The Strategic Petroleum Reserve

A Report on the Capability to Distribute SPR Oil

National Petroleum Council
December 1984

NATIONAL PETROLEUM COUNCIL

1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 12, 1984

The Honorable Donald Paul Hodel
Secretary of Energy
Washington, D.C.

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith The Strategic Petroleum Reserve: A Report on the Capability to Distribute SPR Oil, which was unanimously approved by the Council at its meeting on December 12, 1984. This report was prepared in response to your request of November 7, 1983. It is gratifying to be able to advise you that we have reached the broad conclusion that the SPR is a valuable national asset that is capable of significantly mitigating the impact of a severe oil supply disruption.

The National Petroleum Council proposes a number of recommendations aimed at facilitating the drawdown and distribution of the Strategic Petroleum Reserve in an emergency. The Council found that upon completion of the currently planned 750 million barrel SPR fill, the projected maximum drawdown rate of 4.5 million barrels per day from the storage caverns will be attainable. However, recognizing the changing domestic energy situation--including the loss of two major pipelines--the Council recommends certain actions to ensure the timely and efficient drawdown, distribution, and refining of SPR crude oil. The recommendations are aimed at correcting identified shortfalls in distribution capability from the SPR sites, and providing sufficient flexibility within the system to cover a reasonable range of potential SPR distribution and refining requirements. These recommendations should enhance the system's ability to minimize the effects of future supply disruptions.

As you noted to the Council membership at our meeting today, a proposal to suspend SPR fill at 500 million barrels is being considered. While the Council's analyses are based on the currently approved plan for SPR fill, most of our recommendations would still be applicable should a change be made in the ultimate level of SPR inventories. If SPR fill is capped at 500 million barrels and the associated maximum drawdown rate is lowered, the data and analyses contained in the report can be used to judge the extent of enhancements that may be needed at the three SPR complexes. Obviously, little opportunity would exist to change the mix and location of the fill. The rest of our recommendations are basically independent of inventory level and would remain unchanged.

The National Petroleum Council sincerely hopes that this study will be of benefit to you and the federal government in the difficult decision-making process that lies ahead.

Respectfully submitted,

Robert A. Mosbacher
Chairman

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Wm. C. Douce, Chairman, Committee on
The Strategic Petroleum Reserve

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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Introduction

In 1974 and again in 1975 the National Petroleum Council (NPC) strongly endorsed establishing a strategic stockpile of crude oil for use in the event of supply interruptions. The Strategic Petroleum Reserve (SPR) Program was created in 1975 and constitutes an important element in the nation's ability to meet oil supply shortfalls. Now that its inventories have reached more than half of the planned 750 million barrel level, the major emphasis of the SPR program is shifting toward the ability to draw down and distribute the oil to meet the needs of the nation in the event of an emergency.

On November 7, 1983, the Secretary of Energy, Donald Paul Hodel, requested that the National Petroleum Council conduct a study of various aspects of the Strategic Petroleum Reserve. Separately, the Secretary asked the Council to examine tanker trends from the present to 1990. The Council agreed to both these requests, which are addressed jointly in this report. The request letters from the Secretary, a description of the National Petroleum Council, and a roster of the Council membership are provided in Appendix A.

To assist in responding to the Secretary's requests, the NPC established a Committee on the Strategic Petroleum Reserve under the chairmanship of William C. Douce, Chairman of the Board and Chief Executive Officer, Phillips Petroleum Company. William A. Vaughan, Assistant Secretary for Fossil Energy, U.S. Department of Energy (DOE), served as Government Cochairman of the Committee. The Committee established a Coordinating Subcommittee and four task groups to provide coordination and technical advice to the Committee. Rosters of the study groups are included in Appendix B.

The Secretary specifically asked the Council to address the following areas: types of crude oil stored in the SPR; capabilities to transport the oil from the SPR storage sites to refineries; and long-term availability and movement patterns of tankers, with particular interest in the availability of tankers for movements of SPR oil. He also asked the Council to look at "...any other aspects of the government/industry relationship wherein the Council believes changes in our current plans for SPR distribution and composition would be warranted."

This study is intended to examine the capabilities of the SPR sites, the overland and marine transportation systems, and the domestic refining system to draw down, distribute, and refine SPR crude oil at the SPR's maximum design drawdown rate of 4.5 million barrels per day under DOE's current sales procedures.[1] However, there are a number of aspects of the SPR program that are beyond the scope of this study and are not addressed, including optimum fill and drawdown rates, required SPR size, regional crude oil and product storage, and alternative options for SPR oil sale.

As the maximum sustained design drawdown rate will not be achievable with projected fill rates until 1990, a 1990 disruption scenario consisting of a complete cutoff of all

[1]For the purposes of this study, the term "drawdown" refers to the withdrawal of oil from the SPR storage caverns. The term "distribute" refers to the movement of crude oil and petroleum products to refineries or markets.

crude oil and product imports was defined solely to test the system at its maximum design capability. No attempt was made to identify circumstances that would lead to the 1990 disrupted case, including circumstances affecting the United States' rights or obligations under the IEP supply-sharing mechanism. Nor should the study scenario be construed as a forecast of supply and demand, pipeline availability, or the manner in which refinery or transportation markets would actually respond during an emergency. Rather, its purpose was to provide a means for analyzing the complex logistics involved in drawing down and distributing SPR oil at maximum design rates. In addition, several intermediate time frames and drawdown requirements were considered as sensitivities to the base disruption scenario.

Executive Summary

Background

The SPR system currently consists of six crude oil storage sites in various stages of development and three marine terminals. One of the terminals is owned by DOE while the other two are privately owned. All are located on the Gulf Coast of the United States, as shown in Figure 1. The SPR storage sites were initially designed to be connected to three major interstate crude oil distribution networks, the Seaway, Texoma, and Capline pipeline systems, and their associated, privately owned marine terminals. The Seaway and Texoma pipelines have recently been converted to natural gas service, however, and are no longer available to the SPR.

The 750 million barrel storage capacity of the SPR is being developed in three phases:

- Phase I, completed in 1983, covered the conversion of 260 million barrels of existing storage capacity at five sites (Bryan Mound in Texas, and Bayou Choctaw, West Hackberry, Sulphur Mines, and Weeks Island in Louisiana) and installation of a DOE marine terminal facility at St. James, Louisiana.
- Phase II will increase the storage capacity of three Phase I sites by 290 million barrels.
- Phase III calls for approximately 200 million barrels of additional storage through further expansion of existing sites and the development of a new 140 million barrel site at Big Hill, Texas.

As of September 30, 1984, the SPR had a crude oil inventory of 431 million barrels, and design drawdown capability of 2.1 million barrels per day. Upon completion of Phase II, scheduled for mid-1987, design drawdown capacity will be 3.5 million barrels per day.

At the end of Phase III, projected for 1990, the SPR is planned to contain 750 million barrels, and have a sustained design drawdown capability of 4.5 million barrels per day.

Overview of Study Methodology

To analyze the ability of the SPR system to meet consumer product needs in the event of an emergency, four operational areas were examined: SPR facilities, overland distribution, marine distribution, and refining capabilities. These four areas were examined under three distinct cases: 1983 actual, 1990 nondisrupted, and 1990 disrupted.

The starting point for this analysis was 1983 supply, demand, and refining data for the United States as provided by the Energy Information Administration (EIA) of DOE. Based on these data, 1983 refinery inputs and outputs were defined for 13 U.S. refining centers. The supply of U.S. and foreign flag tankers and barges capable of transporting SPR oil and petroleum products was identified using actual 1983 data supplied by industry, the U.S. Maritime Administration (MarAd), and other government sources.

