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. . . . . . Prepared by the National Petroleum Council's Committee on Emergency Preparedness . . . . Carrol M. Bennett, Chairman . . . . with the Assistance of the Coordinating Subcommittee . . . . James S. Cross, Chairman. . . . .

NATIONAL PETROLEUM COUNCIL

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Industry Advisory Council

to the

U.S. DEPARTMENT OF THE INTERIOR

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INTRODUCTION

The objective of the National Petroleum Council's Committee on Emergency Preparedness is to assess the capability of the United States to cope with a sudden but temporary interruption of energy supplies, and to review the options open to the country to minimize the impact of such an interruption. This denial could occur with little warning as a result of actions over which the United States has no direct control, including situations of a non-military nature.

Ultimately, the only effective protection against an import interruption is a combination of conservation by consumers and developing, to the maximum extent possible, the Nation's domestic energy resources. The Nation has not provided adequate encouragement for either conservation or for the development of these resources. The United States has an adequate energy resource base which, given sufficient time and a proper political and economic environment, can be converted into available supplies. The National Petroleum Council's U.S. Energy Outlook Report examined the long-term requirements for energy in the United States and the changes in government policies and economic conditions that would be required to improve the domestic energy supply situation.*

Even prior to the Middle East conflict in October 1973 and the subsequent embargo, this Nation was faced with growing energy problems. During the past 15 years the United States has not adequately developed its domestic energy resources, and has thus become increasingly dependent on imported oil. The embargo of last winter and the approximate quadrupling of foreign oil prices have necessitated a reassessment of our national energy posture. "Project Independence" has directed attention to the need for accelerating development of indigenous energy sources to stop the trend of increasing reliance on foreign energy sources and to reduce this reliance to an acceptable level.

At this time, there is considerable uncertainty associated with long-range forecasts of U.S. energy supply and demand. Particularly uncertain is the future level of oil imports. Increased prices for energy will dampen demand, but the degree of response is difficult to assess. Consumption will also be affected by the extent of voluntary and mandated conservation.

Higher prices will encourage the development of domestic energy resources. Already there has been an increase in the number of wells drilled per year, a marked reversal of the declining trend of recent years. However, long-range development of domestic energy resources will also be affected by the industry's expectations regarding price controls, tax changes, environmental regulations and

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* NPC, *U.S. Energy Outlook--A Report of the National Petroleum Council's Committee on U.S. Energy Outlook* (December 1972)--hereafter referred to as the U.S. Energy Outlook Report.

rate of leasing of government lands. The availability of capital, skilled manpower and materials, as well as the development of new technology, are also important in influencing the rate of development of domestic energy resources.* But in the short-and intermediate-term the United States has no apparent alternative except to remain heavily dependent upon foreign oil.

The substantial dependence of the United States on petroleum imports has major national security implications. Recognizing these implications and the need for an effective emergency preparedness plan, the Secretary of the Interior requested the National Petroleum Council to undertake a "comprehensive study and analysis of possible emergency supplements to or alternatives for imported oil, natural gas liquids and products in the event of interruptions to current levels of imports of these energy supplies" (see request letters, Appendix A). In the request letters, it is pointed out that, in a period of rapidly increasing dependence on imported petroleum," it becomes mandatory that the Nation's emergency preparedness program to ensure supply of petroleum be improved without delay."

In response to the Secretary of the Interior's request, the National Petroleum Council established a Committee on Emergency Preparedness under the chairmanship of Carrol M. Bennett, Chairman of the Board, Texas Pacific Oil Company, Inc. The Committee is assisted by a Coordinating Subcommittee, chaired by Dr. James S. Cross, Director, Economics and Industry Affairs, Sun Oil Company. (For a listing of industry members of the Committee and its Subcommittees, see Appendix B.)

On July 24, 1973, the National Petroleum Council transmitted to the Secretary of the Interior a report entitled *Emergency Preparedness for Interruption of Imports into the United States, An Interim Report*. *A Supplemental Interim Report*, released on November 15, 1973, focused on the analysis of a 1974 interruption and included an initial appraisal of the impact of the oil embargo which began in mid-October, 1973. Subsequently, *Short-Term U.S. Petroleum Outlook--A Reappraisal* was transmitted to the Secretary of the Interior on February 26, 1974. That report considered significant events occurring during the embargo through January 1974.

A distinction must be drawn between the underlying tight petroleum supply situation and the sudden and limited duration curtailment addressed in this report. Difficult domestic supply conditions result from trends which have been established over a period of years, and it is expected that these conditions will persist for at least the next several years. The solutions available to minimize the impact of a short-duration interruption of imports are fundamentally different from those required to correct the long-term domestic

* The short-term availability of materials and manpower is assessed in a separate report of the NPC's Committee on Emergency Preparedness: *Availability of Materials, Manpower and Equipment for the Exploration, Drilling and Production of Oil--1974-1975*, (September 10, 1974).

supply situation. Solutions to the long-term supply shortages lie in providing a free marketplace and an economic and regulatory climate which encourages an adequate degree of energy self-sufficiency, rather than in temporary emergency measures.

In the event of a short-term interruption of a significant portion of oil imports, it would be extremely difficult for the economy to readjust itself without resorting to emergency measures. Such measures include substantial curtailments in consumption, emergency production measures, reliance on crude and products which have been stockpiled, and maximum utilization of available alternate energy sources. Obviously, most emergency measures can only be maintained for weeks or months rather than for years.

This final report describes the impact of the 1973-1974 embargo on the U.S. energy supply/demand situation and on the economy, and seeks to provide guidance as to the actions that should now be undertaken as a precaution against the possibility that a sudden and limited duration interruption of imports of an assumed 3 million barrels per day (MMB/D) could occur.

SUMMARY

ANALYSIS OF THE RECENT EMBARGO

From mid-October 1973 to mid-March 1974, the United States experienced an embargo on oil shipments from the Arab exporting countries--the fourth sudden oil imports stoppage of political origin in the past 25 years. This was, however, the first time the country found itself without spare domestic production capacity to offset such an interruption and shortage conditions resulted. By 1973, imports had reached 6.2 million barrels per day (MMB/D) or 35 percent, compared with a total supply of 17.6 MMB/D. The embargo sharply reduced the amount of oil exported to the United States and other countries, and at the same time world prices for crude oil and petroleum products escalated very rapidly.

As shown in Figure 1, the effects of the embargo on U.S. supplies were not felt immediately. The long supply lines from the Middle East to the United States provided considerable lag time between the initiation of the embargo and the onset of shortages in the United States. By mid-December, however, reduced receipts of petroleum became apparent, with the full impact of the embargo occurring during January, February and March of 1974. During the first quarter, imports averaged 2.2 MMB/D below earlier projections.

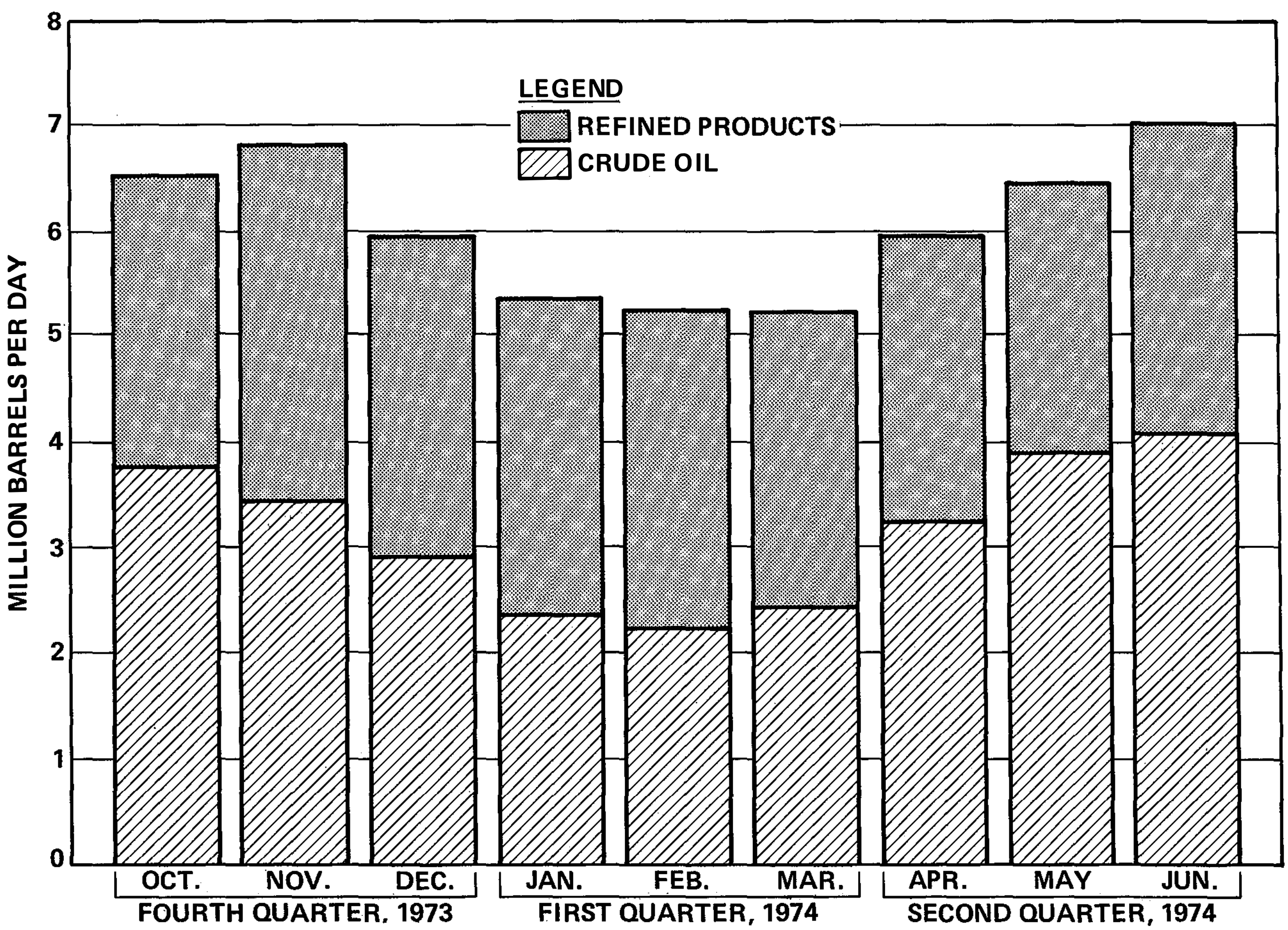

Figure 1. Total United States Petroleum Imports.

Four methods of dealing with the situation were available:

- Reduction of consumption,
- Conversion to alternate fuels,
- Emergency production, and
- Government allocation programs.

Reduction of Consumption

During the first quarter of 1974, oil consumption was reduced approximately 2.7 MMB/D or 14 percent below prior expectations, as shown in Table 1. This reduction was accomplished in part by voluntary actions such as car-pooling, reduced space heating and lighting, more efficient airline operations and the amounts accounted for by mandatory actions such as lower speed limits. Higher prices and warmer-than-normal weather during the 1973-1974 winter also caused consumers to use less fuel.

Conversion to Alternate Fuels

The Committee estimated earlier that conversions of gas and oil burning industrial and utility boilers to coal during the first 90 days of an import interruption could displace 250 MB/D of oil (23 MMT of coal). In view of the constraints involved in coal production,

TABLE 1

OIL CONSUMPTION REDUCTIONS—FIRST QUARTER 1974
(Million Barrels Per Day)

Factors Influencing Consumption	Reductions Realized*
Conservation and Curtailment	1.01
Warmer-than-Normal Weather	.44
Conversion to Alternate Fuels and Reduced Exports	.10
Other†	1.15
Total Reductions	**2.70**
Product Categories Affected	
Motor Gasolines	.60
Aviation Fuels	.19
Middle Distillates	.78
Residual Fuels	.78
All Other (Including Exports)	.35
Total Reductions	**2.70**

* Bureau of Mines actual data compared with pre-denial projections of first quarter demand by the Independent Petroleum Association of America (IPAA).

† Includes price effects, lower economic activity, nonidentifiable conservation efforts, product unavailability, etc.

transportation and environmental standards, it was considered that actual savings might be within the range of 40 MB/D to 120 MB/D. During the first quarter of 1974 actual savings were only 61 MB/D. Coal convertibility on short notice proved to be a complicated and difficult problem, and its future emergency potential is limited. Imports of electricity from Canada accounted for 26 MB/D, making a total of 87 MB/D gained from conversion to or use of alternate fuels.

Emergency Production

Increasing domestic production above normal rates was considered but not employed as another means of covering the emergency shortfall. There are several significant oil fields in Texas which, on a temporary basis, have producing capability above maximum efficient rates (MER).* Also, if properly equipped, the Naval Petroleum Reserves (NPR) could have been of significant benefit. However, these emergency capabilities were not utilized during the 1973-1974 embargo.

The Texas fields are currently producing at MER's established by the Railroad Commission of Texas. In order for these fields to be produced at higher rates, it would be necessary for the Commission to hold hearings to establish that these higher rates could be accommodated for a given period of time without damage to the reservoirs and without reduction of ultimate recovery. Resolution of other problems--including installation of additional facilities, intrafield equity considerations and relaxation of environmental and conservation regulations in regard to gas flaring--would have been required to achieve higher production rates. The Naval Petroleum Reserves are controlled by the U.S. Navy's Office of Naval Petroleum Reserves and under existing law can be produced only when the Secretary of the Navy, with the approval of the President, finds that the reserves are needed for national defense. Production must then be authorized by a joint resolution of Congress. The legal and economic problems involved in additional production from private oil fields and from the Naval Petroleum Reserves precluded a timely response during the recent emergency.

Government Allocation Programs

The Federal Energy Office (FEO) undertook the task of allocating available petroleum products in order to continue essential activities and to minimize adverse effects on agriculture and industry,

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* *Editor's Note:* MER is defined as the highest rate of production that can be sustained over a long period of time without reservior damage and significant loss of ultimate oil and gas recovery. Production in excess of MER for sustained periods may result in both loss of recovery and premature loss of producing capacity.

including use of petroleum as a raw material for non-energy products. The primary thrust of the FEO regulations was to insure that essential activities be given priority access to available supplies, that these supplies be equitably allocated and that adverse effects on employment and the general economy be minimized.

While the government allocation program reduced the severity of the effects of the embargo, many problems arose because of economic distortions which inevitably result when government controls replace market forces. The ability to cope with these problems was affected by the inability to use the services of qualified industry personnel and the normal difficulties involved in creating and effectively operating a new regulatory agency on short notice.

ECONOMIC EFFECTS OF THE EMBARGO

Gross National Product

The cutback in petroleum consumption during the first quarter was accompanied by a 7 percent decrease in real Gross National Product (GNP), whereas a modest increase had been generally expected prior to the embargo. While the primary effects on industry were held to a minimum, the secondary repercussions resulting from disruptions in world energy markets and from consumer reactions were significant. Gasoline shortages and rising fuel prices triggered a demand shift toward smaller cars, which slowed activity in domestic automotive and related industries. The tourist industry and vacation areas were hard hit. Repercussions in money markets contributed to slowdowns in the housing and construction trades. The cumulative short-term effects of the embargo on the economy, although substantial, were eased by various favorable consumer, industry and government actions.

Employment

Unemployment during the first quarter averaged 5.2 percent of the labor force, 0.5 percentage points higher than the rate experienced prior to the embargo. This less than expected increase in unemployment was partly due to the short duration of the embargo and also to the FEO policy of maintaining employment by granting higher priority to industrial users of oil.

Prices

Beginning before the embargo and accelerating during the embargo, the rapid and large increase of world oil prices resulting from producing country government actions had additional impact on the U.S. economy as well as the world economic system. Energy costs are diffused throughout the economy; each commodity and service becoming more costly depending upon its energy component. In the United States, it has been estimated that about one-fourth of the increase in wholesale prices in 1974 could be attributed to the increase in energy costs.

Demand Elasticity

Prior to the embargo, at then current price levels, the demand for petroleum was considered to be quite inelastic. Recent observations of price and consumption changes in gasoline markets, at current prices, suggest that a degree of elasticity exists. However, response in the United States is still modest compared with that noted in other countries. In recent months, European consumers have reduced energy usage to a much greater degree than U.S. consumers in response to higher prices that prevail in Europe. In order to improve decisions relative to meeting future petroleum needs, more information and analysis are needed in this area.

International Trade

The upward shift in oil prices has had a profound effect on the balance of payments between oil producing and oil consuming nations. In 1974, the United States may be faced with a dollar outflow attributable to oil imports on the order of $25 billion. Funds flowing into oil producing countries could approach $100 billion this year. Unsettled conditions in world money markets may result depending upon how these funds are spent or invested.

SUPPLY AND DEMAND OUTLOOK

Short-Term

Due to physical constraints during the first half of the year and higher prices, oil consumption will experience little or no growth in 1974. Because of increased drilling and recovery efforts, domestic oil and gas supply will decline at a slower rate than earlier anticipated. Import volumes may therefore be about the same order of magnitude as in 1973, with inventories being restored and supplies currently adequate to meet demand. The economy has now entered a transitional period between an era of abundant supplies of cheap energy and an era of high prices and insecure supplies.

Long-Term

In order to better evaluate the longer term, the Committee found it necessary to have an updated energy supply/demand outlook. The NPC staff polled several private sources of current U.S. energy supply and demand projections and developed an average or medium case to reflect a consensus of data received. The range of energy consumption projections is shown in Figure 2.

Energy consumption in the medium case is projected to grow, between 1972 and 1985, at an average annual rate of 3.2 percent, the high range being 3.6 percent and the low range 2.6 percent per year. This range of projections is below the annual growth rate of the past 5 years (4.5 percent) and that of the past 25 years (3.7 percent). The high case in this current survey tracks fairly closely

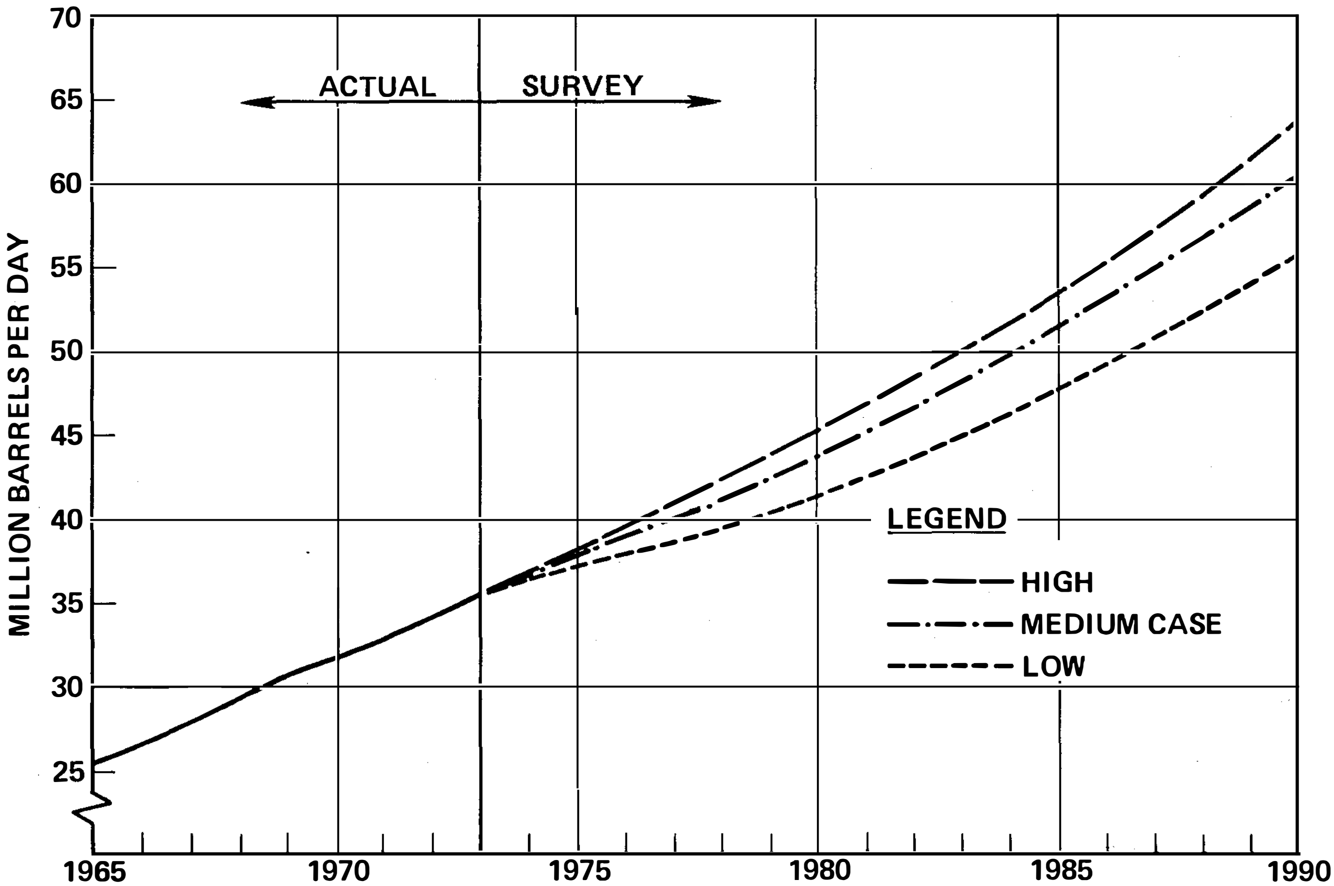


Figure 2. Energy Consumption (Million Barrels Per Day Crude Oil Equivalent).

the low demand case projected in the NPC's U.S. Energy Outlook Study of 1972. The underlying assumption in these projections is that energy conservation measures will be effective and the economy will be using less energy than previously assumed.

As shown in Table 2, a wide range of petroleum import projections was received in the survey, depending upon the assumptions made relative to energy growth and to the rate of growth of other energy sources. The medium case projection reaches 8.4 MMB/D by 1985, after which it tapers to 8.1 MMB/D in 1990. The range in 1990 is between 12 MMB/D and 4 MMB/D. The Committee elected to use the medium case as the basis for its analysis. The details of the total liquid petroleum balance are shown in Figure 3.

Conventional production of crude oil and natural gas liquids is estimated to reverse its recent decline and grow at an average rate of 1.3 percent, reaching a level of 13.2 MMB/D in 1985 and 13.9 MMB/D by 1990. Syncrude is not expected to reach significant proportions until the mid-1980's and is projected at 1.2 MMB/D in 1990. Net imports, having expanded rapidly in 1973, are projected to increase gradually from their present level to over 8 MMB/D in 1985, after which they are expected to decline. Total oil supply in this medium case is projected to grow at the rate of 2.8 percent per year between 1972 and 1980, reaching 20.6 MMB/D in that year. Between 1980 and 1990, the projected growth rate is 1.4 percent per year, reaching 23.4 MMB/D in 1990. In the medium case, net imports as a percent of total oil supply would approach 37 percent in 1985 and 34 percent in 1990. Within this time frame, the Committee addressed itself to the question of what should be done to prepare for any future import denial.

TABLE 2

TOTAL CRUDE AND PRODUCT IMPORTS
(Million Barrels Per Day)

	1978	1980	1985	1990
High	9.4	10.2	12.5	12.0
Low	5.2	5.3	5.4	4.0
Medium Case	7.8	7.8	8.4	8.1

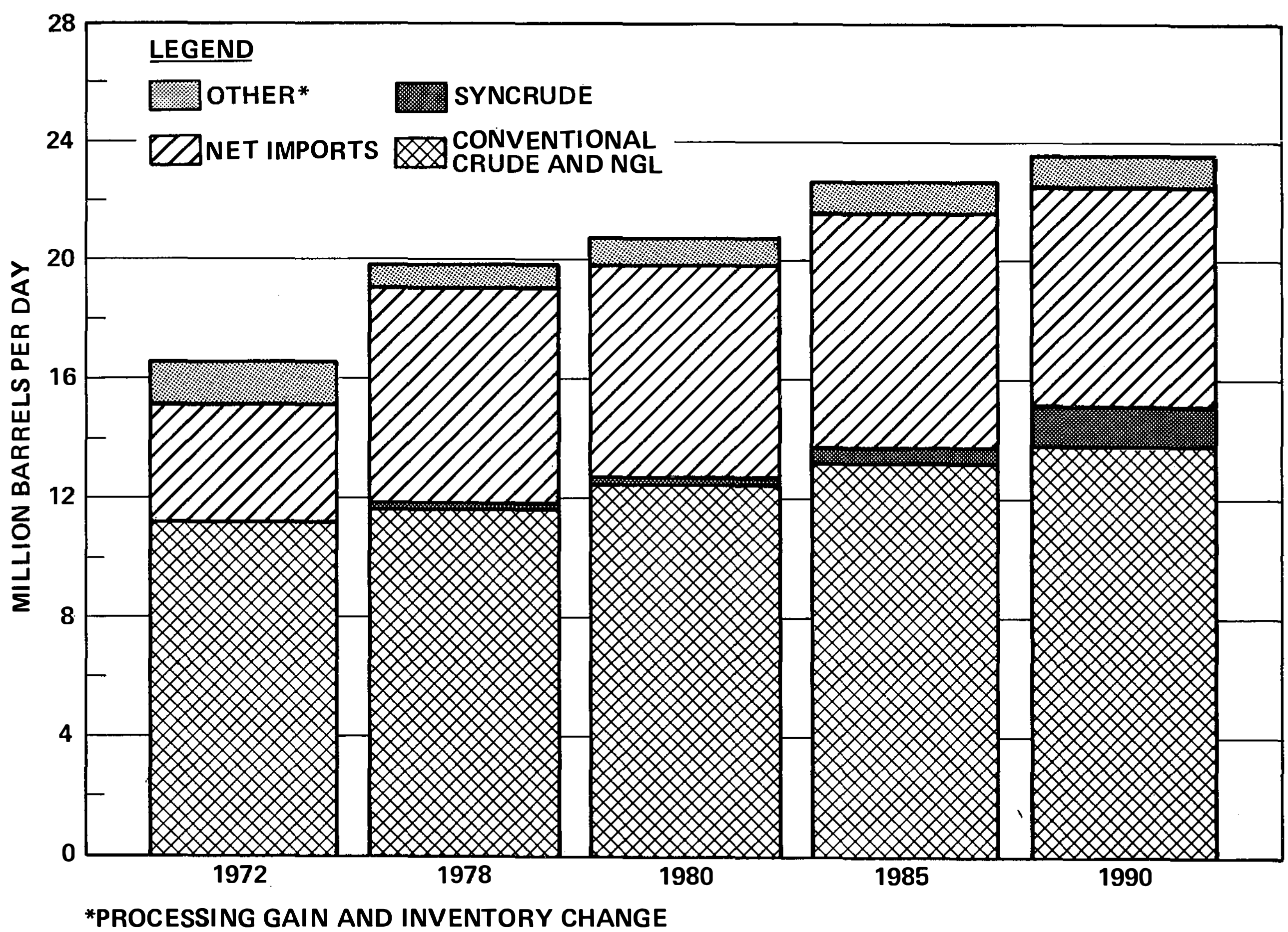


Figure 3. Total U.S. Supplies of Liquid Petroleum--Medium Case.

AVAILABLE ALTERNATIVES FOR RESPONSE TO FUTURE IMPORT DENIAL

Among the steps the Committee considered for response to a future denial are:

- Conversion to alternate fuels,
- Emergency production,
- Reduction of consumption, and
- Emergency standby petroleum supplies.

Conversion to Alternate Fuels

It has been previously assumed that, in a denial period, some relief could be obtained by converting industrial and utility boilers from oil or gas to coal. The opportunities are primarily in the electric utility sector but are quite limited. The medium case projection of fossil fuel use in electricity generation indicates a trend away from oil and gas to coal. Furthermore, the recently passed Energy Supply and Environmental Coordination Act of 1974 provides the authority to require oil and gas burning power plants to switch to coal. The law also permits the Federal Government to direct that new power plants use coal as the primary energy source. Since a high degree of the potential for conversion to coal will be realized over the next several years on a non-emergency basis, there will be little or no future emergency coal substitutability for oil and gas in industrial or utility plants.

Emergency Production

As noted earlier, legal and economic problems involved in additional oil and gas production from private fields and Naval Petroleum Reserves precluded their use during the recent embargo. The potential from private fields will decline over time and this source can be counted on to provide only a small amount of the required volume of emergency supplies in the event of an imports curtailment.

Reduction of Consumption

During a denial period, energy consumption can be reduced by voluntary or mandatory measures. The quantification of savings through voluntary steps is difficult because it requires an assumption of the level of compliance on the part of the public. Substantial potential reductions exist in every energy use sector, such as increased car-pooling in transportation, thermostat adjustments and reduced lighting in the residential and commercial sectors, and increased operating efficiencies in the industrial and utility sectors. In many cases, consumption can be voluntarily reduced promptly and with little or no capital investment. In other instances, reductions effected by such measures as increased insulation and automotive design improvements require investments and time to produce results.

The voluntary actions which would be most effective in responding to an unanticipated interruption in energy supply would be those steps which the public would be willing to implement freely. The effectiveness or compliance level of these measures would relate directly to the cost to the individual or business. Therefore, it has been assumed that only those measures requiring little or no investment would be effective in a short-term emergency situation. A review of such activities in each of the major energy use sectors indicates potential consumption reductions of approximately 1.0 MMB/D and 1.1 MMB/D in 1980 and 1985, respectively.* Since the level of reductions achieved through voluntary curtailment is almost completely dependent upon public compliance, it is imperative that an extensive public information program be initiated at the time of any emergency to ensure favorable public response.

In the event that voluntary demand reductions are not sufficient to bring demand into balance with supply, mandatory actions such as allocation and rationing would be required.

Emergency Standby Petroleum Supplies

There are three basic alternatives for providing standby petroleum supplies to offset a sudden loss of imports. These are: (1) shut-in or reduction of production from domestic oil fields, (2) storage of crude after production from underground reservoirs and (3) storage of refined petroleum products. Several major factors must be considered in developing an optimum emergency standby supply system. First, standby supplies must be located so that facilities existing at the time of an emergency can transport such supplies to locations where needed at rates sufficient to replace imports that cannot be offset by other means. Second, the capability to construct associated facilities and obtain sufficient crude and/or product to fill programmed storage in the desired time frame must be assessed. Finally, the total cost to the Nation of available alternatives must be weighed against the degree of protection provided.

The alternative of providing standby supplies by shutting in or reducing production from domestic oil fields has major disadvantages. Such action would simultaneously reduce the supply of indigenous oil and gas to the U.S. economy. Reduced crude production would have to be offset by increased imports, if available;

* *Editor's Note:* These estimates include the savings from mandatory speed limit reductions and legislation similar to that passed in California to reduce electricity usage.

however, imported crude would probably have a high sulfur content and many U.S. refineries cannot process such crude. This would also make the United States even more dependent on imports and would adversely affect the U.S. economy and balance of payments. Administration of such a program would be extremely complex. For example, provisions would have to be made to compensate owners of shut-in production for reduced current income and, in many cases, reduced ultimate recovery. Establishment of fair compensation would be difficult and litigation on behalf of such owners would probably result. In addition, such action would cost the Nation from 5 to 10 times more per barrel of daily production capacity than security storage of crude or product.

Security storage of refined products or crude after production can be located aboveground in steel tanks or underground in caverns leached in salt or mined in hard rock. The primary advantage of steel tank storage is locational flexibility and the ease with which supplies can be integrated into the existing petroleum logistical system. The major disadvantage of aboveground tank storage is the high cost--$3.80 to $7.00 per barrel, depending on location, type of storage and local conditions. The availability of steel for timely construction of very large scale tankage projects is also of concern.

In contrast, storage in salt domes can be provided for $0.60 to $0.85 per barrel if the volume to be stored exceeds 100 MMB. Many salt domes on the Gulf Coast are capable of accommodating storage projects of several hundred million barrels. Extensive experience with such storage in the United States has proven its safety and reliability. Since crude or product is stored in large caverns, very high redelivery rates are possible. For example, a single 200 MMB project might require only 20 to 40 wells and be capable of a redelivery rate of several million barrels per day during an emergency. Although other underground storage alternatives were also evaluated (mined caverns, salt beds, abandoned mines, depleted reservoirs), storage in salt domes has the lowest cost. Such storage is normally located 2,000 feet below the surface and is, therefore, more secure against natural disasters and sabotage than steel tank storage.

Crude oil storage in salt domes appears more practicable than refined product storage. The potential for weathering is reduced, and any quality problems that might occur with crude oil could be corrected during refining. Problems of quality control, questions of what grades, types and volumes of finished products to store and the seasonal nature of major product demands would exist for high-volume security storage of refined products over an extended period of time in a salt dome environment. Additionally, transportation of product from salt dome storage to terminals would be more difficult and expensive than for crude. Thus, if a product security storage program is implemented, storage aboveground in higher cost steel tankage is probably the best alternative. It is recognized that residual fuel oil imports present a special case because such imports are concentrated on the East Coast.

Because of the apparent inability to protect against a substantial import interruption by any other means, it is concluded that a substantial volume of crude security storage is required. Such storage should be located in Gulf Coast salt domes. A security storage volume of about 500 MMB in combination with other available supplies would provide protection commensurate with similar programs in effect in other consuming nations. Proposed new Gulf Coast deepwater terminal and pipeline facilities, which should be in service by 1978, will be capable of transporting imported crude to a large percentage of Midwest and Rocky Mountain refineries. Therefore, salt dome storage projects should be located near deepwater terminal tank farms to ensure easy distribution of security storage crude to refineries during an emergency.

