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Pages
145

Size
8.5 x 10

ISBN
0309322464

Committee on Strategic Petroleum Reserve; Energy Engineering Board; Commission on Engineering and Technical Systems; National Research Council

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The Logistics of the U.S. Stragetic Petroleum Reserve in the World Petroleum Market: 1990-2000

A Report Prepared by the
Committee on Strategic Petroleum Reserve
Energy Engineering Board
Commission on Engineering and Technical Systems
National Research Council

Order from
National Technical
Information Service,
Springfield, Va.
22161
Order No. PB86-181807
DE86008551

NATIONAL ACADEMY PRESS
Washington, D.C. 1985

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NOTICE: The project that is the subject of this report was approved by the Governing Board of the National Research Council, whose members are drawn from the councils of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine. The members of the committee responsible for the report were chosen for their special competences and with regard for appropriate balance.

This report has been reviewed by a group other than the authors according to procedures approved by a Report Review Committee consisting of members of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine.

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This is a report of work supported by Contract No. DE-FG01-84EP310461 between the U.S. Department of Energy and the National Academy of Sciences.

Copies available from:

Energy Engineering Board
Commission on Engineering and Technical Systems
National Research Council
2101 Constitution Avenue, N.W.
Washington, D.C. 20418

Printed in the United States of America

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PREFACE

This report was prepared in response to a request from the U.S. Department of Energy (DOE) to the National Academy of Sciences (NAS) for a study of how changing world petroleum logistics will affect the U.S. Strategic Petroleum Reserve (SPR) during the 1990s.

In response, the National Research Council, through its Energy Engineering Board, established the Committee on the Strategic Petroleum Reserve. The committee's members were chosen to include expertise in petroleum refining and production, transportation, economics, policy, and operations analysis.

Specifically, DOE asked the committee to:

- Identify and define the assumptions underlying the current SPR logistical system, especially those that might be most affected by changes.
- Identify and rank major issues involved in planning and providing for the physical distribution of petroleum from the reserve to U.S. refineries over the next 10 to 20 years.
- Assess how major issues may affect the efficiency of the reserve's logistical system after 1990 and identify constraints that the planned systems could impose on use of the SPR.
- Identify ways that DOE may improve the SPR data base.

This report asks whether the Strategic Petroleum Reserve will be sufficient to deal with potential supply disruptions during the 1990s. In effect, the problem can be reduced to three primary questions:

(a) What are the major issues involved?

(b) What changes can be expected in the factors that will affect those issues in the relevant time period?

(c) What are the implications of those changes for the SPR in terms of this country's readiness to deal with an oil disruption after 1990?

In proceeding with the task, the committee made the following assumptions:

(a) The major issues fall within the general areas of production, transportation, refining, and oil product imports.
(b) The issues are considered to be of equal importance; hence, they are not ranked.
(c) Domestic demand for petroleum and products will rise only moderately.
(d) Crude oil prices will be reasonably stable.

The study concerns itself with the topics deemed of most importance for critical policy decisions with respect to the logistics of the reserve. Other issues of general importance to the SPR and its use have received only a brief treatment at best. These include an assessment of the likely types and durations of interruptions, the allocation and marketing mechanisms for the distribution of SPR crude, the role of U.S. international obligations under the International Energy Agency (IEA) agreement, and a comparison of such trade-offs as the cost of maintaining the SPR versus the cost of not having it available. It is hoped that other studies will fill in the gap on these important questions at an appropriate time.

In conducting its study, the committee sponsored a two-day workshop on the SPR. Participants included people from government, industry, and academia, as well as committee members and staff. The workshop identified potential problems based on best estimated changes and perhaps one or two less easily discernible trends. As might have been expected, revolutionary prospects were not uncovered.

The committee wishes to thank all those who participated in the workshop (see Appendix E). The committee also wishes to thank Dennis Miller, executive director of the Energy Engineering Board, for his help in organizing and guiding our efforts. Staff officers John Richardson and Louis Jablansky brought diligence and insight to the study. Finally, Cheryl Woodward and Drusilla Alston provided invaluable administrative assistance.

Norman Hackerman, Chairman
Committee on the Strategic
Petroleum Reserve

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BACKGROUND

The Strategic Petroleum Reserve (SPR) was created in 1975 by Congress in response to the Arab oil embargo of 1973-1974 and the subsequent rapid rise in oil prices. Its purpose is to help deter future oil embargoes, to protect U.S. national security and economy in the event of a disruption in supply, and to mitigate any major price increases.

The Energy Policy and Conservation Act (EPCA) of 1975 authorized a storage system, owned and administered by the Department of Energy (DOE). The reserve was to contain up to 1 billion barrels of crude oil. DOE's original plan for the reserve, submitted to Congress in 1977, called for 500 million barrels (MMB) to be in storage by 1982. That target date was later advanced to 1980 and the amount to be in storage by then increased to 750 MMB.

At present, the SPR contains more than 490 million barrels. The Reagan administration, as part of its effort to cut government costs and reduce the budget deficit, has proposed a moratorium on further additions to the reserve. Congress is considering the issue now.

Physically, the SPR has six storage sites, one of which is still under construction, located in Texas and Louisiana on the Gulf of Mexico coast. The storage sites, principally former salt or brine mines, and one marine terminal are connected by pipelines to refineries elsewhere in the country.

FINDINGS OF THE NPC REPORT

A 1984 study by the National Petroleum Council (NPC), a DOE advisory group, examined the SPR facilities, distribution network (both overland and marine), and refining capabilities. The purpose was to determine whether the reserve could be used to meet consumer demand in the event of a disruption in the 1980s. The study also used DOE data to develop a statistical baseline for 1990, both for supply disruption and noninterrupted scenarios.

On balance, the NPC report found that the current SPR can significantly mitigate the effects of an oil embargo or other supply disruption, depending on its length and severity, through the 1980s. It also found that the United States has sufficient domestic refining capacity to process crude oil from both the reserve and from other domestic sources through 1990.

The NPC report, however, did find some problems. It questioned the ability of the reserve to distribute crude oil by overland routes since two of the three pipeline systems intended for such use have been converted to natural gas. The study found that the SPR sites will lack the capacity to deliver crude oil to barges, tankers, or pipelines at the designed rate of 4.5 million barrels per day (MMB/D) for the completed 750-MMB reserve. The report also pointed to a possible future shortage of U.S.-owned tankers and barges to carry SPR crude oil. These future problems, the NPC report added, can be handled in the 1980s given current DOE plans to enhance the reserve's distribution system.

The Committee on the Strategic Petroleum Reserve accepts these findings as the basis for its study of the ability of the SPR to meet a supply disruption in the 1990s. Given its analysis of trends in energy demand, production, and transportation, the committee concludes that the reserve will probably be unable to meet a supply disruption in the 1990s without some major modification in its distribution capability and planned mix of refined petroleum products and crude oil.

DEMAND TRENDS, PRODUCTION, AND SPR CAPACITY

In the first place, domestic demand for crude oil and refined petroleum products is likely to increase moderately in the United States over the next 15 years. At the same time, however, crude oil from domestic sources (both on- and offshore) is expected to decline despite its rather steady rate over the last several years. As a result, there will be an increasing gap between domestic oil production and consumption. Even more than now, the reserve will be based on foreign sources.

Thus, the committee recommends that:

- The DOE base its plans for the SPR on lower rather than higher levels of domestic oil production.

To make up for declining domestic production and gradually rising consumer demand, the level of imported oil is expected to increase. If projected domestic production and demand levels prevail in the 1990s, then the combined import of crude oil and refined petroleum products could reach 10 MMB/D.

In addition, at current consumption rates, the nearly 500 MMB of oil in the reserve today equals about 100 days supply. However, given the demand and production rates projected for the 1990s, the same 500 MMB probably represents only a 50-day supply.

Thus, the committee recommends that:

o The DOE should continue to monitor closely both actual developments and trends in domestic oil production and in imports.

Further, the committee recommends that:

o The DOE should plan to expand the SPR's storage capacity in order to retain the reserve's equivalent supply of about 100 days.

PRODUCT IMPORTS AND U.S. REFINERIES

The United States is importing an increasing amount of crude oil and refined petroleum products. This trend, seen over the past five or six years, is likely to increase as oil-producing countries build more refineries. The result will be a decline in U.S. refining capacity as the less efficient facilities close down. U.S. refinery capacity has dropped 22 percent since 1980. Distillation capacity, less than 80 percent in 1984, is likely to continue to decline.

As a result, the U.S. refining industry may be unable to process sufficient crude oil from the SPR to make up for any shortfall caused by a disruption in supply in the 1990s. This problem is particularly acute given the expected moderate increase in demand and decrease in domestic oil production over the next 15 years.

Thus, the committee recommends that:

o The DOE should consider a separate storage facility within the SPR for refined petroleum products. This would help compensate for any loss of domestic refining capacity.

Despite this trend, the U.S. refining industry is likely to remain competitive in world markets because of its increasing technical capacity. In particular, its ability to remove polluting sulphur compounds from crude oil is geared to the domestic demand for low-sulfur petroleum products. Similarly, the industry's ability to produce lead-free gasoline will help keep it competitive in part at least.

Thus, the committee recommends that:

o The DOE should continue to monitor the capacity of the U.S. refining industry to process crude oil from both the SPR and domestic sources in the event of a disruption.

THE NORTHEAST PROBLEM

If a disruption in oil supplies does occur in the 1990s, the northeastern United States is the area most likely to be affected. Seventy-four percent of the gasoline imported into the United States, for example, goes to the East Coast. Increased imports of refined petroleum products could cause many East Coast refineries to close.

Thus, the committee recommends that:

- The DOE should consider locating a reserve for refined petroleum products in the northeastern United States as part of any expansion of the SPR system.

DISTRIBUTION PROBLEMS

To move crude oil from the SPR to refineries, DOE has based its plans on a network of pipelines, tankers, and barges. As noted above, however, two of the three pipelines intended for SPR use have been converted to natural gas. Reconversion to crude oil cannot be done easily or quickly.

As a result, the SPR will be unable in the 1990s to distribute more than 2.4 MMB/D without any enhancements. (DOE plans to increase the 500-MMB reserve distribution capacity to 3.6 MMB/D and the drawdown capability to 3.3 MMB/D.) This is well short of the 4.5 MMB/D that the reserve was designed to deliver. The NPC recommended specific pipeline and terminal improvements at each site to enhance the reserve's ability to distribute stored crude oil, and recommended increased capacity at the St. James terminal in Louisiana.

Thus, the committee recommends that:

- The DOE should adopt the NPC recommendations to upgrade SPR distribution capacity to the designed 4.5 MMB/D.

TANKER CONSTRAINTS

Even with these improvements, the distribution of crude oil from the SPR could be hampered by a declining fleet of U.S.-owned tankers and barges. Further, the Jones Act, a clause of the Merchant Marine Act of 1920, requires the use of U.S.-owned vessels to carry cargo between most U.S. ports. Because fewer U.S.-owned ships may be available during a supply interruption, foreign tankers may be needed to carry SPR crude oil to achieve the 4.5 MMB/D drawdown rate.

Yet another problem could be maritime scheduling and congestion delays, particularly in the Gulf of Mexico, that prevent the timely movement of SPR crude oil.

Thus, the committee recommends that:

o The DOE should seek waivers to the Jones Act to allow foreign-built or owned tankers to carry SPR crude oil between U.S. ports in an emergency.

o The DOE should consider using tankers anchored offshore to store crude oil temporarily in an emergency or to relieve a crisis.

SYSTEM TESTING

All of the improved planning and enhanced facilities discussed in this report cannot be used by themselves to determine whether the SPR will reliably work as intended. Only a testing of the SPR system under realistic conditions can answer that question. A large-scale test, such as that being planned by DOE, would also improve the system's efficiency and underlying data base by exposing unseen problems.

Thus, the committee recommends that:

o The DOE should conduct periodic tests of the SPR to test and improve its reliability.

1

INTRODUCTION

The history and development of the Strategic Petroleum Reserve (SPR) are intimately linked to the problem of oil supply in the United States. Until 1948 the United States not only produced most of the petroleum consumed domestically, but was one of the world's leading exporters of oil products as well. That year, however, a significant change occurred: imports exceeded oil exports and, for the first time, the United States became a net importer of oil. Nevertheless, despite the fact that cheap imported oil took a larger and larger share of the U.S. market, domestic production of crude oil continued to rise until, in 1970, it peaked at 11.3 million barrels a day (MMB/D). U.S. production has steadily declined thereafter.

Despite the increasing efforts of the oil industry to satisfy domestic demand, sporadic shortages began to develop around the country in the early 1970s. In response, the Nixon administration lifted import quotas on foreign oil in 1973. Foreign oil literally poured into the United States, mainly from Middle Eastern countries. Political instability, economic pressures from the Organization of Petroleum Exporting Countries (OPEC), and the Arab-Israeli war set the stage for the oil shocks of the 1970s.

The first crisis--in late 1973 and early 1974--marked the end of the era of secure and cheap oil. At that time, Arab oil-producing nations embargoed the United States and reduced overall output and shipments to other nations. One result was that the price of oil was eight times more by the end of 1974 than it had been five years earlier. The embargo, which ended on March 18, 1974 six months after it started, caused severe impacts on the U.S. economy and emphasized our vulnerability then to interruptions in imports.

For the next several years the world oil market was relatively stable. Then, beginning in 1978, new events disrupted the normal patterns of crude supply from the Middle East. The overthrow of the Shah of Iran, the subsequent interruption in the flow of Iranian oil, and a 15 percent price hike in OPEC prices set the stage for price increases in 1979 that were greater in dollar value than the total price of oil in 1970.

In all, the 1970s dramatized the frailty of U.S. energy security and made evident the urgent need for U.S. policy makers to take corrective measures. Various actions were taken, one of which created an emergency oil storage program. The SPR was not a new idea. Interior Secretary Harold Ickes in 1944, President Harry Truman's Minerals Policy Commission in 1952, and President Richard Nixon's Cabinet Task Force on Oil Import Control in 1970 had all advocated storing crude oil for emergencies.

THE STRATEGIC PETROLEUM RESERVE

The Strategic Petroleum Reserve was established by the Energy Policy and Conservation Act (EPCA) of 1975 (see Appendix A for a more complete description of the reserve itself). In creating the reserve, the act sought to deter deliberate embargoes or, if deterrence should fail, to protect U.S. national security against the effects of disruptions in petroleum supplies and to mitigate excessive increases in international oil prices. The reserve was to have a capacity of 1 billion barrels of petroleum. The law states that it may not be used unless the President finds such actions are required because of "a severe energy supply interruption or by obligations of the United States under the International Energy Program." A severe energy supply interruption is defined as a supply shortage that:

- Is, or is likely to be, of significant scope and duration, and of an emergency nature.
- May cause major adverse economic impacts or affect the national security.
- Results, or is likely to result, from an interruption in the supply of imported petroleum products.

The original plan, developed by the Department of Energy (DOE) in 1977, called for a government-owned storage system of 500 million barrels (MMB) of crude oil to be achieved by 1982. The target date was later revised to 1980. Later, again, Congress authorized expansion of the planned reserve to 750 MMB. Decisions on the timing and method of achieving the remaining 250 MMB were deferred.

As of December 1984, the SPR consisted of six crude oil storage sites in various stages of development (NPC, 1984). The storage sites are connected by pipeline to three marine terminals. All are located on the Gulf of Mexico coast. One, at St. James, Louisiana, is government-owned while the other two, at Nederland and Greenport, Texas, are privately owned.

The SPR storage sites were initially designed to be connected to three major interstate crude oil distribution networks--the Seaway, Texoma, and Capline pipelines--and their privately owned marine terminals. Contrary to DOE plans, however, the Seaway and Texoma pipelines were recently converted to natural gas service and, thus, are no longer available to the SPR. The SPR does have some of its own pipelines and others may be added in the future.

The SPR and its currently planned 750-MMB storage capacity are being developed in three phases. Phase I, completed in 1983, converted 260 MMB of existing storage capacity at five sites (Bryan Mound in Texas and Bayou Choctaw, West Hackberry, Sulphur Mines, and Weeks Island in Louisiana). In addition, a DOE marine terminal was built at St. James, Louisiana. Phase II will increase the storage capacity of three of the Phase I sites by 290 MMB to a total of 550 million barrels. In addition, facilities will be added to increase the drawdown rate.* Phase III calls for an additional 200 MMB of storage through further expansion of existing sites and the development of a new 140-MMB site at Big Hill, Texas.

As of 1985, the SPR has about 490 MMB of crude oil and a drawdown capability of 2.1 MMB/D. Upon completion of Phase II, scheduled for mid-1987, the drawdown capacity will be 3.5 MMB/D.

At the end of Phase III, projected for 1990, the reserve will contain a planned 750 MMB and have a sustained design drawdown capability of 4.5 MMB/D. Phase III may be delayed, however, because the Reagan administration has proposed an indefinite moratorium on further development of Big Hill and on adding more crude oil for all other sites. The moratorium, which covers 489 MMB, must be approved by Congress.

ANALYSIS OF THE PETROLEUM SCENARIO TO 1990

A 1984 study by the National Petroleum Council (NPC, 1984), a DOE advisory group, analyzed the ability of the SPR to meet consumer demand in the event of an emergency in the 1980s. The NPC report examined four operational areas: SPR facilities, overland distribution, marine distribution, and refining capabilities. These areas were investigated for three distinct cases: 1983 actual, 1990 nondisrupted, and 1990 disrupted.

The NPC study found that:

- There will be sufficient capacity in 1990 to process both SPR and available domestic crude oil unless significant refining capacity is lost. However, the SPR's currently planned mix of crude oils does not provide adequate flexibility to meet potential refining system needs by 1990.
- Since two major pipeline systems (Texoma and Seaway) are no longer available, any future storage site would require water-borne transportation to supply major Midwest and lower Mississippi River refining centers. The NPC report recommended that DOE consider shifting at least 100 million barrels from the Texoma to the Capline complex (NPC, 1984).
- Upon completion of the reserve, the actual capability to withdraw crude oil from the storage caverns will match the sustained design drawdown capability of 4.5 MMB/D. However, without additional

*"Drawdown" refers to oil taken out of the reserve.

distribution capacity, none of the three SPR complexes will be able to deliver crude oil to barges, other ships, or pipelines at the maximum projected 1990 drawdown rates. The SPR system does not have sufficient flexibility to cover a reasonable range of possible shifts in future distribution capacity or requirements.

o The number of U.S. tankers and barges projected for 1990 appears sufficient to meet an emergency use of the SPR. The number of U.S. tankers specifically designed to carry residual fuel oil is projected to decline, however. This raises questions about whether the U.S. tanker fleet can meet consumer demand during a potential supply disruption. On the other hand, an ample supply of U.S.-controlled foreign tankers is readily available if required (NPC, 1984).

The committee accepted these findings as a first step toward reaching its goal.

2

OVERVIEW OF THE ISSUES

Four major issue areas serve as the framework of this study: the production, transport, and refinement of crude oil and petroleum products, and the import of petroleum products. Other issues, such as crisis management (dealing with panic, special interests, and political pressures) and potential market intervention [using the Strategic Petroleum Reserve (SPR) as a vehicle for damping price fluctuations] cut across these four areas and are dealt with separately.

PRODUCTION

As discussed more fully in Chapter 3, domestic crude oil production could possibly remain at present levels or even increase if very optimistic expectations for the 1990s are fulfilled. If these expectations are not fulfilled, however, domestic production will decline and U.S. crude oil imports will, of necessity, increase under an assumption of moderately increasing demand. If that happens, the United States will then be at least as vulnerable to interruptions in supply as it is today.

The major portion of proven world crude oil reserves will continue to be in the Middle East for the foreseeable future simply because of the vast size of the already proven reserves. Therefore, despite such other factors as price reductions by North Sea producers, the spare capacity that exists in the Middle East is the underlying reason for the present comfortable position of world markets. Although capacity has eroded somewhat because of a disinvestment by the companies and governments involved, the spare capacity will continue to be concentrated in OPEC countries.

The amount of spare crude production and refining capacity may decline worldwide over the next five years as demand outside the United States increases gradually and catches up with the lower rate of investment in exploration and refinery construction. If this occurs, the risk of a petroleum supply crisis will increase gradually as spare capacity disappears.

TRANSPORTATION

In the event of an emergency, crude oil in the SPR has to be moved from the point of storage to the refineries. The ability to distribute crude oil from the reserve to refineries has never been tested operationally, although the Department of Energy (DOE) has scheduled a test for November 1985. Paper analyses of how things should happen in an emergency are no substitute for really trying to make the system work.

One potential problem is a clause, the so-called Jones Act, in the Merchant Marine Act of 1920. That clause (see Appendix A for a more detailed discussion) restricts the shipment of cargoes between U.S. ports to U.S.-flag vessels. However, the U.S.-flag fleet has declined in numbers up to the point that there could be concern about its ability to move crude oil from the reserve to refineries under stronger market conditions than at present. If transportation is a potential problem in 1985, it is reasonable to expect that the problem will be much worse in the 1990s. By that time, there may have been further attrition in the U.S.-flag fleet.

Of particular importance is the domestic barge fleet, which has also been reduced in numbers. This fleet is essential for moving crude oil from storage sites to refineries along the Gulf of Mexico coast.

Changes in crude oil pipelines have caused problems in the past for SPR logistical planning and may do so again. Pipelines tend to open and close with changes in refining location and capacity, in each case forcing a transition to a new equilibrium in crude oil transport modes. If an emergency occurs during a transition, movement of SPR crude oil could be impaired. After a transition, domestic crude oil will continue to be accessible to inland refiners to the same degree that it has always been, emergency or not. Imported crude oil, after a transition, may reach inland refiners through a substantial change in the transport system. This change may require corresponding changes in the terminal facilities and connecting links by which SPR, in an emergency, must deliver crude from the reserve into the new transport modes.

REFINERY CAPACITY

Domestic demand for refined petroleum products is likely to remain stable or decline slightly through the 1990s. At the same time, the mix of products may shift somewhat. That would result in some modification of and investment in downstream refinery capacity. However, significant growth in demand is not expected and no obvious significant breakthroughs are anticipated in refinery technology.

Although some refiners are making dire predictions about declines in domestic refining capacity, the United States will probably have enough capacity to meet a post-1990 oil disruption. If an emergency requires the use of the SPR, demand will probably diminish as prices rise or as government restrains demand. Additionally, the United States will probably not lose all its sources of foreign crudes and refined products at the same time. Therefore, some petroleum imports will continue.

However, recent trends have shown an increase in refined petroleum products and a decrease in crude oil being imported into the United States. If these trends continue--and there is no reason to think otherwise--it will be necessary to monitor carefully both the overall and the regional adequacy of available refining capacity for crude oil. If capacity drops below the level necessary to handle domestic oil production and crude in the SPR in an emergency, changes in the reserve may be necessary. Specifically, a reserve of refined petroleum products may have to be added to or replace those now existing for crude oil.

PRODUCT IMPORTS

In addition to a shift in demand by product type, refined petroleum imports will likely increase over the next 10 years. This will be especially true if the new downstream refining capacity is built in other countries rather than in the United States. The demand shift will be toward the middle distillates such as diesel oil and unleaded gasoline. This raises a question of whether a reserve for refined petroleum products should be located on the East Coast, where most imported products arrive.

Refineries are designed to process particular types of crude oil. For the SPR to be useful, the quality of the crude used in the reserve should, as nearly as possible, match that capable of being processed by the refineries, which now refine imported crude. Some concern has been raised that not enough attention has been paid to this matter and that it deserves further study (NPC, 1984).

On the positive side, many U.S. refineries have improved their capability to remove sulphur from crude oil. This will make the United States less vulnerable to a disruption in oil supplies.

SUBORDINATE ISSUES

Crisis Management

The 1973 oil embargo and the 1979-1980 events in Iran have generated a substantial amount of information about the genesis and management of a petroleum crisis. In both cases, the most significant factor was public panic, which induced stockpiling, rather than a genuine shortage. Inventories of both crude oil and refined petroleum products were higher after each of the crises ended than before they started. The shortages were produced by a sudden demand at all levels as individual consumers, retailers, wholesalers, and refiners attempted to operate their businesses off full tanks.

Breaking this hoarding response is essential to managing a crisis, and the SPR is an essential element in convincing people that hoarding is unnecessary. To be convincing, the public needs to see both that the SPR has enough crude oil to carry the country through a short-term crisis and that the oil can be delivered to refineries and eventually consumers.

A future administration may choose a variety of strategies for using the reserve to deal with a crisis, but the fundamental issues of quantity and deliverability are paramount.

Another lesson of past crises is the problem of political panic. In both 1973 and 1979-1980, the various constituencies with stakes in having petroleum and petroleum products available stampeded government policy makers. The result in 1973 was price and allocation legislation, which was ineffective, unenforceable, and keyed to the interest of the groups lobbying for it.

In 1979, DOE, through its Economic Regulatory Administration (ERA), gave successive emergency allocations of petroleum products to different groups as they came to plead their cases. The result was chaos instead of regulated order: farmers fought truckers for available diesel fuel, public transportation systems jumped in to claim priority, and DOE management fell into disarray.

Consumers of home heating oil in the Northeast and farmers were the strongest constituencies and had the greatest ability to obtain results from the political system. Thus, to forestall panic by these groups, special attention could be given at the first sign of a shortage by ensuring that whatever system is adopted will be able to deliver middle distillates to these key constituencies. Special attention could also be given to ensuring adequate transportation to move middle distillates from the refining centers likely to receive SPR crude to their markets. Several East Coast markets now depend on waterborne imports and may face special transportation difficulties in moving domestically refined petroleum products. For these markets, the key issue will be the availability of properly sized and clean tankers and barges.

Successful management of the SPR in the future should be designed to temper, at least, the political pressures that go with an energy emergency. To the extent that the rules for using the reserve can be clearly spelled out in advance and that the plans for handling a crisis can be put in place before it occurs, government policy makers will be able to deal with the logistical and technical problems rather than political issues.

Market Considerations

One possible policy option for DOE is to use the SPR to dampen price fluctuations. Under the law, the SPR inventory can be used to lower market prices, at least in an emergency. Several members of Congress have proposed making legislative, regulatory, or other necessary policy changes to authorize using SPR oil to provide market liquidity and indeed to "make the market" when spot shortages of crude occur. Others have suggested allowing private parties to store oil in the SPR and trade options on it, and even allowing foreign governments to store oil in the reserve. Although none of these ideas have gone past discussion stages, they are policy possibilities for the future.

Using the reserve as a market vehicle requires that it be designed to be drawn down and refilled repeatedly. To keep this policy option open, the design of future storage sites could include this feature.

Ensuring the easy deliverability of reserve crude may mean planning future storage sites in locations far removed from present ones. It may also mean using some of the presently unused above-ground tanks at existing refining centers.

In a purely free market, which is the model adopted by the Reagan administration, the SPR substitutes for privately held inventories. Inventories are costly to store and, in periods of low profitability and declining demand, the private sector will run inventories down to the lowest possible working level. DOE should take this kind of private sector thinking into account when making long-range plans for the SPR.

3

DOMESTIC PETROLEUM PRODUCTION

Although the production of domestic crude oil has declined generally since its peak volume in 1970, it has remained fairly steady during the last few years because of new oil flowing from the Alaskan North Slope and offshore sources. Projections for the next 15 years indicate declines in crude production and additions to the reserve. Forecasts of this type, however, are sensitive to oil prices, economic factors, political events, and unforeseen circumstances.

Overall, the outlook for domestic petroleum production is not promising. The gap between demand and domestic production will continue to be filled by imports vulnerable to disruption. This gap will widen unless demand falls faster than production--an unlikely possibility. Thus, it would be more prudent to plan for lower levels of production than for higher ones.

HISTORICAL TRENDS IN PRODUCTION

The United States produced about 8.75 million barrels of crude oil per day (MMB/D) in 1984, the highest level since 1974 but 4 percent below the peak in 1970. The production of natural gas liquids (NGL) was about 1.63 MMB/D in 1984, bringing total production to 10.38 MMB/D. The production of natural gas liquids was very steady from 1974 until 1981 as total natural gas production remained flat at about 19.2 trillion cubic feet (TCF), but NGL production declined in 1982-1983 as gas production declined substantially. NGL production recovered in 1984 as natural gas production recovered.

U.S. production has been steady since 1979, as the Alaskan North Slope and offshore sources have replaced declining production from "surveillance fields" (old, 1973 or earlier, large fields). The latter accounted for about three-fourths of total crude oil production in 1983 when Prudhoe Bay is included. Not including the Alaskan North Slope and offshore areas, production from the "old" surveillance fields declined by 5.3 percent in 1979. The rate of decline slowed to 1.3

percent in 1983 because of infill* and development drilling, secondary recovery (water floods), reservoir pressure maintenance, and enhanced oil recovery (EOR).

Prudhoe Bay in Alaska began producing oil in 1977. By 1980 it had reached 555 million barrels per year (MMB/yr.), a level expected to be maintained for the next several years. Production at Kuparuk River (near Prudhoe Bay) began in 1981 and by 1983 had reached 40 MMB/yr. Production from offshore waters increased by 5 million barrels (MMB) in 1981, by 33 MMB in 1982, and by 35 MMB in 1983, when the total was 350 MMB.

It is interesting to note that in 1983 there were 1,606 "surveillance fields" (including Prudhoe Bay), which accounted for 75 percent of total production, while 6,315 "new" (post-1973) fields accounted for only 11 percent (see Figure 1). The "new" fields are much smaller and less productive than the "old" fields and are found in the mature areas.** The mature areas are unlikely to yield any big new discoveries.

As already mentioned, infill and extension*** drilling slowed the oil-field decline rate since 1979 by adding to oil-field reserve growth. Annual reserve additions in the conterminous United States roughly equalled the annual level of production. However, infill development wells and similar projects generally accelerate depletion of reserves rather than add to them, ultimately resulting in a much faster production decline rate.

For instance, Alaska production is expected to peak in 1990 at 2.1 MMB/D and then decline rapidly, since extensive waterflooding has been used in the Sadlerochit formation to enhance production. Also, of 568,911 wells drilled from 1974 to 1983, only 175,377 (30 percent) were exploratory. That equalled the average number in the previous 15 years (Grossling, 1985). Most of the effort was to enhance production from existing wells, not an intensified search for new reserves. This fact seems to be behind the recent practice of oil companies acquiring reserves through mergers.

