Emergency Preparedness for Interruption of Petroleum Imports into the United States

Supplemental Papers to Interim Report of November 15, 1973

This document is an interim report only of the Coordinating Subcommittee of the NPC Committee on Emergency Preparedness. While it bears the approval of the Subcommittee, it has not been formally reviewed and approved by the National Petroleum Council or its Committee on Emergency Preparedness. It is being made available in the public interest. The summaries and conclusions contained in the official report of the Committee entitled *Emergency Preparedness for Interruption of Petroleum Imports into the United States-A Supplemental Interim Report of the National Petroleum Council* were based wholly or in part on the findings of the Coordinating Subcommittee and its working Subgroups.

National Petroleum Council
December 21, 1973

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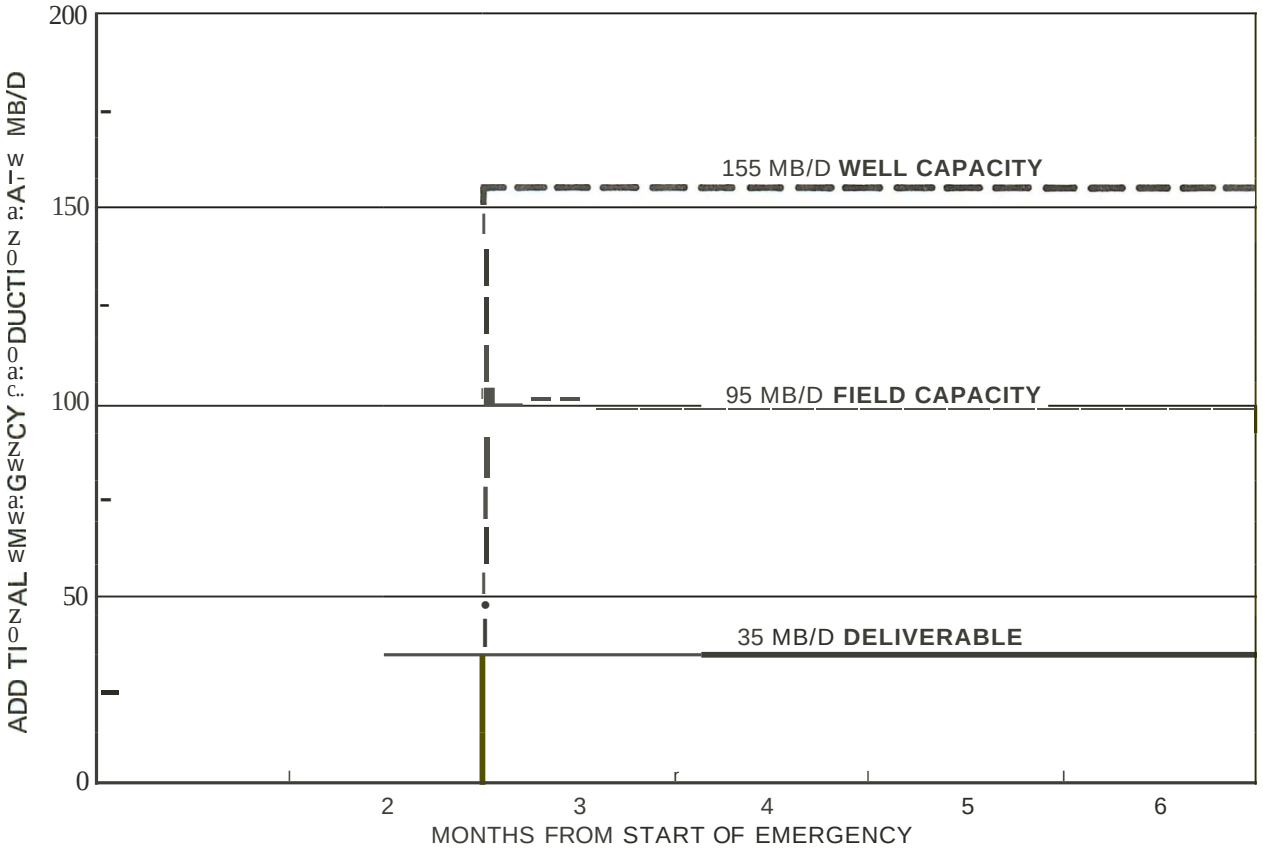

Figure 8. Emergency Production Capacity NPR-l (Elk Hills Field) Current Production: 5 MB/D.

The above figure should be inserted on page 33.

EMERGENCY PREPAREDNESS FOR INTERRUPTION OF PETROLEUM IMPORTS INTO THE UNITED STATES

Supplemental Papers to Interim Report
of November 15, 1973

National Petroleum Council
December 21, 1973

Prepared by the
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of the
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NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF THE INTERIOR

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PREFACE

On November 15, 1973, the National Petroleum Council's Committee on Emergency Preparedness published its findings of the impact of the present embargo of petroleum imports into the United States. This report contains the detailed discussion papers prepared by the Coordinating Subcommittee and published in summary fashion in the November 15th report. This report bears the approval of the Coordinating Subcommittee but has not been formally reviewed and approved by the National Petroleum Councilor its Committee on Emergency Preparedness. This report is being made available in the public interest and is the basis in whole or in part for the findings and conclusions presented in the Supplemental Interim Report of the National Petroleum Council.

Several important events have transpired in the month since the Supplemental Interim Report was published. These events include the signing into law on November 27th of the Emergency Petroleum Allocation Act of 1973 which covers all petroleum products and crude oil, the creation of the Federal Energy Office by executive order on December 4th and a marked reduction in petroleum demand. The reduction in demand was caused by a combination of a warmer than normal November and public acceptance of energy conservation measures recommended by the President in his messages of November 7th and November 25th. Additionally, the immediate effects of the embargo have been delayed slightly and actual import reductions did not occur during the last two weeks of November as assumed in this report but did appear during the early days of December. The net effect of the reduced demand and the delayed denial effects has been to forestall the drawdown of inventories. While this may affect the *average* shortfall during the first quarter of 1974, it does not affect the ultimate magnitude of the effects of the embargo on the Nation's petroleum supply and demand balance and therefore does not alter the conclusions of this report.

PART I

Extract from the Supplemental Interim Report of the National Petroleum Council

On July 24, 1973, the National Petroleum Council approved and transmitted to the Secretary of the Interior an Interim Report entitled *Emergency Preparedness for Interruption of Petroleum Imports into the United States*. This report is a supplement to the July Interim Report and has been prepared expressly to report the findings and recommendations of the National Petroleum Council which are applicable to the interruption of petroleum imports currently being experienced by the United States.

When the Honorable Rogers C. B. Morton, Secretary of the Interior, wrote to the National Petroleum Council requesting an analysis of the Nation's ability to respond to a denial of imported petroleum, hypothetical "study" cases were prescribed (see request letters, Appendix A). Responsive to the Secretary's request, the six cases shown in the tabulation below were chosen for consideration:

Import Interruption Cases Considered

Date of Interruption	Volume (MMB/D) *	Period of Interruption (Days)	Type of Import
1/1/74	1.5	90	Crude 60/40 Crude/Product
	3.0	180	Crude 60/40 Crude/Product
1/1/78	3.0	180	Crude 60/40 Crude/Product

* Millions of 42-gallon barrels per day.

By letter dated October 26, 1973, the Honorable Stephen A. Wakefield, Assistant Secretary of the Interior--Minerals and Energy, wrote to the Council as follows:

> "One of the scenarios of 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

Editor's Note: Extracted from *Emergency Preparedness for Interruption of Petroleum Imports in the United States: A Supplemental Interim Report of the National Petroleum Council*, November 15, 1973.

you have accomplished regarding a January 1, 1974 supply interruption and submit it to the Department of the Interior at the earliest possible date."

This Supplemental Interim Report, therefore, is intended to amplify and expand upon the analyses of a 1974 interruption contained in the July Interim Report. This report is prepared by energy industry experts with the sincere purpose of aiding both government and industry in efforts to alleviate the effects of the current interruption and to cope with the current crisis at hand (see Appendix B for a list of members of the Committee and its Subcommittees). It should be emphasized that this does not represent the final or complete discussion of the 1974 cases, only a compendium of results obtained to date. The final report will be completed as soon as possible.

Prior to the current Middle Eastern crlS1S, the United States average 1973 refined petroleum product demand was projected to be 17.7 million barrels per day. Of this volume, over 35 percent was either directly imported or manufactured in the United States from imported crude oil. As a percent of total energy requirements, the United States was dependent upon foreign petroleum for 17 percent of its energy.

But this has not always been the case. Up until 1967, the United States had sufficient reserve or spare petroleum producing capacity to more than compensate for a loss in imports availability. The Nation's reserve producing capacity has now been exhausted, and in the short-term domestic petroleum self-sufficiency cannot be regained.

In 1970, about 3.4 of the 14.9 million barrels of petroleum required each day in the United States was imported. A number of factors have combined to almost double the import volume over the last three years:

- Stagnation of domestic crude oil production rates
- Decline of domestic natural gas production
- Delays in planned completion and operation of nuclear powered electric utility plants
- Technological difficulties with the development of sulfur control equipment for coal and oil burning equipment
- Rapid upturn of economic activity, and
- Environmental and safety related equipment on motor vehicles.

In combination, these factors, in addition to normal growth in petroleum requirements, forced demand up 2.8 million barrels per day over the 1970 level. The critical aspect of this growth

is the fact that all of the increase came from foreign--primarily Middle Eastern--petro1eum reserves. Middle Eastern countries possess 63 percent of the total non-Communist world crude oil reserves, and the production from these reserves currently represents 42 percent of that in the non-Communist world.

With the resumption of hostilities in the Middle East on October 6, 1973, Arab oil became a diplomatic and economic issue. Since that time, prices nearly doubled, shipments were disrupted, production was cut back and embargoes were enacted. The Committee estimates that by the end of the year, the net effect upon u.S. petroleum supply will reach 3 million barrels per day or 17 percent of the 1973 domestic demand for petroleum products. A reduction of this magnitude will have serious repercussions upon the U.S. economy unless the United States immediately develops and implements a national program to increase supplies and reduce energy consumption on an emergency basis. This should be accomplished within a framework of minimum impact on the economy.

The immediate problems of realizing the potentials of conservation, curtailment and fuel substitution are both administrative and logistic.* Remaining available energy supplies and the results of savings from energy conservation measures will not be evenly distributed throughout the country. However, properly conceived and administered allocation programs will help redistribution greatly. In addition, if the fuel suppliers are allowed emergency flexibility and distribution priorities, the impacts of the denial will be minimized.

Over the longer term, the United States must develop an energy self-sufficiency which will not allow the Nation to be vulnerable to an imports interruption again. Domestic energy resources are more than adequate to meet this goal, but a national goal must be set to develop them. Only through a coherent and cohesive National Energy Policy can we avoid a repetition of the inconvenience and hardship facing the United States today and in the months ahead.

FINDINGS AND CONCLUSIONS

This Supplemental Report represents the first assessment by the National Petroleum Council's Committee on Emergency Preparedness of the impact of the current denial of Middle Eastern oil on the energy posture and economy of the United States. The magnitude and abruptness of the oil denial, the full impact of which will be felt in the next few weeks and months ahead, place the Nation in an extremely precarious situation.

FINDINGS

The National Petroleum Council's Committee on Emergency Preparedness submits the following findings:

The United States Energy Supply Situation was Tenuous Even Before the Arab Embargo.

Even prior to the Middle East conflict which began on October 6, 1973, and the subsequent embargo of Arab oil to the United States, this Nation was faced with an energy crisis. In addition to decreasing production of energy raw materials, refineries were running at maximum rates, inventories were being drawn down and overall energy supplies were short. Mandatory allocation programs were already in effect in an attempt to ensure equitable distribution of supplies.

Primary inventories of gasoline, distillates and heavy fuel oil, the three major liquid petroleum fuels, were 71 million barrels below normal as of October 26, 1973. Crude oil stocks were 14 million barrels below normal.

The United States Has Allowed Itself to Become Critically Dependent Upon Foreign Supplies.

The United States has not developed its own abundant natural resources and has allowed itself to become critically dependent upon imports. Domestic crude production continues to decline and natural gas production has peaked out. Nuclear plants are not being completed as rapidly as scheduled or anticipated. The use of coal has been depressed because of environmental and other reasons. Strip mining restrictions contribute to the limitation of coal supplies. Oil and gas reserves discovered on the North Slope of Alaska and offshore California 5 years ago are still untapped as environmental considerations immobilize their development.* Highly prospective offshore acreage on the continental shelves off our coasts have not been made available in a timely manner. Natural gas prices have been depressed to abnormally low levels under FPC regulations. Oil shale development has been delayed by lack of an effective federal leasing policy.

* These reserves total about 10.5 billion barrels of oil and 27 trillion cubic feet of gas.

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These and other factors have discouraged the development of U.S. natural resources and caused the country to become critically dependent upon foreign imports of oil and gas. During the first quarter 1973, imports represented 35 percent of U.S. petroleum supplies and were growing rapidly. Had the Arab embargo not occurred, imports would have reached 7.4 million barrels per day, or 39 percent of U.S. petroleum supplies by the first quarter of 1974.

What Has Happended to Foreign Supplies

Following the outbreak of war between Israel and the Arab countries on October 6, 1973, the United States was cut off from crude and product supplies coming from Arab sources. The initial impact will be in the order of 2 million barrels per day and is expected to increase rapidly reaching 3 million barrels per day by year-end.

In addition to direct embargoes against shipments to the United States, the Arab countries have reduced total production by 5 to 6 million barrels per day resulting in world shortages of petroleum supplies, thus bringing world pressure on the United States to moderate its position of support for Israel.

Timing of the Impact Will Be Delayed

The impact of these denials is delayed because it takes about one month for a tanker, having been loaded in the Middle East, to reach the United States. Secondly, already critically short inventories needed for this winter season are being drawn down to temporarily to meet consumer demand.

What Will Happen If No Emergency Actions Are Taken

Inventories will be depleted early in the first quarter of 1974 and the petroleum industry will no longer be able to provide the supplies needed. Shortages in the three major products, gasoline, distillates and heavy fuel oil, will average 25 percent during the first quarter of 1974. Heavy fuel oil shortages would average 38 percent on a U.S. basis and could reach 49 percent on the East Coast.

The effect of shortages of this magnitude on the economy is difficult to estimate. On a conservative basis, the effect of a 2-million-barrel-per-day cutoff has been estimated to cause an annual loss of 48 billion dollars to the U.S. economy as measured by the Gross National Product. This slow-down in the economy would cause unemployment to increase from the current 4.5 to 5.0 percent level to over 6 percent. The projected 3-million-barrel-per-day cutoff would have an even greater impact and could push unemployment up to the 7.5 to 8.0 percent range.

It Is Critically Important That Emergency Action Be Taken Immediately.

Industry normally draws down inventories at the rate of about 1 million barrels per day to meet consumer needs in the first quarter of the year. If available inventories are depleted before the end of the year, the 1 million barrels per day of supplies from inventory will not be available. When combined with the 3-million-barrel-per-day import cutoff, a 4-million-barrel-per-day shortage would be created and an even more serious situation would develop.

For these reasons, it is imperative that emergency action be taken immediately so that available inventories can be conserved and used over a longer period of time.

What Emergency Actions Can Be Taken to Increase Domestic Supplies

Under emergency conditions, additional domestic energy supplies equivalent to about 700 thousand barrels per day can potentially be provided this winter if immediate actions are taken. Potential supply sources include: (1) producing the Naval Petroleum Reserves at Elk Hills, California, at maximum rates and temporatily increasing crude production above established field MER's (Maximum Efficient Rates), (2) incremental emergency gas sales to industrial customers now burning fuel oil or distillates, (3) increased electric power supplies by accelerating the licensing of already constructed nuclear power plants, and (4) increased use of coal.

To develop these potential emergency supplies will require a widespread commitment on the part of industry, Federal and state governments, and the American people in order to utilize all readily available resources. In some cases, enabling legislation is required. In almost all cases, quick and aggressive action is needed by both state and Federal governments. The respective jurisdictions and authorities of state oil and gas conservation bodies should be continued.

Even if all the above available emergency supply steps are taken, a significant net shortage of oil will remain.

What Can Be Done About the Net Shortage

The remaining net shortage can only be covered by a reduction in energy use. Many voluntary and mandated energy conservation steps are currently being considered (including such items as a reduction of speed limits, encouragement of carpooling, and a reduction in airline flights). While these measures are important, estimates indicate that they will account for only about 50 percent of the net shortage.

Mandatory rationing is therefore necessary to accomplish required reduction in use and should be instituted immediately.

A distinct difference should be drawn between rationing and allocation programs. Allocation programs should serve the basic function of distributing supplies (or distributing the shortage) throughout the market. Rationing, on the other hand, directly addresses and has the primary function of controlling and curtailing consumption in selected products.

Where Should Consumption Be Cut

The Nation must establish priorities and determine where cuts in demand should be made. On the one hand, priority can be given the individual consumer; on the other hand, priority can be given industry.

The Committee believes that the first reductions should take place in noncritical human consumption and less essential industry areas. High priority should be given to providing the fuel needed by those industries most vital to the economy. Critical human needs must, of course, receive high priority. However, the general public would undoubtedly prefer some discomforts and inconveniences to idle plants and high unemployment.

Mandatory rationing of gasoline for private transportation and of home heating oils offer the opportunity for significant reductions in petroleum use with minimum impact on the economy. Possibilities for comparable residential rationing of electricity and natural gas for residential heating should also be considered.

CONCLUSIONS

In view of the findings, the Nation has no other short-term alternative except to take immediate emergency action to reduce its consumption of energy and increase domestic energy supplies. With the goal of minimizing the effects on economic activity and the American consumer, the National Petroleum Council's Committee on Emergency Preparedness submits the following conclusions:

- Immediate and decisive action is needed by Federal and state governments to minimize the detrimental effects occasioned by the current energy crisis. Delay to act will compound the severity of the situation.

- Both the Federal Government and industry should immediately present the facts to the public and commence an educational program through all communications media to assure public awareness and to urge consumer energy conservation at all levels.

- Government-industry cooperation is needed at all levels. The operations of the energy industries are extremely complex. The expertise available from private industry should be utilized in an advisory and operational capacity.

- National economic health, employment, personal income and the strength of the Nation's defense system depend upon maintaining normal industrial operations. Therefore, every effort should be made to continue the operations of the industrial sector of the U.S. economy as close to normal as possible.

- The extent and endurance of the denial of oil imports to this Nation from the Middle East is beyond the determination of this Committee. However, the United States will experience an actual loss of about 80 million barrels of oil as a result of the embargo to date. Even if the embargo were lifted at an early date, critical shortages will be enacted, and therefore, the Committee emphasizes that programs and policies mentioned in this report should be initiated.

- Any emergency measures enacted during the current denial should be undertaken with the clear provision for their removal at the termination of the denial and its after-effects. The American system should continue to operate on a competitive, free-enterprise basis and increased government intervention for emergency purposes should not be continued upon the cessation of the emergency.

PART II

Supplemental Interim Report Papers of the Coordinating Subcommittee

Chapter One

CRUDE SUPPLY AND TRANSPORTATION

This chapter is a brief summary of the crude supply and transportation system to provide a general understanding of crude and product flows in the United States.

CRUDE PRODUCTION

In 1972, crude and lease condensate production in the United States totaled 9,451 thousand barrels per day (MB/D). It was divided among Petroleum Administration for Defense (PAD) Districts as follows:

PAD District	Crude and Lease Condensate Production (MB/D)
I	66
II	1,045
III	6,550
IV	638
V	1,152
Total	9,451

The three leading states (included in the above totals) were Texas with 3,556 MB/D, Louisiana with 2,448 MB/D and California with 948 MB/D.

U.S. REFINING CENTERS

As of January 1, 1973, the Bureau of Mines reported there were 277 refineries in the United States with total operable crude oil distillation capacity of 13,642 MB/D. The refining capacity is located by Petroleum Administration For Defense (PAD) Districts as follows:

PAD District	Crude Oil Distillation Capacity (MB/D)
I	1,603
II	3,782
III	5,590
IV	459
V	2,208
Total	13,642

Historically, refineries have been located either close to domestic crude oil production centers, major consuming areas or water transportation corridors such as the Mississippi River system or ocean ports. The largest concentration of refining capacity is along the Texas-Louisiana Gulf Coast. Other concentrations are along the Mississippi River in Louisiana, the Philadelphia-New Jersey Atlantic Coast area, Chicago area, Los Angeles and San Francisco.

Significant refining capacity is also located on the Puget Sound in Washington, near St. Louis and in Ohio, Oklahoma, Kansas, West Texas, Southern Wyoming and Salt Lake City. The Atlantic Coast area, Chicago, St. Louis, San Francisco and the Puget Sound concentrations are demand oriented. The other locations have primarily developed because of the proximity of crude production. During 1973, only a small amount of new capacity has been added, and significant changes in refining centers have not occurred.

DOMESTIC CRUDE TRANSPORTATION SYSTEM

Crude movements between domestic producing areas and refining centers are made almost exclusively by pipeline. Of the 9.5 million barrels per day *(MMB/D)* of domestic crude produced in 1972, only 160 *MB/D* moved from the Gulf Coast to East Coast refining centers by tankers, and only 30 *MB/D* moved up the Mississippi to the Midwest by barge. While there are numerous petroleum pipelines, a relatively few large diameter trunk lines have most of the useful capacity. Economics limit the usefulness of small lines to feeder systems for the large trunk lines or to make deliveries to refineries in or near the producing areas.

Texas crudes have traditionally been moved south to the Gulf Coast refineries and north to the refineries in Oklahoma and the Midwest. With the increasing dependency of the United States on foreign crudes, the Gulf Coast refineries are running more foreign crude and require less domestic crude. This has diverted Texas crude north, filling all of the existing pipeline space to Oklahoma and all but 60 to 100 *MB/D* of space from Oklahoma north to the Great Lakes area. The pipelines south to the Gulf Coast are not as heavily loaded, and reversal of some of these lines is being considered to deliver south Texas and foreign crudes to refineries in Oklahoma and the Midwest.

Increasing volumes of foreign crude (80 *MB/D* in May 1973) are being moved to the Midwest via pipeline and barge. Current pipeline capacity is 640 *MB/D,* and an expansion to 840 *MB/D* will be operational in late 1974. The capacity of the present 40-inch pipe can be economically expanded to 1.1 *MMB/D* by addition of pumping capacity.

About 250 *MB/D* of Rocky Mountain and Canadian crude in excess of local needs in PAD District IV moves to the Midwest via the existing pipeline system. The flow in these lines is variable, with about 100 *MB/D* of open space normally available.

Canadian crude deliveries to PAD District II could be increased because some of the about 300 *MBID* of new capacity that has recently been added to bring in this crude is not being utilized.

The East and West Coast refining systems depend on marine deliveries for their crude supply. The tanker fleets and docks serving these refineries are being modestly upgraded to meet the demand for increasing crude runs and to take advantage of the favorable economics of scale in tanker size.

WATERBORNE IMPORTS OF FOREIGN CRUDE AND OTHER FEEDSTOCKS

Waterborne imports of crude oil and unfinished stocks increased 42 percent in 1972 over 1971 levels. A continuing year-to-year increase can be expected in order to offset domestic production decreases and domestic demand increases. The largest percentage increases in imports in 1972 were from West Africa and North Africa, with the latter also being the largest source of imports. The second most important source was the Persian Gulf, which also showed an increase over 1971. Imports from Indonesia and Malaysia were up as well. There were less imports in 1972 from Western Hemisphere sources--mainly Venezuela--than in the prior year. This appears to be a major trend, unless new fields are found, such as in Ecuador. Principal refining centers using water imports are New York Harbor, Northern New Jersey, the Delaware Bay area, Los Angeles Basin, San Francisco Bay, Seattle and the entire Gulf Coast.

Waterborne Product Imports

While 2.3 *MMB/D* of finished product imports in 1972 was quite substantial, the most recent published figures for 1973 to date indicate that these volumes will be greatly exceeded during the current year. Due to the ever-widening gap between domestic demand and domestic supply, the need for sharply increasing imports is almost certain to continue at least until new refinery capacity comes on-stream in the years after 1976. The amounts imported will be limited only by the availability of imports from offshore sources.

Chapter Two

PETROLEUM SUPPLY/DEMAND BALANCES IN THE PRESENT EMERGENCY

PRE-DENIAL SITUATION

Prior to the resumption of the Middle East conflict in early October 1973, it had been anticipated that petroleum supply and demand in the United States would be in very tenuous balance during the first quarter of 1974. Product demands were expected to continue the vigorous expansion of recent years, particularly for distillate and residual fuel oils. With domestic production of petroleum liquids declining slightly, the pre-denial supply/demand balance required the scheduling of sharply increased imports of crude oil and refined products. A comparison of the principal pre-denial supply/demand components for the first quarter of 1973 and 1974 is shown in Table 1.

TABLE 1

PRE-DENIAL U.S. PETROLEUM DEMAND AND SUPPLY

Item	1st Quarter 1973 Actual MB/D	1st Quarter 1974 Pre-denial MB/D	1st Quarter of 1974/73 MB/D	Percent
Total Demand	18,488	19,774	+1,286	+ 7
Inventory Change	- 795	-1,040	- 245	+31
Required Supply	17,693	18,734	+1,041	+ 6
Domestic Production	10,957	10,853	-104	- 1
Imports:				
Crude	2,924	3,672	748	+26
Products, etc.	3,325	3,699	374	+11
TOTAL IMPORTS	6,249	7,371	+1,122	+18
Other Supply*	487	510	+ 23	+ 5
Imports as a % of Required Supply	35%	39%		

* Processing gain, other hydrocarbons, etc.

Total demand, projected at 19,744 MB/D during the first quarter of 1974 is 7 percent greater than in the first quarter of 1973. Inventory drawdown, a seasonal occurrence during the first quarter, was projected to be 245 ME/D greater than 1973. With required supply expanding by 1 MME/D and domestic production declining 0.1 MMB/D, required imports would have to increase 1.1 MMB/D or 18 percent over 1973, to a total of nearly 7.4 MMB/D. At this level, imports would represent 39 percent of total supply.

SOURCE OF IMPORTS

Crude oil imports into the United States during the first 7 months of 1973 are shown on Table 2. Imports from Organization of Arab Petroleum Exporting Countries (OAPEC) were in the order of 800 MB/D during this period, the remaining requirements being made up primarily from Canada, Venezuela, Nigeria, Iran and Indonesia. However, incremental crude oil to accommodate rapidly escalating import requirements during the third quarter had to be scheduled largely from the Persian Gulf. For November 1973, crude oil imports into the U.S. from OAPEC nations were originally scheduled in the order of 1.2 MMB/D.

Product imports during the first half of 1973 are shown on Table 3. During that period total product imports were in the order of 3 MMB/D, consisting primarily of residual and distillate fuel oil received from Venezuela and the Caribbean area. In the third quarter, product imports likewise expanded very rapidly with increasing amounts, including gasoline, corning from Western European refineries. By the first quarter of 1974, required product imports were calculated at 3.7 MMB/D.

OIL IMPORT DENIAL SITUATION

In mid-October 1973, the Arab nations announced cutbacks of oil exports to the United States and to other countries supplying refined products to the United States. The initial amount of these denials is expected to be about 2 MMB/D from pre-denial levels, consisting of 1.2 MMB/D of crude oil and 0.8 MMB/D of products. The impact of the curtailments will be delayed until the latter part of November because of the 30 to 35 day one-way sailing time of tankers carrying crude oil from Middle East loading ports.

The import denials are expected to escalate and approach the 3 MMB/D theoretical curtailment case postulated in the original emergency preparedness study. This case assumed denial of 1.8 MMB/D of crude oil and 1.2 MMB/D of refined products.

A 2 to 3 MMB/D import disruption imposed upon an already tight supply situation in the United States creates a very difficult situation. However or whenever the Middle East conflict is settled, forward planning must recognize the possibility of continued oil

TABLE 2

U.S. IMPORTS OF FOREIGN CRUDE OIL
(MB/D)

Origin of Imports	July 1973	Jan.-July 1973
Canada	959	1,042
Mexico		1
TOTAL NORTH AMERICA	959	1,043
Colombia		2
Ecuador	39	46
Trinidad	31	57
Venezuela	392	290
TOTAL CENTRAL & SOUTH AMERICA	462	395
TOTAL WESTERN HEMISPHERE	1,421	1,438
OAPEC Nations:		
Libya	116	142
Algeria	149	150
Saudi Arabia	644	392
Abu Dhabi and Dubai	102	76
Other OAPEC	36	59
TOTAL OAPEC	1,047	819
Angola	60	36
Nigeria	481	431
Tunisia	7	17
TOTAL OTHER AFRICA	548	484
Israel		2
Iran	229	171
Indonesia	256	195
Malaysia		1
TOTAL EASTERN HEMISPHERE	2,080	1,672
TOTAL WORLD	3,501	3,110

Source: U.S. Bureau of Mines

TABLE 3

UNITED STATES IMPORTS OF REFINED PRODUCTS
JANUARY - JUNE 1973
(MB/D)

Area of Origin	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Other Oils	Total Products
North America	14	10	93	232	349
Central and South America	63	240	1,589	288	2,180
TOTAL WESTERN HEMISPHERE	77	250	1,682	520	2,529
Western Europe	11	122	141	8	282
OAPEC Nations	2	11	45	29	87
Other Middle East	4	-	-	6	10
Other Africa	-	-	17	-	17
Far East, Etc.	-	-	7	29	36
TOTAL EASTERN HEMISPHERE	17	133	210	72	432
TOTAL WORLD	94	383	1,892	592	2,961

disruption. In any event, the effects of a disruption will persist for several months after a restoration of some or all pre-denial imports. There are three principal reasons for this: (1) 30 to 35 days will be required for new crude oil supplies to reach the United States after they are loaded in the Middle East; (2) U.S. inventories will be drawn down to abnormally low levels and will need to be rebuilt before normal operations are possible. Furthermore, European and other offshore inventories that have also been affected by the Middle East embargo must also be restored before supplemental product imports can be expected; (3) U.S. refining capacity being much less than demand, there is no spare capacity available to restore inventories even with adequate crude supplies. Reduced refinery runs resulting from the crude shortage is in effect lost output which cannot be made up at a later date.