A 1990 nondisrupted case was developed based on EIA's aggregate 1990 projections of U.S. production, imports, refinery runs, and demand. Regional supply/demand balances and crude oil and product flows, and refinery inputs

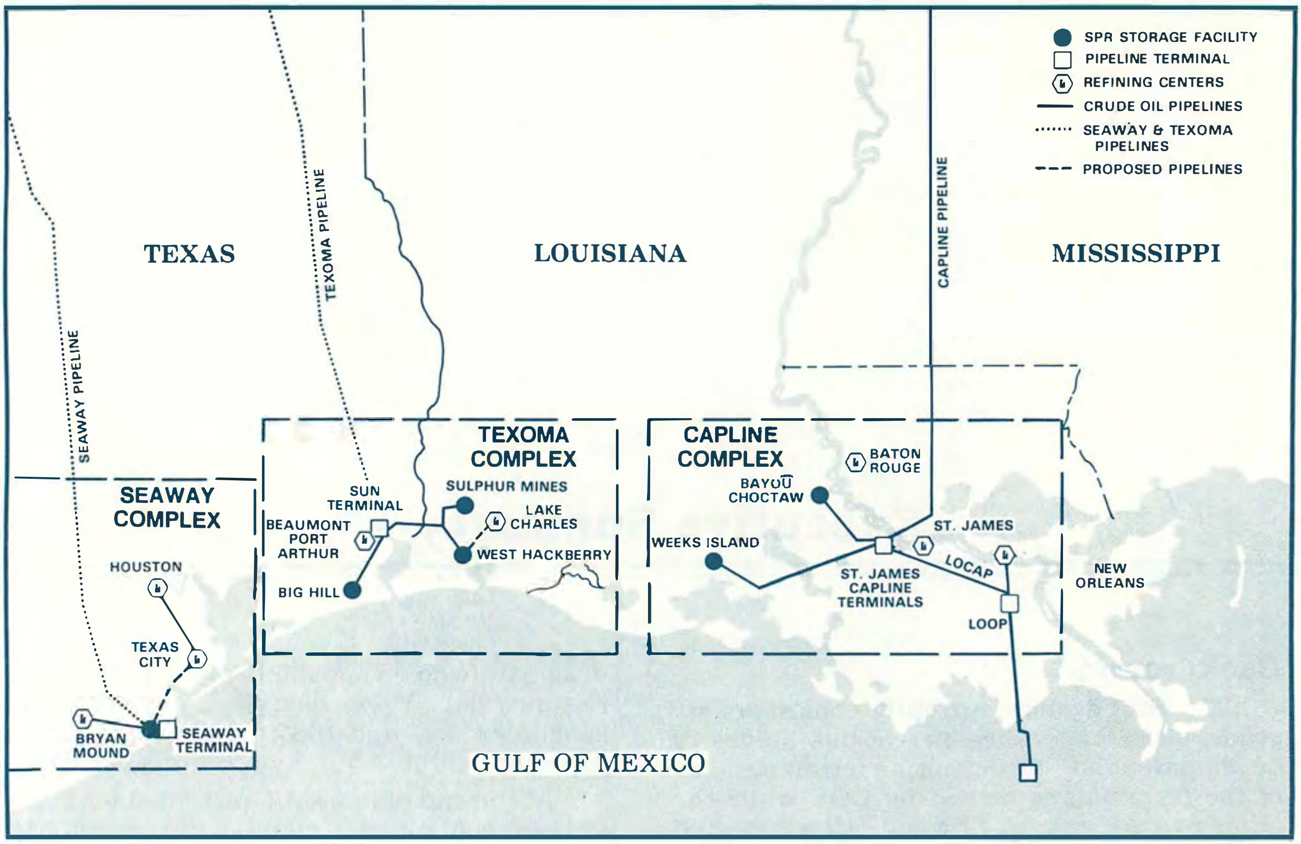

Figure 1. The Strategic Petroleum Reserve.

and outputs, were developed from the 1990 aggregate using 1983 base data and study participants' judgments. Tanker and barge availability for 1990 was determined on the basis of actual 1983 supply data and the judgment of the study participants.

Based on this nondisrupted case, a disruption scenario that virtually eliminates all crude oil and product imports to the United States was developed for 1990. This scenario permits testing the system at its maximum design drawdown rate (4.5 million barrels per day). In order to permit timely completion of the study, several simplifying but key assumptions were made regarding this disruption scenario. These key disruption scenario assumptions are highlighted below:

- There are no *net* crude oil or product movements to or from the United States (Canadian crude oil imports continue for mutually beneficial quality/logistics purposes, but only on an exchange basis).
- Demand is restrained at the level corresponding to U.S. crude oil production plus maximum SPR drawdown. It was assumed that crude oil and product price levels adjust during the postulated disruption so that demand equals available supplies, although quantification of such prices is beyond the scope of this study.
- Market forces will cause redistribution of crude oil from refining centers with ample domestic crude oil under the disruption scenario to refining centers in import-dependent areas.
- Product demand reductions during cutoff are distributed equally among Petroleum Administration for Defense Districts (PADDs). Further, it was recognized that not all categories of products would be uniformly reduced. Demand for some products would drop more sharply than for others. Therefore, individual product elasticities developed by DOE were utilized to define specific demands for individual products.
- Refining capacity remains more than adequate to meet 1990 product demand.
- The U.S. Virgin Islands and Puerto Rico are treated as part of the U.S. supply/demand system (non-U.S. crude oil and product imports to the Virgin Islands/Puerto Rico are disrupted but product shipments from the Virgin Islands/Puerto Rico to the United States continue, although at a reduced rate).

A summary of crude oil supply/demand by area under the 1990 nondisrupted and disrupted cases is shown in Table 1. The Council cautions that it is impossible to accurately predict how markets and consumers will respond to a given disruption scenario and, therefore, variability from the responses postulated here must be expected. However, a reasonable degree of conservatism has been built into the assessment in an attempt to account for potential variations in circumstances that might be encountered in an actual supply emergency.

A number of sensitivities that would test the system under conditions other than the case just described were considered, including larger and smaller disruptions, varied timing of disruptions, altered product demands and/or import levels, and differing configurations of facilities. These sensitivities are addressed in Chapter Three.

Major Findings

Based on the analyses in this report, the NPC's major findings as to the adequacy of SPR system capabilities are highlighted below:

- Barring a sizeable loss of refining capacity from further shutdowns, there will be sufficient capacity in 1990 to process both SPR oil and available domestic crude oil. However, the currently planned 1990 SPR crude oil quality mix does not provide adequate flexibility to meet potential refining system needs.
- Since two major pipeline systems (Texoma and Seaway) are no longer available to the SPR, current plans for location of future SPR fill would require additional marine movements to supply major Midwest and lower Mississippi River refining centers, thereby adding to marine (especially barge) congestion in PADD III. The projected ratios of stored crude oil to local or pipeline-connected refinery capacity are: Seaway complex, 88 days; Texoma complex, 193 days; and Capline complex, 28 days.
- It is believed that upon completion of the SPR fill, the capacity to withdraw crude oil from the storage caverns will match the sustained design drawdown capability of 4.5 million barrels per day. However, without capacity enhancements, none of the three SPR complexes will be able to deliver crude oil to vessels (especially barges) and/or pipelines at the maximum projected 1990 drawdown rates. The SPR system does not provide sufficient flexibility to cover a reasonable range of possible shifts in future distribution capacity or requirements.
- Lack of ballast treatment facilities at SPR terminals could constrain sustainable loading rates by as much as 30 percent, restricting distribution accordingly.
- The supply of U.S. flag tankers and barges in 1990 appears sufficient to meet the waterborne *crude oil* transportation requirements of an emergency drawdown of the SPR.
- Projected declines in U.S. flag *product* tankers could result in a substantial shortage of U.S. flag tonnage for the distribution of residual fuel oil during a supply disruption, although an ample supply of U.S.-controlled foreign flag tonnage is readily available for participation if required.
- Current SPR sales policies and environmental restrictions would limit the timely distribution and use of SPR oil in an emergency.
- As with any system not operated on a daily basis, special attention needs to be given to conducting periodic training exercises for the entire SPR system and to improvements in equipment and procedures at the individual sites.

Study Recommendations

The Council believes that the Strategic Petroleum Reserve is a valuable national asset, capable of being drawn down and distributed in the event of a national emergency. However, in recognition of the changing domestic energy situation—including the loss of two major pipelines—the Council recommends certain modifications to ensure the timely and efficient drawdown, distribution, and refining of SPR inventories. The following recommendations are aimed at providing sufficient flexibility within the system to cover a reasonable range of potential SPR distribution and refining requirements and enhancing the system's ability to minimize the effects of future supply disruptions:

- ***SPR purchases should be reoriented to ensure that at least 43 percent of the planned 750 million barrel reserve is low-sulfur crude oil.*** The currently planned ratio of 35 percent low-sulfur/ 65 percent high-sulfur crude oil could result in regional distribution inequities and/or could compound refinery difficulties in meeting product sulfur

TABLE 1

PROJECTED SUPPLY/DEMAND BALANCE
1990 NONDISRUPTED CASE VS. 1990 DISRUPTED CASE
(Thousands of Barrels per Day)

	PADD						
	I	II	III	IV	V	VI/PR*	Total
1990 Nondisrupted Case							
Supplies							
Local Crude Production	90	1,050	3,600	560	3,330	–	8,630
Net Crude Imports	910	1,110	2,320	40	220	270	4,870
Net Inter-PADD Crude	100	860	150	(140)	(1,140)	170	–
Net Product Imports	1,010	180	(20)	20	(130)	110	1,170
Net Inter-PADD Products	2,970	780	(3,540)	–	100	(310)	–
Other (net)†	260	430	1,300	70	130	–	2,190
Local Demand	5,340	4,410	3,810	550	2,510	240	16,860
1990 Disrupted Case‡							
Supplies							
Local Crude Production	90	1,050	3,600	560	3,330	–	8,630
SPR Crude	640	640	2,900	–	200	120	4,500
Other Inter-PADD Crude	460	980	(380)	(140)	(1,270)	350	–
Net Inter-PADD Products	3,380	890	(3,980)	20	(60)	(250)	–
Other (net)†	270	440	1,310	70	70	–	2,160
Local Demand	4,840	4,000	3,450	510	2,270	220	15,290

*In this report, VI/PR refers to the U.S. Virgin Islands/Puerto Rico.