FUTURE RESERVE ADDITIONS

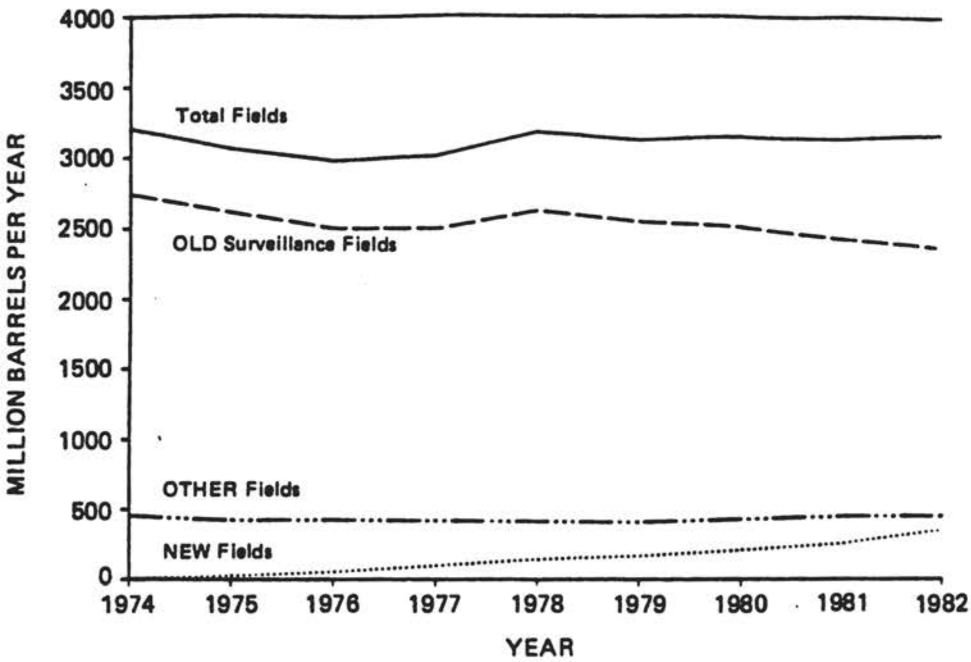
Future production depends on reserve additions. Examining the likely size of reserves, the estimates made in 1981 by the U.S. Geological Survey (USGS) represent a consensus view (USGS, 1981). Grossling (1985) feels that the estimates for land-based wells in the

*"Infill" drilling represents drilling of additional wells at closer spacing in known reservoirs. Depending on reservoir conditions, these wells will either drain hydrocarbons that cannot be drained by existing wells or will merely accelerate the recovery of hydrocarbons that would have, in time, been produced by existing wells.

**"Mature" areas are those where substantial exploratory and development operations have been conducted for a number of years.

***"Extension" wells enlarge the boundaries of known reservoirs or tap additional reserves contained in separate fault blocks or at separate intervals. In either case such wells increase the known reserves.

FIGURE 1 U.S. Oil Production Rate by Field Category, 1974-1982



SOURCE: Impact of Surveillance Fields on Crude Oil Production, U.S. Energy Information Administration, Washington, D.C., U.S. Government Printing Office, November 1984, p. 130.

conterminous United States are probably as good as can be made. But certainties for the frontier areas (i.e., offshore and Alaska) are fragile; subjective probability estimates were used. The USGS estimates are of undiscovered and recoverable conventional resources. These are resources that could be extracted economically under price-cost relationships and technological trends prevailing at the time. Excluded are new pay zones, extensions of existing fields, heavy oil, tar deposits, and oil shales. The last three exclusions make sense under the present environment of lower price forecasts, which exclude synthetic oil until at least well into the twenty-first century.

According to the USGS, the range of undiscovered recoverable crude oil is 64,300 to 105,100 MMB, with a mean estimate of 82,600 MMB (see Table 1). The mean estimate of NGL reserves is 17,700 MMB (see Table 2). Thus, the mean estimate of total petroleum liquids is 100,300 MMB. As of the end of 1980, measured (proved) reserves of crude oil were 27,800 MMB, indicated reserves were 3,600 MMB, and inferred reserves (that part of economic reserves that will be added as a result of revisions, extensions, and additions of new reserves) were 23,400 MMB. Measured NGL reserves were 5,700 MMB and inferred reserves were 4,800 MMB.

If from this total we subtract production of 15,200 MMB over 1981-1984, then remaining resources as of year end 1984 were 150,400 MMB (see Table 3). Cumulative crude oil production has been about 135,000 MMB, so roughly half of the available resources have already been produced.

The estimated amounts of oil and gas credited to the year of discovery tend to increase through time because of revisions, extensions, and additions of new reservoirs to old fields (see Figure 2). Those economic resources that will be added because of future growth are labeled inferred reserves and are generally more prevalent onshore. For example, the combined outer continental shelf and slope contain only 1,500 MMB of inferred reserves out of a total of 23,400 MMB (see Table 1). Recently, a number of large fields have not grown significantly, especially offshore and other frontier areas (Riva, 1985).

Regarding the geographical distribution of undiscovered reserves, USGS estimated that two-thirds of the oil was onshore. Of the offshore oil, two-thirds were thought to be in Alaska and the Gulf of Mexico. Results of exploratory drilling in the Gulf of Alaska, the South California Borderland, and the South Atlantic Shelf have been disappointing. Geologic information derived from this drilling indicates a reduced hydrocarbon potential. However, drilling since 1975 in the Cordilleran Overthrust Belt (Basin and Range,* Rocky Mountains and Northern Great Plains) indicates a large potential for both oil and natural gas. Moreover, it has changed the concept of the potential of other thrust belts. The regions with the greatest onshore

*Basin and Range is a geologic region that is bounded by the western slope of the Rocky Mountains and the eastern slope of the Sierra Nevada mountains. It includes Nevada, eastern Washington and Oregon, western Montana, Idaho, and Arizona, and most of Utah.

TABLE 1 Crude Oil--Production, Reserves, and Estimates of Undiscovered Recoverable Resources of the United States (All tabulated values are rounded numbers; therefore, value for production reserves and for means of undiscovered resources, all of which are additive, may not be precisely so. Values shown are in billions of barrels. Negl., negligible, less than or equal to 0.05 billion barrels of oil.)

Petroleum Region	Cumulative Production[1]	Identified Resources[1] Measured Reserves	Identified Resources[1] Indicated Reserves	Identified Resources[1] Inferred Reserves	Undiscovered Recoverable Resources Low [2]F_{95}	Undiscovered Recoverable Resources High [2]F_{5}	Undiscovered Recoverable Resources Mean	Undiscovered Recoverable Resources Standard Deviation
			Onshore					
1 Alaska	1.2	8.7	0	5.0	2.5	14.6	6.9	4.3
2 Pacific Coast	16.5	3.2	1.6	1.2	2.1	7.9	4.4	2.0
3 Colorado Plateau and Basin and Range	1.7	0.3	Negl.	1.0	6.9	25.9	14.2	8.0
4 Rocky Mountains and northern Great Plains	6.9	1.1	0.2	2.9	6.0	14.0	9.4	2.6
5 West Texas and Eastern New Mexico	25.2	5.4	1.3	4.0	2.7	9.4	5.4	2.2
6 Gulf Coast	34.9	3.8	0.2	5.3	3.6	12.6	7.1	2.8
7 Mid-continent	18.2	1.5	0.2	1.4	2.3	7.7	4.4	1.8
8 Michigan Basin	0.8	0.2	Negl.	0.8	0.3	2.7	1.1	0.8
9 Eastern Interior	4.3	0.2	Negl.	0.1	0.3	1.9	0.9	0.6
10 Applachians	2.8	0.2	Negl.	0.1	0.1	1.5	0.6	0.5
11 Atlantic Coast	0.1	Negl.	0	0.1	0.1	0.8	0.3	0.3
Entire onshore	112.6	24.7	3.6	21.8	41.7	71.0	54.6	10.5
			Offshore--Shelf					
1A Alaska[3]	0.7	0.2	0	0.1	3.8	22.0	10.8	6.4
2A Pacific Coast	1.9	1.2	0	0.5	0.6	3.0	1.5	0.8
6A Gulf of Mexico	5.6	1.7[4]	Negl.[4]	1.0[4]	1.3	7.9	4.0	2.1
11A Atlanta Coast	0	0	0	0	0	3.9	1.3	1.4
Entire shelf	8.2	3.1	Negl.	1.5	9.2	30.2	17.6	6.9
			Offshore--Slope					
1A Alaska[3]	0	0	0	0	0	5.2	1.4	2.3
2A Pacific Coast	0	0	0	0	0.6	6.0	2.4	2.0
6A Gulf of Mexico	Negl.	No data[4]	0[4]	No data[4]	0.9	5.2	2.5	1.4
11A Atlantic Coast	0	0	0	0	0	10.7	4.1	3.6
Entire slope	0	0	0	0	4.2	19.2	10.4	4.9

TABLE 1 (Continued)

Petroleum Region	Cumulative Production[1]	Identified Resources[1] Measured Reserves	Indicated Reserves	Inferred Reserves	Undiscovered Recoverable Resources Low [2]F_{95}	High [2]F_{5}	Mean	Standard Deviation
		Offshore--Combined Shelf and Slope						
1A Alaska[3]	0.7	0.2	0	0.1	4.6	24.2	12.2	6.8
2A Pacific Coast	1.9	1.2	0	0.5	1.7	7.9	3.8	2.2
6A Gulf of Mexico	5.6	1.7	Negl.	1.0	3.1	11.1	6.5	2.5
11A Atlantic Coast	0	0	0	0	1.1	12.9	5.4	3.9
Entire offshore	8.2	3.1	Negl.	1.5	16.9	43.5	28.0	8.5
		Combined Onshore and Offshore						
Entire United States	120.7	27.8	3.6	23.4	64.3	105.1	82.6	13.4

[1]Cumulative production and reserves are as of December 31, 1979. Production and reserve figures were derived from API and AGA data (American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, 1980) except from California for which production and reserve data were taken from California Division of Oil and Gas (1980) and the U.S. Geological Survey (Kalil, 1980).

[2]F_{95} denotes the 95th fractile; the probability of more than the amount F_{95} is 95 percent. F_5 is defined similarly. Fractile values are not additive.

[3]Includes quantities considered recoverable only if technology permits their exploitation beneath Arctic pack ice--a condition not yet met.

[4]API and AGA reserve data from the Gulf of Mexico are not available within separate shelf and slope classifications. However, the declared reserves probably represent only the shelf and are so treated.

SOURCE: USGS (1981).

TABLE 2 Natural Gas Liquids (NGL)--Mean Estimates of Undiscovered Recoverable Resources in the United States (Millions of Barrels)

Petroleum Region	Undiscovered Recoverable NGL
Onshore	
1 Alaska	1.3
2 Pacific Coast	0.3
3 Colorado Plateau and Basin and Range[a]	
4 Rocky Mountains and northern Great Plains[a]	4.0
5 West Texas and eastern New Mexico	1.5
6 Gulf Coast	4.0
7 Mid-continent	1.3
8 Michigan Basin	0.1
9 Eastern Interior	0.1
10 Appalachians	0.2
11 Atlantic Coast	Negl.
Entire onshore United States	12.9
Offshore--Shelf and Slope	
1A Alaska[b]	2.1
2A Pacific Coast	0.2
6A Gulf of Mexico	1.6
11A Atlantic Coast	0.8
Entire offshore United States	4.7
Onshore and Offshore	
Entire United States	17.7

NOTE: All tabulated values are rounded from original numbers and may not be precisely additive. Negl., negligible, less than or equal to 0.05 billion barrels of NGL.

[a]Regions 3 and 4 combined because of data availability.
[b]Includes quantities considered recoverable only if technology permits their exploitation beneath Arctic pack ice--a condition not as yet met.

SOURCE: USGS (1981).

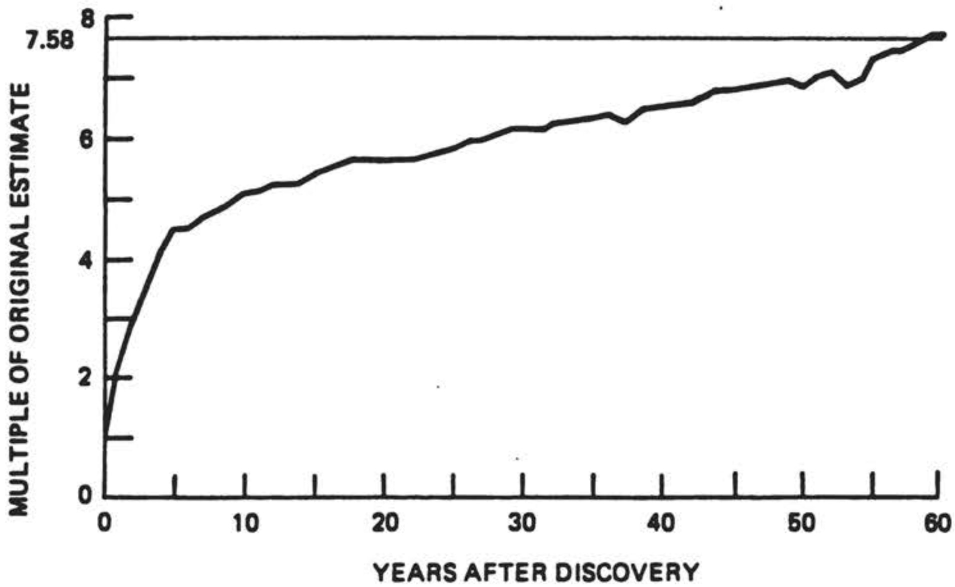
TABLE 3 Available Reserves

Crude oil, measured (proved) reserves	27.8
NGL[a], measured (proved) reserves	5.7
Crude oil, indicated reserves	3.6
NGL, indicated reserves	na
Crude oil, inferred reserves	23.4
NGL, inferred reserves	4.8
Crude oil, undiscovered recoverable	82.6
NGL, undiscovered recoverable	17.7
Cumulative amount	165.6
Produced 1981-1984	15.2
Remaining as of end 1984	150.4

[a]Natural gas liquids.

SOURCE: Grossling (1985).

FIGURE 2 Estimated Amounts of Oil and Gas Shown by Increases Over Time



SOURCE: USGS (1981).

potential are thought to be the Colorado Plateau and the Basin and Range. The offshore potential is probably greatest for Alaska, followed by the Gulf of Mexico and then by the Atlantic Coast (see Figure 3).

The pattern behind this analysis is clear: the relatively unexplored areas in the Basin and Range, Rocky Mountains, the northern Great Plains, and Alaska hold the most promise. Offshore, the most promising area is also a relatively unexplored area in Alaska. Unfortunately, however, drilling in the Rocky Mountain area since 1981 has not resulted in as many major new discoveries, as in the 1970s, and results from offshore Alaska have been mixed.

Alaska--a relatively unexplored state as far as oil and natural gas go--was thought to account for more than 23 percent of the total undiscovered reserves. For instance, 57 percent of the 1 billion acres of U.S. outer continental shelf (OCS) is off Alaska, but only 11 percent has been leased for oil exploration. Also, only 0.1 percent of all wells drilled in the United States since 1954 have been drilled in Alaska.

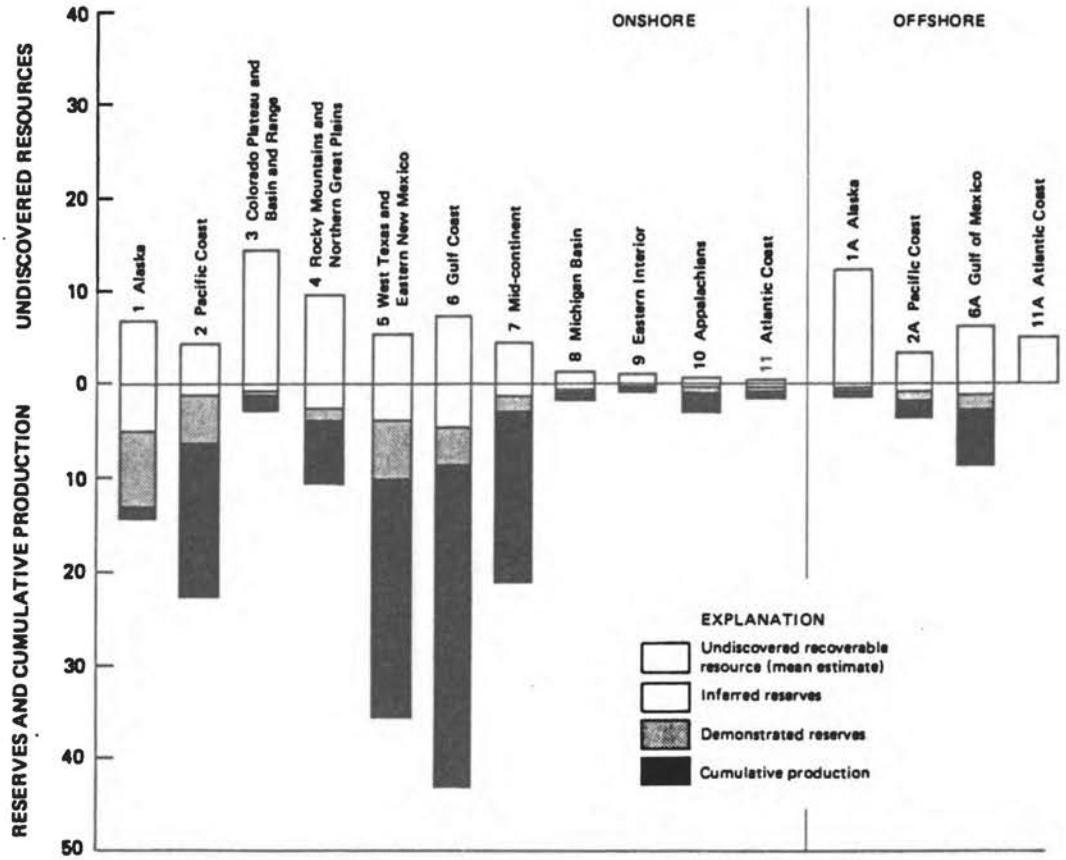
It is for these very reasons that Alaska is so promising. After more than a century of exploration in the conterminous United States, the largest discovery remains the east Texas field with 5,600 MMB of known reserves. Prudhoe Bay, discovered in 1968, contains 9,600 MMB. The Kuparuk River field began production 12 years after discovery (see Figure 4), compared with an average of one year in the rest of the United States outside Alaska.

Despite its potential, Alaska is a high-risk, high-cost operation. The failed Mukluk well off the Alaska coast cost $1.62 billion. Since 1975, there has been a general consensus concerning the order of magnitude (see Figure 5). The point estimates range from 55,000 to 113,000 MMB. The 1981 USGS estimates are little different from their 1975 estimates, but the range of the 1981 estimates is much less. There are indications, however, that these estimates will be substantially reduced (OTA, 1984).

FUTURE PRODUCTION LEVELS

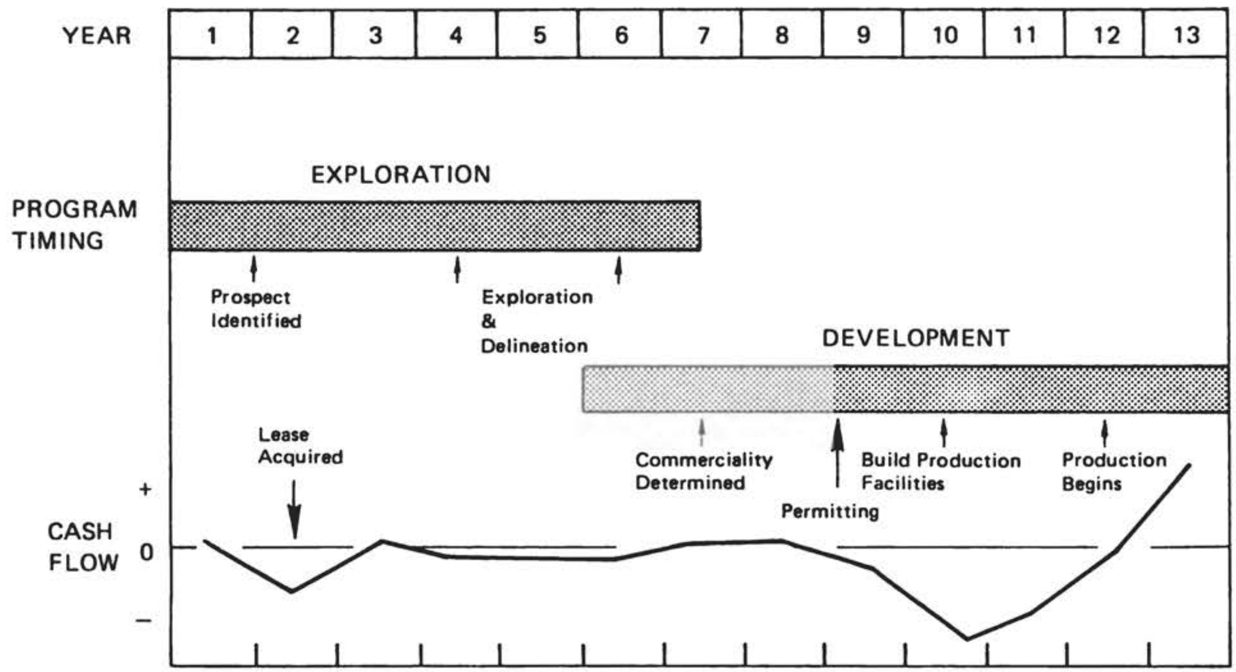
USGS made no attempt to predict what part of the assessed quantities will be discovered or when. Fisher (1985) points out that to keep crude production constant (at about 8.8 MMB/D) through 2000 would require the addition of 45,000 MMB of reserves or about 3,000 MMB/yr., a rate not achieved since 1960. An average of 2,200 MMB has been added to the reserve each year for the past decade. Since 1979, when price decontrol began, the rate of reserve additions has been 2,500 MMB, an increase largely caused by enlarged extension and infill drilling leading to reserve growth in older fields. Recent estimates for the next 15 years project reserve additions for about 2,500 MMB/yr., which is 17 percent below the levels necessary to keep production constant.

FIGURE 3 Potential Oil Reserve Growth by Geographic Region (MMB)



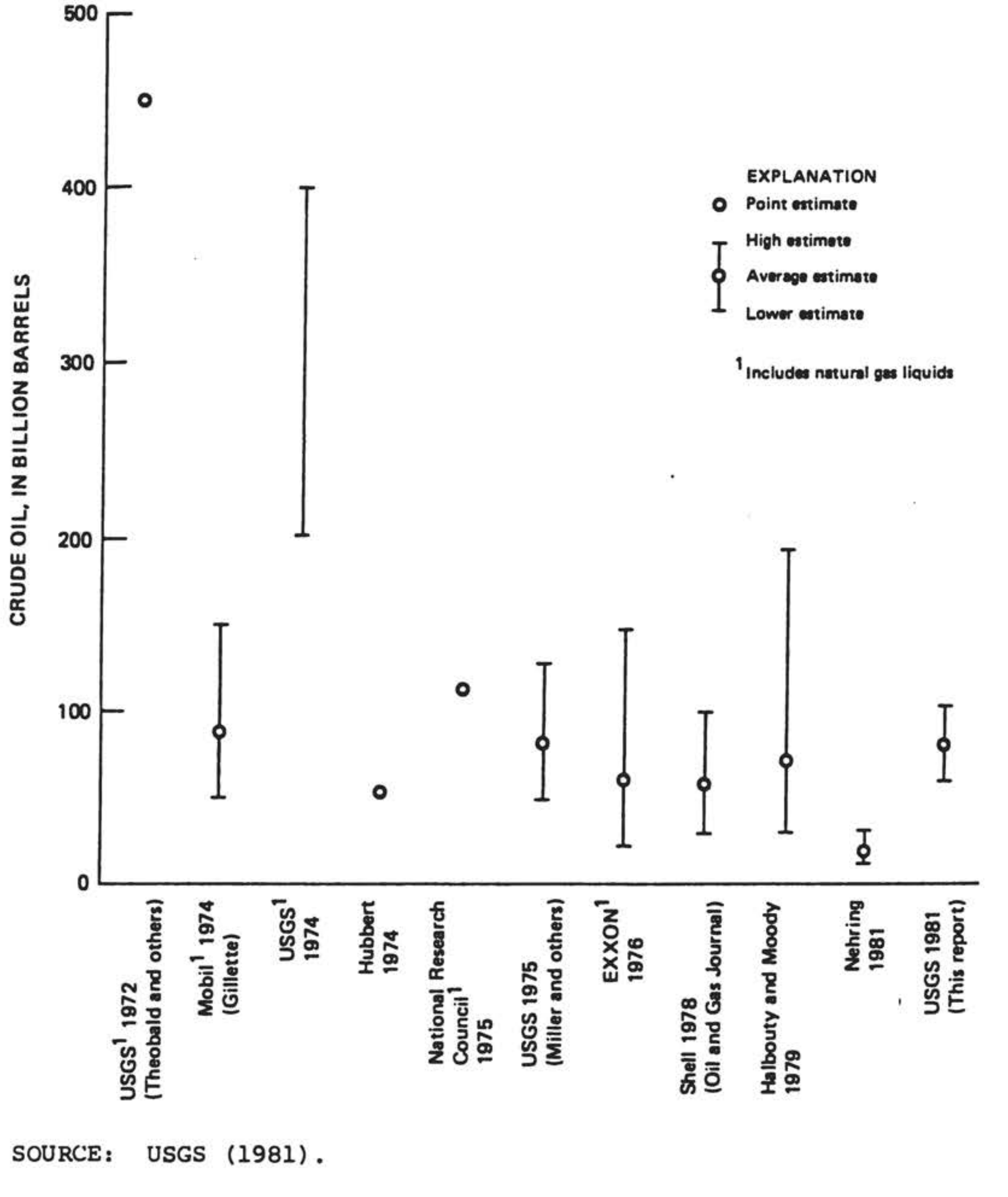
SOURCE: USGS (1981).

FIGURE 4 Arctic Offshore Exploration and Development Scenario



SOURCE: Bray (1985).

FIGURE 5 Selected Estimates of Undiscovered Recoverable Crude Oil in the United States



SOURCE: USGS (1981).

Fisher (1985) concludes that the crude production profile in MMB/D will be (see Figure 6):

1985	1990	1995	2000
8.8	8.2	7.6	7.3

This represents a total decline of 17 percent or 1.05 percent per year. These projections assume reserve additions of 2,500 MMB/yr., essentially the same as since 1979. Fisher predicts that new field additions on and offshore in the conterminous United States will average 25 to 30 percent less than those of the past decade and that conventional reserve growth from all sources will average 90 percent of those in the past decade. To keep production constant, these declines must be offset by substantially enhanced recovery of oil from known fields (at a rate 2.5 times that of the last decade) and by significant discoveries of new fields in Alaska. While conventional reserve growth (infill and extension drilling, chiefly) is not particularly price sensitive, this is not time for enhanced oil recovery and new field discovery (especially in deep offshore and in Alaska). Thus, future production will depend more closely on the price of oil.

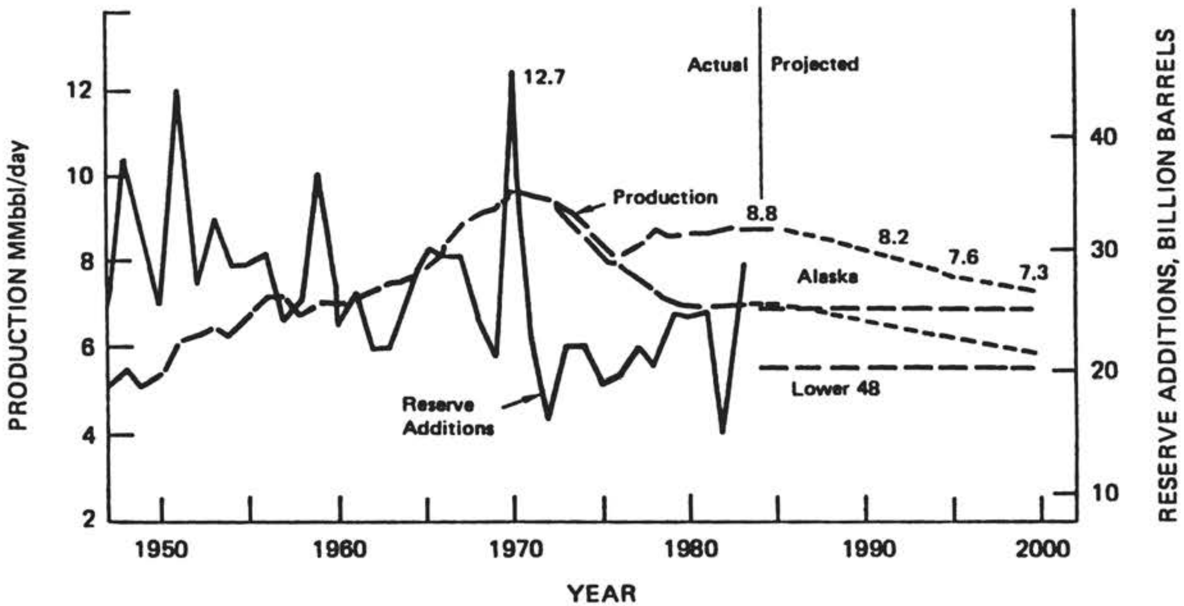
In the Annual Energy Outlook (DOE, 1985), projections for crude oil production in 1995 range from 5.5 MMB/D to 10.5 MMB/D, depending on price. In the base case (world oil price of $74/barrel. in 1995), crude production declines at 1.7 percent per year. In this case, production from conventional sites in the conterminous United States continues its downward trend; production from the OCS peaks in 1986-1988, then slowly declines; Alaska production peaks in 1990, then rapidly falls; and production increases from conventional sites using enhanced recovery methods.

Most of the deviation between the high and low cases stems from the uncertainty of the extent to which conventional onshore sites in the conterminous United States will be developed, especially in the high case. DOE argues that production from other areas cannot respond rapidly to higher prices because of long lead times. However, with lower prices, production from these sources is projected to be lower (DOE, 1985).

DOE's low-price scenario leads to roughly a halving of crude production relative to the high-price scenario. Industry forecasts crude oil prices by 1995 as low as or even lower than the DOE "low" case.* With DOE's general methodology and a lower price forecast,

*The consensus forecast in the industry is for a gradual erosion in crude oil prices in the near term, then a leveling out until about 1990 before increasing somewhat faster than inflation in the 1990s. For example, a recent CONOCO forecast ("World Energy Outlook Through 2000," April 1985, prepared by Planning Department, CONOCO, Inc.) shows that, in the lower range, crude oil prices could fall to $20/barrel by 1986.

