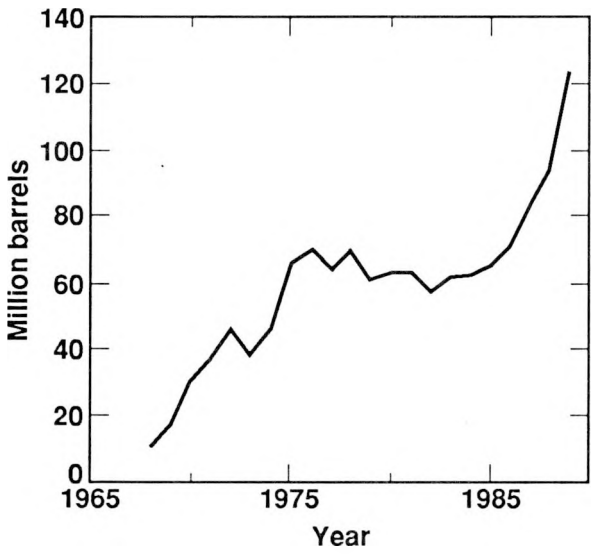

Figure 20. Syrian oil production. Sources: for 1965–1987, *Twentieth Century Petroleum Statistics—1989* (DeGolyer MacNaughton, Dallas, Tex., December 1989), pp. 3–12; for 1988–1989, *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).

by the year 2000.[84] The strategy is to reserve oil for export—either as crude oil or refinery products.

It will be some years before the new fields reach their production peak, at which time the country's total may reach 500,000 bbl/d, up from the 1989 total of 340,000 bbl/d. In 1989, the target was 400,000 bbl/d by year-end; however, in the process of accelerating the production schedule in the Omar field to meet this goal, the reservoir was damaged, as evidenced by a precipitous drop in reservoir pressure after 6 weeks of full flow.[84] Production was dropped in order to avoid further damage. Even with remedial work, the field may not meet its goal of 100,000 bbl/d for several years.

The Yemens

North and South Yemen are among the countries joining the list of oil-exporting nations. They are located in the southern tip of the Arabian peninsula in an area called the "empty quarter." The U.S.S.R. made the discoveries in the Marxist state of South Yemen in 1986, and a subsidiary of the Hunt Oil Company of Texas pioneered the exploration in North Yemen, with the first success in 1984. By mid-1989 there were five commercial fields.[85] The size of the discoveries to date in the two countries is estimated at 1.3 to 6.0 billion barrels.[85,86] A pipeline from the North Yemen fields to the Red Sea carries nearly 200,000 bbl/d to export market; additional pumping capacity could raise the amount to 400,000 bbl/d.[87] South Yemen's exports are expected to be 50,000 bbl/d by the end of 1989.[88]

Both countries are agricultural and among the poorest in the world.* Their largest source of income has been remittances from the more than 1 million Yemenis working in Saudi Arabia.[89] While domestic use of petroleum is expected to increase with the completion of a second small refinery, the bulk of the crude oil produced will be exported.

* It was reported in the *AAPG Explorer* that there were two automobiles in the capital of North Yemen in 1960, one of which was pulled by a camel because its engine was nonfunctional.

Additions to Reserves in Non-OPEC Countries

Normally, an indication of future production in any country can be gleaned from the degree to which annual production is replaced by additions to reserves. Among OPEC countries, combined crude oil reserves have recently increased substantially by their own reckoning (Table 5); however, with the exception of increases in Saudi Arabia and Venezuela, the gains may be more closely related to sharp pencils than to success in exploration.[90] Larger reserves can help individual OPEC countries defend increased production quotas within the OPEC system.

In the case of the non-OPEC countries, additions to reserves in 1988 barely equalled annual production, and in 1987 and 1989, production greatly exceeded additions to reserves (Table 5). The 1989 data were influenced by a series of calamities in the North Sea that affected production and by the reassessment of the reserves in the giant Tenghiz field, U.S.S.R., which resulted in their size being lowered by 9 to 10 billion barrels.[91] While data from 3 years are not definitive, it appears that despite substantial increases in non-OPEC production, additions to reserves are not keeping pace with production.