†Other includes liquified petroleum gas produced and used in each PADD, refinery gain, inventory draw/build, and other adjustments to balance.

‡Assumes a complete cutoff of U.S. crude oil and product imports except a small amount (250 MB/D) of ongoing exchange with Canada. A 9.3 percent reduction in total U.S. demand results from balancing demand with available supplies (i.e., U.S. production plus 4.5 MMB/D SPR crude oil drawdown).

specifications. Therefore, DOE should act immediately to increase low-sulfur crude oil purchases to at least 50 percent of the remaining fill, and to designate segregated storage for this oil.

- ***A shift of at least 100 million barrels of the remaining SPR fill from the Texoma complex to the Capline complex should be considered.*** Since the Texoma and Seaway pipelines are no longer available to the SPR, part of the needs in PADD II that were to be served by these two pipelines can be supplied via Capline. Congestion of water movements from the Texoma complex to refineries served along the Mississippi River may be reduced by connecting one or more SPR sites to Louisiana Offshore Oil Port (LOOP) facilities. Most if not all of the refineries to be served by movements on the Mississippi River can be served by one of several pipelines connected to LOOP's storage facilities. For these reasons, the allocation of Texoma storage should be shifted in some fashion to the Capline complex. Further, such a shift would increase flexibility to meet refiners' crude oil quality needs, and would rectify the imbalance in the days of crude oil supply stored at each of the three SPR complexes. Whether to change the physical location of the storage or to connect existing sites by pipeline to the Capline area will have to be determined after the economics have been studied.

- ***Enhancements should be made to each of the three SPR complexes to increase distribution capacity to match drawdown capability and to provide additional flexibility in the system.*** The following enhancements are recommended:

  —*Seaway Complex:* Construct a 1.0 million barrels per day pipeline from Bryan Mound to the Houston/Texas City area and consider use of the Phillips dock to supplement the Seaway dock. With these enhancements, Bryan Mound drawdown capability could be fully utilized. This is consistent with the current DOE enhancement proposal.

  —*Capline Complex:* Increase the St. James terminal capacity from 880 thousand barrels per day to 1,070 thousand barrels per day consistent with Weeks Island and Bayou Choctaw drawdown capability. This enhancement is required even if future SPR fill is not relocated to the Capline area and is consistent with the current DOE enhancement proposal. If future SPR fill is shifted to the Capline area, additional enhancements at this complex may be required. These will depend upon the location(s) selected and volumes actually relocated.

  —*Texoma Complex:* Even if future SPR fill is shifted to the Capline area, an 860 thousand barrels per day deliverability enhancement is still required at this complex to make maximum use of drawdown capability and provide needed flexibility. Specifically, 580 thousand barrels per day of this throughput enhancement is a 9-mile, 26-inch-diameter pipeline from West Hackberry to Lake Charles and 280 thousand barrels per day is increased terminal throughput capacity available to DOE at Nederland. These enhancements are consistent with the current DOE enhancement proposal.

  If a shift of remaining SPR fill is *not* made to the Capline area, the enhancements recommended above should be supplemented by an additional 730 thousand barrels per day in terminal throughput and marine loading capacity available to DOE at Nederland to meet the 1990 disrupted case, as well as to provide flexibility for future demand shifts.

The effects of current deficiencies and the proposed enhancements at each of the SPR complexes are summarized in Table 2.

- ***Ballast water treatment facilities or alternate means of disposal must be provided for all SPR marine facilities.*** As loading of crude oil requires some method to handle ballast, a cost-benefit study should be conducted to define the most effective means of dealing with this problem. Specifically, the study should examine:

  —Constructing ballast water treatment facilities at SPR marine terminals

  —Tying into nearby marine terminals to increase dock utilization

  —Injecting the ballast water discharged from the vessels into the SPR caverns

  —Exempting vessels loading at the SPR terminals from the "Act to Prevent

TABLE 2

SPR CRUDE OIL REQUIREMENTS AND DISTRIBUTION CAPACITY IN THE 1990 DISRUPTED CASE*
(Thousands of Barrels per Day)

	PADD III						
	Corpus Christi	Houston/ Tx. City	Beaumont/ Pt. Arthur	Lake Charles	Lower Miss.	PADDs I, II, & V	Total
			Without Enhancements				
SPR Crude Oil Required	260	920	520	200	1,000	1,600	4,500
Distribution Capacity Without Enhancements							
Seaway	150	250	–	–	–	–	400
Capline	–	–	–	–	240	640	880
Texoma	–	–	430	–	270	420	1,120
Shortfall	**110**	**670**	**90**	**200**	**490**	**540**	**2,100**
			With Enhancements				
SPR Crude Oil Required	260	920	520	200	1,000	1,600	4,500
Distribution Capacity With Enhancements							
Seaway	260	810	–	–	–	30	1,100
Capline	–	–	–	–	260/*960*†	640	900/*1,600*†
Texoma	–	110	520	200	740/*40*†	930	2,500/*1,800*†
Shortfall	**0**	**0**	**0**	**0**	**0**	**0**	**0**

*The numbers in this table have been rounded.

†Numbers in italics show the effect of relocating 100 million barrels of future Texoma fill to the Capline complex area. Drawdown of this fill is assumed to be 700 MB/D. A similar reduction in Texoma waterborne shipments to lower Mississippi refineries could be accomplished by a 700 MB/D pipeline to the Capline complex area.

Pollution from Ships, 1980," during an emergency.

- ***Jones Act waivers, if necessary, should be expeditiously handled on a case-by-case basis.*** It appears that the level of demand for foreign flag tonnage could be handled by the existing waiver procedures. However, a contingency plan should be developed by MarAd in advance of an emergency for expediting waivers of the Jones Act. Additional MarAd personnel should be allocated to foreign flag waiver evaluation if it appears that case-by-case requests for waivers are not being expeditiously processed. If the drawdown rate is such that case-by-case waivers cannot be administratively handled, a blanket waiver should be granted to Construction Differential Subsidy vessels, enabling MarAd's contingency plan procedure to concentrate on case-by-case waivers for foreign flag tankers to participate in the SPR drawdown. MarAd should develop, and have available to it, a standby blanket waiver procedure for foreign flag vessels, for use in the event that the case-by-case waiver process results in delays in SPR distribution, in spite of having taken the above actions to rectify the situation. MarAd should also establish an ongoing vessel operators and shippers advisory group that:

  —Would periodically meet to evaluate and recommend improvements in MarAd's waiver processing plans and update the vessel supply/demand balance

  —Would be available in the event of a drawdown to assist MarAd in assessing vessel availability and requirements.

  In order to ensure adequate protection of national interests, MarAd should closely coordinate SPR crude oil refining requirements with whatever tonnage the Department of Defense might require.

  An alternative view to the recommendation for case-by-case Jones Act waivers is contained in Appendix D.

- ***Efficient use of tankers and barges should be promoted.*** Adopting minimum lot sizes, for example, 200,000 barrels for tankers and 40,000–60,000 barrels for barges, would help ensure full utilization of vessel capacity. Relaxing the length restrictions at the DOE terminal in St. James will open the terminal up to larger vessels. Also, berthing facilities for barges should be substantially increased to handle PADD III distribution requirements.

- ***A framework should be put in place that would facilitate and expedite the distribution of SPR crude oil during an emergency.*** To promote an efficient drawdown of the SPR and the timely distribution of petroleum products to consumers, it is recommended that SPR Drawdown Plan Amendment No. 4 be modified from the present position of being open "... to all interested buyers..." to a more restricted list of purchasers such as U.S. refiners, their purchasing agents, and/or traditional suppliers. Procedures should be established for precertification of qualified bidders.

  The damage provisions of the current Standard Sales Provisions (SSPs) should be revised to more nearly balance the responsibilities and liabilities of the purchaser and DOE. As currently drawn, these provisions are excessively severe, and place the entire burden to perform on the purchaser.

  Procedures to expeditiously process necessary environmental waivers should be established at the appropriate federal, state, and local levels. In the event of a disruption, variances may be needed for product sulfur specifications and/or facility emissions.

- ***Periodic drawdown exercises should be conducted by the entire SPR organization to achieve and maintain administrative and operational readiness.*** Industry participation in the planning, implementation, and evaluation of such tests is vital. No physical sale of crude oil need be made to have an effective test exercise.