FIGURE 6 US Crude Oil (Plus Lease Condensate) Production and Reserve Additions



SOURCE: Fisher (1985).

crude oil production in 1995 would be even less than 5.5 MMB/D. Whether this would actually occur depends on what measures the U.S. government takes to protect domestic petroleum production from low oil prices. At constant level of demand, each barrel of reduced domestic production leads directly to a barrel of additional imported oil.

There can be no doubt that spending for exploration and production (and thus drilling, reserve additions, and production) depends crucially on oil prices and internal cash flows within oil and related companies. Of course, cash earnings themselves depend in large part on oil prices.

Field size is a very important consideration. More than 75 percent of discovered oil exists in less than 5 percent of known fields, i.e., classes A and B,* the biggest fields (see Table 4). But there has been a shift to exploitation of smaller fields. From 1965 to 1982, a larger portion of the oil discovered was found in the smaller fields (e.g., Class E) than in the entire previous history of the domestic oil industry.

Only 29 new Class A fields have been discovered since 1965. In a recent forecast, Riva (1985) points out that if this is merely duplicated in the next 18 years, an additional 15,134 Class E fields would be needed (see Table 5) to keep domestic production constant. Some 26,811 would be required, almost as many as have been discovered in the entire 123-year history of the industry. This illustrates the importance of large fields and of continued exploration where there is the greatest chance of a big discovery, even though the probability of discovering a Class A-size field is only 0.6 percent.

Riva (1985) forecasts that domestic crude production will decline by 17 percent by the year 2000 to 6.71 MMB/D. He optimistically assumes that the same percent of available convertible crude resources (inferred reserves and undiscovered resources) would be converted to proved reserves in the next 18 years as were converted in the past 18 years. In the Rocky Mountain and northern Great Plains regions, because of the large estimated base apparently only 16 percent of convertible resources were added to proved reserves from 1965 to 1982.

If the same conversion percentage is used as in the forecast, production from these areas would decline 20 percent by the year 2000. However, the existing statistical data base is insufficient to predict future reserves based on past performance of those areas. If the national average of 2 percent per year conversion is used, the production from these areas would increase by 77 percent. Riva stated that if no commercial fields are found in the Oregon-Washington and Atlantic Coast areas and if history repeats itself in the Rocky Mountains and northern Great Plains, then U.S. production in the year 2000 would decline by 29 percent to only 5.84 MMB/D (Riva, 1985).

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*Field size is denoted by alphabetical designation. Descending alphabetical order indicates diminishing size of field.

TABLE 4 Discovered Domestic Crude Oil Field Size Distribution

Class and Size	Average Size (bb[a])	Number of Fields	Percent of Fields	Total Oil (bb[a])	Percent of Oil
A--greater than .050	.161	772	2.8	124.29	67
B--.025-.050	.0375	420	1.5	15.75	9
C--.010-.025	.0175	786	2.9	13.76	7
D--.001-.010	.0055	3,591	13.0	19.75	11
E--less than .001	.0005	21,954	79.8	10.98	6
Totals		27,523	100.0	184.53	100

[a]bb--billions of barrels.

SOURCE: Riva (1985).

TABLE 5 Field Size Distributions[a]

Region	Class A	Class B	Class C	Class D	Class E	Total
Alaska	25	10	9	45	0	89
Oregon-Washington	0	0	2	25	255	282
California	8	11	9	101	929	1,058
Rocky Mtns. and north Great Plains	18	18	35	430	4,419	4,920
West Texas and east New Mexico	3	6	12	150	1,514	1,685
Gulf Coast	10	10	19	251	1,470	1,760
Mid-continent	1	2	7	104	1,059	1,173
Eastern interior	0	0	0	30	302	332
Michigan basin	0	0	1	18	199	218
Appalachians	0	0	0	12	116	128
Atlantic Coast	11	1	4	5	58	79
Totals	76	58	98	1,171	10,321	11,724

[a]Of the 29.38 billion barrels of oil estimated to be discovered between 1983 and 2000.

SOURCE: Riva (1985).

OTHER CONSIDERATIONS AND PRODUCTION LEVELS IN THE 1990s

In estimating U.S. production levels in the 1990s, events during the remainder of the 1980s are of critical importance because of the long lead time that significant exploratory and enhanced oil recovery projects require. In other words, what occurs over the next five years will determine in large part the actual reserve additions and rate of production in the 1990s. In general, the outlook for the remainder of this decade does not appear favorable for the oil industry.

The risk of lower world oil prices is the single most important negative factor, but there are other reasons to believe that the risk for future production is not good. Six major oil companies have been acquired by other companies since 1982; namely, Superior (Mobil), Getty (Texaco), Gulf (Chevron), Cities Service (Occidental), Conoco (Dupont), and Marathon (U.S. Steel). In each case the acquisition was largely financed by borrowed funds and debt securities, thus saddling the combined entities with a heavy debt burden. In addition, Arco, Phillips, and Unocal have undertaken major corporate restructuring, which entails the shrinkage of equity and a major increase in debt.

To reduce this huge debt burden over the next several years, these 15 of the largest U.S. companies must reduce exploratory and development activities, particularly long-term, high-risk ventures. This does not portend well for production levels in the 1990s. In addition, proposed changes in the taxation of oil and natural gas operations are likely to reduce cash flow available for exploration and production.

In addition, there could be a price collapse as a result of an inability of OPEC and other petroleum exporters to limit production to demand and maintain stable prices. This could cause the Middle Eastern producers to opt for volume rather than price in order to maintain their own internal cash flows (Bookout, 1985). If this were to occur, the level of U.S. production would be drastically reduced and most exploratory and enhanced oil recovery efforts would be eliminated. In time, lower oil prices would presumably lead to greater demand and higher prices, but such a reversal would not be in time to revive domestic production levels in the 1990s.

Another factor is that the value of the U.S. dollar has about doubled in relation to many other world currencies since 1980. Oil, however, is paid for in U.S. dollars in the world markets. Thus, in relation to its price in 1980, oil is "cheap" in the United States, but more costly in most other countries than it was in 1980. This has intensified pressures for the industrialized countries in Western Europe and Japan to switch from oil to nuclear energy and coal for many of their energy needs. These changes, once made, are not likely to be reversed.

Moreover, energy conservation worldwide, brought on by the 1979 oil price increases, is not likely to be entirely reversed even with a substantial drop in the relative value of the dollar or in the price of oil. On the other hand, a significant decline in the cost of oil, however brought about, could materially increase the demand for it in developing nonproducing countries.

There are some events that could lead to higher U.S. levels of production. As noted above, a reduction in the relative value of the dollar would increase the market for oil, particularly in developing countries. This hypothetical increase in demand would have consequences difficult to analyze in the quasi-oligopolistic context of the world oil market. Nevertheless, it could well result in a more favorable economic climate for the U.S. oil industry, particularly if the OPEC countries opted for stable oil prices and limited production to demand. And, of course, either a truly significant discovery or series of discoveries in the United States could offset or even overcome the decline from existing U.S. fields. This has a very low chance of happening, however.

Similarly, a technical breakthrough in enhanced oil recovery technology, in oil shale or tar sand recovery, or in the production of synthetic fuels, if economic in terms of prevailing oil prices, could reduce the levels of imported oil. But it is difficult to see these occurring in time to have a material effect on production in the 1990s.

Finally, some major political or similar crisis in the Middle East could be of such proportion and duration as to drive up the price of oil and stimulate all forms of production in the United States.

On balance, however, the negative factors seem to outweigh the positive ones, and it is more prudent to plan for the lower level of production rather than the more optimistic ones. It is important to note the implications if the lower levels of production are actually realized. Most long-term forecasts project U.S. oil demand to grow from 15.8 MMB/D in 1984 to about 17 MMB/D by 2000. This includes both crude and refined oil.

Even with this modest growth in demand, if the lower level of production is realized (5.5 MMB/D of crude and 1.3 MMB/D of NGL) then imports will rise from 5.4 MMB/D in 1984 (of which crude amounted to 3.4 MMB/D and refined products to 2 MMB/D to 10.2 million B/D) which would equate to a 60 percent import dependency.

The most favorable forecast for 2000 is about 9 MMB/D. If demand is 17 MMB/D, then imports would be 8 MMB/D (47 percent import dependency).

* * * * *

MAJOR FINDING: The production of crude oil from domestic services is presently level, but an overall long-term decline is likely to reappear soon and become dominant again through the 1990s. As a consequence, demand is likely to be met by more imported oil. Projections show a 17 percent decline for crude production by year 2000. Estimates for total imports range from 5.4 MMB/D in 1984 to 10 MMB/D in 2000. Because of the relationship between declining domestic production of crude oil and rising imports, the Strategic Petroleum Reserve may not be as capable of meeting an emergency in the 1990s as it is today. With a 500-MMB reserve, current SPR protection is for approximately 100 days; for 2000, protection is limited to about 50 days.

MAJOR CONCLUSION: The DOE will have to plan for increased storage capacity if the SPR is to retain the equivalent supply of approximately 100 days of petroleum (crude and product).

MAJOR RECOMMENDATION: DOE should plan to expand storage capacity in the SPR to accommodate the implications of increased petroleum imports. DOE should also continue to monitor domestic oil production closely as well as imports.

4

TRANSPORTATION OF SPR CRUDE

The Department of Energy (DOE) has based its plans for transporting crude oil from the Strategic Petroleum Reserve (SPR) in the event of emergency on a logistics system consisting of pipelines, tankers, and barges. Two of the three pipelines (Seaway and Texoma) earmarked for the reserve were recently converted to gas transmission service, thereby considerably reducing the ability of DOE to move SPR crude to refineries by overland routes.

The planned maximum SPR drawdown of 4.5 million barrels of oil per day (MMB/D) can be achieved in 1990, but only 2.4 MMB/D can be distributed without the enhancements to the transportation system contemplated by the National Petroleum Council (NPC) report. At present, the single biggest problem with the SPR distribution system is believed to be the congestion and scheduling problems for short-haul marine transport of crude oil in the Gulf of Mexico.

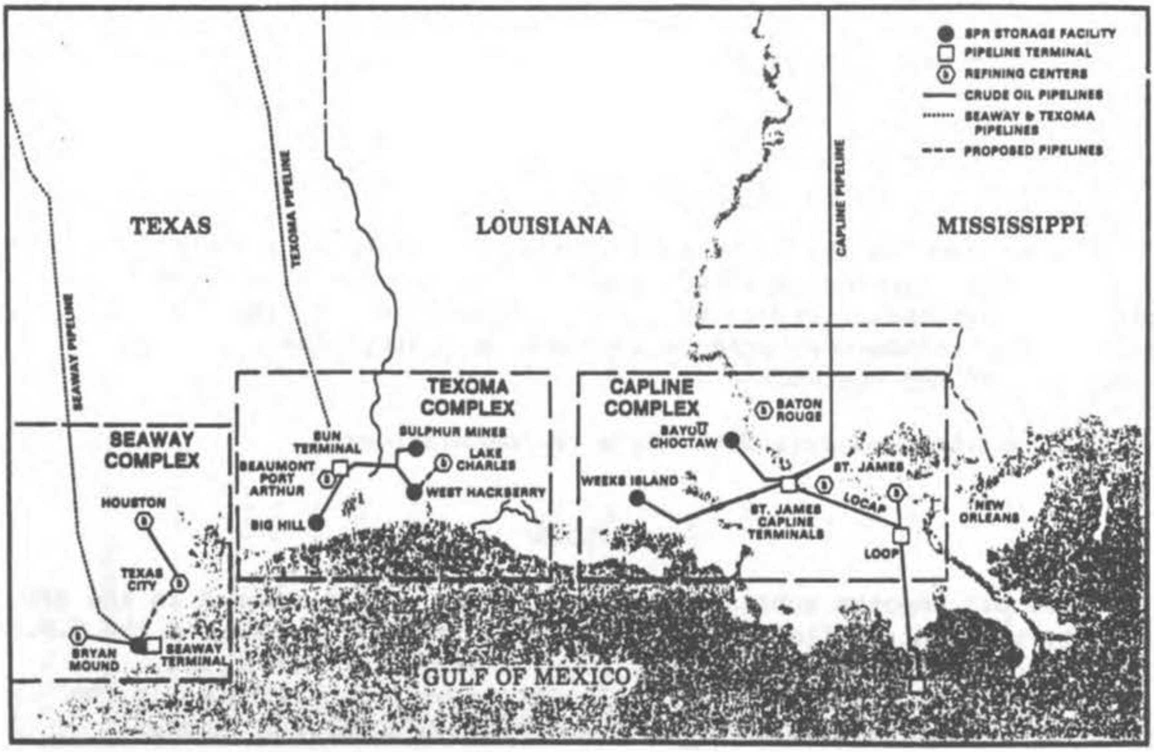
BACKGROUND

In the original design phase, the SPR was integrated into the existing and planned petroleum logistics system* consisting of pipelines, tankers, and barges. This led DOE to locate storage facilities in the Gulf of Mexico (see Figure 7). Crude oil in the reserve at the Seaway Complex will be delivered to the Seaway Marine Terminal, or to the Jones Creek Tank Farm, and then to a local pipeline. The maximum design drawdown capacity is 1.096 MMB/D.

The Texoma Complex will deliver crude to the Texoma Terminal at Nederland, Texas, for tanker/barge liftings, and also to local pipelines serving the Gulf Coast refineries. The maximum design drawdown capacity is 2.337 MMB/D. The Capline Complex will deliver oil to the DOE marine terminal at St. James, Louisiana, and to the Capline pipeline system. The maximum design drawdown capacity is 1.070 MMB/D.

*See Appendix A for details of the logistics system.

FIGURE 7 The Strategic Petroleum Reserve



SOURCE: NPC (1984).

The entire SPR system has a design drawdown capacity of 4.5 MMB/D, which would be achieved in 1990 when the reserve reaches its planned 750-million-barrel fill. However, both the Seaway and Texoma pipelines have been converted to natural gas, and are not available to carry SPR crude oil. Unless enhancements are made to the distribution system, as noted below, there will be a shortfall of 2.1 MMB/D in the system's ability to transport reserve crude (see Table 6).

The NPC report on the capability to distribute SPR oil reviewed these developments and recommended several modifications in the delivery system to accommodate the changed circumstances. The major recommendations were:

o A shift of at least 100 million barrels (MMB) of the remaining crude oil in the SPR from the Texoma to the Capline complex should be considered.

o Enhancements should be made to each of the three SPR complexes to increase distribution capacity to match drawdown capability and to provide additional flexibility in the system. (DOE is implementing some of the recommended enhancements and designing others for the complete 750-MMB system.)

The committee concurs with these recommendations.

OUTLOOK

If crude oil imports substantially exceed the levels assumed in the NPC report, the distribution problems could become more severe and the U.S.-flag tonnages assumed in 1990 may prove inadequate. Attention, therefore, will have to be focused on distribution facilities in the Gulf of Mexico (see Tables 6 and 7 and Figures 8 and 9). Goodell (1985) feels that the single largest problem with the SPR distribution system will be short hauls in and around the Gulf of Mexico, known as Petroleum Administration Defense District (PADD) III. He postulates that congestion will be the problem and not the availability of ships. This assumes that in an emergency there will be adequate tonnage available because of waivers of the Jones Act (see Chapter 2) to allow use of foreign-flag vessels (Goodell, 1985).

A large increase in imported refined products above the levels currently anticipated could result in a substantially reduced refining capacity in PADD I. Under emergency conditions, PADD III might have sufficient excess refining capacity to make up a substantial part of the shortfall in PADD I. But would there be enough tankers to move refined oil products from other areas to Atlantic coast ports? Foreign tankers, with a temporary waiver of the Jones Act, could be used if they were physically available.

DOE's Office of Strategic Petroleum Reserve should monitor the level of refined oil product imports and the availability of suitable vessels and related facilities to transport them. DOE should also determine if additional steps should be taken to assure availability of transport.

TABLE 6 SPR Crude Oil Requirements and Distribution Capacity in the 1990 Disrupted Case[a] (Thousands of Barrels per Day)

	PADD III						
	Corpus Christi	Houston/ Tx. City	Beaumont/ Pt. Arthur	Lake Charles	Lower Miss.	PADDs I, II, and V	Total
			Without Enhancements				
SPR crude oil required	260	920	520	200	1,000	1,600	4,500
Distribution capacity							
Seaway	150	250	--	--	--	--	400
Capline	--	--	--	--	240	640	880
Texoma	--	--	430	--	270	420	1,120
Shortfall	110	670	90	200	490	540	2,100
			With Enhancements				
SPR crude oil required	260	920	520	200	1,000	1,600	4,500
Distribution capacity							
Seaway	260	810	--	--	--	30	1,100
Capline	--	--	--	--	260/(960)[b]	640	900/(1,600)[b]
Texoma	--	110	520	200	740/(40)[b]	930	2,500/(1,800)[b]
Shortfall	0	--	0	0	0	0	0

[a]The numbers in this table have been rounded.
[b]Numbers in parentheses show the effect of relocating 100 MMB of future Texoma III to the Capline complex area.
Drawdown of this III is assumed to be 700 MB/D. A similar reduction in Texoma waterborne shipments to lower Mississippi refineries could be accomplished by a 700 MB/D pipeline to the Capline complex area.

SOURCE: NPC (1984).

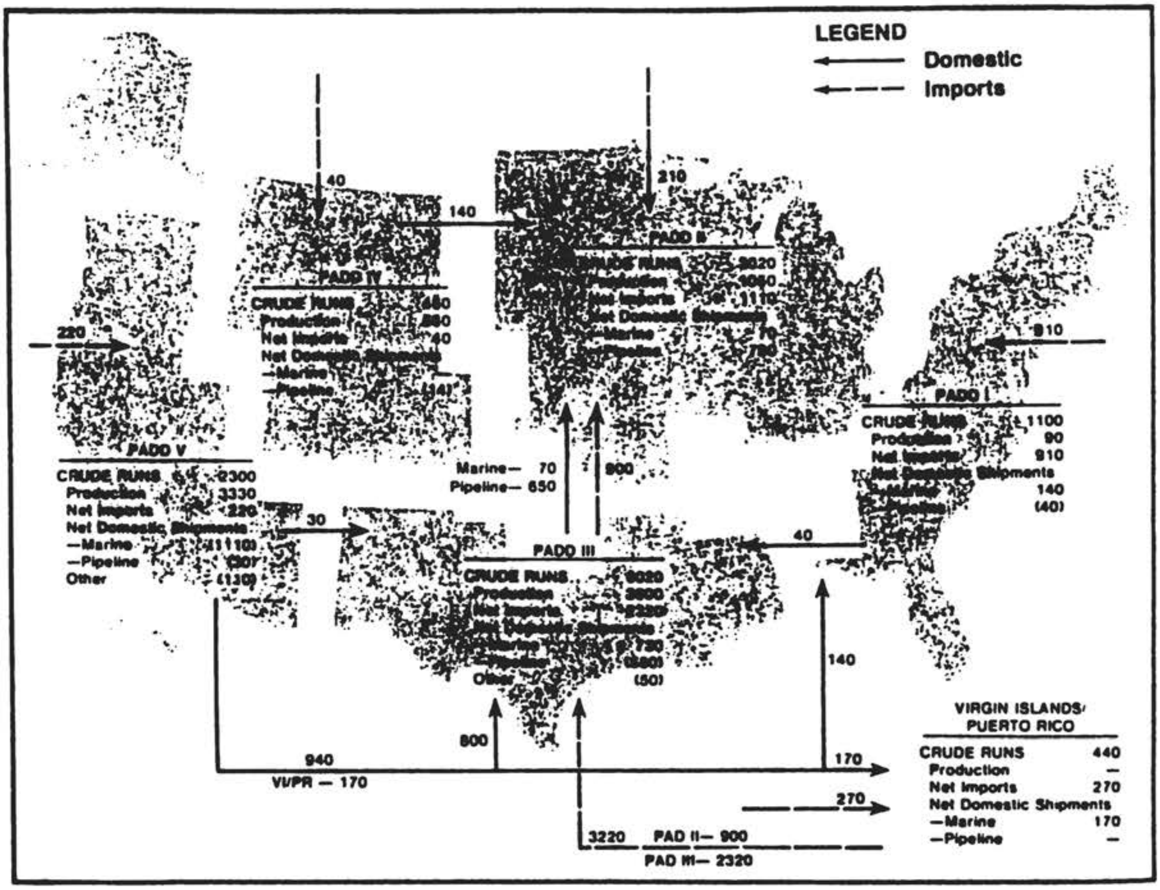
TABLE 7 Projected Supply/Demand Balance by Petroleum Administration Defense District (PADD), 1990 Nondisrupted Case (MB/D)

	PADD						
	I	II	III	IV	V	VI/PR[a]	Total
Local demand	5,340	4,410	3,810	550	2,510	240	16,860
Crude oil supplies							
Production	90	1,050	3,600	560	3,330	--	8,630
Imports[b]	910	1,110	2,320	40	220	270	4,870
Exports	--	--	--	--	--	--	--
Domestic marine shipments	--	--	(70)	--	(1,110)	--	(1,180)
Domestic marine receipts	140	70	800	--	--	170	1,180
Domestic pipeline shipments	(40)	--	(650)	(140)	(30)	--	(860)
Domestic pipeline receipts	--	790	70	--	--	--	860
Other	--	--	(50)	--	(110)	--	(160)
Product supplies[c]							
Imports	1,040	220	270	20	120	110	1,780
Exports	(30)	(40)	(290)	--	(250)	--	(610)
Domestic marine shipments	(90)	(50)	(840)	--	--	(310)	(1,290)
Domestic marine receipts	1,070	170	50	--	--	--	1,290
Domestic pipeline shipments	(190)	(340)	(2,910)	(80)	--	--	(3,520)
Domestic pipeline receipts	2,180	1,000	160	80	100	--	3,520
Other[d]	260	430	1,350	70	240	--	2,350
Total supplies	5,340	4,410	3,810	550	2,510	240	16,860
Memo: crude runs	1,100	3,020	6,020	460	2,300	440	13,340

[a]Movements to/from the U.S. Virgin Islands/Puerto Rico (VI/PR) considered domestic.
[b]Does not include SPR full additions.
[c]Includes refined products, liquified petroleum gas (LPG), and others.
[d]Includes LPG produced and used in each PADD, refinery gain, inventory draw/build, and other adjustments to balance.

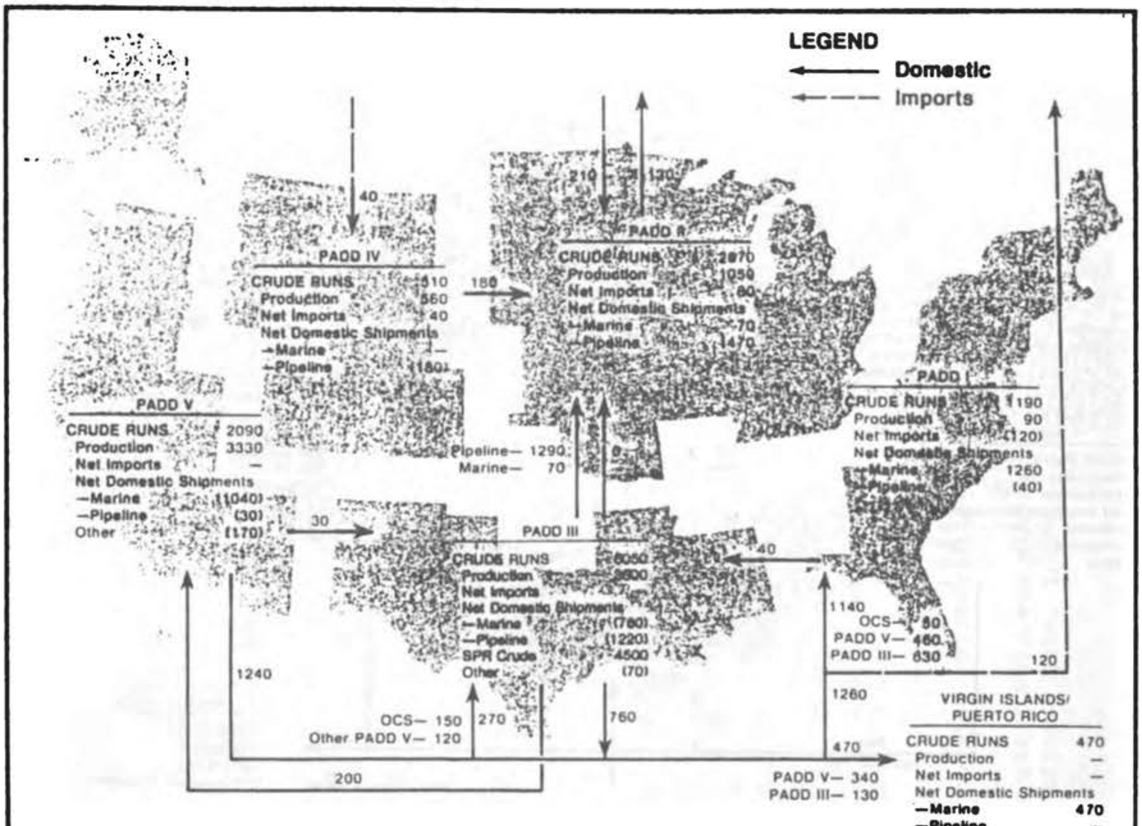
SOURCE: NPC (1984).

FIGURE 8 Crude Oil Logistics (MB/D)--1990 Nondisrupted Case



SOURCE: NPC (1984).

FIGURE 9 Crude Oil Logistics (MMB/D)--1990 Disrupted Case



Note: Case assumes Canadian crude imports/exports continue on exchange basis.

SOURCE: NPC (1984).

TANKER TRANSPORT FOR EMERGENCY STORAGE

The Big Hill storage facility southwest of Beaumont, Texas, now under construction, is designed to store 140 MMB of crude oil. Under current plans, however, completion of this facility is uncertain, and there are no announced plans for its replacement. If in the future severe disruption seems imminent and if additional storage capacity is required, DOE should consider temporary storage of crude oil in tankers (GAO, 1982). These could be placed at the most desirable location or locations as an emergency expedient to relieve a crisis.

* * * * *

<u>MAJOR FINDINGS</u>: The United States has a declining capacity to ship crude oil and refined petroleum products by tankers and barges. This could lead to potential complications involving congestion and scheduling problems in short haul operations in the Gulf of Mexico and the transport of refined products to East Coast locations. The planned maximum SPR drawdown of 4.5 MMB/D can be achieved in 1990, but only 2.4 MMB/D can be distributed without improved distribution facilities.

<u>MAJOR CONCLUSIONS</u>: Foreign tankers may be needed to supplement U.S. vessels to transport refined petroleum products in an emergency in the 1990s. On the basis of full drawdown and distribution, the SPR (as it is now constituted) will be incapable of meeting design performance requirements.

<u>MAJOR RECOMMENDATIONS</u>: DOE should pursue appropriate government channels and agencies for Jones Act waivers, as may be required, to allow use of foreign vessels. SPR distribution facilities should be upgraded in accordance with the recommendations of the National Petroleum Council so that the system will be fully functional at the design drawdown rate of 4.5 MMB/D.

5

TRENDS IN THE DOMESTIC REFINING INDUSTRY

Current trends in the U.S. oil industry point towards a reduced capacity in refined crude oil in U.S. refineries but an increase in the complexity of products refined. While the increase in complexity will help U.S. industry maintain a competitive position in world markets, a reduction in capacity might hamper industry's ability to refine sufficient crude oil from the Strategic Petroleum Reserve (SPR) to meet an emergency in the 1990s.

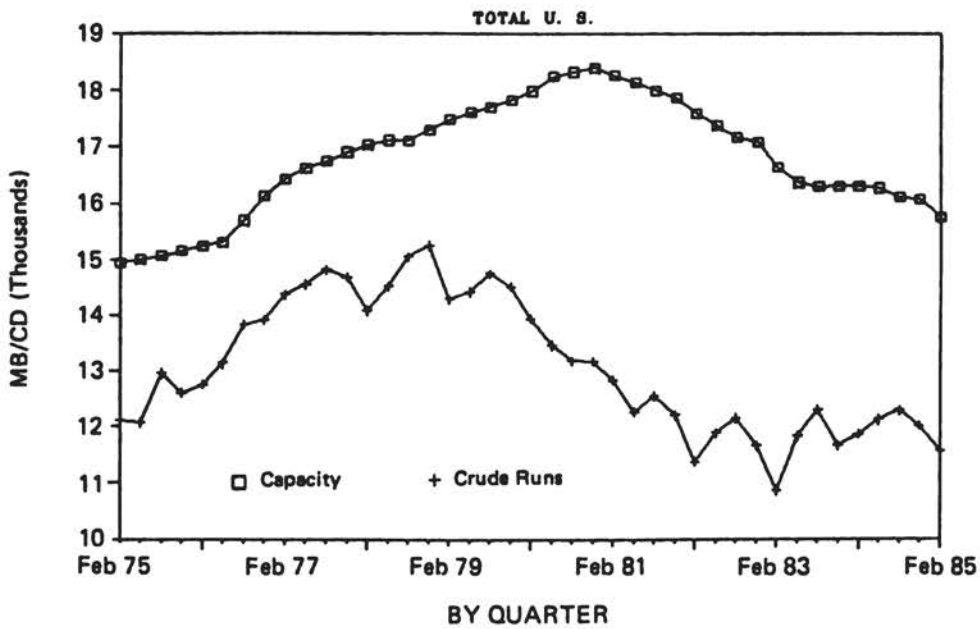
SIZE OF THE DOMESTIC REFINING INDUSTRY

Gross Economic Rationalization

Since the peak year of 1978, the demand for refined petroleum products in the United States steadily declined until 1984. From nearly 19 million barrels per day (MMB/D) in 1978, demand fell to slightly more than 15 MMB/D in 1983 before increasing to 15.9 MMB/D last year (DOE, 1984). Taking into account imports, unrefined natural gas liquids (NGL), and stock changes, refinery runs fell from about 15 MMB/D to about 12 MMB/D over the same period (see Figure 10). That figure shows how crude runs and refining capacity have changed during the past 10 years. U.S. refining capacity, in terms of crude distillation, peaked in 1981 at about 18.5 MMB/D. At that time, refinery runs were only about 13.5 MMB/D, giving a capacity use factor of 73 percent.

Latest capacity figures show 15.1 MMB/D of crude distillation in the U.S. refining industry (Oil and Gas J., 1985). This is a decrease of 4.8 percent in the last year and 22 percent over a five-year period. While major refiners have shut down many of their less efficient operations since 1978, most shut down in 1984 were small refineries. The number of refineries with a capacity of less than 0.2 MMB/D dropped from 108 to 91. The average size of the 28 refineries shut down during 1984 was 0.022 MMB/D.

FIGURE 10 Refining Capacity and Crude Runs



SOURCE: Heinen et al. (1985).