Considering these factors, it is essential that the United States take immediate steps to curtail demand so that crude and product inventories are not drawn down excessively during the next 2 to 3 months. Although it is uncertain how long the disruption will continue and what the operating supply situation will be after the embargo is lifted, a review of the supply effects of a 3 MMB/D denial case (referred to above) will help to illustrate what the impact of the disruption might be and the importance of taking immediate actions to curtail demand and augment supply. (For purposes of this discussion, the denial is not reduced by emergency measures to increase supply that might be available, such as short term crude production increases.)

The breakdown of volumes of disrupted imports in the first quarter of 1974 is assumed to be as follows (see Table 4).

TABLE 4

TYPE AND VOLUME OF IMPORTS DENIED
(MB/D)

Crude		
Products		1,800
Gasoline	80	
Distillates	370	
Heavy Fuel Oil	750	1,200
Total		3,000

The last actual inventory data available (as of October 26, 1973) indicated that total U.S. inventory of the three critical product groups (gasoline, middle distillates, heavy fuel oil) was

SIS MMB and for crude oil, 246 MMB. This is approximately 71 MMB below normal for products and approximately 14 MMB for crude oil. Other products, including liquefied petroleum gases (LPG), petrochemical feedstocks, asphalt, lubricating oils and coke, are not included. These other products, together with unfinished oil stocks, total approximately 250 MMB of inventory and are not available to meet demand for the three major product groups. Stocks by these major product groups, compared to generally considered "normal" levels for this time of the year, are shown in Table 5.

TABLE 5

MAJOR PRODUCT INVENTORIES
(MMB)

Stock (As of October 26, 1973)	Normal	Actual	Difference
Gasoline	225	214	(11)
Distillates	298	244	(54)
Heavy Fuel Oil	63	57	(6)
Total	586	515	(71)
Crude Oil	260	246	(14)

Minimum operable inventories for each product are not well defined. However, the inventories as of December 31, 1973, shown on Table 6 might be considered near the minimum under which reasonably uniform operations can be maintained with only spot shortages and before a physical breakdown occurs. It is clear that long before the end of the first quarter 1974 inventories would be hopelessly below minimum levels and that demand must be curtailed.

The total denial of 355 million barrels represents 14 percent of total demand for the period November 15, 1973 to March 31, 1974, and 20 percent of demand for the period January 1, 1974 to March 31, 1974. Figure 1 shows that the impact of the denial in the first quarter of 1974 will be significantly reduced if actions commence immediately to spread the required demand curtailment over a longer period of time. As indicated in Chapter Four a denial of petroleum products in the 8-10 percent range will begin to have very serious effects on the economy. This is particularly true for reductions in heavy fuel oil (HFO) which directly impact on industry operations. Where the reductions can be taken in less critical areas such as motor gasoline, the economic impact can be softened.

TABLE 6

MAJOR PRODUCT INVENTORIES
(MMB)

	Normal	Without Denial	Effect of * Denial	With Denial	Memo Operable t Minimum
December 31, 1973					
Gasoline	247	225	(28)	197	195
Distillates	253	204	(30)	174	100
Heavy Fuel Oil	55	50	(31)	19	40
Total	555	479	(89)	390	335
April 1, 1974					
Gasoline	265	243	(Ill)	132	195
Distillates	149	125	(120)	5	100
Heavy Fuel Oil	46	42	(124)	(82)	40
Total	460	410	(355)	55	335

* Assumes 1.2 MMB/D crude oil and 0.8 MMB/D products denial from mid-November through year-end 1973; 1.8 MMB/D crude and 1.2 MMB/D products denial during first quarter 1974. Crude denials were converted to product effects based on the following yields for typical Middle East crudes: gasoline--47%, middle distillates--35%, HFO (less refining fuel consumed)--16%.

t Operable minimum inventory results in spot shortages, but can meet required demand.

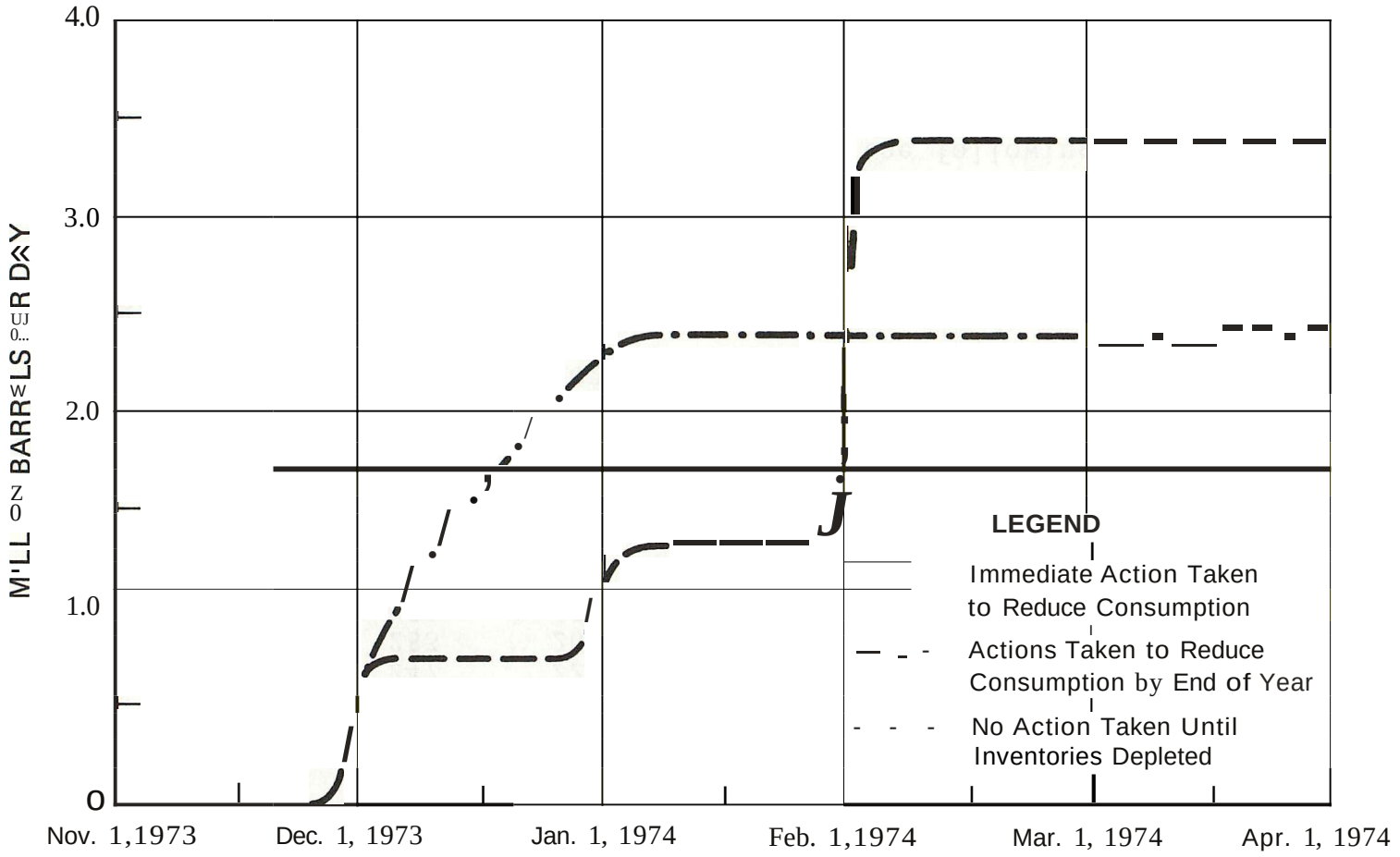


Figure 1. Net Impact of Import Interruption on Supply Availability Under Different Inventory Management Programs.

The effect of the denial on demand and, thus, on the economy is further demonstrated by looking at specific product groups. These data for the total U.S. given in Table 7.

TABLE 7

Product	fota1 Demand--Mi11ion Barrels 4-172 Months 11/15-3/31	3 Months 1/1-3/31	4-172 Months (MMB)	Denial Percent Demand* 11/15-3/31	1/1-3/31
Gasoline	1,052	698	111	11%	16%
Distillates	589	417	120	20%	29%
Heavy Fuel Oil	464	327	124	27%	38%
Total	2,105	1,442	355	17%	25%

*Based on demand for the major product groups only. As a percent of total demand the denial percentage figures are 14% and 20% for the 4-1/2 and 3 month cases respectively.

There is no doubt that, in addition to gasoline, substantial curtailments of heavy fuel oil and distillate consumption will be required. These effects will be heavily concentrated on the East Coast. The potential impact is illustrated in Table 8.

TABLE 8

PAD District I

Product	Total Demand--Mi11ion Barrels 4-172 Months 11/15-3/31	3 Months 1/1-3/31	4-1/2 Months (MMB)	Denial Percent Demand 11/15-3/31	1/1-3/31
Distillates	357	253	80	22%	32%
Heavy Fuel Oil	324	217	106	33%	49%

ANALYSIS OF DENIAL BY PAD DISTRICT

Another important aspect of an import denial is to consider the area of impact of the denial and determine the necessary logistical response in order to equitably distribute the denial geographically. The specific inter- and intra-district movements required are beyond the limited time scope of this report. Elements that must be considered include available sources of crude and products and the intervening refining and transportation systems. The detailed logistical analysis must include all affected parties and

can be started only after the level of demand to be satisfied and crude and import product availability after specific denials are established.

The underlying assumption in analyzing regional dislocations is that the supply shortfall caused by denials should be shared by the entire country proportional to base case demand in a given area of each PAD district. Since base-case imports do not enter the United States in this fashion, various assumptions and inter-district movements are required to balance the system. A detailed analysis of the supply/demand balance is included as Table 9.

The 1.8 MMB/D of crude denial among PAD districts has been assumed to be proportional to waterborne crude imports in the base case. However, PAD V is adjusted to suffer less than a prorata share of denial and PAD III a greater denial share by an equal volume (111 MB/D). This reallocation was made to balance PAD V in proportion to base demand without having to move crude by small tankers from PAD III to PAD V via the Panama Canal. Balance in PAD III is achieved vis-a-vis other districts. The 1.2 MMB/D of product denial has all been taken in PAD I. This is done because roughly 85 percent of U.S. product imports are in PAD I, because the bulk of product types likely to be denied are imported into PAD I, and for simplicity. Offsetting a portion of the denial are additional crude oil and natural gas production, conversion of oil demand to coal and a small adjustment to refinery gain to reflect lower crude runs. Net denial after these adjustments, which are detailed on Table 9, will approximate 2.4 MB/D.

Inter-district movements of crude and product are used to re-balance the system, except PAD V, in which imported crude denial allocation causes this district to balance. The supply/demand balance statement shows an adjustment of 633 MB/D of crude and 344 ME/D of product receipts in PAD I. This crude and product is assumed to originate in PAD III. It is likely that crude imports will be redirected to PAD I from PAD III and substantially reduce the volume of the Gulf Coast-East Coast crude movement. After denial, PAD II will receive 358 ME/D less crude and 235 ME/D less products than in the base case. Most of this crude and all of the product was originating in PAD III and moving north by pipeline in the base case. After denial, PAD III will have 220 MB/D increased net shipments of crude. This is a net of 633 MB/D additional shipments to PAD I by vessel and 413 MB/D less shipments to PAD II by pipeline. The net shipments from PAD III of 88 MB/D of products is the net of increased shipments of 344 MB/D to PAD I and reduced shipments of 235 MB/D to PAD II and 21 MB/D to PAD IV. After denial, PAD IV has 55 MB/D more crude shipments to PAD II and 21 MB/D less product receipts from PAD III. As discussed previously, PAD V domestic crude and product movements are not necessary because imported crude was assumed to be reallocated to balance PAD V.

The most significant problem areas that are pointed up by the inter-district analysis are the large increase in crude movements from PAD III to PAD I, the large volume of imported heavy fuel oil

• These offsetting measures require governmental action such as:

- Approval of emergency MER increase
- Approval of certain third party gas sales
- **Relaxation of 5ulflJT restriction on plant emissions.**

likely to be denied PAD I and the difficulty in redirecting crude to the Midwest if Canadian imports are substantially reduced. The crude movements between PAD's I and III are probably not a serious problem due to the potential reallocation of imported crude between them and the fact that in the past large volumes of Gulf Coast crude have moved to the East Coast. The denial of heavy fuel oil will likely cause major changes in PAD I. These changes, such as replacing heavy fuel oil with clean products or crude, are discussed more fully later in this report.

SUMMARY

The impact of the Arab embargo on petroleum shipments to the United States will have a substantial impact, and it will last for a long period after the embargo is lifted. In order to minimize the effect, the Nation faces hard and unpalatable choices in determining what demands to restrict and the means to accomplish the necessary reductions. Suffice it to say that, given a continuation of the import denial, the Nation has no short-term alternative except a massive reduction in consumption of petroleum liquids. The sooner this fact is recognized and curtailment procedures implemented, the less the impact on economic, leisure and social activities.

Chapter Three

IMPACT OF OIL IMPORT INTERRUPTIONS ON THE NATIONAL ECONOMY

Recent Arab curtailments of oil exports to the United States have prompted consideration of the extent to which these actions would adversely affect national economic activity. Attempts to quantify the effects are hampered by the lack of a definitive analytical framework, and by uncertainties regarding the nature and effectiveness of programs that would be initiated to ease the situation. However, because of the critical nature of the question, quantitative assessment of Gross National Product (GNP) effects arising from oil supply shortages was considered necessary. Estimated effects on GNP on regional output for each of the five PAD districts have been developed. These estimates apply to the fourth quarter of 1973 and first quarter of 1974--the period of most immediate concern. In the long run, when more extensive corrective actions could be implemented, the effects should be considerably smaller.

Three cases are analyzed. Case I assumes that direct imports of Arab oil to the United States are cut off and that Arab oil is denied to Latin American countries which export to the United States. In addition, product imports from Europe are assumed to be zero. These conditions would indicate a reduction in oil imports of about 2 MMB/D, of which half is crude and half is products. Case II differs from Case I in that it assumes that crude oil shortages would disappear at the beginning of 1974, though the product shortage is assumed to continue. Thus, Case II shortages over the winter average about 1.5 MMB/D. Case III assumes that the shortage averages 0.5 MMB/D, again evenly split between crude and products. Results for the three cases are summarized in Table 10.*

* Three cases are used to show the sensitivity of economic factors to the magnitude of a denial. The criteria for these cases were developed prior to the actual embargo which began in mid-October 1973, and therefore a 3.0 MMB/D case is not specifically discussed.

Additionally, preliminary data on demand reduction, supply increases and inter-district movements were used. While minor adjustments could be made to reflect final data, the order of magnitude of these findings would be unchanged.

TABLE 10

SUMMARY OF ESTIMATED GNP EFFECTS
RESULTING FROM OIL SUPPLY SHORTFALLS

	Percentage Deduction in Energy Usage	GNP Decrease $Bn/Yr	GNP Decrease %
Case I (2 MMB/D Shortfall)			
PAD I	9.4	31.6	5.8
PAD II	1.9	0.7	0.2
PAD III	3.9	3.6	2.9
PAD V	9.9	12.5	6.1
Total U.S.	5.6	48.4	3.6
Case II (1.5 MMB/D Shortfall)			
PAD I	7.4	20.3	3.7
PAD II	1.4	0.3	0.1
PAD III	2.8	2.1	1.7
PAD V	5.7	4.2	2.1
Total U.S.	4.1	26.9	2.0
Case III (.5 MMB/D Shortfall)			
PAD I	2.4	0.6	0.1
PAD II	0.5	0.1	
PAD III	1.0	0.2	0.2
PAD V	2.5	0.2	0.1
Total U.S.	1.4	1.1	0.1

Methodology

The initial step in the approach used to assess oil supply shortage effects on GNP was to estimate the absolute and percentage energy shortfall in each market and in each PAD district. Next, the energy shortfall was multiplied by an estimated unit energy value added figure. Finally, estimated GNP multipliers were applied to the estimated total reduction in energy value added to arrive at an estimate of how much GNP would be decreased.

A critical step in the approach is the estimation of GNP multipliers, which were determined largely on a judgmental basis. For a given market, the multipliers are a function both of the percentage reduction in energy consumption and the economic characteristics of the PAD district in which the energy is consumed. It was assumed that small percentage energy reductions would have little effect on GNP, but that successive reductions in energy use would result in increasingly greater marginal economic costs. Within the range of energy use decreases considered here, it was assumed that multipliers would not exceed current GNP to energy ratios.

It should be noted that the effects on GNP derived from this approach are not necessarily predictions of actual future events. Since there is potential for more efficient energy-use management than is reflected in the parameters employed to develop these estimates, significant softening of the adverse GNP effects indicated is considered quite possible.

Case I

The logic of the approach is illustrated for Case I in the following series of steps:

- As shown in Table 11, GNP was allocated to PAD districts on the basis of personal income.

- Estimated Case I imported shortfall by PAD district is shown in Table 13. As indicated in Tables 12 &13, the distillate shortfall of 320 *MB/D* was estimated to fall mainly in PAD I. The residual shortage is based primarily on minus residual output arising from decrements of Arab oil to Carribbean refineries. Table 12 shows that the total shortage of 2,155 *MB/D* was assumed to be slightly offset by coal substitution in the amount of 200 *MB/D* of oil equivalent. It was assumed that sulfur emission controls would be waived to permit this.

- Adjustments were made to reflect likely intra-district movements and yield changes. In order to ease the severe shortage in PAD I, 90 *MB/D* of distillate was assumed to shift out of PAD III to PAD II pipelines and tankered to the East Coast. Distillate yields were assumed to be increased somewhat at the expense of gasoline. Net shortage

TABLE 11

ESTIMATED ALLOCATION OF GNP TO PAD DISTRICTS
FOR Q4 1973 AND Q1 1974

PAD District	GNP $Bn/Yr	GNP %
I	544	40.8
II	428	32.1
III	125	9.4
IV	31	2.3
V	206	15.4
Total U.S.	1334	100.0

NOTE: The allocation of GNP to PAD districts is based on the of personal income.

TABLE 12

U.S. WINTER 1973-74 CRUDE & PRODUCT OFFSHORE IMPORTS
(MB/D)

		Import Requirements	Case I Shortfall
Imports	Distillate	655	320
"	Jet	200	100
"	Resid	2,150	600
"	Other	225	135
	Products	3,234	1,155
	Crude	3,700	1,000
	Total Shortage		2,155
	Less: Offset coal for Resid		200
	Net Shortage =		1,955

TABLE 13

SHORTAGES BY END-USE*
(MB/D)

	PAD District				
Transportation	I	II	III	V	Total U.S.
Gasoline	206	56	109	165	536
Jet Fuel				35	35
Diesel Fuel	111	28	22	1	162
Total Transportation	317	84	131	201	733
Household & Corom.					
Distillate	201	51	39	65	356
Residual	87	1	2	19	109
LPG	23	10	15	8	56
Total H & C	311	62	56	92	521
Industrial					
Distillate	24	6	5	8	43
Residual	96	1	2	21	120
Total Industrial	120	7	7	29	163
Electric Utilities					
Distillate	33	8	6	11	58
Residual	213	3	3	48	267
Total Elec. Uti!.	246	11	9	59	325
Chemicals & Raw MatI.	86	36	57	34	213
Total	1,080	200	260	415	1,955

* Shortfall estimates by PAD district, fuel type, and end-use include estimated adjustments to logistics patterns and refining yields.

TABLE 14

CALCULATION OF MAXIMUM MULTIPLIERS

PAD Districts	Estimated Winter 1973-74 GNP Level ($Bn/Yr)	1973 Potential Consumption of Energy (QBTU's)	1973 Potential Consumption of Energy (MMB/COE)	Ratio of GNP to Energy Value Added*
I	544	19.5	9.75	23.4
II	428	20.8	10.40	17.3
III	125	12.7	6.35	8.3
V	206	7.6	3.80	22.8
U.S.	1,334	62.3	31.15	18.0

* Energy value added at $6.52/barrel.

estimates, including logistics and refining yield adjustments, are detailed in Table 13. In this table, shortages to electric utilities are shown on an input basis; however, other Case I graphs and tables omit the electricity generating sector, but reflect electricity consumption on an output basis as part of each energy consuming market. For example, of the total 1,955 MB/D shortfall indicated in Table 13, 325 MB/D is input to electric utilities. Subtraction of conversion losses (2/3 of 325, i.e., 217 MB/D) brings the consumption loss on an output basis to 1,738 MB/D, as shown in Table 15.

- A total dollar value was ascribed to the energy shortage in each market and PAD district. These estimates are shown in the value added column of Table 15. The $6.52 per barrel figure used represents an estimated average unit value added for all petroleum products.

- GNP multipliers to be applied to the total decrease in energy value added were then estimated. Obviously, this is a critical aspect of the approach used, and also one of the most difficult to quantify. However, some simplifying assumptions afforded a means of estimation. It was first assumed that the incremental ratio of output to energy usage would not exceed the current average ratio, within the range of energy decreases considered. While it was recognized that the incremental multipliers would exceed the average output-energy ratio beyond some level of energy usage decrease (and could well be a continually rising function), for an energy decrease range of say up to 15 percent, the premise described was considered adequate for this purpose. Determination of the average regional output/energy ratios is shown in Table 14.

  Because many possibilities exist to reduce energy consumption without seriously affecting GNP (e.g., lower auto speeds, consolidation of auto and air trips, lower thermostat settings, etc.), low multipliers were estimated for small energy decreases. As energy shortages increase, however, these possibilities diminish (especially in the near term), and the effect on output becomes substantial. The rate at which the multipliers increase in value as energy use decreases is largely judgmental. As previously noted, the rate of increase should be relatively slow in markets where use is largely for personal consumption and relatively rapid where use is largely for production. Thus, the multipliers for the industrial market rise more quickly than those for transportation, about half of which reflects personal passenger-car use. The multiplier for chemicals and raw materials is heavily influenced by the large raw materials component; thus, it does not accelerate as quickly as the average for all industry.

- Figures 2 through 5 show multipliers for each market and PAD district, which are applicable to incremental reductions in energy usage. While they are useful in evaluating the differential effect of alternative energy allocations, average rather than incremental multipliers for a given percentage decline in energy usage are required to compute the decrease in GNP for purposes of this report. In Table 16, the decrease in GNP is shown. It should be emphasized that the multipliers employed to estimate GNP effects resulting from an energy shortage reflect short-term substitution potentials and production relationships. Over the longer term, multipliers, would be substantially lower because of greater opportunities to favorably alter production functions and adjust energy use patterns.

Cases II and III

Estimates of the GNP decrease resulting from Cases II and III are computed in a manner similar to that of Case I. Estimates for Case II were developed at a level of detail similar to those of Case I, but Case III estimates were arrived at from experience gained in Cases I and II.

Results

The results for the three cases are summarized in Table 16. This table indicates that a 2 *MMB/D* oil shortfall would result in GNP reduction of $48 billion annually, or 3.6 percent below the level that would have been attained without an Arab oil cutoff. This figure represents the estimated economic cost of a 2.0 *MB/D* decrement in petroleum supplies for a 12-month period. A 3.0 *MB/D* decrease in supplies during the first quarter would depress GNP about $26 billion, e.g., the magnitude of the potential GNP reduction is an increasing function of the size of the fuel supply restriction imposed.

The $48 billion adverse GNP effect potential could boost unemployment from existing rates of less than 5 percent to levels exceeding 6 percent. Specific unemployment effects would depend upon decreases in overtime, shortening of workdays, etc., as well as the relative share of fuel supply decrements imposed on industrial users relative to other sectors. Energy supply interruptions of the magnitude envisioned are certain to result in a considerable reduction in GNP growth in the near term. Intermediate term income and employment effects would depend upon secondary spending and employment adjustments, the alternative disposition of consumer spending diverted from petroleum consumption, other induced changes in spending and savings behavior, and possible compensatory fiscal and monetary adjustment policies. As Table 16 indicates, GNP is affected much more severely on both East and West Coasts than in the balance of the country, with coastal

TABLE 15
ESTIMATED GNP EFFECTS OF CASE I ENERGY SHORTFALL

SECTOR	POTENTIAL ENERGY DEMAND (QBTU!Yr)	ESTIMATED SHORTFALL MB/D	QBTU/Yr	%	DECREASE IN ENERGY VALUE ADDED @$6.52/Bb1 ($Bn!Yr)	AVERAGE SECTOR MULTIPLIER*	GNP DECREASE ($Bn!Yr)
PAD I							
Transportation	6.3	317	.63	10.0	.75	12.6	9.5
Household & Comm.	7.1	360	.72	10.1	.86	16.1	13.8
Industrial	5.1	153	.31	6.1	.37	13.4	5.0
Chem.&Raw Material	1.0	86	.17	17.0	.20	16.6	3.3
Total	19.5	916	1.83	9.4	2.18	14.5	31.6
PAD II							
Transportation	5.9	84	.17	2.9	.20	1.1	.22
Household & Comm.	6.7	64	.13	1.9	.16	1.3	.21
Industrial	6.8	9	.02	0.3	.02	.5	.01
Chem.&Raw Material	1.4	36	.07	5.0	.09	2.4	.22
Total	20.8	193	.39	1.9	.47	1.4	.66
PAD III							
Transportation	2.6	131	.26	10.0	.31	6.8	2.10
Household & Comm.	1.7	58	.12	7.1	.14	7.1	.99
Industrial	6.0	8	.01	0.2	.02	1.1	.02
Chem.&Raw Material	2.4	57	.11	4.6	.14	3.8	.53
Total	12.7	254	.50	3.9	.61	6.0	3.64
PAD V							
Transportation	3.3	201	.40	12.1	.48	14.3	6.86
Household & Comm.	1.9	103	.21	11.1	.24	16.5	3.96
Industrial	2.0	37	.07	3.5	.09	4.3	.39
Chem.&Raw Material	.4	34	.07	17.5	.08	16.4	1.31
Total	7.6	376	.75	9.9	.89	14.1	12.52
TOTAL U.S.							
Transportation	18.6	733	1.4	7.5	1.74	10.7	18.68
Household & Comm.	17.9	586	1.2	6.7	1.40	13.5	18.96
Industrial	20.5	206	.4	2.0	.50	10.8	5.42
Chem.&Raw Material	5.3	213	.4	8.5	.51	10.5	5.36
Total	62.3 ±	1738	3.4	5.6	4.15	11.7	48.42

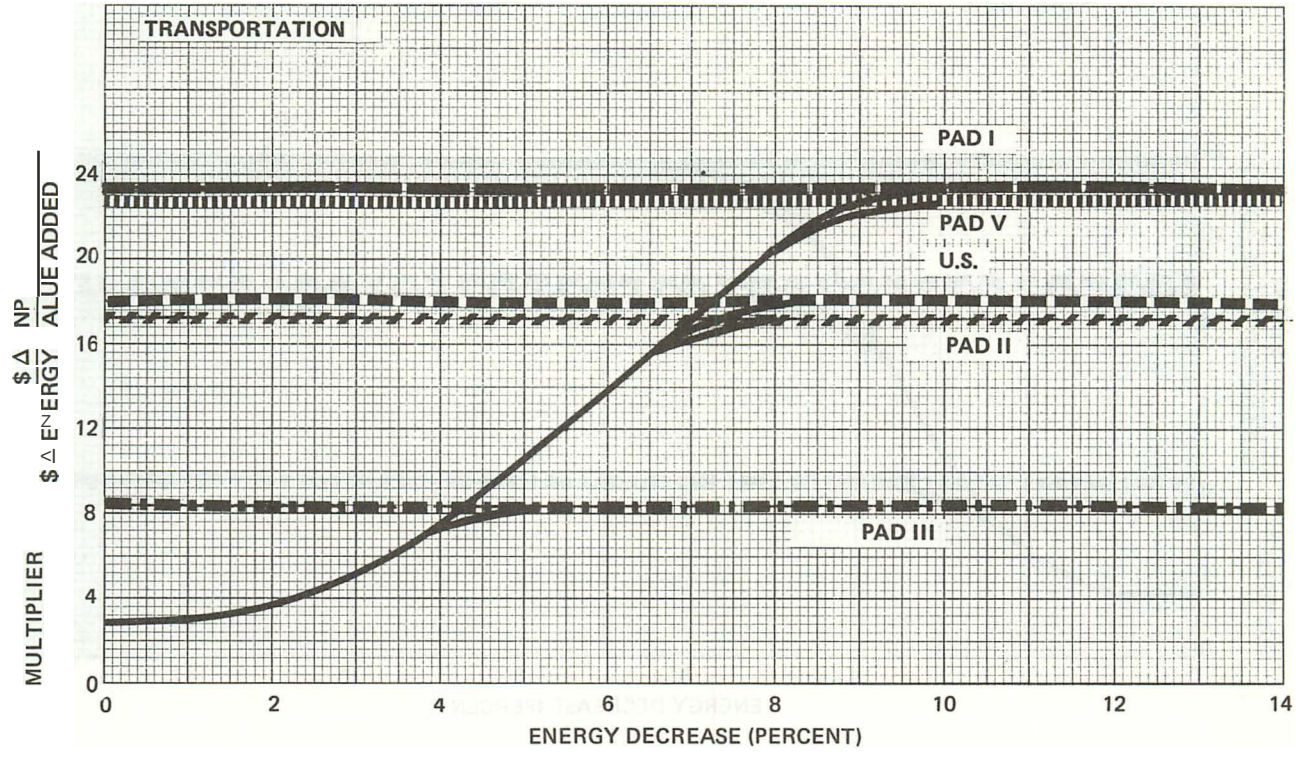
* Units of multipier are average $GNP/$Energy Value Added.