- ***Equipment and procedures at SPR sites should be improved.*** To increase the flexibility of the system, maximum use should be made of existing meters instead of tank gauges for custody transfer of SPR crude oil. Corrosion protection for water and brine systems should be improved, and a complete review of all spare pipe requirements should be made with a view toward reducing inventories and coating the remaining pipe with a preservative. Security of water intake structures, which are critical to drawdown, should be ensured.

Chapter One
Background on the Strategic Petroleum Reserve

History

The need for a national strategic oil reserve has been recognized for at least forty years. The storage of crude oil for emergencies was advocated by Interior Secretary Harold Ickes in 1944; by President Truman's Minerals Policy Commission in 1952; and by the Cabinet Task Force on Oil Import Control in 1970.

The interruption of petroleum supplies during the winter of 1973-1974 dramatically demonstrated the need for an emergency storage program. The petroleum shortage resulting from this supply interruption caused severe impacts on the U.S. economy and emphasized our vulnerability to interruptions in imports. In 1975, the National Petroleum Council recommended that:

> A security storage volume of about 500 million barrels...would provide protection commensurate with similar programs in effect in other consuming nations.

The SPR program was established by the Energy Policy and Conservation Act (EPCA) enacted on December 22, 1975. This legislation declared it to be U.S. policy to establish a reserve of up to one billion barrels of petroleum. The EPCA stipulates that the SPR may not be drawn down and distributed unless the President finds that such actions are required due to "a severe energy supply interruption or by obligations of the United States under the International Energy Program." A severe energy supply interruption is defined in the EPCA as a national energy supply shortage that the President determines:

- Is, or is likely to be, of significant scope and duration, and of an emergency nature
- May cause major adverse impacts on national safety or the national economy
- Results, or is likely to result, from an interruption in the supply of imported petroleum products, from sabotage, or from an act of God.

The authorizing legislation included a storage target of some 500 million barrels by 1982. The SPR plan of January 1977 provided for a 500 million barrel government-owned crude oil storage system to achieve this target. In May 1977, SPR Plan Amendment No. 1 was submitted to Congress to accelerate the schedule to provide for 500 million barrels of crude oil in storage by the end of 1980. SPR Plan Amendment No. 2, submitted to Congress in May 1978, authorized ultimate expansion of the SPR to 1 billion barrels, but only provided for implementing storage of 750 million barrels. Decisions on the timing and method of achieving the remaining 250 million barrel increment were deferred.

On October 31, 1979, DOE submitted to Congress the distribution plan for the SPR as required by the EPCA. SPR Plan Amendment No. 3 described the methods for drawdown and distribution of crude oil from five SPR storage sites.

In the Energy Emergency Preparedness Act (EEPA), Congress required that a new plan establish procedures for the sale of oil from the SPR to meet obligations to the International Energy Program (IEP). The new plan, SPR Drawdown Plan Amendment No. 4, was transmitted to Congress on December 1, 1982, and took effect on that date. This plan provided that the principal method of distributing oil would be price-competitive sales.

On December 21, 1983, DOE published in the Federal Register (48 FR 56538) a final rule governing price-competitive sales of petroleum from the Strategic Petroleum Reserve in the event that the SPR is drawn down to respond to a severe energy supply interruption to meet obligations of the United States under the IEA Agreement. This final rule provided for publication in the Federal Register of Standard Sales Provisions containing or describing contract clauses, terms, and conditions of sale and performance, and financial responsibility measures, which may be applicable to a particular sale of SPR petroleum. On June 15, 1983, draft SSPs were published in the Federal Register (48 FR 27482) for public comment. After consideration of these and other comments and recommendations from the SPR Distribution Readiness Exercise (DIREX-B) report of February 1984, DOE revised the SSPs and adopted them on an interim basis for use in an emergency. These comments and recommendations were published in the Federal Register (49 FR 2692) as an interim appendix to the final rule on January 20, 1984. The SSPs, as currently revised, are included in Appendix F.

Section 161(c) of the Energy Policy and Conservation Act explicitly provides that drawdown and distribution must be in accordance with the SPR plan in effect at that time. Consequently, DOE cannot adopt any SSPs that are not consistent with SPR Drawdown Plan Amendment No. 4.

SPR Drawdown Plan Amendment No. 4 provides that in order to achieve efficient distribution of SPR oil, "...the universe of eligible buyers will not be restricted, except insofar as necessary to assure performance and payments." Thus, all interested buyers, including federal, state, and local agencies, would be eligible to bid for and purchase SPR oil. The plan also provides that under the most extreme circumstances the Secretary may direct the distribution of up to 10 percent of the volume of the SPR oil sold in any calendar month. The price of such SPR oil will be the average price of SPR oil sold at the contemporaneous competitive sale, or at the most recent competitive sale if no contemporaneous sale is held.

Description of SPR Facilities

For maximum distribution efficiency, the Strategic Petroleum Reserve was integrated into the then existing and planned U.S. petroleum logistics system, including pipelines and tanker/barge loading facilities.

The majority of all crude oil imports enter the United States through ports and terminals along the Gulf of Mexico. Three major pipelines, Texoma, Seaway, and Capline, have provided transportation for a portion of these imports into the central United States. (The Texoma and Seaway pipelines terminated in Cushing, Oklahoma, while the Capline system terminates in Patoka, Illinois. The Texoma and Seaway pipelines have been converted to natural gas service and are no longer available to the SPR.) Further, the distribution to refineries in the Midwest is accomplished by a network of additional pipelines. The existence of these ports, terminals, and pipelines resulted in the original decision to locate the SPR storage facilities in the Gulf Coast areas of Louisiana and Texas. Cost-benefit analyses indicated that salt dome storage, either in solution-mined (leached) caverns or mechanically excavated mines, was the most cost-effective approach.

The storage of crude oil in a solution-mined salt cavern and the subsequent recovery of that oil relies on the fact that crude oil is less dense than water and therefore floats on top of the water. When recovery of crude oil from the storage cavern is desired, raw water is injected into tubing that is suspended in the center of the well casing and near the bottom of the cavern in a brine layer. The crude oil is recovered by way of hydraulic lift through the annulus, i.e., the space between the suspended tubing and the outer well casing. The source of raw water for displacement of the crude oil is a nearby surface water body, which may be a lake, river, or the intracoastal waterway. The raw water intake structure is connected by pipeline to injection pumps that force water into, and the oil out of, the cavern and into a DOE crude oil pipeline. The DOE pipeline is connected to a commercial distribution pipeline and/or a pipeline running to a marine terminal where crude oil vessels can be loaded for waterborne transportation to refineries. The procedure is reversed for filling a cavern. Crude oil is unloaded from tankers across the dock and pumped to the site where it is injected into the cavern displacing brine, which is either injected into deep subsurface wells or dispersed into the Gulf of Mexico waters. An example of a typical oil storage cavern is shown in Figure 2.

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

An assessment of existing salt domes in the Gulf Coast area, the availability of existing storage capacity in those domes, and their proximity to the three main crude oil pipeline terminals and port complexes resulted in the