Location of security storage crude for East Coast refineries in Gulf Coast salt domes will save $4 to $5 per barrel in storage cost. Gulf Coast deepwater terminals can be designed to permit loading of security storage crude for delivery to the East Coast during an emergency. However, use of foreign flag vessels to augment the U.S. fleet may be required to ensure timely delivery during an emergency. Need for storage on the West Coast will depend on supply self-sufficiency there. Factors to be considered include the impending availability of North Slope crude and flexibility to ship crude from the Gulf Coast.

Leaching of several hundred million barrels of salt dome storage could be completed in about 6 years. Significant storage could be ready to fill about 1979, which is consistent with the anticipated startup of Gulf Coast deepwater terminals. Therefore, completion of a 500 MMB crude storage program in the early 1980's appears feasible if crude can be made available for fill.

Foreign crude could be utilized for fill; however, cost, timely availability, and high sulfur content are of concern. Production of certain domestic fields above MER to provide storage fill appears to be an unlikely possibility. Elk Hills (NPR-1) crude is low in sulfur content, and represents a reliable large volume, low cost source of supply. Another potential source of oil to fill security storage would be Federal Government royalty entitlements. An advantage of using this oil is that it would be clearly established that it would be available to meet either public (defense) or private needs under emergency conditions without introducing difficult problems of ownership, equity or compensation for inventory holding costs. It must be recognized, however, that commitment of royalty oil to security storage would increase oil import requirements in order to balance supplies with current consumption.

RECOMMENDATIONS

In submitting its recommendations, the National Petroleum Council's Committee on Emergency Preparedness feels that the following points should be emphasized:

- *We will likely be more dependent on foreign oil in the future.* The extent of increased U.S. dependence on imported oil will largely be determined by our ability to conserve energy and increase domestic energy production. In the event of greater dependency on imports, a future embargo would have more severe and lasting effects on the U.S. economy if proper preparation has not been undertaken.

- *We cannot base plans on favorable weather conditions.* The winter of 1973-1974 was 8 percent warmer than normal in the United States and almost 5 percent warmer than the previous year. The resulting reduction in consumption of all heating fuels significantly reduced the severity of the oil shortage. This favorable circumstance cannot be assumed for future planning.

- *Emergency conservation potential will diminish over time.* Until the fall of 1973, energy in the United States was relatively inexpensive and many users were little concerned with energy conservation. Due to widespread public response to the need to conserve during the recent embargo and price increases following the embargo, major efforts are being made to conserve energy. Thus, there will be less potential for quick and easy conservation measures, and future supply shortages will more rapidly begin to impinge on critical energy requirements.

- *Public support of emergency measures must be secured through avoidance of misunderstanding as to the reality, the extent and the impact of an interruption.* Industry and government were ill-equipped to communicate the complex nature of the impact of the embargo on the economy and on the industry's complicated logistical system. As a result, the public became occupied with the question of whether an oil shortage even existed. Industry reporting procedures were not well enough developed to provide the kind of detail required to monitor the shortage effectively. In the event of a future embargo, the government, the communications media and industry need to be better equipped to appraise and communicate the problems to the American public resulting from an interruption in supply.

The Council realizes that years, perhaps decades, will be required to achieve the goal of energy self-sufficiency. In the interim, specific though flexible procedures must be developed to prevent any future interruption of energy supplies from exerting unacceptable pressures upon the U.S. economy.

In the interest of emergency preparedness, the National Petroleum Council submits the following recommendations:

1. The United States must adopt and implement national energy policies designed to increase the Nation's self-sufficiency in energy.

Sound and consistent government policies are required if energy conservation is to be encouraged and if the various energy suppliers to this country are to develop maximum domestic energy supplies and thereby minimize the need for and cost of emergency preparedness to protect against a sudden energy emergency. The key elements of such policies were outlined in the NPC's report, U.S. Energy Outlook, and are reaffirmed in this report:

- The United States must adopt broad national objectives for solving the energy problem.
- Healthy, viable and expanding energy industries should be encouraged by government.
- Import policies should not hinder the growth of domestic refining capacity.
- Field prices of natural gas should be allowed to reach competitive levels.
- A balance should be sought between environmental goals and energy requirements.
- Both the government and industry should continue to promote energy conservation and efficiency of energy use.
- Access to the Nation's energy resource potential underlying public lands should be accelerated.
- Energy research and development of technology should be accelerated.
- Tax policies should foster the discovery and development of domestic energy resources.
- The United States should support its nationals engaged in energy operations abroad.

2. The United States should develop an operational definition of an energy emergency.

At the outset of the recent embargo, the Nation found its emergency mechanisms inappropriate because emergency preparedness plans were based solely upon a military or defense-type emergency. An important lesson of the embargo is that the United States needs to define an "energy emergency," thus empowering its administration to take appropriate emergency actions in the event threatened or actual economic sanctions or boycotts are applied against this country. The form of these powers should be such that a high degree of flexibility in administration is allowed. Such powers would serve the country both as a deterrent to external economic pressure and as an effective means of response should such pressure be applied.

3. Standby emergency preparedness plans should be developed to allow participation by industry personnel.

Through the Emergency Petroleum and Gas Administration (EPGA), the United States has access to the knowledge and experience of experts and technicians within the petroleum industry. The expertise of these individuals is the cornerstone of the EPGA's effectiveness and organization in a declared national emergency.

It became clear in the initial stages of the recent embargo that because of the "conflict of interest" and antitrust statutes, personnel in industry would not be able to respond to the government's request to staff the Energy Allocation Planning Task Force (EAPTF) and the Office of Petroleum Allocation (OPA). It is apparent that this inability to serve on the part of industry personnel seriously affected the government's program. A future energy emergency is likely to produce the same result unless corrective action is taken.

To obviate this problem and to provide the government with the personnel necessary to deal effectively with such emergencies would require substantial amendments to the existing conflict of interest and antitrust statutes.

4. The Federal Government should reassess the potential and use of the Naval Petroleum Reserves in a future emergency.

Of the four Naval Petroleum Reserves, only NPR-1 (Elk Hills in California) has any near-term potential producing capacity for use in an emergency. In 1972, the Comptroller General estimated about $69 million would be required to develop NPR-1 to its maximum efficient rate of 267 MB/D. This rate might be achieved within 2 to 3 years. Regardless of the future dispositions of this reserve, the National Petroleum Council recommends that the requisite development be completed since it would greatly enhance the value of NPR-1 to the Nation.

Because of the uncertainties regarding the Nation's future energy position, the Council recommends that decisions on the ultimate disposition of whatever potential capacity is developed in Naval Petroleum Reserves be made after the reserves have been evaluated.

5. The United States should develop standby emergency consumption reduction measures.

The United States should have available emergency consumption reduction programs specifically designed for responding to an energy supply interruption and available for immediate use. While the FEO rapidly implemented the provisions of the Emergency Mandatory Petroleum Allocation Act of 1973, this legislation was not totally appropriate for an embargo situation. In addition, calls for voluntary use curtailment were often hastily conceived, and the consumer, though willing, was often confused. Any standby energy demand reduction measures developed for use in future emergencies should be strongly oriented toward consumer education and cooperation. While a mandatory rationing system should be carefully developed, its use should be restricted until the effectiveness of other measures has been obtained. The gasoline retailing techniques (odd-even day sales, Sunday closings, minimum sale requirements, staggered and posted hours of services, etc.) used during the recent embargo suggest that substantial reductions in gasoline consumption can be managed without resorting to a coupon rationing system.

6. *In an emergency situation, options to increase domestic energy supplies through additional oil and gas production and additional use of coal should be utilized.*

The volume of temporary emergency oil production available from private fields is quite small compared to the potential size of an import interruption. This capacity above MER can be expected to decline to a negligible amount by the early 1980's. There are a number of legal and regulatory constraints to the effective utilization of such capacity. However, despite these problems such short-term emergency production could provide a degree of protection during the remainder of this decade and should be made available if practicable. This will require that state and federal regulatory agencies cooperate in developing acceptable procedures that will permit such emergency production.

Opportunities for converting utilities from oil or gas to coal will be limited since significant conversion is underway or planned. Since some small potential in dual-fired plants will remain through the end of the decade, conversion of these plants should be part of an emergency preparedness plan. In order to keep the Nation's future options as open as possible, it appears prudent to require such new oil or gas-fired power plants as may be approved to construct and maintain coal handling and burning facilities. Provisions for variances in environmental regulations during an emergency will assure the contribution of coal substitutability in an emergency.

7. *The United States should develop an emergency petroleum security storage system.*

The United States should create a petroleum security storage system that, in combination with other available measures, will provide adequate time to react positively to a substantial, sudden interruption in petroleum imports. Objectives concerning the ultimate size and structure of such a program will undoubtedly change with time because of the constantly changing world political and economic environment. However, it is clear that a substantial volume of petroleum security storage is needed within the United States and that efforts to implement such a program should begin immediately because of the long construction lead times involved. Such a program must, of course, consider future U.S. obligations which may arise from international emergency energy sharing programs.

First consideration should be given to providing crude oil security storage to protect domestic refinery runs. This study indicates that 500 MMB of crude storage in combination with normally available inventories will provide 90 to 180 days of supply for a large percentage range of crude imports presently foreseen. Crude storage can be efficiently located in one or more Gulf Coast salt dome projects and integrated with the crude transportation system that will serve Gulf Coast deepwater terminals. Specific circumstances and specific logistical problems could require storage of fuel oil at strategic locations on the East Coast.

Among other important considerations to be resolved are the extent of government and/or industry financing and administration of the emergency storage and its fill. The Council feels that security storage should not be utilized until after (1) a proper declaration of an energy emergency by government and (2) appropriate voluntary and mandatory standby consumption reduction measures have been implemented.

Chapter One

ANALYSIS OF THE 1973-1974 OIL EMBARGO

While the recent embargo did not last long enough to fully evaluate the effectiveness of all emergency measures employed, analysis of the events of last winter provides useful guidance for future response to an energy emergency. The embargo was announced in mid-October 1973 but was not felt in the United States until late December. A number of factors appear to have combined to delay the impact on the United States.

- Sailing time from the Middle East to the United States is approximately 30 to 35 days. At the time the embargo began, those tankers loaded and enroute to the United States did not reach their destination for about 1 month.
- Offshore refineries supplying products to U.S. markets (primarily Caribbean) had sufficient inventory to continue operations and shipments for at least an additional 3 weeks.
- The worldwide logistical system was able to adjust to absorb some of the impact.

The impact was further reduced by lower demand due to warmer-than-normal weather in the United States and Europe and prompt responses to voluntary and mandated reductions in consumption of energy. These factors were important in keeping inventory at satisfactory levels throughout the embargo period.

The allocation plan developed by the Federal Energy Office established that industry (including utilities) was to be given the highest priority in order to minimize impact on the gross national product (GNP) and employment. The FEO set home and commercial heating requirements as a second priority with provisions for preference over industrial requirements if supplies became critically short. A third major consumption area, non-industrial/commercial use of gasoline, was assigned lowest priority and suffered the greatest shortage. In seeking to maximize heating oil stocks in anticipation of peak winter requirements, the FEO directed refiners to maximize yields of middle distillate and heavy fuel oil. The FEO attempted to adjust supply patterns such that no area of the country suffered greater than average hardship. Unfortunately, the new regulatory agency had analytical and organizational problems which did not allow it to respond quickly enough to local problems, and severe regional dislocations occurred.

Because the full effect of the embargo was delayed, the following analysis will be limited to the first quarter 1974 situation when the embargo was fully effective. Table 3 sets forth the U.S. supply/demand balance by Petroleum Administration for Defense (PAD) Districts (see Figure 4 for a map of the five PAD Districts) for the first quarter 1974 and the first quarter 1973, for comparison purposes, in order to gauge the severity of the dislocation caused

TABLE 3

U.S. SUPPLY/DEMAND BALANCE – FIRST QUARTER COMPARISONS BY PAD DISTRICT

(Thousand Barrels Per Day)

	PAD Districts										Total	
	I		II		III		IV		V		U.S.	
	1973	1974	1973	1974	1973	1974	1973	1974	1973	1974	1973	1974
Domestic Demand												
Motor Gasolines	2,181	2,009	2,160	2,006	907	963	177	182	928	860	6,353	6,020
Aviation Fuels	432	345	221	198	90	100	31	29	332	275	1,106	947
Distillate Fuel Oil*	2,250	1,925	1,154	1,103	387	401	100	111	322	308	4,213	3,848
Residual Fuels	2,258	1,921	311	278	167	184	31	36	443	429	3,210	2,848
All Other	530	498	937	887	1,556	1,511	78	70	274	262	3,375	3,228
Total Domestic Demand	**7,651**	**6,698**	**4,783**	**4,472**	**3,107**	**3,159**	**417**	**428**	**2,299**	**2,134**	**18,257**	**16,891**
Shipments to Other Districts												
Products	160	148	133	155	3,739	3,229	92	104	28	22	–	–
Crude and Unfinished	52	61	52	53	1,734	1,801	291	335	–	–	–	–
Total Shipments	**212**	**209**	**185**	**208**	**5,473**	**5,030**	**383**	**439**	**28**	**22**	–	–
Exports	18	17	5	5	103	108	–	–	105	72	231	202
Stock Change	(317)	(501)	(136)	(84)	(290)	(46)	47	53	(99)	(35)	(795)	(613)
Required Supply	**7,564**	**6,423**	**4,837**	**4,601**	**8,393**	**8,251**	**847**	**920**	**2,333**	**2,193**	**17,693**	**16,480**
Domestic Production												
Crude and Condensate	110	114	986	931	6,377	6,149	639	714	1,126	1,091	9,238	8,999
NGL and Other	27	27	248	253	1,380	1,387	45	45	50	43	1,750	1,755
Receipts from Other Districts												
Products and NGL	3,106	2,579	786	790	81	96	55	48	124	145	–	–
Crude and Unfinished	275	371	1,744	1,730	74	101	1	1	35	47	–	–
Total Receipts	**3,381**	**2,950**	**2,530**	**2,520**	**155**	**197**	**56**	**49**	**159**	**192**	–	–
Imports												
Products and NGL	2,748	2,272	169	157	89	109	51	55	158	171	3,215	2,764
Crude and Unfinished	1,252	993	750	566	222	269	44	44	766	630	3,034	2,502
Total Imports	**4,000**	**3,265**	**919**	**723**	**311**	**378**	**95**	**99**	**924**	**801**	**6,249**	**5,266**
Processing Gain and Other	46	67	154	174	170	140	12	13	74	66	456	460
Total Supply	**7,564**	**6,423**	**4,837**	**4,601**	**8,393**	**8,251**	**847**	**920**	**2,333**	**2,193**	**17,693**	**16,480**
Inventory Close of Period (MMB)												
Actual	174	184.6	246	227	299	331	35	39	131	121.5	887	953.1
5-Year Average (1969-1973)	–	–	–	–	–	–	–	–	–	–	–	924.7

*Includes kerosine and middle distillates.

Source: U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

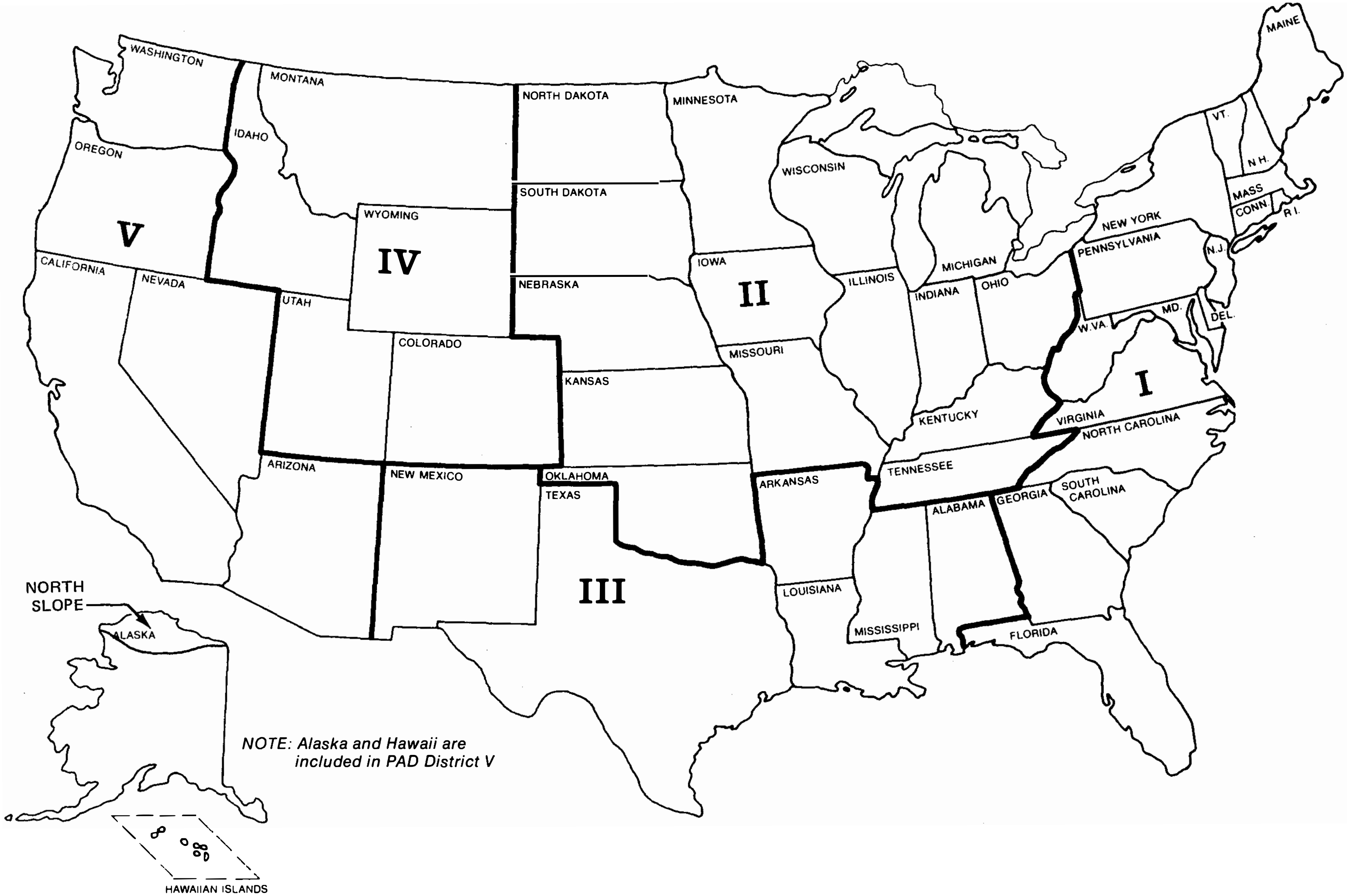


Figure 4. Petroleum Administration for Defense -- (PAD) Districts.

by the embargo. It should be noted, however, that this comparison somewhat understates the effect because the real measure of the dislocation would be the difference between actual results and what 1974 unconstrained demand and unlimited supply would have been without an embargo (most estimates assumed growth over 1973). First quarter 1974 and fourth quarter 1973 estimates on this basis are shown in Table 4 for the total United States. Table 5 shows the monthly total U.S. supply/demand balance for the 6 months--October 1973 to March 1974.

As shown in Table 6, the combined efforts of curtailment and conservation, warmer weather and other factors reduced petroleum product consumption during the first quarter of 1974 by about 326 MB/D *more* than the reduction in supplies caused by the embargo. Even excluding the effects of warmer-than-normal weather, the steps actually taken were almost adequate to offset the embargo's effect. This is, of course, a nationwide average covering all products and understates the seriousness of geographical or specific product problems, particularly fuels used for heating in northern parts of the country. A colder-than-usual winter would have necessitated much more stringent demand restrictions.

LOGISTICAL IMPACT OF THE EMBARGO WITHIN THE UNITED STATES

The embargo causes some redistribution of oil flows within the United States. No major logistical problems appeared to limit these redistribution efforts.

PAD District I was the area most directly affected by the embargo because of its heavy (about 50 percent) dependence on imports. First quarter 1974 imports were down 735 MB/D, and receipts from other districts down 431 MB/D *versus* first quarter 1973. Inventory drawdown within PAD District I contributed significantly to first quarter 1974 supplies. As would be expected, with less oil moving into and within the district, no logistical difficulties were encountered.

The major logistical problems within PAD District II were not a direct result of the embargo but rather, resulted from the FEO's crude allocation plan in response to the embargo. The abnormal crude movements and changes in crude slate to some refiners called for by this plan caused some difficulties in reversing and reconnecting pipelines and causing unwanted inventory buildup of crude and products because refiners could not operate their equipment efficiently. No product limitations were noted.

There was considerable change in the movement of oil into and out of PAD District III. Foreign imports of crude declined but were partially offset by crude shipments from PAD District IV, although these were limited by availability of pipeline capacity which could be redirected. Product shipments to PAD Districts I and II decreased, while shipments to PAD District V increased. Product receipts into PAD District III increased. Other than the

TABLE 4

U.S. SUPPLY/DEMAND BALANCE – ACTUAL *VERSUS* ESTIMATED UNCONSTRAINED
(Thousand Barrels Per Day)

	Fourth Quarter 1973			First Quarter 1974		
	Estimated Uncon-strained*	Actual	Actual Over (Under)	Estimated Uncon-strained*	Actual	Actual Over (Under)
Domestic Demand						
Motor Gasolines	6,704	6,572	(132)	6,615	6,020	(595)
Aviation Fuels	1,155	1,085	(70)	1,138	947	(191)
Middle Distillates	3,822	3,609	(213)	4,629	3,848	(781)
Residual Fuels	3,049	2,856	(193)	3,629	2,848	(781)
All Other	3,685	3,536	(149)	3,564	3,228	(336)
Total Domestic Demand	**18,415**	**17,658**	**(757)**	**19,575**	**16,891**	**(2,684)**
Exports	228	217	(11)	213	202	(11)
Total Demand	**18,643**	**17,875**	**(768)**	**19,788**	**17,093**	**(2,695)**
Stock Change	(443)	(80)	363	(939)	(613)	326
Required Supply	**18,200**	**17,795**	**(405)**	**18,849**	**16,480**	**(2,369)**
Domestic Production						
Crude and Condensate	9,195	9,119	(76)	9,128	8,999	(129)
NGL and Other	1,740	1,783	43	1,725	1,755	30
Total Domestic Production	**10,935**	**10,902**	**(33)**	**10,853**	**10,754**	**(99)**
Imports						
Crude Oil	3,561	3,503	(58)	3,713	2,502	(1,211)
Residual Fuels	2,094	1,762	(332)	2,398	1,771	(627)
Other Products	1,097	1,175	78	1,365	993	(372)
Total Imports	**6,752**	**6,440**	**(312)**	**7,476**	**5,266**	**(2,210)**
Processing Gain and Other	513	453	(60)	520	460	(60)
Total Supply	**18,200**	**17,795**	**(405)**	**18,849**	**16,480**	**(2,369)**
Inventory Close of Period (MMB)						
Actual	–	1,008.3	–	–	953.1	–
5-Year Average (1969-1973)	–	1,002.5	–	–	924.7	–

*Independent Petroleum Association of America, Pre-Denial 1973 Estimate, Report of the Supply/Demand Committee (October 23, 1973).

TABLE 5

U.S. SUPPLY/DEMAND BALANCE – FIRST AND FOURTH QUARTER COMPARISONS BY MONTH
(Thousand Barrels Per Day)

	Fourth Quarter 1973			First Quarter 1974		
	October	November	December	January	February	March
Domestic Demand/Consumption						
Motor Gasolines	6,677	6,823	6,223	5,804	6,100	6,162
Aviation Fuels	1,117	1,058	1,076	936	891	1,009
Middle Distillates*	3,095	3,814	3,923	4,132	4,116	3,323
Residual Fuels	2,547	3,118	2,910	3,035	3,010	2,516
All Others	3,673	3,634	3,310	3,375	3,266	3,047
Total Domestic Demand/Consumption	**17,109**	**18,447**	**17,442**	**17,282**	**17,383**	**16,057**
Exports	221	202	227	207	203	196
Total Demand	**17,330**	**18,649**	**17,669**	**17,489**	**17,586**	**16,253**
Stock Change	703	(473)	(482)	(1,072)	(996)	191
Required Supply	**18,033**	**18,176**	**17,187**	**16,417**	**16,590**	**16,444**
Domestic Production						
Crude and Condensate	9,172	9,144	9,041	8,907	9,156	8,950
NGL and Other	1,785	1,799	1,766	1,731	1,768	1,765
Total Domestic Production	**10,957**	**10,943**	**10,807**	**10,638**	**10,924**	**10,715**
Imports						
Crude Oil	3,740	3,452	2,891	2,382	2,248	2,462
Residual Fuels	1,556	1,942	1,793	1,732	1,923	1,674
Other Imports	1,229	1,470	1,261	1,241	1,050	1,079
Total Imports	**6,525**	**6,864**	**5,945**	**5,355**	**5,221**	**5,215**
Processing Gain and Other	551	639	435	424	445	514
Total Supply	**18,033**	**18,176**	**17,187**	**16,417**	**16,590**	**16,444**
Inventory Close of Period (MMB)						
Actual	1,037.4	1,023.2	1,008.3	975.1	947.2	953.1
5-Year Average (1969-1973)	1,045.8	1,033.8	1,002.5	952.8	917.4	924.7

*Includes kerosine and distillates.

Source: U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

TABLE 6

U.S. PETROLEUM SUPPLY AND DEMAND REDUCTIONS—FIRST QUARTER 1974*
(Thousand Barrels Per Day)

Supply Reductions		**Amount of Decrease**
Domestic Crude and NGL Production		99
Crude Oil Imports		1,211
Residual Fuel Oil Imports		627
Other Product Imports		372
Processing Gain and Other		60
Total Supply Reduction		**2,369**
Demand Reductions in Response to Supply Reductions		
Curtailment and Conservation	1,009	37%
Warmer-than-Normal Weather	441	16%
Conversion to Alternate Fuels	87	3%
Reduced Exports	11	1%
Other (Price effects, lower economic activity, unidentifiable conservation efforts, product unavailability, etc.)	1,147	43%
Total Consumption Reduction	**2,695**	**100%**

*As calculated *versus* unconstrained demand estimated by IPAA. Independent Petroleum Association of America, Pre-Denial Estimate, Report of the Supply/Demand Committee (October 23, 1973).

limitations on crude movements from District IV, it appears that few logistical difficulties in either the products or crude systems were encountered.

PAD District IV supplies were probably the least affected by the embargo, although crude shipments from this district to PAD Districts II and III were increased above previous levels. Crude and product logistics problems were largely averted.

PAD District V saw a reduction in offshore imports and some decline in Canadian imports. As crude rebalancing occurred, some refineries experienced problems due to crude quality. A variety of product inventory and distribution problems were encountered, but apparently none were of industry-wide significance.

Inventory Considerations

Table 7 sets out the actual inventories of crude and principal products for the 12 months ending July 1974 which includes the embargo period, historical average and lowest level in the recent past--presumed minimum operating level (MOL).* It is reasonable to consider for planning purposes that the difference between historical average and MOL for crude or a given product is inventory available in an emergency.

* *Editor's Note:* MOL is defined as the sum of total *unavailable* inventories and working stocks.

TABLE 7

U.S. INVENTORIES OF CRUDE OIL AND PRODUCTS
(Million Barrels)

	1973						1974					
	July	August	September	October	November	December	January	February	March	April	May*	June*
Motor Gasoline												
Actual Inventories	212	205	210	215	207	210	218	219	220	224	229	224
5-year average	200	196	200	202	205	213	227	233	229	223	218	211
5-year low	188	184	189	190	199	209	218	216	208	205	202	200
Distillate Fuel Oil†												
Actual Inventories	161	177	190	203	200	197	181	149	129	126	143	158
5-year average	162	184	199	209	203	182	152	125	111	112	123	142
5-year low	156	175	190	196	183	154	130	112	101	102	113	129
Residual Fuel Oil												
Actual Inventories	53	54	55	55	52	54	47	45	47	51	53	57
5-year average	58	59	61	62	58	56	52	47	47	43	51	54
5-year low	48	43	54	55	52	54	47	43	40	43	45	46
Crude Oil												
Actual Inventories	244	248	241	246	250	243	233	241	245	256	270	273
5-year average	265	260	257	259	261	258	252	253	258	264	275	271
5-year low	244	248	241	246	250	243	233	235	244	349	258	249
Total Crude and Products												
Actual Inventories	986	997	1,016	1,037	1,023	1,008	975	947	953	983	1,006	1,038
5-year average	1,002	1,015	1,034	1,046	1,034	1,001	961	922	925	942	972	992
5-year low	971	983	1,010	1,018	1,018	959	906	867	887	913	934	958

*May and June 1974 preliminary volumes from API weekly bulletins plus estimates for miscellaneous products not reported to API.

†Includes kerosine and middle distillates.

Source: U.S. Bureau of Mines, *Mineral Industries Survey,* Monthly Petroleum Statements.

Under non-emergency conditions, inventory levels of crude and products are a reflection of the following principal factors:

- *Minimum operating levels*: This refers to the inventory level of crude and various products below which the system will not operate. It consists of pipeline fill; volume in transit in ships, tank cars, barges and trucks; crude and products in process in refineries; and a basic level of working stocks in the total distribution system (terminals, bulk plants, service stations). Unless this minimum level is maintained throughout the industry, spot shortages and delays will begin to appear, followed by widespread disruption of supply to consumers if the shortage get severe.

- *Seasonal buildup*: Demand for most products varies according to the season of the year (basically, gasoline in the summer, heating oil in the winter). The industry's total production and refining capability runs at a relatively flat rate throughout the year, but the yields at refineries can be varied to maximize or minimize production of certain products. This flexibility is not sufficient to meet swings in demand from current production. Accordingly, off-season production in excess of current demand goes to inventory buildup to meet the next season's needs. This seasonal inventory buildup cannot be used in an emergency without causing a shortage later.

- *Temporary market dislocations*: From time-to-time, industry over-or under-production occurs because demand fails to develop as anticipated or surges beyond expectations (e.g., aberrations in the weather, variations in economic activity). The extra inventory or relative shortage are of short-term duration, cannot be predicted and, consequently, may either help or hinder during emergency periods.

- *Economics of inventory control*: Carrying inventory of crude or products represents a significant working capital investment. It is obviously good finance to keep inventories at the lowest possible level consistent with the foregoing factors and the objective of meeting market demands. Inventory management has received considerable attention in recent years as the cost of money has risen and is evidenced by the fact that the amount of supply on hand relative to demand has tended downward.

It is apparent from examination of the inventory levels that distillate fuel oil was the only product group that was in adequate supply during the embargo period. The reason was an allocation program that restricted use in order to accommodate anticipated cold weather, which then turned out warmer-than-normal so that the accumulation was not needed. The other products and crude oil hovered at or just above minimum operating level.

FACTORS AFFECTING PETROLEUM DEMAND IN THE FIRST QUARTER OF 1974

During the first quarter of 1974, consumption of the principal petroleum products was reduced through mandatory measures by government and voluntary measures by consumers. In addition, large price increases were instrumental in reducing demand, while fortuitous weather conditions contributed a significant downward influence. The combined effect on each major product varied. An analysis of the major factors which reduced the consumption or production of the major fuel products during the first quarter of 1974 follows.

Motor Gasoline

The major factors affecting motor gasoline are shown in Table 8.

TABLE 8

FACTORS AFFECTING CONSUMPTION OF MOTOR GASOLINE
(Thousand Barrels Per Day)

Motor Gasoline Consumption	**Consumption (Reduction)**
Projected Domestic Consumption	6,615*
Actual Domestic Consumption	6,020†
Apparent Reduction	(595) 9%
Principal Constraining Factors	
Reduced Speed Limit	(120)
Less Discretionary Driving	(180)
More Car-Pools	(150)
Higher Prices and Other	(145)
Total Reduction	(595)

*Independent Petroleum Association of America, Pre-Denial 1973 Estimate, Report of Supply and Demand Committee (October 23, 1973).

†U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

Reduced Speed Limit

The effect of reduced speed on demand is based on *An Interim Report on Some Ways of Conserving Oil* by the Office of Energy Conservation, published October 1, 1973, and the analysis of the Committee. Each assumes a 50 miles per hour (MPH) maximum speed limit and arrives at similar reductions equal to about 3.5 percent of total motor gasoline consumption, or about 250 MB/D. The Committee assumes a 75 percent compliance level, which brings the reduction to 190 MB/D.

In relating these studies to the first quarter 1974, two variations must be considered. The first is that the speed limit was set at 55 MPH instead of 50 MPH. The second is that a compliance level of 90 percent appears warranted instead of 75 percent because it was legislated, not voluntary. The speed limit change to 55 MPH, instead of 50 MPH, is estimated to reduce the savings to 2 percent from 3.5 percent or 132 MB/D instead of 250 MB/D. The application of the 90 percent compliance further adjusts the savings to 120 MB/D.

Reduction in Discretionary Driving

As a result of the FEO's mandatory allocation program, the Sunday closings and limited hours of service station operation on other days and the concern of the public for conserving energy, a definite reduction in discretionary travel took place. There are no statistics available to quantify accurately the reduction, but 10 percent appears reasonable and conservative. Studies indicate that 80 percent of gasoline consumption is by passenger cars, and one-third of this amount is for discretionary driving. Accordingly, the estimate for this use in the first quarter 1974 was 1,764 MB/D, and a 10 percent reduction would approximate 180 MB/D.