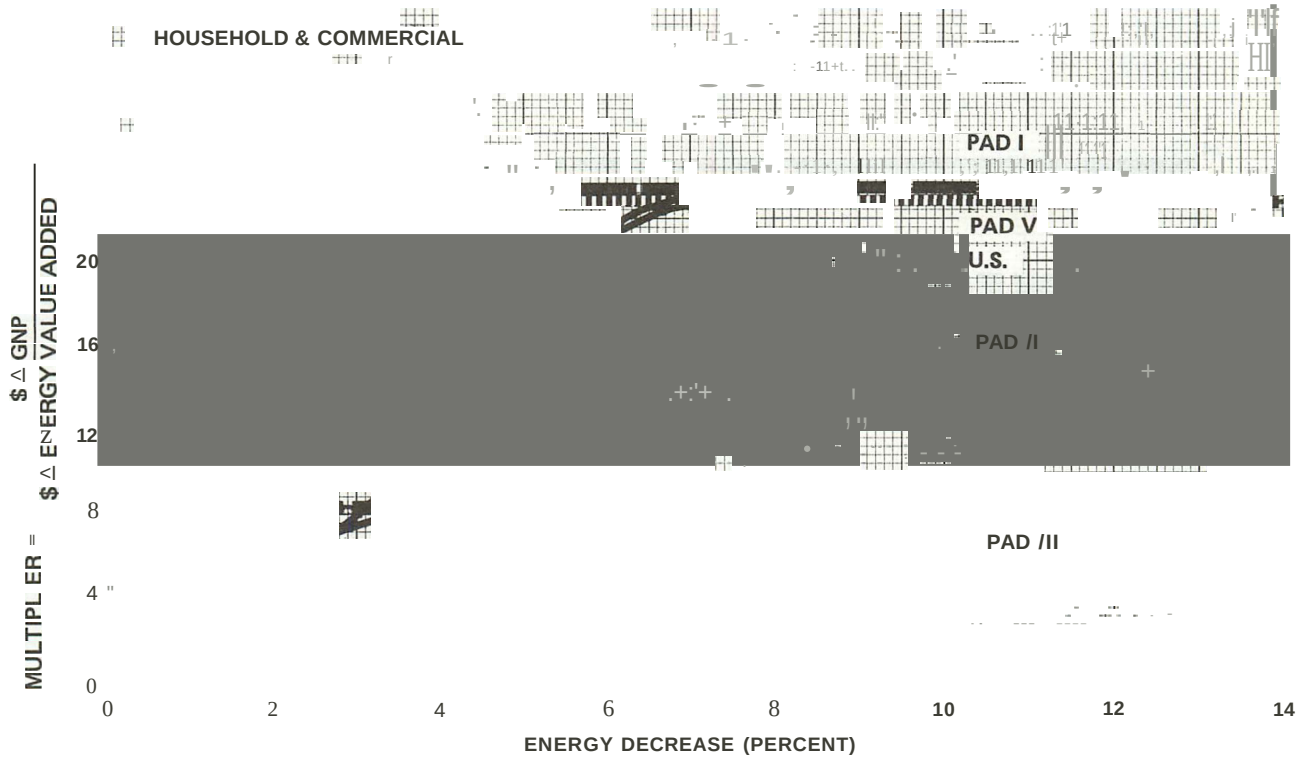
± PAD IV included.

TABLE 16

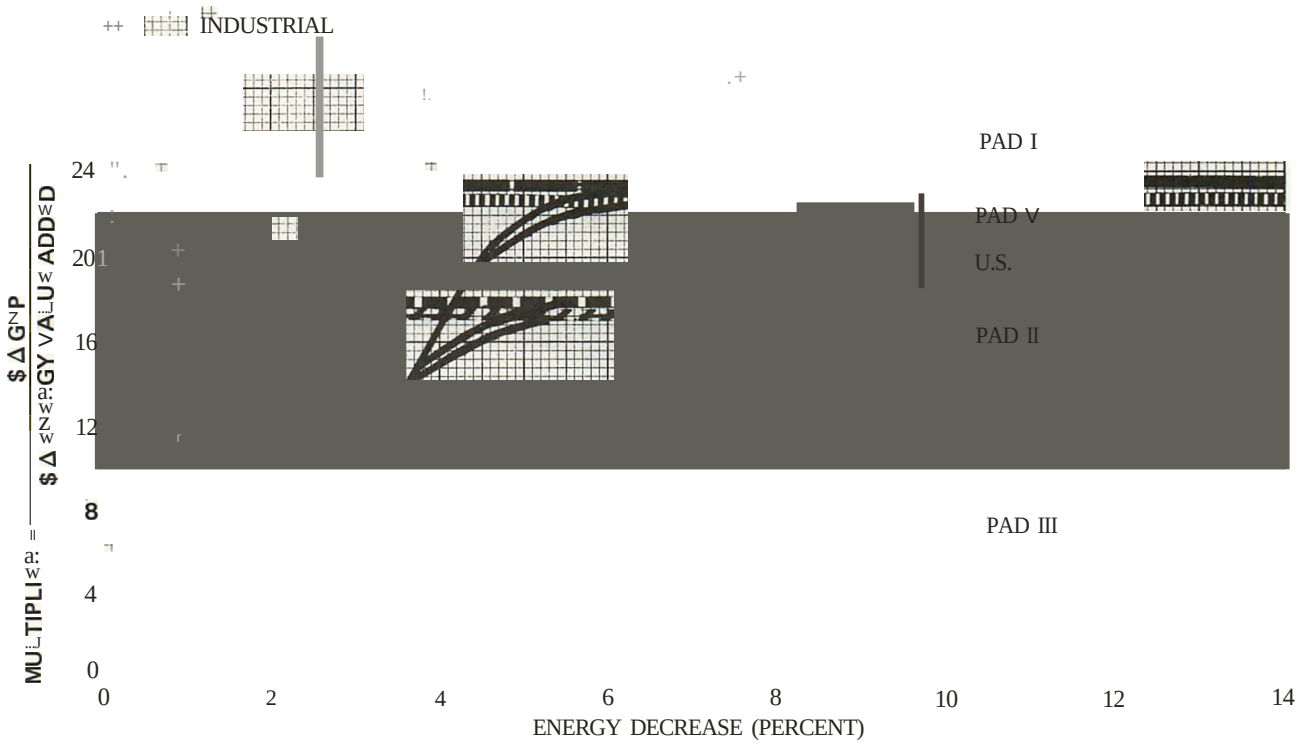
SUMMARY OF GNP EFFECTS OF ENERGY SHORTFALL CASES

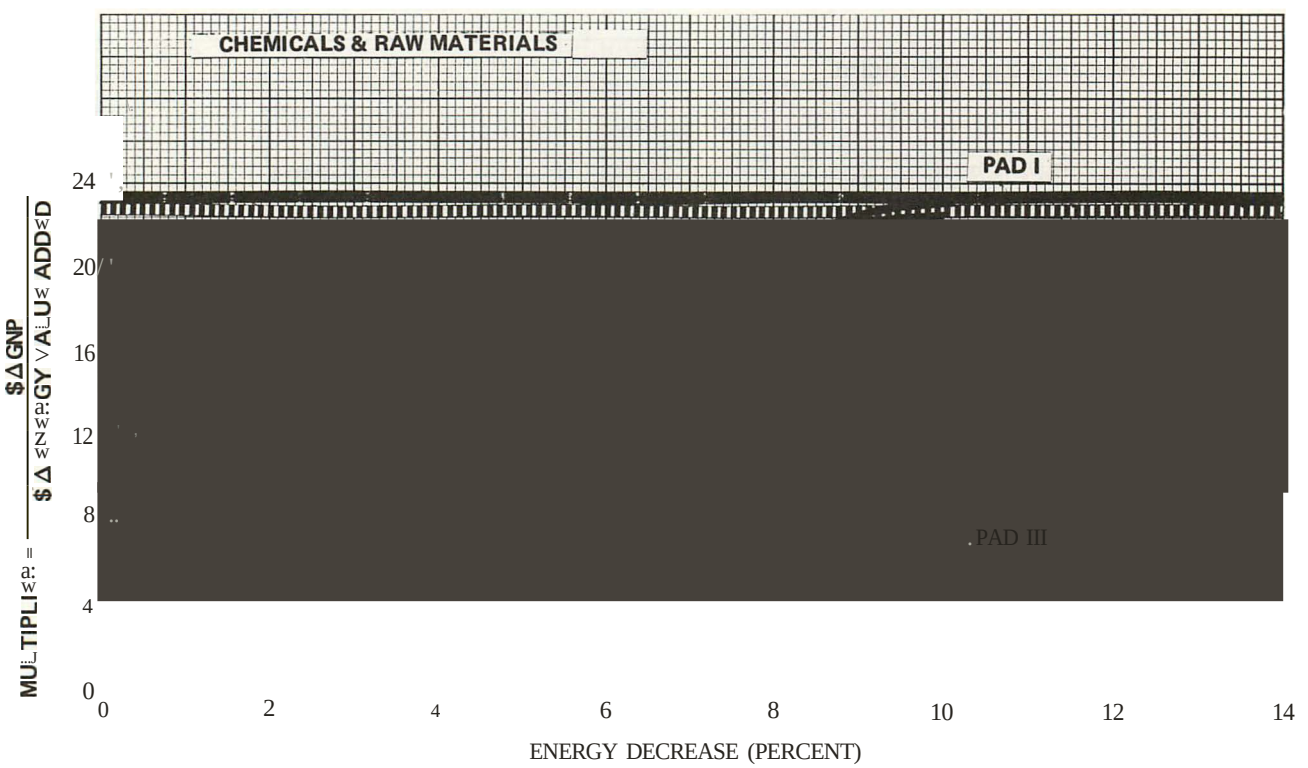
	POTENTIAL LEVELS WINTER 1973-74		ENERGY SHORTFALL		GNP DECREASE		GNP TO ENERGY ELASTICITY
	GNP ($Bn/Yr)	ENERGY USAGE (QBTU/Yr)	QBTU!Yr	%	$Bn/Yr	%	
CASE I (2,000 *MB/D* Shortfall)							
PAD I	544	19.5	1.83	9.4	31.60	5.8	.6
PAD II	428	20.8	.39	1.9	.66	.2	.1
PAD III	125	12.7	.50	3.9	3.64	2.9	.7
PAD IV	31	1.7					
PAD V	206	7.6	.75	9.9	12.52	6.1	.6
Total U.S.	1334	62.3	3.47	5.6	48.42	3.6	.6
CASE II (1,500 *MB/D* Shortfall)							
PAD I	544	19.5	1.45	7.4	20.26	3.7	.5
PAD II	428	20.8	.30	1.4	.32	.1	.1
PAD III	125	12.7	.35	2.8	2.11	1.7	.6
PAD IV	31	1.7					
PAD V	206	7.6	.43	5.7	4.23	2.1	.4
Total U.S.	1334	62.3	2.53	4.1	26.92	2.0	.5
CASE III (500 MB/D Shortfall)							
PAD I	544	19.5	.46	2.4	.55	.1	.04
PAD II	428	20.8	.10	.5	.07		
PAD III	125	12.7	.12	1.0	.21	.2	.20
PAD IV	31	1.7					
PAD V	206	7.6	.19	2.5	.25	.1	.04
Total U.S.	1334	62.3	.87	1.4	1.08	.1	.07





Figures 2&3. Sector Incremental GNP Multipliers vs. Output Energy Decrease.





Figures 4&5. Sector Incremental GNP Multipliers vs. Output Energy Decrease.

decreases amounting to about 6 percent. This should be a consideration in designing measures to ease the effects of the energy shortfall.

The geographic pattern of the income effects of Cases II and III are broadly similar to the Case I pattern, except where very small numbers are involved. Also, the ratio of GNP growth to energy growth (elasticity of GNP with respect to energy consumption) rises from 0.1 in Case III to 0.5 in Case II and 0.6 in Case I.

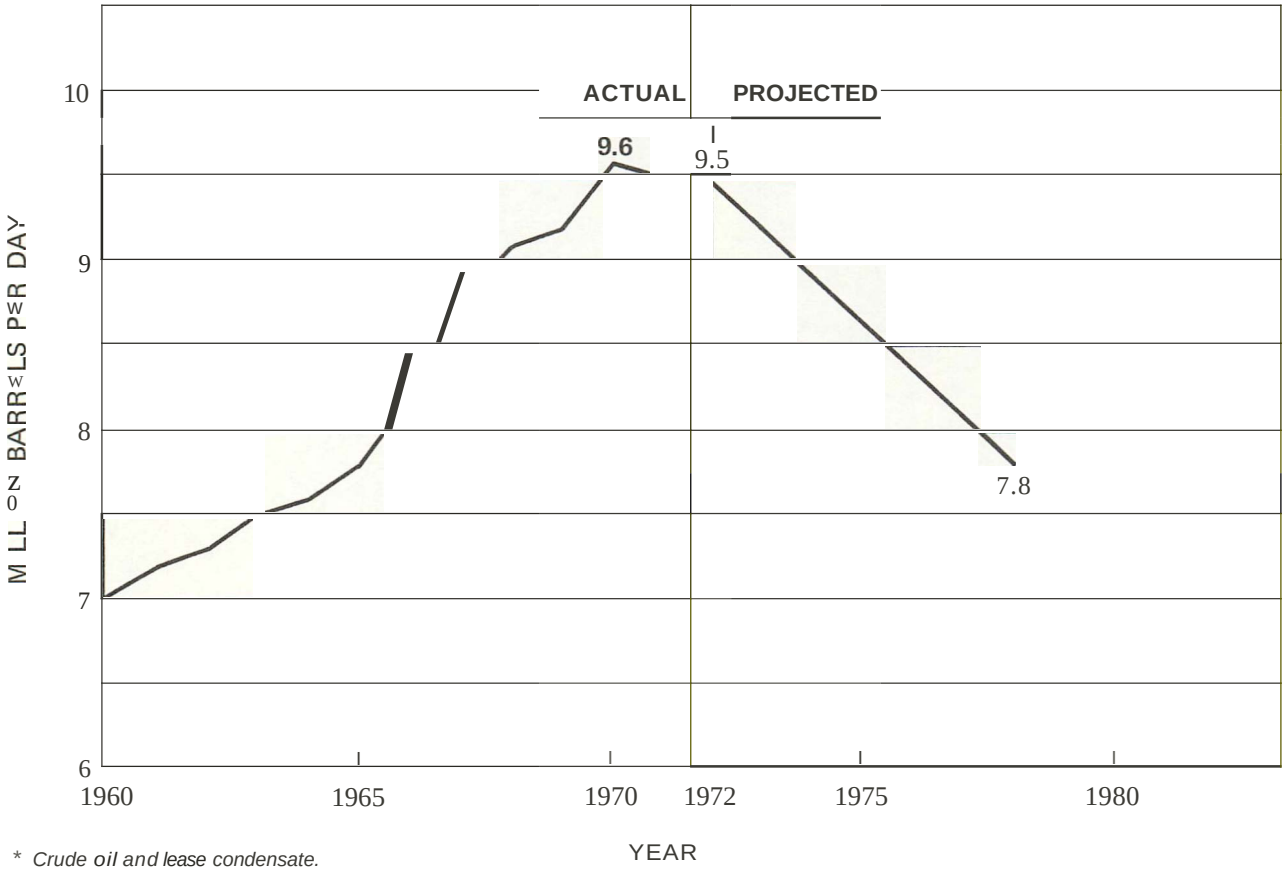
Chapter Four

EMERGENCY OIL AND GAS PRODUCTION

EMERGENCY OIL PRODUCTION

Domestic crude and condensate production increased from 7.0 MMB/D in 1960 to a peak of 9.6 MMB/D in 1970, and since that time production has declined to about 9.2 MMB/D (see Figure 6). This trend of declining production can be expected to continue. Domestic oil production is at capacity, and essentially all fields are producing at their legally established maximum efficient rate (MER). The only exceptions are the Naval Petroleum Reserves (NPR) which consists of four areas set aside to provide standby petroleum production capacity when required for national defense. Of these, only NPR-l (Elk Hills) in California currently has any potential for near-term use.

The MER of a field is defined as the highest rate of production which can be sustained over a long period of time without reservoir damage and loss of ultimate oil and gas recovery. Production in excess of the MER for sustained periods may result not only in loss of recovery but also in premature loss of producing capacity.



* *Crude oil and lease condensate.*

Source: Historical data - U.S. Bureau of Mines; Projected data - NPC U.s. Energy Outlook, Case IV.

Figure 6. Domestic Crude Oil Production.*

Most oil producing states have an oil and gas regulatory agency which operates under the state's oil and gas conservation laws. Typically, the oil and gas laws provide that the regulatory agency promulgate rules and regulations to prevent physical waste of oil and gas and to protect correlative rights of mineral interest owners. For example, the Texas Oil and Gas Law provides, in part, that:

> The production, storage or transportation of crude petroleum oil or of natural gas in such a manner, in such amount, or under such conditions as to constitute waste is hereby delcared to be unlawful and is prohibited. The term *waste*, among other things, shall specifically include:
>
> - Underground waste or loss however caused and whether or not defined
>
> - Physical waste or loss incident to or resulting from drilling, equipping, locating, spacing or operating well or wells as to reduce or tend to reduce the total ultimate recovery of crude petroleum oil or natural gas from any pool
>
> - Waste or loss incident to, or resulting from unnecessary, inefficient, excessive or improper use of reservoir energy or water drive in any well or pool
>
> - The production of crude petroleum oil in excess of transportation or market facilities or reasonable market demand. The Commission may determine when such excess production exists or is imminent and ascertain the reasonable market demand.

To establish the MER for a field, the Texas Railroad Commission, or comparable agencies in other major producing states, receives technical testimony from producing companies and establishes the field MER or in many cases the MER for individual reservoirs. Monthly forecasts are made of market demand for crude oil. When the aggregate MER's in the state are greater than the forecast demand, the regulatory agency will *prorate* production among fields and wells as a percentage of the MER.

In the past, this nominal spare capacity which existed between the production at the prevailing demand factor and the MER provided a large measure of national security. However, since all states and fields are now essentially producing at their MER, no significant spare producing capacity exists (except at NPR-l).

Although the established MER's in existing fields represent the maximum rate of production which can be sustained without loss of recovery, it is possible in a limited number of fields to exceed the MER for short periods of time without reservoir damage.

Precise definition of the amount and time period in which production can be sustained in excess of the MER is highly dependent on the individual field. This report has not considered producing in excess of the MER for more than 6 months.

Any production in excess of the established MER entails some risk of losses in ultimate recovery. However, in a short-term emergency of the type defined in this study, these risks should be minimal for the fields and capacities considered. On this basis, potential emergency production capacity exists in a few large fields in Texas--East Texas, Yates, West Hastings, etc. Based on the type and quality of these reservoirs, it is reasonable to believe that they can be produced at rates in excess of the sustainable MER for periods of at least 90 to 180 days without excessive risk of losses in recovery. In addition, some capacity above MER exists in a number of small scattered fields.

In this study, the potential additional production which can be obtained from the Naval Petroleum Reserves and the amount of emergency production in excess of MER which can be temporarily obtained from other producing fields has been estimated. These estimates represent producing rates which could be obtained within a period of a few weeks or months and thus could be utilized to reduce the impact of the current supply shortages. The estimates consider reservoir and producing facility limitations as well as pipeline limitations between the producing fields and refineries. The emergency capacity estimates for the Naval Petroleum Reserves and each of the major fields are summarized in the following discussions.

Naval Petroleum Reserves

The Naval Petroleum Reserves consist of four areas which were originally set aside between 1912 and 1924 to provide sources of oil for Navy vessels (see Figure 7). The objective of these reserves was later redefined by law to provide standby producing capacity until needed for national defense.

The Naval Petroleum Reserves are controlled and operated by the U.S. Navy's Office of Naval Petroleum Reserves and under existing laws can only be produced when "...the Secretary, with the approval of the President, finds it is needed for national defense and the production is authorized by a joint resolution of Congress." The production of the reserves for national defense has been permitted once before when NPR-1 was authorized to produce 65 MB/D during World War II.

NPR-1 (Elk Hills Field) and NPR-2 (Buena Vista) are located about 20 miles west of Bakersfield, California. NPR-1 contains about 1.3 billion barrels of recoverable reserves, and it is the most important Naval Reserve from the standpoint of short-term production potential. It will be discussed in more detail below.

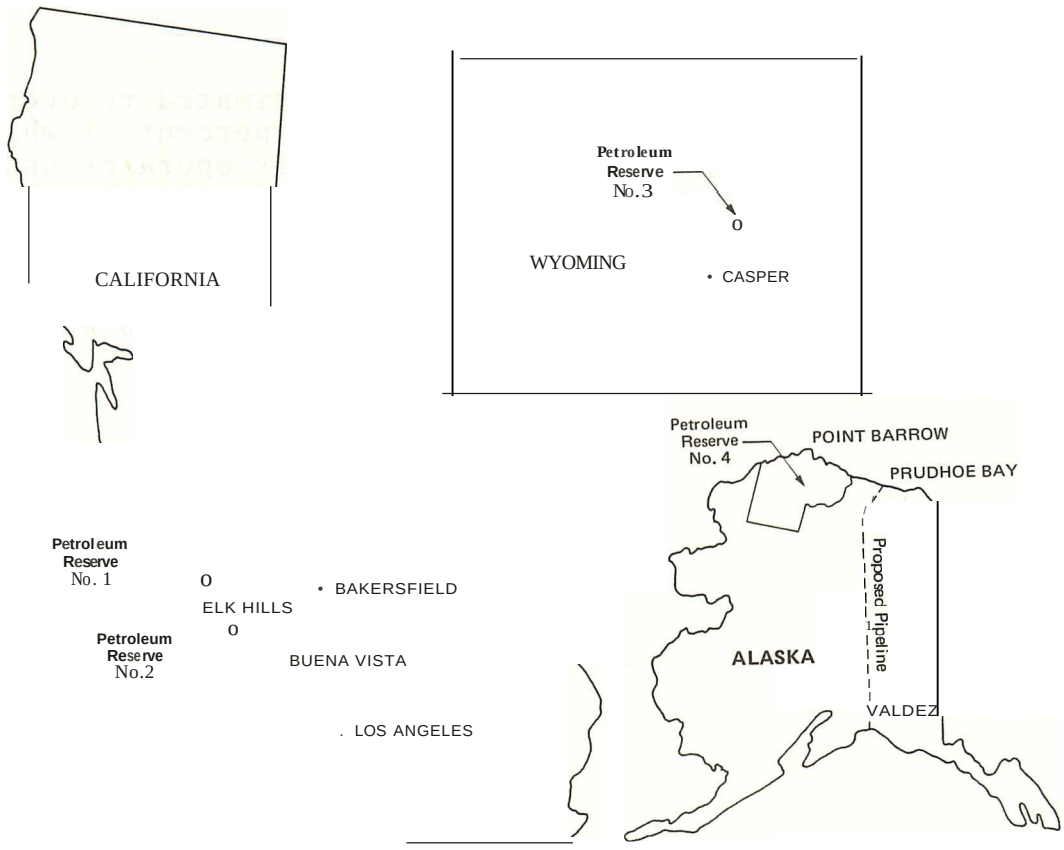


Figure 7. Naval Petroleum Reserves.

NPR-2 (Buena Vista) contains about 50 MMB of reserves and is currently producing at its capacity of around 8 MB/D. The government owns only about 35 percent of the lands in NPR-2; thus, it has been necessary to lease and produce this reserve to prevent drainage.

NPR-3 is located near Casper, Wyoming and contains reserves of about 50 MMB. It is currently producing about 500 barrels per day. Navy estimates indicate a maximum producing capacity of about 5 MB/D if fully developed.

NPR-4 consists of about 24 MM acres located on the North Slope of Alaska which have not been fully explored or developed. Exploration programs conducted by the Navy from 1944 to 1953 resulted in the discovery of about 100 MMB of oil reserves and a small gas field. Estimates of potential but undiscovered reserves vary widely; however, even if additional reserves exist, they are of no short-term value for several reasons. A costly exploration and development program of several years duration would be required to find the reserves and develop a capability to produce the oil. Even if substantial additional reserves were developed, utility would be limited by lack of transportation facilities.

It is apparent that NPR-2, 3 and 4 have little or no utility in a short-term interruption of oil supplies. However, NPR-l (Elk Hills) does have some immediate potential.

NPR-1 (Elk Hills)

The Elk Hills field (Figure 8) contains estimated recoverable reserves of about 1.3 billion barrels, about 80 percent of which are owned by the government. The field currently operates under a unit agreement and produces about 5 MB/D to maintain the standby facilities in an operable condition. As a result of previous development, Elk Hills contains about 1,000 wells capable of producing about 160 MB/D. Field gathering system and oil and gas processing facilities limit the actual producing rate to about 100 MB/D deliverable to pipelines.

Figure 8. Emergency Production Capacity NPR-1 (Elk Hills Field) Current Production: 5 MB/D.

Two months would be required to expand production from the current rate of 5 MB/D to a sustained maximum rate of 100 MB/D (see Figure 8), resulting in a maximum spare capacity of 95 MB/D.

The Navy has also estimated that the MER of Elk Hills is 267 MB/D and indicated that it could be even higher if further exploration develops additional reserves. However, attainment of this rate would involve major field development programs and the expansion of pipeline capacity which would require several years.

The amount of Elk Hills production deliverable to refineries by existing trunk pipelines may be severely limited. Estimates of the additional production which can be delivered to refineries in the Los Angeles and San Francisco areas under normal conditions with existing pipelines is about 40 MB/D, or 35 MB/D spare capacity.

This results in a maximum deliverable capacity of 35 MB/D from NPR-1 and an average deliverable capacity of 23 MB/D during a 6-month period. The Navy currently estimates that Elk Hills could produce and deliver to refineries 160 MB/D within 60 days. This more optimistic estimate implies a crash effort to remove the transportation and production facility bottlenecks.

East Texas Field

The East Texas field (Figure 9) is currently producing at an MER of about 210 MB/D from about 13,000 wells located on about 2,000 separate leases which are owned and operated by about 350 individuals and corporations. In an emergency, production from the field can be increased by 40 MB/D to a total of 250 MB/D within a period of days and with only minor modifications to production and gathering facilities. This additional volume of production can be delivered to refineries through existing pipelines, thus initial deliverable spare capacity from East Texas is 40 MB/D.

Maximum temporary production in excess of MER which can be sustained for 180 days is estimated to be 200 MB/D for a total production rate of 410 MB/D. However, producing at this rate will require flaring of up to 20 million cubic feet per day (MMCF/D) of gas due to inadequate gas handling equipment. Also, about 3 months would be required to expand field production facilities and saltwater disposal systems at a cost of $4.5 million.

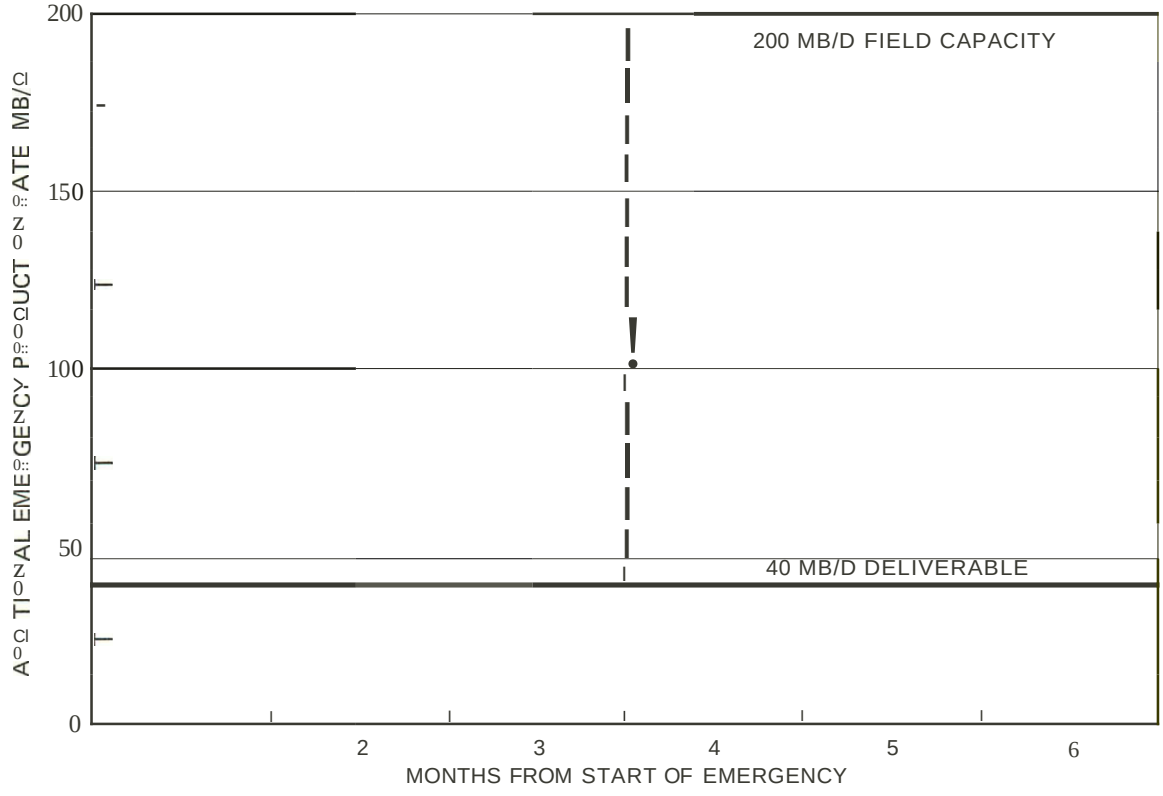


Figure 9. Temporary Emergency Capacity in Excess of MER (East Texas Field) Current Production: 210 MB/D.

Maximum production deliverable to refiners is limited by existing trunk line capacity of about 250 MB/D. Thus, for a short-term emergency, spare capacity in excess of MER at East Texas is a maximum of 40 MB/D and will average 40 MB/D for 6 months. Expansion of the East Texas Trunk Line System would require 12 to 18 months.

West Hastings

The MER for West Hastings field (Figure 10), effective January 1, 1974, is 75 MB/D. It is estimated that additional emergency production from this field of 45 MB/D for a total rate of 120 MB/D could be obtained. This would require substantial modifications to existing oil and gas handling equipment which would require a minimum of 90 days and would cost about $3.5 million.

The maximum additional deliverable capacity at West Hastings is limited to a maximum of about 27 MB/D by existing trunk line capacity, and the average deliverable capacity for a 180-day period is about 13 MB/D.