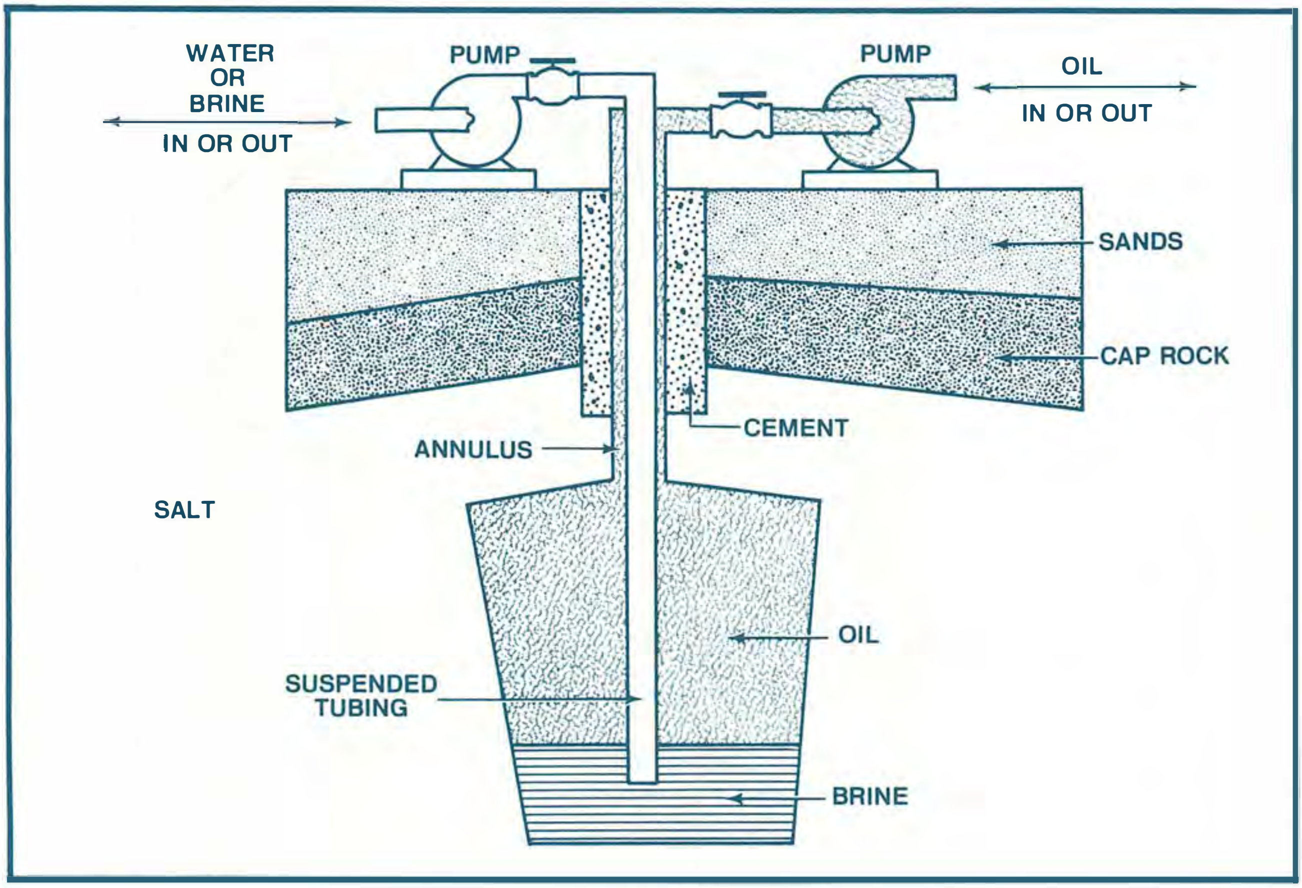

Figure 2. Configuration of Typical Oil Storage Cavern.

selection of five sites to meet the initial storage objective of 250 million barrels. The locations of the SPR storage sites and their interconnecting pipelines to the tanker/barge terminals and major pipeline systems are shown in Figures 3 through 5. Four of the selected sites, i.e., West Hackberry, Bryan Mound, Bayou Choctaw, and Sulphur Mines, contain solution-mined caverns. The fifth site, Weeks Island, contains a mechanically excavated salt mine. A sixth site at Big Hill, Texas, is currently under development and current plans call for storage capability of about 140 million barrels.

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

Phase II of the SPR development program consists of the expansion of three Phase I sites to increase the SPR storage capacity by 290 million barrels. The Bryan Mound site is being expanded by 120 million barrels and the West Hackberry site is being expanded by 160 million barrels, both by leaching (solution mining) new caverns. A further 10 million barrel capacity will be added by Phase II through acquisition of an additional existing storage cavern at Bayou Choctaw. The Phase II storage program is projected to be complete in 1987.

Plans for Phase III, consisting of approximately 200 million barrels of storage capacity, currently call for the further expansion of existing sites (40 million barrels at Bryan Mound, 10 million barrels at West Hackberry, and 10 million barrels at Bayou Choctaw) and the development of a new 140 million barrel site located at Big Hill, Texas. The Phase III storage program is currently projected for completion in 1990. The completed fill and the projected fill of the SPR sites, by Phase and by type of crude oil, are shown in Table 3.

The estimated cost for development of the 750 million barrel Reserve and the acquisition cost of the crude oil is $27 billion.

SPR Sites

The SPR sites are grouped into the three distribution complexes that were originally

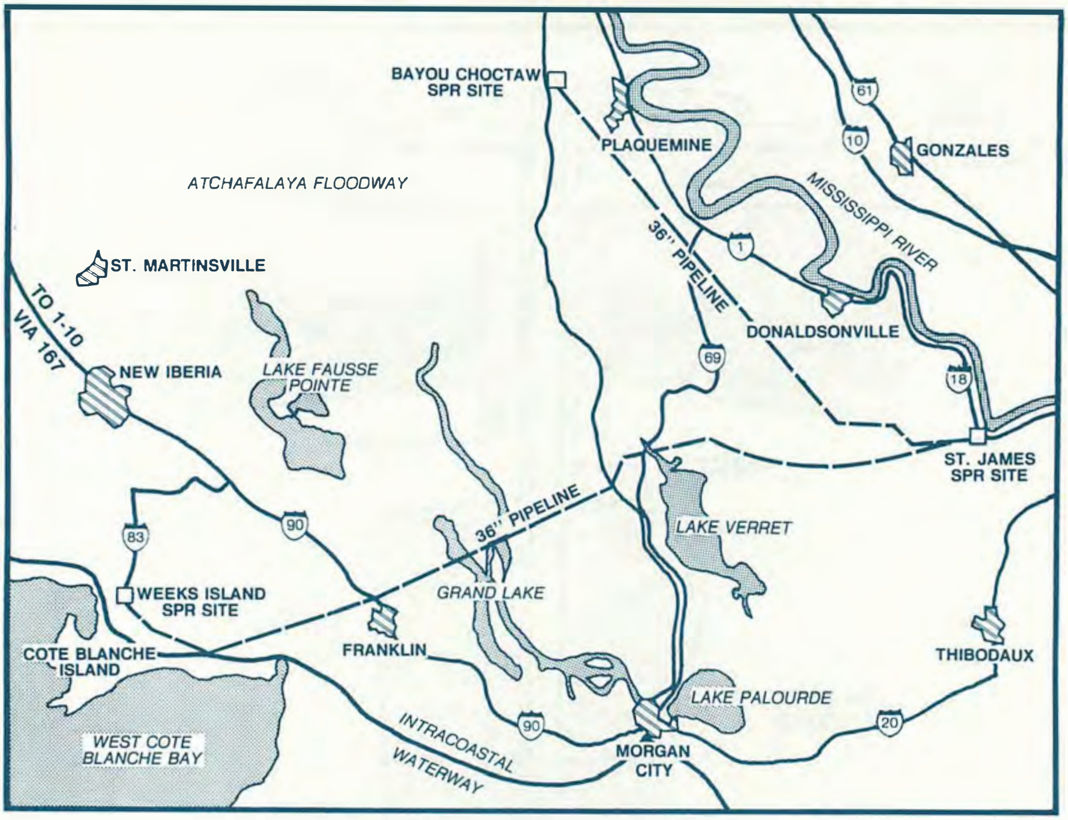

Figure 3. Capline Complex.

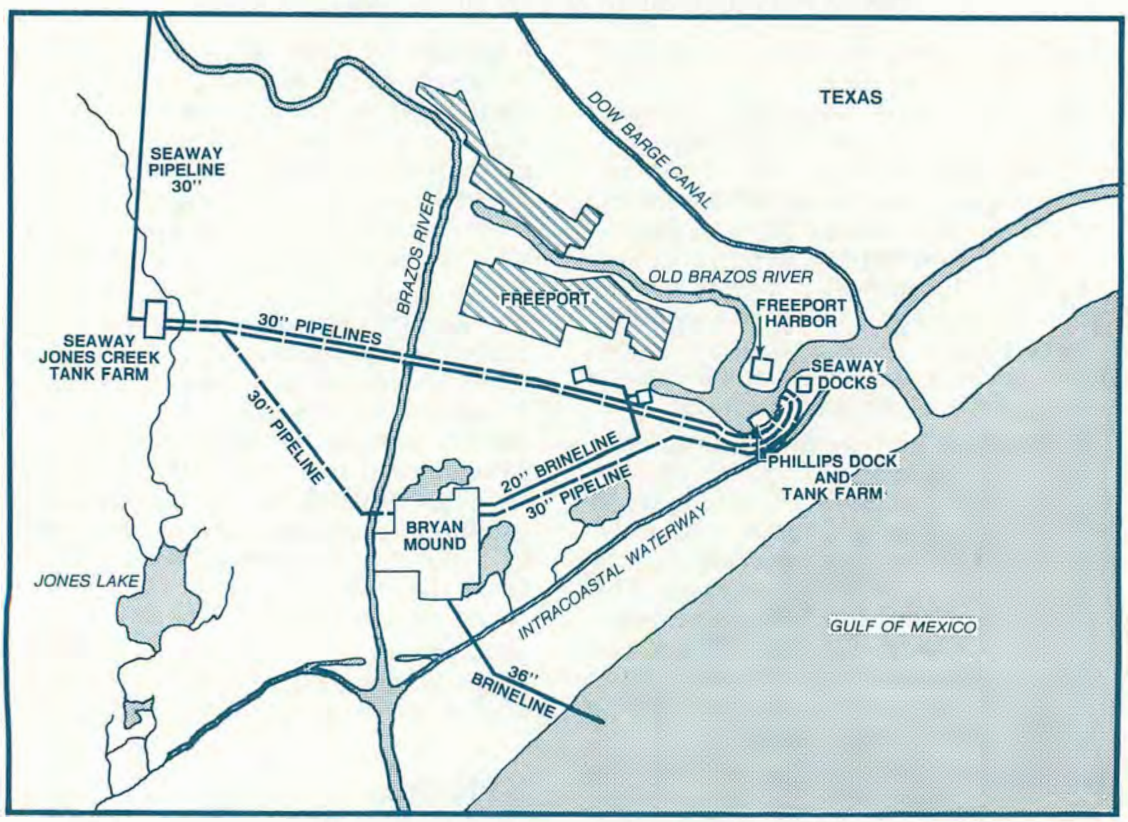

Figure 4. Seaway Complex.