More Car-Pools

Estimates of reduced gasoline consumption attainable from increased participation in car-pools have ranged upward from 300 MB/D. While it was evident by observation during the embargo that there was an increase in car-pooling, it is impossible to determine accurately the extent. Nevertheless, a saving on the order of 150 MB/D can be attributed to increased car-pooling by the following reasoning.

Automotive travel represents 80 percent of total gasoline demand. Of this, some 34 percent is work related (34% x 80% = 27%). Since 70 percent of this travel is by individuals with no passengers (70% x 27% = 19%), it is assumed that some 75 percent of these drivers might be able to join car-pools (75% x 19% = 14%). If this 14 percent joined in four person car-pools, 75 percent of their travel would be eliminated--i.e., one driver, three passengers (75% x 14% = 11%). On the assumption that there was 20 percent compliance, consumption was reduced 2.2 percent (20% x 11%), or 150 MB/D (6,615 MB/D x 2.2%).

Demand Elasticity

A number of studies have been made to determine to what extent price change affects gasoline demand. The relationship is expressed as the percent change in demand for each percent change in price and is characterized as price elasticity of demand. Estimations by various organizations vary rather widely. Four representative demand elasticity estimates for gasoline are described in Table 9.

TABLE 9

COMPARISON OF GASOLINE DEMAND ELASTICITY ESTIMATES

Organization	Elasticity Estimate
Data Resources	-.12 to -.16
Stanford Research Institute	-.40
Chase Econometrics	-.15
FEO	-.16
Average	**-.21**

Applying the arithmetic average elasticity factor of .21 to the 24 percent average gain in regular gasoline pump prices (price increase from January 1, 1974 through March 31, 1974) would indicate a gasoline demand decrease of 4.05 percent. Thus, based on a "normal" demand of 6,615 MB/D, a reduction of about 333 MB/D might be expected.

However, the effects of price on demand are both direct and indirect. For example, a direct user response simply would be to reduce miles driven; more indirect responses might include reduced speed, increased car-pooling, engine tune-up, etc. While quantitative division between direct and indirect effects is indeterminate, for purposes of this report, it is assumed that more than half of the indicated elasticity effect is indirect and has already been counted in previously discussed conservation estimates. Thus, the direct elasticity effects, not previously accounted for, are estimated to be 40 to 50 percent of the 333 MB/D, or about 145 MB/D.

Aviation Fuel

Principal factors affecting supply/demand of aviation fuels are shown in Table 10. The 191 MB/D reduction in consumption of aviation fuel reflects the curtailment dictated in the Mandatory Allocation Program of January 15, 1974. The allocation levels established in the program ranged from 95 percent of 1972 purchases for airline companies to 75 percent of 1972 purchases for pleasure flying by individuals. In addition to the curtailment/reduction forced by allocation levels, sales to all aviation users were subject to the allocation fraction of each supplier. These fractions had a wide range across the country, but it is believed the average was no greater than 90 percent. As a consequence of these two factors, principal users such as major airlines were able to obtain only 85.5 percent of their 1972 purchases. Other users received less, while a limited number of priority users were able to obtain as much as 90 percent of 1972 purchases.

TABLE 10

FACTORS AFFECTING CONSUMPTION OF AVIATION FUELS
(Thousand Barrels Per Day)

Aviation Fuel	Consumption (Reduction)	
Projected Domestic Consumption	1,138*	
Actual Domestic Consumption	947†	
Apparent Reduction	**(191)**	**17%**
Principal Constraining Factors		
Assumed Load-Factor Increases	(100)	
Known Conservation Steps	(15)	
Further Increase in Load-Factor or Conservation Steps	(76)	
Total Reduction	**(191)**	

*Independent Petroleum Association of America, Pre-Denial 1973 Estimate, Report of the Supply/Demand Committee (October 23, 1973).

†U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

The following comments are devoted primarily to listing measures taken by the aviation industry to operate with the volume available rather than quantifying reduction efforts under a voluntary curtailment program. Since approximately 75 percent of the total aviation fuel consumed in the first quarter of 1974 was kerosine-type fuel, it is reasonable to look to the performance of the commercial airlines to determine where the reductions in use were achieved. In previous reports, it has been stated that a 15 percent increase in load-factor would generate a 23 percent reduction in demand for fuel. Table 11 was developed from statistics on domestic trunkline travel as published in *Aviation Week and Space Technology*.

The tabulation shows that between the initiation of the embargo and January 1974, the load-factor increased 7.6 percentage points with virtually no change in revenue miles, but with a 13 percent decrease in available seat miles. The load-factor improvement is, therefore, a valid reflection of the reduction in jet fuel. Using the same ratio of load-factor to consumption reduction noted above, the 7.6 point increase in load-factor resulted in a reduction of 11.7 percent in jet fuel demand. The unconstrained demand for jet fuel in the first quarter of 1974 would have been 845 MB/D; therefore, the reduction due to increased load-factor can be estimated by 100 MB/D.

In addition to the savings generated by the increased load-factor, the Air Transport Association indicates that airlines in

TABLE 11

RESPONSES BY THE AIRLINE INDUSTRY TO REDUCED FUEL SUPPLY

	Revenue Seat Miles x 10^3	Available Seat Miles x 10^3	Load-Factor (%)
October 1973	9,567	19,778	48.4
January 1974	9,616	17,166	56.0

Source: *Aviation Week and Space Technology*; October 1973 data from February 18, 1974 issue, January 1974 data from April 22, 1974 issue.

general have been employing fuel conservation measures as far back as 1970 for economic reasons. These steps include:

- Reducing use of engines while on the ground
- Operating at the highest altitude permitted
- Reaching high altitude rapidly
- Staying at high altitude as long as possible
- Selecting most direct route
- Reducing air speeds to optimum rate.

Prior to the embargo, it was estimated that the measures noted above contributed savings in the order of 21 MB/D. Since the embargo, these same measures have been implemented to an even greater degree and the Air Transport Association estimates an additional savings of 15 MB/D.

The voluntary conservation measures described above are assumed to account for 115 MB/D of the estimated reduction of 191 MB/D, and it is extremely difficult to say with certainty exactly where the remaining 76 MB/D reduction occurred. It is quite probable that it is attributable to price increases which apparently motivated the airline industry to greater conservation measures or higher load-factors than estimated above.

Middle Distillates

"Middle distillates" is a general term for products more usually identified as #1 oil (stove oil), #2 oil (furnace oil), #4 oil (fuel oil, mostly for space heating), diesel fuel and kerosine not consumed as aviation fuel.

The principal factors affecting middle distillates are shown in Table 12.

TABLE 12

FACTORS AFFECTING CONSUMPTION OF MIDDLE DISTILLATES
(Thousand Barrels Per Day)

Middle Distillates	Consumption (Reduction)	
Projected Domestic Consumption	4,629*	
Actual Domestic Consumption	3,848†	
Apparent Reduction	**(781)**	**17%**
Principipal Containing Factors		
Warmer-than-Normal Weather	(275)	
2° Thermostat Setting Reduction	(230)	
Allocation/Conservation/Price/Lower Economic Activity	(286)	
Total Reduction	**(781)**	

*Independent Petroleum Association of America, Pre-Denial 1973 Estimate, Report of the Supply/Demand Committee (October 23, 1973).

†U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

Warmer Weather

About half the middle distillates are consumed for heating purposes on an annual basis. The greatest proportion is consumed in the first quarter of the year when the coldest weather occurs. Of the 4,629 MB/D unconstrained demand for middle distillates estimated for the first quarter 1974, some 3,590 MB/D would have been used for heating according to historical experience. Of this, about 93 percent was estimated to be PAD Districts I and II. Some 18 percent of this amount is used for heating water and, therefore, is not affected significantly by weather patterns. If the effect of warmer-than-normal weather, as measured by degree days in principal cities, is applied to the distillates used for space heating (12.2 percent warmer in PAD District I, 5 percent warmer in PAD District II), the indicated effect of the warmer weather was to reduce consumption by 275 MB/D.

Thermostat Settings

It is difficult to determine with any degree of certainty the extent to which the public responded to the suggestion that home thermostat settings be reduced. However, an overall effective reduction of 2 degrees appears reasonable. Studies indicate that a 2 degree reduction in thermostat settings will produce a 9 percent reduction in consumption. In the first quarter 1974, this would have been equal to 230 MB/D (3,590 MB/D less 18% for water heating x 9%).

Other Factors

A number of additional factors accounted for the 286 MB/D remainder of the reduction. Price was undoubtedly responsible for a significant amount, including additional thermostat adjustment. Some 40 MB/D can be ascribed to lower economic activity as measured by a 2 percent reduction in the Federal Reserve Board production index in the first quarter 1974 *versus* that expected.

Residual Fuel Oil

Residual fuel oil consumption was reduced by 781 MB/D during the first quarter 1974 as shown in Table 13.

TABLE 13

FACTORS AFFECTING CONSUMPTION OF RESIDUAL FUEL OIL
(Thousand Barrels Per Day)

Residual Fuel Oil	Consumption (Reduction)	
Projected Domestic Consumption	3,629*	
Actual Domestic Consumption	2,848†	
Apparent Reduction	**(781)**	**22%**
Principal Constraining Factors		
Lower Electricity Use	(74)	
Conversions to Coal and Electricity Imports	(87)	
Warmer-than-Normal Weather	(166)	
2°F Thermostat Setting Reduction	(140)	
Lower Refinery Throughput	(44)	
Lower Economic Activity, Allocation/Conservation	(270)	
Total Reduction	**(781)**	

*Independent Petroleum Association of America, Pre-Denial 1973 Estimate, Report of the Supply and Demand Committee (October 23, 1973).

†U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly and Annual Petroleum Statements.

Lower Electricity Use

Due to a combination of price effect, warmer weather, conservation and some voltage reductions, use of electricity in the first quarter of 1974 was slightly less than the year before (445.2×10^9 KWH *versus* 457.2×10^9 KWH). Expected growth in the first quarter would have been 6 percent under normal conditions.

The measure of growth that did not occur was equivalent to 74 MB/D and represents the effect of the demand reduction measure noted above.

Conversion to Coal

Prior to the last denial period, it was estimated that conversion of gas and oil burning boilers to coal over the first 90 days of the denial would have a maximum potential of displacing 250 MB/D of oil with 23 MMT of coal. This was predicated on implementing several necessary measures such as increasing coal production from existing mines, allocating coal supplies, relaxing sulfur limits, constructing or rehabilitating railroad hopper cars and other transportation equipment, and repairing coal handling and transfer facilities.

Because of the difficulties expected in implementing these actions, a range of 39 MB/D to 119 MB/D was considered likely of quick attainment during an emergency. During the recent embargo, the acutal experience in fuel convertibility proved to be only 61 MB/D, due primarily to the inability of plants to get air quality variances and coal supplies of required quantity and quality and adequate transportation facilities. In addition to these conversions, 26 MB/D was saved by importing power from Canadian sources.

Warmer-Than-Normal Weather

Normal heating requirements expected for the total United States in the first quarter 1974 would have been 1,480 MB/D. About 93 percent of this total is normally consumed in PAD Districts I and II. Applying the warmer weather percentage as measured by degree days in these two PAD Districts, a savings of 166 MB/D is indicated.

Two Degree Reduction in Thermostat Settings

Applying the 9 percent savings attributable to lowering thermostats, 2 degrees results in a saving of 140 MB/D at 100 percent compliance. It appears reasonable to assume the equivalent of 100 percent compliance was achieved since residual fuel consumption for heating is by commercial and industrial establishments. It is likely, in fact, that the settings may have been adjusted to an even lower level in many instances.

Lower Refinery Throughput

Refinery runs in the first quarter 1974 averaged 11,303 MB/D or 890 MB/D less than the year before. For incremental crude run, a heavy fuel oil consumption of about 5 percent appears to be a reasonable estimate. Applying 5 percent to 890 MB/D indicates a reduction in refinery fuel and loss of 44 MB/D.

Other Factors

Real Gross National Product (GNP) in the first quarter was down 7.0 percent on an annual basis. GNP probably cannot, however, be translated directly to lower residual fuel consumption. The remaining 270 MB/D of unidentified reduction, therefore, can only be attributable to a combination of the smaller real growth rate, conservation and allocations.

ECONOMIC IMPACT OF THE EMBARGO

Effect on GNP

Any review of the effects of the recent embargo on U.S. energy consumption and GNP is beset by uncertainties regarding what the growth in consumption and GNP would have been without the embargo. With respect to pre-embargo GNP, the Chase Econometrics forecast of September 1973 has been used.

Figure 5 shows the estimate of the impact of the embargo on GNP developed by the NPC in November 1973. That estimate indicated U.S. oil supply shortages would have the following impact on U.S. GNP:

Shortage (MMB/D)	Percent Reduction in Real GNP
2.0	3.6
3.0	7.8

The actual shortage during the first quarter 1974, as estimated by the Federal Energy Office, was 2.7 MMB/D. Figure 5 indicates that a 2.7 MMB/D shortage would entail a reduction in real GNP of about 6.7 percent *versus* what would have been expected without the embargo. Prior to the announcement of the embargo, Chase Econometrics forecast a 1.4 percent increase (annual rate base) in first quarter real GNP growth.

Putting these results together yields the following estimates for first quarter 1974 real GNP gain/loss (annual rate basis):

- 1.4 percent estimated before embargo
- (6.7) percent oil shortage effect
- (5.3) percent projected with 2.7 MMB/D shortage.

The latest estimate of first quarter 1974 actual results is that real GNP showed a decline of 7.0 percent (annual rate basis), the sharpest decline for a single quarter since 1958.

Although the NPC relationships would appear to understate the GNP effect, other factors should, of course, be considered. For example, the forecast of GNP under the "no embargo" assumption

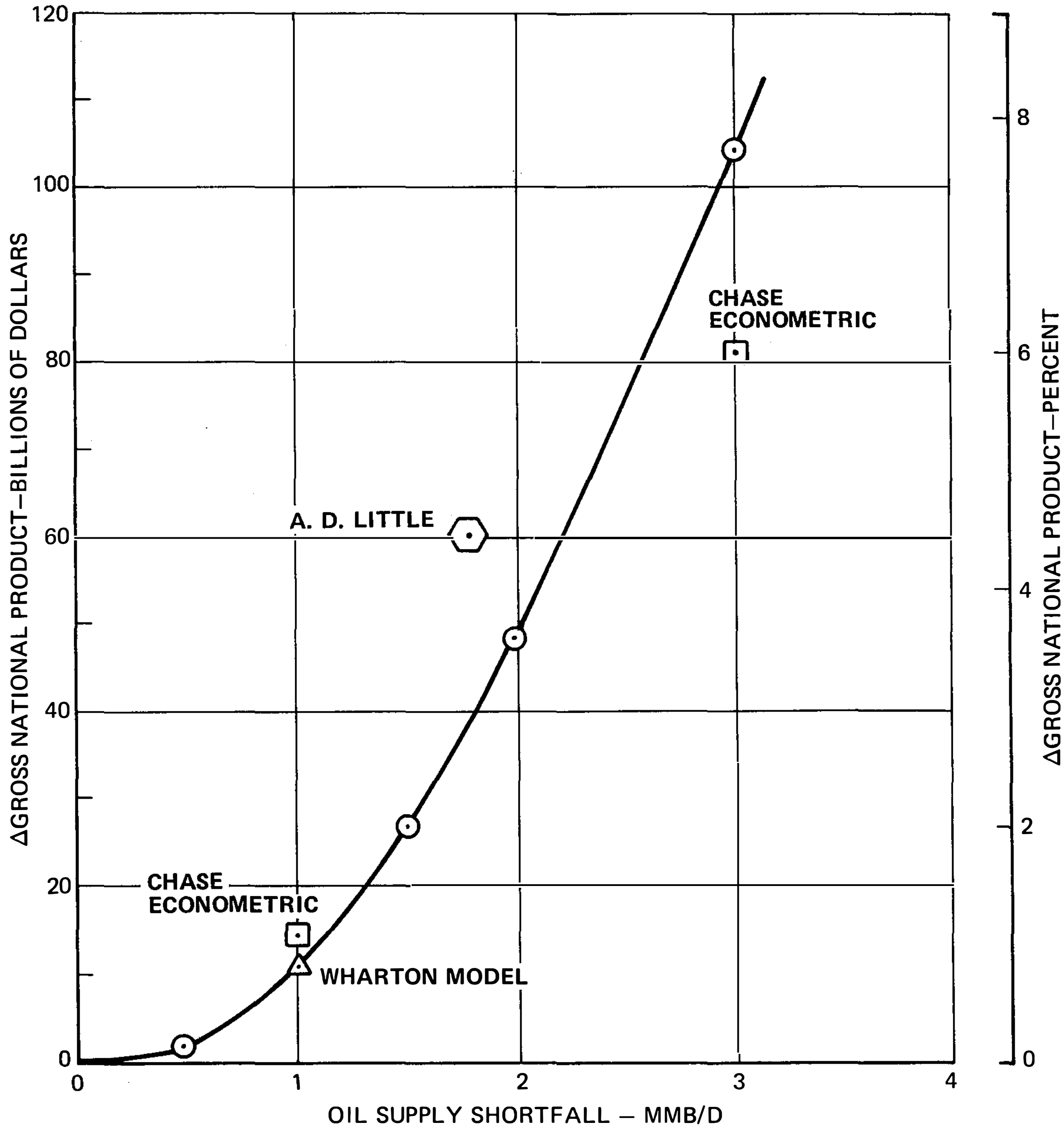


Figure 5. Comparison of Estimated Effects of Oil Supply Shortage on GNP.

might be overestimated, due to greater than expected response in reducing pruchases of gasoline, heating oil and electricity, and to very prompt reactions in such industries as automobiles and airlines. Finally, it may well be that the estimated relationship between energy consumption and real GNP, particularly in the short-term, is not adequately precise to expect more accuracy than is exhibited in the first quarter comparison.

Government action in maintaining the flow of energy toward industry apparently was successful in confining the effects on economic activity and employment to relatively few firms. In general, industrial activity and transportation services were well maintained, with an insignificant number of man-hours lost. It was the consumer who most directly felt the impact of the shortage. Consequently, it was the secondary but significant impact on the automobile, construction, recreation, motel and similar industries which had the most depressing effects on the general level of economic activity. It appears that the policy followed prevented the spread of stagnating effects throughout the economy and precluded development of a deflationary spiral which could easily have had more serious implications for the Nation. However, it should be pointed out that the adverse GNP effects of energy use curtailments increase exponentially rather than in direct proportion. Thus, there is substantial incentive to effect even moderate reductions in dependency on overseas oil imports.

Even though employment declined significantly in specific industries (for example, in the auto industry from an average of 1,847,000 in the fourth quarter 1973 to 1,707,000 during the first quarter 1974), overall unemployment during the first quarter of 1974 averaged only 5.2 percent. This was 0.5 percentage points higher than the rate experienced prior to the embargo.

Factors tending to minimize unemployment during the first quarter included:

- Reductions in overtime and normal working days lowered the unemployment rate by about 0.5 percentage points compared to what it might have been.

- The decrease in productivity (real GNP per man-hour) was greater than anticipated. Of the 7.0 percent decline in real GNP, only about one-fourth was due to a reduction in man-hours, and three-fourths was due to declining productivity. Therefore, it appears that because of uncertainties about the duration and economic impact of the embargo, many employers retained workers who might otherwise have been laid off.

- The primary industrial effects were concentrated principally in industries which are relatively capital-intensive rather than labor-intensive.

Thus, it appears that the policy of protecting jobs by giving industrial oil requirements high priority was generally effective in keeping unemployment to a minimum.

Effect on Inflation

The recent embargo exerted upward pressure on the rate of domestic price inflation in several ways:

- It increased the cost not only of oil but of all forms of energy. The principal reason the embargo had such an enormous impact on the economies of the Western World is that oil, specifically imported Arab oil, was relied upon as the swing fuel in the West's energy supply. In the United States and in most other countries, oil is accorded that role by the process of elimination: nuclear power is still in its infancy; natural gas supplies are in decline largely because the price of gas has been held below its value; coal is faced with environmental problems; and hydropower has limited development potential. Thus, oil remains the incremental fuel, and as such, sets the level toward which other energy prices tend.

- Beginning before the embargo and accelerating during the embargo, the rapid and large increase of world oil prices resulting from producing country government actions had additional impact on the U.S. economy as well as the world economic system. Energy costs are diffused throughout the economy, each commodity and service becoming more costly depending upon its energy component. In the United States, it has been estimated that about one-fourth of the increase in wholesale prices in the first half of 1974 could be attributed to the increase in energy costs.

- The embargo has resulted in enormous shifts in the balance of payments between oil producing and oil importing nations. Uncertainties regarding the future impacts of continuing balance of payment problems promotes an atmosphere of monetary instability.

- The embargo prompted the Federal Reserve Board to increase the money supply at the risk of increasing inflation. Consequently, growth in the money stock which had averaged 6.1 percent per year in the 12 months ending in October 1973 increased to an annual rate of 10 to 12 percent in November/December, and an average 8.8 percent per year through April 1974. Since that time, the money stock has grown at a considerably slower rate.

OBSERVATIONS OF THE EMBARGO EXPERIENCE

The major lesson of the oil embargo is the necessity of a standby organization prepared and empowered to implement pre-planned programs to allocate efficiently, and possibly ration, crude oil and refined products as required by the emergency. Also needed is a data gathering system which can provide a quick and accurate assessment of the impact of any future supply disruption. The Emergency Petroleum and Gas Administration (EPGA) established under the Defense Production Act is such an organization and provides for prestaffing through the Executive Reservist program.

It became clear in the initial stages of the recent embargo that because of the "conflict of interest" and antitrust statutes, personnel in industry would not be able to respond to the government's request to staff the Energy Allocation Planning Task Force (EAPTF) and the Office of Petroleum Allocation (OPA). It is apparent that this inability to serve on the part of industry personnel seriously affected the government's program. A future energy emergency is likely to produce the same result unless corrective action is taken.

To obviate this problem and to provide the government with the personnel necessary to deal effectively with such emergencies would require substantial amendments to the existing conflict of interest and antitrust statutes.

The embargo has awakened the Nation, as no other event could, to the desirability of increasing U.S. energy self-sufficiency. Such a course of action, though justifiable as a national imperative, will boost the rate of expenditures on energy, increase the volume of funds that must be withdrawn from other purposes, and exert upward pressure on the general price level.

In addition to the broad points discussed above, the following items briefly allude to other specific problems arising during the embargo. At the outset, it should be noted that these items are discussed to assist consideration of measures for possible future import curtailments and are not intended to be critical:

- Because of the ineffectiveness of voluntary allocation programs and the legal inability of companies to jointly discuss and coordinate effective actions to alleviate the shortage, the Mandatory Allocation Program adopted by the government was critically needed. Generally, the priorities selected were appropriate and effective in minimizing hardships.

- Combined efforts of federal and state governments in initiating and enforcing actions such as reduced speed limits and Sunday gasoline station closings were quite effective.

- Crude allocation rules apparently were made without regard for maximizing utilization of the more efficient refining capacity and contained some inequitable features.

- State "set-asides" frequently were poorly administered by states having no expertise in this area.

- Product allocation regulations were excessively rigid, thus leaving suppliers with inadequate flexibility to achieve efficient product distribution.

- Because of the complexity of normal market activities, emergency product allocation approaches used by the government frequently were ineffective and inequitable.

- Price controls in effect during the embargo introduced disturbing economic effects in both the oil and coal industries. For example, disallowing pass-through of non-crude refining costs discourages domestic refining capacity expansion and favors product imports. Price controls also resulted in shortages of critical coal mining items such as roof bolts and ammonium nitrate.

In formulating standby programs for use in the event of a future import curtailment, these and other factors should be considered to minimize counterproductive features and to provide a congruence of government and industry effort.

Chapter Two

LONG-TERM IMPACTS OF THE EMBARGO

The disruption of oil imports into the United States from October 1973 through March 1974 dramatically demonstrated the critical need for developing a plan for coping with possible future interruptions. Supply/demand patterns, cost/price relationships, rate of energy growth in various sectors, energy economics at the consumer level, environmental impact and government policy were all affected by the circumstances of the import disruption.

IMPACTS ON FUTURE SUPPLY/DEMAND

Prior to October 1973, U.S. oil demand projections over the next 10 to 15 years reflected compound growth rates in the range of 4 to 6 percent per year. Domestic oil demand was not generally assumed to be supply limited. Any deficit between projected U.S. oil demand and supply was assumed to be balanced by foreign oil imports. Cost of oil was assumed to remain low, relative to the other energy fuels, reflecting only inflationary price trends.

Today there is considerable uncertainty associated with the long-range projection of U.S. energy and oil demand. Particularly uncertain is the future level of oil imports that will be required. Calls for energy self-sufficiency have directed attention to the need for accelerating the development of U.S. energy supplies in order to minimize our Nation's reliance on foreign sources of energy. The following sections deal first with a number of factors which contribute to the uncertainties surrounding future U.S. energy supply and demand, therefore contributing to the uncertainty in future import requirements. Subsequent to these discussions a projection of U.S. supply and demand, including imports, is presented.

The Effect of Energy Conservation

It is evident that the volume of oil imports in the future can be significantly affected by the degree to which the United States is successful in conserving energy. During the embargo, government encouragement, plus skyrocketing prices, led to savings in energy that were most important to the Nation in weathering the supply interruption. It now seems clear that total energy (and particularly, petroleum) consumption could be significantly reduced if a positive, well-constituted conservation program were implemented. On the other hand, its success will depend largely on the degree and extent of voluntary acceptance by consumers.

Uncertainties regarding consumer acceptance and government policies relating to energy conservation make projecting future energy supply/demand balances difficult. It should be pointed out, however, the degree to which energy conservation is implemented in the United States will determine the size of the conservation "cushion" at its disposal in a future emergency.

The Effect of Price

The recent embargo and steep increases in petroleum prices have further complicated energy supply/demand projections. Prior to the embargo, price elasticity of demand, especially for gasoline, was not considered. Indeed, considering the very moderate petroleum price growth in the United States since World War II, and the minor price variation within the range of the market, little or no empirical basis for elasticity estimates had been available. However, petroleum prices have increased dramatically since early 1973 as shown in Table 14.

TABLE 14

MAGNITUDE OF CRUDE COST INCREASES
(Dollars Per Barrel)

	Approximate Crude Oil Market Price		
	Early 1973	Mid-1974	Percent Gain
Average Domestic	$3.50	$7.00 to 7.50	100% +
Arab. Light, fob Persian Gulf	2.00	9.00 to 11.00 +	350 to 450% +

While the above figures are only approximates, they demonstrate the sharp price increases over recent months. Precise demand reductions arising directly from these price increases are difficult to estimate. However, even very low estimates of price elasticity would still result in substantial absolute volume effects when applied to the extremely large price increments noted above.

Prices, of course, also have important upward effects on the supply of energy. In the petroleum industry, drilling activity has sharply increased in recent months, which contrasts with the steady decline of the last decade. In addition to boosting drilling activity, other favorable supply effects of higher domestic crude prices include encouragement of secondary/tertiary recovery projects that would otherwise be uneconomic, and extension of the economic life of marginal and stripper wells.

The Effect of Government Actions

To a significant degree, federal, state and local governments influence energy supply and demand either through action or inaction. Government energy policy is finally reflected in the level of domestic energy supply and in the quantities of petroleum imports that are required over the years, and such policy is, therefore, an important element in establishing an emergency preparedness program. The most significant areas of positive and negative government influence on U.S. energy supply and demand include:

- Environment-related laws and regulations affecting speed limits, car size, pollution control equipment and stack-gas emission standards
- Environmental constraints for oil and gas exploration and development, for coal and shale oil mining and for nuclear plant siting and operation
- Construction standards to promote energy conservation in residential and commercial structures
- Price controls on various forms of energy
- Tax incentives, such as liberal investment tax credits on facilities or for new processes, and disincentives, such as the possible reduction or elimination of the depletion allowance or other punitive tax law changes
- Financial aid for energy development, such as grants for R&D and pilot plants.

The Effect of Progress Toward U.S. Energy Self-Sufficiency

Achieving the goal of energy self-sufficiency depends primarily on leadership from the government in developing comprehensive, viable natural energy policies. Before this can be accomplished, the government must coordinate the often confusing and conflicting policies of the more than 60 agencies or departments involved in energy related matters.

Proposals for financial incentives to accelerate all phases of energy development are mentioned with offsetting proposals within Congress to reduce present incentives or create disincentives to new energy development activities. Resolution of these conflicting views is essential as uncertainty regarding their outcome will continue to have a depressing effect on U.S. energy supplies. Energy development requires huge investments, and the supply of capital is finite, both from the standpoint of a given industry and from individuals within an industry. Important to capital supply is the rate of internal cash flow generation which currently does not appear to be sufficient to meet all requirements. Capital markets will have to provide the balance. In order for energy suppliers to attract capital at reasonable costs in competition with other industries, they must be allowed to operate at a profit level which is competitive.

Another factor affecting energy development is technology. Examples of areas where technology is still not perfected are the *in situ* recovery of shale oil, more efficient processes for synthesizing crude and gas from coal and offshore oil and gas development in very deep (over 1,500 feet) water. While much progress in these areas has been made, the speed of future energy development is highly dependent on how effectively the technological problems are resolved. These factors add to the uncertainty of the rate of progress toward U.S. energy self-sufficiency.

The Effect of Availability of Foreign Oil Supplies

Future availability and price of foreign oil supplies to the United States will depend on at least four critical factors:

- The still uncertain, but emerging, balance between world crude oil requirements and availability
- The decisions to be made by producing country governments with respect to expansion of productive capacity and subsequent allowable production levels
- The extent to which the large oil importing nations can restrain consumption
- The future impact on oil costs and price relationships of the changing relationship (participation) between producing country governments and the companies.

The eventual outcome with respect to each of the above four factors is highly uncertain at this time, as is the anticipated result of the interaction of these four factors.

SURVEY OF CURRENT PROJECTIONS OF LONG-TERM OUTLOOK

As a result of the sudden change in the international energy supply and price conditions, previous appraisals of the energy supply/demand by both government and industry have been significantly modified. Although the National Petroleum Council's U.S. Energy Outlook Report of 1972 is still a useful analytical tool, that study did not analyze the impact of an oil embargo or of a sharp upsurge in world oil prices.

In order to better evaluate the longer term, the Committee found it necessary to have an updated energy supply/demand outlook. The NPC staff polled several private sources of current U.S. energy supply and demand projections and developed an average or medium case to reflect a consensus of data received. As might be expected, the current projections of total energy consumption are substantially below pre-embargo estimates. In fact the high range of estimates received follows closely the low average demand projections of the U.S. Energy Outlook study in 1972. Most of the reduction can be attributed to energy conservation caused primarily by higher prices and the development of a new conservation ethic. Somewhat slower economic growth projections would account for relatively modest reductions from earlier energy consumption projections.

Eight individual energy supply/demand projections were submitted to the NPC staff on a confidential basis--i.e., not to be released to other members of the industry--and a consensus balance was developed. The findings of the survey indicated many striking differences of opinion regarding the demand outlook and supply trends; therefore, a medium case was formulated to represent a reasonable consensus among the various views of the respondents. Table 15 shows the high/low range of the projections which were submitted.

The projections of the medium case by fuel are summarized in Table 16. This case suggests that domestic production of oil will increase (which would be a reversal of the recent trend) and that the decline in natural gas production will be halted. It further indicates that there will be substantial progress in the development of coal reserves, and in the technology for converting coal to synthetic fuels. Finally, all the respondents were optimistic regarding the future production of nuclear power. Although the projections of nuclear energy are not as high as many analysts envisioned several years ago, the current estimates do not reflect expectations of serious environmental or technological roadblocks in the development and siting of nuclear power plants.

The medium case shows continuing large volumes of oil imports through 1990. In most projections imports tended to stabilize in 4 to 5 years, but at levels higher than currently experienced. One projection included in this survey foresees a substantial decline in oil imports, but even in that estimate oil imports provide about 6 percent of the total energy in the United States in 1990. The high/low range of the import range of the import projections is summarized in Table 17.

The range of potential import levels is admittedly quite broad, which is not unexpected recognizing current uncertainties affecting the worldwide energy situation. An equally wide divergence of views is evidenced in recent published projections. In general, the range of projections within the survey group shows less dispersion for total energy consumption than for some of the components of supply and demand such as domestic production, imports, electric power output and consumption in the component sectors.

Energy consumption in the medium case is projected to grow, between 1972 and 1985, at an average annual rate of 3.2 percent, the high range being 3.6 percent and the low range 2.6 per year. This range of projections is below the annual growth rate of the past 5 years (4.5 percent) and that of the past 25 years (3.7 percent). The apparent differences were results of different concepts regarding economic growth, political incentives or constraints and especially fuel availabilities.

Background Assumptions in Survey

Although the background assumptions regarding political and economic conditions varied among the individual respondents to the survey, there were the following general similarities:

TABLE 15

RANGE OF ENERGY CONSUMPTION PROJECTIONS
(Million Barrels Per Day Crude Oil Equivalent)

	Actual	Survey Projections			
	1972	1978	1980	1985	1990
High		42.1	45.2	53.9	63.7
Low	34.1	39.2	41.2	47.5	55.6
Medium Case		41.0	43.7	51.4	60.5

- Government will continue to encourage voluntary energy conservation but it will not pass major legislation creating end-use controls.