Even with those shutdowns, crude distillation capacity use was less than 80 percent in 1984, with crude runs at about 12.8 MMB/D (DOE, 1985). With this low use factor, refinery crude capacity seems destined to continue to decrease. One estimate shows that a net of 14.1 MMB/D will be required in 1990 to support a demand that will only increase by about 5 percent (1 percent per year) in the DOE base case (Heinen et al., 1985). In addition, an estimated 0.6 MMB/D will be "idle" in 1990 beyond the required net crude capacity. This gives an overall use factor of about 92 percent using the National Petroleum Council (NPC) estimate of crude runs in 1990.

However, even though idle capacity is defined as that capacity which can be brought on line within 90 days, it is not likely to become available quickly in an emergency (Burch, 1985). There is also a possibility that some of the 90-day estimates of availability are optimistic. Experience shows that once shut down for more than a few months refining units undergo deterioration that makes them very difficult to reactivate.

The continuing surplus of refining capacity throughout the 1980s will place economic pressure on the refining industry to close more of their smaller, less efficient operations. Therefore, U.S. refineries will not likely have much spare capacity above demand by the end of the decade.

Captive vs. Market Refineries

The strength of the U.S. refining industry is affected by one other important factor in addition to demand. About 57 percent of the crude oil processed in U.S. refineries in 1983 came from domestic petroleum sources (Fesharaki and Isaak, 1985). The remaining 43 percent of refinery capacity could process either domestic or imported crude oil, usually the latter. The former is called "captive" capacity because it is committed to domestic sources and the latter "market" because it has access to both. While the crude supply was not controlled, the market for refined petroleum products was inside the United States.

Market refineries are less secure and competitive within the United States boundaries than are captive ones, particularly in times of unstable crude oil supplies and prices. Thus, the market part of the U.S. industry may be particularly vulnerable to competition from imported refined petroleum products if the rest of the 1980s turn out to be unstable in that regard. Oil exporting countries could create that instability if they become exporters of refined petroleum products. The 43 percent of the U.S. refining capacity represented by market refineries could be shut down by the oil-exporting countries shifting from crude to refined oil. This represents a serious risk beyond that needed to cope with basic overcapacity for the SPR.

A further threat to the U.S. refining industry is the expected decline in U.S. crude production. Fisher's estimates (see Chapter 3) plus the refining capacity figures cited above show the following:

	1985	1990
Domestic Production, MMB/D	8.8	8.2
Refining Capacity, MMB/D	15.1	14.1
Percent Captive Refining	57	57

However, crude production is expected to fall to 7.3 MMB/D by 2000, a decrease of 11 percent. Needed refinery capacity will either stay constant or increase slightly. Thus, by the year 2000, half or more of the U.S. refining industry will likely depend on foreign crude. The percentage could be appreciably more than one half in the likely event that domestic crude production does not meet expectations. This substantially raises the consequences of a supply interruption.

PROTECTIVE TECHNICAL CHARACTERISTICS OF THE DOMESTIC REFINING INDUSTRY

Desulfurization Capability

U.S. refineries depend to a large extent on their desulfurization capability to promote stability. U.S. markets are more geared to low sulfur petroleum products because of environmental concerns than those elsewhere in the world. As a result, those refineries that have shut down since 1981 have much lower desulfurization capability than those still operating (Heinen et al., 1985).

Taken together, this means that U.S. refineries will have a much better chance of being able to produce low sulfur products, particularly fuel oil and distillates, than refineries in other parts of the world. With the possible exception of the new, complex, Mideast export refineries, the U.S. industry will have an edge in meeting requirements of the domestic market.

In addition, producers of low sulfur crude, such as Libya, will find it more difficult to disrupt U.S. markets by withholding supplies than it would have been in 1978 because domestic refineries can remove sulphur from crude oil from other sources.

Capability to Produce Lead-Free Gasoline

The second technical ability that protects the U.S. refining industry is the large and growing use of lead-free gasoline. The oil industry's ability to make sufficient unleaded gasoline to meet demand over the next several years will be very tight (Dosher, 1985). However, because of decreasing gasoline demand, this advantage will disappear in the

1990s. Thus, refiners are unlikely to invest in equipment to make additional unleaded gasoline over such a short period.

However, there will be continuing shutdowns of U.S. refineries that cannot make enough unleaded, so that the remaining refinery mix will likely be a strong competitor in world markets for that type of fuel. Use of such expedients as ethanol and methyl tertiary butyl ether (MTBE) in unleaded gasoline, metallic additives such as manganese in the remaining low-lead level gasoline, and cracking catalysts to produce higher octane gasoline will help the U.S. refining industry through this difficult period.

Meanwhile, several Middle Eastern countries have or are building new petroleum refineries. These will be best suited to export refined petroleum products to the U.S. market because they were built with American technology and are set up to produce high octane lead-free gasoline. Because European refiners are also faced with declining lead levels, Mideast refined petroleum products may flow into Europe, where the local industry will have no more enthusiasm for further investment than their U.S. counterparts. As noted below, however, logic may not prevail when considerations of national security close markets to imports. If the European countries banned the importing of refined petroleum products, for example, more of those products might find their way to the United States.

Product Demand

This discussion assumes that the demand for refined petroleum products will reflect the projected fall in demand for gasoline and an increase in demand for distillates so that total demand for refined products will rise marginally during the remainder of the decade (Dosher, 1985; in Bookout, 1985). However, it may be much more difficult to predict economic activity than oil demand. Oil, as a swing fuel, will change rapidly as economic activity changes.

However, once rationalization is complete, refining is likely to be sized to meet average rather than maximum demand. Incremental demand will be met by importing refined petroleum products, if an emergency triggers use of the SPR during a period of high economic activity. In that case, the nation will cut back on less-essential industrial production and take other measures to decrease oil demand, including importing refined products. Thus, if protection of some part of the U.S. refining industry is deemed appropriate, it need not be as much as is required to serve sustained economic growth over a long period. Of course, the costs avoided in unneeded refinery capacity must be balanced off against the loss in gross national product occasioned by such emergency slowdowns in industrial production.

The final aspect of demand is the shift from gasoline to distillate. If the oil industry uses expedients to cover the rapid move to unleaded gasoline in the next few years, it will be in a good position to increase distillate production in the 1990s without becoming overinvested in it ability to produce gasoline. It should be very competitive in world markets and thus able to keep imports of refined petroleum products to a minimum.

With a different near-term scenario--i.e., much greater volumes of product imports from now until 1990--the industry may not have the capacity to refine SPR crude at the desired rate in the 1990s. The various aspects of petroleum product imports are discussed in Chapter 6.

POLICY TRENDS

Income Tax Policy

Current administration proposals to modify the U.S. income tax could affect the refining industry and, in turn, the SPR. The direct effect may not be as great as the indirect effect on integrated refiners. An end of investment tax credits, for example, will not affect the oil refiners as much as the producers because the days of heavy investments in refining are over for the immediate future. (The industry has been overly invested for the last few years.)

However, a weakened producing industry could also weaken the integrated U.S. oil companies to such an extent that they can no longer support their refining divisions during the lean years ahead. It is unlikely that present treasury proposals would have a great impact in this area, but in a worst case, nonintegrated refining companies might not be able to survive an onslaught of imported petroleum products. Thus, the entire industry could face shutdowns to such an extent that capacity to refine SPR crude would not be available.

Tariff and Excise Tax Policy

The argument has been made that increased tariffs on imported crude and/or refined petroleum products, along with increased excise taxes on gasoline, would induce conservation, which would help keep demand low (Fesharaki and Isaak, 1985). Gasoline prices in this country, the argument goes, would be more like those in other industrialized countries. Under such a scenario, the dependence of the refining industry on foreign crude oil would shrink, leaving a greater proportion of captive refiners. With a protected industry, the balance between U.S. production and demand would move closer.

Others, however, believe that such protective policy is unwarranted and the industry must go through a wringing out period brought on by either a collapse in prices, which the exporting countries cannot stop, or a deliberate "OPEC volume" strategy (Safer, 1985; Bookout, 1985). Still others contend that a petroleum import policy of some kind is necessary for national security reasons (Thomas, 1984). As would be expected, opinions tend to vary on this controversial issue.

RECAPITULATION

The domestic refining industry in the 1990s is likely to be smaller, more complex than it is now, faced with declining demand for gasoline and increased demand for distillates, and tested against other reserve options, such as refined product storage.

Based on economic rationalization alone, about 1 MMB/D of capacity could be eliminated. If additional imported products come at that same level or higher, then the refinery industry could theoretically maintain an equivalent capacity on standby for an emergency. However, without major national policy changes, the refinery industry is unlikely to be sized either for maximum economic activity or for special emergency situations.

Domestic refining will be more complex than now and more technically sophisticated by virtue of more effective sulfur removal and better product quality than most of the rest of the world's refining industry. Consequently, it should be able to handle a wide range of crudes and be competitive with foreign refineries in producing those refined petroleum products demanded by U.S. markets, unless product imports and unstable crude supplies and prices overwhelm it during the next few years.

The industry should be in a good position to handle demand shifts based on declining demand for gasoline and increased demand for distillates. However, despite current trends toward higher gasoline and lower distillate imports, in the long run imported distillates will be more likely to find a place in the U.S. market than imported gasoline.

A domestic refining industry is vital if the SPR is to be viable in the 1990s. If domestic refineries cannot survive completion from imported refined products, then other reserve options, such as storing refined products, will have to be reconsidered by DOE to provide for national security against a petroleum crisis.

* * * * *

<u>MAJOR FINDINGS</u>: The U.S. refining industry is in a general state of decline. It will be smaller but more competitive in the 1990s by virtue of its technical sophistication. However, the industry remains particularly vulnerable to competition from lower-priced petroleum products refined abroad.

<u>MAJOR CONCLUSION</u>: If refining capacity continues to deteriorate because of rising imports, a separate reserve may be required for refined petroleum products.

<u>RECOMMENDATION</u>: DOE should carefully monitor the U.S. refining industry to determine if capacity will fall below the level necessary to handle U.S. production and strategic reserve quantities. If this appears likely, DOE should consider a separate reserve for refined products to compensate for loss of domestic refining capacity.

6

TRENDS IN PRODUCT IMPORTS

Imports of refined petroleum products have increased significantly in the past few years. Although most of these refined products are imported from countries in the Western Hemisphere and the quantity of refined products that entered the United States in 1984 is less than the mid-1970 level, the recent increases are regarded as very significant by the petroleum industry. The Petroleum Administration for Defense District (PADD) I on the East Coast has traditionally imported the greatest quantity of refined products. Expectations are that this region would continue to import a disproportionate share of refined products in the future.

CHANGING PATTERNS

The Department of Energy's (DOE) Office of Strategic Petroleum Reserve has been operating under the assumption that refined petroleum products would not be imported into the United States, on a large scale, in the forseeable future. This assumption requires careful reconsideration. Recent trends, as discussed by several speakers at the committee's workshop (Bookout, 1985; Dosher, 1985; McNamara, 1985; and Tahmassebi, 1985), show large increases in imported refined petroleum products. In addition, the OPEC Downstream Project of the East-West Center (Fesharaki and Isaak, 1985) has prepared an extensive analysis of the changing patterns of the worldwide petroleum refining industry and the distribution of refined products. This chapter is largely based upon the information provided from these sources.

The United States has historically been a large importer of fuel oil as a refinery raw material and as a fuel. Fuel oil imports were depressed in the late 1970s and there have been significant changes in the absolute and relative quantities of refined petroleum products imported into the United States over the past six years (see Table 8).

TABLE 8 Petroleum Product Imports for the United States from 1979-1984[a]

Year	Quantity (MB/D)[b] Light Products	Residual Fuel Oil	Other[c]	Total	Percent of U.S. Consumption
1979	452	1,151	334	1,937	9.6
1980	362	939	345	1,646	9.7
1981	392	800	433	1,599	10.0
1982	361	776	488	1,625	10.6
1983	499	699	535	1,722	11.3
1984	696	674	609	1,979	12.6

[a]Department of Energy, Annual Energy Review, Petroleum Supply Monthly as presented by Hossein Tahmassebi, 1985, p. 3.
[b]MB/D--thousands of barrels per day.
[c]Finished gasoline, gasoline blending components, jet fuel, and distillate fuel oil.

Indeed, gasoline imports rose about 40 percent from 0.22 million barrels per day (MMB/D) in 1983 to 0.3 MMB/D in 1984. There were even larger increases in such middle distillates as kerosene, jet fuel, heating oil, and diesel fuel (McNamara, 1985). These trends illustrate the changing import level for gasoline for the past five years (see Figure 11). The rapid economic recovery in the United States and the strong value of the dollar contributed to the surge in imported refined products. The large increases in gasoline imports in 1984 are, in part, a consequence of the coal strike in Great Britain in that year. A recent report (New York Times, 1985) suggests that gasoline imports have been diminishing since the settlement of this labor dispute. It is pertinent that the current level of imports is significantly less than the levels of the mid-1970s.

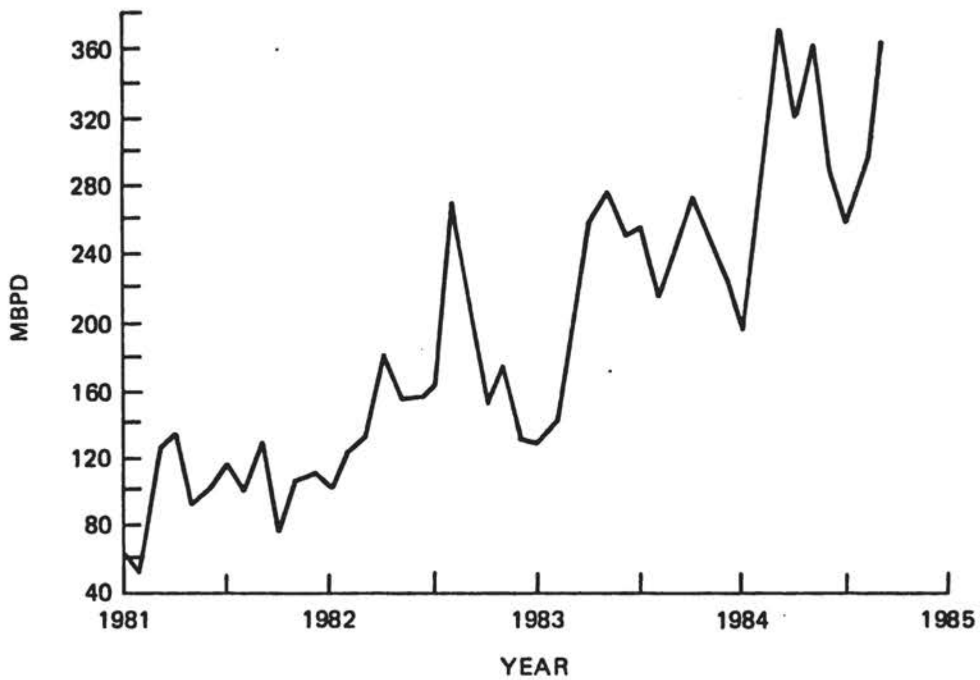
These imports were not distributed uniformly throughout the United States. Rather, about 74 percent of the gasoline was imported into the East Coast, about 14 percent into the West Coast, and about 10 percent into the Gulf Coast. The East Coast also received a disproportionately large share of other refined products.

Most gasoline imported into the United States in 1983 came from traditional sources--the Virgin Islands (19 percent), Venezuela (14 percent), the Netherlands Antilles and the Netherlands (12 percent), and Canada (9 percent). Some came from newer sources such as Romania (7 percent), Brazil (6 percent), and China (9 percent). Other important supplies of refined petroleum products have been received from Algeria, Indonesia, Brazil, and Great Britain.

The East-West Center report (Fesharaki and Isaak, 1985) concludes that about 75 percent of refined petroleum product imports come from the Western Hemisphere and that 60 percent come from U.S. allies, possessions, and refineries in the Caribbean area. At the present, few refined products are imported from the Middle East.

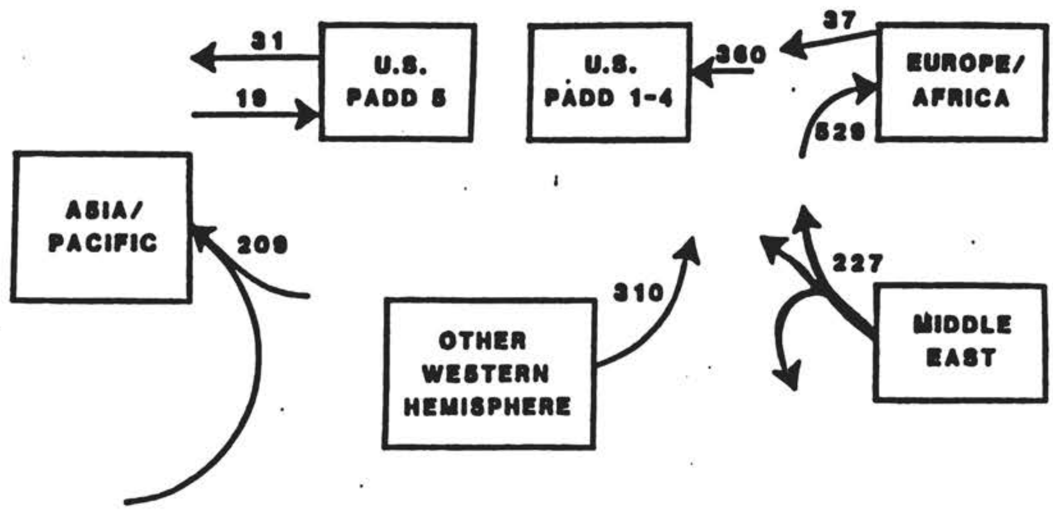
Global perspective is provided by the worldwide distribution pattern for light refinery products in 1983 shown in Figure 12. The numerical values do not balance because the Eastern European countries export an additional 406 MMB/D of light refinery products. Until recently, refineries on the East and the West coasts have supplied gasoline and other refined products needed in the eastern United States. Further increases in imports to that region may lead to refinery closings. Once closed, refineries tend to undergo deterioration that makes them very difficult to reactivate (see Chapter 5). As a consequence, several U.S. refiners have urged Congress to take immediate corrective measures, such as major tariffs, to reduce the level of refined petroleum imports.

FIGURE 11 U.S. Gasoline Imports over the Past Four Years



SOURCE: McNamara (1985).

FIGURE 12 The Worldwide Trade Pattern Expressed in MB/D for Light Refined Petroleum Products in 1983



Source: Dosher (1985).

FUTURE CHANGES IN THE 1980s

Figure 13 presents a demand forecast for gasoline and distillate in the United States for the next 10 years. As shown, gasoline demand is projected to fall modestly until 1990 as automobile efficiency increases and then to increase slightly for the remainder of the decade as the number of automobiles increases. The growing need for distillate reflects the increasing demand for transportation fuels other than gasoline. All such predictions are subject to great uncertainty because it is extremely difficult to predict the levels of national and worldwide economic activity. Nevertheless, some educated estimates are needed to gauge the energy situation likely to prevail in the 1990s.

Although the construction of many planned refineries around the world have been delayed, some OPEC countries are increasing their refinery capacity. An additional 1.1 MMB/D of refined petroleum products will become available in world markets from six new refineries built in Middle Eastern and North African countries during the next three years. The locations of these refineries are shown in Figure 14 and the changes in refining capacity in all OPEC countries are summarized in Table 9. Four countries--Kuwait, Saudi Arabia, Nigeria, and Indonesia--are currently expanding their refinery capacity with a clear intent to increase export capacity.

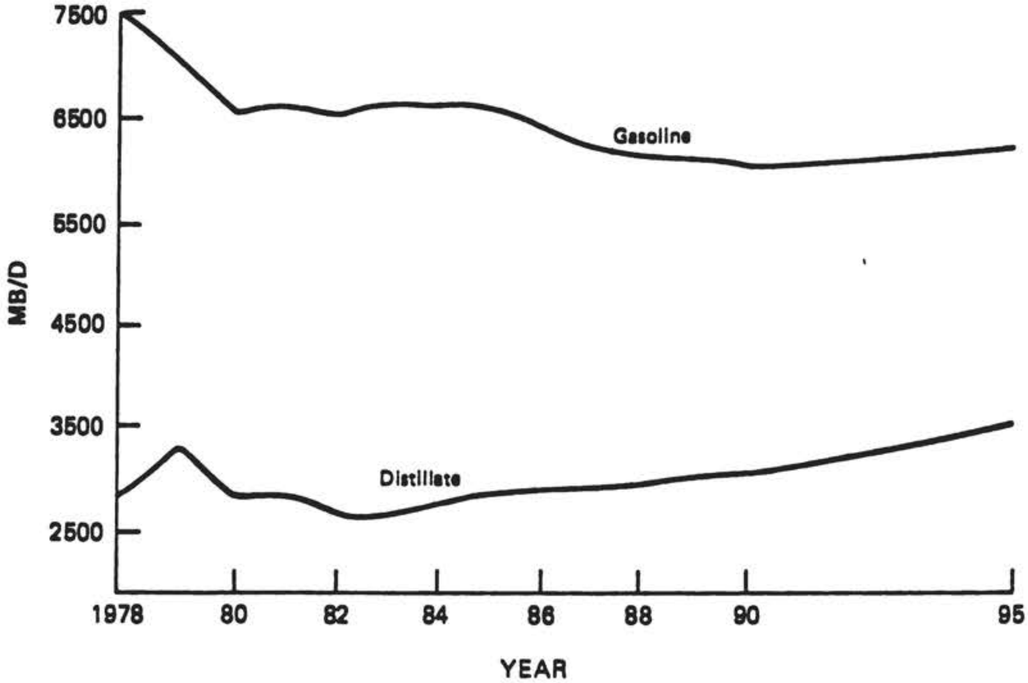
The Petromin-Mobil refinery at Yanbu, Saudi Arabia, for example, will convert 0.25 MMB/D of crude oil into gasoline, jet fuel, diesel fuel, and fuel oil for export markets. The Petromin-Shell refinery at Jubail, Saudi Arabia, will also process 0.25 MMB/D. The products from this sophisticated plant can be altered to change the mix of light petroleum products to meet demand. The largest new plant in Saudi Arabia, located at Rabigh, is a cooperative project of Saudi Arabia and the Greek Petrola Company. This plant is slated to produce fuel oil, diesel fuel, kerosene, and a relatively small amount of gasoline.

The Downstream Project report (Fesharaki and Isaak, 1985a) argues that the joint venture relationship will direct the exported products of these refineries into definite regional markets. Most pertinent for this study is their conclusion that the products of the Petromin-Mobil refinery will be exported to the United States.

The Kuwait Petroleum Corporation is establishing an integrated operation by the purchase of overseas assets and by the construction of sophisticated refineries. Although the planned refinery additions are modest by comparison with those in Saudi Arabia, the product mixture is suitable for export, presumably to Kuwait's European customers.

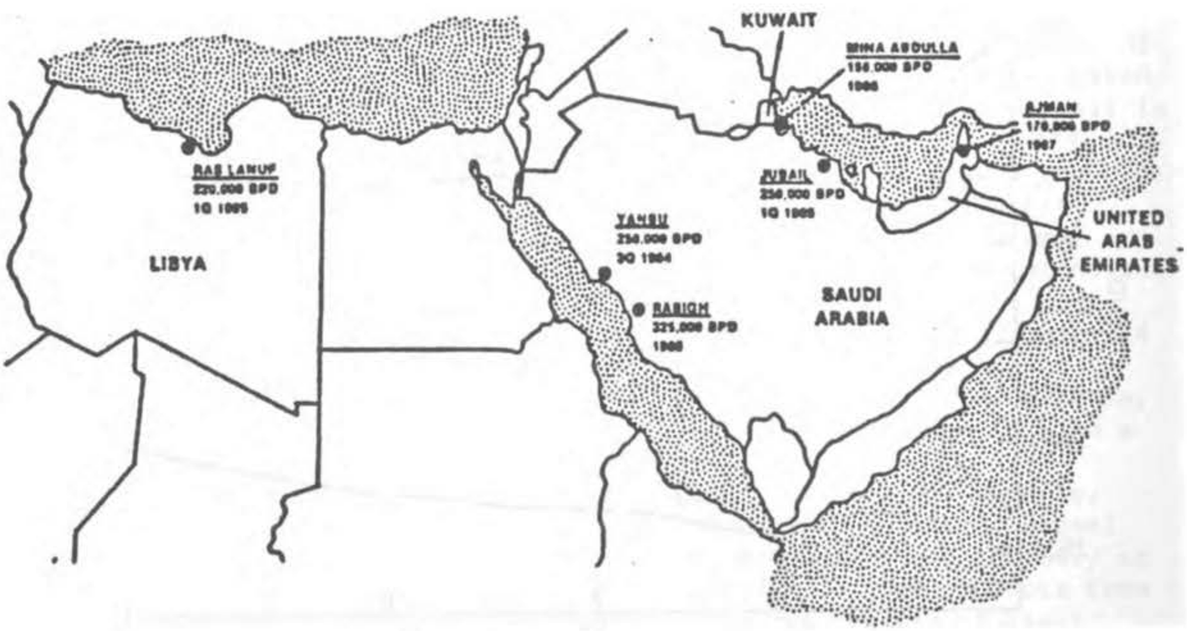
Indonesia is also expanding its refinery operations. The OPEC Downstream Project report concludes that Indonesia will have a relatively small amount of petroleum products--0.15 to 0.30 MMB/D of fuel oil and gasoline--will be available for export in 1990. While the projection for 2000 is much more difficult to make, there is no secure basis for suggesting that refined products from this country will be imported into the United States.

FIGURE 13 Demand Forecast for Gasoline and Distillate in the United States



SOURCE: Dosher (1985).

FIGURE 14 Locations of the Major New Refineries in North Africa and the Middle East



SOURCE: McNamara (1985).

TABLE 9 Changes in Product Export Potential from OPEC Countries for 1987-1988

Country	In 1984[a]	Additions[a]	1987[a] Total Capacity	1987[a] Domestic Demand	1987[a] Export Capacity[b]
Iran	545	250	795	740	0
Iraq	170	240	410	430	0
Kuwait	550	80	630	95	454
Oatar	10	50	60	16	33
Saudi Arabia	950	1,125	2,075	614	868
UAE	130	45	175	125	29
Total Gulf	2,355	1,790	4,145	2,020	1,384
Ecuador	85	--	85	127	0
Venezuela	1,360	--	1,360	420	667
Gabon	20	--	20	44	0
Libya	350	--	350	146	142
Algeria	435	--	435	130	217
Nigeria	260	150	410	221	108
Indonesia	460	400	860	550	217
Other OPEC	2,970	550	3,520	1,638	1,351
Total OPEC	5,325	2,340	7,665	3,658	2,735

[a]Capacity in thousands of barrels per day.
[b]The estimated export capacity at a gross refinery use rate of 75 percent, as presented by Hossein Tahmassebi during the workshop. These values are also based on data assembled in Chapter 4 of above reference.

Source: Fesharaki and Isaak (1985).

Nigeria has not announced its plans for new refinery capacity, but there is every reason to believe that its refined petroleum products will be exported.

Table 9 shows that the OPEC nations will have about 2.74 MMB/D of export capacity by the end of the current decade. The recent changes in refinery capacity have been undertaken for export in many of these countries in the expectation that the refineries would be operated at a true economic profit, enabling the nation to realize the added value of the refined products in addition to the value of crude oil.

In the current environment of decreasing markets for gasoline and other light petroleum products and the economic attractiveness of the U.S. market, there is great concern among U.S. refiners that the refined petroleum products of other countries will be sold, relatively indiscriminately, at low prices in this country. Their fears are exacerbated further by the restrictive import policies of Western European and Asian countries. Thus, since neither Japan nor Western European countries will become major importers of refined oil products, the OPEC nations will export their excess products to the United States and sell them at low prices (Tahmassebi, 1985).

A somewhat different viewpoint also exists (Dosher, 1985). While new additions to the world refining industry would continue, a considerable portion of the capacity would not be suitable for processing heavy crude and even less would be suitable for octane improvement. This fact, coupled with the recent reduction in the allowable concentration of tetraethyl lead in gasoline in the United States, means that only a portion of the excess foreign capacity for refined petroleum products will be suitable for sale in the United States.

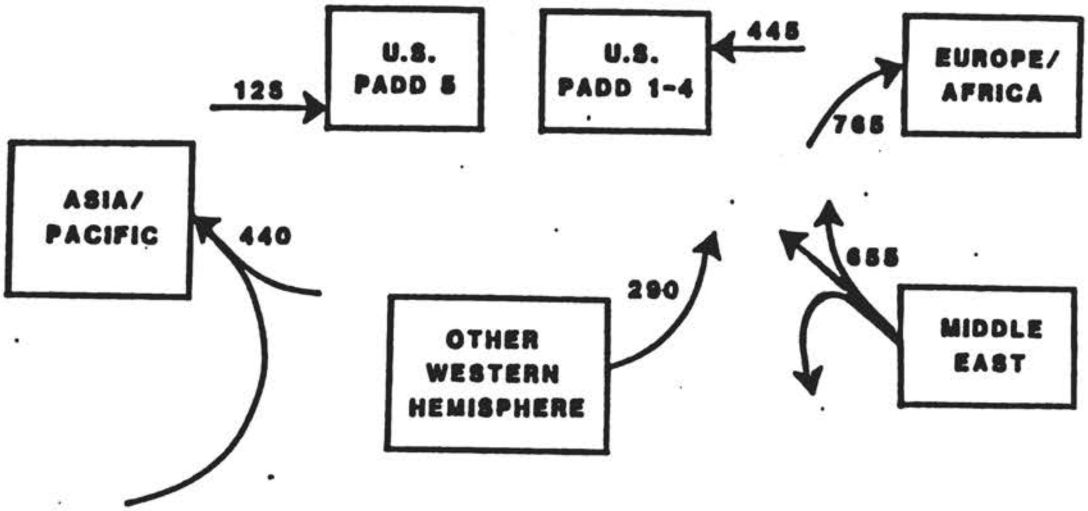
Canada, Mexico, China, Brazil, and some Eastern European countries (i.e., Romania) export refined petroleum products to the United States. However, these producers are more constrained by economic considerations. It is unlikely that new refinery capacity designed to produce quality products for the U.S. market will be created in these countries until the world market is more favorable. Thus, significantly, increased imports of refined products from these countries are not expected in the near future.

Figure 15 projects the import-export pattern for petroleum products in 1990. This chart implies that the increases in exports from the Middle Eastern countries will be absorbed by European, Asian, and Pacific nations. As already discussed, however, not all energy observers agree with the projection.