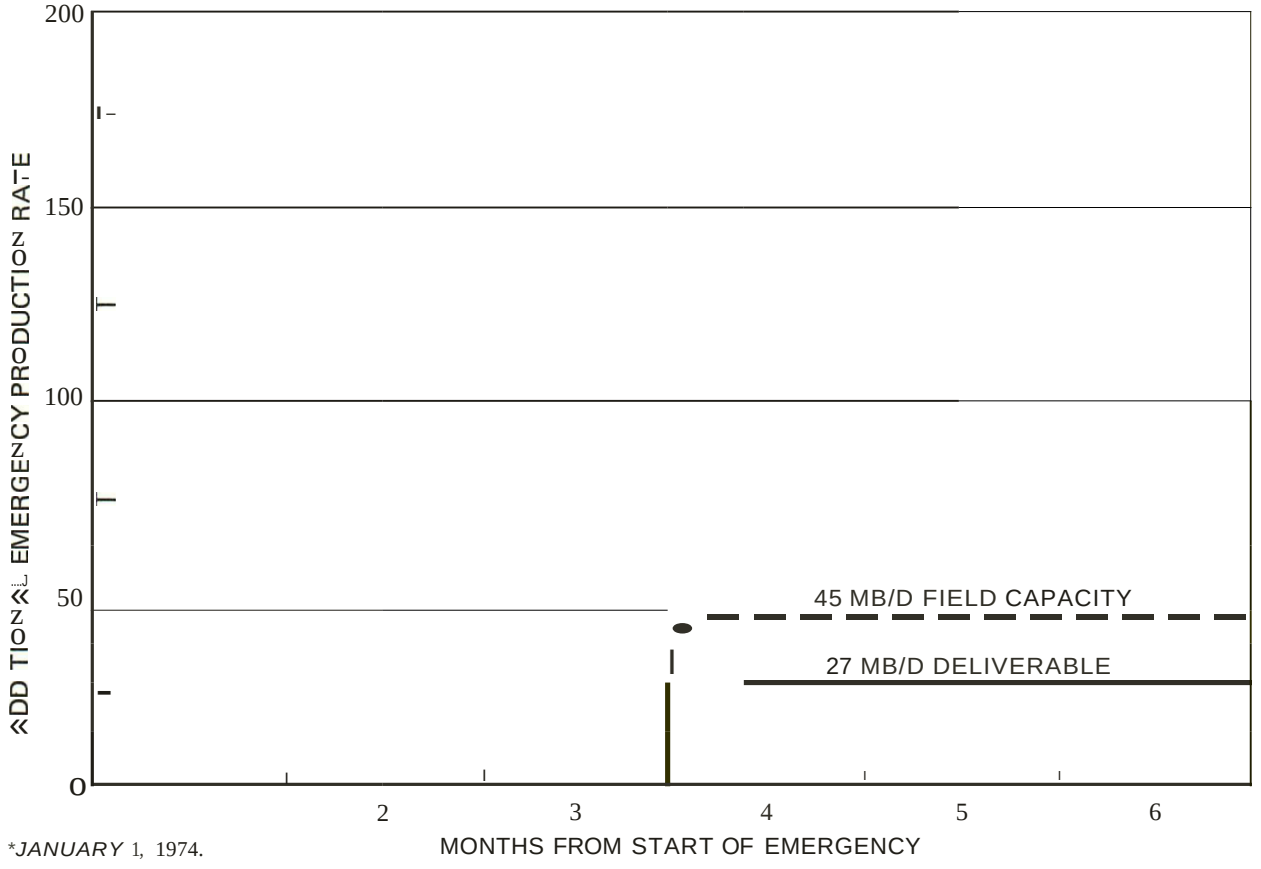
Yates

The Yates field (Figure 11) is currently producing at an MER of 50 MB/D from about 600 wells. In an emergency, production from the field could be temporarily increased by 50 MB/D to a total of 100 MB/D. This increased production can be handled with only minor modifications to existing field oil and gas handling facilities. It may be possible to temporarily increase the field's production by as much as 100 MB/D (to a total of 150 MB/D during an emergency. However, this would require additional modifications to field facilities and special facilities to incinerate approximately 10 MMCF/D of gas which could not be handled in existing gas processing facilities. These modifications would require at least 3 months and cost several hundred thousand dollars.

Total temporary emergency capacity from Yates which is deliverable to refineries is estimated to be 60 MB/D with existing pipelines and some trucking. Thus, deliverable emergency capacity from Yates reaches a maximum of 60 MB/D and averages 55 MB/D for a 6-month period.

Tom O'Connor Field

The Tom O'Connor field is currently producing at an MER of about 80 MB/D. Additional deliverable capacity through existing pipelines (and including some trucking) is estimated to be about 22 MB/D for a total field rate of 102 MB/D. These rates can be handled with existing production facilities. It appears that temporary well capacity is sufficient to permit additional



*JANUARY 1, 1974.

Figure 10. Temporary Emergency Capacity in Excess of MER (West Hastings Field) Current Production: 75 MB/D.*

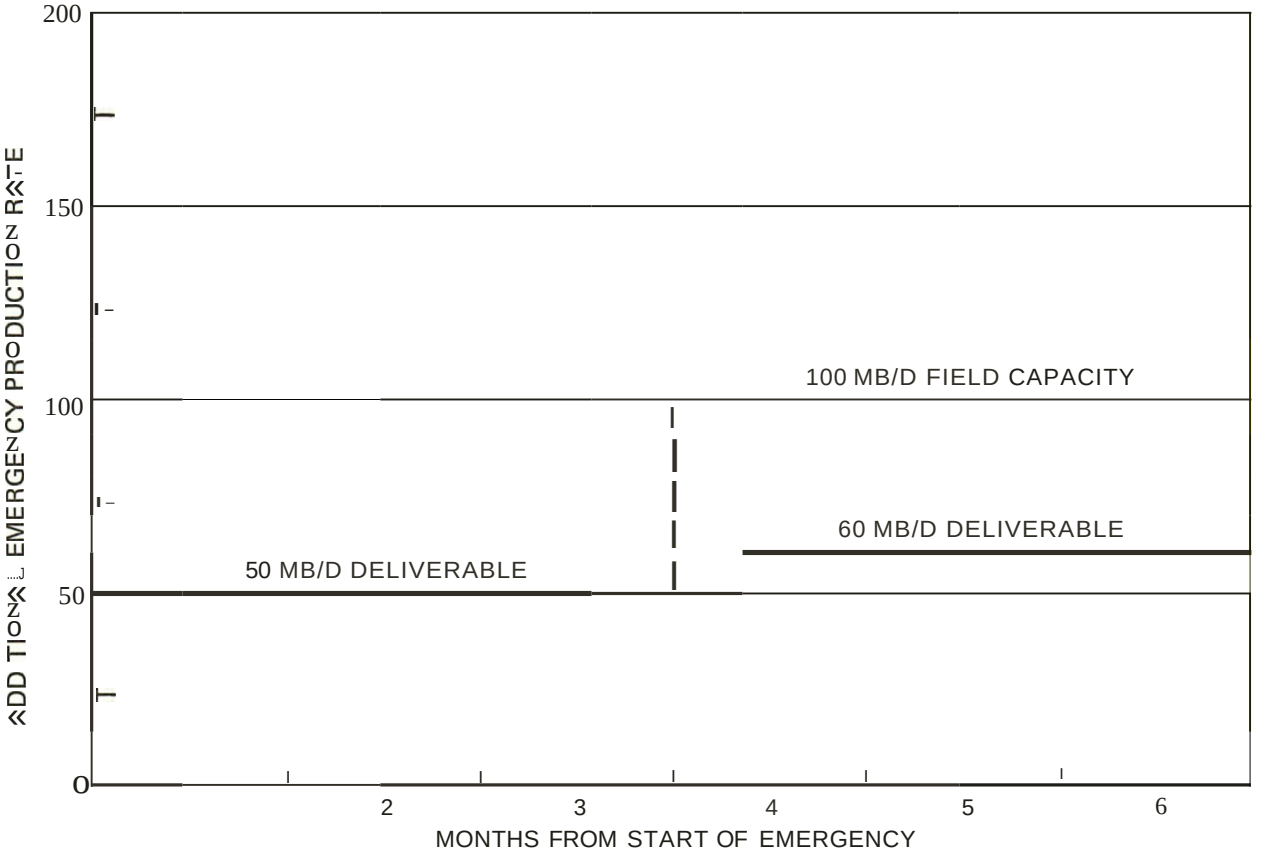


Figure 11. Temporary Emergency Capacity in Excess of MER (Yates Field) Current Production: 50 MB/D.

emergency production of up to 60,000 barrels per day or a total field rate of about 140 MB/D. However, these rates are limited by existing production and gas handling facilities and trunk line capacity.

Hawkins

The Hawkins field is currently producing at an MER of 112 MB/D. Although additional temporary well capacity of as much as 40 MB/D may be available, this capacity is limited by available gas handling facilities and by existing trunk line capacity. Total deliverable temporary emergency capacity at Hawkins is only about 5 MB/D.

Other Fields

Eight other major fields, primarily located in Texas, are estimated to have small volumes of deliverable emergency capacity which total 78 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 the deliverable capacity in these fields may average as much as 94 MB/D during a 180-day emergency.

Summary of Current Emergency Crude Production Capacity

The emergency producing capacity deliverable to refineries is summarized in Table 17 and is shown in Figure 12. The maximum deliverable capacity is 369 MB/D, and because of the lead times necessary to expand facilities in some cases, the deliverable emergency capacity averages 292 ME/D and 331 MB/D during the first 90 and 180 days of an emergency, respectively. These temporary emergency production rates in excess of MER can be sustained for about 6 months without substantial reservoir damage (except for Elk Hills, where the emergency production can be sustained for several years or more). The deliverable capacity builds up from about 275 MB/D at the start of an emergency to the peak rate of 369 MB/D after about 3 months.

Attainment of the emergency capacities in the field will require some gas flaring and investments of approximately $8 million for additional field production facilities. These facilities can be generally added within the first 90 days of an emergency and should payout based on the temporary additional production during the emergency.

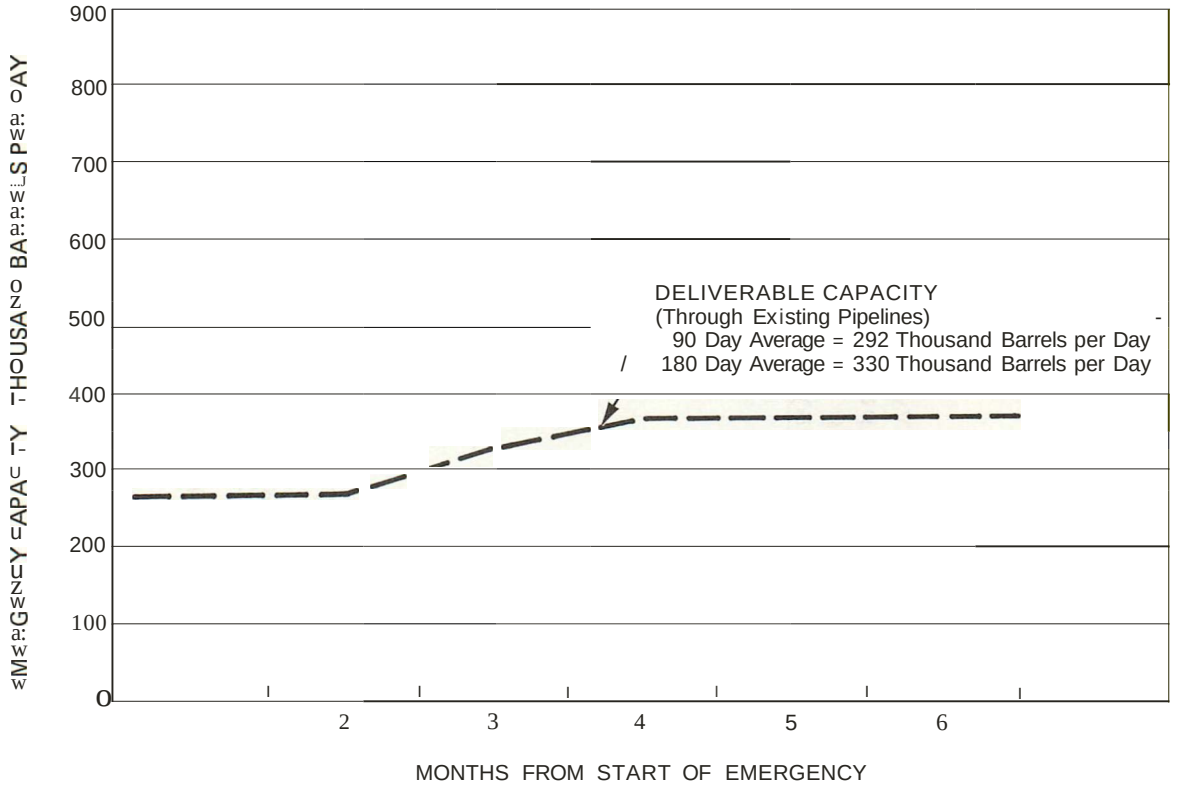
The emergency production capacities in excess of MER estimated in this report differ substantially from the spare producing capacities estimated each year by the API. The principal reasons for this are differences in the definition of spare and emergency capacity. For example, the API defines spare capacity as the

TABLE 17

SUMMARY
SOURCE OF EMERGENCY CRUDE PRODUCTION CAPACITY
TEMPORARY CAPACITY IN EXCESS OF MER
1974 (MB/D)

Field	Current Production	Maximum Additional Capacity Deliverable To Refineries	Average Additional Capacity Deliverable To Refineries For 90 Days	180 Days
NPR-l (Elk Hills)	5	35	12	23
East Texas	210	40	40	40
West Hastings	75*	27	0	13
Yates	50	60	50	55
Tom O'Conner	80	22	22	22
Hawkins	112	5	5	5
Other Major Fields (8)	-	78	78	78
All Others	-	102	85	94
TOTAL		369	292	330

*Effective January 1, 1974.



* *NPR-1 (Elk Hills) production does not exceed MER.*

Figure 12. Emergency Domestic Crude Production Capacity--1974 (Temporary Capacity in Excess of Current MER).*

instantaneous rate which could be achieved at the field level on March 31 of each year. The API definition ignores pipeline limitations between the field and refineries and assumes that "intrafield equity considerations will be resolved." By contrast, the emergency capacities estimated in this study represent average rates for the period which can be produced and delivered.

It should be emphasized that numerous legal and administrative obstacles would have to be overcome before these capacities could be attained. The MER's for the Texas fields have been established by the Texas Railroad Commission. Action by this body will be required to exceed any current MER. This action would have to be based on a finding that the temporary higher production would not damage the reservoir. In addition, substantial differences of opinion exist among the operators in most of these fields regarding the MER, and in some cases litigation is involved. The higher emergency rates can be obtained by permitting all wells in the field to increase their production rather than by producing only certain selected wells. Although this would appear to be the most equitable approach, it is anticipated that controversies and possible litigation will result when production is increased unless the enabling legislation provides clear authority for emergency production. Also, attainment of the estimated emergency rates in many fields will require the relaxation of various environmental regulations, particularly those regarding gas flaring.

Many of these obstacles can be overcome. This will require the full participation of both state and federal regulatory agencies as well as the operators. Specifically, it will be necessary to establish the level of emergency production permitted in each field and guidelines regarding the relaxation of environmental and other regulations. In the case of NPR-l (Elk Hills), action by the Federal Government is required to permit production of this reserve. Immediate initiation of this type of emergency action is imperative if these capacities are to be realized.

EMERGENCY GAS PRODUCTION

Emergency gas producing capacity must be considered in emergency preparedness planning since the opportunity may exist to substitute natural gas for liquid fuels. To assess this capability it is necessary to consider three factors. These are (1) the ability to produce additional emergency volumes of natural gas, (2) the ability of oil users to make emergency conversions to natural gas, and (3) the ability of existing pipeline systems to transport the additional production to consumers having conversion capabilities.

Three potential sources of additional emergency natural gas production exist:

Associated and Dissolved Gas. First is the additional associated and dissolved gas produced in conjunction with the emergency oil production described earlier. Based on the estimated emergency capacity of 369 MB/D, additional gas production of about 0.2 BCF/D might be expected. However, part of this gas must be flared in order to achieve the estimated oil production, and most of the remainder will replace other gas production from already loaded facilities. The net additional production from this source will be negligible.

Seasonal Swing Capacity. A second potential source results from the traditional seasonal demand and production of natural gas. During the high-demand winter months, production is at a peak and then gradually declines to a low during the summer months. The difference between the winter peak production and the lower summer rates (or seasonal swing) can obviously be produced and delivered by existing pipelines.

Table 18 summarizes the estimated seasonal swing capacity available in 1974 by geographic areas. This data indicates that negligible swing capacity exists during the winter heating season from November through March. During the low-demand summer months (April through October), seasonal swing capacity of about 3.3 BCF/D exists. About 20 percent of this capacity (0.6 BCF/D) is located in California, and 12 percent (0.4 BCF/D) is located in New Mexico and probably is marketed in the southern California area. Another one-third of the swing capacity (1.1 BCF/D) is located in the Kansas, Oklahoma and Texas Panhandle area, and the remainder is scattered.

TABLE 18

SEASONAL SPARE GAS PRODUCING CAPACITY
1974 (BCF/D)

Area	Winter Season (November-March)	Summer Season (April-October)
Arkansas		0.2
California	0.1	0.6
Kansas		0.5
Montana		
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-lO		0.3
West Virginia		0.3
Wyoming		0.1
Total United States	0.3	3.3

Table 19 summarizes the estimated distribution of oil to gas convertibility among PAD districts for both the electric utility and the industrial sectors. The bulk of the oil to gas convertibility is located in PAD I (East Coast) and PAD V (West Coast). Therefore, it would appear that the seasonal swing volumes located in West Virginia (and possibly in Texas RRC Districts 3 and 4) might potentially be utilized on the East Coast, and the swing volumes located in California and New Mexico might be utilized on the West Coast. However, the swing capacity located in Kansas, Oklahoma and the Texas Panhandle is not directly connected to areas having substantial oil to gas conversion capability.

Other factors may also tend to minimize the utility of seasonal swing capacity. First, many consumers maintain a dual oil-gas fuel capability primarily because they have interruptible gas service. That is, gas transmission companies sell gas to large industrial and utility customers during the low-demand summer months to maintain a constant year-round load on their distribution system. These contracts provide for interruption of gas service during the peak-demand winter months, requiring the consumer to switch to an alternate fuel. Thus, a large number of the interruptible consumers with dual fuel capability will already be using gas during the summer months. This minimizes the potential for emergency substitution of gas for oil. A second complication is the fact that gas reserves, unlike oil, are normally dedicated to specific pipelines, and in some cases specific markets by long-term contracts. In addition, Federal Power

Commission regulations place certain restrictions on the disposition of reserves dedicated to interstate pipelines. Therefore, the flexibility of producers and pipelines to supply seasonal swing production is limited.

TABLE 19

OIL TO GAS FUEL CONVERTIBILITY
(BCF/D)

PAD District	Electric Utilities	Industrial Users*	Total
I	1.8	1.3	3.1
II	0.1	0.1	0.2
III	0.1		0.1
IV			
V	0.5	0.4	0.9
Total	2.5	1.8	4.3

* Assumes same distribution as electric utility sector.

The amount of swing gas capacity which can actually be delivered and utilized by consumers during an emergency cannot be precisely defined in this report. Table 18 indicates that the potential is negligible in the winter months but may be in the range of 3 BCF/D from April through October. However, based on the location of the conversion capability and the other factors cited above, no more than half of the potential swing capacity is directly connected to areas having oil to gas conversion capability.

The most effective way to identify and implement usuable swing capacity is for federal agencies (such as the FPC) to encourage consumers having a dual fuel capability to assess their potential for reducing summer oil consumption by switching to gas. Those having sufficient potential could then be assisted in negotiating emergency gas supply arrangements with pipeline companies.

Spare Capacity. A third possible source of emergency natural gas production could be spare capacity in excess of the current peak production. A precise assessment of spare gas capacity above peak would require an extensive and detailed study of all major

gas producing fields and pipeline systems. This was not undertaken because a number of factors indicated that the magnitude of this type capacity is likely to be small.

First U.S. natural gas production has reached a peak and is actually declining. Figure 13 illustrates the fact that winter peak production of total natural gas leveled off beginning in the winter of 1970-1971 after steadily increasing for a number of years. Figure 14 illustrates the declining trend of proved reserves and the rapidly increasing depletion rate of U.S. non-associated gas. Non-associated gas is that which does not occur in direct contact with oil. Oil reservoirs contain substantial volumes of natural gas associated with or dissolved in the oil. However, the production rate of this gas is primarily controlled by the maximum efficient rate of oil production. Thus, only non-associated spare capacity is of interest in emergency preparedness planning.

Proved non-associated gas reserves in the United States reached a peak of 222 trillion cubic feet (TCF) in 1967 and have since declined rapidly to about 186 TCF at year-end 1972. This results from the fact that production of natural gas has exceeded new discoveries since that time. In addition, the rate at which these non-associated gas reserves are being depleted has increased dramatically during this same period. The rate at which reserves are depleted provides an indication of the amount of excess capacity which may exist. For example, it is generally accepted that non-associated gas reserves are at capacity when the depletion rate is about 10 percent per year, and that production capacity is likely to decline at higher depletion rates. The depletion rate of U.S. non-associated gas reserves has increased from about 5.7 percent per year in 1966 to 9.5 percent per year at year-end 1972. This indicates that little spare capacity is likely to exist, which is confirmed by the leveling of total gas production as shown in Figure 13.

A more detailed review of spare gas producing capacity by states was also made and tended to confirm this. It indicated that where some additional field producing capacity did exist, as was the case in Western Kansas, it was limited by pipeline capacity. In this instance, 1 to 2 years would probably be required to expand the line capacity. The excess producing capacity is projected to decline to current pipeline capacity with 3 to 5 years. Thus, a major pipeline expansion cannot be justified based on the projected short life. In 1970, the FPC declined to approve a proposal to loop one of the lines out of the area because of the inadequacy of long-term new supply prospects.

These factors, combined with the contractual and regulatory constraints discussed previously, indicate that spare gas capacity above peak offers little opportunity for minimizing the impact of liquid petroleum shortage. However, consumers with substantial oil to gas conversion capability should be encouraged, and if possible, assisted in attempts to attain this type of emergency gas supplies.

Each year the American Gas Association (AGA) estimates total domestic gas producing capacity. Comparisons of projections of this capacity with the projected peak production rates indicate that, based on the AGA definition, appreciable volumes of spare capacity could exist. However, according to the AGA definition, spare capacity consists of gas which is producible at the wellhead without regard to the capacity of flowlines and gathering systems, field compression and processing facilities, or trunk lines. Also, this includes gas which is utilized in pressure maintenance and cycling projects which, if diverted, would result in reduced liquid recovery and/or reduced ultimate oil recovery. These are not spare capacities which can be made readily available.

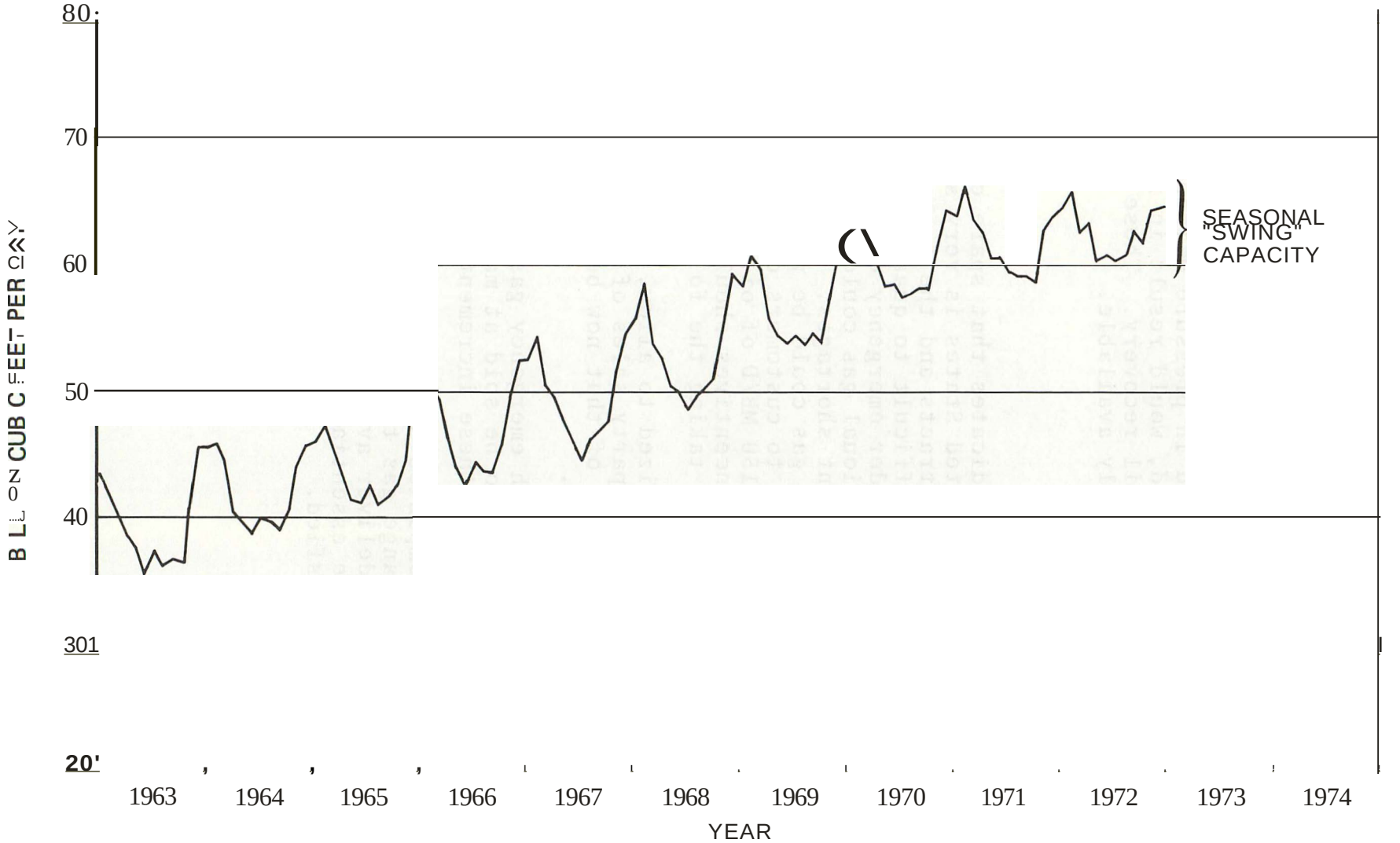
ESTIMATED EMERGENCY GAS CAPACITY

In summary, available data indicates that spare capacity to produce and deliver gas in the United States is very small. In addition, the multitude of gas contracts and the large number of gas producers make it extremely difficult to quantify the amount of gas which might be available under emergency conditions. However, such a small volume of additional gas could play a significant role in alleviating the current shortages. It is estimated that perhaps as much as 1 BCF/D of gas could be produced under emergency conditions and delivered to customers currently burning oil. This would be equivalent to 150 MB/D of oil. Under emergency conditions, mechanisms and incentives should be provided to release additional gas supplies by taking the following steps:

(1) The FPC should be authorized to allow, for a temporary period, emergency third-party sales of available interstate gas in excess of that now being taken under existing contracts.

(2) The FPC's current 6-month emergency gas sales program, wherein gas is allowed to be sold at market clearing prices, should apply to these incremental volumes.

(3) Gas transmission companies should be encouraged to transport and exchange gas to load all trunk lines to full capacity and deliver available gas to industrial customers after the essential needs of its residential customers are satisfied.



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

Source: U.S. Bureau of Mines.

Figure 13. Marketed Natural Gas Production--Total United States.*

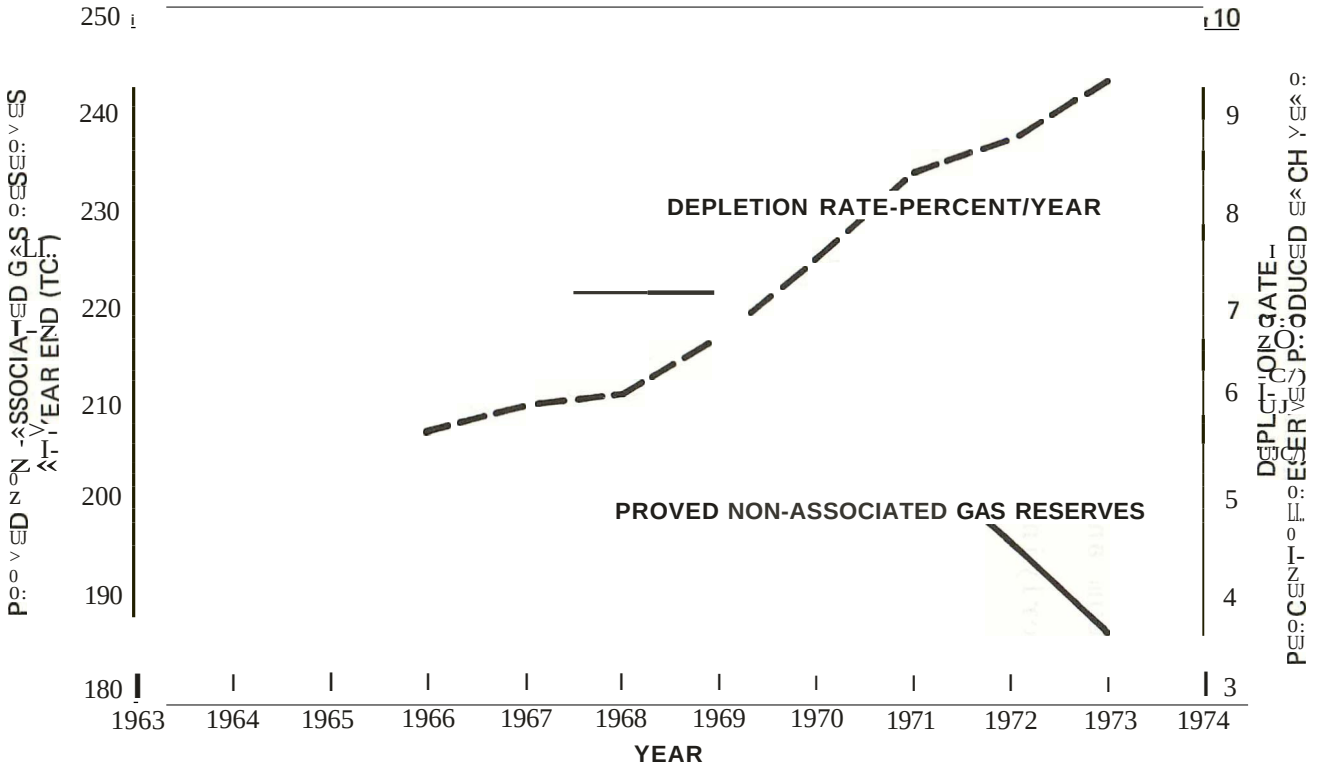


Figure 14. U.S. Non-Associated Gas Reserves and Depletion Rate.