- There will be no massive, emergency government programs to achieve energy self-sufficiency, however, policies will be modified to accelerate the development of indigenous energy resources, while still retaining desired environmental goals.

- There will be no major political disruption that would upset the energy supply/demand balance for individual countries or regions.

- Private industry will be permitted to make decisions and pursue the most economic means of meeting energy needs without undue restriction by federal and state governments and without significant reduction in economic incentives through excessive taxation and other means.

- Total primary energy costs will remain near the current level, in terms of constant dollars. Natural gas prices will rise to more nearly reflect true market values.

- The long-term growth rate for real gross national product will be a little less than 4 percent per year.

Energy Consumption

U.S. energy consumption by fuels and by consuming sector for the medium case is shown in Table 18. Very little growth is expected for oil consumption in the residential/commercial markets; therefore, most of the new heating load must be assumed by gas and electricity. Much of the limited new gas supply is shown to be used in the high priority residential/commercial sector, while the electric utility sector will receive declining volumes of gas.

TABLE 16

U.S. ENERGY SUPPLY AND DEMAND BALANCES
1972-1990 – MEDIUM CASE
(Trillion BTU's Per Year)

Energy Form*	1972†	1978	1980	1985	1990	Average Annual Percent Change 1972-1980	Average Annual Percent Change 1980-1990
Oil	32,966	39,500	41,100	44,500	46,800	2.8	1.3
Gas	23,125	23,500	24,400	26,400	28,300	0.7	1.5
Coal	12,495	15,900	17,300	19,700	22,000	4.2	2.4
Nuclear	576	4,400	6,500	14,200	25,500	35.4	14.6
Hydroelectric	2,946	3,200	3,300	3,500	3,600	1.4	0.9
Geothermal	8	120	170	300	400	46.5	8.9
Other (Solar, etc.)	–	–	–	200	600	–	11.6
Total	**72,116**	**86,620**	**92,770**	**108,800**	**127,200**	**3.2**	**3.2**

*Energy is classified according to its final consumption, i.e. synthetic oil is in "Oil," and syngas is in "Gas." "Coal" includes conventional usage plus losses for production of synthetic fuels.

†Source for 1972 figures: U.S. Bureau of Mines, News Release March 13, 1974.

TABLE 17

RANGE OF OIL IMPORT PROJECTIONS
(Million Barrels Per Day)

	1978			1980			1985			1990		
	High	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**
Total Crude and Product Imports	9.4	5.2	7.8	10.2	5.3	7.8	12.5	5.4	8.4	12.0	4.0	8.1
Total Offshore Crude and Product Imports	8.4	4.5	6.9	9.3	4.6	7.1	11.8	3.7	7.5	11.4	2.0	7.2
Total Offshore Crude Imports Only	5.9	2.0	4.5	6.6	2.3	4.9	8.1	2.3	5.1	7.6	1.0	4.9

TABLE 18
TOTAL U.S. ENERGY CONSUMPTION BY FUELS AND BY CONSUMING SECTORS—NPC SURVEY MEDIUM CASE
(Trillion BTU's)

Sectors	Pet. Liq.*	Nat. Gas* (Dry)	Coal*	Nuc.	Hydro-Electric	Geo-Thermal	Other—(Solar, etc.)	Total Primary Energy	Electricity Distributed To Sector	Total† Energy Consumption
	Primary Energy Inputs to Sector									
Residential/Commercial										
1972‡	5,530	7,642	387	–	–	–	–	13,559	3,478	17,037
1978	5,800	8,900	200	–	–	–	–	14,900	4,800	19,700
1980	5,900	9,500	200	–	–	–	–	15,600	5,400	21,000
1985	6,000	10,700	150	–	–	–	200	17,050	7,300	24,350
1990	6,000	12,000	100	–	–	–	600	18,700	9,000	27,700
Transportation										
1972‡	17,108	790	4	–	–	–	–	17,902	17	17,919
1978	20,600	900	–	–	–	–	–	21,500	20	21,520
1980	21,800	950	–	–	–	–	–	22,750	30	22,780
1985	23,800	1,100	–	–	–	–	–	24,900	90	24,990
1990	24,800	1,100	–	–	–	–	–	25,900	200	26,100
Industrial										
1972‡	3,533	9,917	4,143	–	35	–	–	17,628	2,493	20,121
1978	4,700	9,700	4,700	–	35	–	–	19,135	3,380	22,515
1980	4,800	10,000	5,000	–	35	–	–	19,835	3,770	23,605
1985	5,300	10,800	5,500	–	35	–	–	21,635	5,010	26,645
1990	5,700	11,200	7,000	–	35	–	–	23,935	6,800	30,735
Electric Utility										
1972‡	3,134	4,102	7,837	576	2,911	8	–	18,560	(5,988)	12,580
1978	3,500	3,200	10,800	4,400	3,165	120	–	25,185	(8,200)	16,985
1980	3,400	3,100	11,800	6,500	3,265	170	–	28,235	(9,200)	19,035
1985	3,100	2,800	13,100	14,200	3,465	300	–	36,965	(12,400)	24,565
1990	3,000	2,700	13,100	25,500	3,565	400	–	48,265	(16,000)	32,265
Non-Energy & Other										
1972‡	3,661	674	124	–	–	–	–	4,459	–	4,459
1978	4,830	800	150	–	–	–	–	5,780	–	5,780
1980	5,100	850	150	–	–	–	–	6,100	–	6,100
1985	6,170	1,000	200	–	–	–	–	7,370	–	7,370
1990	7,150	1,300	250	–	–	–	–	8,700	–	8,700
Synthetic Conversion Losses										
1972‡	–	–	–	–	–	–	–	–	–	0
1978	70	–	50	–	–	–	–	120	–	120
1980	100	–	150	–	–	–	–	250	–	250
1985	130	–	750	–	–	–	–	880	–	880
1990	150	–	1,550	–	–	–	–	1,700	–	1,700
Total										
1972‡	**32,966**	**23,125**	**12,495**	**576**	**2,946**	**8**	**–**	**72,116**	**–**	**72,116**
1978	**39,500**	**23,500**	**15,900**	**4,400**	**3,200**	**120**	**–**	**86,620**	**–**	**86,620**
1980	**41,100**	**24,400**	**17,300**	**6,500**	**3,300**	**170**	**–**	**92,770**	**–**	**92,770**
1985	**44,500**	**26,400**	**19,700**	**14,200**	**3,500**	**300**	**200**	**108,800**	**–**	**108,800**
1990	**46,800**	**28,300**	**22,000**	**25,500**	**3,600**	**400**	**600**	**127,200**	**–**	**127,200**

*Energy is classified according to its final consumption, i.e. synthetic oil is in "Oil," and syngas is in "Gas." "Coal" includes conventional usage pluss losses for production of synthetic fuels.

†For all sectors except "Electric Utility" and "Synthetic Conversion Losses," total consumption equals primary energy inputs plus electricity. For electric utility sector, total consumption equals generation, transmission and distribution losses. For "Synthetic Conversion Losses," total consumption equals net primary fuel losses in synthetic oil and gas manufacture.

‡1972 data are from U.S. Bureau of Mines press release dated March 13, 1974. Gross consumption table adjusted for non-energy items as shown in instructions.

Energy Supply

The breakdowns of U.S. fuel supplies for the medium case are shown on Table 19. The estimated trends of domestic production are especially significant: projections of oil and gas production indicate a substantial increase in drilling activity in the United States which is expected to reverse the historical decline in crude oil productive capacity and to slow the decline in natural gas productive capacity in the lower 48 states. When North Slope gas becomes available (around 1980) there may be a small upturn in natural gas production. The rapid growth anticipated for coal output is premised on large-scale development of western coal fields. A summary of the growth rates for U.S. production in the medium case compared with the highest and lowest estimates by respondents is shown in Table 20.

The medium case projection of a 60 percent rise in oil import levels (*versus* the 1972 level) indicates that the group is very doubtful that the Nation will achieve complete self-sufficiency in energy during the 1980's, despite a large production of synthetics. The one projection in the sample that comes closest to achieving self-sufficiency shows large gains in domestic production and very high outputs of synthetics. But it also includes fairly high estimates for demand. According to this case, *net* imports of all forms of energy would amount to 5 to 6 percent of total consumption in the year 1990 (approximately 4 MMB/D equivalent). Under such supply conditions, the fairly high demand estimate appears realistic assuming no further oil embargoes.

Projections of fossil fuel supplies, expressed in terms of physical units, are shown in Table 21. In addition, this table includes estimates of total installed capacity of nuclear power plants and average plant heat rate.

Outlook for Refining Capacity

Based on the medium case projection of future energy supply and demand, the United States will continue to import about 8 MMB/D of crude and products for the foreseeable future. The medium case indicates that crude imports will be in the range of 5 to 5.5 MMB/D, with product imports 2.5 to 3.0 MMB/D.

A projection of U.S. refining capacity growth through 1978 by PAD Districts and for total United States is given in Table 22. This projection was prepared by analyzing announced expansion plans and weighing each project's probability of actually being built. Including only those projects which were considered to have a good or average probability of being completed, U.S. refining capacity should increase by about 3 MMB/D (to 17.25 MMB/D) by January 1, 1978. It is felt that this level of capacity growth is within the industry's engineering, capital, and construction capability. Domestic crude, condensate and NGL plus crude imports projected for 1978 in the medium case total 16.8 MMB/D, and are within projected U.S. refining capacity.

TABLE 19

U.S. ENERGY SUPPLIES*
(Trillion BTU's Year)

	Actual 1972	NPC Survey Medium Case 1978	1980	1985	1990
Oil†					
Total Domestic Production	21,928	22,910	24,100	25,900	27,300
Crude and Lease Condensate	19,344	20,340	21,550	23,400	24,850
NGL	2,584	2,570	2,550	2,500	2,450
Total Imports‡	10,112	16,440	16,600	17,350	16,650
Total Crude	4,541	10,300	10,900	11,600	11,400
Canadian	1,749	1,100	1,000	1,200	1,300
Other	2,792	9,200	9,900	10,400	10,100
Total Products (Incl. NGL and Unfinished)	5,571	6,140	5,700	5,750	5,250
Canadian	561	750	600	550	500
Other	5,010	5,390	5,100	5,200	4,750
Exports	-463	-400	-400	-400	-500
Processing Gain, Etc. §	912	1,000	1,100	1,250	1,300
Syncrude	—	80	300	1,030	2,400
From Shale	—	80	270	840	1,800
From Coal	—	—	30	190	600
From Inventory	477	-190	-200	-200	-200
Crude	74	-60	-70	-70	-50
Products	403	-130	-130	-130	-150
Total Oil Supply	**32,966**	**39,840**	**41,500**	**44,930**	**46,950**
Gas‖					
Production (Marketed Production of Wet Gas)**	24,878	24,140	24,270	24,350	24,250
Extraction Loss, Transfers Out	-2,584	-2,570	-2,550	-2,500	-2,450
Imports	1,051	1,650	2,230	3,020	3,730
Exports	-80	-80	-80	-80	-90
From Inventory	-140	-150	-200	-230	-240
Total Dry Natural Gas	**23,125**	**23,090**	**23,700**	**24,560**	**25,200**
Syngas	—	410	700	1,840	3,100
From Coal	—	70	270	1,220	2,350
From Liquids	—	340	430	620	750
Total Gas Supply	**23,125**	**23,500**	**24,400**	**26,400**	**28,300**
Coal‖ ††					
Total Production	14,500	18,420	20,450	24,760	29,500
For Conventional Domestic Markets	14,500	18,300	20,000	22,600	25,000
For Synthetic Oil and/or Gas Plants	—	120	450	2,160	4,500
Net Exports	-1,543	-2,080	-2,350	-2,510	-2,600
From Inventory	-580	-290	-320	-350	-360
Losses, Gains and Unaccounted for	-118	-30	-30	-40	-40
Total Coal Supply	**12,495**	**16,020**	**17,750**	**21,860**	**26,500**
Nuclear					
Equivalent Primary Energy Input	576‡‡	4,400	6,500	14,200	25,500

*Including Alaskan production.

†U.S. Bureau of Mines, Petroleum Statement, 1972 Annual (final) and News Release, March 13, 1974.

‡Breakdown of BTU values for Canadian and other imports for 1972 ratioed from barrel data in Annual Petroleum Statement. Total BTU data from U.S. Bureau of Mines March 13, 1974 press release.

§Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude inputs and losses.

‖U.S. Bureau of Mines, News Release, March 13, 1974, source for 1972 (final) and 1973 preliminary figures.

**Excludes quantities for repressuring, vented and flared.

††Anthracite, bituminous and lignite.

‡‡Based on net generation of 54,031.5 million KWH converted at the 1972 average of 10,660 BTU per net KWH.

TABLE 20

ESTIMATED GROWTH RATES FOR U.S. ENERGY PRODUCTION – 1972-1985
(Percent)

	Petroleum Liquids	Natural Gas	Coal
Highest Estimated	2.6	1.6	5.5
Lowest Estimated	0.4	- 3.0	3.3
Medium Case	1.3	- 0.3	4.2

Assessing U.S. refining growth beyond 1978 is difficult because a number of powerful forces, both positive and negative, will tend to influence the rate of growth. For example, the United States will likely adopt policies which favor U.S. refining self-sufficiency. On the other hand, producing nations have announced plans toward greater industrialization, including refining and petrochemical facilities. There will also be continuing pressure to operate existing Caribbean and Eastern Canadian refining facilities, many of which are a major element of the local economy.

In spite of these uncertainties, it is possible to infer from the medium case the needed growth in U.S. refining capacity. This can be done by examining the growth of total U.S. crude, condensate, and NGL plus imported crude from one period to the next. By using this technique, the changes listed in Table 23 can be used to estimate U.S. refining capacity. Given the industry's recent growth record and presently planned capacity changes, all of the net increases presented in Table 23 appear well within the industry's capabilities assuming a conducive economic climate.

IMPACT OF FUTURE EMBARGOES ON SUPPLY/DEMAND

The foregoing assessment of refining capacity indicates that by late in the decade, the United States should reach a position of near self-sufficiency with regard to refining capacity for clean products. However, both the East Coast and the West Coast of the United States may still be to a degree dependent upon foreign refineries in meeting residual fuel oil requirements. It has been pointed out that at least the East Coast imports will likely come almost entirely from refineries in relatively secure locations on the east coast of Canada and the Caribbean.

TABLE 21

U.S. ENERGY SUPPLIES*
(In Physical Units)

	Actual 1972	NPC Survey Medium Case 1978	1980	1985	1990
Oil† (MMB/Y)					
Total Domestic Production	4,093.6	4,289	4,502	4,816	5,060
Crude and Lease Condensate	3,455.4	3,654	3,872	4,199	4,455
NGL	638.2	635	630	617	605
Total Imports	1,735.3	2,864	2,900	3,048	2,944
Total Crude	811.1	1,839	1,947	2,071	2,036
Canadian	312.4	196	179	214	232
Other	498.7	1,643	1,768	1,857	1,804
Total Products (Incl. NGL and Unfinished)	924.2	1,025	953	977	908
Canadian	93.1	127	103	96	89
Other	831.1	898	850	881	819
Exports	-81.4	- 70	-70	-70	-88
Processing Gain, Etc.‡	157.8	172	190	216	224
Syncrude	—	14	53	184	428
From Shale	—	14	48	150	321
From Coal	—	—	5	34	107
From Inventory	85.0	- 34	-35	-35	-35
Crude	13.3	- 11	-12	-12	- 9
Products	71.7	- 23	- 23	-23	-26
Total Oil Supply	**5,990.3**	**7,235**	**7,540**	**8,159**	**8,533**
Gas§ (BCF/Y)					
Production (Marketed Production of Wet Gas)*‖	22,532	21,762	21,873	22,005	21,888
Extraction Loss, Transfers Out	-908	-902	-895	-877	-860
Imports	1,019	1,634	2,208	2,961	3,620
Exports	-78	-78	-78	-78	-90
From Inventory	- 136	- 146	- 194	- 223	-233
Total Dry Natural Gas	**22,429**	**22,270**	**22,914**	**23,788**	**24,325**
Syngas	—	410	700	1,840	3,100
From Coal	—	70	270	1,220	2,350
From Liquids	—	340	430	620	750
Total Gas Supply	**22,429**	**22,680**	**23,614**	**25,628**	**27,425**
Coal§** (MT/Y)					
Total Production	602,492	768,200	861,700	1,088,500	1,363,700
For Conventional Domestic Markets	602,492	762,500	840,300	982,600	1,136,400
For Synthetic Oil and/or Gas Plants	—	5,700	21,400	105,900	227,300
Net Exports	-57,104	-77,000	-87,400	-93,700	-97,400
From Inventory	-24,100	-12,100	-13,400	-15,200	-16,400
Losses, Gains and Unaccounted for	4,403	-1,200	-1,300	-1,800	-2,000
Total Coal Supply	**525,691**	**677,900**	**759,600**	**977,800**	**1,247,900**
Nuclear					
Installed Capacity (MW)	(Est.) 15,300	76,000	115,000	248,000	440,000
Heat Rate (BTU/KWH)	10,660	10,550	10,550	10,400	10,350

*Including Alaskan production.

†U.S. Bureau of Mines, Petroleum Statement, 1972 (final) and News Release, March 13, 1974.

‡Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude inputs and losses.

§U.S. Bureau of Mines, News Release, March 13, 1974 for 1972 and 1973 preliminary figures.

‖Excludes quantities for repressuring, vented and flared.

**Anthracite, bituminous and lignite. (Data reported in short tons.)

TABLE 22
EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974
(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion 1974	1975	1976	1977	1978	No Date	Rating*
District I									
Standard Oil (CA)	Perth Amboy, NJ	88	–	72	–	–	–	–	G
B.P.	Marcus Hook, PA	100	–	43	–	–	–	–	G
Exxon	Bayway, NJ	275	–	30	–	–	–	–	G
Mobil	Paulsboro, NJ	98	–	–	–	150	–	–	G
Pennzoil (Elk)	Falling Rock, WV	5	1	–	–	–	–	–	G
United Refining	Warren, PA	38	14	–	–	–	–	–	G
Young Refining	Douglasville, GA	3	2	–	–	–	–	–	G
Shell	Logan Township, NJ	–	–	–	–	–	–	150/200	A
Crown Central	Baltimore, MD	–	–	–	–	200	–	–	A†
Ashland & Harrison Land	Fort Pierce, FL	–	–	–	–	–	–	250	P
Georgia Refining Co.‡	Brunswick, GA	–	–	–	200	–	–	–	P
Belcher Oil	Manatee County, FL	–	–	–	–	200	–	–	P
Carolina Ref.	Cape Fear River, NC	–	–	–	–	–	–	30	P
Charter, Florida Gas	Florida	–	–	–	–	–	–	150	P†
Gibbs & No. Ill. Gas	Sanford, ME	–	–	–	–	–	250	–	P†
Hampton Roads Energy	Norfolk, VA (FTZ)	–	–	–	–	–	–	175	P†
JOC Oil Co.	Burlington, NJ	–	–	–	–	–	–	50	P†
Motor Gas Oil & Refining	Money Pt., NJ	–	–	–	–	–	–	100	P
New England Petroleum	Oswego, NY	–	–	–	200	–	–	–	P †
Pepco International	Saybrook, CT	–	–	–	–	–	–	400	P
Olympic Refineries	Rochester, NH §	–	–	–	–	–	–	240	P
Pittston	Eastport, ME	–	–	–	–	–	–	250	P
Shaheen	Rochester, NH	–	–	–	–	–	–	?	P
International Oil Venture	New England	–	–	–	–	–	–	400	P
All Other Existing		1,067	–	–	–	–	–	–	
Total District I		**1,674**	**17**	**145**	**400**	**550**	**250**	**2,195**	
Total Additions with Good or Average Probability			**17**	**145**	**0**	**350**	**–**	**150**	

*See notes at end of table District V.

†Project linked with SNG production.

‡Fuel Desulfurization Inc. owner, Ashland operator.

§Considering alternate sites in Louisiana and Mississippi.

TABLE 22 (Cont'd)

EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974

(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion 1974	1975	1976	1977	1978	No Date	Rating*
District II									
Amoco	Whiting, IN	315	25	–	–	–	–	–	G
Mobil	East Chicago, IN	47	-47†	–	–	–	–	–	†
Shell	Wood River, IL	260	–	–	–	30	–	–	G
Texaco	Lockport, IL	72	–	–	25	–	–	–	G
Apco	Cyril, OK	12	–	2	–	–	–	–	G
Apco	Arkansas City, KS	25	–	20	–	–	–	–	G
Clark	Hartford, IL	36	45	–	–	–	–	–	G
Conoco	Wrenshall, MN	24	1	–	–	–	–	–	G
Conoco	Ponca City, OK	117	19	–	–	–	–	–	G
CRA	Coffeyville, KS	42	7	–	–	–	–	–	G
CRA	Phillipsburg, KS	20	5	–	–	–	–	–	G
CRA	Scottsbluff, NE	5	2	–	–	–	–	–	G
Crystal Princeton Refining	Princeton, IN	–	4‡	–	–	–	–	–	G
Delta (Earth Res.)	Memphis, TN	32	10	–	–	–	–	–	G
Indiana Farm Bureau Coop.	Troy, IN	–	15‡	–	–	–	–	–	G
Witco	Hammond, IN	–	10‡	–	–	–	–	–	G
Kerr-McGee	Wynnewood, OK	34	–	16	–	–	–	–	G
Koch	Pine Bend, MN	107	5	–	–	–	–	–	G
Murphy	Superior, WI	37	3	–	–	–	–	–	G
North American	Shallow Water, KS	5	–	5	–	–	–	–	G
Marathon	Detroit, MI	58	4	–	–	–	–	–	G
Osccola Refining	West Branch, MI	9§	–	–	–	–	–	–	G
Skelly	El Dorado, KS	74	5	–	–	–	–	–	G
Lakeside Ref. Co.	Kalamazoo, MI	4	–	–	–	–	–	3	G
Vickers	Ardmore, OK	32	–	23	–	–	–	–	G
Northland Oil	Dickinson, ND	–	5	–	–	–	–	–	G
Bay Ref. Co.	Bay City, MI	12	–	–	–	–	–	5	G
Mid-American Refinery	Chanute, KS	3	–	–	–	–	–	4	A
Ashland	Cattletsburg, KY	–	–	–	100	–	–	–	P
Mobil	Joliet, IL	175	–	–	–	–	–	50	P
Midland Cooperation	Cushing, OK	19	–	–	–	–	–	17	P
All Other Existing		2,313	–	–	–	–	–	–	
Total District II		**3,889**	**165**	**71**	**125**	**30**	–	**79**	
Total Additions with Good or Average Probability			**165**	**71**	**25**	**30**	–	**12**	

*See notes at end of table District V.

†Refinery shutdown.

‡Startup of idle unit.

§Cost to replace existing facilities.

TABLE 22 (Cont'd)
EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974
(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion						Rating*
			1974	1975	1976	1977	1978	No Date	
District III									
Standard Oil (CA)	Pascagoula, MS	240	–	40	–	–	–	–	G
Arco	Houston, TX	213	–	–	95	–	–	–	G
Exxon	Baton Rouge, LA	445	–	10	5	–	–	–	G
Exxon	Baytown, TX	400	–	–	250	–	–	–	G
Texaco	Convent, LA	140	–	–	–	–	200	–	G
Kerr-McGee	Corpus Christi, TX	100	145	–	–	–	–	–	G
Adobe Oil & Gas	Wickett, TX	–	6†	–	–	–	–	–	G
Pioneer	Nixon, TX	–	2	–	–	–	–	–	G
Atlas Processing	Shreveport, LA	29	16	–	–	–	–	–	G
La Gloria	Tyler, TX	28	10	–	–	–	–	–	G
Charter	Houston, TX	70	–	60	–	–	–	–	G
Kerr-McGee	Cotton Valley, TX	8	3	–	–	–	–	–	G
Crystal Oil	LaBlanca, TX	4	2	–	–	–	–	–	G
Crystal Oil	Longview, TX	7	5	–	–	–	–	–	G
Danahoe Refining	Pettus, TX	–	10†	–	–	–	–	–	G
Champlin	Corpus Christi, TX	62	–	–	63	–	–	–	G
Fomariss	Lovington, NM	–	30	–	–	–	–	–	G
Howell-Quintana	Corpus Christi, TX	10	30	–	–	–	–	–	G
Hunt Oil	Tuscaloosa, AL	15	15	–	–	–	–	–	G
Plateau, Inc.	Bloomfield, NM	5	–	–	–	–	–	2	G
J & W Refining	Tucker, TX	–	3†	–	–	–	–	–	G
Marion	Mobile, AL	15	4	–	–	–	–	–	G
Murphy Oil	Meraux, LA	93	–	–	22	–	–	–	G
Navajo Refining	Artesia, NM	21	9	–	–	–	–	–	G
Pride Refining	Abilene, TX	15	15	–	–	–	–	–	G
Tenneco	Chalmette, LA	98	8	–	–	–	–	–	G
Tesoro Petroleum	Carrizo Springs, TX	13	9	–	–	–	–	–	G
Tesoro Petroleum	Hawley, TX	–	7†	–	–	–	–	–	G
Wood County Ref. Co.	Quitman, TX	–	–	–	–	–	–	3†	G
Coastal States	Corpus Christi, TX	135	50	–	–	–	–	–	G

*See notes at end of table District V.

†Startup of idle refinery.

TABLE 22 (Cont'd)
EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974
(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion 1974	1975	1976	1977	1978	No Date	Rating*
District III (Cont'd)									
Winston Refining	Fort Worth, TX	15	5	–	–	–	–	–	G
Saber Oil	Corpus Christi, TX	–	9†	–	–	–	–	–	G
Toro	Port Allen, LA	–	36	–	–	–	–	–	G
Eddy Refining Co.	Houston, TX	2	–	–	–	–	–	3	G
Alabama Ref. Co.	Theodore, AL	15	–	–	–	–	–	3	G
Mid Texas Ref.	Hearne, TX	–	6	–	–	–	–	–	G
Louisiana Land Expl.	Mobile, AL	–	–	30	–	–	–	–	G
South Hampton	Silabee, TX	6	6	–	–	–	–	18	G
JOC	St. James Parish, LA	–	–	–	–	–	200	–	A
Energy Corp. of La.§	Reserve, LA	–	–	–	200	–	–	–	G
Continental	Houston Area	–	–	–	–	–	–	150/200	P
Hercules-Apco	So. Louisiana	–	–	–	–	–	–	150	P
El Paso Natural Gas	Corpus Christi, TX	–	–	–	–	–	–	300	P‡
Gulf	Port Arthur, TX	312	–	–	–	–	–	?	P
Wallace & Wallace	Tuskegee, AL	–	–	–	–	–	–	150	P
Fuels Desulfurization	Pascagoula, MS	–	–	–	–	–	–	150	P
Odessa	Mobile, AL	–	–	–	120	–	–	–	P
United Gas Pipeline	Pascagoula, MS	–	–	–	–	–	–	150	P
Gulf Energy & Develop.	San Antonio, TX	–	–	20/30	–	–	–	–	P
Pioneer, Okla. Nat. Gas	Houston Area, TX	–	–	–	–	–	–	100	P
Refining Co. of La.	Coastal Parish, LA	–	–	–	–	–	–	100	P
Union Texas	Geismar, LA	–	–	–	–	–	–	200	P
All Other Existing		3,525	–	–	–	–	–	–	
Total District III		**6,041**	**311**	**160**	**755**	**0**	**400**	**1,479**	
Total Additions with Good or Average Probability			**311**	**140**	**635**	**0**	**400**	**29**	

*See notes at end of table District V.

†Startup of idle refinery.

‡Project linked with SNG production.

§Northeast Petroleum and Ingram are owners.

TABLE 22 (Cont'd)
EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974
(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion 1974	1975	1976	1977	1978	No Date	Rating*
District IV									
Farmers Union	Laurel, MT	42	8	–	–	–	–	–	G
Husky	Salt Lake City, UT	12	14	–	–	–	–	–	G
Pasco	Sinclair, WY	40	8	–	–	–	–	–	G
Thunderbird Res.	Chinook, MT	–	1†	–	–	–	–	–	G
V-1 Oil	Glen Rock, WY	–	7	–	–	–	–	–	G
Arizona Fuels	Provo, UT	–	–	–	–	–	–	15	P
Crown Refining	Woods Cross, UT	1	–	–	–	–	–	–	P
All Other Existing		411	–	–	–	–	–	–	
Total District IV		**506**	**38**	–	–	–	–	**32**	
Total Additions with Good or Average Probability			**38**	**0**	**0**	**0**	**0**	**0**	
Total Districts I-IV		**12,002**	**513**	**376**	**1,280**	**580**	**650**	**3,785**	
Total Additions with Good or Average Probability			**513**	**356**	**660**	**380**	**400**	**191**	
Total Capacity End-of-Year Using Good or Average Probability Only			**12,515**	**12,871**	**13,531**	**13,911**	**14,311**	**14,502**	

*See notes at end of table District V.

†Startup of idle refinery.

TABLE 22 (Cont'd)
EXISTING AND ANNOUNCED U.S. REFINING CAPACITY AS OF JULY 1974
(Thousand Barrels Per Day)

Company	Location	Existing Jan. 1, 1974	Announced Projects – Estimated Year of Completion 1974	1975	1976	1977	1978	No Date	Rating*
District V									
Standard Oil (CA)	Richmond, CA	190	–	–	175	–	–	–	G
Standard Oil (CA)	El Segundo, CA	230	–	–	175	–	–	–	G
Arco	Carson, CA	165	20	–	–	125	–	–	G
Texaco	Anacortes, WA	63	15	–	–	–	–	–	G
Mobil	Torrance, CA	124	–	–	–	–	–	25	P
Douglas	Paramount, CA	35	–	15	–	–	–	–	G
Energy Co. Alaska	Fairbanks, AK	–	–	–	–	15	–	–	G
Hawaiian Independent	Barbers Pt., HI (FTZ)	40†	30	–	65	–	–	–	G‡
Kern County	Bakersfield, CA	13	–	3	–	–	–	–	G
Toscopetro Corp.	Bakersfield, CA	27	–	–	–	–	–	10	G
Newhall Refining	Newhall, CA	8	–	12	–	–	–	–	G
Sunland Refining	Bakersfield, CA	9	10	–	–	–	–	–	G
U.S. Oil & Refining	Long Beach, CA	–	5§	–	–	–	–	–	G
Calif. Oil Purification	Ventura, CA	–	–	15	–	–	–	–	G
Powerine	Santa Fe Springs, CA	29	–	–	–	–	–	19	G
Lunday Thegard Oil Co.	South Coote, CA	3	–	–	–	–	–	4	G
Dillingham	Barbers Pt., HI	–	–	–	–	–	–	50	P
Getty	Bakersfield, CA	–	–	–	–	–	–	100	P
Pacific Resources	Portland, OR	–	–	–	–	–	–	50	P
Pac. Res. & S.D. Gas & Elec.	Carlsbad, CA	–	–	–	–	100	–	–	P‖
Thor International	Yuma, AZ	–	–	–	–	200	–	–	P
Urich	Martinez, CA	–	–	–	–	–	–	28	P
All Other Existing		1,323	–	–	–	–	–	–	
Total District V		**2,259†**	**80**	**45**	**415**	**440**	**–**	**286**	
Total Additions with Good or Average Probability			**80**	**45**	**415**	**140**	**–**	**33**	
Total Capacity End-of-Year Using Good or Average Probability Only			**2,339**	**2,384**	**2,799**	**2,939**	**2,939**	**2,972**	
Total United States		**14,369**	**611**	**421**	**1,695**	**1,020**	**650**	**4,071**	
Total Additions with Good or Average Probability			**611**	**401**	**1,075**	**520**	**400**	**224**	
Total Capacity End-of-Year Using Good or Average Probability Only			**14,980**	**15,381**	**16,456**	**16,976**	**17,376**		

Note: Tables include only projects that add to crude distillation capacity. Downstream processing not included.

*Rating corresponds to project likelihood. G – Means good probability of being built.
A – Means average probability of being built or active project lacking site approval.
P – Means poor probability of being built or data too incomplete to permit better evaluation.

†FTZ capacity is included in totals.

‡Stepwise expansion 30 MB/D seems firm in 1974. Expansion in 1976 given average probility of being built.

§Startup of idle refinery.

‖Project linked with SNG production.

TABLE 23

REQUIRED GROWTH IN U.S.
REFINING CAPACITY – MEDIUM CASE
(Million Barrels Per Day)

Period	Net Growth Required	Projected Capacity End-of-Period
1978-1980	.9	18.2
1980-1985	1.2	19.4
1985-1990	.6	20.0

It also appears that in an emergency as much as 1 MMB/D of product demand reduction can be achieved by feasible conservation programs. Therefore, the major impact of any future embargo or interruption would manifest itself as a shortage of crude supplies for both U.S. domestic and other Western Hemisphere refining centers which supply the United States. Other shortages due to a cutoff of imports from other areas could reasonably be offset by conservation measures to reduce demand. If emergency crude supplies could be obtained, remaining product shortages could likely be covered by using refining flexibility to shift yields somewhat between products. West Coast shortages could be met by shipping products from the Caribbean and U.S. Gulf refineries.