THE 1990s

Projected requirements for oil products in the 1990s are subject to many errors, mostly due to the uncertainty in the actual level of economic activity. In this situation, one must be skeptical about all long range forecasts. However, the building of sophisticated refineries requires considerable time and 1995 is only a decade away. John Dosher's estimates for worldwide trade in light refined petroleum products in 1990 are shown in Figure 15. His forecasts for the imports

FIGURE 15 The Worldwide Trade Pattern Expressed in MB/D for Light Refined Petroleum Products in 1990



NOTE: The imbalance in exports and imports arises because the exports of the Eastern European bloc are not shown. This group is projected to contribute 620 MB/D in 1990.

Source: Dosher (1985).

of light products and for worldwide trade in 1995 are presented in Figures 16 and 17, respectively (Dosher, 1985).

The projected gasoline demand and import levels for light petroleum products for 1985, 1990, and 1995 are presented in Table 10 for convenient comparison. This projection implies there will be little change in the demand and importation of gasoline, but significant growth in the demand and importation of distillate. While the market share for imported refined gasoline is not projected to increase, that for distillate will increase by about 30 percent. These changes are really quite modest. The pattern presented in these figures implies that the market share of foreign refiners will not increase significantly for gasoline or for distillate and fuel oil from 1985 to 1995.

However, a disruption of product imports could have an adverse local impact on the East Coast. Seventy-four percent of the gasoline imported into the United States, for example, goes to the East Coast. Increased imports of refined petroleum products could cause many East Coast refineries to close. That would make the Northeast, in particular, vulnerable to supply interruption.

The projections, as pointed out, depend significantly on estimates of international economic activity and reflect current trends in the petroleum industry. It now seems reasonable to believe that replacement fuels, such as propane and ethanol, will have little impact on the gasoline markets of the 1990s. Nevertheless, ethanol usage has grown enormously since 1978 (Anderson, 1985). Also, the economic viability of alternate fuels depends critically on the cost of gasoline.

Factors governing commerce in the 1990s will have to be constantly reviewed by the Department of Energy (DOE) to determine whether or not the strategic petroleum reserve contains adequate quantities of crude oil, finished oil products, and alternate fuels to protect U.S. interests. If there is a need perceived for a products strategic reserve, special investigations will have to be undertaken. Specifically, the need to avoid deterioration of products by recycling or to impede the formation of heavier, jelly-like hydrocarbons by agitation, cooling, or the addition of special additives will have to be considered.

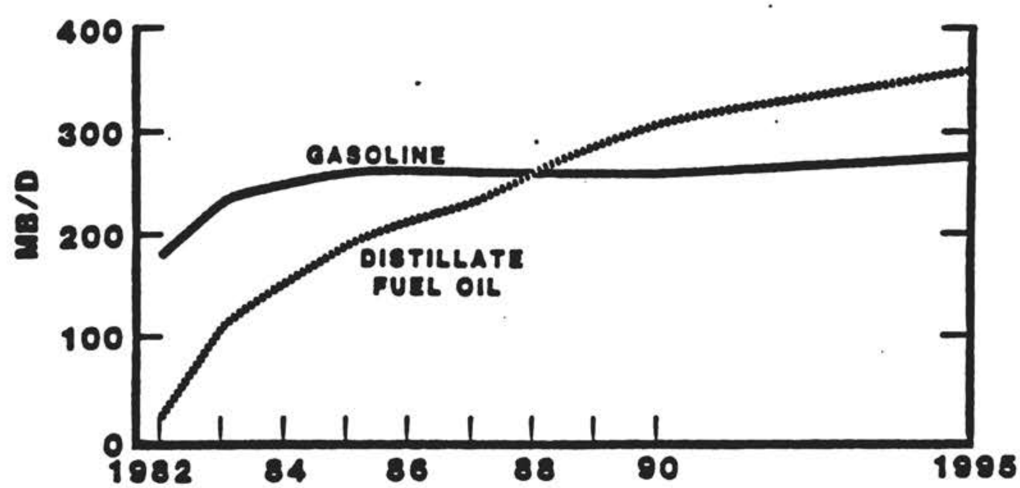
* * * * *

<u>MAJOR FINDING</u>: The growing trend towards imported petroleum products is expected to continue into the 1990s. The Northeast is the largest consumer of these imports in the United States.

<u>MAJOR CONCLUSION</u>: A rising trend in product imports will result in greater U.S. dependency on foreign energy sources and more vulnerability to supply interruption, especially in the Northeast.

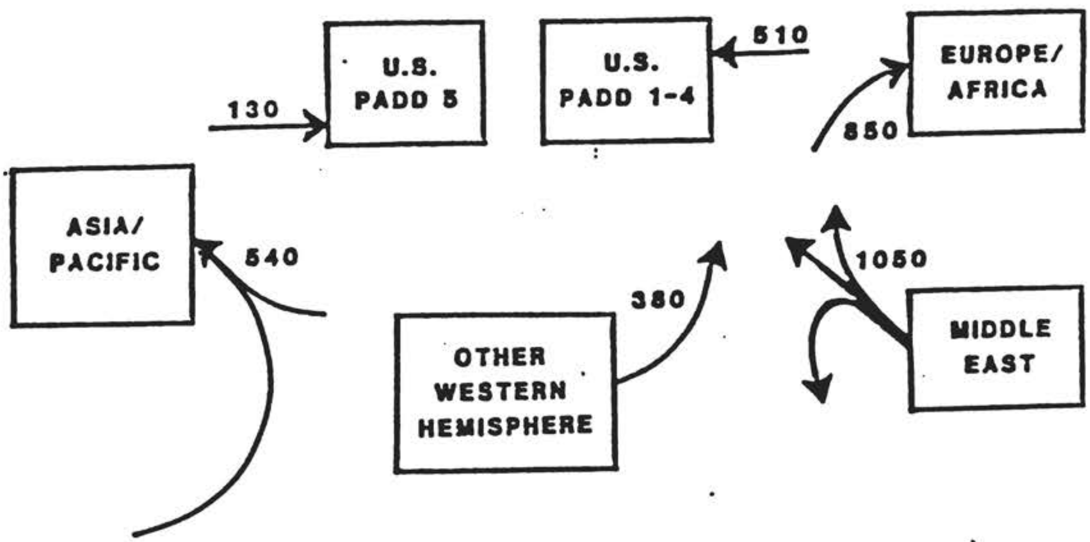
<u>MAJOR RECOMMENDATION</u>: DOE should consider locating a petroleum product reserve in the Northeast.

FIGURE 16 Forecast for Net Imports of Refined Products Into the United States



Source: Dosher (1985).

FIGURE 17 The Worldwide Trade Pattern Expressed in MB/D for Light Refined Petroleum Products in 1995



NOTE: The imbalance in exports and imports arises because the exports of the Eastern European bloc are not shown. This group is projected to contribute 600 MB/D in 1995. John Dosher, "Outlook for Product Imports," paper presented to NRC committee on the SPR, April 2, 1985.

SOURCE: Dosher (1985).

TABLE 10 Projections for Demand and Importation of Light Refined Products[a] for 1985, 1990, and 1995

Product	1985 Demand	1985 Imports	1985 %	1990 Demand	1990 Imports	1990 %	1995 Demand	1995 Imports	1995 %
Gasoline	6500	250	4	6500	250	4	6500	275	4
Distillate	2750	185	7	2800	300	11	3500	350	10

[a]Thousands of barrels per day (MB/D).

Source: Dosher (1985).

7

STEPS TO BE CONSIDERED NOW IN ANTICIPATION OF CHANGED CIRCUMSTANCES OF THE 1990s

Can the Strategic Petroleum Reserve (SPR) be used to help protect the U.S. national security and economy in the event of a disruption in petroleum supplies in the 1980s? Yes, according to the National Petroleum Council (NPC). As Robert Mosbacher, NPC chairman, stated in a letter to then Secretary of Energy Donald Hodel (NPC, 1984): "... the SPR is a valuable national asset that is capable of significantly mitigating the impact of a severe oil supply disruption."

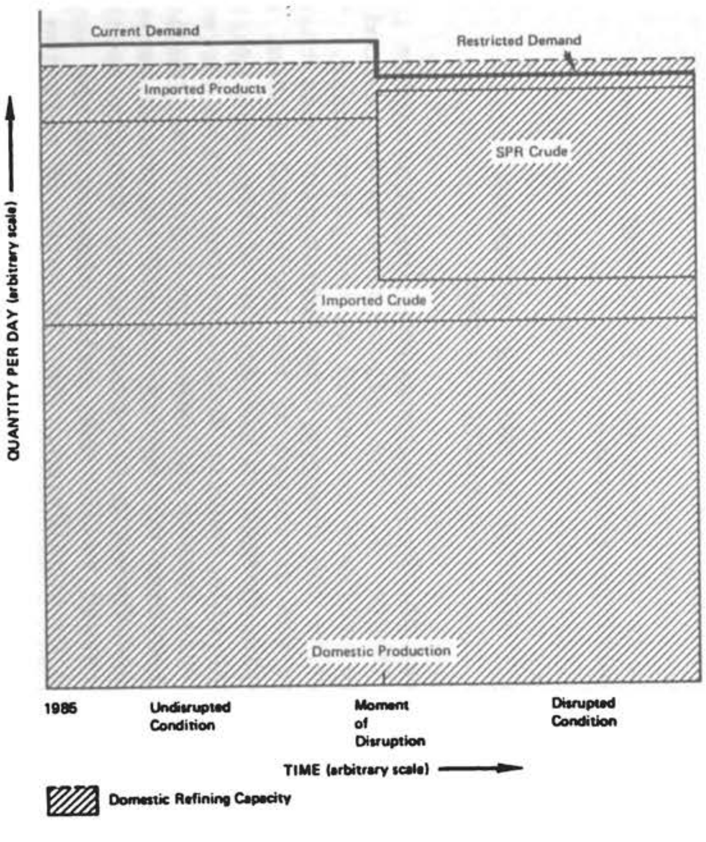
What, however, about the 1990s? Will the SPR be capable in the next decade of mitigating the kind of disruptions experienced in the 1970s? Given the trends in energy supply, demand, production, and transportation discussed at the committee's workshop and analyzed in Chapters 3 through 6, the answer is probably not.

Figure 18 shows how crude oil stored in the reserve can make up for a disruption in oil supply in the 1980s. The figure assumes a flat continuation of trends affecting the reserve into the 1990s. In it, there is no shortfall of supply or of refining capacity in a period of disrupted imported oil supplies.

Figure 19 shows that, because of lower domestic production, a larger SPR crude reserve could be needed in the 1990s. More importantly, because of rising demand and reduced domestic refining capacity a shortfall in refined products could occur, regardless of the size of the crude reserve. The extent of the shortfall would, of course, depend on the length and severity of the disruption.

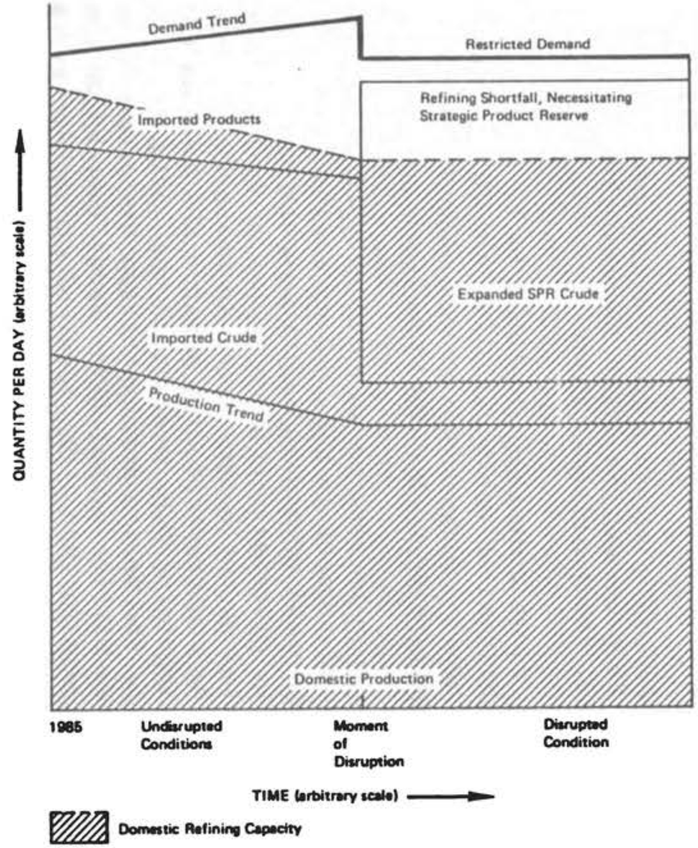
Whether the SPR can accomplish its goals will depend on a complicated set of technical, economic, and political factors. This study has focused on technical factors, specifically the ability of the transportation and refining systems to obtain and process oil from the reserve with sufficiency during a disruption. "Sufficiency," in the context of current planning, may be taken as the ability to move, refine, and use the maximum amount of oil that can be pumped out of the reserve, e.g., 3.5 million barrels per day (MMB/D) upon completion of the Phase II facilities and 4.5 MMB/D when, and if, Phase III facilities are completed.

FIGURE 18 Undisrupted and Disrupted Conditions Assuming Flat Trends from 1985 to Moment of Disruption (1985 Conditions)



NOTE: The relative magnitudes are for illustrative purposes only. They should not be construed as specific estimates or projections.

FIGURE 19 Undisrupted and Disrupted Conditions Assuming Existing Trends in Domestic Production, Imported Crude, Imported Products, and Domestic Refining Capacity (1990 Conditions)



NOTE: The relative magnitudes are for illustrative purposes only. They should not be construed as specific estimates or projections.

THE SPR STORAGE CAPACITY AND FILL LEVEL

"How much is enough?" is a question that has haunted SPR planners from the inception of the program. In 1944, Secretary of the Interior Harold Ickes (Ickes, 1944) declared that:

> "One of our very first undertakings should be to store in this country vast quantities of crude oil....We should buy and buy and buy and store and store and store until we are able to face the whole world, if necessary, with calm assurance."

Ickes's proposal can be seen as an early example of a powerful and traditional school of thought in U.S. policy making that sees American vulnerability to external events as an intolerable diminution of national power. The classical approach to the problem of assured oil supplies--represented on the policy level in the 1970s by Senator Henry Jackson--regards the construction of a massive SPR as a necessary, and modest, cost of maintaining U.S. stature in the world.

In recent months, the Reagan administration has proposed to halt the SPR program at a 490 million-barrel (MMB) level instead of the 750 MMB authorized by Congress in 1978. The level of protection envisioned by the 490-MMB reserve is the equivalent of 108 days of net imports of crude oil and petroleum products in 1985. Currently, this level should deter embargoes and provide some options for occasionally using the reserve in response to an extreme disorder in the international market.

This position leads to an obvious question: Will the level of U.S. oil import dependence in the 1990s be considerably higher than that of the mid-1980s? As noted previously, there are indications that U.S. production levels of crude will decline in the 1990s at a greater rate than was previously estimated.

As a consequence of these changes, a 500-MMB reserve will no longer provide 100 days worth of imports.

CHANGES IN THE U.S. PETROLEUM LOGISTIC SYSTEM

The possible changes in the U.S. petroleum logistic system have already been discussed in Chapter 4. The purpose here is to respond to these changes as they are unlikely to unfold in the years ahead. The discussion will divide the changes into "strategic" ones that substantially alter the structure of the logistical system, and hence may require wholesale changes in the design of the reserve, and "tactical" ones that only require modifications in the current system.

Two broad strategic issues influence the logistical requirements of the SPR program: the size of the reserve and the ratio between U.S. refinery capacity and domestic oil production. Broadly speaking, if the reserve is increased to 750 MMB, major changes in the logistical system will have to be considered. As the ratio of refining capacity to domestic oil production approaches unity, the United States imports more and more refined petroleum products relative to crude oil. At the same time, the need for major changes in the composition of the reserve as well as in its logistical system increases.

Strategic Issues

The first strategic issue concerns the effects of the size of the reserve on the transport system. The committee endorses the conclusions of the NPC study. That study, which was completed before the moratorium on further additions to the SPR was announced, did not distinguish the logistical requirements of a 500-MMB reserve from those of a 750-MMB one. With respect to the overland transport system, the NPC study assumed that the next 250 MMB of capacity would be constructed. It recommended a major change in DOE's current program by relocating 100 MMB of capacity from the Texoma to the Capline complex or changing pipeline connections so oil stored at the former could be sent to the latter (NPC, 1984). Obviously, if the reserve stays at 500 MMB, these changes need not be considered.

The other strategic issue for logistics is the effect of import disruptions on crude and refined product supplies, respectively. At the extreme, if the United States is importing only refined petroleum products and no crude oil in the 1990s, then the crude in the reserve will have little value for domestic refiners. Obviously, this extreme case does not really represent a logistics issue. Should such eventually occur, the reserve will have to be changed from storing crude oil to refined petroleum products (as will be discussed later).

More realistic, however, is a case in which increased imports of refined products render more and more marginal U.S. refineries uncompetitive, causing substantial changes in the concentration of refining capacity. Increased dependence on imported refined products may create circumstances in which refining capacity is still adequate to process SPR crude, but product refined from that crude will have to move in an unfamiliar pattern. In other words, the issue raised by incremental increases in refined product imports will not be getting crude to (mostly PADD III) refineries, but moving refined product from those refineries to regions that had previously relied on imports.

Tactical Issues

On the "tactical" level, the transportation network for the SPR needs to be tested repeatedly in a manner that simulates real conditions as closely as possible. With respect to marine transport, several changes have been suggested. One is that the facilities of the Louisiana Offshore Oil Port (LOOP) be integrated into the SPR system.

With respect to the marine fleet itself, emphasis was placed first on the availability of sufficient tankers to carry refined products and second on the operational complications created by a massive shift in the pattern of shipments. A major oil import disruption and resulting use of the reserve would obviously cause a major reorientation of shipping schedules. Test drawdowns on a sufficiently large scale to simulate a real disruption may be a useful device to increase DOE expertise and industry confidence.

DRAWDOWN EXERCISES

Any actual use of the reserve will have to contend with both strategic and tactical issues. On the strategic level, plans must deal with the questions of when and how to use the reserve, what price to charge, and how much to use in any particular situation. These decisions will affect the benefits to the petroleum industry and consumers. The policy choices set the framework for the tactical issues, including the specific logistical, legal, and financial decisions. In essence, while the planning process itself need not, and should not, be cumbersomely complicated, it deals with an enormously complex set of issues.

Exercises that test the ability of the Department of Energy (DOE) and the oil industry to actually use the SPR are not only useful, but essential elements in preparing a sound policy. Exercises, such as Direx B conducted by DOE in 1983, can be broadly or narrowly defined. They can test DOE's ability to analyze international circumstances and domestic reactions thereto, and to develop sound policy options. They can also test DOE's ability to construct an administrative process that expeditiously puts SPR oil onto the market, including designing sales provisions that do not create logistical bottlenecks.

The principal issue has been about the value of large- versus small-scale exercises. To date there has been no large-scale exercise actually selling and drawing down substantial quantities of reserve oil (say, 2 MMB/D for one week); however, a major SPR exercise has now been scheduled. Such exercises, conducted every two or three years, would do much to increase DOE's capabilities and the perception of its capabilities. Conducting such confidence-building exercises in the 1980s could materially improve the credibility of the SPR in the 1990s, as well as the data base underlying its actual operation.

CHANGES IN THE PROPORTION OF PRODUCT IMPORTS IN THE 1990s

Product Reserve Considerations

In principle, if the United States becomes more dependent on imported refined products, DOE will have to consider either augmenting the crude oil reserve with petroleum products or replacing part of the crude with stocks of refined products. It is difficult to move from this agreement in principle to deciding when this threshold will be crossed. As noted earlier, at the extreme, a situation in which the United States imports only finished products and domestic refining capacity is sufficient only to refine domestically produced crude, the entire reserve might have to be finished products.

The salience of this issue in the 1990s is particularly difficult to assess because of the ongoing debate about the need for increased tariffs, quotas, or other measures such as mandatory storage of refined petroleum products. It simply is not known whether such measures will be imposed and whether, if imposed, they will have the desired effect.

As more information on the level of U.S. dependence on imports of refined petroleum products becomes available, DOE should consider augmenting the SPR with product stocks. Such stocks would probably be best located somewhere on the Atlantic coast since that region has the greatest dependence on imported oil. Locating product stocks there would also reduce concerns about congestion at SPR sites along the Gulf of Mexico.

If DOE accepts this recommendation, the immediate need is to develop benchmarks at which such serious consideration of product stockpiling will begin. In this connection, DOE should recognize that refineries' "operable" capacity, as contrasted with actual "operating" capacity, may not be a useful guide to the quantity of petroleum that can be refined at short notice.

PROBLEMS OF PRODUCT STORAGE

The U.S. Army recently studied the problems of storing both crude oil and refined petroleum products (Giles, 1985). Its conclusions are worth quoting at some length:

> "A number of studies have demonstrated conclusively that both crude oil and refined products can be stored for prolonged periods without undergoing deleterious changes in quality. The most practical and economic mode of storage, especially for large volumes of petroleum, is in caverns in salt deposits. Other modes of storage, such as in surface tanks or caverns in granite, are also suitable, provided certain precautions are exercised. Oxygen and moisture must be excluded to the maximum extent practicable. The latter is likely the single most significant contributor to petroleum degradation because it will harbor microorganisms and fungi which metabolize hydrocarbons. Hypersaline water existing in solution-mined caverns effectively inhibits all microbial activity. Long-term storage stability can be enhanced by selecting products which are inherently stable and are additive treated. The storage stability of the product should be thoroughly evaluated so that turnover of the stocks can be scheduled to preclude an unacceptable degree of quality deterioration. Finally, a monitoring program should be instituted to periodically assess the quality of the petroleum in storage."

DOE's Office of Strategic Petroleum Reserve has entertained plans for storing refined petroleum products in the past, but has taken no action to date because of considerations of cost and necessity. At the present time, DOE still has no plans for stockpiling refined petroleum products.

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APPENDIX A

THE SPR SYSTEM, PLANS, REFINERIES, AND DISTRIBUTION SYSTEM

This appendix details the system, plans, refineries, and distribution system for the Strategic Petroleum Reserve (SPR). More detailed information can be obtained from the National Petroleum Council (NPC), whose report* forms the basis for this discussion.

SPR SYSTEM

Most crude oil imports enter the United States through ports and terminals along the Gulf of Mexico. Three major pipelines--Texoma, Seaway, and Capline--transport a portion of these imports into the central United States (the Texoma and Seaway pipelines terminate in Cushing, Oklahoma, while the Capline system terminates in Patoka, Illinois). The Texoma and Seaway pipelines have been converted to natural gas service and are no longer available to the SPR. Further, the distribution to refineries in the Midwest is accomplished by a network of additional pipelines.

The existence of these ports, terminals, and pipelines resulted in the original decision to locate the SPR storage facilities in the Gulf coast areas of Louisiana and Texas. Cost-benefit analyses indicated that storage in salt domes, either in solution-mined (leached) caverns or mechanically excavated mines, was the most cost-effective approach.

The storage of crude oil in a solution-mined salt cavern and the subsequent recovery of that oil relies on the fact that crude oil is less dense than water and therefore floats on top. To recover the crude oil, raw water is injected into tubing that is suspended in the center of the well casing and near the bottom of the cavern in a brine layer. The crude oil is lifted hydraulically through the annulus; i.e., the space between the suspended tubing and the outer well casing. The source of raw water for displacement of the crude oil is a nearby lake, river, or other waterway. The raw water intake structure

*National Petroleum Council, December 1984. The Strategic Petroleum Reserve: A Report on the Capacity to Distribute SPR Oil.

is connected by pipeline to injection pumps that force water into, and the oil out of, the cavern. The crude oil flows into a pipeline that is connected to a larger commercial distribution pipeline and/or a pipeline running to a marine terminal, where it is pumped into a tanker or barge for a shipment to as refinery.

The procedure is reversed for filling a cavern. Crude oil is unloaded from tankers across the dock and pumped to the site where it is injected into the cavern displacing brine, which is either injected into deep subsurface wells or dispersed into the Gulf of Mexico waters. An example of a typical oil storage cavern is shown in Figure A-1.

Storage of crude oil in solution-mined caverns has been used for years in Europe and the Louisiana Offshore Oil Port (LOOP) moves crude oil into and out of salt dome storage on a daily basis.

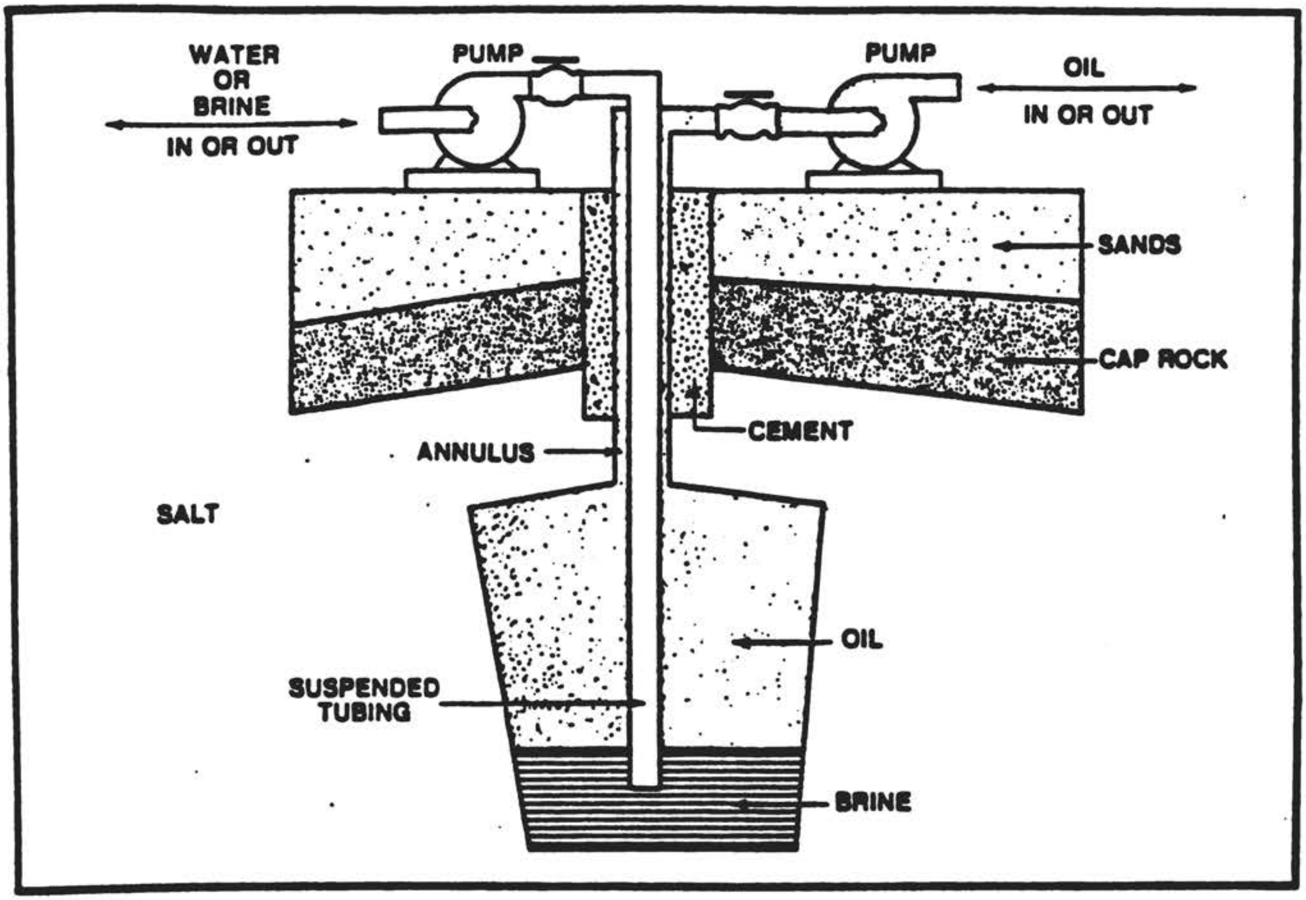
An assessment of existing salt domes in the Gulf Coast area, the availability of existing storage capacity in those domes, and their proximity to the three main crude oil pipeline terminals and port complexes resulted in the selection of five sites to meet the initial storage objective of 250 million barrels. The locations of the SPR storage sites and their interconnecting pipelines to the tanker/barge terminals and major pipeline systems are shown in Figures A-2, A-3, and A-4. Four of the selected sites--West Hackberry, Bryan Mound, Bayou Choctaw, and Sulphur Mines--contain solution-mined caverns. The fifth site, Weeks Island, contains a mechanically excavated salt mine. A sixth site at Big Hill, Texas, is currently under development and current plans call for storage capability of about 140 million barrels.

SPR Sites

The SPR sites are grouped into the three distribution complexes that were originally intended to deliver the crude oil to refiners through either respective pipeline systems. Because of refinery closings and therefore reduced crude oil demand, two of these pipelines--Seaway and Texoma--have been converted to natural gas and are no longer available to the SPR. The Seaway complex, which includes the Bryan Mound site, will deliver crude oil to the Seaway marine terminal. The Texoma complex will deliver crude oil to the Sun Oil terminal at Nederland, Texas, for tanker or barge liftings and also to local pipelines serving Gulf Coast refineries. The Capline complex, consisting of the Bayou Choctaw and Weeks Island sites, will deliver crude oil to the Department of Energy (DOE) marine terminal at St. James, Louisiana, and to the Capline pipeline system.