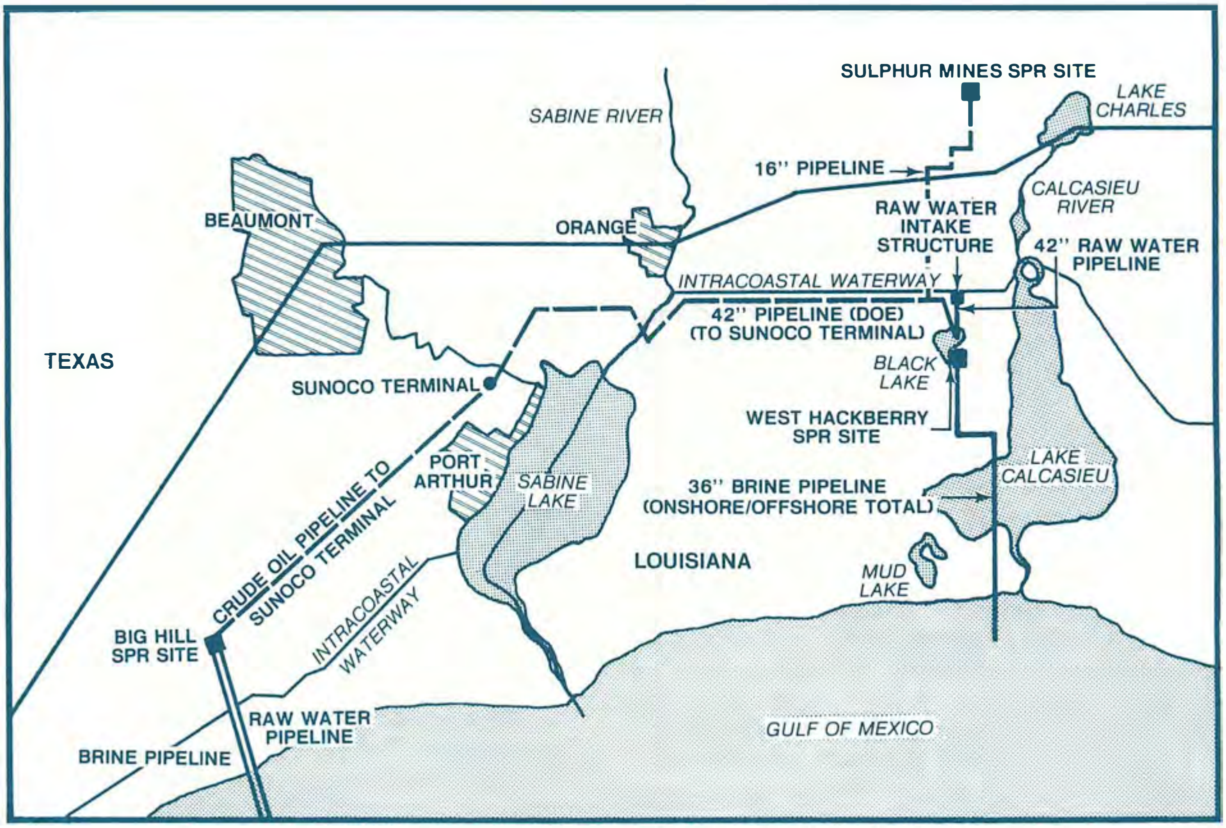

Figure 5. Texoma Complex.

TABLE 3

DOE CURRENT AND PROJECTED SPR FILL*
(Millions of Barrels)

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

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

intended to deliver the crude oil to refiners through three major crude oil pipeline systems. Because of refinery closings and therefore reduced crude oil demand, two of these pipelines, Seaway and Texoma, have been converted to use as natural gas lines and are no longer available to the SPR. The Seaway complex, which includes the Bryan Mound site, will deliver crude oil to the Seaway marine terminal. The Texoma complex will deliver crude oil to the Sun terminal at Nederland, Texas, for tanker/barge liftings and also to local pipelines serving Gulf Coast refineries. The Capline complex, consisting of the Bayou Choctaw and Weeks Island sites, will deliver crude oil to the DOE marine terminal at St. James, Louisiana, and to the Capline pipeline system.

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

Representatives of the NPC visited the SPR Project Management Office in New Orleans, the six SPR storage sites, and the Seaway, Sun, and DOE St. James terminal facilities. During these visits, the representatives received comprehensive briefings and observed first-hand the operation of the pumps, valves, and related control equipment by SPR personnel for leaching and crude oil movements. Following is a brief description of the SPR sites and related terminal facilities.

Capline Complex

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

Bayou Choctaw. The Bayou Choctaw site is located about 12 miles southwest of Baton Rouge, Louisiana, and was acquired in April 1977. It consists of approximately 356 acres. Upon completion of Phase III, the site will have storage capacity for 65 million barrels of oil. As of September 30, 1984, it had an inventory of 46.6 million barrels, consisting of 18.3 million barrels of low-sulfur crude oil and 28.3 million barrels of high-sulfur crude oil. The site is designed to deliver 480 MB/D to the DOE St. James terminal through a 37-mile, 36-inch-diameter pipeline. A diagram of the site is shown in Figure 6.

Weeks Island. The Weeks Island site is located about 95 miles southwest of New Orleans, Louisiana, and was acquired in September 1977. It consists of approximately 6½ surface acres and 383 subsurface acres. Development and fill of the former salt mine is completed and it contains approximately 73 million barrels of high-sulfur crude oil. The system is designed to deliver 590 MB/D through a 67-mile, 36-inch-diameter pipeline to the DOE St. James terminal. A diagram of the site is shown in Figure 7.

Seaway Complex

Bryan Mound. The Bryan Mound site, located near Freeport, Texas, was acquired in April 1977 and consists of 499 acres. Upon completion of Phase III, the site will store approximately 225 million barrels of crude oil. As of September 30, 1984, it had an inventory of 169.7 million barrels, consisting of 64.4 million barrels of low-sulfur crude oil and 105.3 million barrels of high-sulfur crude oil. The system was designed for a drawdown rate of 1,054 MB/D through a 3.6-mile, 30-inch-diameter pipeline to the Seaway docks or through a 4.6-mile, 30-inch-diameter pipeline to the Jones Creek Tank Farm and thence to a local pipeline. This facility has four 200,000-barrel crude oil tanks. A diagram of the site is shown in Figure 8.

Texoma Complex

Sulphur Mines. The Sulphur Mines site, acquired in February 1979, is located 3 miles west of Sulphur, Louisiana, and consists of approximately 174 acres. The site, which has a storage capacity of 26 million barrels, has been completely filled and consists entirely of high-sulfur crude oil. The designed drawdown rate is 100 MB/D through a 16-mile, 16-inch-diameter spur pipeline to a 34-mile, 42-inch-diameter pipeline to the Sun terminal, Nederland, Texas. A diagram of the site is shown in Figure 9.

West Hackberry. The initial acquisition of the West Hackberry site was in April 1977 and consisted of 405 acres. It is located about 12 miles southwest of Lake Charles, Louisiana. Total area through Phase III will be 565 acres. Upon completion, the site will have a storage capacity of 219 million barrels. As of