Therefore, the first order of priority in developing measures to ameliorate effects of embargoes or interruptions is the development of alternate crude supplies for both U.S. domestic and other Western Hemisphere refineries. While substantial refinery flexibility exists to shift yields of various products to meet seasonal or emergency needs, the U.S. refineries do not have a large amount of flexibility with regard to crude type. Alternate crude supplies would be required which either match fairly closely or exceed the quality of the interrupted supplies. This would be especially important if sweet light crudes such as North African crude would be interrupted. Provision of emergency supplies of light sweet crude, however, poses a particular problem because production of such crude is quite limited today on a worldwide basis and diversion of a substantial portion of today's production could well result in a near-term product shortage. A possible solution worthy of further study would be the production of the high quality crude from NPR-1 for storage purposes. This would not interfere with normal supplies during the storage period and, in fact, would place this storage supply in a much more useful form than leaving it unproduced in the original reservoir.

Chapter Three

AVAILABLE ALTERNATIVES FOR RESPONSE TO FUTURE IMPORT DENIAL

Among the steps the Committee considered for response to a future denial are:

- Reduction of consumption,
- Conversion to alternate fuels,
- Emergency production, and
- Strategic storage.

This chapter discusses the first three responses, strategic storage is covered in Chapter Four.

REDUCTION OF CONSUMPTION

The policy of the government should be to encourage the conservation of energy. However, even with conservation, a possible future denial of 3 MMB/D would require emergency energy curtailment. Many of the conservation programs will not be fully effective for many years. A standby updated allocation program should be the basic method of distributing available supplies in an equitable manner during the emergency. However, supplementary emergency programs can temporarily reduce normal demands and hence ease the allocation problem.

Although it is generally recognized that price has a direct relationship to energy use, an artificially imposed price increase, for example, through a large surtax, would be regressive in nature. Other measures might serve this purpose with less economic and physical disruption.

Table 24 summarizes the expected savings that could be available during an emergency period through a combination of voluntary and mandatory use curtailment measures. It should be pointed out that these data are on an annualized basis; thus, individual sector or product potential could be higher or lower depending on the season in which a demand might occur. The voluntary measures are primarily in the residential and commercial markets, while mandatory programs would be directed at the transportation and the electric utility sectors.

It must be noted that the conservation potential cited by the NPC Committee on Energy Conservation is based on 1972 consuming patterns and economic conditions (Past Trends-Continue Case). The medium case (Table 18, Chapter Two) is a reflection of current (July 1974) industry projections of future energy supply/demand balances and include some degree of price and policy induced energy conservation. The Committee compared the difference between these

TABLE 24

AVERAGE ANNUAL DEMAND REDUCTIONS THROUGH CONSERVATION AND CURTAILMENT MEASURES
(Thousand Barrels Per Day Crude Oil Equivalent)

	Demand Reductions	
Sector	1980	1985
Residential	219	253
Commercial	231	228
Electric Utilitiy	115	105
Industrial	280	315
Transportation	150	200
Total	995	1,101

two cases to determine the degree of conservation reflected in the medium case and eliminated these reductions from further consideration. For purposes of this report, however, the remaining potential is more significant than the absolute level of consumption in each sector.*

Residential Sector

The residential sector accounted for approximately 12 percent of the total U.S. energy consumption in 1972 and could be reduced by about 22.5 percent through steps involving little or no investment on the part of the consumer. Table 25 shows this total potential savings broken down into six possible conservation steps.

Based on the Past Trends-Continue case projections of energy demand, these potential savings are translated into energy savings as shown in Table 25. Realistically, public response will never attain the full potential; rather it will be substantially less. Table 26 indicates the effective compliance for the years 1980 and 1985 that could be expected using a low or pessimistic public response.

* *Editor's Note:* A more detailed analysis of energy conservation potential in the United States can be found in the report of the NPC Committee on Energy Conservation, *Potential for Energy Conservation in the United States: 1974-1978* (September 10, 1974).

TABLE 25

POTENTIAL SAVINGS – RESIDENTIAL SECTOR
(Trillion BTU's)

Conservation Measure	Assumed Reduction (Percent of 1972 Residential Demand)	Calculated Reduction 1972	1980	1985
Reduce winter heating to 68°F	8.2	993	1,427	1,709
Reduce heating to 60°F at night	3.8	463	666	797
Tune-up furnace	5.5	662	952	1,139
Reduce hot water temperature to 120°F	3.4	405	582	697
Air conditioner thermostat setup to 78°F	0.8	97	139	167
Tune-up air conditioner	0.8	97	139	167
Total Potential Savings	22.5	2,717	3,905	4,676
(MB/D Crude Oil Equivalent)		(1,284)	(1,844)	(2,209)
Total Residential Market Demand*		12,031	17,295	20,700

*Includes distributed electric generation losses.

TABLE 26

DENIAL POTENTIAL – RESIDENTIAL SECTOR
(Trillion BTU's)

Conservation Measure	1980 Total Potential	1980 Already In Effect*	1980 Remaining Potential	1980 Additional Compliances 10%	1980 Additional Compliances 30%	1985 Total Potential	1985 Already In Effect*	1985 Remaining Potential	1985 Additional Compliances 10%	1985 Additional Compliances 30%
Reduce winter heating to 68°F	1,427	542	885	89	267	1,709	649	1,060	106	318
Reduce heating to 60°F at night	666	53	613	61	80	797	96	701	70	91†
Tune-up furnace	952	76	876	88	115	1,139	137	1,002	100	120†
Reduce hot water temperature to 120°F	582	169	413	41	123	607	239	460	46	138
Air conditioner thermostat setup to 78°F	139	40	99	10	30	167	57	110	11	33
Tune-up air conditioner	139	12	127	13	19†	167	22	145	14	22†
Total	**3,905**	**892**	**3,013**	**302**	**624**	**4,676**	**1,200**	**3,478**	**347**	**634**
(MB/D Crude Oil Equivalent)	**(1,845)**	**(429)**	**(1,423)**	**(143)**	**(294)**	**(2,209)**	**(567)**	**(1,643)**	**(164)**	**(300)**

*Based on minimum compliance level (assumed to be one-half that experienced during the 1973-1974 embargo).

†30 percent additional compliance exceeds maximum compliance thought achievable. Potential savings have been reduced to the maximum level.

During an emergency period, when governmental encouragement of these programs would be more emphatic, an additional 10 to 30 percent compliance could be expected. This additional saving can be considered to be effective immediately.

Because of time considerations, other possible conservation measures such as increased weatherstripping and ceiling insulation and the installation of storm doors and windows, cannot be considered as available for a reduction in residential energy during an emergency period.

Commercial Sector

The commercial market consumed approximately 11.2 percent of the total energy used in the United States in 1972 and has the potential to reduce its consumption of energy by about 19.1 percent through steps involving little or no investment on the part of the commercial establishments. Table 27 shows the total potential savings broken down into six possible conservation steps.

Based on the Past Trends-Continue Case of energy demand, these potentials translate into energy savings as shown in Table 27. It is assumed that the public response to the potential savings noted will achieve a level of 33 percent estimated by the NPC Committee on Energy Conservation in 1980 and approximately 45 percent in 1985 as extrapolated from the low learning curve. The remainder, or unused portion of the conservation potential, can therefore be considered available for further curtailment through mandated measures. Table 28 shows this additional savings, assuming that a 10 to 30 percent compliance over normal implementation during an emergency period could be expected.

As in the residential market, there are many other conservation considerations that may be instituted, such as weatherstripping, maintenance or insulation, but the six items listed on these tables are the ones that can be instituted almost immediately during an emergency period.

Electric Utility Sector

There are three methods of reducing electricity consumption during an emergency period, based on actions to be taken directly by the utilities. The methods are: mandatory end-use reduction in the order of 5 to 10 percent, 5 percent voltage reduction and load shedding.

Some mandatory programs, particularly those passed in California, have been successful in reducing electricity usage. Southern California Edison Company has experienced to date a reduction of 7.2 percent compared to the same period last year. If the normal growth is added to this, the reduction is on the order of 12 percent from the expected level.

TABLE 27

POTENTIAL SAVINGS—COMMERCIAL SECTOR
(Trillion BTU's)

Conservation Measure	Assumed Reduction (Percent of 1972 Commercial Demand)	Calculated Reduction 1972	1980	1985
Apartments at 68°F; commercial at 65°F	9.0	1,084	1,643	2,075
Night temperature 5°F less in apartments and 10°F less in commercial	5.7	688	1,041	1,314
Reduce lighting levels	2.4	292	438	553
Air conditioner thermostat setup to 78°F	0.8	96	146	184
Air conditioners off 1 hour early	0.7	86	128	161
Reduce hot water temperature to 120°F	0.5	59	91	115
Total Potential Savings	**19.1**	2,305	3,487	4,402
(MB/D Crude Oil Equivalent)		(1,088)	(1,647)	(2,080)
Total Commercial Market Demand*		12,044	18,260	23,055

*Includes distributed electric generation losses.

TABLE 28

DENIAL POTENTIAL – COMMERCIAL SECTOR
(Trillion BTU's)

Conservation Measure	1980 Total Potential	1980 Already In Effect	1980 Remaining Potential	1980 Additional Compliances 10%	1980 Additional Compliances 30%	1985 Total Potential	1985 Already In Effect	1985 Remaining Potential	1985 Additional Compliances 10%	1985 Additional Compliances 30%
Apartments at 68°F; commercial at 65°F	1,643	542	1,101	110	330	2,075	934	1,141	114	342
Night temperature 5°F less in apartments and 10°F less in commercial	1,041	344	697	70	221	1,314	590	724	72	216
Reduce lighting levels	438	145	293	29	87	553	249	304	30	90
Air conditioner thermostat setup to 78°F	146	48	98	10	30	184	83	101	10	30
Air conditioners off 1 hour early	128	42	86	9	27	161	72	89	9	27
Reduce hot water temperature to 120°F	91	30	61	6	18	115	52	63	6	18
Total	3,487	1,151	2,336	234	740	4,402	1,980	2,422	241	723
(MB/D Crude Oil Equivalent)	(1,647)	(547)	(1,104)	(111)	(350)	(2,080)	(935)	(1,144)	(114)	(342)

Through the adoption of an emergency energy curtailment plan by the Los Angeles City Council, the Los Angeles Department of Water and Power has experienced a load reduction to date of approximately 17 percent below the 1973 consumption level. If the normal growth is added onto this reduction, the actual effects of the program are on the order of 23 percent from the expected level.

These programs, which could serve as a guide for the Nation as a whole in a future emergency, contained penalty provisions and effected reductions through the following measures:

- Reduced street lighting
- Prohibited or diminished outdoor advertising and decorative lighting
- Prohibited use of functional outdoor business lighting
- Restricted comfort heating and cooling in commercial or industrial establishments when such premises are not open for business
- Prohibited use of electricity for outdoor public exhibitions
- Prohibited indoor business lighting when the business is not carrying on the usual and customary activities
- Restricted residential use to 90 percent of the amount used during a specified base period
- Restricted commercial establishments to 80 percent of a specified base period
- Restricted industrial use to 90 percent of a specified base period.

Other techniques for electricity reduction such as lowering voltage 5 percent and selective load shedding may not be possible on a country-wide basis. The electric utility industry, however, should have specific emergency plans available so that during an emergency, reductions in electricity use of 5 to 10 percent can be instituted immediately.

Oil and gas savings resulting from voltage reductions of both 5 percent and 10 percent are shown in Table 29. Assuming average reduction in electricity usage (7.5 percent), the oil savings would be 120 MB/D in 1980 and 110 MB/D in 1985. Gas use would also be reduced in the amounts shown, which, if made available to other markets (assuming logistic problems are minimal) could also be considered a direct oil savings. These savings average 110 MB/D in 1980 and 100 MB/D in 1985.

TABLE 29

POTENTIAL OIL AND GAS SAVINGS FROM VOLTAGE REDUCTIONS*
(Trillion BTU's)

	1972		1980		1985	
	Oil	Gas	Oil	Gas	Oil	Gas
Demand	3,073	4,106	3,400	3,100	3,100	2,800
Potential Savings	–	–	170-340	155-310	155-310	140-280
Average Potential Savings (MB/D crude oil equivalent)	–	–	120	110	110	100

*Based on assumed 5 to 10 percent reduction in total demands.

Industrial Sector

The industrial sector, (i.e., iron and steel, aluminum, chemical, petroleum, agriculture and food processing, paper and automobile manufacturing), consumed about 31 percent of U.S. energy in 1972, of which 2.2 percent was petrochemical feedstock. Table 30 summarizes the potential savings of energy that could be achieved through conservation efforts that can be achieved through the 1974-1978 period for the individual industries. The percentage savings are based on 1972 energy consumption. The industries that were studied in detail account for about 75 percent of the energy consumed by the industrial sector. A percentage saving for the remaining industries was assumed to be 10 percent. The weighted average percentage for potential savings for industry as a whole by 1978 is calculated to be 10 percent. This projection is over and above the reduction in energy usage that could have been anticipated if historical trends in energy use efficiency had continued.

TABLE 30

ESTIMATED CONSERVATION POTENTIAL—INDUSTRIAL SECTOR—1974-1978
(Based On 1972 Energy Consumption)

Industry	Potential Savings Per Unit Of Output (Percent)
Primary Metals (Steel, aluminum, etc.)	5*
Chemicals	20
Petroleum Refining	15
Agriculture	
Farming	2
Food Processing	10
Automobile Manufacturing	10
Paper	15
Remaining Industries	10
Weighted Average	**10**

*The 5-percent savings for primary metals is extrapolated from the steel and aluminum projections as these metals make up the primary portion of the primary metals group.

Source: NPC, *Energy Conservation in the United States: 1974-1978* (September 10, 1974).

It is difficult to estimate what additional demand reductions could be effected in the industrial sector during a short-term emergency situation. Obviously, the policy which gave priority in fuel and feedstock use to industry during the recent embargo should be continued to prevent serious economic disruptions. However, it has been assumed that in an emergency situation an additional reduction of 2.5 percent could be realized through mandated measures such as allocation programs, without causing a significant economic impact on the industrial sector. It is important to distinguish, in such allocation programs, between hydrocarbon as fuel and hydrocarbon use as feedstock. Curtailment of feedstock use has significant multiplier effects on the economy. Based on the medium case (Table 18, Chapter Two), this additional saving equates to 280 MB/D in 1980 and 315 MB/D in 1985.

Transportation Sector

In a future energy denial period, some of the past methods of reducing transportation demands rapidly, such as imposing a speed limit and increasing airline load factors will no longer be available since these are already in effect. The NPC Committee on Energy Conservation has listed other specific actions for fuel conservation in passenger cars and light trucks. (Passenger cars and trucks comprise 68 percent of the fuel used in the transportation market.) These are, increased car-pooling, moderated emissions and gasoline regulations, improved auto design, smaller cars, changes in travel characteristics, and better vehicle maintenance. Of these, increased car-pooling offers the best method for voluntarily reducing gasoline consumption during an embargo and would have a minimum economic impact.

The total potential from car-pooling could be 352 MB/D in 1980 and 411 MB/D in 1985, based on the assumption that half of the auto commuters can car-pool, with an average load of three persons. Although some of this potential will already be achieved due to higher gasoline prices and parking fees, a portion should be available for emergency savings. Governmental actions such as establishment of priority parking, would be one method of encouraging full participation. It is assumed that additional emergency savings could be similar to that believed achieved during the recent embargo, i.e., 150 to 200 MB/D.

As indicated on Table 24, the reduction in demand through voluntary/mandatory curtailment equals 995 MB/D and 1,101 MB/D in 1980 and 1985, respectively. Since the level of reductions achieved through voluntary curtailment is almost completely dependent upon public compliance, it is imperative that an extensive public information program be initiated at the time of any emergency to ensure favorable public response. In the event of a denial of 3 MMB/D, there would be a serious gap between supply and demand which could only be closed by more intensive mandatory curtailment.

Initially, a mandatory allocation program, similar to that implemented in January 1974, should be instituted by the government. If the effectiveness of this program is not sufficient to bring supply/demand into balance, there would be no palatable alternative but to implement a system of mandatory rationing of transportation fuels.

To avoid the inefficiencies and errors inherent in a program quickly developed in the midst of a critical energy shortage, a basic rationing program should be developed now. Furthermore, the program should be continually updated to reflect the energy situation as it evolves so that when the need arises for its implementation, the results will be prompt and effective.

CONVERSION TO ALTERNATE FUELS

During an oil denial period, the ability to convert quickly from oil to another available fuel could mitigate the potential economic and social disruptions caused by the denial. Fuel convertibility, however, will be almost completely concerned with substitution of coal in electric utility boilers. Nearly all the convertibility in the industrial sector is between oil and gas. Although some additional gas may be available through curtailment and allocation measures, the logistical problems associated in transferring this excess to oil users are extensive and time consuming. Additionally, as utilities plan to use more coal for generation, the conversion potential in the future is thereby reduced.

Table 31 shows projected electric utility generation capacity, by type, implied in the medium case developed in Chapter Two.

TABLE 31

ELECTRIC UTILITIES INSTALLED CAPACITY – YEAR-END 1972-1985
(Million Kilowatts)

Plant Types	1972	1978	1980	1985
Hydro	56.2	71	73	79
Gas Turbine/Internal Combustion	32.7	55	61	81
Non-Peaking Fossil	295.0	364	377	415
Geothermal	.4	3	4	7
Nuclear	15.3	76	115	248
Total	399.6	514	569	830
Generating Capacity (10^9KWH)	1,747	2,385	2,683	3,587
Generating Capacity (Trillion BTU)	18,560	25,185	28,235	36,965

The non-peaking (baseload) fossil plants including the medium case are shown in Table 32. The projected large growth in coal units will significantly decrease the potential for conversion to coal in the future and the convertibility of currently in-place oil and gas fueled plants is limited.

Table 33 shows electric utility fuel capability by fuel type *versus* the fuel used in 1972. It appears that the maximum amount

TABLE 32

ELECTRIC UTILITIES INSTALLED CAPACITY – FOSSIL FUELS*
(Million Kilowatts)

Fuels	1972	1978	1980	1985
Oil	54	67	64	61
Coal	165	235	254	299
Gas	76	62	59	55
Total	**295**	**364**	**377**	**415**

*Excluding peak generation facilities.

TABLE 33

ELECTRIC UTILITY FUEL CONVERSION CAPABILITY – 1972
(Million Kilowatts)

Capacity by Fuel Used	Capacity by Fuel Capability: Coal	Coal/Oil	Coal/Gas	Coal/Oil/Gas	Oil	Oil/Gas	Gas	Total*
Coal	128	5	18	6	–	–	–	157
Oil	–	13	–	0	23	18	–	54
Gas	–	–	2	1	–	30	47	80
Total	**128**	**18**	**20**	**7**	**23**	**48**	**47**	**291**

*Totals do not agree with Table 32 due to incomplete reporting by fuel capability.

of oil to coal conversion could be 13 x 10^6 kilowatts, and from gas to coal, 3 x 10^6 kilowatts. This is approximately 380 MB/D.

During the last emergency period, it was estimated that approximately 250 MB/D could be converted from oil and gas to coal within a 90 day period. Actual convertibility through March 1974 was approximately 60 MB/D, which is about 2.5 x 10^6 kilowatts of installed capacity. The unavailability of coal supplies of proper quality characteristics and the inability to obtain air quality variances were the principal reasons for lower conversion rates. An analysis of coal convertibility by PAD Districts (Table 34) indicates a maximum future potential convertibility of 15.6 x 10^6 kilowatts.

TABLE 34

COAL CONVERTIBILITY—1972
(Million Kilowatts)

PAD Districts	Coal/Oil	Coal/Gas	Coal/Oil/Gas	Total	Coal Only 1972	Total Coal Possible	Actual Coal 1972	Potential Remaining
I	15.5	.2	4.3	20.0	48.4	68.4	54	14.4
II	2.6	16.1	1.8	20.5	71.5	91.5	92	–
III	–	.3	–	.3	11.7	12.0	12	–
IV	–	1.7	.5	2.2	2.8	5.0	5	–
V	.2	1.6	–	1.8	1.4	3.2	2	1.2
Total	18.3	19.9	6.6	44.8	135.8	180.6	165	15.6

The recently passed Energy Supply and Environmental Act of 1974 (HR 14368), which was signed into law on June 22, 1974, should have significant bearing on the amount of coal being burned in utilities through 1980. This Act gives the Federal Energy Administration power to require power plants and other major users burning oil or gas to switch to coal. These conversions are to be limited to the extent possible within primary air quality standards of the Clean Air Act. The Act authorizes temporary suspension of air quality restrictions on coal burning and requires the EPA under certain conditions to grant exemption from State Secondary Standard Implementation Plan Regulations to those who convert to coal. The law also gives the FEA power to allocate low-sulfur fuels.

The subsections dealing with coal conversion and allocation require the FEA to prohibit any power plant and empower the FEA to prohibit any other major fuel user from burning natural gas or petroleum products. These provisions apply if the FEA determines that (1) as of July 1974 the facilities had the capability and the necessary equipment to burn coal, (2) burning coal is practical and consistent with the purposes of the Act, (3) coal is available and (4) the power supply for the area serviced by the plant will not be impaired by the Prohibition Order.

The FEA is also authorized to require new power plants to be built to use coal as the primary energy source if the FEA determines that (1) using coal will not impair service and (2) a reliable source of coal is expected to be available.

The FEA can also suspend any stationary source fuel or emission limitation described in the Clean Air Act. This may be extended to January 1, 1979, if the FEA finds that (1) the source will not be able to burn available coal without a compliance date extension, (2) the source will be able to comply throughout the period of the compliance date extension with all applicable primary standard conditions, and (3) the source has submitted a plan to the EPA setting forth means for compliance by December 31, 1979, with the most stringent admission requirement of the Clean Air Act Implementation Plan applicable to the plant.

To qualify, the plant must provide for either (1) the acquisition of long-term contracts for low-sulfur coal, or (2) the acquisition of long-term contracts for high-sulfur coal plus the acquisition of contracts for emission reduction devices which will enable the plant to achieve the required air quality while burning the coal.

Under this law, as of June 1974, 42 units and 23 plants are in line for conversion to coal (see Table 35). Some of these conversions will take from 6 months to 3 years. Thus, the future potential of PAD District I will be reduced from 14.4 x 10^6 kilowatts (Table 34) to 3.7 x 10^6 kilowatts (87 MB/D) by the order to convert these plants. The potential for PAD District V remains 1.2 x 10^6 kilowatts (25 MB/D). Under the present conditions, there will be little or no future oil/gas to coal convertibility after the following conversions are completed.

TABLE 35

FIRST GROUP OF UTILITIES ORDERED TO CONVERT TO COAL*

Status	No. of Plants	No. of Units	MW	Oil Savings (MB/D)
Ordered Immediately	3	5	2,190	55
Precipitator Needs to Be Checked	5	11	3,420	85
Precipitators to Be Upgraded/Installed	8	15	1,635	48
SO_2 Removal Device Required	7	11	2,480	73
Total	**23**	**42**	**9,725**	**261**

*Ordered by Federal Energy Administration as of June 18, 1974. Utilities affected are all located in PAD District I.

Refinery Yield Variations

Refinery yield variations can provide flexibility in the product mix. When an emergency situation denies the United States a certain product that is normally imported, domestic refineries can partly offset the effect by increasing production of that product, and, of course, decreasing production of other products. Directionally the result would be to spread the shortage, insofar as consumers are concerned, proportionately among all products.

If an import denial is crude oil or includes all products normally imported, and if we accept the premise that industrial needs should be filled at the expense of supply of motor gasoline for private cars, the product flexibility of refineries should be directed toward increasing the supply of heavy fuel oil and distillate fuel oil and reducing the supply of motor gasoline. The ability to vary production among the end-products was the subject of a survey of U.S. refineries conducted by the NPC staff in 1973 which asked respondents to indicate the range in yields possible in 1978 based on projected operable capacity. The results are indicated in Table 36. If required, additional heavy fuel oil could be produced, principally at the expense of middle distillates. Experience indicates that a yield change of approximately 2.5 percentage points is feasible. This would be equal to about 376 MB/D.

TABLE 36

RANGE IN END-PRODUCT YIELDS

End-Products	Yield	Spread	Volume*
Gasoline			
Normal Yield in Gasoline Season	48.3%	5.9%	888 MB/D
Minimum Yield in Heating Oil Season	42.4%		
Middle Distillates			
Normal Yield in Heating Oil Season	29.8%	3.6%	541 MB/D
Minimum Yield in Gasoline Season	26.2%		

*Based on projected throughput of 15,053 MB/D. Using the projected 1978 throughput of 17,376 MB/D in Table 22, these volumes would be 1,025 MB/D for gasoline and 626 MB/D for middle distillates.

While substantial refinery flexibility exists to shift yields of various products to meet seasonal or emergency needs, the U.S. refineries do not have a large amount of flexibility with regard to crude type. Alternate crude supplies would be required which either match fairly closely or exceed the quality of the interrupted supplies. This would be especially important if sweet light crudes such as North African crude would be interrupted. Provision of emergency supplies of sweet light crude, however, poses a particular problem because production of such crude is quite limited today on a worldwide basis and diversion of a substantial portion of today's production could well result in near-term product shortages.

EMERGENCY OIL AND GAS PRODUCTION

There are certain oil and gas fields in the United States that could produce at higher than normal rates during an emergency. This section will discuss how such potential production might be utilized to offset an import interruption.

Emergency Oil Production

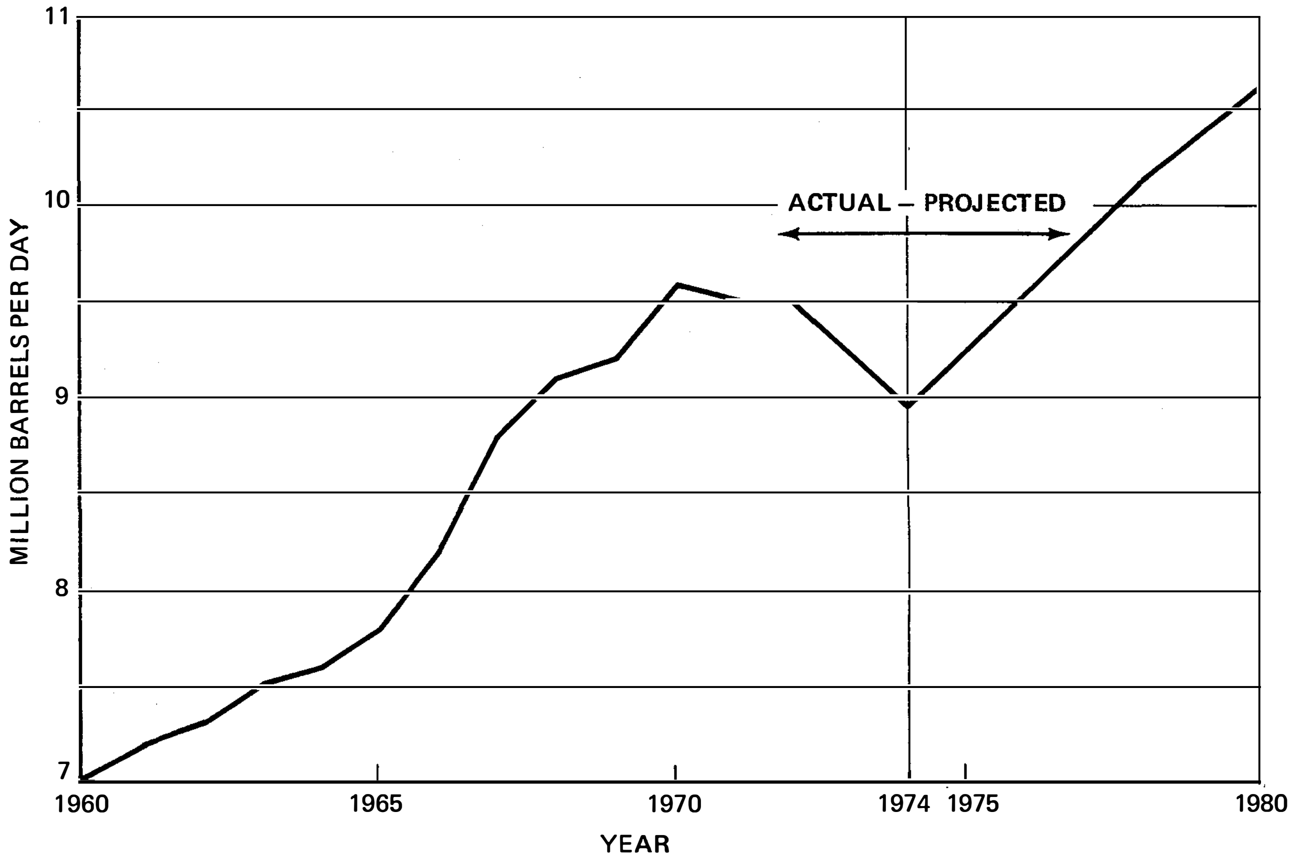
Increasing U.S. energy demand and efforts by domestic oil and gas companies to maximize energy supplies have resulted in a situation where the private sector maintains no shut-in producible reserves (except for fields such as Prudhoe Bay which cannot be produced due to lack of facilities). Therefore, potential emergency production from this source must be obtained by producing in excess of maximum efficient rate (MER).*

Most oil producing states have a regulatory agency that is responsible for enforcing the state's oil and gas conservation rules and regulations. Although such regulations take various forms, they are basically designed to prevent physical waste of oil and gas and to protect the correlative rights of mineral owners. (By definition, waste includes production in excess of reasonable market demand or the capacity of facilities to handle production efficiently.) In the case of offshore fields located beyond state jurisdiction, similar responsibilities are discharged by the U.S. Geological Survey (USGS). The MER of most major oil fields and reservoirs is based on technical data and detailed reservoir studies provided to such federal and state agencies by industry and other expert sources.

As shown on Figure 6, domestic crude and condensate production increased rapidly during the late 1960's, peaked in 1970 and has since declined. Prior to 1972, regulatory agencies in Texas and Louisiana, the only states with significant spare producing capacity, limited oil production to less than MER because market demand would not support additional supplies. However, as demand increased, these agencies permitted domestic production to increase to fill the gap between supply and demand. This used up most of the available spare producing capacity. Since mid-1972, virtually all U.S. fields have produced continuously at 100 percent of MER. This situation will continue in the future as domestic supplies remain tight and the United States seeks to move toward energy self-sufficiency.

Privately owned U.S. oil fields have no spare producing capacity unless established MER's are exceeded. Although the established MER's of major oil reservoirs represent the maximum rate of production that can be sustained over a long period of time, it is possible to exceed the MER in certain high-quality oil reservoirs for a

Editor's Note: MER is defined as the highest rate of production that can be sustained over a long period of time without reservoir damage and significant loss of ultimate oil and gas recovery. Production in excess of MER for sustained periods may result in both loss of recovery and premature loss of producing capacity.



Source: Historical data - U.S. Bureau of Mines; projected data - Table 21, Chapter Two.

Figure 6. Domestic Crude and Lease Condensate Production.

period of up to 6 months with minimum risk of reservoir damage or significant loss of ultimate recovery. Such potential emergency oil production capacity exists primarily in a few large Texas fields. As shown on Table 37, an estimate has been made of the volume of emergency production that could be obtained from currently producing fields in 1974 and 1978, based on both reservoir and facility limitations. The estimate of emergency production available from the "All Others" category (see Table 37) is based on data published by the American Petroleum Institute (API). Field capacity data have been adjusted to "Deliverable Capacity" to account for facility limitations between the fields and refineries.*

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* *Editor's Note:* The distinction between spare wellhead producing capacity and the capacity deliverable to refineries must be recognized. For example, the API estimate of spare oil producing capacity does not consider facility bottlenecks beyond the field (major trunklines, etc.), assumes that conflicting legal and equity problems that arise between the private owners of a field as a result of increasing production could be satisfactorily resolved and suggests that substantial gas flaring would be permitted. In actual practice, these factors will all act to significantly reduce the volume of increased production that can actually be delivered to refineries during an emergency.

TABLE 37

TEMPORARY EMERGENCY OIL PRODUCTION FROM PRIVATELY OWNED FIELDS*
(Thousand Barrels Per Day)

Field	Current Production	Maximum Field Capacity	Average 1974 Emergency Capacity†		Average 1978 Emergency Capacity†	
			Field	Deliverable to Refineries	Field	Deliverable to Refineries
East Texas	200	410	130	50	130	50
Yates	50	150	75	55	75	55
West Hastings	70	120	50	35	0	0
Tom O'Conner	70	130	60	32	0	0
Other Major Fields	–	–	100	50	0	0
All Others	–	–	100	50	0	0
Total Emergency Capacity	–	–	515	272	205	105

*Detailed information by field is provided in Appendix C.

†180 day average production above "current production" from start of emergency. Considers time required to debottleneck facilities.

As indicated, 1974 major field production might be increased by 515 MB/D; however, because of facility limitations, the maximum capacity deliverable to refineries would average only 272 MB/D for an emergency of 180 days. Such deliverable volumes assume some trucking to bypass pipeline bottlenecks where feasible. The emergency production available in 1978 is somewhat lower because producing capacity will decline as major field reserve-to-production ratio (R/P) decline. In fact, it appears that all currently producing fields except East Texas and Yates will be producing at capacity by 1978.

Assuming that no major pre-investments are made for standby production or pipeline facilities, maximum additional field production would average only 205 MB/D during 1978. However, the production deliverable to refineries would be limited by facilities to only 105 MB/D for an emergency of 180 days. Production decline from nearby fields might result in some increase in future trunkline capacity. In addition, fields yet to be discovered might provide additional capacity to produce in excess of MER during an emergency. Even so, the amount of emergency oil production available will be small relative to the level of oil imports.