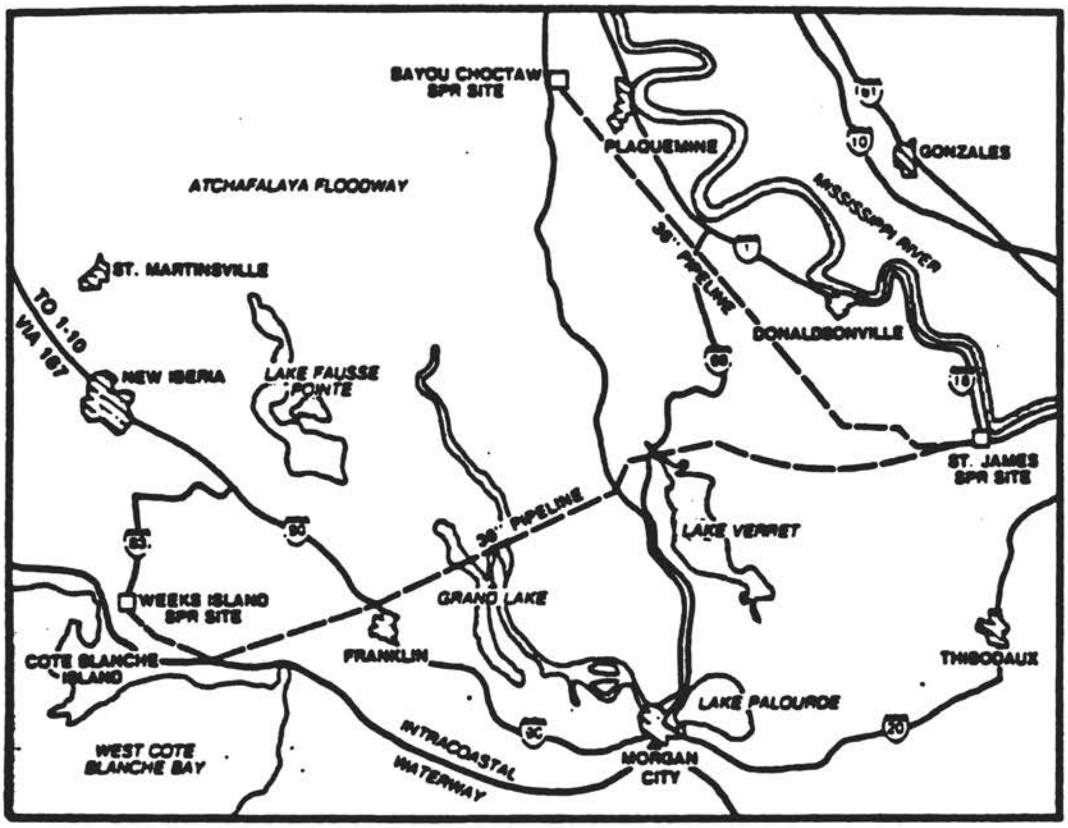
All the sites except Weeks Island are designed to move the oil from the caverns to the surface by pumping in raw water to displace the crude oil and force it to the surface. The Weeks Island site operates differently. Because Weeks Island was originally a salt mine and has a very irregular shape, submersible booster pumps were installed to move the oil to the surface.

FIGURE A-1 Configuration of Typical Oil Storage Cavern



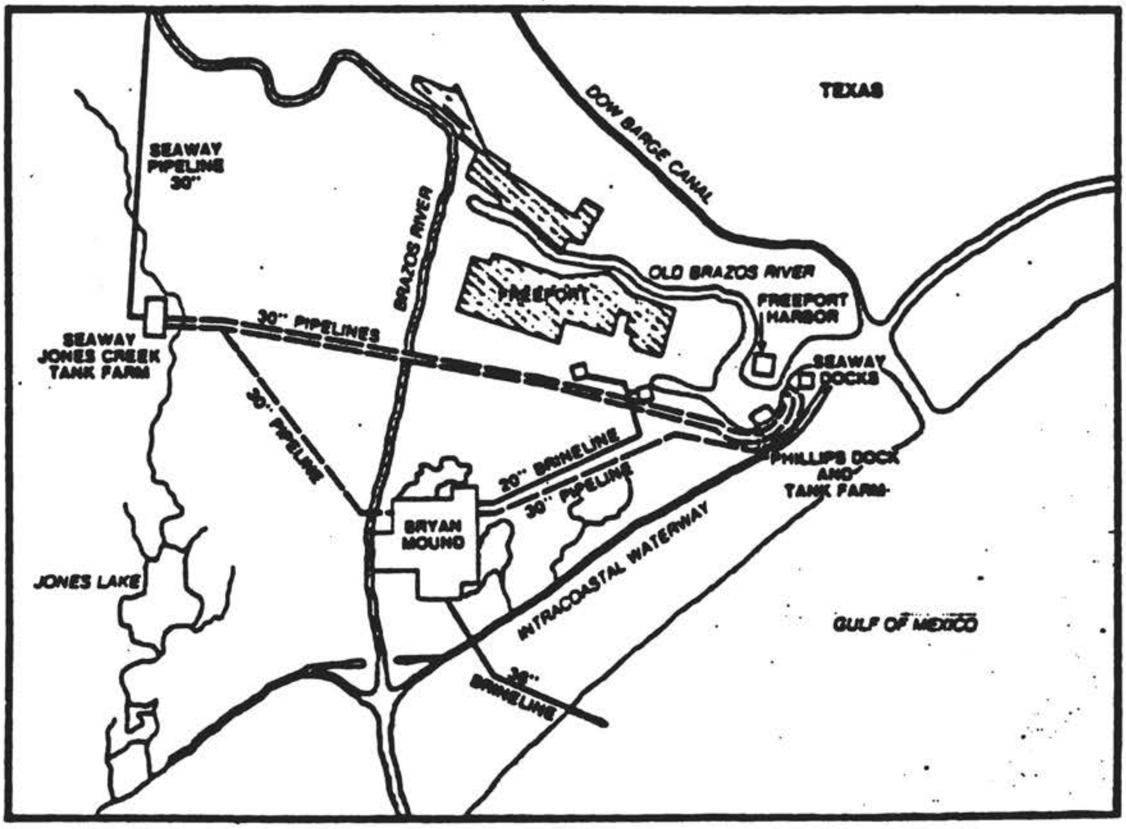
SOURCE: NPC (1984).

FIGURE A-2 Capline Complex



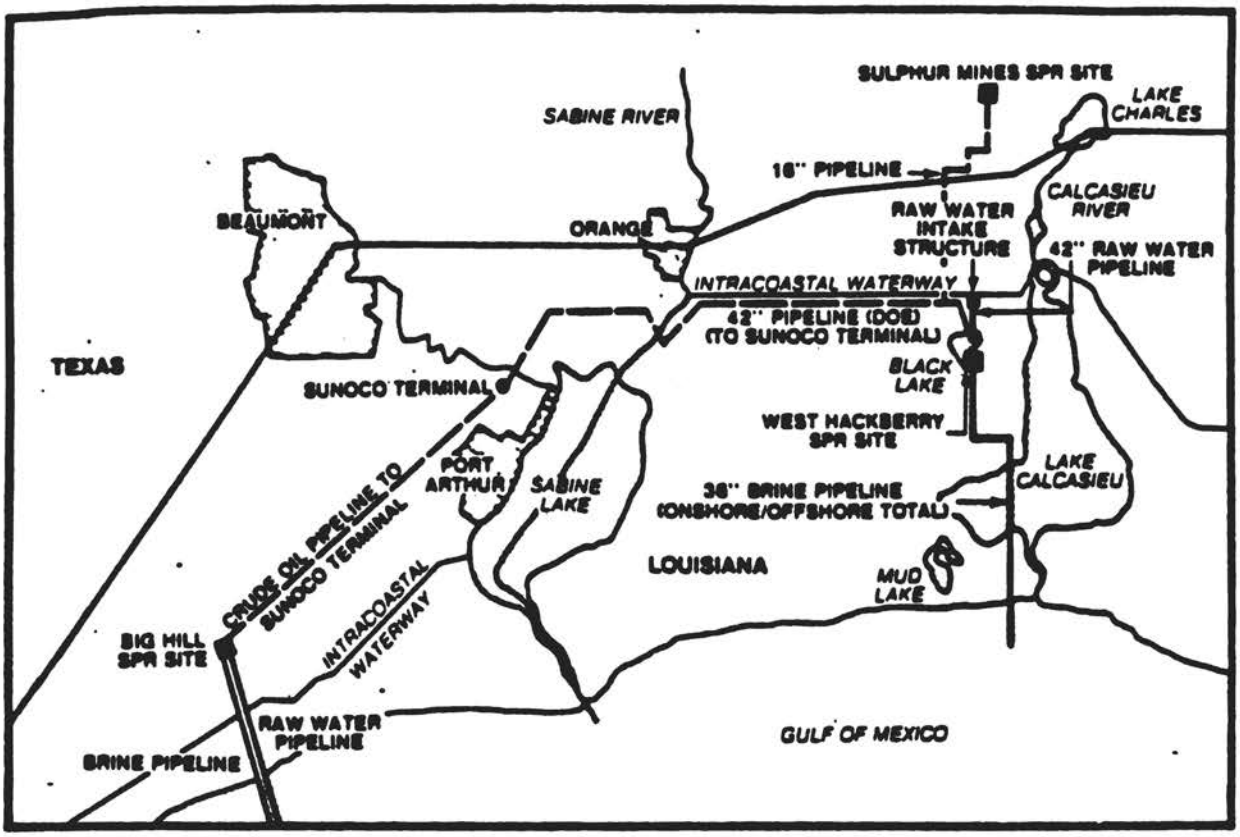
SOURCE: NPC (1984).

FIGURE A-3 Seaway Complex



SOURCE: NPC (1984).

FIGURE A-4 Texoma Complex



SOURCE: NPC (1984).

Capline Complex

St. James Terminal. The St. James terminal is a DOE facility located on the west bank of the Mississippi River, 30 miles southeast of Baton Rouge, Louisiana. The terminal consists of some 173 acres with 6 storage tanks totalling 2 million barrels of capacity and connected by 36-inch-diameter pipelines to the Bayou Choctaw and Weeks Island sites 39 and 67 miles away, respectively. The terminal tankage is also connected by 42-inch-diameter pipeline to the LOCAP/Capline and Koch Oil terminals as well as to two DOE docks capable of accommodating vessels up to 125,000 deadweight tons (DWT). The St. James terminal docks have a sustained throughput of 350,000 barrels per day.

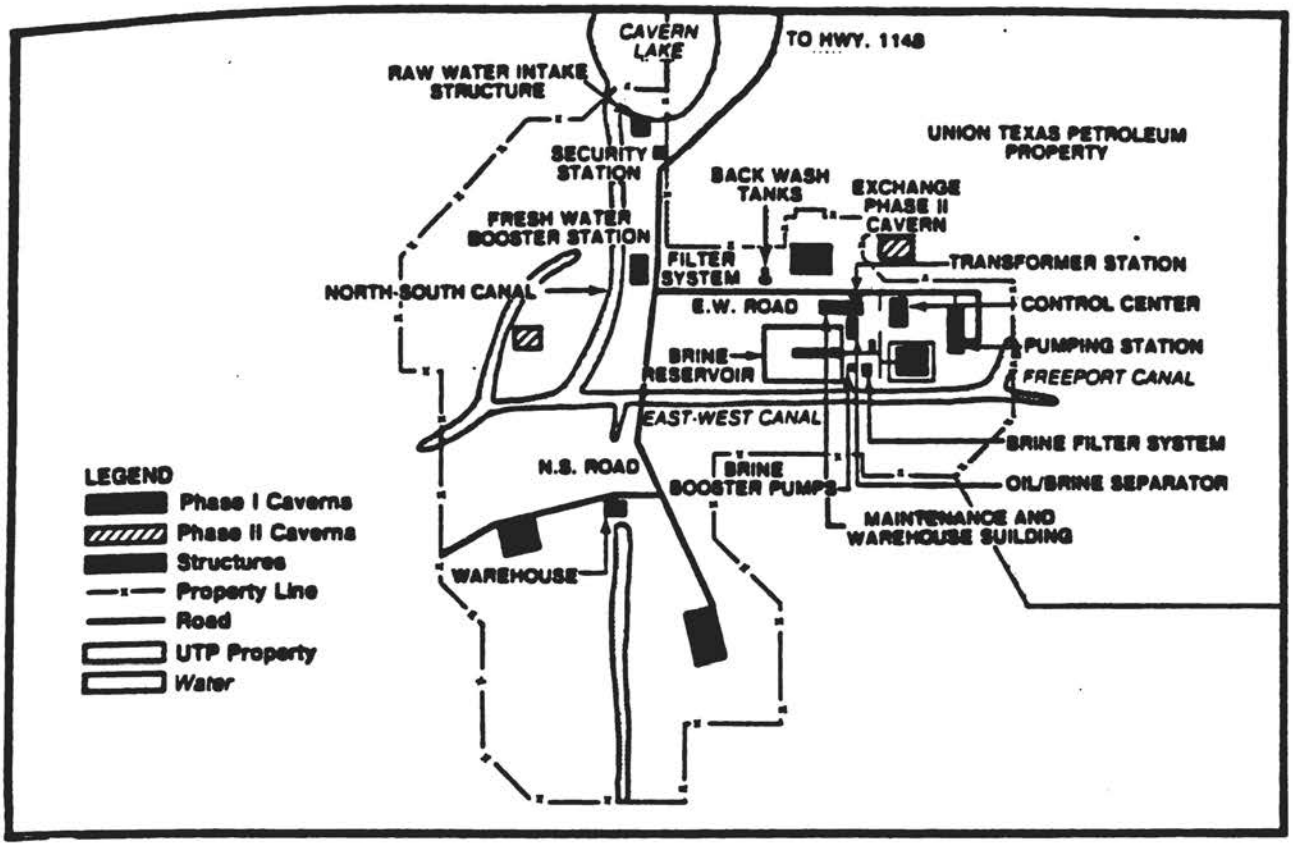
Bayou Choctaw. The Bayou Choctaw site is located about 12 miles southwest of Baton Rouge, Louisiana. DOE acquired it in April 1977. It consists of approximately 356 acres. Upon completion of Phase III, the site will have storage capacity of 65 million barrels of oil. As of September 30, 1984, it had 46.6 million barrels, consisting of 18.3 million barrels of low-sulfur and 28.3 million barrels of high-sulfur crude oil. The site is designed to deliver 480 MB/D to the DOE St. James terminal through a 37-mile, 36-inch-diameter pipeline. A diagram of the site is shown in Figure A-5.

Weeks Island. The Weeks Island site is located about 95 miles southwest of New Orleans, Louisiana. DOE acquired it in September 1977. It consists of approximately 6.5 surface acres and 383 subsurface acres. Development and fill of the former salt mine is completed and it contains approximately 73 million barrels of high-sulfur crude oil. The system is designed to deliver 590 MB/D through a 67-mile, 36-inch-diameter pipeline to the DOE St. James terminal. A diagram of the site is shown in Figure A-6.

Seaway Complex

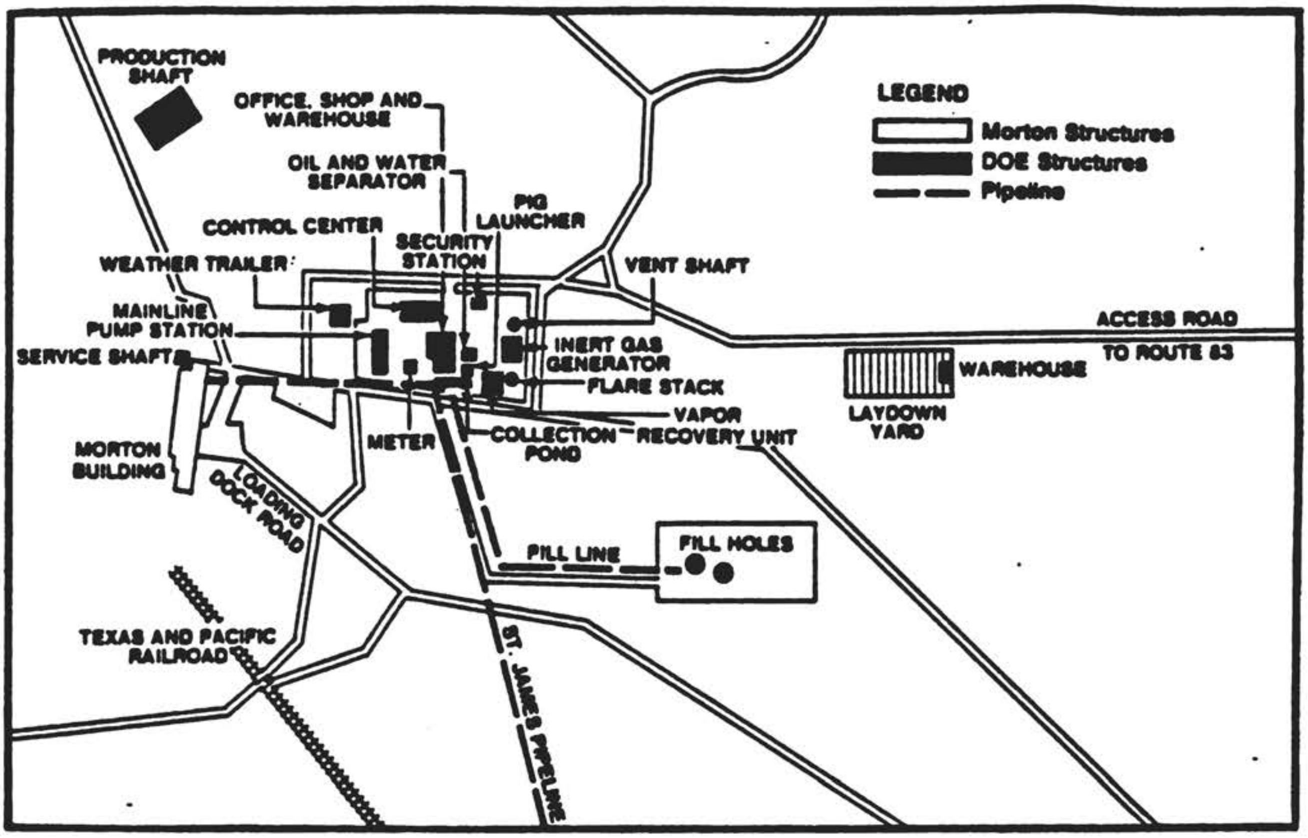
Bryan Mound. The Bryan Mound site, located near Freeport, Texas, was acquired by DOE in April 1977. It consists of 499 acres. Upon completion of Phase III, the site will store approximately 225 million barrels of crude oil. As of September 30, 1984, it had 169.7 million barrels, consisting of 64.4 million barrels of low-sulfur and 105.3 million barrels of high-sulfur crude oil. The system was designed for a drawdown rate of 1,054 MB/D through a 3.6 mile, 30-inch-diameter to the Seaway docks or through a 4.6-mile, 30-inch-diameter pipeline to the Jones Creek Tank Farm and thence to a local pipeline. This facility has four 200,000-barrel crude oil tanks. A diagram of the site is shown in Figure A-7.

FIGURE A-5 Bayou Choctaw Site



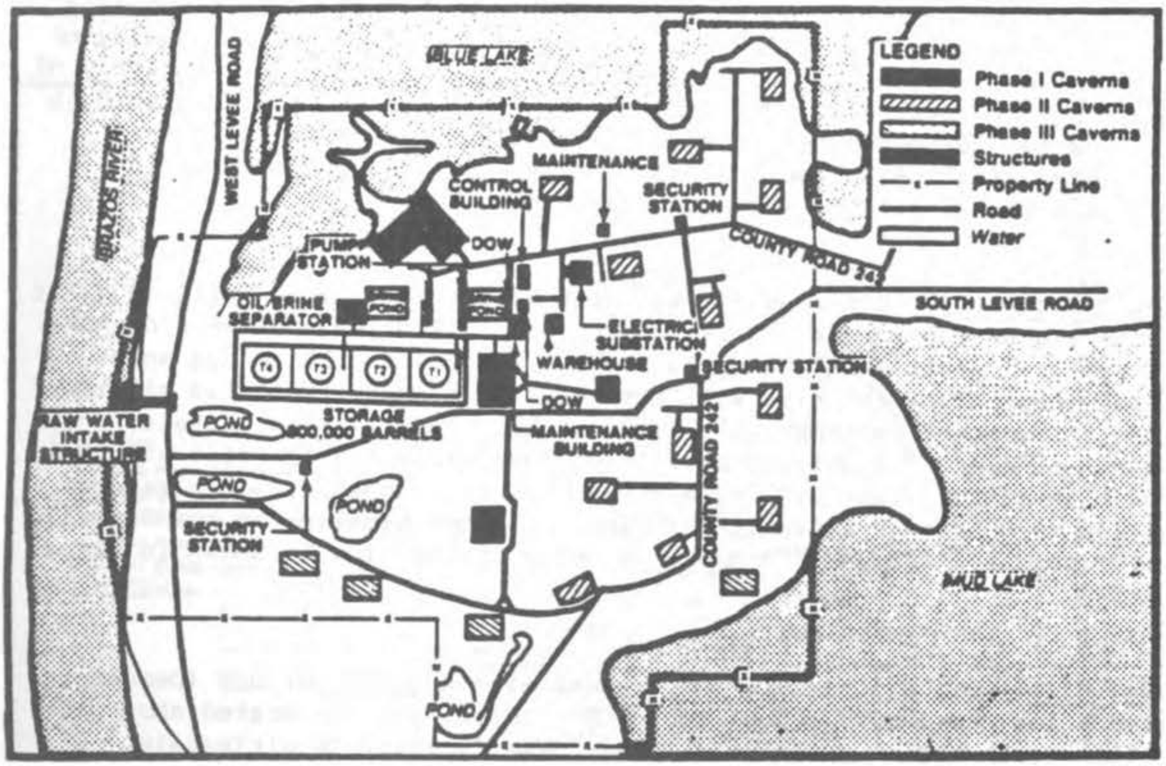
SOURCE: NPC (1984).

FIGURE A-6 Weeks Island Site



SOURCE: NPC (1984).

FIGURE A-7 Bryan Mound Site



SOURCE: NPC (1984).

Texoma Complex

Sulphur Mines. The Sulphur Mines site, acquired by DOE in February 1979, is located three miles west of Sulphur, Louisiana, It consists of approximately 174 acres. The site, which has a storage capacity of 26 million barrels, has been completely filled and consists entirely of high-sulfur crude oil. The designed drawdown rate is 100 MB/D through a 16-mile, 16-inch-diameter spur pipeline to a 34-mile, 42-inch-diameter pipeline to the Sun Oil terminal at Nederland, Texas. A diagram of the site is shown in Figure A-8.

West Hackberry. DOE acquired the West Hackberry site in April 1977. It consists of 405 acres. It is located about 12 miles southwest of Lake Charles, Louisiana. Total area through Phase III will be 565 acres. Upon completion, the site will have a storage capacity of 219 million barrels. As of September 30, 1984, it had 115.4 million barrels, consisting of 78.4 million barrels of low-sulfur and 37 million barrels of high-sulfur crude oil. The system has a designed drawdown rate of 1,400 MB/D through a 42-mile, 42-inch-diameter pipeline to the Sun Oil terminal at Nederland, Texas. A diagram of the site is shown in Figure A-9.

Big Hill. Big Hill is the most recent site acquired by DOE (December 1982) for the SPR. It consists of 271 acres. It is located about 15 miles southwest of Nederland, Texas. The facility is ultimately intended to store 140 million barrels of crude oil in 14 newly leached caverns. Drilling of the first well at Big Hill began in May 1983. Seven of the first ten wells were completed by December 31, 1983. The site is designed for a drawdown rate of 935 MB/D to be delivered to the Sun Oil terminal at Nederland, Texas, through a 36-inch-diameter pipeline.

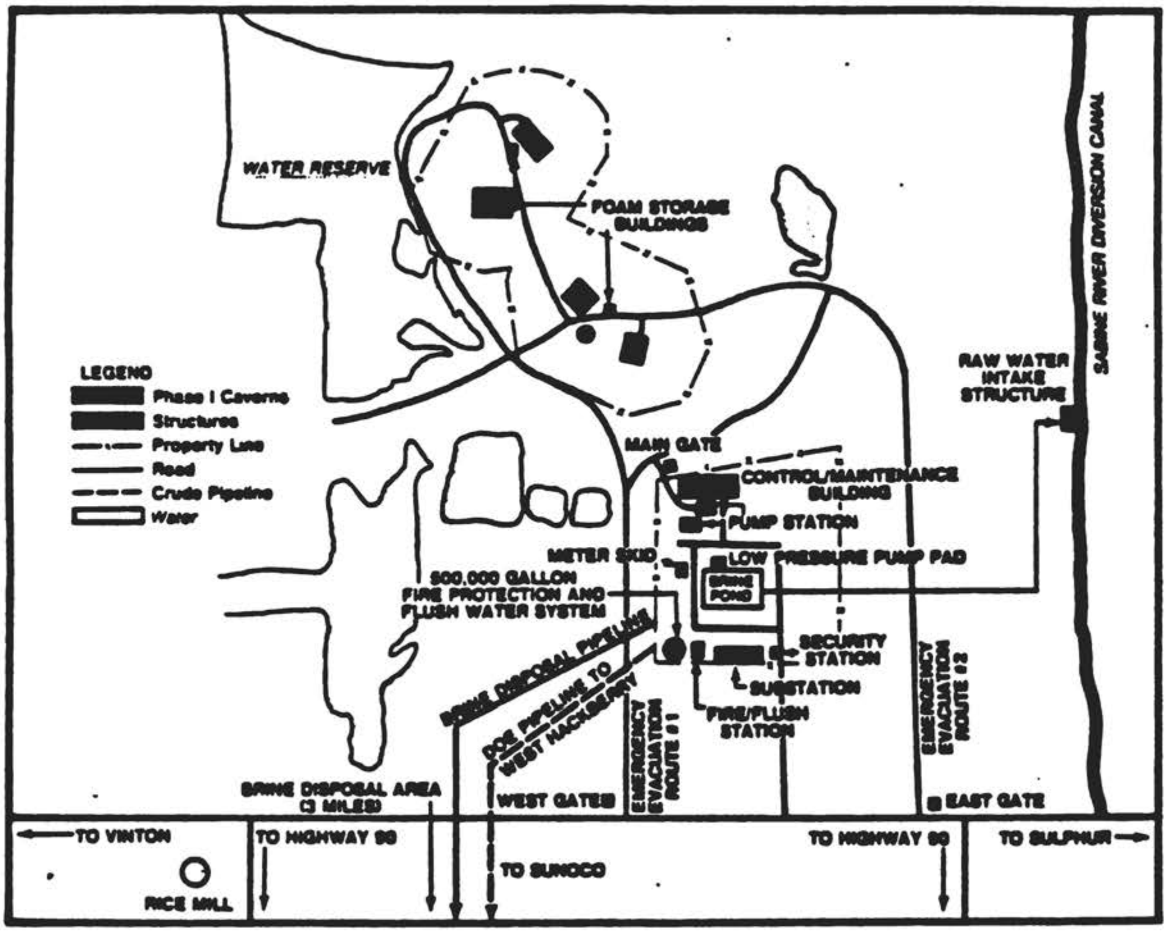
SPR PLANS

The main plan (at this time) is still to complete the 750 MMB fill in accordance with the Energy Policy and Conservation Act of 1975 even though a moratorium has been proposed by the Reagan Administration at 489 MMB.

The 750-million barrel storage capacity of the SPR is being developed in three phases. Phase I consists of the acquisition and construction of five sites with storage capacity of approximately 260 million barrels, plus a marine terminal facility at St. James, Louisiana. The Phase I sites--Bryan Mound in Texas and Bayou Choctaw, West Hackberry, Sulphur Mines, and Weeks Island in Louisiana--were mostly filled in 1980. The only exception was Sulphur Mines, which was filled in 1983.

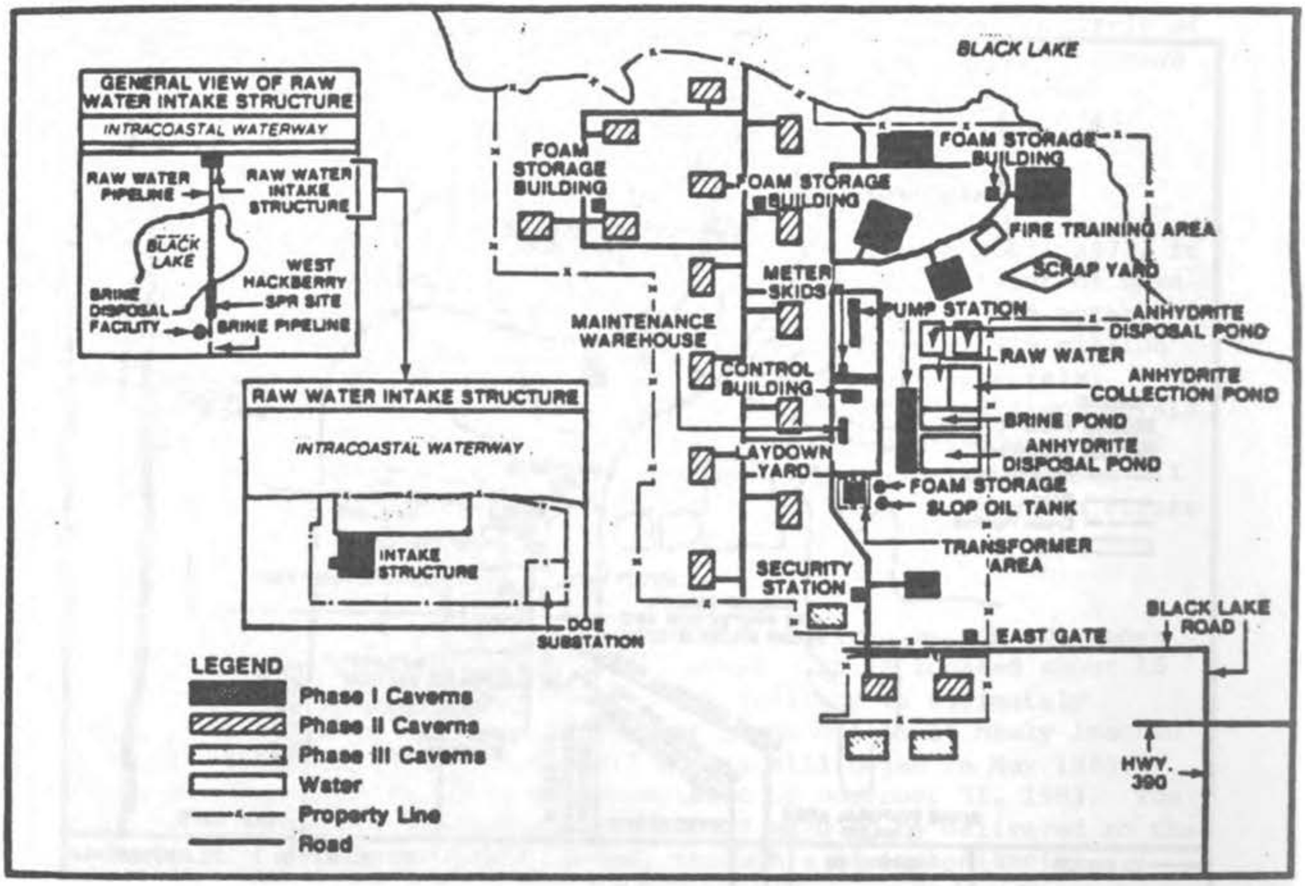
Phase II consists of expanding the three Phase I sites to increase the SPR storage capacity by an additional 290 million barrels. The Bryan Mound site by 120 million barrels and the West Hackberry site

FIGURE A-8 Sulphur Mines Site



SOURCE: NPC (1984).