Another important portent for future production is the size of undeveloped resources; it is most difficult to estimate, however, since all such estimates are contingent on future prices. There have been several recent trends noted by analysts[92] that bear on the ultimate size and timing of development of these resources. First, there has been a clear and significant

Table 5. Replacement of production (billions of barrels).[a]

	OPEC			Non-OPEC			World		
	1987	1988	1989	1987	1988	1989	1987	1988	1989
Change in reserves[b]	192.9	5.4	91.1	–3.0	14.7	3.0	90.0	20.1	94.1
Production	6.5	7.2	7.9	14.0	14.1	13.8	20.5	21.3	21.7
Net change	186.4	–1.8	83.2	–17.0	0.6	–10.8	169.5	–1.2	72.4

[a] Source: *Oil and Gas J.*, Vol. 88, pp. 31–32 (March 19, 1990).
[b] Change from previous estimate due to information obtained from additional exploration.

of many non-OPEC countries, such as the U.S.S.R., Argentina, and the U.K., in the fiscal terms associated with cooperative and independent oil exploration within them by international oil companies. Fiscal terms have become less onerous and have encouraged new investment and development. The international oil industry is increasingly investing in potentially productive foreign terrain, where development costs are well under $5/bbl, and are moving away from mature, higher-cost areas such as those in the U.S.

The Next Ten Years: Conclusions

Contributors to the surge in non-OPEC production that led to a surplus of oil on world markets and a precipitous fall in oil prices all face an inevitable production decline in the future. An important question is: how long can they, together with new oil-producing countries, continue to grow or even maintain supplies at current levels? Other questions concern the growing demand in countries such as Mexico, China, and India, which may cause them to look increasingly to world markets for additional supplies. Another set of questions concerns the growing inadequacy of conventional domestic oil supplies in countries such as the U.S. and Canada.

In terms of volume, the U.S.S.R., the U.K., Mexico, Norway, and China registered the largest increases in non-OPEC output over the 1973–1989 period. It is likely that the U.S.S.R. will be able to stave off large-scale production declines through the nineties; declines in West Siberian oil fields will in part be countered by the large volumes of condensates coming on-stream through the development of its supergiant gas fields. Production in the U.K. will continue to decline but not precipitously. Exports from Mexico will probably cease by 2000; however, foreign participation in some part of the oil and gas industry may result in new energy supplies to meet the anticipated 3 to 4 percent annual growth in domestic demand. Norway expects to see continued growth to 2 million bbl/d by 1995, up from 1.4 million bbl/d in 1989. China will try to maintain production through the nineties, but growing demand may require imports from foreign sources.

Amongst the smaller contributions to the non-OPEC supply, Egypt's production may be stable through the mid-nineties, with additional productions from small new discoveries in the western part of the country countering declines expected in the Gulf of Suez. India may see a slight rise in output for the next few years; however, demand is rising so rapidly that the country will require a large increase in imports during the same period. Small discoveries will continue in Oman, and production will continue to grow for at least 5 years, declining rapidly thereafter. Similarly, the Yemens are still in an expansion stage of oil development. Brazil is another bright spot. A steady increase in production is expected through 2000—provided the government is able to finance expensive exploitation of deep-water resources. Continued increases in output to the end of the century are likely in Angola, but both Colombia and Syria will reach peak production in the mid-nineties and decline thereafter. There are other non-OPEC countries whose oil and gas industries may grow, e.g., Malaysia and Australia, but their potential contributions may not be as large as those of many of the countries reviewed.

In summary, it appears that most of the oil production since 1973 will have reached peak levels in the 1995–2000 time frame. In the view of some

forecasters, non-OPEC production may have risen at that point by as much as 2 million bbl/d over current production.[92] Prospects continue to be bright for additions to reserves in both virgin exploration areas and semimature oil provinces, and more and more resources of the international oil industry will be directed to exploration outside of North America. Decline in U.S. oil production is expected to continue despite an increased contribution from enhanced oil recovery and new discoveries in frontier areas. Canada may be able to maintain its production at current levels if large increases in bitumen production are realized by 2000.

Increase in demand in countries such as China, India, and Mexico during the next decade could well erode the gains made on the supply side. Thus it seems almost certain that by the mid-nineties, competition for supplies on world markets will elevate the price of available oil from OPEC sources. By the turn of the century, the situation may well worsen because of supply disruptions as surpluses on world markets disappear.

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