Attainment of the emergency capacities indicated requires that additional facilities be placed in operation shortly after an emergency is declared. This includes debottlenecking of oil treating and separation equipment, oil and gas gathering systems and saltwater disposal facilities, and, the installation of temporary compression facilities to minimize gas flaring. The petroleum industry should be able to provide such temporary facilities with minimum delay if given proper authorization to produce at the higher rates during an emergency.

The amount of emergency production deliverable in 1978 could be increased to a maximum of 310 MB/D by substantial pre-investment in longer lead time standby production and pipeline facilities. These include gas processing facilities for the East Texas and Yates fields and expansion of the East Texas field saltwater disposal system and of pipeline capacity from the East Texas and Yates fields. This could cost over $30 million. Installation of such facilities is unlikely because there is little economic incentive for individual operators to provide major facility expansions that would be used only during an emergency of indefinite timing and duration.

The emergency capacity estimates provided in this report probably represent an optimistic assessment of what can be accomplished. Numerous legal and administrative obstacles would have to be overcome before such potential production could be realized. The MER's of the subject Texas fields have been established by the Texas Railroad Commission and approval of that body will be required to exceed them. In addition, there are differences of opinion concerning the established MER and allowable allocation procedure in certain fields. In some cases, litigation is in progress to settle these differences. Thus, considerable controversy might result from increasing production above the current MER in such fields.

It must also be recognized that most of these major fields are not unitized and that the operators and royalty owners share only in production from their own properties. Higher emergency rates could, of course, be obtained by permitting all wells in a field to increase production. However, some wells and properties will be incapable of producing at higher rates. Thus, it is possible that litigation might result due to changes in intrafield equities resulting from a period of emergency production. Also, attainment of estimated emergency rates in some fields might require relaxation of environmental and conservation regulations that control gas flaring and disposal of produced saltwater.

On balance, the volume of temporary emergency oil production available from currently producing private fields is quite small compared to the potential size of an import interruption. This capacity can be expected to decline to a negligible volume by the early 1980's. There are a number of legal and regulatory constraints to the effective utilization of such capacity. However, despite these problems, such short-term emergency production could provide valuable protection during the remainder of this decade and should be made available if practicable. This will require that state and federal regulatory agencies cooperate in developing acceptable precedures that will permit such emergency production.

Production from Naval Petroleum Reserves

Between 1912 and 1924, Executive Orders established four Naval Petroleum Reserves (NPR). The stated purpose of these reserves is to maintain petroleum resources in a standby production status until needed for national defense. As shown on Figure 7, NPR-1 and NPR-2 are located west of Bakersfield, California, NPR-3 is located northeast of Casper, Wyoming, and NPR-4 is located on the North Slope of Alaska. In general, Naval Petroleum Reserves cannot be produced unless (1) the Secretary of the Navy and the President of the United States find that production is necessary for national defense and (2) such production is authorized by a joint resolution of the U.S. Congress.

An October 1972 report to the Congress by the Comptroller General of the United States (*Capability of the Naval Petroleum and Oil Shale Reserves to Meet Emergency Oil Needs*) stated that NPR-1 (Elk Hills) had remaining proven recoverable oil reserves of 1,022 MMB and that 80 percent of NPR-1 reserves were government owned. Subsequent statements suggest that remaining reserves may be as high as 1,363 MMB. It is also possible that future exploratory drilling might increase proven reserves.

NPR-1 presently produces at a rate of about 4 MB/D. Its maximum historical producing rate was about 62 MB/D for a short time during World War II. In 1967, the Secretary of the Navy established

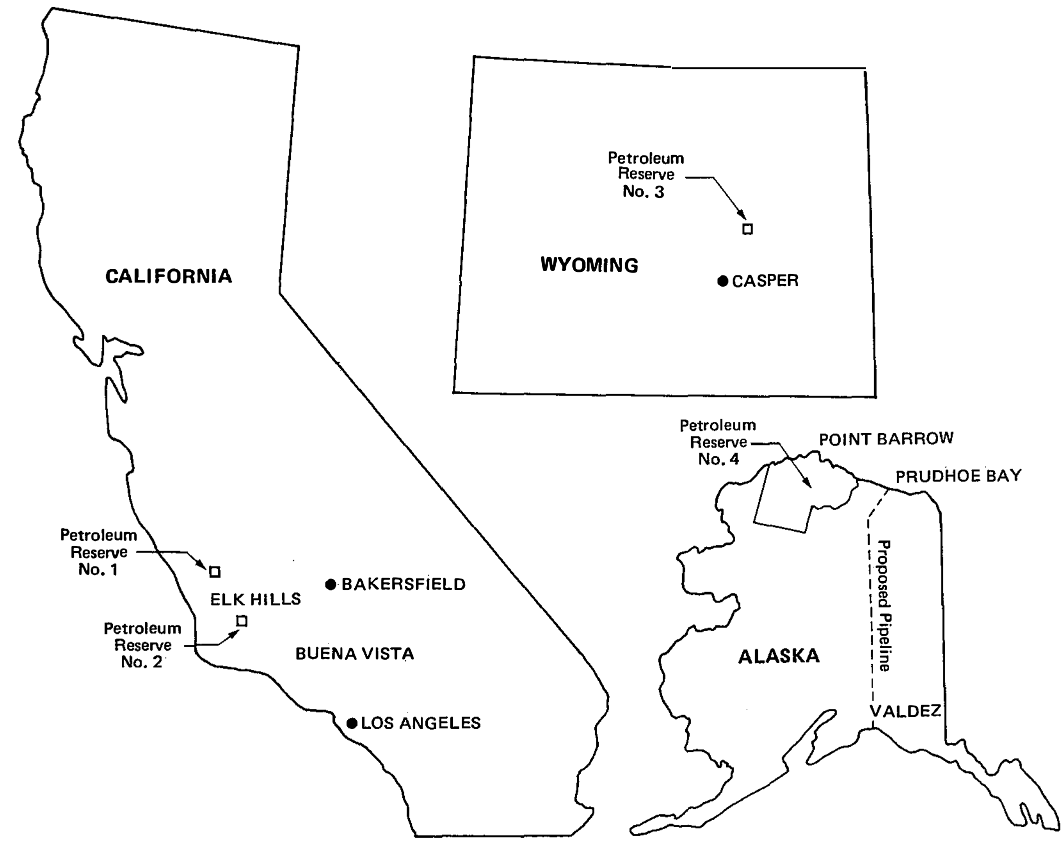

Figure 7. Naval Petroleum Reserves.

an operational readiness requirement for NPR-1. This stipulated that an oil production rate of 160 MB/D be achievable within 60 days after passage of a joint resolution by Congress authorizing production for national defense, and that such average rate be sustainable for 5 years. Testimony before Congress during December 1973 indicated that "within 60 days of the implementing order, Elk Hills could be contributing 100 MB/D or more to the Nation's crude supply and within a relatively short time thereafter could be brought up to 160 MB/D." However, the 1972 Comptroller General's Report indicated that additional producing facilities costing $21.6 million would be required to permit efficient operation of NPR-1 at its operational readiness level. In addition, the capability of the existing network of crude pipelines to deliver 160 MB/D from the field to appropriate West Coast refineries or crude loading terminals has not been proven.

The 1972 Comptroller's Report stated that more than $69 million would be required to develop NPR-1 to produce at its MER of 267 MB/D. In addition, substantial investment will be required to develop the adequate logistical facilities to deliver NPR-1 production at MER to consuming markets. A producing rate of 267 MB/D and a remaining reserve of 1,363 MMB would result in a reserve-to-production ratio of 14 (reserve depletion rate of 1/14 or 7 percent per year). Experience indicates that the producing rate of high quality oil reservoirs can usually be economically maintained at full

MER until the remaining reserve-to-production ratio declines below 10. Thus, it is reasonable to assume that NPR-1 can be produced at its maximum efficient rate for a number of years if an appropriate number of wells are drilled to maintain producing capacity.

NPR-2 has been under lease to private operators for some 50 years and is presently producing at its capacity of about 8 MB/D. In 1971, a Navy geologist advised that exploratory drilling had not resulted in discovery of additional producible oil deposits. According to the 1972 Comptroller General's Report, remaining proven oil reserves were 21 MMB. About 90 percent of the ultimate proven reserve from Navy lands has been produced. Therefore, it appears that little additional producing capacity could be obtained from NPR-2.

According to the Comptroller's Report, NPR-3 has a productive capacity of about 1 MB/D and remaining proven oil reserves of about 43 MMB. It was also estimated that an additional investment of about $10 million would be required to increase field production to its MER of 5 MB/D. Thus, NPR-3 is of minor significance in terms of national security protection.

NPR-4 has neither been fully explored nor developed, and no oil is being produced. This reserve covers approximately 37,000 square miles. Its eastern boundary is located about 50 miles west of the Prudhoe Bay field on the North Slope of Alaska. After discovery of Prudhoe Bay, the USGS estimated that NPR-4 might contain as much as 10 to 33 billion barrels of oil. It must be recognized that such an estimate is highly speculative. While some drilling has occurred on NPR-4, the 1972 Comptroller General's Report indicated that proven oil reserves were only 100 MMB. Because of its remote location, much larger reserves must be proven by exploratory drilling before field development and construction of transportation facilities to move NPR-4 reserves to U.S. refineries can be justified and completed. This will require many years. It should also be noted that production from the Prudhoe Bay field (about 1.6 MMB/D) and other North Slope fields outside of NPR-4 should be capable of filling the 2 MMB/D capacity of the Trans-Alaskan Pipeline. In order to assess the proper role of NPR-4 in post-1980 emergency preparedness planning, sufficient exploration must be completed to realistically define its reserves.

NPR-1 is the only Naval Petroleum Reserve that will be capable of providing significant additional production during an emergency for a number of years. This protection is relatively limited. For example, if NPR-1 had been produced at its maximum efficient rate during the 1973 embargo, it could have provided only 267 MB/D to offset a U.S. import denial of 2.7 MMB daily. In addition, existing facilities will not permit production of NPR-1 at MER, and existing laws effectively preclude use of NPR-1 reserves except for national defense. The government should strongly consider installing the additional facilities required to permit NPR-1 to deliver crude to refineries at its maximum efficent rate.

Potential for Emergency Gas Production

Spare gas deliverability should be considered in emergency preparedness planning since natural gas may be substituted for liquid fuels to help offset an import interruption. To assess the physical capability to do this, it is necessary to consider three factors: (1) the ability to produce additional emergency volumes of gas, (2) the capability of liquid fuel consumers to convert to gas during an emergency, and (3) the capacity of existing pipeline systems to transport additional gas production to consumers having such conversion capability.

A precise assessment of spare domestic gas producing capacity is not available and would require an extensive study of all major gas fields and transmission systems. However, a number of factors indicate that the amount of potential emergency gas production is small.

U.S. natural gas production peaked during the winter of 1970-1971 after increasing for a number of years. Winter peak production has remained about level since that time despite increasing demand. Figure 8 shows that remaining recoverable non-associated gas reserves reached a maximum of 222 trillion cubic feet (TCF) at year-end 1967 and have since declined steadily to about 172 TCF

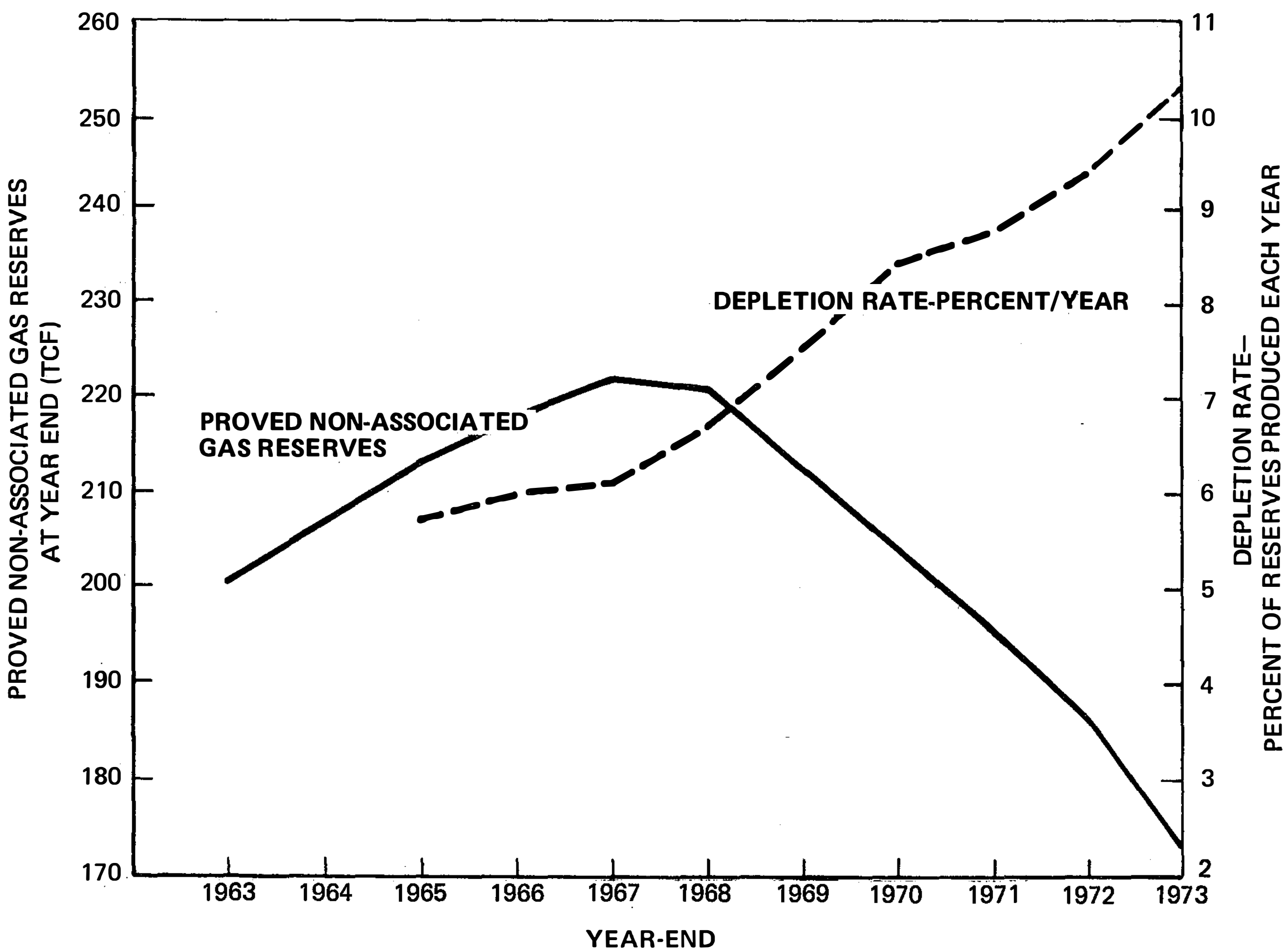

Figure 8. U.S. Non-Associated Gas Reserves and Depletion Rate.

at year-end 1973.* During this same period the depletion rate of non-associated gas reserves increased from 6 percent to over 10 percent per year.

The rate at which reserves are depleted provides an indication of the amount of excess capacity that may exist. For example, it is generally accepted that non-associated gas reserves are at capacity when the depletion rate reaches about 10 percent per year. Producing capacity can be expected to decline at higher depletion rates. This indicates that little spare gas deliverability exists in the United States and this is confirmed by the leveling of peak winter gas production.†

A detailed review of AGA "spare" producing capacity by states also confirms this conclusion. For example, additional field producing capacity reportedly exists in the Western Kansas area; however, such capacity cannot currently be utilized because of limited pipeline capacity through this area. Because field gas deliverability is projected to decline to existing pipeline capacity within a few years, a major pipeline expansion cannot be justified. In fact, the Federal Power Commission (FPC) declined to approve a 1970 proposal to loop one of the transmission pipelines out of this area because of inadequate long-term supplies.

A second potential source of emergency gas production results from the traditional seasonal demand for natural gas. Since gas is used primarily as a heating fuel, demand is much greater in the winter than in the summer. Therefore, the difference between peak winter and reduced summer rates (seasonal swing capacity) might be produced to and delivered by existing pipelines if an emergency occurred during the summer. However, if an emergency occurred during the heating season, such swing capacity would be essentially zero.

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* *Editor's Note:* Non-associated gas is gas that is not in direct contact with an oil reservoir. The production rate of gas in solution or in contact with oil, i.e., in a gas cap, is primarily controlled by the oil reservoir MER.

† *Editor's Note:* Each year the American Gas Association (AGA) estimates total domestic gas producing capacity. Comparison of this capacity with peak production indicates that appreciable spare producing capacity could exist. However, the AGA definition of spare capacity is based on wellhead capacity without regard for gathering system, field compression and processing facility, or trunkline capacity. Also included is the capacity to produce gas utilized in pressure maintenance and gas cycling projects which, if diverted, would result in reduced ultimate oil recovery. Thus, this is not spare capacity that can be effectively delivered and utilized during an emergency.

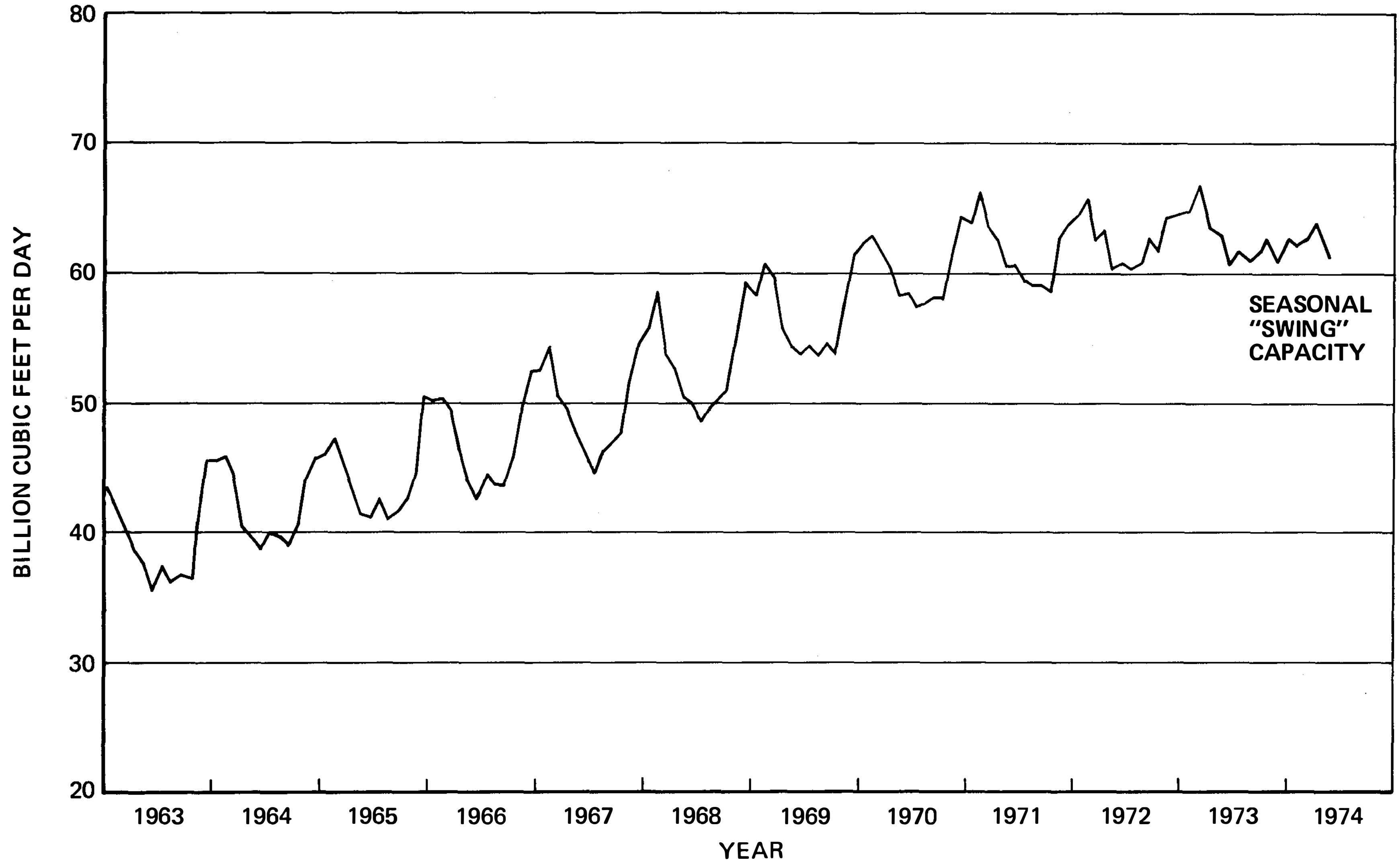
Figure 9 illustrates the historical variation in marketed U.S. gas production between summer and winter. Seasonal swing capacity has decreased during the past few years for several reasons. First, as spare producing capacity declined, peak winter deliverability leveled off. Second, the capacity of underground gas storage projects along pipeline transmission and distribution systems has steadily increased. Gas is placed in such storage during the summer and produced from storage during the heating season to supply demand in excess of conventional producing and transportation facility capacity. Also, gas transmission companies and distributors deliver gas to large industrial and utility customers during the low demand summer months in an effort to maintain a constant year-round load on their systems and reduce cost of service to the consumer. Contracts governing such deliveries provide for interruption of gas service during the peak demand winter months when additional gas must be delivered to heating fuel customers with firm contracts. Thus, both delivery of gas to "interruptible" customers and into underground storage during the summer have reduced the amount of swing capacity available.

It should be noted that gas storage requirements are increasing due to continued increases in heating season demand. If gas scheduled for underground storage is diverted to other use during an emergency, deliveries would be correspondingly reduced during the following winter.

Table 38 summarizes 1973 seasonal swing capacity by geographic area. Swing capacity was negligible during the winter season but averaged about 3.3 billion cubic feet per day (BCF/D) during the summer months. Geographically, about 18 percent of this capacity was located in California, 12 percent in New Mexico, 40 percent in Kansas, Oklahoma and the Texas Panhandle, with the remaining 30 percent scattered in other areas. As shown on Figure 9, production during the winter of 1974 suggests that currently available swing capacity may be somewhat lower than that available during 1973 and that producing capacity is declining.

Usable emergency gas volumes will also be limited to considerably less than total "available" swing capacity for several additional reasons. For example, virtually all of the oil to gas conversion capability is located in PAD District I and PAD District V. However, the large concentration of swing capacity located in Kansas, Oklahoma and the Texas Panhandle is not pipeline connected to either PAD Districts I or V. In addition, many consumers with dual fuel capability already use gas during the summer when swing capacity is available and convert to oil in the winter when gas deliveries are curtailed. This further reduces the potential for emergency substitution of gas for oil.

Also, FPC regulations place certain restrictions on the disposition of reserves dedicated to interstate pipelines. In addition, the FPC restricts the market price of gas sold in interstate commerce below the price available in intrastate markets. This economic debit reduces the potential for interstate movement of emergency gas swing capacity contracted to intrastate markets. Furthermore, gas reserves, unlike oil, are normally dedicated by long-term



* *Marketed production is non-associated and associated-dissolved wellhead production less lease use, field use and losses.*

Source: U.S. Bureau of Mines.

Figure 9. Marketed Natural Gas Production--Total United States.*

TABLE 38

SEASONAL SPARE GAS PRODUCING CAPACITY – 1973
(Billion Cubic Feet Per Day)

Area	Winter Season (November-March)	Summer Season (April-October)
Arkansas	–	0.2
California	0.1	0.6
Kansas	–	0.5
Montana	–	0.1
New Mexico	–	0.4
Oklahoma	0.1	0.3
Texas – RRC-3	–	0.1
RRC-4	–	0.2
RRC-8	0.1	0.2
RRC-10	–	0.3
West Virginia	–	0.3
Wyoming	–	0.1
Total United States	**0.3**	**3.3**

contract to specific pipelines and in some cases to specific markets. Thus, suppliers of emergency swing capacity could be faced with litigation by firm gas customers if delivery of emergency gas production to new customers acted to reduce their future contracted supplies.

Because of lack of specific data in such areas as transmission company deliverability, contractual commitments and consumer capability, etc., the amount of swing gas capacity that could actually be delivered and utilized by consumers during an emergency could not be defined in this study. However, based on the location of existing oil to gas conversion capability and the other factors cited above, it appears that no more than half of the potential 3.3 BCF/D (275 MB/D oil equivalent) swing capacity could be supplied to suitable customers. In addition, the amount of swing capacity available will decline in future years due to reductions in field producing capacity and the need for increased summer storage to meet increasing heating season demand.

Another possible source of emergency gas is the additional associated and dissolved gas that would be produced in conjunction with the emergency oil production discussed previously. The maximum associated and dissolved gas volume that would accompany production of 200 MB/D of oil is equivalent to about 20 MB/D of oil. However, since part of this gas might have to be flared during an emergency if existing gas production facilities were loaded, the deliverable gas associated with emergency oil production would be negligible.

In summary, available data indicate that spare capacity to produce and deliver additional gas during an emergency is limited, particularly during the winter, and is declining rapidly. In addition, the multitude of gas contracts, the large number of gas producers, distributors and consumers, and potential legal problems make it extremely difficult to quantify the amount of emergency gas which might be utilized under emergency conditions. For this reason, other more reliable supply sources should form the basis for emergency preparedness planning. However, even a relatively small volume of emergency gas supply capability could be of value during the remainder of this decade. Therefore, those consumers having unutilized oil to gas conversion capacity should work directly with the gas transmission companies in an effort to arrange for an emergency gas supply.

Chapter Four

EMERGENCY STANDBY PETROLEUM SUPPLIES

There are three basic alternatives for providing standby petroleum supplies to offset a sudden loss of imports. One alternative is to shut in or reduce production from domestic oil and gas reservoirs to provide spare producing capacity that could be turned on during an emergency. Shut-in crude production would replace interrupted crude imports, while shut-in gas production might be utilized as a substitute for imported liquid fuels. The second alternative is to store crude oil after production from underground reservoirs and the third is to store refined petroleum products.

Storage of refined petroleum products or crude after production can be located aboveground in tanks or in underground caverns mined in rock or leached in salt. Very high redelivery rates are possible from such storage relative to production from natural petroleum reservoirs. To provide effective emergency producing capacity, shut-in reserves must be developed with adequate wells. Also, field facilities must be capable of handling produced fluids efficiently at emergency rates without waste or damage to the environment. In addition, transportation facilities existing at the time of an emergency must be capable of moving standby supplies to locations where needed at rates sufficient to replace those imports that are interrupted and cannot be fully offset by other measures (discussed in Chapter Three).

The alternative of shutting in or reducing production from domestic oil and gas fields has several disadvantages. The major disadvantage is that such action would simultaneously reduce the supply of indigenous oil and gas to the U.S. economy. This could be offset in two ways.

The first method is to increase crude imports to replace shut-in domestic crude production (gas produced with shut-in crude could not be replaced by imports). However, this may not be possible because of rapidly increasing competition for available crude supplies worldwide. Furthermore, most domestic crude has a low sulfur content whereas imported crude, if available, would quite likely be high in sulfur. Many U.S. refineries cannot process such crude without substantial capital investment and lead time for conversion. In addition, such action would make the United States even more dependent on imports, which would defeat the basic purpose for which standby supplies were created. It would also have a negative effect on the U.S. economy and balance of payments.

A second method to offset domestic production reductions (without increasing crude imports) is to reduce consumption and thus, offset reduced product availability resulting from running U.S. refineries spare. This alternative would probably require rationing and would create severe problems for industry, business and the consumer and would adversely affect the U.S. economy.

There are several other disadvantages to reducing domestic production:

- A nationwide prorationing or shut-in reserve program would require a massive and complex administrative system. Provisions would have to be made to compensate the owners of reduced production for loss of current income. There is a strong probability of litigation on behalf of such owners.

- If oil or gas reservoirs that have produced for a number of years were shut-in, there is a high probability that ultimate oil and gas recovery would be reduced because established reservoir pressure gradients would permit uncontrolled migration of oil, gas and water within such reservoirs.

- In addition, such uncontrolled migration could result in some properties not being returned to production after a long shut-in (e.g., leases located on the edge of a field having a natural water drive). This would affect equities, with some owners gaining and others losing reserves. Establishment of fair compensation for owners suffering reduced ultimate recovery would be extremely difficult.

- The cost of maintaining shut-in reserves in a state of operational readiness would be high, particularly in hostile environments such as offshore and the Arctic.

- A reduction in tax and other revenues to local governments, and decreased demand for services associated with field operation, would have a particularly negative effect on the economy of areas where shut-in fields were located.

- It is reasonable to expect a delay in bringing reserves that have been shut in for some time up to full production potential. For example, wells located offshore Louisiana often partially fill with sand and require remedial work to re-establish production after being shut-in for a significant period. The larger the amount of shut-in reserves, the more difficult it would be to mobilize the work force and equipment required to place such reserves on production, particularly if they were located in a remote area.

- Finally, such a course of action would cost the Nation from 5 to 10 times more per barrel of daily producing capacity than storage of crude or products in aboveground steel tanks or underground salt domes.*

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* Refer to Appendix D for a complete discussion of the cost of these alternatives.

SECURITY STORAGE OF REFINED PRODUCTS OR CRUDE AFTER PRODUCTION

To be fully effective, a petroleum security storage program must meet two basic requirements:

- It must provide a sufficient volume of crude or product to satisfy the desired level of protection.
- Associated facilities must be capable of delivering such crude or product at the required daily rate. For example, if protection against an import interruption of 3 MMB/D for 180 days is to be provided by security storage, 540 MMB of crude and/or product is required. More importantly, capacity must be provided to deliver such crude or product to those locations where it is needed at a rate of 3 MMB/D.

Aboveground Storage in Tanks

The primary advantage of aboveground storage in tanks is locational flexibility. Such storage can be easily integrated into the existing petroleum logistical system. Crude can be stored in tanks at individual refineries, and refined products can be stored at the optimum location for rapid supply to consumers, either at refineries or product terminals.

One disadvantage of tank storage is the cost per barrel of storage capacity. Such cost is a function of location, local construction requirements and tank size. An additional disadvantage is vulnerability to sabotage, natural disasters or acts of war.

Location plays an important role in tank cost. An obvious factor is location with respect to existing transportation facilities. A remote storage location requiring an expensive pipeline connection would add significantly to the unit cost. A second factor is the variation in material and construction cost at different locations in the United States. For example, it is estimated that a 5 MMB crude tankage project using simple foundations at an existing Gulf Coast refinery would cost about $3.80 per barrel, whereas a similar installation in the New York-Philadelphia area would cost about $5.20 per barrel.* If pilings must be driven to provide an adequate foundation, the cost per barrel could easily increase by 70 to 100 percent. It is recognized that actual estimates for a specific site may vary significantly from these values. However, the above comparison is believed to be representative of an average installation.

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* *Editor's Note:* While tanks can be constructed from various materials such as concrete, all cost comparisons in this report are based on steel tankage construction and mid-1974 dollars unadjusted for inflation. Because of rapidly rising costs, facilities constructed in the late 1970's will likely be much more expensive than indicated.

A third factor is the economy of scale provided by large tanks. Crude storage to protect the runs of a major refinery could utilize large tanks because the security storage requirement would probably be large (60 days of protection for a 200 MB/D refinery equals 12 MMB) and the number of crude segregations should be relatively small. On the other hand, product storage at terminals with relatively low throughput might require several small tanks because of the need to segregate a large number of individual products and grades or because sufficient land is not available to construct large tanks.

The cost of a typical 2 MMB East Coast clean product storage facility utilizing an average 180 MB tank would be about $5.70 per barrel. In contrast, a 500 MB storage facility utilizing an average 70 MB tank would cost about $7.00 per barrel. These costs would be even higher if heated tanks were required for viscous products.

In summary, the cost to construct steel tank storage at sites that can be tied into existing installations with minimum additional facilities should be in the general range of $3.80 to $7.00 per barrel. Higher costs would be anticipated for the following: locations near existing East Coast refineries *versus* Gulf Coast locations; product *versus* crude tankage; small *versus* large tanks; soil conditions requiring special foundations; and construction at locations that are a significant distance from existing terminal or refinery sites.

Tankage Construction Limitations

If a large-scale security storage program utilizing steel tankage were undertaken, the capacity to construct such tankage as rapidly as desired could become a limiting factor. About 3,400 tons of steel are required to provide 1 MMB of tank storage capacity. If the United States is to achieve a high degree of energy independence by 1985, a staggering amount of drilling and construction of refineries and other energy related facilities will be required. For example, total tankage for the two proposed Gulf Coast deepwater terminal tank farms (LOOP and SEADOCK) will probably exceed 50 MMB. These projects and many other energy related facilities will be constructed during the next 5 years.

This will (1) place an enormous load on the construction and fabrication industries, (2) significantly increase the demand for steel and (3) lengthen the interval between the time that materials are ordered and construction is completed. Therefore, the availability of steel must be given careful consideration in planning the facilities required for timely implementation of an emergency preparedness plan.

Underground Storage

Three proven methods of providing underground storage for petroleum are: (1) cavities leached in salt domes or salt beds, (2) cavities mined in hard impermeable rock formations such as granite, shale or limestone, and (3) abandoned underground mines that have been specially adapted for storage.