Chapter Five

FUEL CONVERTIBILITY AND ALTERNATE ENERGY SOURCES

FUEL CONVERTIBILITY DURING A NATIONAL EMERGENCY

Total displacement of a particular energy source by another is possible given appropriate incentives and sufficient time. This chapter, however, is not primarily concerned with total or ultimate potential for energy substitution; rather, emphasis is directed to capabilities, limitations and problems pertaining to short-term substitution of energy and redistribution of available fossil fuel supplies where the United States is confronted with a temporary import denial of petroleum and natural gas.

Several of the underlying issues are:

- In which markets and in what quantities are fossil fuels interchangeable and how accurately can convertibility be measured?
- What costs are associated with fuel conversion and what economic dislocations could emerge?
- What technical, political and social constraints must be overcome?
- Are alternate fuels available?
- What are the time constraints?

POTENTIAL AND LIMITS OF FUEL CONVERTIBILITY

Ultimate fuel convertibility in the United States is about 13.4 quadrillion BTU (a crude equivalent of 6.5 MMB/D), which represents 18.5 percent of total energy consumption in 1972 (see Table 20). Conversely, 81.5 percent (28.3 MMB/D) is nonconvertible; that is, it represents energy that can be supplied only by a single fuel or an energy source for which there is no immediate substitute. Apparent convertibility must be qualified since it assumes interchangeability between fossil fuels under ideal conditions of continuing supply. Furthermore, most potential fuel substitution in the United States represents a switch between natural gas, propane, fuel oil and other fluid fuels in the general industrial and electric utility fuel markets. This is particularly true in the general industrial sector where an estimated 4.0 MMB/D is convertible.

An earlier study by the National Petroleum Council concluded that in 1964 all industrial boilers fired by natural gas or fuel oil could have been converted to another fluid fuel within 5 days, but conversions to coal would have required major modifications of the fuel-burning units and taken much longer than 5 days. The

TABLE 20

ESTIMATED CONVERTIBILITY OF PRIMARY ENERGY CONSUMED
IN THE UNITED STATES: 1972
(Oil Equivalent Expressed in *BID* of Crude Oi1)*

Reference	Consuming Sector	Quadrillion Btu			Oil Equivalent (million bid)		
		Conv.	Non-Conv.	Total	Conv.	Non-Conv.	Total
1.	Household and Commercial	t	14.8	14.8	‡	7.1	7.1
2.	Transportation	t	18.1	18.1	‡	8.7	8.7
3.	Electric utilities						
3a.	Hydroelectric	....	2.9	2.9	....	1.4	1.4
3b.	Nuclear	....	0.6	0.6	....	0.3	0·3
3c.	Steam-Electric	4.6	9.9	14.5	2.2	4.8	7.0
3d.	Other	0.5	§	0.5	0.3	§	0.3
3e.	Sub-Total	5.1	13.5	18.6 **	2.5	6.5	9·0
4.	General Industrial						
4a.	Coke Ovens	....	2.1	2.1	....	1.0	1.0
4b.	Other	8.3	10.4	18.7	4.0	5.0	9.0
4c.	Sub-Total	8.3	12.5	20.8	4.0	6.0	10.0
5.	Total Sectors	13.4	58.9	72.3	6.5	28.3	34.8
	Percent Total	18.5%	81.5%	100.0%			

* Based upon 5,675,000 Btu per barrel.
t Less than 50 trillion Btu.
‡ Less than 0.1 percent.
§ All gas turbine and internal combustion units included in convertible column.
**Components do not add due to rounding.

Sources: Total Btu consumption in major categories from U.S. Department of the Interior, Bureau of Mines.
Line3c. based on analysis of FPC Form 36 by Federal Power Commission staff and FPC Fuel Convertibility Committee.
Line 4b. estimate based on analysis in Emergency Fuel Convertibility, National Petroleum Council (Washington, D.C., 1965), 40 pp. and Appendix.

number of industrial multiple fuel-fired units that can burn coal has been considerably reduced since 1964. Many coal-fired plants have been permanently converted to oil and gas and in many instances coal-fired equipment and coal-handling equipment were dismantled. Where they still exist, these facilities will require extensive maintenance or major reconstruction before they can be operational.

In this analysis, emphasis has been placed on fuel convertibility in electric utility power plants although only 38 percent of the convertible energy in the United States is consumed by utilities. This seemingly disproportionate emphasis on electric utilities is warranted for several reasons:

- Nearly all the convertibility in the general industrial sector is between oil and gas, and curtailment of foreign oil will limit the extent consumers can convert from one fuel to another.

- A shortfall in energy supplies of electrical utilities in a given area will have a more immediate impact because power shortages will magnify the adverse effects of fuel shortages on industrial operations.

- Residential, commercial and industrial consumers will attempt to compensate for direct cutbacks of oil and gas by more intensive utilization of electric energy, e.g., residential users faced with shortages of home heating oil will use portable electric heaters.

- Many large utility plants concentrated in relatively small areas consume 10 to 30 MB/D of residual fuel oil. If coal is available, it does not take many plants of this size switching to coal to release increments of 100 MB/D which can be diverted to hundreds of small plants that do not have any convertibility potential.

- Information of fuel substitution capabilities is available for power plants but not for industrial facilities.

ANALYSIS OF CONVERTIBILITY DATA

An estimated crude oil equivalent of 2.5 MMB/D, 28 percent of the primary energy input of electric utilities in 1972, represents a theoretical maximum volume of fossil fuels that could have been replaced by another fuel (Table 21); however, only 25 percent of the 2.5 MM/D equal to about 7 percent of the electric utilities' total energy input could have switched from oil and gas to coal. After allowing for maximum sulfur levels stipulated by air pollution regulations already in effect, coal substitutability is reduced from a theoretical maximum of 614 MB/D to 250 MB/D. Under proposed state implementation plans scheduled to become effective in 1975, convertibility in the electric utility industry (based on 1972 fuel consumption patterns) will be reduced to less than 200 MB/D.

TABLE 21

ESTIMATED CONVERTIBILITY OF FUELS AND PRIMARY ENERGY CONSUMED BY ELECTRIC UTILITIES IN THE UNITED STATES: 1972

Type of Generation	Convertible	Non-Convertible	Total
Quadrillion Btu			
Hydroelectric		2.9	2.9
Nuclear		0.6	0.6
Fossil Steam-electric	4.6	9.9	14.5
G.T. and I.C.	0.5	*	0.5
Total	5.1	13.5	18.6 t
Crude Oil Equivalent (Million bid) ‡			
Hydroelectric	...	1.4	1.4
Nuclear	...	0.3	0.3
Fossil Steam-electric	2.2	4.8	7.0
G.T. and I.C.	0.3	*	0.3
Total	2.5	6.5	9.0
Refined Product Equivalent (million bid) §			
Hydroelectric	....	1.3	1.3
Nuclear	....	0.3	0.3
Fossil Steam-electric	2.1	4.5	6.5
G.T. and I.C.	0.2	*	0.2
Total	2.3	6.0 t	8.3
Percent Total	27.7%	72.3%	100.0%

*All gas turbine and internal combustion units included in convertible column.

tComponents do not add due to rounding.

‡Based upon 5,675,000 Btu per barrel of crude oil (U.S. Bureau of Mines).

§Based upon 6,087,000 Btu per barrel of refined products (E.E.I.).

The NPC Committee's estimate of fuel that can be converted to coal is lower than that shown in staff reports of the Federal Power Commission published in September 1973. These analyses indicate that if coal were substituted for all the oil and gas consumed in multiple fuel-burning units in 1972, the equivalent of about 750 MB/D (540 MB/D in oil and 210 MB/D in gas) could have been converted. Analysis of fuel interchangeability by the NPC Committee was prepared independently; consequently, there are differences in interpretations and conclusions even though the common reference is FPC Form 36. The NPC Committee's evaluation of fossil fuel interchangeability makes allowance for constraints on fuel convertibility such as the physical conditions of multiple fuel-fired boilers, design characteristics of boilers at each potentially convertible plant, coal-handling equipment, available transportation and air pollution regulations.

Variations in the physical and chemical properties of different coals also affect convertibility. A boiler is engineered to burn coal with specific characteristics; consequently, variations within only a relatively narrow range can be tolerated because boiler failures, safety hazards and other operating problems develop whenever coal is used that significantly departs from design specifications. A major change of fuel characteristics for an existing plant requires extensive and costly modifications to the boiler, and production is lost during the rebuilding period. Even though a boiler may have been engineered and built to burn coal, a changeover from oil or gas could take as long as 2 to 3 years if the station does not have facilities to unload, store, convey or pulverize coal. Particulate emission controls and ash disposal equipment may be inadequate or completely lacking. Some plants would have to be completely rebuilt to burn coal.

HISTORICAL PATTERNS OF FUEL CONVERTIBILITY

Generally speaking, the most significant pe,riodic changeovers between competitive fuels have been between coal and residual fuel oil in PAD District I, particularly along the northeastern seaboard between Philadelphia and Portland, Maine. The relative importance of coal and fuel oil fluctuated very widely from year to year, especially in the electric utility fuel market, but by the end of the 1960's, imported residual fuel oil became the dominant fuel. A similar periodic shift between oil and gas occurred in PAD V but coal never had a major role as an industrial fuel.

Interruptible natural gas displaced millions of tons of coal in the electric utility and general industrial markets in PAD Districts I and II during the 1950's and 1960's. Even though aggregate fuel convertibility did not appreciably change in the general industrial fuel market during this period, there was a significant shift in the type of convertibility during the past two decades--from units that burned coal and oil or gas to units that now can only burn oil and gas.

DEPENDENCE ON IMPORTED RESIDUAL FUEL OIL IN PAD I

Most of the residual fuel imported into the United States is consumed in PAD I. Imports rose sharply after World War II, increasing fivefold between 1946 and 1959 when import quotas were put on residual fuel oil, other refined products and crude oil. Consumption of foreign residual oil stabilized during the first 4 years of the mandatory quota program but picked up in 1964 and 1965 when quotas were liberalized. In 1966, the Secretary of the Interior lifted all restrictions on residual fuel oil imported into Pad District I so that by 1973, foreign receipts doubled as a series of developments caused demand for residual to increase very rapidly.

Passage of air pollution ordinances by New York City, New Jersey and other areas along the East Coast beginning in 1969 were accompanied by federal air quality standards; consequently, consumers in PAD I turned to imported low-sulfur oil because adequate domestic supplies of low-sulfur fuel were not available. The growing concern over air pollution accelerated low-sulfur residual oil imports so that by 1973, direct imports of residual oil and low-sulfur oil produced from imported crude oil accounted for about 95 percent of total residual fuel oil supply along the East Coast.

The full impact of these developments is better understood when PAD District I is divided into sub-regions, PAD I-A and PAD I-B (see Figure 15). Coal-fired electric generating capacity in PAD I increased by about 50 percent between 1965 and 1972; but all the growth took place in PAD I-B, the sub-region which includes the Appalachian coalfields and adjacent areas (Table 22). Coal-fired capacity in PAD I-A, the coastal areas, actually declined by 26 percent, although total steam-electric capacity rose by 40 percent. Even more significant is the fact that in PAD I-A, steam-electric generating capacity entirely dependent on oil and gas, more than doubled between 1965 and 1972. In addition, gas turbine (oil- or gas-fired) and internal combustion generating capacity in PAD District I increased from nearly nothing in 1965 to 17 million kilowatts in 1972 when their oil and natural gas consumption was about 150 MB/D.

CURRENT CONVERTIBILITY POTENTIALS

Electric utilities in PAD District V have the greatest potential interchangeability, which is evident from the fact that 89 percent of the fossil-fired capacity is equipped to burn more than one fuel (Table 23). In other words, as long as either oil or gas is available, utilities on the Pacific Coast can readily switch between them. The opposite situation exists in PAD District I-B where convertibility is insignificant. Forty percent of the total steam-electric generating capacity in PAD District I is located in this sub-region and nearly all of it is fired by coal. In PAD District I-A, 30 percent of total steam-electric capacity is equipped to burn only oil and about 1 percent is entirely gas-fired

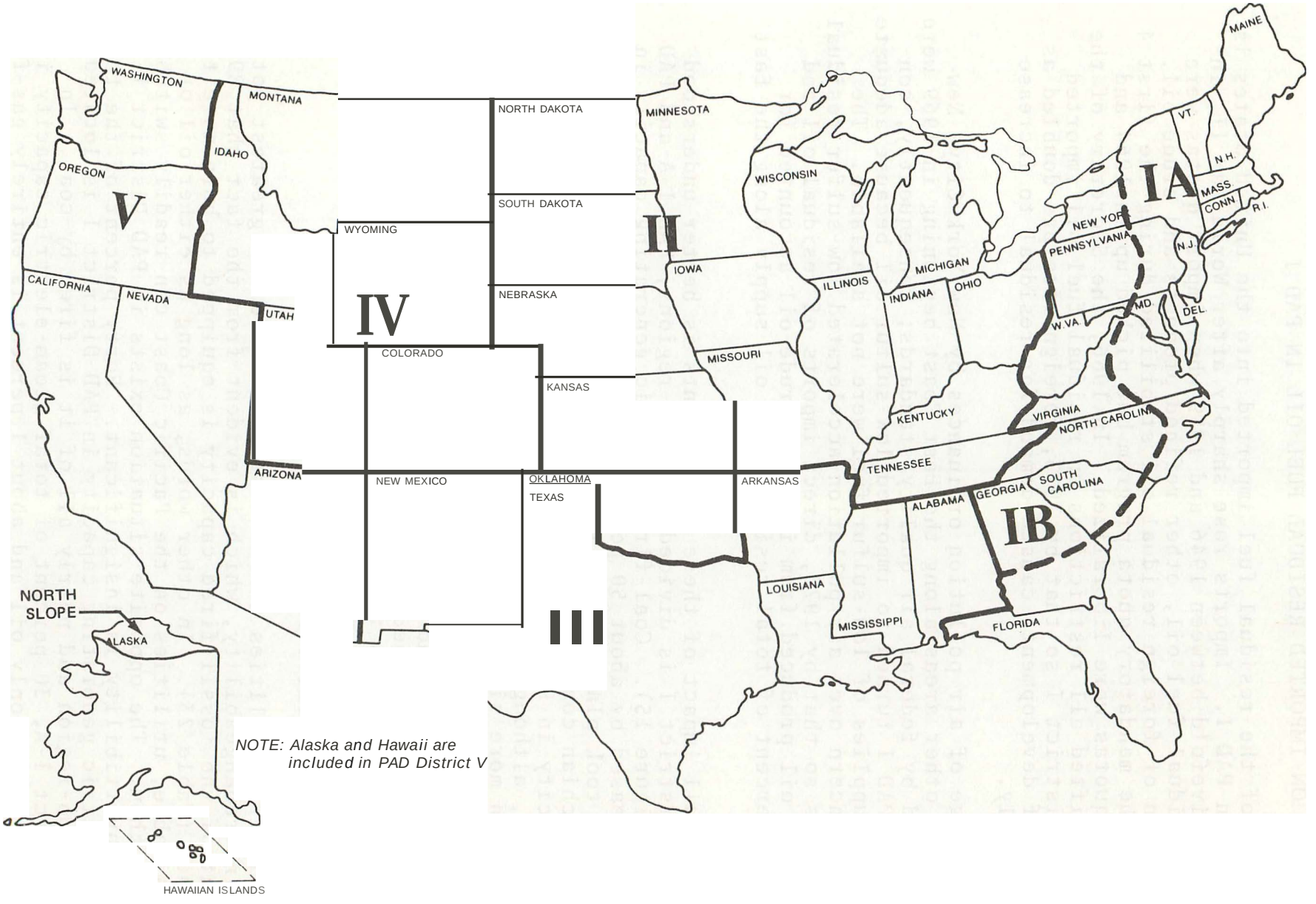


Figure 15. Petroleum Administration for Defense (PAD) Districts.

TABLE 22

INSTALLED GENERATING CAPACITY BY TYPE OF FUEL CAPABILITY
IN PAD DISTRICT I: 1972 VS. 1965

Boiler Fuel		PAD IA 1972	PAD IA 1965	PAD IB 1972	PAD IB 1965	Total PAD I 1972	Total PAD I 1965
Coal only	MW	8,885	12,067	37,908	19,293	46,793	31,360
	%	14.5	27.7	90.5	89.4	45.6	48.2
Oil only	MW	16,382	8,667	27	27	16,409	8,694
	%	26.8	19.9	0.1	0.1	15.9	13.4
Gas only	MW	297	0	0	0	297	a
	%	0.5	-	-	-	0.3	
Coal-Oil	MW	14,891	11,682	2,000	0	16,891	11,682
	%	24.4	26.8	4.8	-	16.4	17.9
Coal-Gas	MW	3,253	2,745	1,927	2,258	5,180	5,003
	%	5.3	6.3	4.6	10.5	5.0	7.7
Coal-ail-Gas	MW	5,968	3,689	36	0	6,004	3,689
	%	9.8	8.5	0.1	-	5.8	5.7
Oil-Gas	MW	11,455	4,687	0	0	11,455	4,687
	%	18.7	10.8	-	-	11.1	7.2
Total	MW	61,131	43,537	41,898	21,578	103,029	65,115
	%	100.0	100.0	100.0	100.0	100.0	100.0

Source: FPC Form r.

TABLE 23

INSTALLED STEAM-ELECTRIC GENERATING CAPACITY IN THE U.S.
BY PAD DISTRICT AND TYPE OF FUEL CAPABILITY: 1972*
(Gigawatts)

Fuel Capability	PAD 1A	PAD 1B	PAD 1 Total	PAD 2	PAD 3	PAD 4	PAD 5	Total U. S.
Single Fuel-Fired Capacity								
Coal only	9.3	39.1	48.4	64.3	11.7	1.9	1.4	127.7
Oil only	18.8	-	18.8	0.7	0.2	t	1.1	20.8
Gas only	t	-	t	6.0	35.6	-	0.6	42.2
Sub-Total	28.1	39.1	67.2	71.1	47.5	1.9	3.2	190.8
% of Total	46.1%	93.7%	65.5%	73.8%	84.1%	44.8%	11.3%	66.3%
Multiple Fuel-Fired Capacity								
Coal-Oil	15.3	0.2	15.5	2.6	-	-	0.2	18.3
Coal-Gas	1.8	2.4	4.2	17.1	0.3	1.7	1.6	25.0
Oil-Gas	11.4	-	11.4	3.7	8.7	0.2	23.0	47.0
Coal-Oil-Gas	4.3	-	4.3	1.8	-	0.5	-	6.6
Sub-Total	32.8	2.6	35.4	25.3	9·0	2.3	24.8	96.9
% of Total	53.9%	6.3%	35.5%	26.2%	15.9%	55.2%	88.7%	33.7%
Total	60.8	41.8	102.6	96.3	56.5	4.2	28.0	287.6

* Plants convertible to coal within 90 days are included in coal-oil, coal-gas or coal-oil-gas capcity.

t Less than 500 megawatts.

Source: FPC Form 36.

CTables 22 and 23). Another 20 percent can use either oil or gas, so that one-half of the generating capacity in PAD I-A is entirely dependent on oil and gas.

A relatively large portion of the total steam-electric capacity is multiple fuel-fired in PAD Districts II and IV, but most of it is in units that can be fired by gas or coal. Boilers that burn only coal dominate in PAD District II, and to a smaller extent in PAD IV. Some old coal-fired plants in PAD II were converted to low-sulfur oil subsequent to recently enacted air pollution legislation, but widespread conversions to fuel oil did not occur due to its unavailability.

Steam electric boilers in PAD III are predominately gas-fired. Coal-burning stations in Alabama, Mississippi, New Mexico and Texas account for 20 percent of the steam-electric capacity; and, the capacity of coal-fired boilers is greater than that of those multiple fuel-fired units that can burn either oil or gas.

PAD District I--specifically, the East Coast sub-region--is one of the two most critical areas based upon the extent to which consumers are heavily dependent on natural gas and imported fuel oil. In PAD District V, conversions from oil and gas to coal offer no immediate or direct relief because only 6 percent of the total steam-electric capacity can use coal interchangeably with oil or gas, and most of this capability is already burning coal.

THE LEVEL, TIMING AND LIMITATIONS OF CONVERSIONS TO COAL BY ELECTRIC UTILITIES

Based on analyses of FPC Form 36 data ,potential conversions from oil and natural gas to coal within a 3-month period could have replaced the equivalent of 614 MB/D in 1972 (see Table 24). However, during the first 8 months of 1973, about 40 MB/D of oil and gas had been converted to coal, so the potential convertibility by late summer was reduced to 574 MB/D. About two-thirds of total potential convertibility in the electric utility industry is from oil to coal, and two-thirds of total convertibility is in PAD I. If one considers only those plants which currently burn coal along with oil and gas (these have the highest probability of an immediate changeover to coal), convertibility in PAD I is only 25 percent of the national total, with coal-oil plants accounting for only 25 percent of the total in Category 6. This aspect of immediate convertibility is significant because it implies that in 1972 more natural gas than oil could have been replaced by coal, and most of it would have occurred in PAD II. Units that have switched entirely from coal offer the greatest potential savings in oil and gas, but reconversions to coal will take many months. Spokesmen for both the coal and electric utility industries have expressed serious doubts whether coal production can be immediately expanded to supplant a significant volume of oil and gas.

TABLE 24

ELECTRIC UTILITY CONVERTIBILITY TO COAL BY PAD DISTRICT: 1972
(MElD Equivalent)*

Category	From	To	PAD 1	PAD 2	PAD 3	PAD 4	PAD 5	Total U.S.
1	Oil	Coal	29					29
	Gas	Coal	1	4		5		10
	Total		30	4		5		39
2	Oil	Coal		10				76
	Gas	Coal		4				4
	Total			15				80
3	Oil	Coal	15	12				28
	Gas	Coal	4	t		2		7
	Total		20	13		2		35
4	Oil	Coal	42	18				59
	Gas	Coal	4	2		5		11
	Total		45	20		5		70
5	Oil	Coal	188					188
	Gas	Coal	3	15				18
	Total		190	15				205
Total 1-5	Oil	Coal	338	41				379
	Gas	Coal	11	26		12		50
	Total		350	67		12		429
6	Oil	Coal	26	5		14		45
	Gas	Coal	20	95	1	20	4	140
	Total		46	100	1	33	4	185

* Based upon air pollution regulations that were in effect during 1972.

t Less than 500 bid,

NOTE: Components may not add due to rourlding.

Source: Basic data from FPC Form 36.

TABLE 24 (Cont'd)

DEFINITION OF CONVERTIBILITY CATEGORIES

Electric utility plants which do not presently burn coal but are capable of converting to coal are grouped into five categories, based upon information in FPC Form 36. Coal-firing systems in these plants can be operable within three months (i.e., deliverability, storage capacity, conveying and preparing).

Category #1 — Plant has an existing contract for coal or else coal is assumed to be available, and the sulfur content of this coal will meet current state and local regulations on sulfur content. Boilers are designed to burn coal within the maximum regulations on sulfur content.

Category #2 — Plant has an existing contract for coal or else coal is assumed to be available; however, the sulfur content of the coal is higher than the maximum sulfur content allowable under present state and local regulations. Boilers are capable of burning coal within the maximum regulations on sulfur content.

Category #3 — Plant has an existing contract for coal or else coal is assumed to be available; however, the sulfur content of the coal is higher than the maximum allowable under present state and local regulations. Boilers are not designed to burn coal that can meet these regulations.

Category #4 — Plant has no existing contract for coal. Boilers are designed to burn coal which meets the sulfur regulations.

CateBory #5 — Plant has no existing contract for coal. Boilers are not designed to burn coal that can meet existing state and local regulations on sulfur content.

Some plants have not entirely converted to oil and gas. They burned these fuels as well as coal in 1972; therefore, these plants are shown in a separate category.

Category #6 — Plant is presently burning either coal and oil or coal and gas in the same boilers. Convertibility represents the additional amount of coal that the plant can use.

However, air pollution regulations present an overriding limitation. Existing air pollution regulations prevent potentially convertible plants from burning coal equivalent to 320 MB/D because the boilers are not designed to burn coal of the quality stipulated by maximum sulfur requirements, or the sulfur content of the coal available to these plants exceeds the maximum legal limits. In other words, compliance with air pollution regulation reduces potential convertibility to coal by more than 50 percent.

Fuel Convertibility and the Supply of Alternate Fuels

Spokesmen for the coal producing, transportation and consuming industries have publically stated that additional coal mine capacity and transportation facilities must be built to convert the equivalent of 650 MB/D of fuel oil and natural gas in PAD Districts I, II and IV. This total includes 614 MB/D in the electric utility market and an estimated 35 MB/D in the general industrial market. A large-scale coal mine and coal transportation expansion program will be needed which will require an investment of as much as $1.5 billion over a period of several years with some assurance that the coal mines, rolling stock and other facilities will not be prematurely retired or abandoned before the investments have been recovered or even before the expansion program is completed. This implies a long-term national commitment to coal. Several short-term measures are available by implementing an emergency program which could temporarily increase coal consumption of convertible plants by about 250 MB/D, but these measures would not significantly increase total coal supplies. Most of the increased coal consumption will be high in sulfur content and cannot be consumed in areas with sulfur restrictions. Additionally, some of the coal currently is in stockpiles of electric utility stations which are permitted to burn high sulfur coal but facilities are not available to reload and transship the coal to other plants. These alternatives will require immediate implementation--supervision and administration by people knowledgeable of coal transportation and coal-consuming plants; participation and cooperation of industry, labor and government; and new legislation in certain areas. This program will probably be costly and inefficient in the short run, with no assurance that the 250 MB/D goal can be achieved. The various short-term alternatives include:

- Increasing coal production from existing mines
- Modifying certain legislation, such as extending federal financial participation under Title IV of the 1969 Federal Coal Mine Health and Safety Act
- Modifying price controls under Phase IV regulations
- Allocating coal supply
- Relaxing sulfur limits on fuel

- Constructing or rehabilitating railroad hopper cars and other transportation equipment through government financial assistance

- Rehabilitating coal handling and transfer facilities, especially for waterborne traffic

- Diverting transportation equipment capable of handling coal to critical areas, such as transferring self-unloading vessels from the Great Lakes to the East Coast during the winter when the Lakes are ice-bound.

Increased Coal Production

The coal resources in this country are capable of supplying greater portion of the energy requirements of this country, given the incentive for development. Recoverable coal reserves in the United States are measured in hundreds of billions of tons, and the life of remaining reserves are expressed in centuries. Current deficiencies in coal supplies are not the consequence of resource depletion or exploration cutbacks; rather, the inability to immediately expand production above current output is attributable to underdevelopment of new reserves and the reduction of existing coal mine capacity during the past 5 years, particularly in the high-sulfur coal areas of the Northern Appalachian and Midwestern coal fields. West Virginia, for example, is a major source of low-sulfur coal; however, production in the entire state has declined about 30 percent since 1967, and the state has dropped behind Kentucky as the leading coal producer (see Table 25). A number of factors have offset the increased demand for low-sulfur coal produced in West Virginia so that total production and total mine capacity has declined during the past several years. Production data by state in Table 25 is shown for the first 6-month periods of 1970 through 1973 because latest production, by state, published by the U.S. Bureau of Mines in 1973 is for the period January to June, and six months' production data in 1971 eliminates the distortion in annual production caused by the industry-wide strike that occurred in the last half of that year. The reduction in West Virginia's production is synonomous to a drop in mine capacity and is important when considering coal supply during the current energy crisis because the state has been a major supplier of industrial coal in PAD Districts I and II. Other eastern coal-producing states have experienced similar declines during the last 4 years, except Kentucky, Virginia and Alabama, where much of the coal is locally consumed. These latter states and at least 6 other states, all in the West, will report all-time record production in 1973, so that the current production pattern in the coal industry is paradoxical--concurrent contraction and expansion.

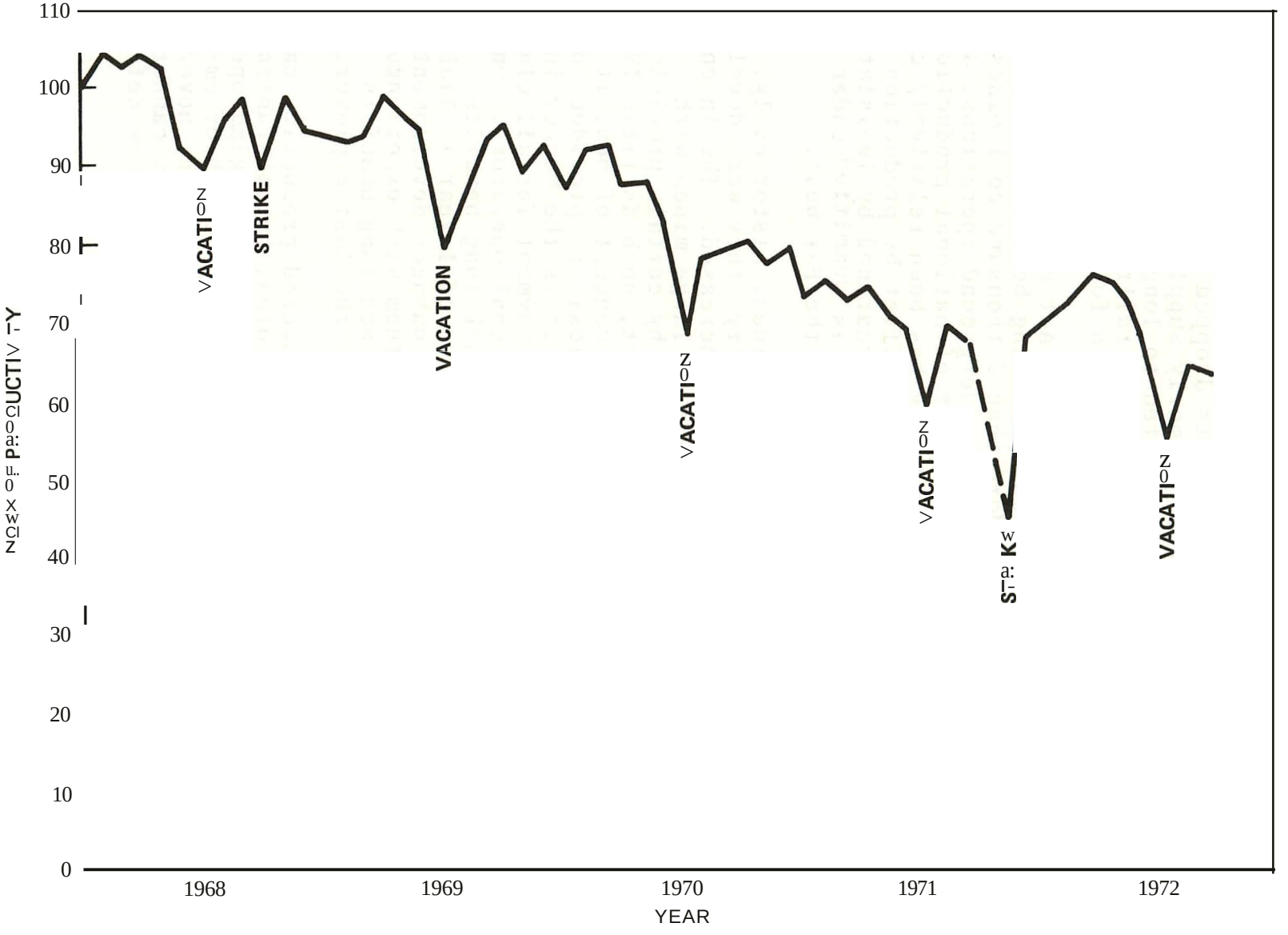
Mine capacity dropped in West Virginia, Pennsylvania and several other eastern and midwestern states for two reasons--mine closures and lower labor productivity (see Figure 16). Hundreds of mines were abandoned since the late 1960's in consequence to the

TABLE 25

BITUMINOUS COAL PRODUCTION IN THE UNITED STATES
JANUARY - JUNE 1970-1973
(Millions of Net Tons)

STATE AND REGION	1970	1971	1972	1973
West Virginia	73.8	70.1	65.8	57.1
Pennsylvania	40.0	42.0	39.7	38.4
Ohio	26.6	28.2	26.5	24.6
Indiana	10.5	12.3	13.0	11.7
Illinois	32.3	33.5	34.7	30.4
Sub-Total, 5 States	183.2	186.0	179.8	162.2
Kentucky				
East	33.3	37.9	34.0	37.1
West	25.7	25.3	25.9	27.6
Sub-Total, State	59.0	63.2	59.9	64.7
Virginia	17.7	17.5	17.7	17.1
Alabama	9.8	9.6	10.4	9.6
Sub-Total, 3 States	86.5	90.3	87.9	91.5
Other Eastern U.S.	4.4	5.6	6.5	5.3
Eastern United States	274.1	281.8	274.2	258.9
Western United States	21.6	26.0	32.6	32.7
Total United States	295.7	307.8	306.8	291.6

Source: U.S. Bureau of Mines



SOURCE: West Virginia, School of Mines.