FIGURE A-9 West Hackberry Site



SOURCE: NPC (1984).

expanded by 160 million barrels, both by leaching (solution mining) new caverns. A further 10-million barrel capacity will be added by Phase II through acquisition of an additional existing storage cavern at Bayou Choctaw. The Phase II storage program is projected to be completed in 1987.

Plans for Phase III, consisting of approximately 200 million barrels of additional storage capacity, currently call for the further expansion of existing sites (40 million barrels at Bryan Mound, 10 million barrels at West Hackberry, and 10 million barrels at Bayou Choctaw) and the development of a new 140 million barrel site located at Big Hill, Texas. The Phase III storage program is currently projected for completion in 1990. The completed and the projected fill of the SPR sites, by phase and by type of crude oil, are shown in Table A-1.

The NPC considered and recommended various ways to improve each of the sites for SPR purposes.

- Bryan Mound (Seaway Distribution Complex)
  - -- Build a 42-inch (1.0 MMB/D) pipeline connection from the Bryan Mound site to a commercial terminal in the Texas City area, less than 50 miles away. This would permit direct shipment of SPR crude oil to Houston area refineries by pipeline as well as loading tankers (at least 400 MB/D) in the Gulf of Mexico. This pipeline would expand future Bryan Mound distribution capabilities mpre than 1 million barrels per day, in line with the drawdown capabilities expected at that site when it is complete in 1986.
  - -- Construct a direct pipeline interconnection between DOE's pipeline to the Seaway Docks and Phillip's Terminal pipeline.
- West Hackberry (Texoma Distribution Complex)
  - -- Construct a 26-inch 700 MB/D tie-in to the Lake Charles, Louisiana area, including access to both CITGO and CONOCO marine terminals. This would provide both overland access to refineries in this vicinity and also the ability to load tankers.
  - -- Upgrade existing Sun Terminal piping manifolds to increase the distribution capability of the Sun Terminal.
- Big Hill (Texoma Distribution Complex)
  - -- Construct a 30-inch pipeline spur from the Big Hill-to-Sun Terminal pipeline to the Texas Oil and Chemical Marine Terminal in the Beaumont, Texas, area.

The following decisions were made and plans budgeted for fiscal year 1987*:

- Direct pipeline connection to LOCAP the terminal and pipeline that connects LOOP to the Capline Terminal and several refineries.
- A separate direct pipeline to Capline Terminal.
- Other possible Capline enhancements: DOE has published an internal report setting forth other alternatives for increasing the distribution in the Capline complex.

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*Engineering Study on Enhancements for the Capline Group of the Strategic Petroleum Reserve, July 1985.

TABLE A-1 DOE Current and Projected SPR Fill[a] (Millions of Barrels)

Facility	Phase I		Phase II		Phase III		Total	
	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur
Seaway Complex								
Bryan Mound	66.0	-	-	120	-	40	66.0	160
Capline Complex								
Bayou Choctaw	18.3	27.7	-	10	10	-	28.3	37.7
Weeks Island	-	73.0	-	-	-	-	-	73.0
Texoma Complex								
Sulphur Mines	-	26.0	-	-	-	-	-	26
West Hackberry	13.0	36.0	90	70	-	10	103	116.0
Big Hill	-	-	-	-	70	70	70	70
Total	**97.3**	**162.7**	**90**	**200**	**80**	**120**	**267.3**	**482.7**

[a]Low-sulfur crude oil has a sulfur content less than or equal to 0.50 weight percent. High-sulfur crude oil has a sulfur content greater than 0.50 weight percent.

Source: NPC, 1984.

REFINERIES

The NPC divided the 263 refineries it studied in the United States into 13 refining centers according to common geographic location and accessibility to shipments of crude oil from the SPR. The refining centers are listed in Table A-2 and a map of their locations is shown in Figure A-10. A complete listing of the refineries in each refining center may be found in Appendix E of the NPC report (NPC, 1984).

Refinery Inputs and Outputs-1983

The 1983 inputs and outputs for each refining center were developed from information routinely submitted by each refinery to DOE's Energy Information Administration (EIA). This information includes actual 1983 refinery inputs and product outputs, projected capacities of refinery processing units for January 1, 1984, and January 1, 1985, and projected refinery inputs and product outputs for 1984 and 1985.

EIA aggregated the refinery specific information into the 13 refining centers for the NPC. (Data provided by the EIA may be found in Appendix E.) The data for each refining center covered all details needed for the NPC study except the quality of crude oil input. The EIA data contain only weighted average sulfur content, weighted average API gravity, and receipts of Alaskan crude oil. Additional information on the quality of imported crude oil was obtained by EIA from the Bureau of the Census and was combined by refining center. (See Appendix E of the National Petroleum Council report).

Based on these sources, the estimated distribution and composition of domestic crude oil production in 1983 are shown in Table A-3. The input and output balances for each refining center in 1983 are shown in Table A-4.

DISTRIBUTION SYSTEM

Existing Distribution System--Overland

In the NPC report, a supply/demand balance case was developed for each PADD and the U.S. Virgin Islands and Puerto Rico using actual 1983 data from the DOE's Energy Information Administration in the "Petroleum Supply Annual, 1983." A summary of these supply/demand balances along with inter-PADD crude oil and product receipts and shipments is contained in Table A-5. Corresponding crude oil movements are shown in Figure A-11. These balances treat liquified petroleum gas (LPG) as a product and that LPG movements are included in the receipt and shipment data.

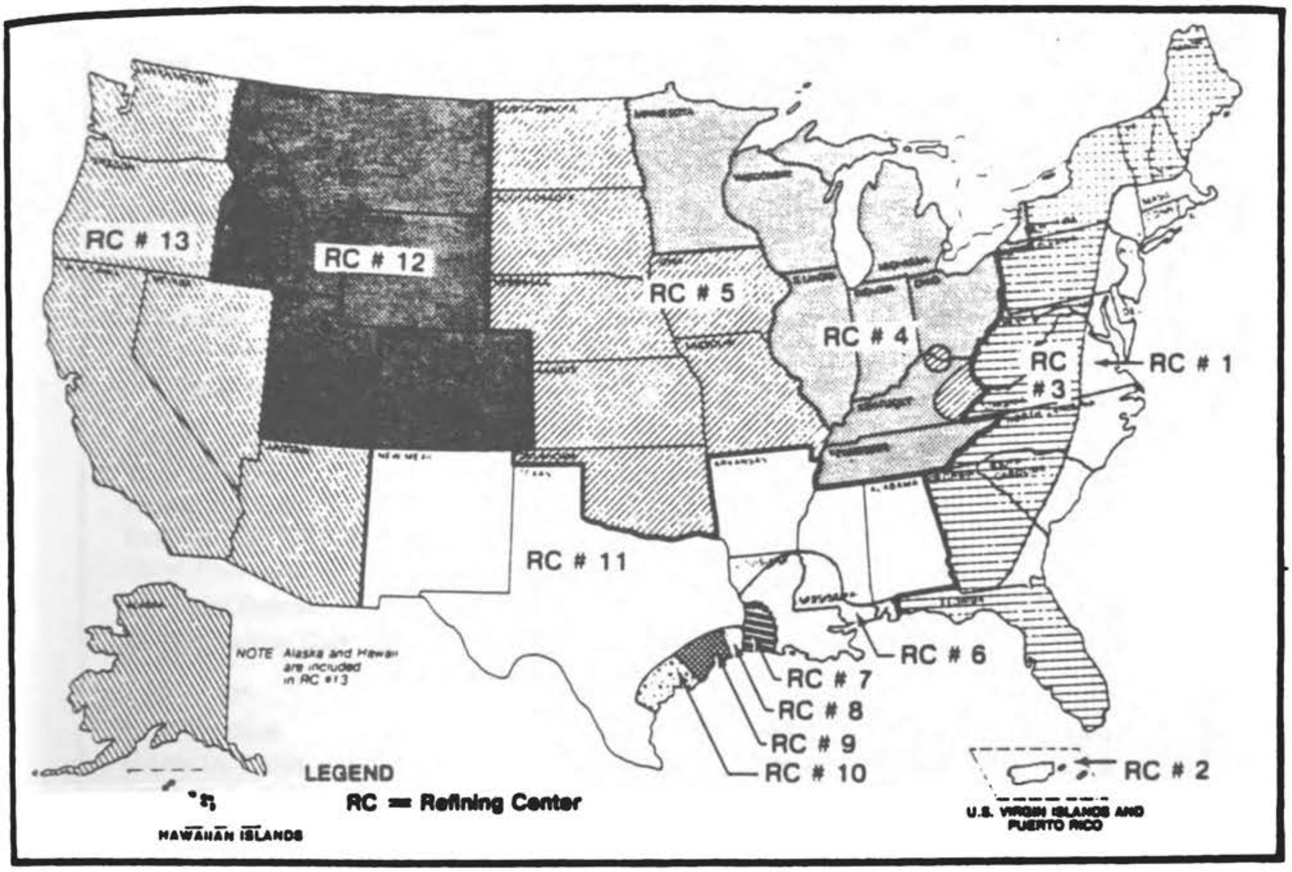
TABLE A-2 Summary of U.S. Refining Centers

	Refining Center	SPR Access*	Source of Incremental Crude Oil	Number of Refineries
RC#1	PADD I	Connected	Waterborne	15
RC#2	Virgin Islands and Puerto Rico	Connected	Waterborne	5
RC#3	PADD I	Not Connected	Lower 48 Domestic	10
RC#4	PADD II Capline Pipeline Access	Connected	Waterborne	28
RC#5	PADD II	Not Connected	Lower 48 Domestic	30
RC#6	PADD III Lower Mississippi River Area	Connected	Waterborne	20
RC#7	PADD III Lake Charles Area	Connected	Waterborne	6
RC#8	PADD III Beaumont, Port Arthur Area	Connected	Waterborne	8
RC#9	PADD III Houston, Texas City Area	Connected	Waterborne	12
RC#10	PADD III Corpus Christi Area	Connected	Waterborne	7
RC#11	PADD III	Not Connected	Lower 48 Domestic	42
RC#12	PADD IV	Not Connected	Lower 48 Domestic	24
RC#13	PADD V	Connected	Waterborne	56

*Refineries that receive part or all of their crude oil by waterborne transport have assured access to the SPR and, hence, are considered connected.

Source: NPC (1984).

FIGURE A-10 U.S. Refining Centers



U.S. Refining Centers.

Source: NPC (1984).

TABLE A-3 Domestic Crude Oil and Lease Condensate Quality--1983[a]

	Production (MB/D)	Volume Percent Low Sulfur	Volume Percent High Sulfur
PADD I	80	57	43
PADD II	1,040	95	5
PADD III	4,180	72	28
PADD IV	570	44	56
PADD V	2,820	0	100

[a]Numbers have been rounded.

Source: NPC (1984).

TABLE A-4 Refinery Input/Output by Refining Center--1983 Base Case (MB/D)

	Virgin Islands/ Puerto Rico	PADD I		
	Water Connected	Water Connected	Not Connected	Subtotal
Input				
Total Crude Oil & Lease Condensate	422	944	47	991
Domestic: Low Sulfur	-	-	44	44
High Sulfur	-	8	3	11
Alaskan & California OCS	130	140	-	140
Foreign: Low Sulfur	104	470	-	470
High Sulfur	195	348	-	348
Unidentified	(7)	(22)	-	(22)
Unfinished Oils	(27)	119	0	119
NGLs & Gasoline Blending Comp.	6	18	3	21
Total Input	401	1,081	50	1,131
Output				
Total Gasoline	106	542	12	554
Middle Distillates	111	281	16	297
Residual Fuel Oil & Asphalt	142	157	3	160
Other Products	47	152	16	168
Total Output	406	1,132	47	1,179
Net Processing Gain	(5)	(51)	3	(48)
Yields (%)*				
Total Gasoline	25.3	49.3	19.1	48.0
Middle Distillates	26.1	26.4	34.0	26.8
Residual Fuel Oil & Asphalt	35.9	14.8	6.4	14.4
Other Products	11.9	14.3	34.0	15.1
Total Yields†	101.3	104.8	93.8	104.3
Gross Crude Oil Distillation Input	439	953	47	1,000
Operable Capacity	737	1,446	57	1,503
Operating Rate (%)	59.6	65.9	82.1	66.5
Crude Sulfur (W. Avg.%)	0.98	0.98	0.30	0.94
API Gravity (W. Avg.)	29.12	31.32	41.61	31.80

*Yields are based on Crude and Unfinished Oil inputs with NGLs and Gasoline Blending components excluded from output.
†Numbers may not add because of rounding

TABLE A-4 Refinery Input/Output by Refining Center--1983 Base Case (MB/D) (Continued)

	PADD II		
	Capline Connected	Not Connected	Subtotal
Input			
Total Crude Oil & Lease Condensate	**2,052**	**727**	**2,779**
Domestic: Low Sulfur	988	688	1,676
High Sulfur	395	31	426
Alaskan & California OCS	43	1	44
Foreign: Low Sulfur	229	-	229
High Sulfur	294	7	301
Unidentified	103	-	103
Unfinished Oils	(5)	4	(1)
NGLs & Gasoline Blending Comp.	128	86	214
Total Input	**2,175**	**817**	**2,992**
Output			
Total Gasoline	1,290	487	1,777
Middle Distillates	538	235	773
Residual Fuel Oil & Asphalt	161	31	192
Other Products	279	91	370
Total Output	**2,268**	**844**	**3,112**
Net Processing Gain	(93)	(27)	(120)
Yields (%)*			
Total Gasoline	56.8	54.9	56.3
Middle Distillates	26.3	32.1	27.8
Residual Fuel Oil & Asphalt	7.9	4.2	6.9
Other Products	13.6	12.4	13.3
Total Yields†	**104.5**	**103.7**	**104.3**
Gross Crude Oil Distillation Input	2,099	739	2,838
Operable Capacity	2,727	958	3,685
Operating Rate (%)	77.0	77.2	77.0
Crude Sulfur (W. Avg.%)	1.01	0.55	0.89
API Gravity (W. Avg.)	35.05	37.79	35.77

*Yields are based on Crude and Unfinished Oil inputs with NGLs and Gasoline Blending components excluded from output.
†Numbers may not add because of rounding.

TABLE A-4 Refinery Input/Output by Refining Center--1983 Base Case (MB/D) (Continued)

	PADD III			
	Lower Mississippi	Lake Charles	Beaumont, Port Arthur	Houston, Texas City
Input				
Total Crude Oil & Lease Condensate	1,553	308	887	1,527
Domestic: Low Sulfur	671	137	439	442
High Sulfur	-	73	236	475
Alaskan & California OCS	212	22	26	202
Foreign: Low Sulfur	216	6	60	235
High Sulfur	434	71	126	173
Unidentified	20	(1)	-	-
Unfinished Oils	24	9	11	76
NGLs & Gasoline Blending Comp.	114	14	28	117
Total Input	1,691	331	926	1,720
Output				
Total Gasoline	811	175	427	832
Middle Distillates	507	95	275	463
Residual Fuel Oil & Asphalt	145	12	97	102
Other Products	291	63	148	393
Total Output	1,754	345	947	1,790
Net Processing Gain	(63)	(14)	(21)	(70)
Yields (%)*				
Total Gasoline	44.2	50.8	44.4	44.6
Middle Distillates	32.2	30.0	30.6	28.9
Residual Fuel Oil & Asphalt	9.2	3.8	10.8	6.4
Other Products	18.5	19.9	16.5	24.5
Total Yields†	104.0	104.4	102.3	104.4
Gross Crude Oil Distillation Input	1,569	310	898	1,587
Operable Capacity	2,269	497	1,435	1,977
Operating Rate (%)	69.2	62.4	62.6	80.3
Crude Sulfur (W. Avg.%)	0.77	1.07	0.85	1.04
API Gravity (W. Avg.)	33.72	34.38	35.80	34.22

*Yields are based on Crude and Unfinished Oil inputs with NGLs and Gasoline Blending components excluded from output.
†Numbers may not add because of rounding.

TABLE A-4 Refinery Input/Output by Refining Center--1983 Base Case (MB/D) (Continued)

	PADD III (Continued)		
	Corpus Christi	Inland (Not Connected)	Subtotal
Input			
Total Crude Oil & Lease Condensate	367	738	5,380
Domestic: Low Sulfur	153	458	2,300
High Sulfur	-	247	1,031
Alaskan & California OCS	57	12	531
Foreign: Low Sulfur	93	18	628
High Sulfur	64	4	872
Unidentified	-	(1)	18
Unfinished Oils	46	31	197
NGLs & Gasoline Blending Comp.	22	57	352
Total Input	435	826	5,929
Output			
Total Gasoline	198	373	2,816
Middle Distillates	151	252	1,743
Residual Fuel Oil & Asphalt	34	82	472
Other Products	70	122	1,087
Total Output	453	829	6,116
Net Processing Gain	(18)	(3)	(189)
Yields (%)*			
Total Gasoline	42.8	41.1	44.2
Middle Distillates	36.6	32.8	31.3
Residual Fuel Oil & Asphalt	8.2	10.7	8.5
Other Products	16.9	15.9	19.5
Total Yields†	104.4	100.4	103.4
Gross Crude Oil Distillation Input	384	762	5,510
Operable Capacity	563	1,042	7,783
Operating Rate (%)	68.2	73.2	70.8
Crude Sulfur (W. Avg.%)	0.60	0.80	0.87
API Gravity (W. Avg.)	35.94	37.29	34.88

*Yields are based on Crude and Unfinished Oil inputs with NGLs and Gasoline Blending components excluded from output.
†Numbers may not add because of rounding.

TABLE A-4 Refinery Input/Output by Refining Center--1983 Base Case (MB/D) (Continued)

	PADD IV	PADD V	U.S. Total
Input			
Total Crude Oil & Lease Condensate	420	2,100	12,092
Domestic: Low Sulfur	211	-	4,231
High Sulfur	171	1,046	2,685
Alaskan & California OCS	-	844	1,689
Foreign: Low Sulfur	-	202	1,633
High Sulfur	38	8	1,762
Unidentified	-	-	92
Unfinished Oils	(17)	20	291
NGLs & Gasoline Blending Comp.	19	40	652
Total Input	422	2,160	13,035
Output			
Total Gasoline	221	985	6,459
Middle Distillates	146	624	3,694
Residual Fuel Oil & Asphalt	32	361	1,359
Other Products	32	305	2,009
Total Output	431	2,275	13,521
Net Processing Gain	(9)	(115)	(486)
Yields (%)*			
Total Gasoline	50.1	44.6	46.9
Middle Distillates	36.2	29.4	29.8
Residual Fuel Oil & Asphalt	7.9	17.0	11.0
Other Products	7.9	14.4	16.2
Total Yields†	102.2	105.4	103.9
Gross Crude Oil Distillation Input	426	2,133	12,352†
Operable Capacity	560	3,115	17,386†
Operating Rate (%)	76.2	68.5	71.0
Crude Sulfur (W. Avg.%)	0.95	0.99	0.91
API Gravity (W. Avg.)	35.39	25.74	33.05

*Yields are based on Crude and Unfinished Oil inputs with NGLs and Gasoline Blending Components excluded from output.

†Numbers may not add because of rounding.

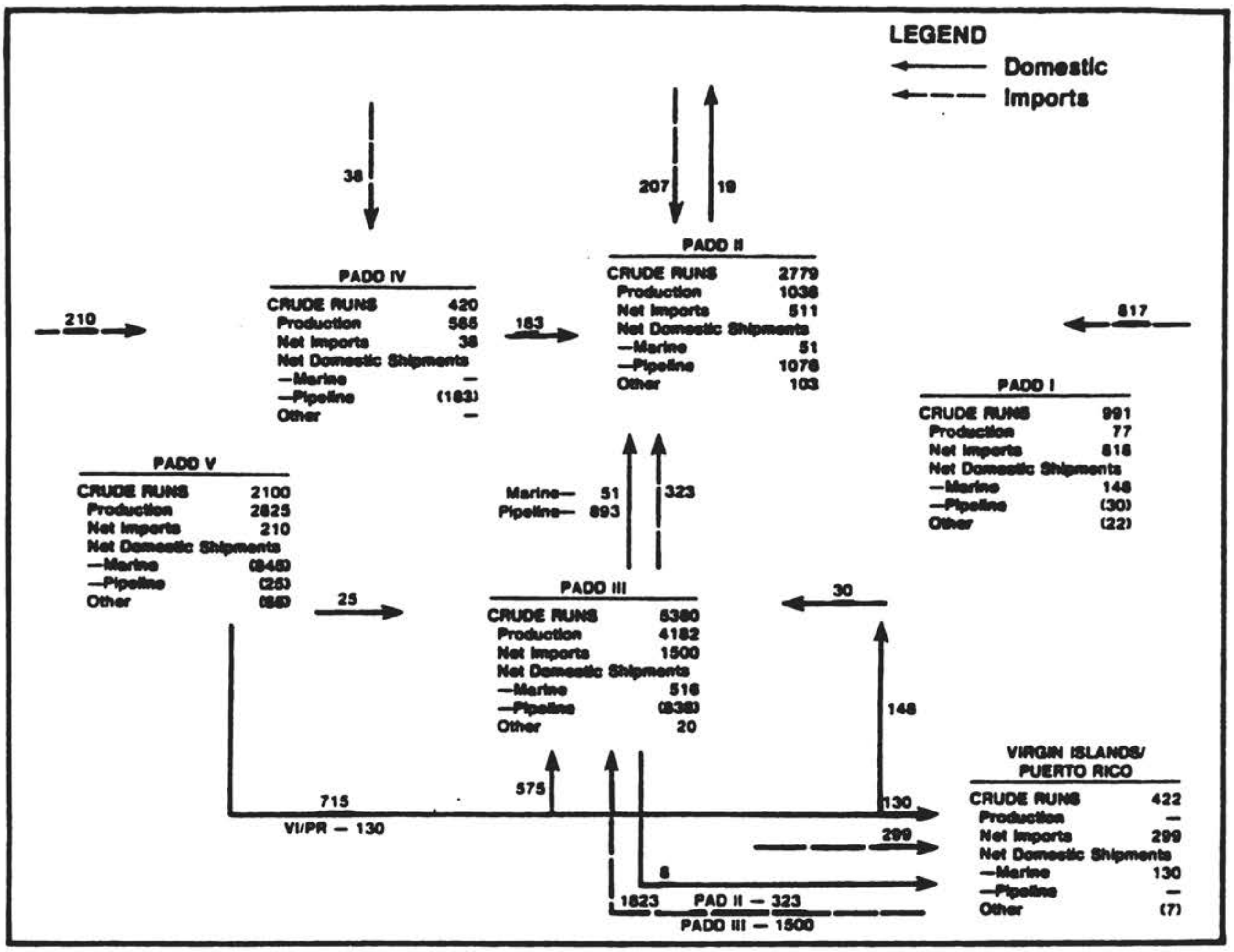
TABLE A-5 Supply/Demand Balance by PADD--1983 Base Case (MB/D)

	PADD I	PADD II	PADD III	PADD IV	PADD V	VI/PR*	Total
Local Demand	**4,864**	**4,084**	**3,458**	**507**	**2,317**	**223**	**15,453**
Crude Oil Supplies:							
Production	77	1,038	4,182	565	2,825	-	8,687
Imports†	818	530	1,500	38	210	299	3,395
Exports	-	(19)	-	-	-	-	(19)
Domestic Marine Shipments	-	-	(59)	-	(845)	-	(904)
Domestic Marine Receipts	148	51	575	-	-	130	904
Domestic Pipeline Shipments	(30)	-	(898)	(183)	(25)	-	(1,136)
Domestic Pipeline Receipts	-	1,076	60	-	-	-	1,136
Other	(22)	103	20	-	(65)	(7)	29
Product Supplies:‡							
Imports	875	181	226	21	97	113	1,513
Exports	(28)	(37)	(266)	-	(229)	(12)	(572)
Domestic Marine Shipments	(84)	(41)	(851)	-	(5)	(322)	(1,303)
Domestic Marine Receipts	1,037	165	64	-	22	15	1,303
Domestic Pipeline Shipments	(184)	(335)	(2,658)	(101)	-	-	(3,278)
Domestic Pipeline Receipts	1,990	932	195	72	89	-	3,278
Other§	267	440	1,368	95	243	7	2,420
Total Supplies	**4,864**	**4,084**	**3,458**	**507**	**2,317**	**223**	**15,453**
Memo: Crude Oil Runs	991	2,779	5,380	420	2,100	422	12,092

*Movements to/from the U.S. Virgin Island/Puerto Rico (VI/PR) considered domestic.
†Does not include SPR fill additions.
‡Includes refined products, LPG, and others.
§Includes LPG produced and used in each PADD, refinery gain, inventory draw/build, and other adjustments to balance.

SOURCE: NPC (1984).

FIGURE A-11 Actual Crude Oil Logistics (MB/D)--1983 Base Case



SOURCE: NPC (1984).

PADD I

PADD I depends heavily on imports and domestic movements from other PADDs to meet local demand. With 1983 crude oil production averaging about 80 MB/D and local product demand of 4,860 MB/D, PADD I relies heavily upon the ability of domestic pipelines and marine transportation to move crude oil and refined petroleum products from PADDs III and V, the U.S. Virgin Islands and Puerto Rico, and foreign sources.

Crude Oil The only pipeline system capable of delivering crude oil to PADD I is the Inter-Provincial/Kiantone system from Westover, Canada. Crude oil originating in the Chicago area can be moved through this system to Buffalo, New York, and from there to Warren, Pennsylvania. Because these two cities in PADD I are connected by pipeline to Capline through PADD II, their refineries are considered as part of NPC Refining Center No. 4.

Two pipelines allow crude oil movements out of PADD I--the 155 MB/D capacity pipeline from Florida to Mobile, Alabama, and the 292 MB/D capacity pipeline from Portland, Maine, to Montreal, Canada. The pipeline crossing Maine is used for shipping waterborne crude oil to Canada and is not connected to any domestic U.S. refinery.

With the exception of the Inter Provincial/Kiantone system, the demand for PADD I refinery crude oil is met by indigenous production and marine movements (domestic and imported).

Products Two major clean product pipelines serve PADD I (Colonial and Plantation). Both had spare capacity on average during 1983. While spare capacity existed in southern segments of the Plantation pipeline, it was essentially full in the main-line portion north of the Greensboro, North Carolina, pump station.

Imported products are shipped primarily to Mid-Atlantic and New England states in foreign flag tankers. Also, about 20 MB/D of domestic products move to PADD I from PADD II by barges via island waterways.

U.S. Virgin Islands/Puerto Rico

With no crude oil production, the U.S. Virgin Islands and Puerto Rico are totally dependent upon marine transportation for crude oil and refined products. Both U.S. territories have aggregate refining capacity that exceeds local demand, allowing refined product to be exported to the United States. Unique to the Virgin Islands, shipments to and from the islands are not subject to the provisions of the Jones Act. For the purposes of this study, these territories are considered part of the U.S. logistics network.

PADD II

Crude Oil During 1983, indigenous crude oil production represented only about 25 percent of PADD II product demand. Hence, this PADD is heavily dependent on other areas to satisfy local demand. Crude oil movements to PADD II during 1983 are shown in Table A-6.

Products Net refined product movements into PADD II during 1983 were 865 MB/D, including Canadian imports. While the main PADD III to PADD II product pipelines had some spare capacity during 1983, there is only limited capability to increase clean product shipments in these lines above current levels.

PADD III

Crude Oil With local crude oil production and imports exceeding local refinery runs, PADD III provides 950 MB/D to other PADDs, primarily PADD II. PADD 111 also imported about 1,500 MB/D of crude oil during 1983, not including the 323 MB/D ultimately delivered to PADD II.

Products PADD III is also a net shipper of refined products to other PADDs. Net product movements from PADD III during 1983 amounted to almost 3,300 MB/D, primarily by pipeline to PADDs I and II, with lesser quantities moving by water.

TABLE A-6 Crude Oil Movements into PADD II

Source		MB/D
PADD III Domestic		944
Pipeline:	893	
Marine:	51	
PADD III Imported		323
PADD IV		183
Net Canadian Imports		188
Total Net Movements		1,638

Source: NPC (1984).

PADD IV

Crude Oil Unlike any of the other PADDs, the Rocky Mountain area has no waterborne imports (all imports are overland from Canada). It has surplus crude oil supplies and is self-sufficient in refining capacity. In 1983, PADD IV shipped over 180 MB/D of crude oil to PADD II.

Products Pipeline movements of products to and from PADD IV during 1983 virtually balance and consist primarily of shipments to PADDs II and V, with pipeline receipts from PADD II.

PADD V

Crude Oil During 1983, PADD V had crude oil supplies in excess of local refinery demand, allowing shipments of about 870 MB/D to U.S. refineries east of the Rocky Mountains and to the U.S. Virgin Islands and Puerto Rico. There is one major crude oil pipeline (Four Corners) that can ship crude oil to PADD IV or PADD III, but its capacity is only about 60 MB/D. Consequently, the vast majority of crude oil moved from PADD V is transported by tankers using the TransPanama pipeline. During 1983, PADD V imported approximately 210 MB/D of low-sulfur crude oil.

Products As PADD V is essentially self-sufficient in refinery capacity, product movements into this area occur primarily to increase logistic efficiencies in Arizona and Washington.