A wide variety of hydrocarbon products and petrochemical feedstocks are stored underground. According to a Natural Gas Processors Association report of August 1973, about 255 MMB of light hydrocarbon underground storage capacity exists in the United States. About 95 percent of this capacity is located in cavities leached either in salt domes or salt beds, and only about 5 percent is in cavities mined in hard rock.*

Salt Dome Storage

As illustrated by Figure 10, a salt dome is a massive column of rock salt, typically 0.5 or more miles wide, thrusting upward from many miles below the surface and topped by a thick caprock. The top of the salt may be near the surface, and in many cases, salt from such domes is mined for commercial use. Salt mining operations have resulted in creation of many millions of barrels of cavities which might be utilized for underground storage purposes. Also, there are more than 350 known salt domes within a 50,000 square mile area along the Gulf Coast (Figure 11).

Underground petroleum storage projects have an excellent record of safety and reliability based on more than 20 years of experience. Additionally, because salt caverns are generally located 2,000 or more feet below the surface, maximum protection against hazards such as fire, storm and sabotage is provided. Some 180 MMB of salt dome storage capacity are presently utilized. Individual storage well capacities commonly range from 0.5 MMB to 2 MMB, and a number of wells are designed to store up to 5 MMB. Even larger individual storage caverns are technically feasible.

Underground storage in leached salt dome cavities can be provided at a cost of $0.60 to $0.85 per barrel (1974 dollars), depending upon the cost of pipelines required to connect the storage facility to distribution facilities and the distance from a suitable brine disposal and water source area. This estimate does not include the cost of crude or product to fill such storage and is valid only for large volume projects (100 MMB or greater) consisting of wells having individual storage capacities of at least 3 MMB. These costs are based on a detailed analysis of several typical salt domes on the Texas and Louisiana Gulf Coast. Gulf Coast salt domes have an extremely large total storage potential. A few of these domes, such as Stratton Ridge, are large enough to provide 1 billion barrels of storage capacity, and many domes are large enough to provide a storage capacity of several hundred million barrels.

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* Natural Gas Processors Association, *L-P Gas Storage Survey--1973*, Tulsa, Oklahoma (August 1973).

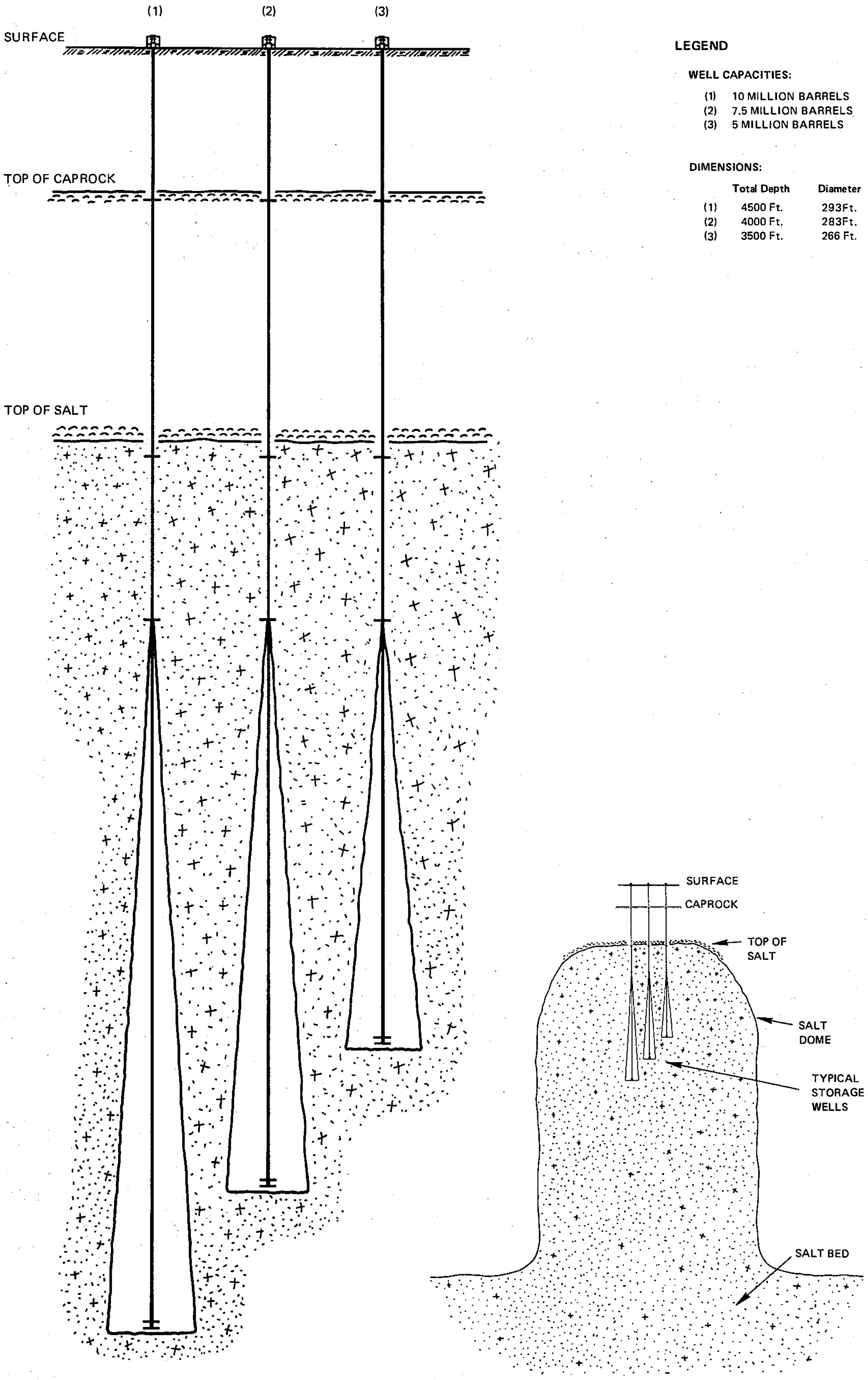
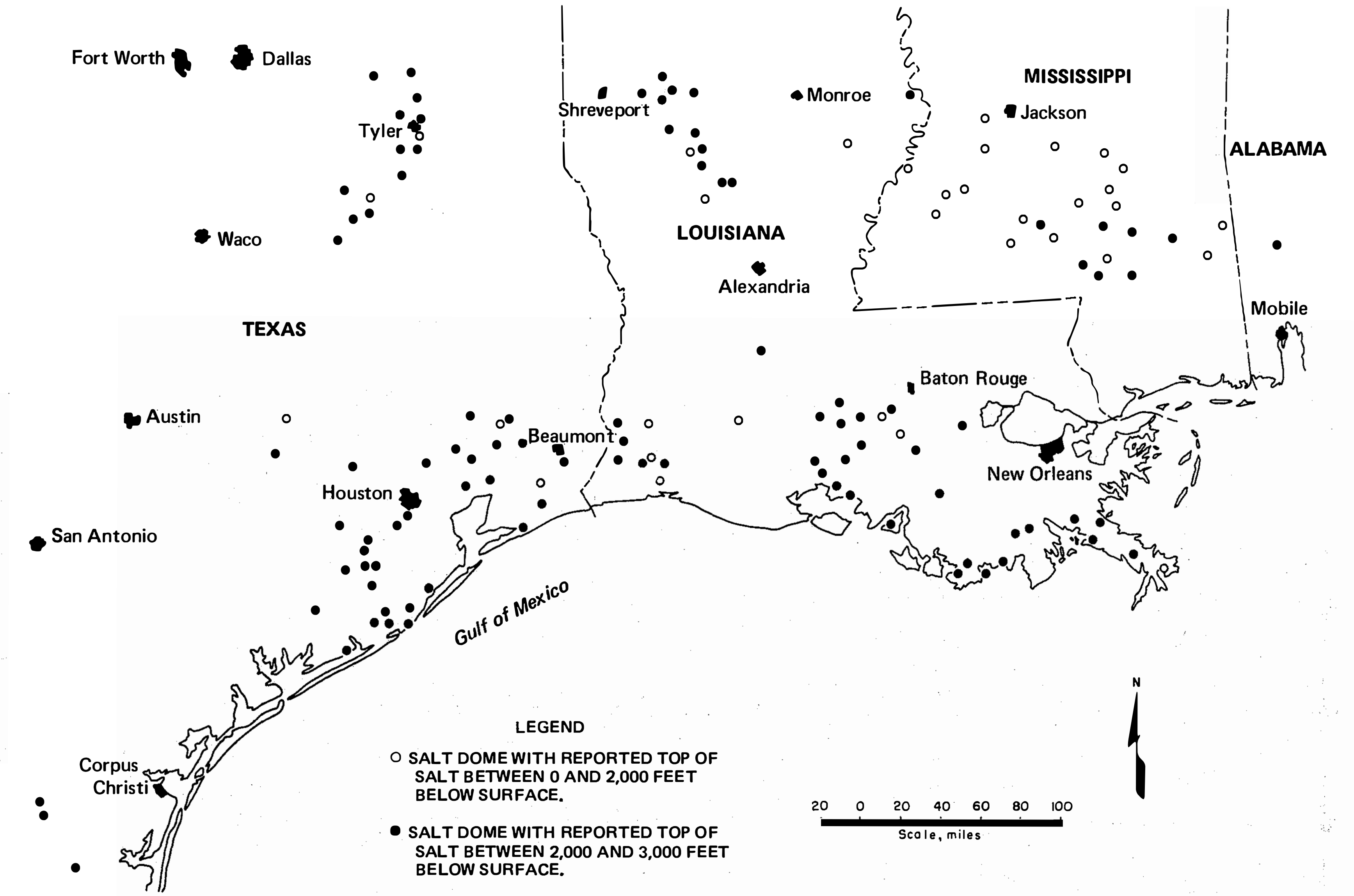


Figure 10. Typical Salt Dome and Storage Wells.



Source: U. S. Department of the Interior, Bureau of Mines, Information Circular 8313, (Washington, D. C.).

Figure 11. Onshore Salt Domes That Offer Good Possibilities for Salt Extraction or Underground Storage Sites.

The leaching of a salt dome storage well is a fairly simple process. First, a well is drilled into the top of the salt formation. Several steel casing strings are set and cemented to protect freshwater beds and to seal off all intervening formations. Fresh water is then pumped down an inner string of pipe. The salt is dissolved and the resulting brine solution is circulated back to the surface where it is disposed of by one of several methods designed to fully protect the environment. For very high water circulation rates, an acceptable technique is to transfer the brine by pipeline to a point several miles offshore for disposal.

After leaching, the well is filled by pumping product or crude into the cavern and displacing brine. The oil, of course, floats on top of the brine that remains. Because the oil is stored in a large cavern, it can be withdrawn at a very high rate by pumping water down a tubing string at an equal rate to displace product up the casing-tubing annulus. With proper casing design, delivery rates of 200 MB/D per well are readily achievable. Thus, a 100 MMB storage project might require only 10 to 20 wells which could have a combined redelivery capacity of over 1 MMB/D. Water for displacement need not be stored in pits. Rather, it would be supplied from either a large body of fresh water, such as a river, or from the Gulf of Mexico via pipeline. For very high product displacement rates, the Gulf might be the most practical source of supply.

Figure 12 illustrates how economy of scale affects the unit cost of a typical salt dome storage project. The cost of constructing a 100 MMB project is indicated to be one unit per barrel of storage capacity. A 50 MMB project is indicated to cost 1.25 units per barrel or 25 percent more than the 100 MMB project. Similarly, a 20 MMB project would cost nearly twice as much per barrel as a 100 MMB project. Projects larger than 100 MMB should exhibit costs somewhat below one unit per barrel. This indicates that substantial cost savings can be achieved by combining storage requirements in large caverns at a single location.

The $0.60 to $0.85 per barrel cost range assumes a plentiful and nearby supply of water to leach the caverns and the disposal of brine offshore. For large caverns, about 7 barrels of fresh water are required to leach 1 barrel of storage. Seawater can be used for leaching if adequate fresh water is not available. This would not add significantly to the unit cost if the project were located near the Gulf. The assumption of offshore brine disposal capability is also important. About 1.3 MMB/D of brine would be produced from development of a 200 MMB storage site in 3 years. Subsurface disposal of such a volume would be physically impossible at most locations and in addition, prohibitively expensive. After leaching is completed, a properly sized offshore brine disposal pipeline could be used to supply seawater for crude displacement at very high rates if a sufficient supply of fresh water is not available.

It is recognized that water requirements and brine disposal considerations associated with large-volume salt dome storage projects raise questions concerning environmental protection. These

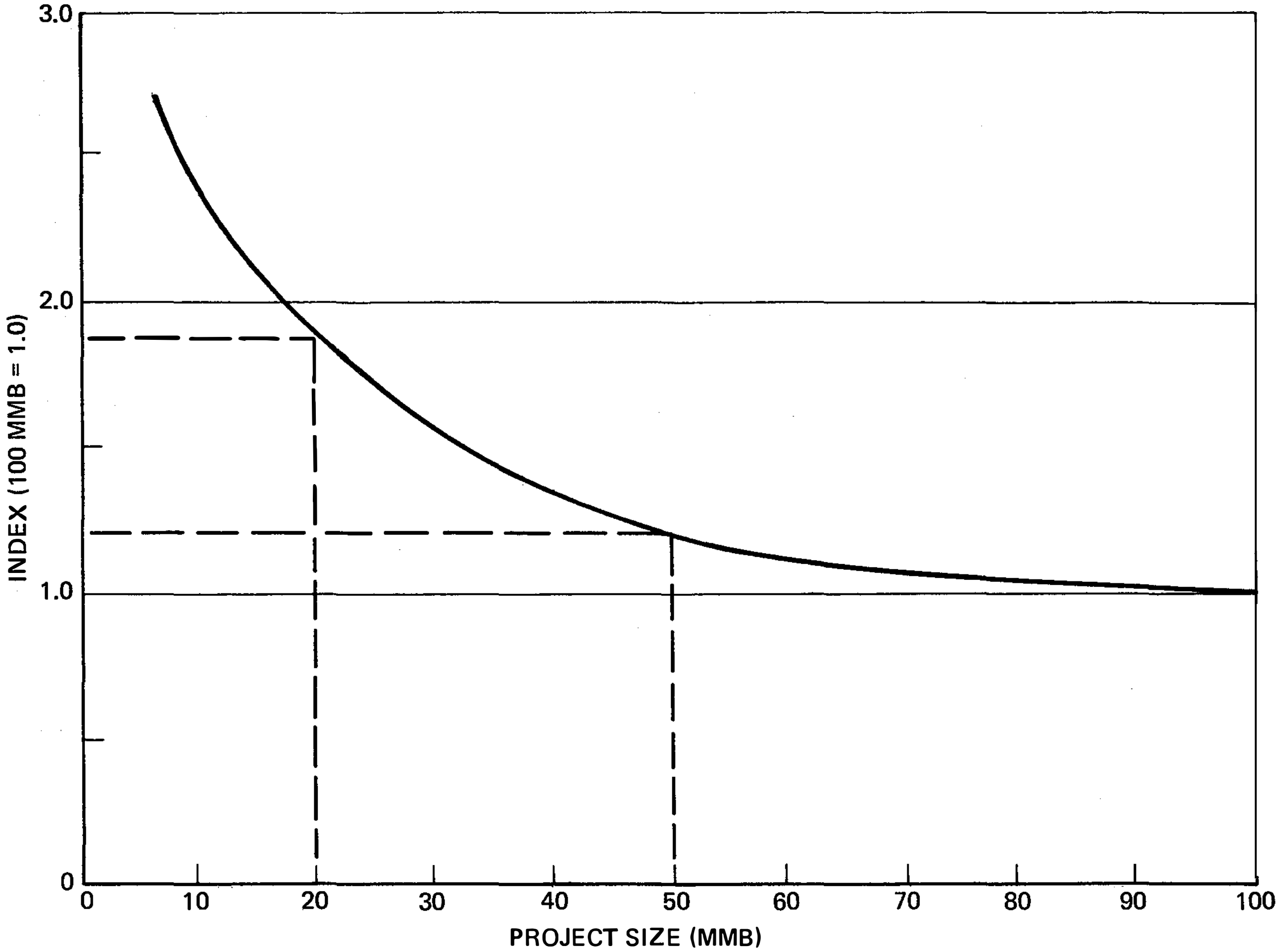


Figure 12. Salt Dome Storage--Economy of Scale Index of Relative Construction Cost per Barrel of Storage.

questions will of course be addressed in the planning, authorization and execution of specific projects. However, at most applicable Gulf Coast locations, it appears that sufficient water supplies can be obtained and that the environmental effects of disposing of essentially pure sodium chloride brine through a properly designed Gulf of Mexico disposal system will be small.

Storage cavities leached in salt beds are also a proven technique, although the potential utility of such beds for large volume security storage projects is limited. Most salt beds are located inland where freshwater costs are relatively high and where subsurface brine disposal would be required, thus making very large volume projects impractical.

Mined Cavern Storage

There are currently some 60 U.S. storage projects in mined caverns in hard rock. These generally vary in size up to about 800 MB and are usually used to store light hydrocarbons under pressure. Storage costs in mined caverns are substantially higher per barrel than salt dome storage capacity. In addition, ample salt domes are available, and such storage has been extensively utilized by industry with demonstrated effectiveness. Therefore, mined cavities need not be considered for large-scale security storage projects.

Storage in Abandoned Mines

Storage of crude in specially converted abandoned mines is a proven technique. Although no such storage exists in the United States, a large project has been in operation in South Africa since 1969. Under ideal conditions, costs for this type of project can be competitive with salt dome storage. However, if suitable mines cannot be found near existing distribution systems, construction of transportation facilities to remote locations would add significantly to project cost. The potential for large-volume storage projects in abandoned U.S. mines is questionable. Detailed surveys would be required to ensure that products could not leak from such mines. Since salt dome storage is a proven technique at competitive (and probably lower) cost, it appears preferable to the alternative of abandoned mine storage.

Storage in Depleted Reservoirs

The possibility of storing crude in depleted oil reservoirs has been considered in the past. This type is not practical for several reasons. First, even if reservoir pressure has not been depleted, the rate at which crude can be injected into and withdrawn from porous reservoir rock is normally limited to the order of hundreds of barrels per day per well. This is severely restrictive compared to several hundred thousand barrels per day from a salt dome storage well. In addition, experience indicates that crude loss from such a system would be high.

Gas Storage

Over 6 TCF of underground gas storage capacity currently exists in the United States. Such storage is drawn down to meet heating season demand in excess of producing and transportation capacity and refilled during the non-heating period. The cost to develop new working gas storage capacity is about $1,250/MMCF. This cost, which includes development and related facilities but excludes the cost of gas fill, is about 8 to 10 times as high as salt dome crude storage on a BTU equivalent basis. In addition, it is doubtful that a significant volume of gas over and above that necessary to satisfy normal requirements will be available for security storage fill.

On balance, salt dome storage appears to be by far the most viable and lowest cost method of underground storage. In addition, the per barrel cost of such storage is only 10 to 20 percent of the cost of steel tank storage. Salt dome storage also provides maximum opportunity to reduce unit cost through economy of scale. In addition, material availability, particularly steel, appears to be less of a problem than with construction of very large amounts of steel tankage. Salt dome caverns can normally be filled and emptied many times without causing structural integrity problems, even when fresh water or seawater is utilized to displace stored crude or product. Since infrequent usage of security storage is anticipated, cavern enlargement during water displacement should not be a significant problem. Also, after leaching facilities are installed, salt dome storage can be expanded rapidly at a relatively low incremental cost per barrel.

ASPECTS OF CRUDE *VERSUS* PRODUCT STORAGE

If salt dome cavern storage is accepted as the least expensive and generally most feasible storage technique in view of steel and appropriate land availability problems, the Texas/Louisiana Gulf Coast is indicated as the best location for emergency inventory.

Location/Distribution

In deciding whether crude or products or a combination are to be stored, distribution facilities are of primary concern. If crude were stored, it would be possible and desirable to locate the caverns within convenient distance of crude distribution facilities such as the contemplated LOOP and SEADOCK projects, existing pipelines and marine terminals. If products were stored, the best location would be contiguous to existing marine (ship and barge) terminals and product pipelines such as Explorer and Colonial. Further analysis is required to determine whether, under the various likely circumstances of a crude and/or product import cutoff, sufficient capacity would exist in the available product distribution system from Gulf locations to make product storage logistically viable. Perhaps supplementary marine terminal facilities would be indicated in order to develop the necessary product distribution capacity and flexibility.

Product Import Cutoff

Detailed studies should be made of the projected imports into the United States of crude and products and of projected domestic refinery capacity plus presumed available Caribbean refinery capacity. A range of product import cutoff cases, with and without crude cutoff, could be considered and tested against the logistical viability of various combinations of crude and/or product storage at Gulf Coast locations. Such studies may indicate that problems will exist if there is no product storage at all--for example, to meet the very large heavy fuel oil demand that is concentrated in the Northeastern states. Much of this fuel oil demand is normally supplied by imports largely from Caribbean refineries. It is possible that there will not be sufficient refinery yield and distillate blending flexibility, conversion to alternate fuels, conserved consumption and running of domestic crude in possibly available Caribbean refineries to offset completely the effects of a fuel oil import cutoff.

If studies indicate a need for fuel oil storage to meet such Northeast demand, or that similar studies reveal a special need for product storage in other parts of the country, then further studies can determine if central storage of products in the Gulf area is a viable way to meet the problem. If not, product storage geographically proximate to the demand would be indicated.

Quality Considerations

Deterioration, weathering or contamination problems should not be a concern for crude oil when stored for long periods, especially under pressure in salt dome caverns. In any case, the normal refining process would likely correct these problems without undue penalty. With respect to products, there is more of a possibility that long-term storage would affect product specifications, particularly if salt dome caverns were utilized. Studies of quality maintenance while in storage for each product should be undertaken, together with a determination of the treating and/or processing required to correct any problems uncovered, including the costs.

Flexibility Considerations

Storage of crude will, of course, provide a full slate of products when refined and avoid the necessity, as in the case of products, of deciding the quantities of each grade, specification and type of product to store in order to meet projected future demand. Furthermore, there are far fewer segregations required for crude oil *versus* the full range of products. Accordingly, individual storage volumes in the case of salt dome caverns can be greater for crude, thus realizing the economies of size. Also, some products (e.g., heavier grades of resid) cannot be stored in salt dome caverns. If storage of these products were indicated, steel tankage would be necessary.

FACILITIES FOR FILLING STORAGE AND MOVEMENT OF CRUDE FROM GULF COAST SALT DOMES TO OTHER LOCATIONS

Total U.S. security storage crude supplies could be located in Gulf Coast salt domes to take advantage of lower construction cost. However, in this event, transportation facilities must be capable of both filling such storage efficiently and transporting security storage crude to other areas of the Nation, particularly PAD District I, during an import interruption, with minimum delay.

Figure 13 shows the location of two proposed deepwater crude unloading terminals, LOOP and SEADOCK (neither project is designed

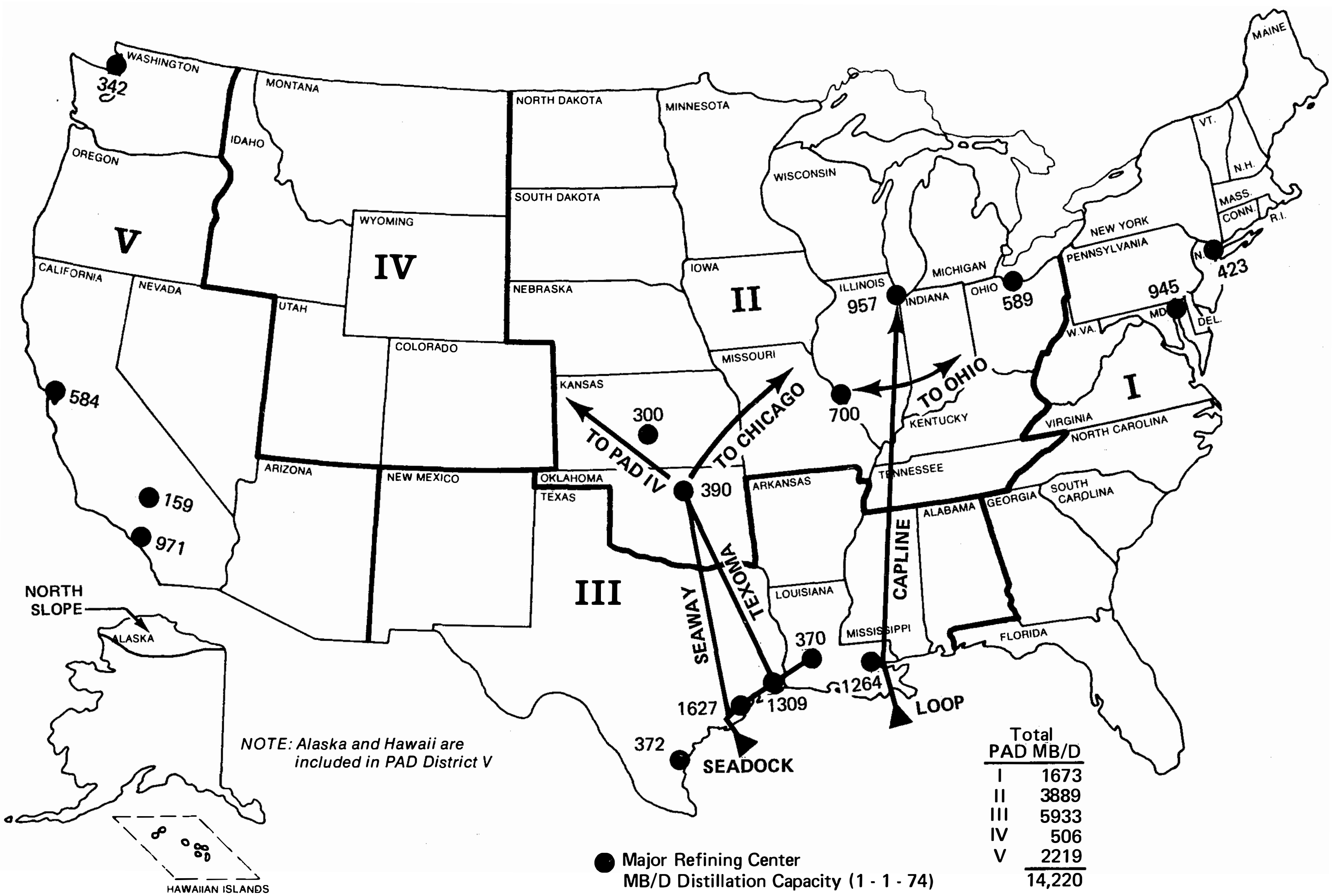


Figure 13. Major U.S. Refining Centers and Proposed Gulf Coast Deepwater Terminal Locations.

for finished product throughput). Both projects are still in the preliminary design stage, and enabling federal legislation must be enacted before these or similar deepwater terminals can be constructed in international waters off the United States. However, it appears reasonable to assume that either LOOP, SEADOCK or essentially identical projects will be constructed during the late 1970's. At both projects, deep-draft very large crude carriers (VLCC's) will tie up to buoys (single point moorings) located 20 to 30 miles offshore and unload crude. The crude will be pumped through buried pipelines to onshore tank farms and then to Gulf Coast and Midwest refineries.

Figure 13 also shows the sites for several proposed new large-diameter crude pipelines to be built for transportation of imported crude to U.S. refineries. These include pipelines to be constructed downstream of the LOOP and SEADOCK tank farms and the proposed Seaway and Texoma pipelines, which will run from Freeport and Beaumont, Texas, respectively, to Cushing, Oklahoma. Capline, which moves crude from the Gulf Coast to the Chicago area, can be expanded, and significant crude pipeline capacity is already in service between Cushing and the Chicago area. In addition, there is a large network of crude trunklines from North and West Texas to the Gulf Coast. Reversal of some of these lines to handle imported crude is being considered. The crude pipelines connecting PAD Districts II and IV presently move crude from west to east because PAD District IV has a surplus supply. However, should PAD District IV become short of crude in the future, one or more of these pipelines could be reversed to move imported crude to PAD District IV refineries. Figure 13 also shows the location of the major U.S. refining centers within each PAD District.

When these facilities are completed, imported crude will be able to flow to most of the refining capacity in PAD Districts II, III and IV. If Gulf Coast salt domes are utilized for security storage, these same refineries could easily receive security storage crude during an emergency. It is also feasible to design deepwater terminals so that tankers can load crude for shipment to other U.S. ports in an emergency. Thus, with proper planning, a large percentage of refining capacity east of the Rockies could effectively be supplied with crude out of Gulf Coast salt dome storage during an emergency.

By 1978, North Slope crude should be available to the lower 48 refineries. Such production may be capable of offsetting any loss in PAD District V crude imports and, therefore, the need to provide a formal security crude storage system for West Coast refineries appears minimal. Additionally, Elk Hills reserves would be available for emergency use in PAD District V. However, if necessary, crude could be supplied to this District during an emergency by exchange or direct shipment from Gulf Coast storage.

There is a significant economic incentive to store emergency crude for East Coast refineries in Gulf Coast salt domes. This would save about $4 to $5 per barrel *versus* steel tank storage. The transportation cost of moving crude by tanker from Gulf Coast storage to the East Coast during an emergency should not exceed $1 per barrel and could be significantly less, depending on the cost of chartering in ships at the time of an emergency. If an East Coast deepwater terminal is constructed, transportation cost for the Gulf to East Coast voyage could be minimized to utilizing VLCC's. The Gulf Coast deepwater terminal projects are not presently planning to design their facilities to permit tanker loading. However, this could probably be accomplished at a relatively low cost, if tankers loading security storage crude during an emergency were permitted to discharge ballast water into the Gulf as opposed to pumping it to onshore facilities.

If imports are interrupted, a substantial volume of crude will normally be in transit by tanker to the United States. For example, about 30 days is required for a tanker to move from the Persian Gulf to the United States; therefore, on the average, a 30 day supply of Persian Gulf imports should be in transit to the United States at the time an interruption occurs. Such crude will be in transit to both the Gulf and East Coasts and thus, each area will be afforded some protection from crude imports on the water. If additional crude should be needed for East Coast refineries, a portion of the in-transit crude destined for the Gulf Coast might be diverted immediately to the East Coast. This would reduce transportation cost and provide additional time to divert tankers to deepwater terminals to load crude for movement to East Coast ports. If sufficient U.S. flag vessels are not available, utilization of foreign flag vessels should be allowed.

If a salt dome security storage program is implemented, consideration should be given to utilizing the approximately 100 MMB of existing cavities created from salt mining operations at the Stratton Ridge salt dome. Consideration should be given to construction of a second salt dome crude storage project in the vicinity of the pipeline between the LOOP onshore tank farm and the Capline terminal. This would enable direct connection of additional PAD Districts II and III refineries to a security storage crude supply. It would also increase total system redelivery capacity by connecting security storage crude to additional transportation facilities and would eliminate the need to move crude by tanker from Texas to Louisiana during an emergency. In the event Gulf Coast deepwater terminals are not completed by the time salt cavern storage is available, pipeline connections to existing crude distribution systems would be required. However, even in this case, salt dome storage on the Texas and Louisiana Gulf Coast still appears the most attractive means of providing security storage.

Construction Timing

Figure 14 illustrates the time required to construct a large scale Gulf Coast salt dome crude storage project. From the time that a contractor is selected, it will take about 2.5 years to reach the stage where cavern leaching can begin. During this period, engineering design, environmental studies, material acquisi-

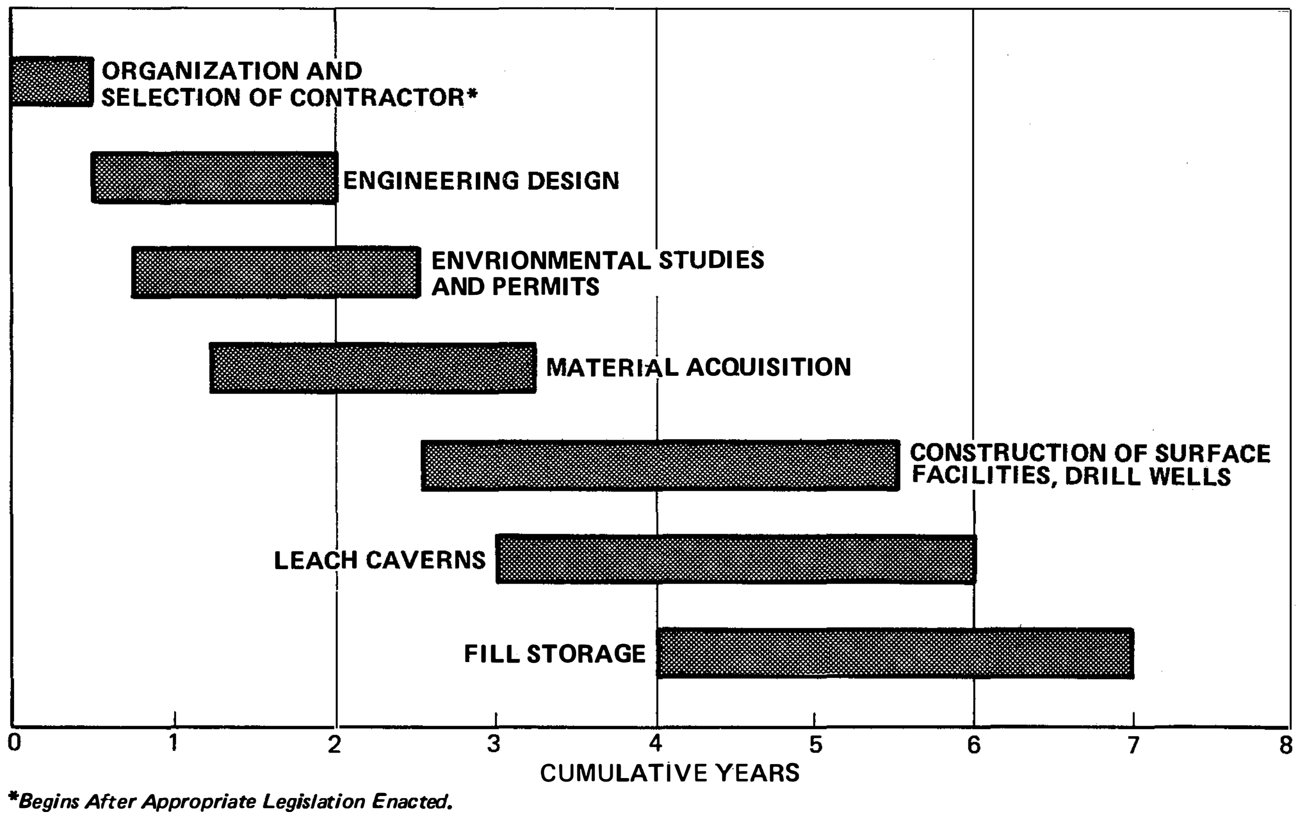


Figure 14. Salt Dome Crude Storage -- Project Construction Schedule.

tion, construction of service facilities and a portion of the well drilling would be completed. A key assumption is that long lead time materials will either be ordered in advance of obtaining necessary permits or that the time required to process permit applications will be reduced.