Figure 16. Tons Per Man-Day of a Representative Group of Underground Coal Mines in Eastern United States: 1968-1972.

erosion of coal markets by imported residual fuel oil and natural gas and the adoption of stringent air pollution regulations. Tidewater shipments to electric utilities, for example, dropped from a high of 16.8 million tons in 1965 to 1.1 million in 1972, and deliveries to general industry suffered a similar decline since 1960 (Table 26). Metallurgical coal shipments dropped about 40 percent between 1967 and 1972. Mines which formerly supplied coal to eastern markets have either been committed to long-term contracts or abandoned permanently. The impact on the railroads and coal piers was equally severe and is discussed in a following section.

The Federal Coal Mine Health and Safety Act caused many mines to close, especially small operations producing between 25 thousand and 200 thousand tons annually. More than 2 thousand coal mines have closed since 1970, mostly eastern underground operations, and these mines accounted for about 20 percent of national production in 1970. Total production of the industry has been relatively constant because some of the lost tonnage was offset by production from surface mines whose existence is now threatened by legislation, by new large underground mines whose tonnage is committed under long-term contracts and by new production in the Far West.

Smaller underground mines and surface mines, historically, have been the "surge bins" of the coal industry; they were developed rapidly when demand for coal suddenly increased. The incentive to open small coal mines and, to some extent large mines with relatively short lives, has been discouraged by certain provisions of the Federal Coal Mine Health and Safety Act, such as Title IV, which provides for black lung benefits. The concept of benefit payments to miners suffereing from pneumoconiosis as provided for under the 1969 Act is not the issue; rather, it is the manner in which certain provisions have been applied. Payment for all claims filed after July 1, 1973, must be assumed by coal operators. On prior claims, the Federal Government pays black lung benefits. The last operatDr who employs a miner for a period of 1 year is liable for black lung payments. This provision discourages development of temporary mining operations and staffing them with experienced coal miners, who eventually may qualify for black lung benefits which will be the financial responsibility of the last employer.

Other provisions of the 1969 Act have lowered productive capacity in the coal industry through mine closures, by substantially lowering productivity of existing mines, and by discouraging opening of new mines. No compromise in the safety and health of employees is suggested or to be inferred in this discussion; nevertheless, the 1969 Act is one reason why the coal industry cannot significantly expand production in order to meet short-term deficiencies in energy supplies.

Expansion of capacity at existing mines and development of new mines will require an intensive training program for miners and supervisory personnel sponsored by federal and state agencies, the unions and the operators. More emphasis in federal and state inspection systems should be put on correcting and preventing hazardous conditions before they occur. This means better trained inspection personnel.

TABLE 26

TIDEWATER MOVEMENT OF BITUMINOUS COAL: 1960-1972
(Thousands of Net Tons)

Year	Electric utilities	Other Steam	Metallurgical	Total
1960	14.0	2.2	6.0	22.2
1961	13.7	1.8	5.6	21.2
1962	13·1	1.8	5.7	20.6
1963	15.6	2.0	6.0	23.6
1964	15.6	2.0	6.2	23.8
1965	16.8	0.9	6.2	23·9
1966	16.2	0.7	6.1	23.1
1967	14.5	0.6	6.3	21.4
1968	13.0	0.5	5·3	18.7
1969	8.5	0.4	5.1	14.0
1970	5.1	0.3	5.1	10.4
1971	3.5	0.1	4.7	8.3
1972	1.1	0.1	3.9	5.1

Source: u. S. Bureau of Mines.

Another adverse effect on current coal production has been labor unrest which is manifested by widespread wildcat strikes. Estimates of lost tonnage directly attributable to these work stoppages in 1973 range between 10 to 15 million tons--equivalent to about 100 to 165 MB/D. Frequently, a local wildcat strike spreads to mines of other companies where no grievance is involved, but at these mines the coal miners do not cross the picket lines set up by roving strikers.

Another problem has been recently implemented imposing surface mine regulations which limit expansion of existing mines, development of new mines and increase costs of production. Surface-mined coal accounted for 27 percent of total electric energy generation in the United States and two-thirds of the power generated by coal during 1971. Certain provisions in existing and pending legislation have little or nothing to do with environmental conservation, but they have thwarted the industry's efforts to increase coal production. Proposed regulations become constraints even though they are not currently in effect.

Material and fuel shortages are having an increasingly detrimental effect on current coal production. Supplies of ammonium nitrate explosives, diesel fuel, hydraulic oil and rubber belting, which contain varying quantities of petroleum and natural gas derivatives, have been tight for several months. Other materials such as roof bolts and electric motors are also in short supply. Many operators have been unable to obtain diesel fuel to operate new equipment as well as existing machinery.

Price Controls Under Phase IV Regulations

Rigid price controls on coal have reduced the industry's earnings which, in turn, have prevented coal companies from improving existing facilities in order to offset lower productivity and purchasing new, more efficient mining machinery. Many new ventures have been cancelled, postponed, or curtailed since 1971. Even though total coal production has been near the all-time record set in 1947, coal companies have been reporting deficits or very meager earnings under price controls.

Allocations of Coal

Some immediate, short-term relief with regard to convertibility is possible by an allocation system for coal which, by itself, will not increase total coal supplies but will enable some plants to change over from fuel oil or natural gas. The program will not be simple to administer because, among other considerations, it will require a curtailment in coal deliveries to many plants which have long-term contracts, and frequently the coal is transported in consumer-owned transportation equipment. Legal problems are involved and must be resolved.

Based upon coal stockpile reports filed by electric utilities with the Federal Power Commission, fuel convertible plants have 14 million tons of coal inventories (see Table 27). Stations that completely switched to fuel oil or natural gas had 4 million tons of coal in stockpiles on December 31, 1972, which was equivalent to about an average of 24 days supply. All power plants in the United States had 97 million tons on June 30, 1973, equivalent to 91 days supply; but, many plants capable of burning coal had no inventories so that the national average is not meaningful. Normal stockpile levels vary widely depending on a plant's location, coal supply agreement and seasonal inventory patterns.

Based upon the current stock levels, about 7 million tons could be shipped to plants that shifted completely from coal, and that would enable these plants to be coal-fired and base-loaded for 90 days, assuming that some oil- and gas-fired units would be cut back if coal is available. Seven million tons of coal is equivalent to one week's production of bituminous coal in the three largest coal-producing states. A rapid buildup of coal inventories, therefore, is not possible, but spread over a 3-month period, it would be equivalent to diverting about 500 thousand tons per week to convertible plants. This level would be difficult to reach in an allocation program because 80 percent of the total would have to be shipped to plants along the East Coast and the logistic problems would be very difficult. The railroads would have to increase coal traffic by an annual rate of 20 million tons--equivalent to four-fifths of their 1972 coal deliveries--to states in PAD I where nearly all coal-convertible plants are located. Although the proposal appears feasible, it would be a huge task even at half this rate.

A similar problem of coal allocation exists in PAD District II where most of the potential convertibility outside of PAD I is located. Aggregate stockpiles of convertible plants in PAD II are equivalent to about a 90-day supply, but some convertible stations have small or no coal stockpiles. So again, the district average is not meaningful. PAD II has a more diversified coal supply and transportation system; however, coal must be delivered to many plants by water routes. No deliveries can be made during the winter when the waterways are frozen, and current coal shipments have been restricted by shortages of barges and tow boats. The coal industry has also been hurt by chronic shortages of rail cars and locomotives in PAD II.

Many other problems are inherent in a coal allocation scheme. In order to resolve them, the services of experts with extensive knowledge of coal quality, combustion characteristics, distribution networks, fuel pricing and seasonal demand will be required. Availability of experienced personnel to administer an allocation program is another difficult problem.

TABLE 27

COAL STOCKPILES OF ELECTRIC UTILITY PLANTS, BY PAD DISTRICT, DECEMBER 31, 1972
(Thousands of Net Tons)

Category	PAD 1A	PAD 1B	PAD 1	PAD 2	PAD 3	PAD 4	PAD 5	Total U.S.
1	-	59	59	81	-	24	-	164
2	649	-	649	1,431	-	-	-	2,080
3	256	-	256	189	-	16	-	461
4	545	-	545	49	-	43	-	637
5	727	-	727	226	-	-	-	953
Sub-Total	2,177	59	2,236	1,976	-	83	-	4,295
6	1,318	792	2,110	6,433	205	959	288	9,995
Grand Total	3,495	851	4,346	8,409	205	1,042	288	14,290

Source: FPC Form 4 and Form 36.

Relaxation of Sulfur Limits

Sulfur limits on coal impose another constraint on fuel convertibility. Most electric utility and industrial plants switched from coal to imported oil because coal with a sulfur content that could meet the limits imposed by air pollution regulations--i.e., 0.5 percent or less--was not available; therefore, when these plants are unable to get imported low-sulfur oil, they will have no fuel that meets air quality standards. Even if low-sulfur coal were available, most oil- and gas-fired convertible boilers are not equipped with sufficient precipitator capacity and the coal cannot be burned without experiencing other major environmental problems.

When an industrial boiler is engineered to burn a specific type of coal, substitution by another coal may be difficult. Boilers are designed to provide some flexibility, but large industrial units usually burn coal that has particular physical and chemical characteristics including sulfur content. Some units have been forced out of service within hours after a switch was made to the "wrong" coal. This problem is frequently mentioned in the electric utilities' comments attached to FPC Form 36.

Most coal reserves and production in eastern United States are high-sulfur coal (see Table 28). Without commercially feasible systems that remove sulfur oxides from stack gases or processes that can produce a coal-derived low-sulfur fuel, there is no alternate energy source in the United States that will offset deficits caused by curtailments in low-sulfur oil imports. If a coal allocation system is implemented, most of the coal reassigned to plants in eastern United States will be high-sulfur fuel from existing mines and existing stockpiles. New development of high-sulfur coal reserves has come to a near standstill in the United States since state and local sulfur regulations were implemented once EPA announced national guidelines on maximum sulfur content of fossil fuels.

Construction of Coal Transportation Equipment

Aggregate capacity of open-top hopper cars, the type most commonly used to haul coal, has steadily declined in the United States (see Table 29). The two principal coal-hauling railroads serving the North Atlantic Seaboard (Penn Central and Baltimore and Ohio) have reported the sharpest declines in hopper car capacity, especially since 1966 when quotas on residual fuel oil imports were lifted. During the last 10 years, every railroad transporting steam coal for domestic tidewater delivery reported a sharp decline in this traffic (Table 30). The Chesapeake and Ohio is an exception due to a continuation of tidewater shipments of coking coal to a steel plant. Tidewater shipments by two railroads dropped to zero in 1972. Three of the railroads shown on Table 30 have gone bankrupt during this period, and the drop in coal traffic was a major factor contributing to the insolvency of these companies. The decline in car capacity and coal traffic are related because,

TABLE 28

RECOVERABLE COAL RESERVES IN THE UNITED STATES
BY RANK AND SULFUR CONTENT: JANUARY 1, 1965

(Billions of Net Tons)

	1.0% or Less	1.1 to 2.0%	2.1 to 3.0%	Over 3.0%	Total *
Lignite					
East	-	t	-	-	t
West	203	21	†	-	224
Total	203	21	t	-	224
Sub-Bituminous					
East					
West	194	†	-	†	194
Total	194	t	-	t	194
Bituminous					
East	42	46	43	103	233
West	66	3	6	54	129
Total	108	49	49	157	362
Anthracite					
East	6	-	-	-	6
West	1	†	†	-	1
Total	7	t	t	-	7
Total Reserves					
East	48	46	43	103	235
West	464	24	6	54	548
Total	512	70	49	157	783
Total Reserves - % Total					
East	9%	66%	88%	66%	30%
West	91%	34%	12%	34%	70%
Total	100%	100%	100%	100%	100%

* Totals may not add due to rounding in billions.
t Less than 500 million tons.

Source: U.S. Bureau of Mines

TABLE 29

AGGREGATE CAPACITY OF OPEN-TOP HOPPER CARS OWNED & LEASED FOR SELECTED CLASS I RAILRQADS: 1966-1973
(Thousands of Net Tons)

Railroad	1966	1973	August 1, 1973	Peak Jan. 1	Capacity
EASTERN DISTRICT					
Baltimore & Ohio	2,033	1,896	1,782	Jan. 1, 1966	2,033
Bessemer & Lake Erie	707	676	654	Jan. 1, 1966	707
Chesapeake & Ohio	3,111	3,639	3,582	Jan. 1, 1972	3,643
Chicago & Eastern Ill.	135	145	158	Jan. 1, 1967	173
Erie Lackawanna	160	158	157	Jan. 1, 1969	202
Norfolk & Western	4,454	5,022	4,863	Jan. 1, 1972	5,194
Penn Central	5,160	4,457	4,321	Jan. 1, 1966	5,160
Reading	478	352	338	Jan. 1, 1966	478
Western Maryland	464	390	386	Jan. 1, 1967	485
Sub-Total Eastern	16,702	16,735	16,241		
SOUTHERN DISTRICT					
Carolina, Clinchfield, & Ohio	256	375	297	Jan. 1, 1968	331
Illinois Central Gulf	1,059	1,026	1,025	Jan. 1, 1970	1,085
Louisville & Nashville	2,110	2,464	2,386	Jan. 1, 1972	2,535
Seaboard Coast Line	293	675	669	Jan. 1, 1972	678
Southern	651	1,038	1,012	Jan. 1, 1973	1,038
Sub-Total Southern	4,369	5,518	5,389		

TABLE 29 (Cont'd)

AGGREGATE CAPACITY OF OPEN-TOP HOPPER CARS OWNED & LEASED FOR SELECTED CLASS I RAILROADS: 1966-1973
(Thousands of Net Tons)

Railroad	January 1		August 1,	Peak	
	1966	1973	1973	Jan. 1	Capacity
WESTERN DISTRICT					
Atchison, Topeka & Sante Fe	389	431	429	*Jan.* 1, 1968	438
Burlington Northern	1,384	1,419	1,399	Jan. 1, 1967	1,443
Chicago & Illinois Midland	30	5	1	*Jan.* 1, 1968	82
Chicago & North Western	569	307	296	*Jan.* 1, 1967	551
Denver & Rio Grande Western	128	207	213	Aug. 1, 1973	213
Milwaukee	216	178	179	*Jan.* 1, 1969	242
Missouri Pacific	465	609	596	*Jan.* 1, 1968	625
Rock Island	100	167	166	*Jan.* 1, 1973	167
St. Louis-San Francisco	229	227	220	*Jan.* 1, 1966	229
Union Pacific	502	657	662	Jan. 1, 1972	665
Sub-Total Western	4,012	4,207	4,161		
Grand Total	25,083	26,460	25,791		

Source: Association of American Railroads.

TABLE 30

TIDEWATER LOADINGS OF BITUMINOUS COAL: 1965-1972
(Thousands of Net Tons)

Year	Penn Central			Baltimore & Ohio		
	Domestic	Foreign	Total	Domestic	Foreign	Total
1965	6,662	201	6,863	2,535	2,259	4,794
1966	7,145	306	7,451	2,713	2,046	4,759
1967	7,216	282	7,498	3,870	1,573	5,443
1968	6,334	279	6,613	3,847	1,874	5,721
1969	4,658	-	4,658	4,009	2,619	6,628
1970	3,217	318	3,535	3,014	3,651	6,665
1971	2,123	113	2,236	1,370	2,938	4,308
1972	1,486	113	1,599	924	3,517	4,441

	Reading			Central of New Jersey		
	Domestic	Foreign	Total	Domestic	Foreign	Total
1965	5,408	32	5,440	3,581	-	3,581
1966	5,054	10	5,064	2,923	-	2,923
1967	4,419	5	4,424	2,423	-	2,423
1968	4,098	-	4,098	2,023	-	2,023
1969	2,225	4	2,299	1,279	-	1,279
1970	2,219	102	2,321	787	-	787
1971	2,104	9	2,113	217	-	217
1972	421	-	421			

TABLE 30 (Cont'd)

TIDEWATER LOADINGS OF BITUMINOUS COAL: 1965-1972
(Thousands of Net Tons)

Year	Western Maryland			Chesapeake & Ohio		
	Domestic	Foreign	Total	Domestic	Foreign	Total
1965	838	362	1,200	2,607	10,055	12,662
1966	**1,124**	126	1,250	2,727	9,215	11,942
1967	644	79	723	2,937	8,687	11,624
1968	497	246	743	2,311	7,761	10,072
1969	499	1	500	2,204	9,397	11,601
1970	125	917	1,042	2,708	13,794	16,502
1971	24	364	388	3,005	8,488	11,493
1972	-	42	42	2,770	6,567	9,337

	Norfolk & Western			Grand Total		
	Domestic	Foreign	Total	Domestic	Foreign	Total
1965	4,376	22,448	26,824	26,007	35,357	61,364
1966	3,677	22,658	26,335	25,361	34,362	59,723
1967	3,104	23,872	26,976	24,614	34,498	59,112
1968	2,641	24,577	27,218	21,752	34,736	56,488
1969	2,198	27,970	30,168	17,143	39,991	57,134
1970	1,072	33,159	34,231	13,141	51,942	65,083
1971	412	25,310	25,722	9,254	37,221	46,475
1972	621	24,933	25,554	6,223	35,172	41,395

Source: Tidewater Bituminous Coal Statistical Bureau.

as coal traffic dropped due to displacement by oil and gas, the aggregate capacity of open-top hoppers declined even though hopper cars are used to transport iron ore, sand and gravel, agricultural products and other commodities.

The reduction in revenues from coal shipments to the East Coast, coupled with the high cost of maintaining surplus, equipment and repair facilities on a standby basis, added to the railroads' financial problems. Their financial difficulties would even be worse if they attempted to maintain unproductive plant and equipment to meet emergency or unpredictable demand for coal, so their railroad cars, locomotives and personnel rosters were programmed for current traffic requirements. Adoption of the highly efficient trainload and unit train concept in response to competitive pressures meant that a large volume of coal could be loaded, transported and unloaded in a fraction of the time once considered acceptable. This contributed to the elimination of surplus equipment, facilities and personnel. The railroad industry's financial difficulties will continue to restrict its capability of handling large volumes of coal during emergencies. A number of proposals have been advanced to assist the railroads such as federal assistance in rehabilitating coal-handling facilities and acquiring rolling stock.

The reduction in rail coal traffic has not been confined to the eastern seaboard nor to tidewater shipments. Based upon information supplied to the National Coal Association by the railroads, conversions to fuel oil and natural gas between 1965 and 1972 in PAD District II displaced 17.4 million tons of coal--equivalent to 190 MBID and represented one-third of the coal traffic lost to competitive fuels east of the Mississippi River. Most of the coal displaced in PAD I and II was permanent--that is, consumers never intended to use coal again in the converted units.

Problems which adversely affected the coal industry--among others, air pollution and surface-mining legislation, interfuels competition and the absence of a national guideline policy on energy have also hurt the railroads.

Diversion of Coal Transportation Equipment

Most of the coal consumed by large industrial plants in metropolitan areas along the East Coast and inland waterways must be delivered by small colliers or barges. Whenever coal traffic deteriorates, the transfer facilities are either scrapped or put to other uses, and the colliers, tug boats and barges are disposed of in a similar manner. This happened along the East Coast because of the sharp decline in coal consumption and tidewater deliveries (Tables 26 and 27).

Railroad coal dumping installations in the New York Harbor area have shrunk from 11 to 1. A second facility still exists, but a major rebuilding program is needed to make it operational.

The situation with respect to unloading piers in Philadelphia, Baltimore and Hampton Roads is better, but problems related to deliverability beyond the coal piers are equally severe. The annual dumping capacity of the single operating pier in the New York area is about 4 million tons--enough coal for two large electric utility plants. Convertible capacity in the New York metropolitan area is two or three times that volume, but most of it must be delivered by barges which are not available. Several utilities commented on FPC Form 36 that coal barges and tug boats have been scrapped or diverted to other traffic. Consequently, immediate convertibility in the New York Harbor area is only about one-fourth of the potential.

Self-propelled, self-unloading colliers could be transferred from the Great Lakes to the Atlantic Seaboard in the winter as a means of increasing the capacity of waterborne coal deliveries. Most self-unloading lake vessels are owned by Canadian firms; however, four American companies operate self-unloaders. Several factors restrict the number of coal-carrying vessels that may be transferred to ocean service. One constraint is the maximum size vessel that can go through the Welland Canal--i.e., 730-foot length and 75-foot beam. A second problem is related to hull and keel design. Lake vessels generally have flat-bottomed hulls while ocean vessels have long, extended keels; consequently, the design of lake vessels may not permit them to be safely operated on the open sea, especially in rough water. Since dumping capacity is limited in the New York-New Jersey area, self-unloading vessels would be loaded at other ports and sail the open sea and be subjected to the vagaries of winter storms and rough water. A third limiting factor is that many lake vessels are steam-powered and use fresh water from the lake in their condensers. This means that only diesel-powered lake vessels can be used in ocean traffic since it is not practical for steam-powered vessels to carry their entire fresh water supplies. The overall dimensions of lake colliers may also preclude their use alongside plants because they are too large to be accommodated at some sites.

The basic overriding constraint in an analysis of convertibility is not the capability of furnaces to convert to coal but how much coal can be diverted to potentially convertible plants based on limiations imposed by coal mining capacity and coal transportation capacity. Although the several alternatives mentioned above will enable some plants to convert from fuel oil and natural gas to coal, it appears that the short-term convertibility is only a fraction of the total potential of 650 MB/D due to the limited capacities of coal production and transportation.

Additional Energy From Nuclear Power Plants

A 1,000-megawatt base-loaded power plant, either nuclear or fossil, consumes about 30 MB/D of oil equivalent; therefore, each thousand megawatts (MW) of nuclear capacity that can be put in service represents a net savings of 30 MB/D. As of November 5, 1973, six nuclear stations were compelled by the Atomic Energy

Commission to reduce their aggregate capacity by 391 MW--equivalent to 12 MB/D (see Table 31). All the deratings are for fuel densification and each plant has operated at the equivalent of full power. The derated capacity in PAD I is 327 MW which, under normal base-load operation, is equivalent to 10 MB/D. The remaining 2 MB/D is in PAD II.

Twelve nuclear units, with an aggregate capacity of 9,800 MW, have been scheduled for commercial operation between October 1, 1973 and July 1, 1974. These units operated on base load represent an energy supply equivalent to 300 MB/D. Three units with a total capacity of 2,800 MW (84 MB/D) are in PAD I. If these units come on-line as base-load capacity they will help offset some of the projected deficiency in energy supply during the current crisis.

The magnitude and seriousness of problems associated with slippages in scheduled operation of electric generating units is illustrated in an FPC study released in March 1973. The report shows that 30 nuclear units with an aggregate capacity of 27,389 MW were originally scheduled for service prior to the summer of 1973 but were not expected to be in service by that time. Some units are experiencing delays as long as 4 years. Based upon the aforementioned conversion factor (1,000 MW is equivalent to 30 MB/D under base-load operation), the nuclear delay of 27,389 MW equates to 822 MB/D. Most of the slippage, 453 MB/D, occurs in PAD District I. PAD V delays are 63 MB/D. The FPC survey also showed that 90 percent of nuclear capacity schedules to come on-line between 1972 and 1975 has already experienced delays and will not meet original completion dates. This compares with one-third of the fossil-fired steam plants that will miss their scheduled completion. Multiple reasons for delays are shown for most nuclear units, but 21 units were entirely or partially delayed due to regulatory problems. In five cases the delays were attributed entirely to regulatory difficulties.

The problem of nuclear slippages is compounded by the fact that utilities have had to build new fossil-fired plants (particularly peaking units that burn distillate oil or natural gas) and lncrease generation at old plants in order to compensate for the lag in nuclear plant completions. This has resulted in higher levels of natural gas and oil consumption, especially light distillates.

Direct Burning of Crude Oil

Crude oil can be burned as a boiler fuel much like heavy fuel oil, but certain modifications in storage and handling are required. Direct burning of crude may be considered feasible during the current emergency if motor gasoline is rationed so that crude oil runs can be reduced and some crude can be used as boiler fuel. This alternate is based upon the premise that output of fuel oils are restricted by maximum product yields; consequently, refineries cannot convert to fuel oil all the available crude oil that may be

TABLE 31

NUCLEAR PLANTS DERATED
(As of November 5, 1973)

Station	State	Rated Capacity, Megawatts	Derating	
			Percent	Megawatts
Nine Mile Point	New York	620	10	62
Oyster Creek	New Jersey	640	9	57
Turkey Point No. 3 & 4	Florida	1,450	7	100
Vermont Yankee	Vermont	540	20	108
Subtotal, PAD I		3,250	10	327
Dresden 2	Illinois	809	8	64
Subtotal, PAD II		809	8	64
Total United States		4,059	10	391

Source: Atomic Energy Commission.

diverted from gasoline production. Direct firing of crude oil, therefore, would overcome the constraints imposed by refining inflexibility to the extent that crude burning facilities exist or can be built.

Direct firing of imported crude oil totaled about 8.9 MMB (49 MB/D) during the first half of 1973. Most of it was consumed by electric utilities in PAD District 1--7.5 MMB, or 86 percent of the U.S. total. PAD District II accounted for 10 percent and PAD V for 4 percent.

A limited potential exists for increasing crude burning in the immediate future beyond present levels. Safety hazards associated with crude oil storage and handling are the principal obstacles. Construction of floating-roof steel tanks takes from 6 to 12 months, and special pumps are required for safety. Low-sulfur Libyan crude accounted for 24 MB/D, or one-half of the total consumed in direct burning during the first half of 1973. Denial of Libyan crude could be made up by substituting high-sulfur, non-Arab oil if it is available or by curtailing product yields, such as gasoline. Nearly all the Libyan crude was burned in PAD I; therefore, the full benefit of diverting non-Arab crude from refinery runs would be concentrated in this district because most of the crude burning facilities are in this district, and the East Coast will experience the most critical shortfall in imported energy supply during the current OAPEC embargo.

Other Supplements to Domestic Energy Supply

Several alternatives have been considered to supplement domestic energy supply. These include an embargo on coal exports, diversion of electric power from uranium enrichment plants and expansion of geothermal and hydroelectric generating capacity. The potential increase in energy supply associated with each alternative, however, is limited due to short- and long-range constraints; or, it creates long-range problems.

Embargo on Coal Exports

An oversimplified solution to fuel shortage in this country has been the proposal to embargo coal exports. Although some export coal can be directed to American consumers, this solution is fraught with numerous problems. Nearly all of the coal exported overseas and one-half of that sent to Canada is metallurgical grade. Furthermore, at least 40 percent of overseas exports and 10 percent of Canadian exports in 1972 were low-volatile coal, equivalent to about 200 MB/D. Low-volatile coal is a superior raw material used to make coke for iron and steel production, but very few industrial furnaces originally designed to burn low-volatile coal are presently in existence. Low-volatile coal is more expensive to mine; therefore, it is higher priced. Generally, this type of coal is clean burning and has a high heat content. However, in steam boilers, problems are experienced with initial ignition and

maintenance of combustion. These characteristics create hazards unless compensated for in furnace design or by using oil or gas for initial ignition and during regular operation. Consumption of these auxiliary fuels is equivalent to as much as 15 percent of the coal burned in a furnace using low-volatile coal.

Other technical constraints may preclude burning high-volatile, low-sulfur, metallurgical coal in cyclone or wet-bottom boilers. Furthermore, most boilers along the eastern seaboard cannot use high-volatile, low-sulfur coal because they would violate regulations that restrict the emission of particulate matter because the efficiency of electrostatic precipitators declines as the sulfur content of coal drops. Consequently, precipitator capacity would have to be increased by as much as 300 percent in these plants if they use low-sulfur coal.

An export embargo on high-volatile coal shipped to Canada has obvious political implications because Canada exports oil, natural gas and electric energy to the United States. Furthermore, the largest importer of American coal--Ontario Hydro-Electric Commission--is interconnected with utilities in New York and Michigan. Consequently, any curtailment in coal exports from the United States would have an adverse impact on Canadian electric power exports to PAD Districts I and II. In 1972, American imports of electric energy were equivalent to about 40 MB/D.