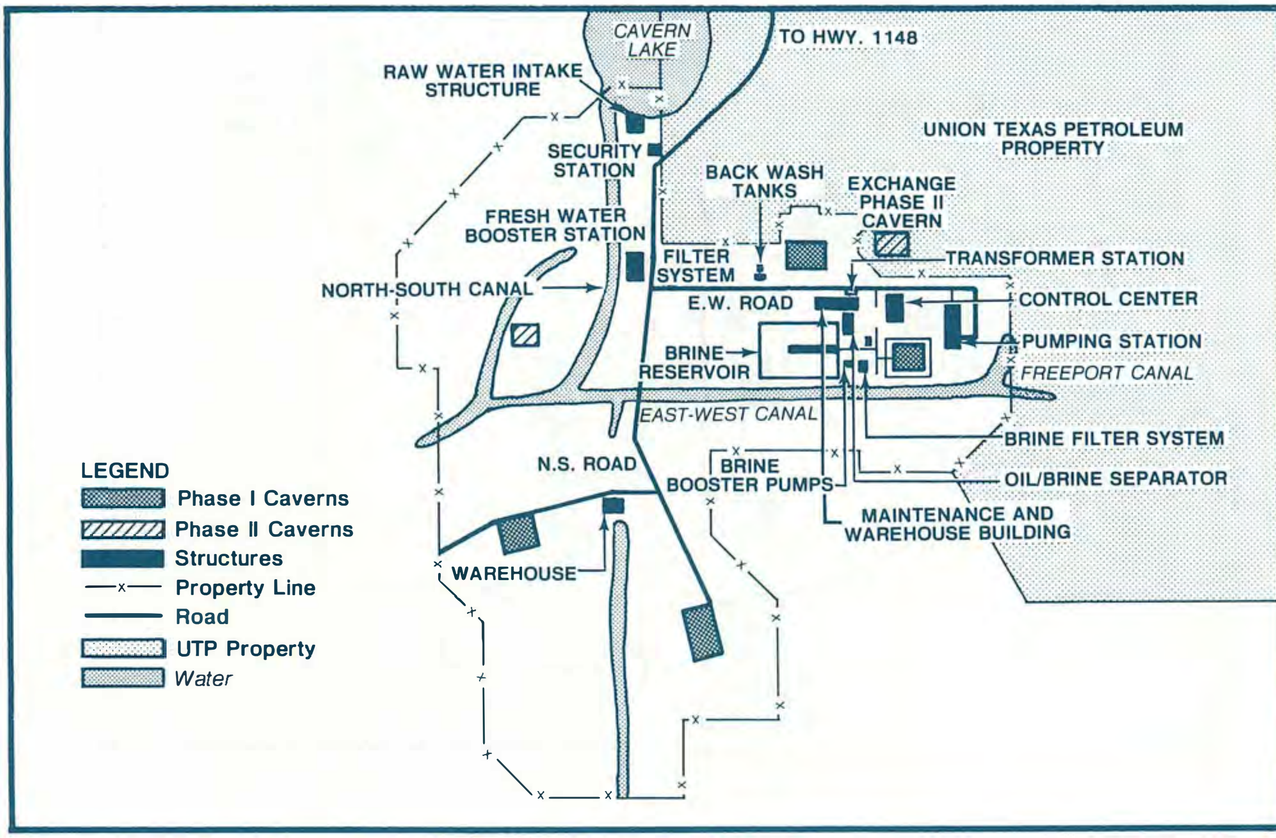

Figure 6. Bayou Choctaw Site.

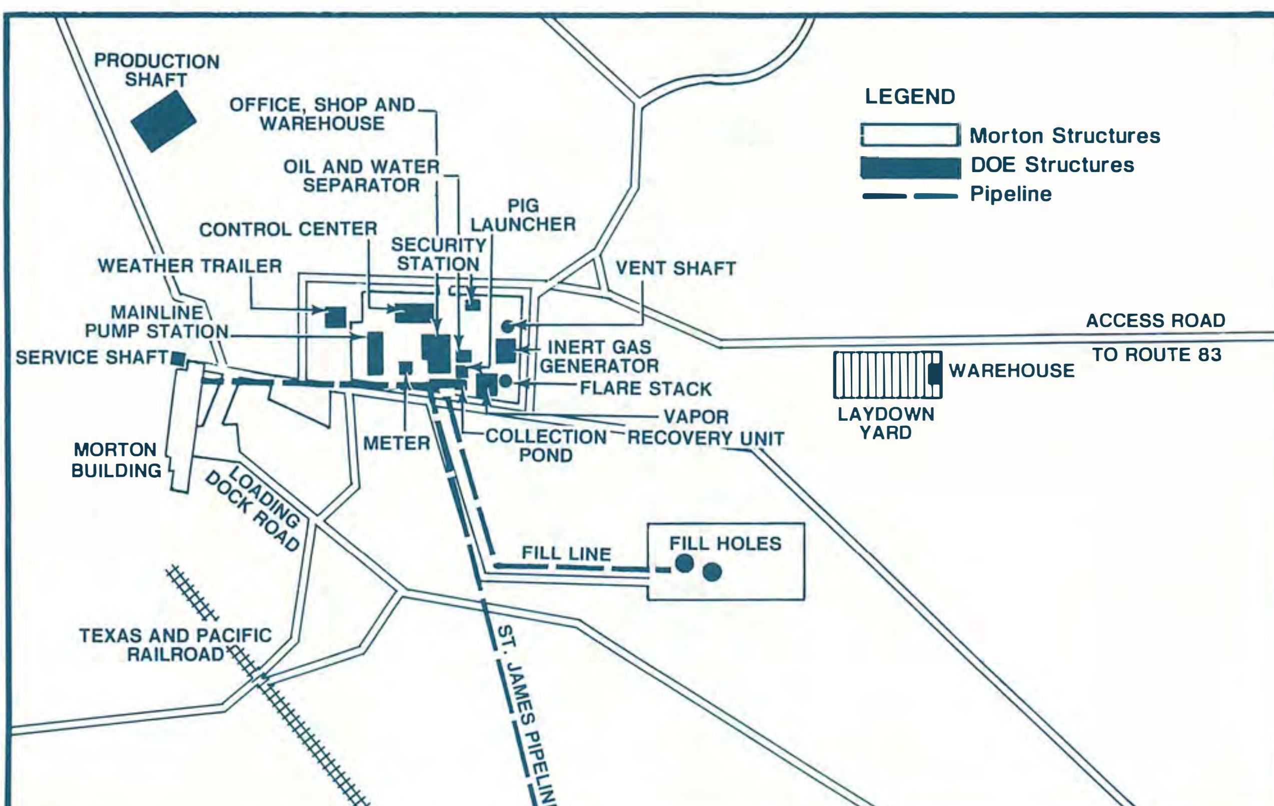

Figure 7. Weeks Island Site.

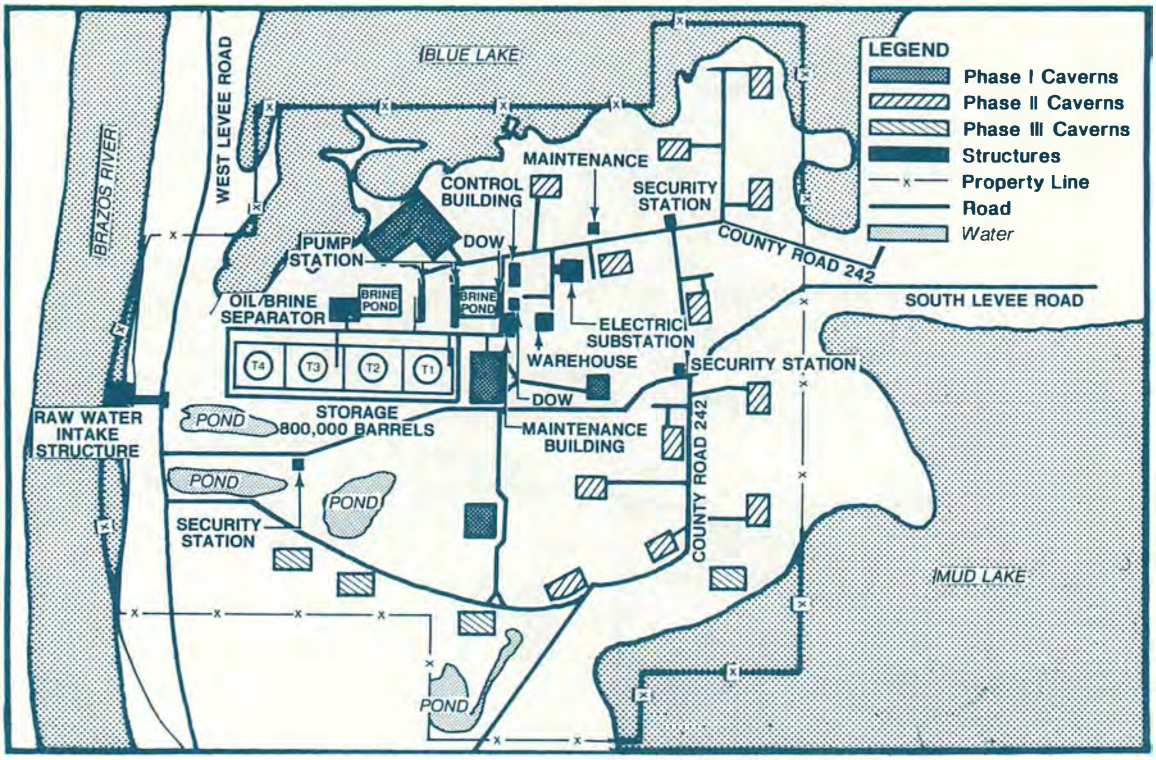

Figure 8. Bryan Mound Site.