Leaching is a time-consuming process requiring the circulation of about 7 barrels of water for each barrel of storage capacity. Completion of 100 MMB of storage capacity per year would require a water circulation rate of about 1.9 MMB/D. While time to complete the ultimate storage capacity of a project is dependent on total size, location, degree of urgency and funding, it should be possible to leach a 100 to 200 MMB project in 3 years. If filling of the caverns could be completed in 3 years, the entire project from selection of a contractor to completion of fill would take about 6.5 years. This schedule suggests that completion of such a project by the early 1980's is possible. It also indicates that fill of newly constructed storage could probably not begin before 1979. Completion of two such projects simultaneously or one much larger project might require additional time depending upon the site(s) chosen, fresh water and drilling rig availability, etc. Since about 3 years is currently required to obtain materials and construct steel tankage, fill could not be initiated much, if any, earlier than if the aboveground storage alternative were selected.

Gulf Coast deepwater terminals are expected to become operational during 1978 or 1979. If imported crude is purchased for security storage fill, utilization of deepwater terminals and VLCC's for transportation of such crude would minimize the transportation portion of security storage costs. If deepwater terminals are not utilized, importation in smaller vessels might well over-load conventional dock facilities. This would make concentration in large-volume storage projects more difficult and expensive. However, the primary incentive for location of salt dome storage near deepwater terminal onshore tank farms is the relative ease with which security storage crude could be delivered to refineries during an emergency.

ADDITIONAL CONSIDERATIONS FOR EMERGENCY STORAGE RESERVES

Volume of Security Storage Required

In his letter of January 22, 1973, the Secretary of the Interior requested the NPC to analyze the possible effects of and responses available to a 3 MMB/D interruption of petroleum imports. If protected in total by security storage, this situation would require 540 MMB of storage. This volume alone would protect against a 6 MMB/D interruption for 90 days. In addition to the protection offered by such security storage, protection (time to implement emergency preparedness plans) would be provided by imported crude in transit at the time of an interruption and by usable U.S. working inventories.

According to the Bureau of Mines, U.S. crude inventories have fluctuated between a low of about 230 MMB and a high of about 290 MMB over the past few years.* The NPC Committee on Petroleum Storage Capacity has estimated that minimum crude inventories of 240 MMB are required for the system to remain fully operational. This minimum inventory includes line fill, unusable tank bottoms and working inventories required to maintain continuous operations. Therefore, if an interruption occurred when U.S. inventories were near the minimum, no usable inventory would be available, assuming operations were to continue at full capacity. To the extent that U.S. crude inventories are above this minimum level when an interruption occurred, that oil would be available for drawdown and use as an added cushion before security storage supplies would have to be utilized.

Availability of Supplies for Security Storage Fill

Imports could be utilized for security storage fill. An input rate of 500 MB/D would be required to fill 500 MMB of storage in 3 years. However, it is possible that surplus foreign supplies may not be available for this purpose. Exporting nations have in-

* U.S. Bureau of Mines, *Mineral Industries Survey*, Monthly Petroleum Statements.

dicated that expansion of producing capacity must be consistent with achievement of their national objectives. Politics as well as economics will play an important role in determining the upper limit of production that these producing nations will allow.

In addition, the cost of imported supplies would be high. Assuming world prices at the time security storage fill commences are at the current $10 to $12 per barrel level, the fill for a 540 MMB salt dome storage program utilizing imported crude would cost between $5.4 and $6.5 billion. Furthermore, any surplus imported crude available for storage fill would probably be high in sulfur content. Many U.S. refineries will not be able to process sour crude, and relaxation of environmental regulations would be required during an emergency to permit maximum utilization of sour crude in certain areas.

On balance, relying on foreign imports to fill crude storage by the early 1980's involves a risk that sufficient crude above normal demand may not be available to the United States. The probable high cost and relatively high sulfur content of imported crude is also of concern.

Another potential source of crude for security storage fill is domestic production. Except for the Naval Petroleum Reserves and certain proven reserves on Alaska's North Slope and in the Santa Barbara Channel, all U.S. oil fields are producing at maximum efficient rate as defined by federal and state conservation rules and regulations. While it is believed that certain fields could produce at higher rates for short periods during an emergency without reducing ultimate recovery, the capability of such fields to supply emergency crude will be reduced significantly through normal reservoir decline by 1979. Also, by 1979 it is felt that all existing reserves as well as future exploration discoveries will be producing at MER's consistent with the U.S. goal of moving rapidly toward energy self-sufficiency.

As discussed earlier, NPR-1 (Elk Hills) appears to be the only Naval Petroleum Reserve with sufficient proven reserves to support a substantial rate of production. With proven reserves of 1 to 1.4 billion barrels, NPR-1 is capable of providing a minimum of 500 MMB of security storage fill. If 500 MMB were produced from NPR-1 and placed in security storage, remaining NPR-1 reserves of several hundred million barrels would still support a substantial intrafield producing rate. Additional exploration on NPR-1 could add to reserves and, therefore, to producing capacity. This remaining producing capacity could be reserved for emergency production, used to provide additional security storage or maintained as a Naval Petroleum Reserve.

It should be noted, however, that there is a strong possibility that not all of the presently indicated recoverable reserves could be produced if production were suspended for a period of time after as much as 500 MMB had been produced. Losses in recovery from partially depleted reservoirs could occur during a prolonged shut-in. Accordingly, it should be recognized that once a substantial percentage of reserves is withdrawn, it may be necessary to continue production in order to maximize ultimate recovery. If Elk Hills crude were stored in Gulf Coast salt domes, such crude could be transferred to refineries at a rate of several million barrels per day. This is many times greater than the rate which could realistically be achieved from NPR-1 reservoir rock without adversely affecting ultimate recovery. Such action would therefore greatly enhance the national security protection capability provided by NPR-1 crude reserves.

In addition, Elk Hills crude is relatively low in sulfur content and could thus be utilized by a high percentage of U.S. refineries without adding to environmental problems. Also, utilization of Elk Hills crude for security storage fill would eliminate the need to purchase an equivalent amount of foreign crude, thus reducing the out-of-pocket cost of implementing the program by an estimated $5 to $6 billion.

Existing or new pipelines could be used to relocate 500 MMB of Elk Hills reserves in a Gulf Coast salt dome facility at a cost of about $1 per barrel (230 MB/D for 6 years). If tankers were used--either 50-55,000 deadweight tons (DWT) through the Panama Canal or VLCC's around South America--the transportation cost would be about $1.60 per barrel. While a combination of these methods could be used, tanker availability and cargo preference legislation may limit the latter alternative.

Another potential source of oil to fill security storage would be Federal Government royalty entitlements. An advantage of using this oil is that it would be clearly established that it would be available to meet either public (defense) or private needs under emergency conditions without introducing difficult problems of ownership, equity or compensation for inventory holding costs. It must be recognized, however, that commitment of royalty oil to security storage would increase oil import requirements in order to balance supplies with current consumption.

Among other important considerations to be resolved are the extent of government and/or industry financing and administration of emergency storage and its fill. The Council feels that security storage should not be utilized until after (1) a proper declaration of an energy emergency by government and (2) appropriate voluntary and mandatory standby consumption reduction measures have been implemented.

Appendices

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

DEC 5 - 1972

Dear Mr. True:

The United States is in a period of rapidly increasing dependence on imported petroleum. Associated with this dependency is the high risk involved to the Nation's economic well-being and security in the event these needed, imported energy supplies are interrupted for any reason. With such an alarming trend it becomes mandatory that the Nation's emergency preparedness program to insure supply of petroleum be improved without delay.

Over the past years, the Council has provided the Department of Interior with many outstanding studies which have contributed directly to preparedness for a national emergency. The Council's recent comprehensive energy outlook study indicates national policy options which will minimize dependence on imported petroleum over the long term. However, the study does not examine and evaluate alternatives, possible emergency actions and the results of such actions in the event of a temporary denial or marked reduction in the volume of imported petroleum available to the Nation during the next few years ahead.

The Council is therefore requested to make a comprehensive study and analysis of possible emergency supplements to or alternatives for imported oil, natural gas liquids and products in the event of interruptions to current levels of imports of these energy supplies. Where possible, the results of emergency measures or actions that could be taken before or during an emergency under present conditions should be quantified. For the purpose of this study only, assume that current levels of petroleum imports to the United States are reduced by denial of (a) 1.5 million barrels per day for a 60-day period, and (b) 2.0 million barrels per day for a 90-day period.

Of particular interest are supplements to normal domestic supply such as: the capability for emergency increases in production, processing, transportation and related storage; the ability to provide and maintain an emergency storage capability and inventories; interfuel substitution or convertibility of primary fuels in the major fuel consuming sectors; side effects of abnormal emergency operations; gains in supply from varying levels of curtailments, rationing and conservation measures; gains from temporary relaxation of environmental restrictions; as well as the constraints, if any, imposed by deficient support capability if an extraordinary demand occurs for manpower, materials, associated capital requirements and operating expenses due to emergency measures.

Such studies should be completed as soon as practicable, with at least a preliminary report presented to me by July 1973.

Sincerely yours,
Hollis M. Dole
Hollis M. Dole
Assistant Secretary of the Interior

Mr. H. A. True, Jr.
Chairman
National Petroleum Council
1625 K Street, N. W.
Washington, D. C. 20006

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

In Reply Refer to:
MOG

JAN 22 1973

Dear Mr. True:

In our letter to you of December 5, 1972, we asked that the National Petroleum Council make a comprehensive study and analysis of possible emergency supplements to or alternatives for imported oil, natural gas liquids and products in the event of interruptions to current levels of imports of these energy supplies. We are pleased that the Council has agreed to undertake this study.

Our request letter set out several assumptions regarding petroleum supply levels which we now believe require clarification. Rather than assuming a reduction in petroleum imports to the United States of (a) 1.5 million barrels per day for a 60-day period, and (b) 2.0 million barrels per day for a 90-day period, it would be more useful to assume a denial of (a) 1.5 million barrels per day for 90 days, and (b) 3.0 million barrels per day for a period of 6 months. It is anticipated that the Committee will consider the current and predicted mix between crude and product imports in determining the impact of the assumed denials.

We wish to reaffirm that a preliminary report should be submitted by July 1973.

Sincerely yours,

Rog Morton

Secretary of the Interior

Mr. H. A. True, Jr.
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In Reply Refer To:
EOG

OCT 26 1973

Dear Mr. True:

One of the scenarios in the National Petroleum Council's Emergency Preparedness Study considers a major interruption in foreign oil supplies to the United States as of January 1, 1974.

Though this phase of your Study is nearing completion, recent events have added new urgency to this scenario. Therefore, I ask that you quickly draw together the work which you have accomplished regarding a January 1, 1974 supply interruption and submit it to the Department of the Interior at the earliest possible date.

Sincerely yours,

Stephen A. Wakefield

Assistant Secretary of the Interior

Mr. H. A. True, Jr.
Chairman, National Petroleum Council
1625 K Street, N.W., Suite 601
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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

DEC 21 1973

Dear Mr. True:

The present energy situation makes it imperative that increased domestic exploration for energy sources, particularly oil, be undertaken at the earliest possible time.

So that a rational program might be developed the Department of the Interior has an urgent need to know the availability of materials, manpower and equipment necessary for the exploration, drilling and production of oil during the next two years. Any shortages of materials, manpower or equipment needed for these tasks should indicate the probable limitation on drilling activity. The duration and causes of such shortages, together with any possible measures to alleviate them, should be set forth.

At our request the National Petroleum Council's Committee on Emergency Preparedness is presently conducting a study to examine and evaluate alternatives, possible emergency actions and the results of such actions in the event of a temporary denial or marked reduction in the volume of imported petroleum available to the Nation.

In our letter to you of December 5, 1972, requesting the National Petroleum Council to undertake the above study one of the items mentioned was the capability for emergency increases in production. Because the information needed on the availability of materials, manpower and equipment for exploration and production falls within this category I am requesting that you have the National Petroleum Council's Committee on Emergency Preparedness appoint an appropriate subcommittee to undertake this task.

Because of the urgency of this matter your early response and cooperation will be greatly appreciated.

Sincerely yours,

Stephen A. Wakefield

Stephen A. Wakefield
Assistant Secretary

CONSERVE AMERICA'S ENERGY

Mr. H. A. True, Jr.
Chairman
National Petroleum Council
c/o True Oil Company
Post Office Drawer 2360, Casper, Wyo. 82601

Save Energy and You Serve America!

The following industry representatives have participated in this study.

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EMERGENCY OIL PRODUCTION FROM PRIVATELY OWNED FIELDS

This appendix summarizes the temporary emergency production in excess of MER available from currently producing privately owned fields in 1974 and 1978. Such producing rates could be realized for 6 months without significantly reducing ultimate recovery. The field level capacities consist of the maximum production that can be delivered through field production and gathering facilities, without creating excessive operating problems (in some cases gas would have to be flared). Production deliverable to refineries consists of that portion of the additional field production which can be moved through existing trunklines. The results presented are based on an individual analysis of 23 major oil fields which have essentially all of the spare oil producing capacity in the United States.

EAST TEXAS FIELD

The East Texas field currently produces at an MER of about 200 MB/D from some 13,000 wells located on about 2,000 separate leases. These are owned and operated by some 350 individuals and corporations. In an emergency, production from the field can be increased by 50 MB/D to a total of 250 MB/D within a period of days (see Figure 15), and with only minor modifications to production and gathering facilities. This limit is set by the capacity of existing saltwater disposal facilities. This additional production can also be delivered to refineries through existing pipelines.

Maximum production in excess of MER which could be sustained for 180 days is estimated to be 210 MB/D for a total production rate of 410 MB/D. Producing at such rate would require flaring of some 20 MMCF/D of gas because of inadequate gas handling facilities. Additional compression and gas plant processing facilities could be installed to handle this flare volume; however, this would take more than 6 months. It is assumed that an increased per well allowable would be administered under current field rules. This would result in a substantial increase in saltwater production, and both field production facilities and the saltwater disposal system would have to be expanded. This would take 3 months and would cost about $4.5 million. The average field level emergency production for 6 months would therefore be 130 MB/D.

Maximum production deliverable to refineries is limited by the existing trunkline capacity of about 250 MB/D. Thus, for a short-term emergency, production deliverable in excess of MER from the East Texas field would average 50 MB/D for 6 months. Such emergency capacity should be available through at least 1978. Expansion of the East Texas trunkline system would require 12 to 18 months.

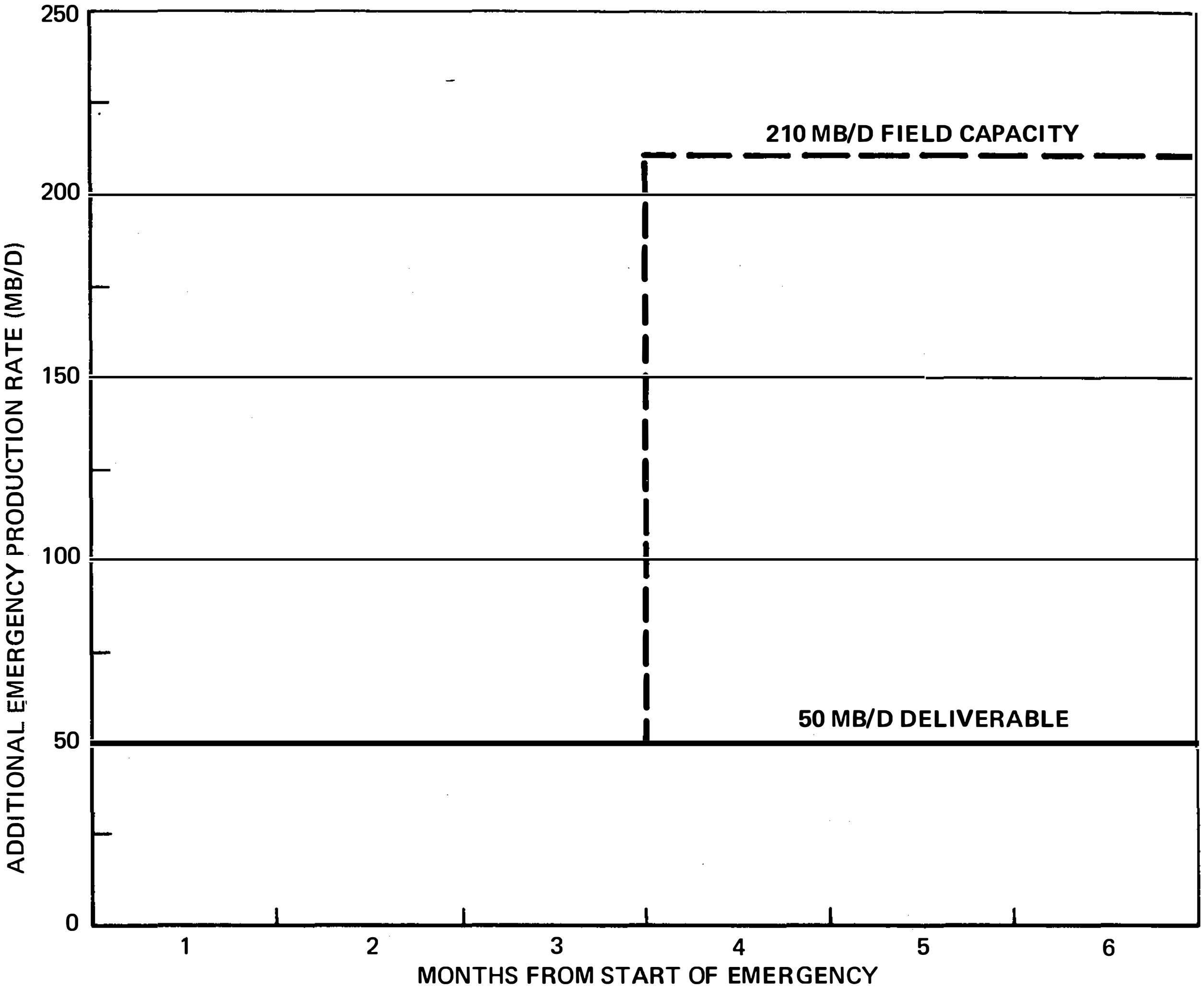

Figure 15. Temporary Emergency Capacity in Excess of MER--East Texas Field (Current Production: 200 MB/D).

WEST HASTINGS FIELD

The West Hastings field is currently producing about 70 MB/D. It is estimated that additional emergency production of 50 MB/D could be obtained from this field for a total rate of 120 MB/D. The maximum additional production deliverable from the West Hastings field to refineries is currently limited to about 90 MB/D through the new trunkline capacity which has just been completed. However, by November 1974, this capacity will be increased to 120 MB/D. It is estimated that West Hastings will have no spare producing capacity by 1978.

YATES FIELD

The Yates field is currently producing at an MER of 50 MB/D from about 600 wells (see Figure 16). In an emergency, production from the field could easily be increased by 50 MB/D to a total of 100 MB/D. This limit is set by the capacity of the gas processing

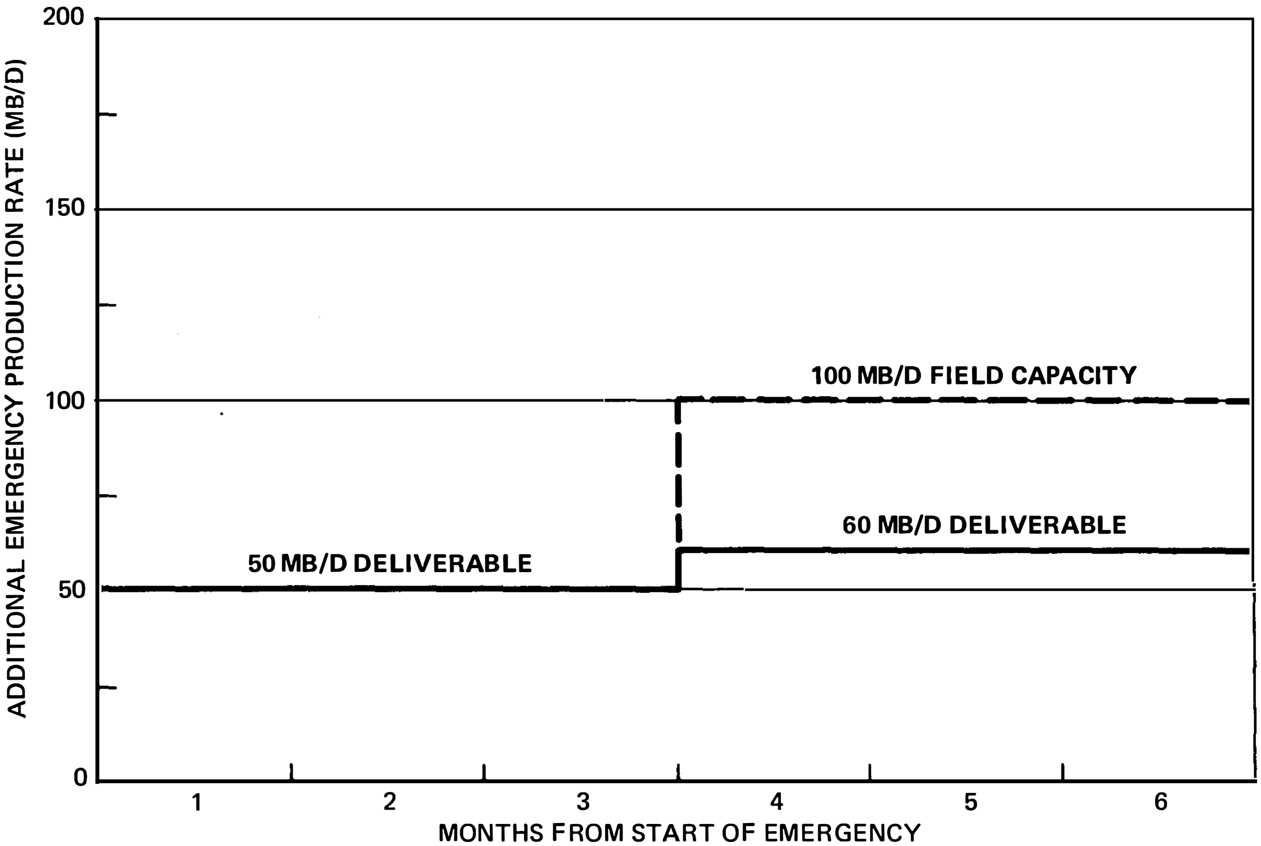

Figure 16. Temporary Emergency Capacity in Excess of MER--Yates Field (Current Production: 50 MB/D).

plant; flaring is not a viable alternative because of the high mercaptan and hydrogen sulfide content of the gas (about 6 percent by volume). At a producing rate of 100 MB/D, the field reserve-to-production ratio would still exceed 30. For this reason it should be possible to produce the Yates field at a rate of 150 MB/D for 6 months without reservoir damage. However, this would require additional field facilities and special equipment to incinerate the sour gas which could not be handled in existing gas processing facilities. Such modifications would require 3 months. Thus, average 6 month field level emergency production would be 75 MB/D.

Total emergency production deliverable to refineries from the Yates field is estimated to be 60 MB/D with existing pipelines and some trucking. Thus, deliverable capacity could average 55 MB/D for a 6 month period and will be available through at least 1978.

TOM O'CONNOR FIELD

The Tom O'Connor field is currently producing at an MER of about 70 MB/D. It appears that well capacity is sufficient to permit additional emergency production of 60 MB/D for a total field rate of about 130 MB/D. However, current deliverable capacity through existing pipelines, including some trucking, is estimated to be only 32 MB/D for a total field rate of 102 MB/D. Such a rate can be handled with existing production facilities. By 1978, this field should be producing at a capacity with a reserve-to-production ratio well below 10. Therefore, deliverable emergency production in 1978 will be essentially zero.

OTHER FIELDS

Several other major fields, primarily located in Texas, are estimated to have a current deliverable emergency capacity of about 50 MB/D. Small volumes of emergency producing capacity probably also exist in a number of scattered small fields. Based on data published by the American Petroleum Institute, it is estimated that current deliverable capacity from such fields would not average more than 50 MB/D during a 180 day emergency.* Because of normal decline, it is estimated that the emergency capacity from this group of fields will be essentially zero by 1978.

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* API, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1973*, Vol. 28 (June 1974).

ECONOMIC ANALYSIS OF THE COST OF MAINTAINING STANDBY EMERGENCY SUPPLIES

Given adequate planning and lead time, there are three basic alternatives for providing standby petroleum supplies to offset a sudden loss of imports. These are: (1) shut-in or reduction of production from domestic oil fields, (2) storage of crude after production from underground reservoirs, and (3) storage of refined petroleum products.

Alternatives for storage of emergency petroleum supplies include aboveground storage in steel tanks or underground storage in salt domes, mined caverns or abandoned mines. Restriction of production alternatives consists of nationwide prorationing (production of the majority of oil fields at less than MER) or shutting-in selected fields completely. This appendix discusses the feasibility, initial construction cost and relative economics of these standby supply options.

The alternatives which involve maintaining reserves in the ground by restricting production require a large total volume of reserves to provide the required daily producing capacity. This results from the basic mechanism of fluid flow in petroleum reservoirs. Extensive investigations have shown that the producing capacity of most domestic reservoirs will have begun to decline when the annual reserve-to-production ratio (R/P) drops below 8.0 (at an R/P of 8.0, one-eighth or 12.5 percent of the reserves are produced each year). Thus, to provide protection against a 6 month, 3 MMB/D interruption (540 MMB total), a minimum shut-in reserve of 8.8 billion barrels (3 MMB/D x 365 days x 8) would be required. Furthermore, if reserves at this stage of depletion were shut-in and produced during an emergency, producing capability would decline unless replacement shut-in reserves were provided.

Although some fields can and do produce at lower R/P's, it is doubtful if enough reserves of this type exist to provide an appreciable amount of shut-in protection. On the other hand, selection of fields with significantly higher R/P's would increase the amount of reserves dedicated to the program. For example, the Yates field is currently producing 50 MB/D and has a deliverable capacity to refineries of 110 MB/D (limited by trunkline capacity). Even at the higher producing rate, the field R/P would exceed 30, which is much greater than the average R/P of 8 assumed in this analysis.

In contrast, storage after production requires producing and transferring only the required volume of oil into storage where it can be delivered at very high rates when an emergency occurs. For example, in comparison to the requirement of 8.8 billion barrels mentioned earlier, only 540 MMB of security storage crude would be required to provide protection against a 6 month, 3 MMB/D crude import interruption.

PRESENT VALUE COST OF ALTERNATIVES*

To realistically compare the cost of maintaining emergency standby supplies, it is necessary to compare the costs on a unit of capacity basis. A per barrel cost comparison is not meaningful because it is the replacement of a given import interruption *rate* that is of importance. Such comparisons are logically based upon the total present value cost per barrel per day of emergency supply provided. The comparison in this study was based on a 3 MMB/D, 180 day interruption as specified by the Secretary of the Interior and assumes that the total denial would be offset by either security storage or restriction of domestic production.

The unit costs presented in Table 39 are based on large volume projects and are calculated in constant 1974 dollars. The cost associated with transporting emergency standby supplies to points of consumption such as refineries is not included. Depending on the type of interruption (crude or products) and the location of emergency preparedness facilities, logistical considerations could add significantly to cost. However, the unit cost at the field level provides a valid basis for ranking the cost of alternative emergency supply systems.

The results of the cost evaluations summarized on Table 39 indicate that storage in steel tanks or salt domes is a much less expensive method of providing emergency standby supplies than restricting production. The total present value costs of salt dome and steel tank storage are only 10 percent and 20 percent of the restricted production alternative, respectively. Also, salt dome storage costs only about one-half as much as steel tank storage. Present value costs listed on Table 39 are based on a discount rate of 10 percent. Various sensitivity cases were evaluated at higher discount rates, higher prices and more optimistic R/P's for the restricted production options. Although the absolute cost of the various alternatives changed in these cases, the ranking of the alternatives did not. Note also that the present value costs of a 10 year program are only about 25 to 30 percent less than the cost of a 20 year program.

COST ELEMENTS OF MAINTAINING EMERGENCY STANDBY SUPPLIES

The cost of maintaining any type of emergency standby supply is a combination of several factors. First is the initial cost of

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* *Editor's Note: The present value concept* simply recognizes that a dollar received today is worth more than a dollar received some years in the future by the amount of interest or return that dollar can be expected to earn. For example, if a dollar received today were invested in bonds, a savings plan or some other investment which earned interest at a rate of 10 percent, it would be worth $2.59 in 10 years. Conversely, a dollar of income received 10 years in the future is worth only $0.39 today, assuming a 10 percent interest rate. This is a common and well accepted method of comparing the present value of various future income streams.

TABLE 39

UNIT COST OF PROVIDING STANDBY EMERGENCY SUPPLIES
(Dollars Per Barrel Per Day)

	20 Years	10 Years
Salt Dome Storage		
$0.75 Per Barrel Facility Cost	930	620
$1.00 Per Barrel Facility Cost	970	660
Steel Tank Storage		
$5.00 Per Barrel Facility Cost	1,790	1,370
$7.00 Per Barrel Facility Cost	2,200	1,750
Production Restriction by Shutting-in Fields or by Prorationing	10,300	7,400

Note: Based on present value cost per unit of supply. Assumptions are that:

- Emergency capacity initiates in 1975 and reserves are retained until 1985 or 1995 when they are sold.
- Cost is present value cost to operators, royalty owners and government (discounted at 10 percent) resulting from deferred producing income and/or receipt of direct tax payments.
- Unit costs are based on providing full protection for a 3 million barrel per day, 180 day interruption.
- All costs are calculated in constant 1974 dollars.
- Oil has a constant price of $8.00 per barrel of stored or shut-in crude.

establishing the emergency supply--for example, the cost of building steel tanks or salt dome storage facilities and of filling such storage with crude or products. Second is the cost of maintaining the standby supply. This includes the cost of direct labor and equipment maintenance required to maintain the capability to produce at full capacity during an emergency. An additional cost includes necessary expenditures to construct or replace pipeline, transportation and producing facilities.

Another major cost item is the loss in present value profit to the owners of shut-in production, government and the economy that would result from deferring the production and sale of standby supplies. For example, consider the case of shutting-in existing fields to provide emergency spare capacity. Under normal conditions, these fields would be produced to depletion over a period of years with resulting income accrued to operators and royalty owners from the sale of oil and gas. Income to local, state and federal governments in the form of production, sales and income taxes and, in some cases, royalty payments would similarily be deferred. There would also be substantial additional costs to the economy which have not been quantified in this analysis. It was assumed that emergency protection would be required for either 10 or 20 years, at which time alternative energy forms would be available and the security supplies could be produced and sold. Thus, if the fields were shut in to provide standby supplies for 20 years and then produced, income would be deferred for 20 years which would result in a substantial loss in present value to operators, royalty owners and government.

In the case of security storage, the sale of crude or products necessary to fill the storage would also be deferred. These products would also be sold after 20 years with a loss in present value. Although substantial, such loss would be far less than for the shut-in reserve case because of the smaller total volume involved.

Additional bases used in computing the costs shown on Table 39 are summarized below:

- Basis for Shut-In Reserve Cost

  --Operating expense saved as a result of shut-in equals 21 percent of revenue.

  --Annual maintenance cost of shut-in capacity equals $50 per barrel per day.

- Basis for Salt Dome Storage Cost

  --Large volume (at least 100 MMB) salt dome storage construction costs would range from $0.65 to $0.85 per barrel, depending on location with respect to suitable water source and brine disposal areas. Thus, using a cost of $0.75 per barrel, a 540 MMB storage program would have a total cost of $405 million excluding the cost of crude fill.

  --Construction costs are assumed to be spread over a 5 year period starting in 1975, and fill costs over a 3 year period beginning in 1978.

  --Maintenance cost of $0.01 per barrel of stored crude per year.

- Basis for Steel Tank Storage Cost

  --Steel tank storage costs for a large volume crude storage project are estimated at $4.00 to $6.00 per barrel. Using a cost of $5.00 per barrel results in a total cost of $2,700 million for a 540 MMB storage program excluding the cost of crude fill.

  --Timing of construction and fill costs are assumed to be the same as for salt dome storage.

  --Maintenance cost is 5 percent of capital investment per year.