Besides the economic and political benefits of continuing American coal exports abroad and to Canada, specific technical and economic constraints preclude the imposition of an embargo on all coal exports because these restrictions will not automatically result in a net expansion of domestic energy supply equivalent to 450 MB/D. Some foreign purchasers of American coal have furnished capital to coal producers in the United States. An embargo on coal exports means the long-term contracts with foreign buyers must be negated and substantial funds which were extended to the American coal industry by foreign consumers will have to be reimbursed. Overseas customers of American coal will turn to other suppliers during the curtailment, and this can result in a permanent loss of foreign markets for U.S. coal.

Diversion of Electric Power From Uranium Enrichment

The Atomic Energy Commission's three gaseous diffusion plants will operate at an average electric power input of 4,295 MW during the first 6 months of 1974. Based on the conversion factor, 1,000 MW is equivalent to about 30 MB/D; a complete diversion, which is not feasible, would amount to about 130 MB/D. Some of this electric power could be diverted to the East Coast if the gaseous diffusion plants are "throttled back" and wheeling capacity is available. The minimum power required for the lower operating mode is between 1,500 and 2,000 MW. The load can be reduced by 30 MW per hour. AEC diverted 500 MW from its gaseous diffusion plants in 1971 in order to help meet an emergency summer peaking

requirement in New York. Potentially, 1,500 to 2,500 MW could be made available to areas where oil and gas supplies were critically short. The lower range appears more likely because of transmission line and wheeling limitations. Most of the electric energy used in the gaseous diffusion plants in eastern United States is generated by coal-fired units.

The penalty for diverting power from uranium enrichment for 180 days would result in a cumulative reduction of about 4,000 tons of separative capacity in the form of preproduced enriched uranium. The economic penalties associated with diverting power could approach the cost of the power itself.

Geothermal Power

Potential sites for geothermal power development are located in western United States and along the Gulf Coast. Natural subterranean stearn, however, cannot provide any significant additional energy prior to 1978. The only major geothermal facility in the United States is the Geysers plant in Northern California. Total installed capacity, as of early 1973, is 300 MW (9 MB/D), representing 1 percent of California's total electric generating capacity.

Pacific Gas and Electric, operator of the Geysers plant, has programmed four additional units at this site with an aggregate capacity of 300 MW. The last of these units is scheduled for completion in 1975 when generation of geothermal electricity in the United States will be equivalent to about 18 MB/D. Time required for development of other geothermal plants in the United States precludes any significant additional capacity prior to 1978.

Hydroelectric Power

An additional emergency supply of electric energy from hydroelectric plants is limited by water storage in reservoirs that supply existing facilities and completion of units already under construction. A rapid draw-down from storage reservoirs releases water that ultimately would have been used to produce power so that when hydroelectric energy is generated sooner than originally planned, the equivalent energy must be made up by fossil-fired or nuclear stations, if at all. Currently, the Pacific Northwest is experiencing a power shortage because water storage levels are at critically low levels due to abnormally low precipitation over the past year, and the region does not have enough standby or alternate sources of electric energy to make up for the shortfall in hydroelectric energy. A similar situation could develop in other areas of this country if hydroelectric generation is accelerated, but fossil fuels are not available to permit fossil-fired plants to make up the deficit in the future.

The Edison Electric Institute estimates that about 1,800 MW of new hydroelectric capacity will be completed in 1973 and 1974. This additional capacity is equivalent to 26 MB/D. The oil equivalent is less than the same capacity installed in fossil and nuclear plants because hydroelectric units coming on-line in 1973 and 1974 will operate at a lower rate (plant factor) than steam-electric plants due to available water supply.

Additional Alternatives

Several other alternatives can supply a limited quantity of emergency energy but these are difficult to quantify because they are dependent on myriad local or regional conditions. Excess electric energy, for example, can be transmitted to coastal areas from inland stations hundreds of miles away after local requirements are met. Oil-fired plants along the East Coast can be operated during peak periods and coal-fired plants base-loaded.

When a nuclear plant is scheduled for refueling, it can be operated through a coast-down period for approximately 4 additional months at progressively reduced power levels. The nuclear plant operator must decide whether to refuel as scheduled and accept an outage of 3 to 5 weeks or to coast-down from 100 percent to 40 percent and then refuel at the end of the 4-month period. Utilities typically schedule refueling during the spring and autumn off-peak periods so that the 4-month coast-down could result in an outage for refueling during a peak period. If the oil import crisis continues after the coast-down period, this option may worsen the energy shortage because over a period of time it actually decreases total energy availability.

Chapter Six

ENERGY USE CURTAILMENT

INTRODUCTION

Table 32 summarizes the net shortages resulting from a 3 MMB/D loss of petroleum imports consisting of 1.8 MMB/D of crude and 1.2 MMB/D of products.

TABLE 32

NET SHORTAGE CALCULATIONS
(ME/D)

	Gasoline & Naphtha	Total Middle Distillates	Heavy Fuel Oil & Other
Crude Loss - 1.8 MMB/D			
Total Naphtha - 47%	846		
Total Middle Distillate - 35%		630	
Heavy Fuel Oil & Other - 22%			396
Product Loss - 1.2 MMB/D	80	370	750
Total Loss	926	1,000	1,146
Offsetting Measures*			
Additional Domestic Oil Production (292 MB/D)	(138)	(102)	(64)
Oil to Gas Conversion		(75)	(75)
Oil to Coal Conversion in Electric Utility Sectort			(250)
Gasoline Deconversion to Distillate‡	100	(100)	
Refinery Fuel &Process Gain	28	18	(98)
Net Shortage	916	741	659
Percent Demand	13.5%	13%	16.8%

* These offsetting measures require government actions to be fully effective.

t Attainment of these savings would require relaxation of sulfur in fuel standards.

‡ The figures shown are somewhat arbitrary--additional deconversion capacity probably exists at the lower crude runs if further use of this option is deemed desirable/acceptable.

The loss of crude and product imports results in total product shortages of 926 MB/D motor gasoline, 1,000 MB/D total middle distillates and 1,146 MB/D of heavy fuel oil and other products. After fully utilizing available emergency measures, such as additional oil production (292 ME/D) and maximum conversion of electric utilities from oil to coal (250 MB/D), increased operation of nuclear plants and adjustment of refinery yields substantial shortages remain. These shortages are 916 MB/D of Mogas (13.5 percent of demand), 741 MB/D of middle distillates (13 percent of demand) and 659 MB/D of heavy fuel oil (16.8 percent of demand).

Two options exist for dealing with these substantial net shortages. The most straightforward approach is to immediately initiate a mandatory rationing program for motor gasoline designed to reduce demand by about 13.5 percent, to utilize the existing mandatory allocation program for distillates by setting allocation factors of about 87 percent of demand (which is a step proposed in the President's recent energy message) and to extend the mandatory allocation program (with some modifications) to heavy fuel oil.

An alternative approach is to strive for comparable reductions by means of a combination of voluntary conservation steps (such as reduced heating and lighting) and mandatory steps (such as reduced speed limits).

To analyze the merits and effectiveness of the various rationing and curtailment procedures, it is first necessary to develop a philosophy or priority for demand reductions. For the purposes of this report, the following broad use categories were considered in the following order of priority: (1) uses related to protection of the public health and welfare and National defense, (2) uses related to the maintenance of employment, and a healthy domestic economy and (3) uses related to public comfort and convenience.

Obviously, services related to public health and welfare--such as police and fire protection--must be maintained. This area would also include maintaining a minimum acceptable level of home heating. Uses related to the maintenance of jobs and economic activity consist primarily of industrial activity. Business and industry must be encouraged by every available means to use energy more efficiently. *However, it was considered imperative by this Committee that the basic industrial activities which provide the bulk of U.S. employment and economic strength be maintained at the highest possible level.*

Rationing and conservation steps proposed in this report are aimed primarily at increasing the efficiency of energy use, by both industry and the public, and at reducing "non-essential" energy demand which, to a large extent, consists of energy utilized by the public for comfort and convenience. Much of the impact of these reductions falls in the area of motor gasoline and other transportation fuels.

The most preferable methods of reducing energy consumption to meet the anticipated shortages are--first, improved energy use efficiency and second, elimination of non-essential demand. However, as the analyses discussed in this chapter will show, these measures alone do not provide sufficient amount of relief quickly enough to meet the current emergency. Therefore, it is recommended that mandatory rationing of motor gasoline and mandatory allocations of distillates and HFObe initiated as rapidly as possible. However, 30 to 60 days are likely to be required for these programs to take effect. Thus, all other available voluntary and mandated conservation measures should also be instituted simultaneously in order to achieve maximum energy savings as rapidly as possible.

The following sections of this chapter discuss in more detail the situation with respect to motor gasoline, distillates and heavy fuel oil. They address the consumption patterns for each fuel, the considerations pertaining to establishing rationing or allocation programs and available conservation measures.

ALTERNATIVES FOR OFFSETTING NET LOSS

Gasoline

Pre-denial first and second quarter 1974 gasoline demand (includes motor and aviation gasolines, and naphtha jet fuel) are projected to be about 6.9 and 7.6 MMB/D, respectively. The bulk of this demand--some 6.6 to 7.3 MMB/D or 96 percent--is motor gasoline. About 0.2 MMB/D(3 percent) is naphtha jet fuel and the remaining 0.05 MMB/D or 0.7 percent aviation gasoline.

TABLE 33

GASOLINE/NAPHTHA COMPONENTS

	First Quarter 1974		Second Quarter 1974	
	MMB!D	Percent	MMB!D	Percent
Motor Gasoline	6.606	96.3	7.334	96.3
Naphtha Jet Fuel	0.208	3.0	0.224	3.0
Aviation Gasoline	0.050	0.7	0.053	0.7
	6.864	100.0	7.611	100.0

Of the total motor gasoline sold approximately 80 percent is used in passenger cars--the remainder is consumed by trucks and buses.

Regarding the pattern of passenger car use, it is estimated that over half of the auto trips are less than 5 miles and nearly three quarters are under 10 miles. Less than 1 percent of auto trips exceed 100 miles one way; however, these trips account for 17 percent of the total auto miles traveled. As can be seen on Table 34, 42 percent of the vehicle miles traveled are attributed to earning a living and 33 percent to "social and recreational" or "discretionary" use.

TABLE 34

PASSENGER CAR USE*
(Percent)

	Trips	Miles	Average Occupants Per Car
Earning a Living	36.7	42.1	1.4
Family Business	31.4	19.6	2.0
Education/Civic/Religious	9.4	5.0	2.5
Social and Recreational	22.5	33.3	2.5
All Purposes	100.0	100.0	1.9

* *1972 Automobile Facts and Figures*

The denial or loss of gasoline is calculated to be 916 MB/D in the first quarter 1974 and will probably worsen as the summer period approaches. To put the 916 MB/D figure into perspective, this denial is equivalent to 13.5 percent of the gasoline/naphtha demand which is the sum of the motor and aviation gasoline and naphtha jet fuel demands.

Since motor gasoline accounts for about 96 percent of total gasoline demand, efforts to significantly reduce demand should be aimed at this product. In addition, since 80 percent of the motor gasoline sold is consumed by passenger cars, the largest potential for curtailment appears in this sector. Absorbing the entire 916 MB/D shortage by reducing passenger car demand would mean a 17.3 percent reduction. To place this in perspective with experience during World War II, the following table illustrates that the relative degree or severity of rationing would still be less than World

War II, both with regard to overall percent curtailment, 17.3 percent *vs.* 30 percent, and the percent of non-essential use eliminated, 52 percent *vs.* 67 percent.

TABLE 35

COMPARISON WITH WORLD WAR II EXPERIENCE*

	First Quarter 1974	World War II
Total Motor Gasoline Demand, MB/D	6.6	1.5 - 2.0
Passenger Car Demand, MB/D	5.3	
Non-Essential Passenger Car Demand--Social/Recreational Use, Percent	33.0	45.0[t]
Reduction Necessary/Attained, Percent	17.3	30.0
Percent of Non-Essential Demand Which Must Be/Was Utilized, Percent	52.0	67.0

* See also Gulick, Frances A. "U.S. Experience with Voluntary and Mandatory Rationing of Gasoline and Fuel Oil During World War II." Library of Congress: Congressional Service-Environmental Policy Division, Dec. 5, 1973 (prepared for Senator Edmund S. Muskie, Chairman of the Subcommittee on Intergovernmental Relations of the Committee on Government Operations).

t See Mansfield, *A Short History of OPA*, Office of Temporary Controls, Office of Price Administration, 1948.

Stated another way, curtailing at a 916 MB/D rate would be rationing at approximately 17/30 or 57 percent of the World War II rate.

It is unlikely that voluntary and mandated conversion efforts discussed previously can reduce demand by the necessary amounts. An optimistic assessment of these procedures would suggest that they would yield only about 600 MB/D reduction in the aggregate. Since this 600 MB/D reduction is equivalent to only 2/3 of the reduction needed, it is concluded that a formal rationing system should be implemented as soon as possible--hopefully within the next 6 to 8 weeks.

Temporary restrictive measures which can be implemented immediately should be taken to dampen demand prior to the time formal controls can be effective. Examples of this type of measure include instructing suppliers to reduce motor gasoline allocations to all stations they supply by a certain percentage of a recent prior period sales level. This type of allocation was utilized during the early stages of World War II and, while it exhibited many problems, it did reduce consumption and it can be implemented quickly.

Many of the gasoline suppliers already have their own allocation systems in place and can effect across the board reductions quickly.

The fundamental principle of a coupon rationing system should be to maintain equity between all users while at the same time provide sufficient fuel for critical military, public service and industrial uses. This requires a definition of priority users (for example police and fire departments, mass transit systems, and certain critical military and industrial users). These users must be provided sufficient fuel to maintain a minimum acceptable level of services. The remaining motor fuel can be prorated among other users (primarily private autos) by issuing a coupon book for each automobile owned currently.

Another important principle of a coupon rationing system should be to provide the individual maximum freedom of choice in the use of his available gasoline. This can be aided by permitting individuals to buy and sell ration coupons in a free market. Thus, if an individual chooses or can arrange to consume substantially less fuel than his minimum allotment, he can legally and profitably transfer part of his fuel to another individual who is then able to exceed his minimum allotment, but at a cost which should fluctuate in proportion to the total gasoline supply.

In terms of severity, the gasoline rationing recommended represents 57 percent of the level in effect during World War II. Even though the general public of the 1940's was vitally aware of the factors which required rationing, there was a high level of resentment and violation. The current emergency is much less visable and less personal to the public. Therefore, in spite of the fact that the degree of rationing is not as high as during World War II it is probable that the resentment may well be greater. For this reason, it becomes imperative to provide steps which the motorist can take to minimize the inconveniences brought about by a rationing program. By employing these curtailment and conservation steps, the public can compensate for a large part of the 13 percent reduction without experiencing a serious impact on personal comfort or liberty. It should be noted that rationing per se does not dictate the use of coupons. The final decision as to the use of the gasoline available rests with the motorist. The steps which follow provide means through which the public may optimize the gas available.

OTHER CURTAILMENT AND CONSERVATION MEASURES

Mandated measures can be implemented quickly and should be aggressively promoted to not only reduce demand prior to controls, but also to *force* more efficient usage after controls are established. In addition, the savings which could be achieved through the compliance levels indicated have been shown to estimate the overall effect on solving the gasoline shortage anticipated.

Reduce Speed to 50 MPH

Significant savings in gasoline can be obtained by reducing the driving speed to 50 MPH. Of the total vehicles that travel on main rural roads, where 40 percent of all travel is done, 70 percent drive at speeds exceeding 50 MPH. It has been estimated that a reduction in driving speed from 70 MPH to 50 MPH reduces gasoline consumption by 14 percent. The corresponding reduction from 60 MPH to 50 MPH is 7 percent. Applying these savings to the proportions of vehicles that exceed 50 MPH results in an average reduction of 6.3 percent on the main rural roads. On the local rural highway system, the average speed is somewhat lower, and 50 MPH driving could only generate savings of about 3.8 percent. Using a weighted average of 3.5 percent for the total highway system and assuming a compliance level of 75 percent, gasoline consumption could be reduced by 190 MB/D.

Increased Participation ln Car Pools

Work-related travel represents 34 percent of all automotive travel. Most of this travel (70 percent) does not involve car pooling. It is estimated that one-quarter of those people who drive along would be unable to join car pools. The remaining three-quarters now traveling alone could drive with others if full public compliance is assumed. The maximum reduction in miles traveled resulting from the increase in car pools is equivalent to a savings of 11 percent of total gasoline demand by cars. And since cars consume about 80 percent of total motor gasoline, this 11 percent savings is equivalent to a total savings of 9 percent. If only half of the drivers who are able to join car pools did so, a reduction of 316 MB/D would be realized.

Reduced Recreational Driving

Data available from 1972 *Automobile Facts and Figures,* as published by the Motor Vehicle Manufacturers Association of the United States Inc., indicates that one-third of passenger car travel is for social and recreational purposes. Since 80 percent of the total Mogas demand is used by passenger cars, 27 percent or 1,790 MB/D of all the Mogas is used for private, social and recreational travel.

Approximately half of this travel is concentrated in the summer vacation months and should not be totally curtailed due to the economic impact on resort areas. Similar consideration should be given to the economy of local areas totally or primarily dependent on winter recreational activities. However, the balance involves a high percentage of weekend trips which could be eliminated with a minimum effect on the national economy as a whole.

Due to the seasonality of recreational driving, savings during the first quarter of 1974 (winter) would be less than those which could be effected in the summer months. With 50 percent cooperation on the part of the public, gasoline usage during the first 3 months of 1974 would be approximately 108 ME/D.

Miscellaneous Conservation of Gasoline

Without attempting to quantify the savings that could be achieved, several options do exist for individuals to improve the operating efficiency of their automobiles. These options include regular tune-ups, limited use of air conditioners, full inflation of tires and improved driving practices.

Middle Distillates

The broad category of middle distillates includes kerosine jet fuel, diesel, heating oil, kerosine and distillate fuels consumed by residential, commercial and industrial users. An estimate of the supply/demand balance for the first quarter 1974 is shown below:

Total Middle Distillates

Demand	MB/D
Kerosine Jet Fuel	885
Kerosine	333
Distillate	4,428
Total	5,646
Estimated Supply	4,905
Shortage	741

Approximately 80 percent of the shortage indicated above can be eliminated through a series of curtailment steps which are listed below. However, there still remains a net shortage of about 140

MB/D which can only be overcome through some form of mandatory control. An effective and reasonably equitable control mechanism already exists in the form of the Mandatory Allocation Program which became effective November 1, 1973. With a minimum of time, this mechanism could be adjusted to establish allocation levels to a point where supply and demand balance.

In conjunction with the allocation program, curtailment steps should be put into effect to selectively reduce distillate demand. These steps, which are listed below, were developed with the intent to distribute the curtailment as equitably as possible and at the same time have a minimum impact on the economy.

Distillate Curtailment Steps	Time Required to Reach Probable Savings	Probable Savings (MB/D) Winter	Summer
1. Reduce speed limits to SO MPH.	3 weeks	19	19
2. Reduce residential and commercial lighting.	4-8 weeks	60	60
3. Increase commercial airline load factors to 65 percent	2 weeks	207	207
4. Reduce commercial airline speeds.	3 weeks	SO	SO
5. Reduce space heating thermostat setting *SOp.*	1 month	265	100
Total Curtailment		601	436

HEAVY PUEL OIL

Heavy fuel oil is primarily utilized by industry and large institutions as boiler fuel and by electric utilities for electrical power generation. About 75 percent of the total residual oil used in the United States is consumed in PAD I. Therefore, the most fruitful areas for curtailing consumption are in these end uses particularly in PAD I. Total pre-denial demand for heavy fuel oil was forecast to be 3.9 MMB/D in the first quarter of 1974 and slightly less in the second quarter. It is of interest and concern that of these demands approximately 65 percent or 2.5 MMB/D is normally supplied by offshore imports--mostly from the Carribbean.

The total denial or loss of 1,146 MB/D can be offset by additional domestic gas, crude production and utility coal conversions. This reduces the *net* shortage to 659 MB/D which represents

about 17 percent of total U.S. demand; but since the bulk of the HFO is normally imported into and consumed in PAD I, the effect in this geographical area will be significantly greater than 17 percent.

Heavy Fuel Oil Curtailment

The shortage in heavy fuel oil can be partially eliminated by effecting a reduction in space heating of 5°F. throughout the country. It has been estimated that for each degree reduction in heating, a reduction of 16 MB/D of heavy fuel and 50 MB/D oil equivalent of gas is achieved. Therefore, a 5°F. reduction will generate a 330 MB/D savings. It is assumed that flexibility in the Industrial/Utility/Refining sectors is sufficient to allow the savings in gas to appear as heavy fuel oil.

The savings through reduced lighting noted in the section on distillates would also generate a 35 MB/D savings in fuel oil.

The net result, after considering all of the items noted above is that only 55 percent of the 659 MB/D of heavy fuel oil denial can be accounted for and supply falls short of demand by some 294 MB/D in the first quarter of 1974. To completely close this gap and to assure compliance with the reductions to be obtained in space heating and lighting, some form of mandatory control is necessary.

Mandatory Control

It is recognized that an impartial "across the board" allocation procedure similar to the recently imposed Mandatory Allocation Program for Distillates which is based on sales during a prior period would possibly be more severe on those Industries/Utilities which have grown rapidly in recent months or have initiated expansion projects. Nonetheless, an allocation program for heavy fuels similar to that for distillates represents a starting point and a procedure for initiating immediate action and has the advantage of being an extension of a program which already exists. However, as mentioned previously, it should also be modified to incorporate a philosophy or priority for demand reduction.

A further benefit of extending the distillate program to cover heavy fuels is that an appeal mechanism would be immediately provided for the handling of "hardship cases."

Chapter Seven

LEGAL AUTHORITY, CURRENT ACTIONS AND EXISTING PLANS

SUMMARY

The President appears to have adequate authority under the Economic Stabilization Act Amendments of 1973 to redirect available petroleum supplies in the Nation's priority interests, including consumer rationing. This authority does not cover other mandatory use curtailment. Mandatory allocation regulations for propane and middle distillates have been promulgated by the Energy Policy Office under this Act. Authority to implement the allocation program was delegated to the Secretary of the Interior who redelegated to the Administrator, Office of Petroleum Allocation.

Federal authority is available under the Defense Production Act of 1950 Voluntary Agreement Provisions for the President to consult with representatives of industry and other groups to encourage the development of voluntary agreements and programs to further the objectives of the Act. The Secretary of the Interior has under this Act recently activated the Foreign Petroleum Supply Committee and the Emergency Petroleum Supply Committee. The Voluntary Agreement authorizing the plans under which these Committees function applies only to emergencies in which deprivation of petroleum supply occurs in friendly foreign nations. A new and different Voluntary Agreement would be necessary for an industry advisory group to address domestic supply problems.

Also under authority of the Defense Production Act of 1950 and other statutes, the Emergency Petroleum and Gas Administration can be activated by the Secretary of the Interior to coordinate and direct the operation of the petroleum industry in mobilizing the oil and gas resources of the United States. Except in the case of an attack upon the United States when activation would be automatic, the Secretary cannot mobilize the EPGA until a National Defense Emergency is declared by the President or Congress.

Except for oil reserves under public lands and the Outer Continental Shelf controlled by the Federal Government, all oil and gas production in the United States is under statutory authority of the respective states. Production from Naval Petroleum Reserves is restricted by law to those situations when it is needed in the national defense and is approved by the President and a joint resolution of the Congress.

Statutes of oil-producing states forbid the production of any oil or gas field in an inefficient manner or in a way that would reduce ultimate recovery. Therefore, state regulatory agencies cannot legally allow production rates above currently established maximum efficient rates (MER's) unless there is technical evidence to show that the field MER's on a field-by-field basis can be increased in the short-term without affecting ultimate recovery.

THE ECONOMIC STABILIZATION ACT AMENDMENTS OF 1973

The Economic Stabilization Act was amended April 30, 1973, and provides in part in Section 203(a):

> ..., and that in order to maintain and promote competition in the petroleum industry and assure sufficient supplies of petroleum products to meet the essential needs of various sections of the Nation, it is necessary to provide for the rational and equitable distribution of those products.

A new Section 203(a)(3) provides that the President is authorized to issue orders and regulations and:

> ...make appropriate for the establishment of priorities of use and for systematic allocation of supplies of petroleum products, including crude oil in order to meet the essential needs of various sections of the Nation and to prevent anticompetitive effects resulting from the shortages of such products.

Under authority of this Act, the Chairman of the Oil Policy Committee announced on May 10, 1973, a voluntary program for allocation of crude oil and refinery products backed up by (1) guidelines established by the Federal Government, (2) a mechanism for providing continuous scrutiny of compliance with guidelines and (3) the authority of imposition of mandatory allocation if necessary. Guidelines were issued by the Office of Oil and Gas on May 23, 1973.

Hearings, as required by the Act, concerning the operation of the voluntary program and the need for a mandatory program were held June 11-14, 1973.

The Energy Policy Office was established in the Executive Department by the President under the Act on July 23, 1973. The Director, Energy Policy Office, by notice published in the *Federal Register* on October 24, 1973, delegated authority to the Secretary of the Interior with respect to petroleum products under the Act. The Secretary, on November 6, 1973, redelegated this authority to "make the determinations and take the actions required as permitted under the Act" to the Administrator of the newly established Office of Petroleum Allocation.

The Energy Policy Office published on August 13, 1973, for comments, proposed *Mandatory Fuel Allocation Program, EPO Regulation* 1. Implementation of the Program is assigned to the Department of the Interior. There were no plans published for implementation. The program would provide that major refiners (175 MB/D capacity), if operating at greater than 90-percent capacity must, on request, sell part of their domestic crude supply to operate at 90-percent capacity. Imported crude under the proposed regulation would not be subject to allocation, but the refiner's

domestic supply would be computed as the same fraction of his total supply as was his 1972 supply. Also, *new oil* as defined by Phase IV regulations of the Cost of Living Council, published August 17, 1973, would not be subject to allocation. *New oil* is that volume produced and sold from a property in excess of the volume produced and sold from that property during the base period in 1972.

The proposed mandatory regulations also provided for allocations of petroleum products and liquefied petroleum gas. The stated intent was to distribute to wholesalers equitably and establish a state reserve.

No regulations have been proposed to provide for end use or consumer rationing of fuel. However, the wording of Section 203 (a)(3) of the Economic Stabilization Act Amendments of 1973--"establishment of priorities of use and for systematic allocation of supplies of petroleum products ... ,"--appears broad enough to authorize a consumer rationing program.

EPa Regulation 3, Mandatory Allocation Program for Propane

On September 5, 1973, the Energy Policy Office announced a proposed mandatory allocation program for propane and on September 7, 1973, held a hearing on proposed regulation. This hearing was followed by EPa Regulation 3, Mandatory Allocation Program for Propane, effective on October 3, 1973. Propane is defined as including propane-butane mixes supplied to end users and excludes raw mixed streams of natural gas liquids.

Priority customers are defined as end-use customers to the extent they use propane for any of the following purposes and where no feasible alternate fuel is available:

- Residential use
- Agriculture production
- Food processing
- Mass transit vehicles
- Buildings primarily utilized for housing medical and nursing patients
- Industrial vehicles or equipment used primarily in enclosed facilities where alternative vehicles or equipment cannot be utilized because of gaseous emissions
- Essential government services such as fire and police use
- Oil and gas well drilling and field production operations, and fuel for pipelines and other transportation for delivering propane to markets

- Commercial requirements with total annual consumption not to exceed 15,000 gallons per year per location

- Peak shaving to supplement normal supplies of pipeline gas for distribution by gas utilities during periods of high demands, limited to volumes of propane equivalent to those amounts contracted for or purchased for delivery during the September 1, 1972, to April 30, 1973, heating season. No priority use of propane for peak shaving will be granted as long as a public utility continues gas service to interruptible industrial customers who can use alternate fuels other than natural gas.

The Regulation requires that suppliers who produce or otherwise supply propane to other suppliers must sell to those suppliers the same proportion of this total propane available for sale, transfer or use, after deduction for sales for current priority customers, as they sold in the period October 2, 1972-April 30, 1973.

Operators of propane storage facilities with capacity of 500,000 gallons or more who store for others are prohibited from delivering from storage to non-priority consumers volumes greater than deliveries to those consumers during the base period month. Monthly reports to Department of the Interior are required of volume in storage and ownership.

The propane mandatory allocation program was designed to be self-administering. Customers and resellers certify monthly their priority needs to their suppliers. Suppliers certify monthly to their customers as to their allocations and forward an updated allocated fraction monthly to the Department of the Interior. Regular monthly reporting is required on custom storage of more than 500,000 gallons. Records must be kept of all propane transactions by suppliers, resellers, users and storage facility operators.

EPO Regulation 1, Mandatory Allocation Program for Middle Distillate Fuels

Energy Policy Office Regulation 1, for a Mandatory Fuel Allocation Program, published as a proposed regulation on August 13, 1973, was promulgated for Middle Distillate Fuels only on October 16, 1973. It went into effect November 1, 1973, and will continue until cancelled by the Energy Policy Office. Middle Distillate Fuels are defined as "any derivative of petroleum, such as kerosene, jet fuel, home heating oil, range oil, stove oil, diesel fuel, and gas oil, which have a 50 percent boiling point in the ASTM D86 standard distillation test falling between 350°F and 700°F."

The intent of the program is to distribute middle distillate fuel products among wholesale purchasers equitably and to provide for a state reserve for alleviating end-user hardships. The program is administered by the Department of the Interior, Office of Petroleum Allocation. The regulation provided no priority schedule as almost all end uses would be considered essential.

The program covers all states, the District of Columbia, U.S. territories and possessions. Suppliers will operate separate programs for PAD Districts I-IV and for District V. The program applies to any person, firm or corporation either supplying or purchasing middle distillates in bulk at wholesale level.

Wholesale distributors will be allocated the same quantities of middle distillates each month as purchased in the corresponding month of 1972. If these quantities are not available, wholesale distributors will be allocated a proportional share of the suppliers supplies. If a wholesale purchaser was not in business during the base month of 1972 or has had a substantial increase in fuel requirements, he may petition the Department of the Interior to be assigned a supplier. Any customer assigned must be accepted by the supplier for the duration of the program.