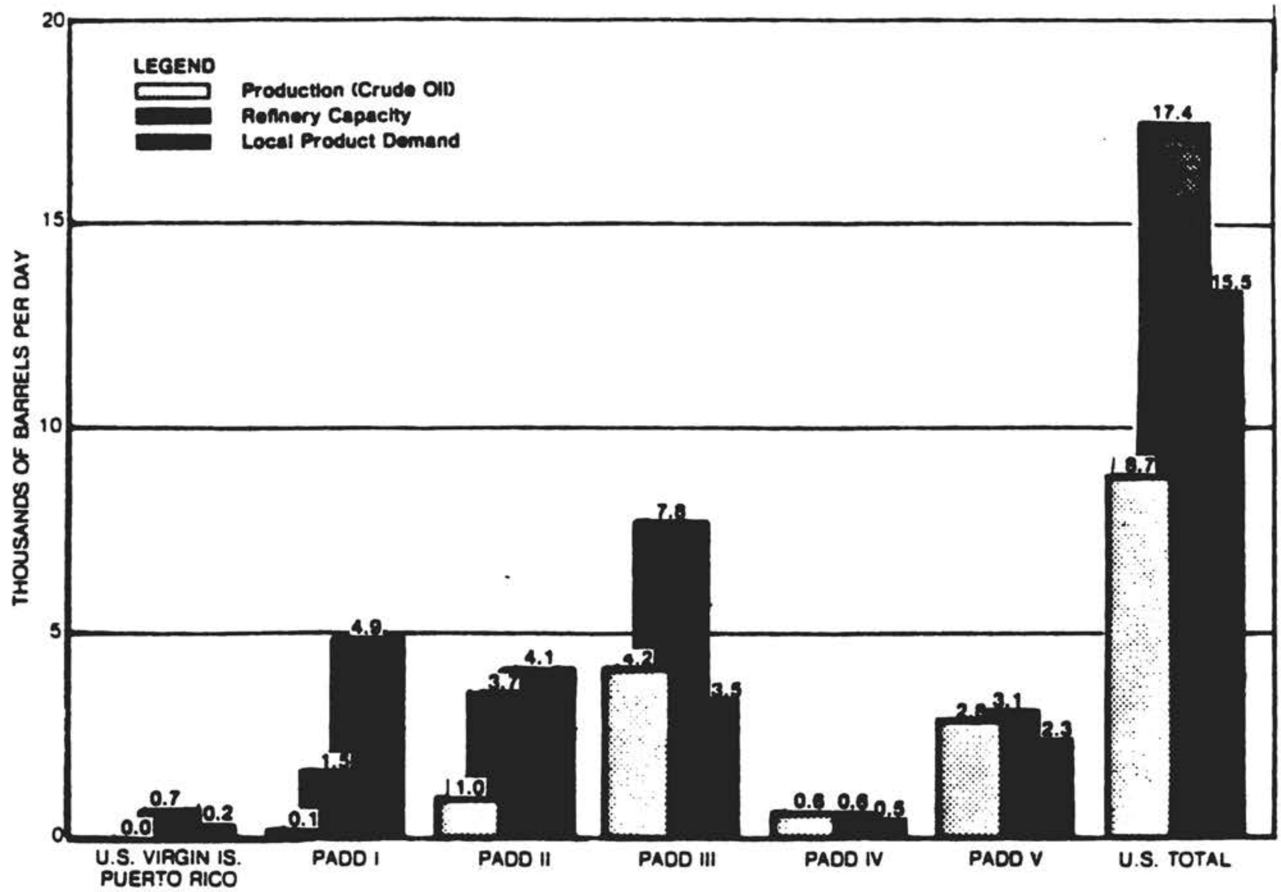
A summary of crude oil production, refinery capacity, and product demand for all PADDs for 1983 is shown in Figure A-12.

Pipeline Systems

There were two significant pipeline developments during 1984 affecting current and future SPR drawdown capabilities at the Seaway and Texoma complexes. Both the Seaway and Texoma pipelines were sold in 1984 and have been converted to natural gas.

In the original SPR development plans, the Seaway and Texoma pipelines provided capability to transport SPR crude oil from the Bryan Mound site and the Texoma complex, respectively, to Midwest refiners

FIGURE A-12 Summary of Crude Oil Production, Refining Capacity and Product Demand (MMB/D)--1983



SOURCE: NPC (1984).

through interconnection to other crude oil pipelines at Cushing, Oklahoma.

The impact of the loss of the Seaway and Texoma pipelines on SPR distribution is addressed in Chapter 3. It should be noted that the Capline system (1,200 MB/D of crude oil) remains available to transport SPR crude oil from the DOE terminal at St. James. It is currently used to transport crude oil from PADD III to PADD II.

Figures A-13 and A-14 show the major inter-PADD crude oil and product pipelines identified in a 1979 NPC study (NPC, 1979).

Existing Distribution System-Marine

To assess the availability of U.S. ships to distribute SPR crude oil in an emergency, NPC examined the existing marine distribution requirements for domestic tankers and barges (NPC, 1985). Demand estimates for U.S. flag vessels in 1983 were derived from the distribution data in Table A-4. The existing fleet, as of, June 1984, of domestic tankers and barges was allocated to specific trade routes based on general operating characteristics to develop the 1983 base case. The resulting 1983 supply/demand balance for U.S. flag ships was used as a projection base for the 1990 nondisrupted and disrupted cases.

1983 Supply of U.S. Flag Tankers and Barges

The U.S. tanker fleet is made up of two major categories: the Jones Act fleet for domestic trading and the subsidized fleet built for foreign trade. A detailed discussion of the Jones Act, Title V of the Merchant Marine Act of 1936 (Construction Differential Subsidy program), and waiver procedures as they affect the U.S. tanker fleet is included in Appendix D, National Petroleum Council (1984) report.

The Jones Act Fleet The Jones Act is an amendment to the Merchant Marine Act of 1920. It prohibits the use of any but U.S.-built, -owned, and -documented vessels for carrying cargo between U.S. ports. Section 21, however, exempts the U.S. Virgin Islands and certain other noncontiguous U.S. points. As a result, foreign tankers can trade between the Virgin Islands and the U.S. mainland.

The Jones Act fleet, for the purposes of this report, refers to U.S. flag tankers that qualify to operate in the domestic oil trade. As shown in Table A-7, the fleet has a total deadweight tonnage of approximately 10 million long tons. The most significant source of employment for Jones Act tankers in terms of cargo volume is the movement of Alaskan crude oil to domestic refining centers.

FIGURE A-13 1978 Crude Oil Pipelines

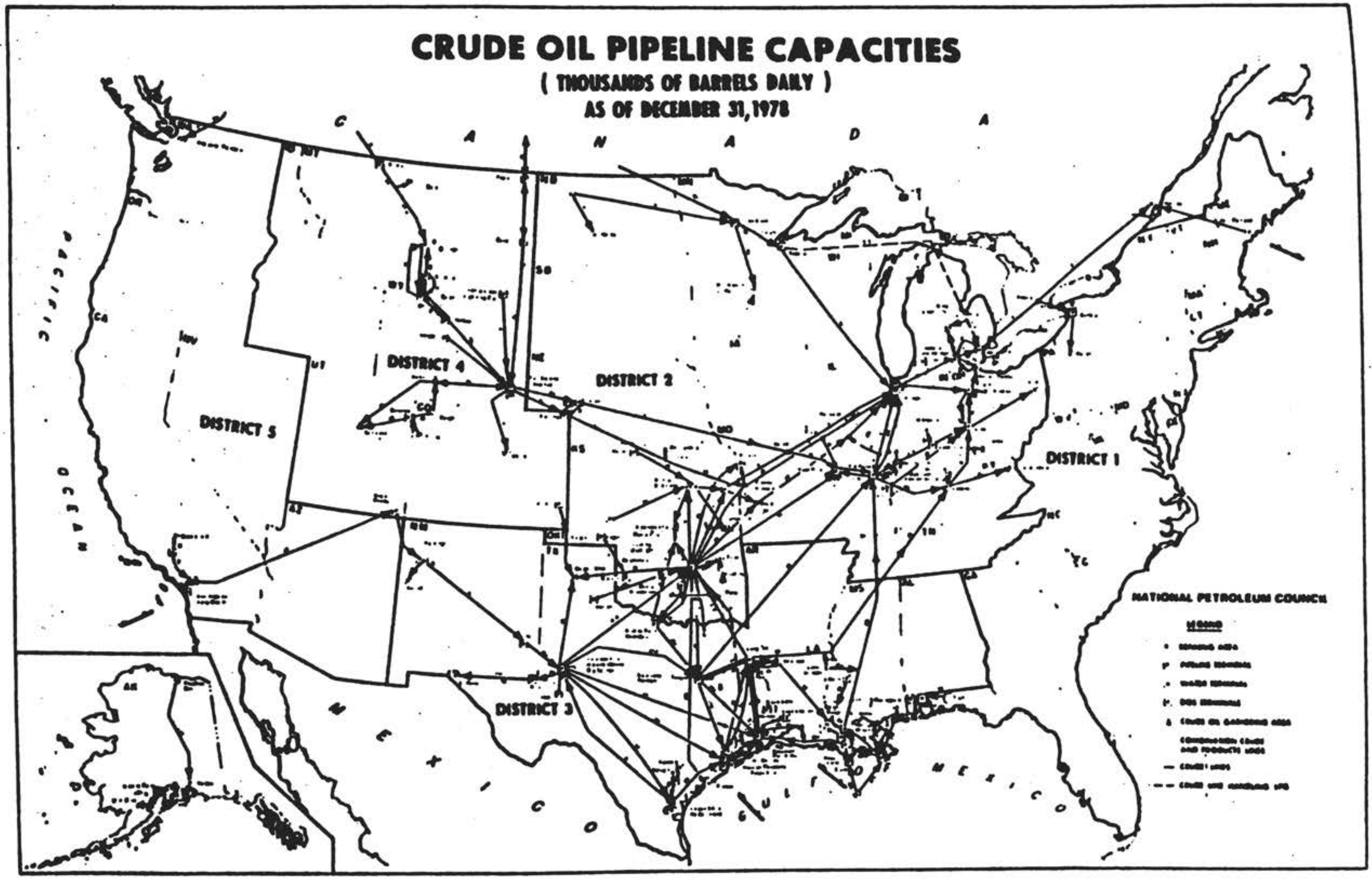


FIGURE A-14 1978 Petroleum Products Pipeline Capacities

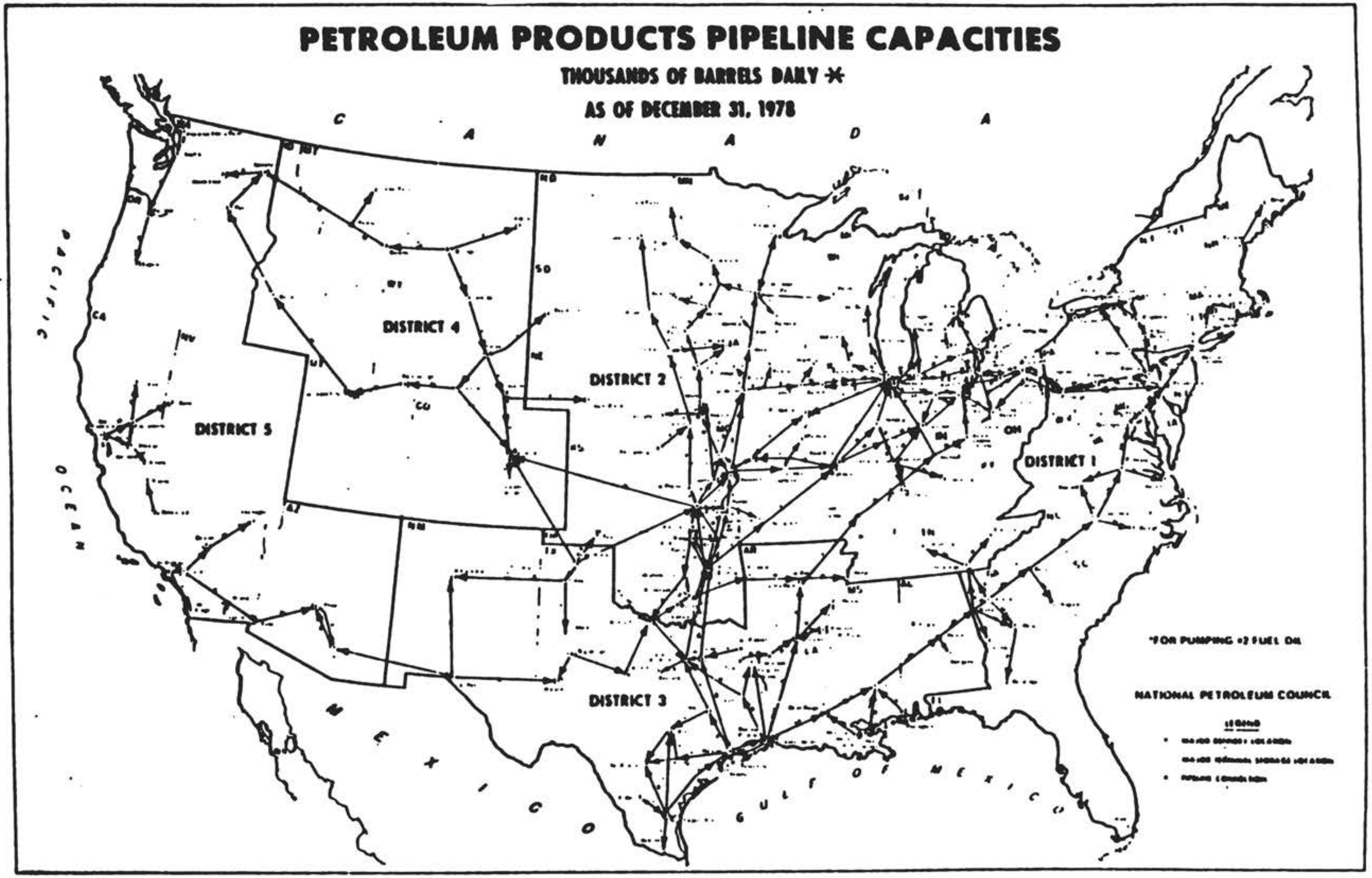


TABLE A-7 Supply of U.S. Flag Tonnage as of June 1984

	Thousand Deadweight Tons
Jones Act Tankers:	
20,000-39,999 DWT	2,513
40,000-69,999 DWT	1,916
70,000-99,999 DWT	1,817
100,000-199,999 DWT	3,135
Over 200,000 DWT	450
Total	9,830
CDS Tankers:	
20,000-39,999 DWT	377
40,000-69,999 DWT	0
70,000-999,999 DWT	711
100,000-199,999 DWT	0
Over 200,000 DWT	1,774
Total	2,863
Jones Act Barges:	
Over 50,000 barrels	1,109
Total U.S. Flag Tonnage	13,802

SOURCE: NPC (1984).

Waivers of the Jones Act are provided if they are deemed necessary in the interest of national defense. Waiver procedures are discussed in Appendix D, of the National Petroleum Council (1984) report.

The Subsidized Fleet The Merchant Marine Act of 1936 provided a number of programs to help U.s. flag ships participate in the foreign commerce of the United States by subsidizing their cost to make them more competitive with foreign ships. Title V of the act, the Construction Differential Subsidy (CDS) program, authorizes the Department of Commerce to make grants for up to 50 percent of the cost of constructing ships in domestic shipyards, provided the owners of the subsidized ships agree to operate them solely on foreign trade routes.

The Merchant Marine Act was amended in 1970 to extend subsidies to the construction of bulk vessels, including oil tankers. This amendment resulted in the construction of the CDS tanker tonnage listed in Table A-7. These vessels have essentially three requirements: they must have been built in the United States, they must be manned by U.S. crews, and they must operate in foreign trades.

Domestic Operation of CDS Vessels CDS tankers are not excluded from domestic trades by the Jones Act. However, Title V, Section 506 of the Merchant Marine Act of 1936 does place domestic trading restrictions on these vessels.

Still the Department of Transportation (DOT) can permit to a CDS vessel to operate in domestic trades for up to six months at a time. In determining whether to grant permission, DOT considers whether there are any vessels with domestic trading privileges that could accomplish what is proposed for the CDS vessel. Generally, if there are eligible vessels available, the requested domestic operation by the CDS vessel would not be authorized, since authorization would allow the CDS vessel to compete unfairly with the unsubsidized domestic vessel.

Under current policy, only CDS tankers of 100,000 deadweight tons (DWT) or more are considered for domestic operation permission and these only for service from Alaska to Panama. Since these carriers can operate under such permission for only six months at a time, 885,000 DWT, or about half of the total available supply of CDS tonnage over 100,000 DWT shown in Table A-7, was used in the tanker supply assessment.

In a drawdown situation, CDS tankers of all sizes would almost certainly be considered by for domestic operating permission of up to six months at a time. For each proposed waiver, however, there would still be a need for to determine that a vessel with domestic trading privileges was not available. The processing could be expedited, but permissions covering more than a single vessel at a time are considered unlikely.

Chemical Carriers Those vessels that were specifically designed to be sophisticated parcel tankers in the chemical trades and are under long-term contract to the chemical industry have not been included in the inventory of U.S. tankers for carrying of crude oil or refined products in this report. These vehicles would continue to be used in the chemical trades in the event of a disruption. They are not equipped to efficiently handle one homogeneous cargo and could be sufficiently contaminated by carrying crude oil or refined petroleum products to preclude a timely and economical transition back to chemicals.

1983 Demand Estimates for U.S. Flag Tankers and Barges

The demand for tankers and barges was derived for each specific distribution requirement or trade route by assigning factors to each trade route that could be used to convert daily throughput requirements developed by the study participants into deadweight-ton equivalents. Based on actual vessel operating experience, these factors were derived from average times for round-trip voyages, taking into consideration such things as routine delays, average load factors, weather, and other operational constraints. They were used to allocate sufficient deadweight tonnage to each trade that would provide a net carrying capacity to meet throughput requirements. These factors are listed in Tables A-8, A-9, and A-10.

In the case of two-way moves or reversals of flow, the same factor was applied. Transshipment schemes, although practical in an extreme demand situation, were not included because they appeared to be unnecessary for the projected distribution requirements.

Refined product movements from PADD III to PADD I were assigned to both tankers and barges. The demand for barge tonnage in the distribution of refined products was derived by allocating a percentage of the total flow to barges by region, as shown in Table A-11.

The allocation for 1983 was based primarily on the experienced judgment of the study participants. For product movements to Florida, an average factor of 1.25 was used. This represents a simple average for Tampa and Jacksonville. All other inter-PADD flows for both crude oil and refined products were assumed to be carried by tanker.

Exceptions to the above methodology were made in estimating the demand for tonnage for intra-PADD requirements for distributing refined products on the East and West coasts, and for Military Sealift Command requirements. The methodology used in estimating these demand segments is explained below.

TABLE A-8 Marine Planning Factors for Crude Oil Distribution

Loading Ports	Discharge Ports	Factor*
Valdez	U.S. West Coast	2.20
	Hawaii	2.67
	Puerto Armuelles, Panama	4.63
	Virgin Islands (via Cape)	12.07
Offshore/ U.S. West Coast	California	0.68
	Puerto Armuelles, Panama	2.90
	U.S. Gulf Coast	5.13
	U.S. Atlantic Coast	5.72
	Puerto Rico	4.71
	Virgin Islands	4.90
	Virgin Islands (via Cape)	10.84
Puerto Armuelles	U.S. Gulf Coast/Puerto Rico	2.43
	U.S. Atlantic Coast	3.14
Chiriqui Grande	U.S. Gulf Coast/Puerto Rico	1.79
	U.S. Atlantic Coast	2.37
U.S. Gulf Coast	Puget Sound	5.69
	California	4.96
	U.S. Atlantic Coast	2.32

*Factor X (MB/D) - MDWT Required.

Source: NPC (1984).

TABLE A-9 Marine Planning Factors for Products Distribution by Tanker

Loading Ports	Discharge Ports	Factor*
Beaumont	Jacksonville	1.80
	New York	2.30
	Boston	2.50
	Los Angeles	5.00

*Factor X (MB/D) - MDWT Required.

Source: NPC (1984).

TABLE A-10 Marine Planning Factors for Products Distribution by Barge

Loading Ports	Discharge Ports	Factor*
Beaumont	Jacksonville	1.70
	New York	2.70
	Tampa	0.80
Philadelphia	Boston	0.80

*Factor X (MB/D) - MDWT Required.

Source: NPC (1984).

TABLE A-11 Percentage of Refined Product Movements from PADD III to PADD I by Barge--1983

Region	Percentage
Florida	70
Other South Atlantic	35
Mid-Atlantic/New England	5

Source: NPC (1984).

Intra-PADD Coastwise Demand

Since it was not possible to develop volumes and distribution patterns for intra-PADD coastal movements, Maritime Administration data for 1983 were used to define the employment status of the Jones Act tanker fleet. These data indicated that tankers trading on the West Coast totaled approximately 500,000 DWT, and East Coast tankers totaled approximately 150,000 DWT. Similar data were developed in assigning the coastal requirements for barge tonnage. These estimates for both tankers and barges are reasonably accurate and suitable for use in establishing the 1983 base case.

Demand estimates for coastal tanker and barge requirements for the East and West coasts in 1990 were arrived at by indexing the 1983 demand levels by the changes in product consumption in PADDs I and V that are projected for the 1990 nondisrupted case.

Military Sealift Command Requirements

Since the Military Sealift Command (MSC) requirements represent a significant demand segment in the commercial market for Jonès Act tankers, it had to be incorporated in the overall tonnage balance in this study.

Maritime Administration data that report on the status of the U.S. merchant fleet for 1983 were reviewed to identify Jones Act tankers on charter to MSC. Since those vessels on lifetime charter to MSC are not included in the available inventory of vessels for this study, only those tankers on short-term charters to MSC were used to estimate this demand segment.

The 1983 data indicated that approximately 400,000 DWT of Jones Act tankers were on charter to MSC. For the purposes of this study, it was assumed that the 400,000 DWT figure would be used for MSC demand in 1990 under both the nondisrupted and disrupted cases. The 400,000 DWT demand estimate was confirmed by MSC as a reasonable steady-state requirement through 1990.

1983 Marine Balance and Assumptions

In order to allocate the available tonnage to individual requirements, it was necessary to assign trading priorities for each segment of the fleet based on the following assumptions:

o Tankers in the over 100,000 DWT category are assumed to trade exclusively in the West Coast crude oil.

o Tankers in the 70,000-99,999-DWT category are assumed to trade primarily from the Chiriqui Grande Terminal in Panama to coastal refining centers in PADDs I and III. However, the vessels at the larger end of this category would be expected to move to the

West coast to the extent that deficit exists in the supply of tankers over 100,000 DWT.

o Tankers in the 40,000-69,999-DWT category are assumed to trade from Chiriqui Grande and Puerto Armuelles (transiting the Panama Canal) to PADDs III and I, and from PADD III to PADD I.

o Tankers in the under 40,000-DWT category are assumed to trade exclusively in the coastal product trades.

o Barges in the over 50,000-barrel category are assumed to trade exclusively in the coastal and inter-PADD product trades.

Although there would probably be specific exceptions to the above assumptions, the allocation is sufficiently representative for the purposes of this study. The tanker and barge requirements for crude oil and product movements by trade for 1983 route are shown in Tables A-12 and A-13.

The supply/demand balance for U.S. ships carrying domestic crude oil and refined products in 1983 appears in Tables A-14, A-15, and A-16.

TABLE A-12 U.S.-Flag Tanker Requirements for Domestic Crude Oil Distribution--1983 Base Case[a]

	MB/D	Factor	MDWT
Non-SPR Crude Distribution:			
Valdez—			
U.S. West Coast	745.00	2.20	1,639.00
Puerto Armuelles	705.00	4.63	3,264.15
Hawaii	60.00	2.67	160.20
Puerto Armuelles—			
U.S. Gulf Coast/P.R.	0.00	2.43	0.00
U.S. East Coast	0.00	3.14	0.00
Chiriqui Grande—			
U.S. Gulf Coast/P.R.	565.00	1.79	1,011.35
U.S. East Coast	140.00	2.37	331.80
U.S. Gulf Coast—			
U.S. East Coast	8.00	2.32	18.56
California—			
U.S. West Coast	-	0.68	0.00
U.S. Gulf Coast	40.00	5.13	205.20
U.S. East Coast	0.00	5.72	0.00
Total Requirement			6,630.26

[a]The above distribution lists U.S. flag requirements only and does not show 100 MB/D moving from Valdez to the U.S. Virgin Islands, which moves in foreign flag tankers.

SOURCE: NPC (1984).

TABLE A-13 U.S.-Flag Tanker Barge Requirements for Domestic Product Distribution--1983 Base Case

	MB/D	Factor	MDWT
Tankers			
U.S. Gulf Coast—U.S. East Coast	352.00	2.00	704.00
U.S. Gulf Coast—U.S. West Coast	22.00	5.00	110.00
U.S. West Coast—U.S. West Coast	-	-	500.00
U.S. East Coast—U.S. East Coast	-	-	150.00
Total			**1,464.00**
Barges			
U.S. Gulf Coast—U.S. East Coast	381.00	1.25	476.00
U.S. West Coast—U.S. West Coast	-	-	212.00
U.S. East Coast—U.S. East Coast	-	-	700.00
Total	**755.00***		**1,388.00**

*755 MB/D of the total PADD I manne receipts of 1,037 MB/D in Table 10 was estimated to have moved from PADD III to PADD I by water in 1983. Also included in PADD I receipts are 36 MB/D moving from Puerto Rico to the East Coast. The above distribution does not include 246 MB/D moving from the U.S. Virgin Islands that qualifies for foreign flag vessels.

SOURCE: NPC (1984).

TABLE A-14 U.S.-Flag Marine Tonnage Balance for Domestic Crude Oil Distribution--1983 Base Case

	Over 100 MDWT	70–99.9 MDWT	40–69.9 MDWT	Total
Supply				
Jones Act	3,585.00	1,817.00	1,916.00	7,318.00
CDS Waivers	885.00	0.00	0.00	885.00
Total Supply	**4,470.00**	**1,817.00**	**1,916.00**	**8,203.00**
Demand				
Alaskan North Slope—				
U.S. West Coast/Hawaii	1,799.20	0.00	0.00	1,799.20
Panama	3,264.15	0.00	0.00	3,264.15
Panama—				
U.S. Gulf Coast/P.R.	0.00	1,011.35	0.00	1,011.35
U.S. East Coast	0.00	331.80	0.00	331.80
California—				
U.S. Gulf Coast	0.00	0.00	205.20	205.20
U.S. Gulf Coast—				
U.S. East Coast	0.00	0.00	18.56	18.56
U.S. West Coast	0.00	0.00	0.00	0.00
Total Demand	**5,063.35**	**1,343.15**	**223.76**	**6,630.26**
Surplus/(Deficit)	**(593.35)**	**473.85**	**1,692.24**	**1,572.74**

SOURCE: NPC (1984).

TABLE A-15 U.S.-Flag Tankers Under 40,000 DWT Balance for Domestic Product Distribution--1983 Base Case (MDWT)

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	476.00
U.S. Gulf Coast—U.S. West Coast	-
U.S. West Coast—U.S. West Coast	212.00
U.S. East Coast—U.S. East Coast	700.00
Total Demand	**1,388.00**
Jones Act Supply:	
Barges Over 50,000 Barrels	1,109.00
Total Supply	**1,109.00**
Surplus/(Deficit)	**(279.00)***

*Deficit results from study limitation that restricts the available supply to barges in excess of 50,000 barrels.

SOURCE: NPC (1984)

TABLE A-16 U.S.-Flag Barges over 50,000 Barrels Balance for Domestic Products Distribution--1983 Base Case (MDWT)

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	476.00
U.S. Gulf Coast—U.S. West Coast	-
U.S. West Coast—U.S. West Coast	212.00
U.S. East Coast—U.S. East Coast	700.00
Total Demand	**1,388.00**
Jones Act Supply:	
Barges Over 50,000 Barrels	1,109.00
Total Supply	**1,109.00**
Surplus/(Deficit)	**(279.00)***

*Deficit results from study limitation that restricts the available supply to barges in excess of 50,000 barrels.

SOURCE: NPC (1984).

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ENERGY ENGINEERING BOARD

Committee on the Strategic Petroleum Reserve

WORKSHOP ON THE STRATEGIC PETROLEUM RESERVE

Room 353 (except as noted)
Joseph Henry Building
2100 Pennsylvania Avenue, N.W.
Washington, D.C.

April 1-2, 1985

AGENDA

Monday, April 1, 1985

6:00 p.m.	RECEPTION AND COCKTAILS, Committee Room 2, Second Floor	
7:00 p.m.	DINNER, Committee Room 2, Second Floor	
8:30 p.m.	SESSION I. OVERVIEW. M. Hackerman, Session Chairman.	
	Purpose and Scope of the Workshop	N. Hackerman
	Comments from U.S. Department of Energy	R. Furiga
	Trends in the Petroleum Industry	J. Bookout
	Policies Affecting the Petroleum Industry	A. Alm

Tuesday, April 2, 1985

8:30 a.m.	SESSION II. U.S. CAPACITIES AS THEY AFFECT THE STRATEGIC PETROLEUM RESERVE. B. Kerr, Session Chairman.	
	Domestic Exploration and Production, A	W. Fisher
	Domestic Exploration and Production, B	B. Grossling
	BREAK	
	Marine Transport	J. Goodell
	Overland Transport	W. Bush
12:00 noon	LUNCHEON, Buffet Style	

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Tuesday, April 2, 1985 (Continued)

1:00 p.m.	SESSION III. U.S. CAPACITIES AS THEY AFFECT THE STRATEGIC PETROLEUM RESERVE (Continued). K. McHenry, Session Chairman.	
	Refining Capacity	W. Burch
	Refining Trends	J. Moore
	BREAK	
2:45 p.m.	SESSION IV. PRODUCT IMPORTS. E. Krapels, Session Chairman.	
	Product Imports, A	J. Dosher
	Product Imports, B	J. McNamara
	Product Imports, C	H. Tahmassebi
4:15 p.m.	SESSION V. WORKSHOP SUMMARY. H. Hackerman, Session Chairman.	
	Discussants: R. Bamberger, D. Porcier, C. Masters, D. Merriman, A. Safer, H. Woo	
5:30 p.m.	ADJOURNMENT*	

*The committee will meet from 8:30 a.m. until noon on April 3, 1985, to digest the workshop material and to plan a final report.

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Committee on the Strategic Petroleum Reserve

03-29-85

WORKSHOP ON THE STRATEGIC PETROLEUM RESERVE

April 1-2, 1985
Washington, D.C.

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GLOSSARY

B/D:	Barrels per day
CDS:	Construction Differential Subsidy
DOE:	Department of Energy
DOT:	Department of Transportation
DWT:	Deadweight tons
EIA:	Energy Information Administration
EOR:	Enhanced oil recovery
EPCA:	Energy Policy and Conservation Act
GAO:	General Accounting Office
LOOP:	Louisiana Offshore Oil Port
LPG:	Liquified petroleum gas
MB/D:	Thousands of barrels per day
MMB:	Million barrels
MMB/D:	Millions of barrels per day
MSC:	Military Sealift Command
MTBE:	Methyl tertiary butyl ether
NGL:	Natural gas liquids
NPC:	National Petroleum Council
OCS:	Outer continental shelf
OPEC:	Organization of Petroleum Exporting Countries
OTA:	Office of Technology Assessment
PADD:	Petroleum Administration for Defense District
SPR:	Strategic petroleum reserve
SPRO:	Strategic Petroleum Reserve Office
TCF:	Trillion cubic feet
USGS:	U.S. Geological Survey

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