Any wholesale purchaser may apply to the designated state office to obtain supplies to alleviate exceptional hardships by any end-users. No more than 10 percent of a wholesale purchaser's supply may be reallocated on the basis of the state's recommendation. A Federal Government representative within the state will consider such recommendations and authorize reallocations as he considers necessary and appropriate. Action recommended by the state may not in any way interfere with interstate commerce in middle distillate fuels or discriminate against non-residents.

In order to meet imbalances in supply that may arise from unusual conditions, the Department of the Interior may order the transfer of middle distillates from one region to another within the limits of existing transportation facilities and may allocate among suppliers when such could help relieve imbalances.

Each supplier is required to notify his wholesale purchasers of their period supply volumes for each product for each month. Suppliers must file monthly and yearly reports with the Department of the Interior unless this requirement is modified by order. Monthly estimates of supplies of each middle distillate product he expects to have available within a state must be furnished to the designated state official by the supplier.

The Voluntary Agreement Relating to Foreign Petroleum Supply

The Defense Production Act of 1950 contained specific titles authorizing priorities and allocations, requisitioning and condemnation, expansion of productive capacity and supply, stabilization of wages and prices, settlement of labor disputes and control

of real estate credit. Its title on general provisions included a section on voluntary agreements--Section 708. This Section authorized the President to consult with representatives of industry and other groups with a view to encouraging such persons to develop voluntary agreements and programs to further the objectives of the Act. Such agreements and programs were required to be approved by the President. The Act exempted certain actions taken pursuant to an authorized voluntary agreement or program from the antitrust laws or the Federal Trade Commission Act of the United States.

As early as June 25, 1951, the first proposed "Voluntary Agreement Relating to Foreign Petroleum Supply" was approved by the Director of the Office of Defense Mobilization and the Attorney General, and 19 oil companies agreed to participate in the agreement. That Voluntary Agreement established the procedure under which participating companies could take cooperative action to prevent, eliminate or alleviate shortages of petroleum supplies in friendly foreign nations which threaten the defense interests or programs of the United States. The fundamental procedure prescribed in the Voluntary Agreement revolved around the recommendation of an emergency plan of action. The Agreement also established the Foreign Petroleum Supply Committee to assist in carrying out the objectives of the Agreement.

The amendment to the Voluntary Agreement of October 24, 1961, authorized the establishment of the Petroleum Security Subcommittee to meet the continuing need of U.S. defense agencies for information on petroleum supply and requirement potentials of specific national security programs of the United States and for technical assistance to such agencies in evaluating petroleum resources available to support such plans and programs in possible future emergencies. The Subcommittee was divided into six functional working groups for Program, Production, Refining, Supply and Transportation, Materials and Manpower.

A plan of action developed under the Voluntary Agreement and the Foreign Petroleum Supply Committee in 1967 is still in existence on a standby basis and could presumably be utilized in an emergency such as that treated in this report. The plan authorized the participating companies to take the following actions:

- To arrange between and among themselves, or with such other persons and agencies designated by the government for the most efficient use, without regard to ownership, of terminal and storage facilities and tankers, pipeline capabilities and other transportation facilities so as to minimize duplication, multiple loadings and discharging, split cargoes, long hauling, cross hauling, back hauling and idle time in port.

- To make arrangements among the participants for the purchase, loan, sale or exchange for distribution in, to or from foreign countries or areas of crude oil, petroleum products and blending agents by and among themselves or other designated persons or agencies

- To make alterations in the rate of production of crude oil and the manufacture of refined petroleum products as may be appropriate for the purpose of alleviating the emergency

- To take actions within the Continental United States which will result in making petroleum available to foreign areas affected by the emergency.

These actions must be set out in "schedules" which must be issued by the Administrator and copies of which must be furnished to the Attorney General, the Chairman of the Federal Trade Commission and the General Services Administration at least 48 hours prior to issuance. The Attorney General has 48 hours to disapprove any such schedule.

The objective of the Voluntary Agreement is to assure continuity of foreign oil supplies deemed essential to U.S. national security programs. It derives from the fact that well over half the petroleum used by U.S. armed forces abroad comes from foreign sources and that our NATO allies in Europe depend almost entirely upon foreign sources for their oil supply.

Beginning in 1951 with the petroleum crisis in Iran, the Secretary of the Interior has utilized the Voluntary Agreement several times to ensure continuity of foreign oil supply considered vital to the U.S. national security.

The emergency provisions of the Voluntary Agreement have been used in three serious petroleum crises. On three separate occasions (1951, 1956 and 1967), serious interruptions to oil supplies have occurred as the result of political or military disturbances in one or more of the principal oil-exporting nations of the world.

A plan of action under the Voluntary Agreement was first approved on July 26, 1951, and was used extensively during the Korean conflict until its termination on July 8, 1952. The Foreign Petroleum Supply Committee and its subcommittees continued to gather information and prepare estimates until the Voluntary Agreement was terminated on April 30, 1953. A revised Voluntary Agreement was approved on May 1, 1953, and the Foreign Petroleum Supply Committee was reestablished. Amendments to the Agreement were made in 1954 following termination of the Petroleum Administration for Defense, and again in 1956 after the Defense Production Act was amended in 1955.

An ad hoc Middle East Emergency Committee was established under the Voluntary Agreement in 1956 at the time of threatened closure of the Suez Canal. A plan of action was developed and approved and was in operation through June 1957.

In June of 1967, at the time of the Arab-Israeli confrontation, it was determined that an emergency existed. The Foreign Petroleum Supply Committee was convened and subcommittees established. A plan of action was developed and "schedules" approved for the fourth quarter of 1967 and first quarter of 1968. The plan of action

provided for the establishment of the Emergency Petroleum Supply Committee and two subcommittees. However, the supply situation was eased by individual company action and the "schedule" provisions of the 1967 plan were not utilized.

The Foreign Petroleum Supply Committee was called into closed session by the Secretary of the Interior on October 30, 1973, to address the present situation. The Emergency Petroleum Supply Committee was also activated by the Secretary on November 8, 1973.

The information-gathering and technical assistance provisions have been used continuously from the inception of the Voluntary Agreement program in 1951.

The major value of this Voluntary Agreement is that it provides a joint government/industry mechanism which is immediately available for dealing with serious disruptions to petroleum supply in situations short of a national emergency. If the Agreement were not in existence, many of the immediate actions necessary to restore petroleum supply from foreign sources would be difficult or impossible to take short of a declared national emergency, and a resultant crisis buildup of government bureaucracy despite the fact that disruption of petroleum supply to our allies and to our own armed forces abroad could lead to conditions of national emergency.

There is a question as to whether the Voluntary Agreement Relating to Foreign Petroleum Supply can be used to cope with an oil shortage just within the United States. The Department of Justice has pointed out that the Voluntary Agreement is very explicitly limited in scope, both by its terms and historical practices, to emergencies in which deprivation of petroleum supply occurs in friendly foreign nations--that is, outside the United States. For the President to utilize the Voluntary Agreement provisions of the Defense Production Act in order to consult with representatives of industry on domestic oil supply problems, an entirely new and separate voluntary agreement would have to be developed and approved.

The non-energy provisions of the Agreement permit a continued surveillance of the petroleum industry's capability to meet essential U.S. military requirements allover the world. This includes the conduct of periodic surveys of worldwide petroleum supply and demand potentials under various assumptions as to possible emergency conditions furnished by the Department of Defense and its U.S. military agencies.

THE EMERGENCY PETROLEUM AND GAS ADMINISTRATION

The President promulgated a National Plan for Emergency Preparedness in 1964 which recognizes that a future emergency might range in seriousness from international tension to limited conventional warfare or even to a nuclear attack. The principal statu-

tory authorities are the National Security Act of 1947, the Federal Civil Defense Act of 1950, the Defense Production Act of 1950, and the Strategic and Critical Materials Stockpiling Act.

The plan provides broad guidelines for actions by government from national to local community levels, by industry and private organizations and by individual citizens throughout the country. Sound emergency planning for the petroleum and gas industries could not be conceived and developed without constant awareness of and coordination with the industrial and military complex. The petroleum and gas industries are inextricably interrelated and interdependent with most other areas of the economy.

Chapter 10 of the National Plan for Emergency Preparedness, entitled "Fuel and Energy," deals with oil and gas, solid fuels and electric power. In oil and gas, the most important planning effort has gone into the establishment, staffing and training of the Emergency Petroleum and Gas Administration.

The Emergency Petroleum and Gas Administration (EPGA) is a standby organization designed to meet the need for an agency which is ready and authorized to coordinate and direct the operations of the petroleum industry in mobilizing the oil and gas resources of the United States in the event of a national emergency.

The facilities and operations of the petroleum and gas industries are far-flung and generally complex. They are tied together by an intricate series of gathering, processing, transportation and distribution systems. This operating structure inherently necessitates that, in time of national emergency, these industries be guided and directed on a unified basis by one federal organization thoroughly familiar with these industries and so specialized as to be able to deal with their internal problems in all branches of their operations.

This basic plan has been given recognition by the government with its establishment of the Emergency Petroleum and Gas Administration. The National Petroleum Council, which has worked closely with the government on emergency preparedness matters since its inception in 1946, continues to believe strongly that no organization other than one of this character, reporting directly to the Secretary of the Interior, could achieve its objectives.

Priorities and allocation authorities of the Defense Production Act of 1950 as amended are still available for defense needs. The current Defense Materials Systems (DMS) of the Department of Commerce is operated under this basic authority. DMS provides a system of priorities and allocations of basic materials for military and defense production. Similar authority for petroleum and gas has been delegated to the Secretary of the Interior.

Under limited war conditions or a declared national defense emergency, the President or the Congress might deem it necessary to invoke controls over production of essential materials, including petroleum, and other economic matters such as price and rent controls.

Depending upon the severity, EPGA may be partially or fully activated. Although present plans call for full activation of the EPGA by the Secretary of the Interior upon declaration of a National Defense Emergency by the President or Congress, it is also assumed that the Secretary will activate the EPGA in any limited war situation which requires the capability provided by the EPGA.

Under limited emergency conditions, the Federal Government will carryon such programs and invoke such emergency control measures as necessary to assure adequate supplies and the best use of petroleum and gas for military and civil defense purposes. State and local governments may be called upon to adapt their normal petroleum and gas regulations to fit the emergency conditions, to assist the Federal Government in administering a petroleum consumer rationing program, if such a program is needed, and to control the local distribution of natural gas and secondary inventories of petroleum products as requested by the Department of the Interior or the EPGA.

EPGA's primary function in an actual emergency is to assist, coordinate and direct, where necessary, activities of the oil and gas industry in order to assure that domestic and foreign supplies of oil and gas meet essential military and civilian requirements of the Nation and its allies. In discharging this broad function, the EPGA would have to perform, among others, the following activities:

- Formulate and coordinate oil and gas supply programs
- Act as claimant for the oil and gas industry before other government agencies to obtain supporting resources such as manpower, materials, transportation, communications and funds needed for vital programs
- Coordinate and direct the allocation and distribution of petroleum products from primary inventories to distributors, wholesalers, etc., and gas to local distribution systems
- Establish and maintain communications with the oil and gas industry and with government agencies, as necessary to perform the above functions.

By Executive Order 10480, and Defense Mobilization Order 8400.1, the Secretary of the Interior has the authority to impose priorities and allocations over petroleum and gas. This authority has been pre-delegated to EPGA for use when activated and might be utilized by EPGA officials in taking such actions as:

- Direction of petroleum and gas production and processing facilities to meet essential needs

- Allocation of petroleum products from primary inventories to marketing companies for retail sales, to military and Atomic Energy Commission installations, to ports for export and to industrial plants usually supplied by primary inventories

- Curtailment of gas deliveries to consumers in accordance with a Federal Gas Priority System developed by EPGA under the guidelines furnished by the Office of Defense Resources and approved by the EPGA National Administrator which specify the order of curtailment of gas supply to consumers in emergency situations.

The EPGA, on activation, would be an independent government agency headed by a National Administrator who will be the Secretary of the Interior. Other key positions will be filled primarily by personnel drawn from the petroleum and gas industry who will be immediately available and trained because they are members of the petroleum and gas unit of the National Defense Executive Reserve with specific responsibilities in the EPGA.

The EPGA cannot be activated by the Secretary of the Interior unless there has been a declaration by the Congress or the President of a National Defense Emergency. If the United States should be attacked, activation would be automatic.

The Defense Production Act of 1950 says:

> The term "National Defense" means programs for military and atomic energy production or construction, military assistance to any foreign nation, stockpiling, and directly related activity.

It thus appears that since denial of petroleum supplies would affect military programs, a serious denial could be considered as affecting National Defense and justify the President or the Congress declaring a National Defense Emergency which would authorize activation of the EPGA.

NAVAL PETROLEUM RESERVES

Naval Petroleum Reserve 1 (Elk Hills Field), located about 20 miles west of Bakersfield, California, is by far the largest petroleum reserve in the United States from the standpoint of short-term additional production potential. Naval Petroleum Reserves are controlled and operated by the U.S. Navy's Office of Naval Petroleum Reserves and under existing laws can only be produced when "...the Secretary, with approval of the President, finds it is needed for national defense and the production is authorized by a joint resolution of Congress." The production of the reserves for national defense has been permitted once before when NPR-1 was authorized to produce 65,000 barrels per day during World War 11.

The law here is clear. Authority to produce NPR-1 during the present emergency will require a resolution of Congress, approved by the President.

STATE AUTHORITY FOR OIL AND GAS PRODUCTION

With the exception of production from federal public lands and the Outer Continental Shelf, all oil and gas production in the United States is under the authority of the respective state laws. Therefore, any additional production from fields not under federally controlled lands must be in compliance with state laws.

Some additional short-term productive capacity may be made available from five major fields in Texas and a number of other scattered smaller fields. All are now producing at their maximum efficient rate as has been determined by state regulatory agencies, based upon technical data on individual fields. These maximum efficient rates (MER's) are for long-term continuous production without reservoir damage. State statutes forbid the production of any oil or gas field in an inefficient manner or in a way that would reduce ultimate recovery. Therefore, state regulatory agencies, such as the Texas Railroad Commission, cannot legally allow production rates above MER.

Since current field MER's are for sustained rates, the state regulatory agencies could make a technical determination of possible short-term higher MER's on a field-by-field basis where there is spare productive capacity. Setting up temporary higher allowables should be permissible for this procedure under the state laws.

To obtain this potential additional production for the duration of the present supply emergency will require the cooperation of the state regulatory agencies in establishing temporary higher MER's. Since oil production "allowables" are not mandatory producing rates, producers in the fields involved would have to voluntarily make whatever facility additions are necessary to produce at the higher but temporary rates.

EXECUTIVE ACTIONS

On November 7, 1973, the President proposed to the Nation his recommendations for countering the domestic energy crisis. The President ordered the following actions:

- Industries which currently use coal will be prevented from converting to oil in the immediate future. Power plants using oil which are able to convert to coal will be encouraged to do so.

- Fuel allocations to commercial and other jet fuel users will be reduced, leading to schedule changes and a 10 percent cutback in the number of flights.

- Heating oil for homes, offices and other establishments will be reduced approximately 15 percent.

- In addition to the previously ordered 7 percent reduction in the Federal Government's consumption of energy, further steps will be taken. Daytime temperatures in federal offices will be maintained at 65-68°. In addition, the 500,000 federal vehicles will be ordered to travel no faster than 50 miles per hour, emergencies excepted.

The Atomic Energy Commission was requested to speed the licensing and construction of nuclear plants in order to reduce lead times for construction from 10 years to 6.

The President directed Governor John A. Love, Assistant to the President for Energy, to work closely with Congress to develop an emergency energy act. The proposed legislation would grant the executive branch the authority to:

- Order an immediate return to daylight savings time year-round

- Relax environmental regulations on a temporary, case-by-case basis

- Impose special energy conservation measures, i.e., reduction of commercial operating hours

- Increase the production of the Naval Petroleum Reserves

- Use the proceeds from the sale or exchange of the Navy-owned oil to fund further development and production from Elk Hills, California, and for exploration and proving the Naval Petroleum Reserves

- Reduce highway speed limits nationwide.

The President also requested that governors and mayors reinforce his actions on the state and local levels.

The following actions are currently being taken by the Administration, primarily under the authority of the Economic Stabilization Act of 1970 and the Defense Production Act of 1950:

- The President has directed the Secretary of Transportation to give priority to grant applications for the purchase of buses for mass transit under the authority of the Federal Aid Highway Act of 1973 and the Urban Mass Transportation Act.

- The Office of Management and Budget has been directed to establish an interagency task force to monitor the allocation and rationing programs and develop plans in anticipation of a shortage.

- The Secretary of the Interior was directed to establish a fuel allocation administration to administer all programs and to activate the Emergency Petroleum Supply Committee.

- The establishment of a National Industrial Energy Conservation Council has been directed of the Secretary of Commerce.

- Governors and mayors are being asked to determine the supply/demand situation in their areas, develop programs to reduce energy consumption, coordinate with federal agencies that are allocating fuel. Steps requested of the governors and mayors to reduce gasoline demand include:

  --greater use of mass transit and car pools

  --50 miles-per-hour speed limits on highways

  --special bus lanes

  --higher parking taxes

  --blocking off certain sectors to cars with only one passenger

  --preferential parking for car pools

  --staggering of working hours in state and local governments.

- Contingency plans are currently being developed which include programs for the rationing of gasoline. A proposed plan to ration heating oil will be published in the *Federal Register* in mid-December.

- Administration legislative proposals awaiting Congressional action during this session include:

  --Alaska Pipeline

  --Natural Gas Supply Act

  --Mined Area Protection Act

  --Deepwater Port Facilities

  --Energy Research and Development Administration/National Energy Commission Reorganization.

APPENDICES

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

DEC 5 - 1912

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.

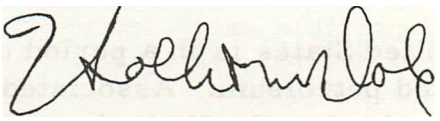
Of particular interest are supplements to normal domestic supply such as: the capability for emergency increases in production, processing, transportation and related storage; the ability to provide and maintain an emergency storage capability and inventories; interfuel substitution

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



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:
MaG

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.
Chairman
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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

In Reply Refer To:
EOG

OCI 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,

Assistant Secretary of the Interior

Mr. H. A. True, Jr.
Chairman, National Petroleum Council
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EXAMPLES OF PROBLEMS RELATING TO CONVERTIBILITY BY ELECTRIC UTILITIES--RESPONSES TO FPC FORM 36*

ATLANTIC CITY ELECTRIC COMPANY--DEEPWATER STATION

Units 3/5 and 4/6 were converted to oil firing because of operational considerations and not pollution restrictions. These units are in excess of 40 years old and we would be extremely reluctant to make any major modifications on them since they are nearing the end of their useful life. When these units were converted to oil firing they were stripped of most of their coal firing equipment including the mills on unit 4/6.

Past experience indicates it is virtually impossible to secure sizeable amounts of the low sulfur coal (less than 3 percent sulfur) with the chemical and physical properties required to burn in these boilers. It is our opinion, that in the event of a wholesale conversion to coal firing, there is insufficient mining capacity to handle the requirements.

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

The coal conveyors have been retained but combustion control and burner logic systems would require major work to become operational.

The pulverizer control system would have to be reinstalled, and certain electrical equipment would have to be purchased and installed.

Electrostatic precipitators are installed but there is no method to dispose of the collected fly ash.

The Company's consulting engineering firm estimates that reconversion of the generating units at the Danskammer Station from oil to coal would require approximately 12 months.

The availability of coal will depend on the demand for coal throughout the country. If restoration of coal burning capability is widespread it is anticipated that coal would be difficult to obtain until new mines are opened. Further, it is expected that any marked increase in coal usage would result in a severe shortage of railroad cars.

* Sample responses extracted from open FPC files available from the Office of Public Information Federal Power Commission.

DUKE POWER COMPANY--RIVERBEND STATION

Boilers 1, 2, 3 and 4 built 1929. Steam supply to associated turbine-generators now from heat recovery boilers 8C, 9C, 10C and llC. To restore boilers 1, 2, 3, and 4 to full capability will require extensive rehabilitation of boilers including repairs to superheaters, boilers, casings, furnace walls, ash hoppers and auxiliaries. Fly ash hoppers will have to be installed. Expected operation of associated generators does not economically justify repairs and installation of fly ash collectors. Associated generators are expected to be in cold reserve status before boilers could be restored to full capability.

JERSEY CENTRAL POWER AND LIGHT COMPANY--SAYREVILLE STATION

Question: 8d Do you still have capability to burn coal in boilers? If boiler burned coal in the past, but cannot do so now, explain.

Answer: Boilers 002 and 003 were stoker-type boilers whose mechanisms were removed and discarded when the boilers were converted to oil. Because of the age of the boilers, parts can no longer be purchased.

Question: 11 Describe on separate sheet what problems, if any, you might encounter in securing coal which could be burned in your boilers if restored to coal firing?

Answer: Although we have not purchased coal for the past several years, we have in general observed the market and assess it to be extremely tight. Reports indicate that several mines we formerly patronized have closed, others remaining open are suffering from reduced productivity in the order of 25 percent, and for the most part, are committed under long-term contracts. It is our opinion that we would be fortunate in obtaining coal in sufficient quantity of any quality. Prior to oil conversion, an exhaustive research and testing program to obtain environmentally acceptable coals (at that time 1.0 percent sulfur was allowed by the Code) which also met the Ash Fusion Temperature Requirements of these boilers was unsuccessful.

As of this date, the tidewater piers, normally used to transship our coal from train to barge for final delivery to the plant, are closed. There are indications that one of the three potentials will be reopened on a limited basis.

Additionally, due to relatively shallow water along the unloading dock of each plant, barges of shallow draft are required; generally 1,100 ton capacity or less with a maximum draft of 12 feet. Those formerly in our service are no longer available and we are aware of no others with acceptable dimensions in this area. In fact, prior to conversion to oil while still burning coal, our expanded need for barge capacity could only be met by making do with an oversized barge that presented operational problems both to the contractor whose tugs delivered the barge, and while moored at our dock side. We feel new barges would have to be constructed.

LONG ISLAND LIGHTING COMPANY--GLENWOOD STATION

The two coal piers in New Jersey, formerly used to load barges to transport coal, are closed and the coal barges are not available. In an emergency it is possible large stone or gravel trucks may be employed, or sand barges could be commandeered by the government.

The area formerly used to store coal is now occupied 100 percent with a gas turbine site.

Boilers 5 and 6 cannot prepare coal. The mills, millroom, and coal unloading equipment for these units have been removed.

Burners have been removed and wind boxes altered to give better firing condition on oil - boilers 5 and 6.

Fly ash removal and storage equipment for boilers 5 and 6 have been removed.

Boilers 5 and 6 have been so altered as described in 8c, 8d and 8e that it is not practical to restore them to coal-burning capability.

In addition to the transportation problems described in 8a, the mines which formerly supplied coal to this plant are not generally operating and most of the coal would not meet present day emission standards. To be assured of a firm supply of coal, contracts would have to be made in advance, and it may take up to two years and an investment of $100,000,000 to open mines of sufficient capacity to serve our coal-burning system.

METROPOLITAN EDISON COMPANY--CRAWFORD STATION

It is not feasible to restore full capability to burn coal in boilers 1 through 6 because:

a. The burners and controls were removed and the openings were bricked in.

b. The coal transport pipe from the pulverizer house to the bunkers was removed.

c. The pulverizers were scrapped.

d. The pulverizer house was leveled to the ground.

e. Conversion to oil was made because fly ash collectors could not be installed in the available space.

We would have only minimal problems securing coal if the pollution laws were relaxed. We do not have precipitators on boilers 1 through 6. Low stacks (we are near an airport) would require use of low-sulfur coal to meet Federal (EPA) ambient air standards.

MONTAUP ELECTRIC COMPANY--SOMERSET STATION

Unloading equipment at plant is operable.

There is no railroad siding at the plant.

Coal barges and colliers formerly used have been scrapped.

Some coal-loading facilities formerly used which were owned by railroads have been dismantled.

Mining companies and railroads require long-term contracts to justify investment of opening mines and transporting coal to loading terminals. Due to age of boilers at Somerset (some are 50 years old), long-term contracts are not prudent.

Use of coal of any type at the plant would result in violations of the strict air quality laws of the Commonwealth of Massachusetts especially in regard to particulate emissions. The type of coal formerly used contained from 1.25 to 2.0 percent sulfur and would violate the existing standard.

NEW JERSEY POWER AND LIGHT COMPANY--GILBERT STATION

Although we have not purchased coal for the past several years, we have in general observed the market and assess it to be extremely tight. Reports indicate that several mines we formerly patronized have closed, others remaining open are suffering from reduced productivity in the order of 25 percent, and for the most part are committed under long-term contracts. Practically speaking, environmentally acceptable coals are not available in sufficient quantities, moreover, when viewed realistically, we would be fortunate in obtaining coal in sufficient quantity of any quality.

As a result of additional oil storage facilities necessitated by expanded generating capacity at this site, trackage required to successfully handle trainload quantities of coal has been lost. While this does not affect our ability to burn coal, the economic penalty of single car shipment would eventually be passed on to our customers through our fuel clause.

NORTHEAST UTILITIES SERVICE COMPANY--A REVIEW OF SOME PROBLEMS IN CONNECTION WITH THE RESTORATION OF COAL SUPPLIES TO ELECTRIC GENERATING STATIONS

It is difficult to evaluate the problems that may arise when trying to re-enter the coal market unless the general ground rules are specified. Should a single plant be switched back to coal, the procurement problems would be minor. If the entire Northeast Utilities system is reconverted, the task becomes one of major proportions. If the entire northeast region re-enters the coal market simultaneously, the supply problem would be impossible to solve.

A second obstacle is imposed by the sulfur and ash quality criteria which are presently in force in our area. Although some volumes of 1 percent sulfur 9 percent ash coal may be found for Massachusetts stations, coal with less than 0.5 percent sulfur would not be available in Connecticut.

When coal was flowing in quantity into New England, hopper car shortages became a common occurrence. Although hoppers are probably presently plentiful, a massive switch to coal would certainly again reveal this deficiency.

Negotiating for new coal supplies of significant volumes will require the reopening of inactive mines and possibly the construction of new mines. Firm assurances must be provided to the utilities and to the mine operators with regard to the sanctity of the required long-term coal contracts. Short-term coal commitments will not permit the mine operators to attract the manpower and capital necessary in providing an assured fuel supply. Provisions must be made to guarantee at least an optimum 5-year contract period.

When considering the tidewater stations, a restart of a waterborne movement would be difficult. Coal hopper barges may be in short supply and at this time there is only one coal-dumping pier left in New York Harbor to serve the potential business.

A major disadvantage of coal is, of course, the ash disposal problem that it generates. Again, with increasingly strict environmental regulations, the disposal of ash can be a major obstacle.

Although coal-burning capability has been maintained at the previously coal fueled stations, out of necessity the stockpile areas at some stations have been utilized for the construction of

oil storage tanks. Most plants therefore are not able to return to the 90-day coal storage position which was once required during high fuel demand periods.

When a utility is operating with an established coal flow network, it is normally possible to make a significant increase in volumes if required. If all coal has been eliminated, as in the case of Northeast Utilities, it is far more difficult to realign the entire fuel flow system for a return to coal. With this in mind, it is recommended that a program be implemented to permit utilities that are so equipped to return to a moderate flow of nonconforming coal. Possibly some minimum percent of total energy requirement could be fueled in this mode. This arrangement would re-establish a commitment from the mines, from the railroads, and from the dump piers and barge towing companies when required. With this base flow, it would then be possible to increase volumes to some degree when attempting to compensate for failures in oil deliveries. It would also facilitate establishment of an orderly switching program should it be required that utilities withdraw from the oil market to free up petroleum fuel for other consumers not equipped with a dual fuel capability.

THE UNITED ILLUMINATING COMPANY--BRIDGEPORT HARBOR STATION

Equipment associated with units 1 and 2 exists and could be made operational in two weeks. Unit 3 coal unloading, crushing, and conveying facilities have never been completed as unit 3 has only operated as an oil-fired unit. The cost to complete the coal-handling facilities is approximately $160,000.

Units 1 and 2 last burned coal in 1967. These cyclone units would require extensive work on the boilers, bottom ash slag tanks, fly ash reinjection and bottom ash disposal systems before they could be operated on coal. Unit 3, designed for coal firing or oil firing has never operated on coal, and would require extensive modification of its precipitator ash disposal and handling system as well as boiler work to establish coal-firing capability.

All 3 units have precipitators which have been modified to operate on oil firing of their associated boilers. Precipitators on units 1 and 2 could be converted to handle fly ash from coal, however the rebuilding of the ash reinjection system would take approximately 3 months to complete. The fly ash handling system on unit 3 is now a wet sluice system and would require conversion to a dry reinjection system. The estimated cost for such a conversion is $250,000 and could take up to a year to design, construct and assure full operating capability.

Time estimates include unit outage requirements of from 4 to 6 weeks. Conversion of all units to coal firing would require the design and construction of an additional liquid retention basin for adequate handling of bottom ash. Previous estimates indicate that

a year or more would be required to design and construct such as basin at a cost of approximately $300,000. Such a requirement would obviously extend the time for conversion.

Cost estimates include boiler work, ash collection modification and order of magnitude replacement power costs for necessary unit outages. Return of units to oil firing would require expenditures of $200,000 to $300,000 in total, and such costs are not included in estimates.

VIRGINIA ELECTRIC AND POWER COMPANY

If a significant number of our boilers were restored to coal firing we would expect major problems in the area of supply, costs and quality.

Overlooking the reasons that contribute to this situation, we have noted the closing of mines, the drop in productivity and the trend of the larger coal companies to place more sales emphasis on the metallurgical market and the higher quality and cost coals. An additional impact on supply will be occasioned by rising customer demand if other utilities revert to coal firing.

To alleviate the coal supply problem coal operators will be required to reactivate old high cost mines and develop new mines which will require several years to attain full operation. It will be necessary to re-evaluate the coal processing methods and economics to the end more coal can be made available to the steam market. All of this leads to higher costs for a product that is currently in a non-competitive position.

It is important to note that we cannot meet environmental standards utilizing coal as an alternate fuel in most of our units, without considerable upgrading of facilities. Costs for this upgrading would be in the tens of millions of dollars. Also ash handling and disposal problems, which are minimal now when burning oil, would be major if coal were consumed: on the order of 100 times as great.

Lastly but not the least of our problems would be quality, particularly as it relates to sulfur. In our opinion there is insufficient coal available of the quality required to permit us to meet the standards established by the various regulatory bodies for control of air pollution.