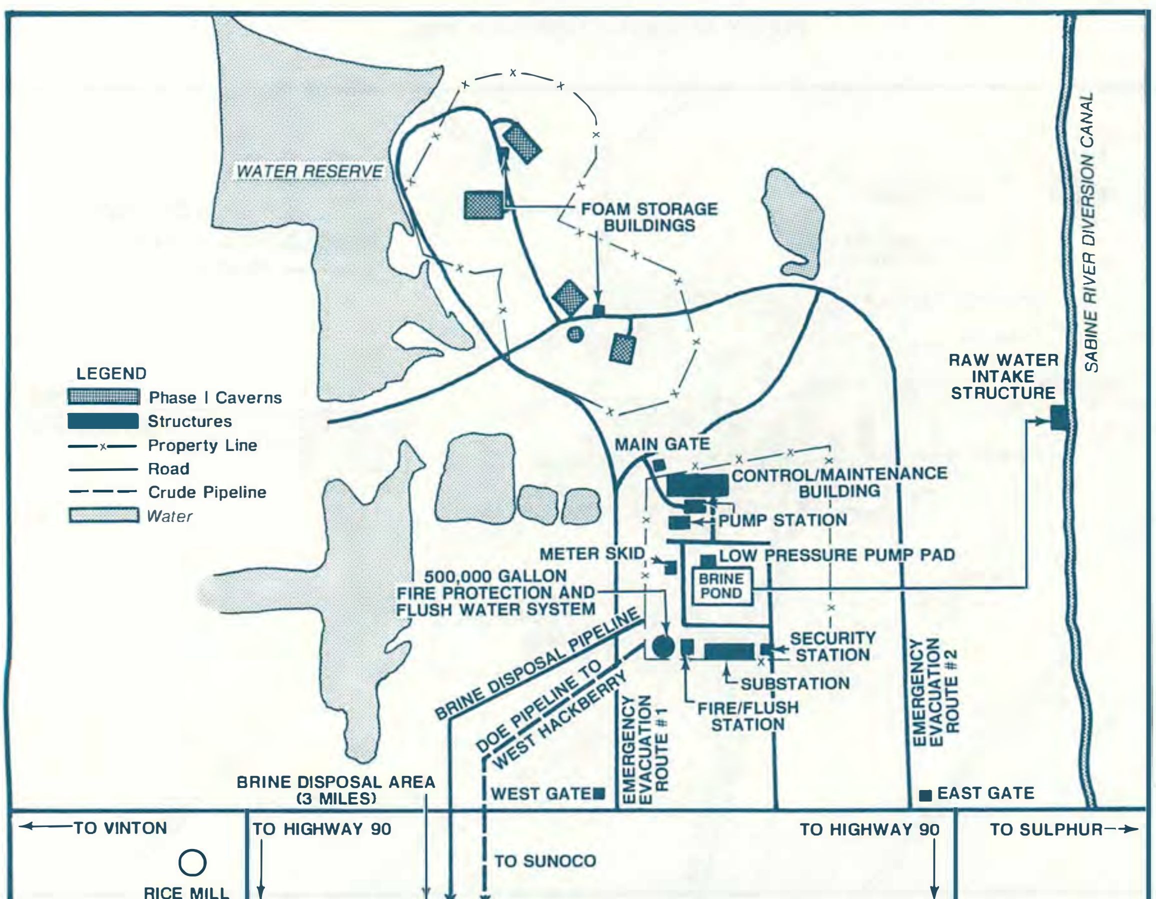

Figure 9. Sulphur Mines Site.

September 30, 1984, it had an inventory of 115.4 million barrels, consisting of 78.4 million barrels of low-sulfur crude oil and 37 million barrels of high-sulfur crude oil. The system has a designed drawdown rate of 1,400 MB/D through a 42-mile, 42-inch-diameter pipeline to the Sun terminal, Nederland, Texas. A diagram of the site is shown in Figure 10.

Big Hill. Big Hill is the most recent site acquisition (December 1982) for the SPR and consists of 271 acres. It is located about 15 miles southwest of Nederland, Texas. The facility is ultimately intended to store 140 million barrels of crude oil in 14 new leached caverns. Drilling of the first Big Hill well began in May 1983. Seven of the first ten wells were completed by December 31, 1983. The site is designed for a drawdown rate of 935 MB/D to be delivered to the Sun terminal at Nederland, Texas, through a 36-inch-diameter pipeline. A diagram of the site is shown in Figure 11.

Figure 12 provides a complete overview of the SPR storage and distribution facilities for the planned 750 million barrel underground storage program.

Current SPR Inventory and Drawdown Capability

As of September 30, 1984, SPR crude oil inventory was approximately 431 million barrels. Of that total, some 270 million barrels were high-sulfur crude oil while 161 million barrels were low-sulfur crude oil. Table 4 shows the maximum current drawdown rates for the five operational sites. DOE has conducted drawdown pumping tests at Bryan Mound, Bayou Choctaw, and West Hackberry, the results of which are shown in Table 5.

Hydraulic calculations were performed by study participants to determine whether crude oil could be moved from the storage caverns and through the DOE pipelines at a rate sufficient to allow a 1990 drawdown of 4.5 million barrels per day (MMB/D). These calculations were done conservatively, without considering the use of booster pumps that would increase the drawdown rate. Table 6 shows that a 4.5 MMB/D drawdown rate could be achieved in 1990 and would be sustainable for 90 days.

The current delivery rate, shown in Table 4, is considerably less than originally planned

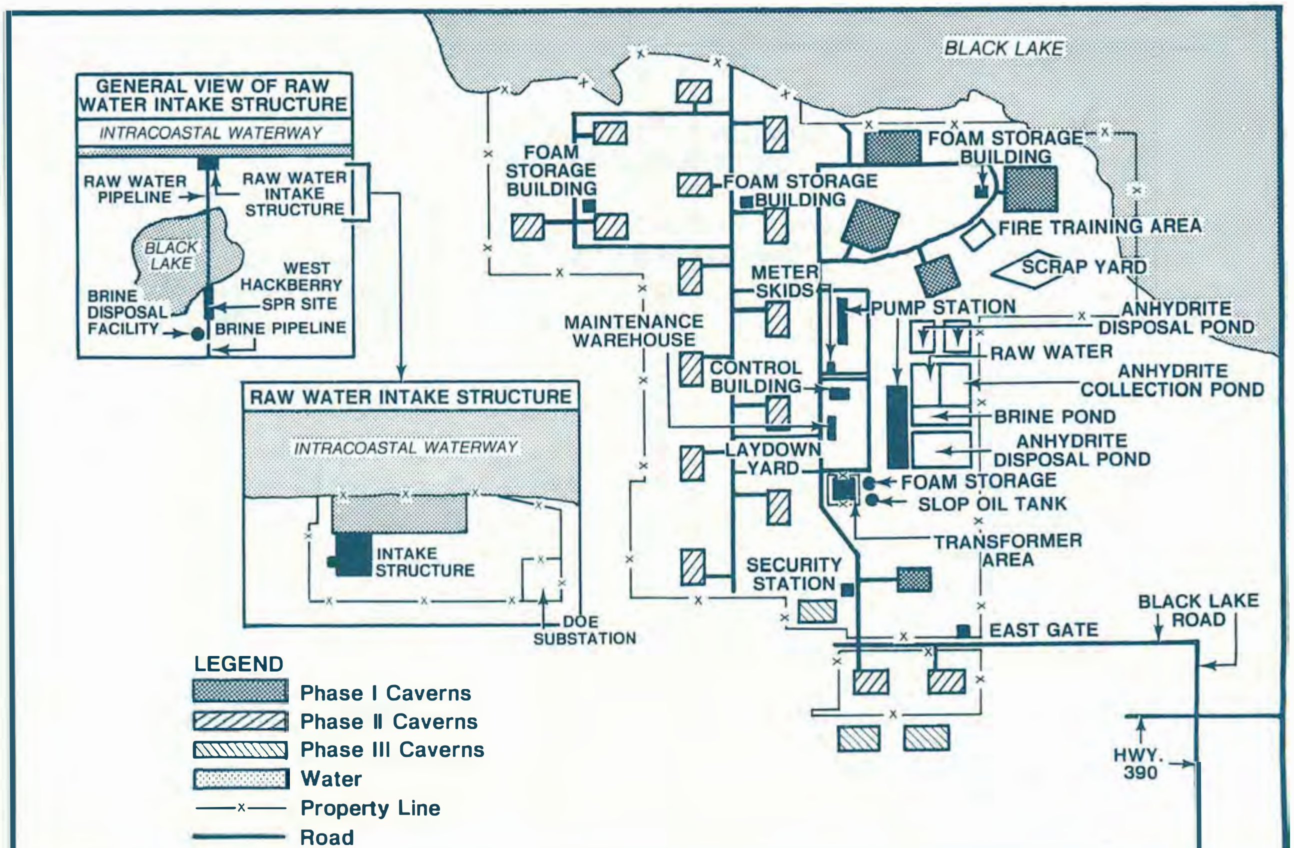

Figure 10. West Hackberry Site.

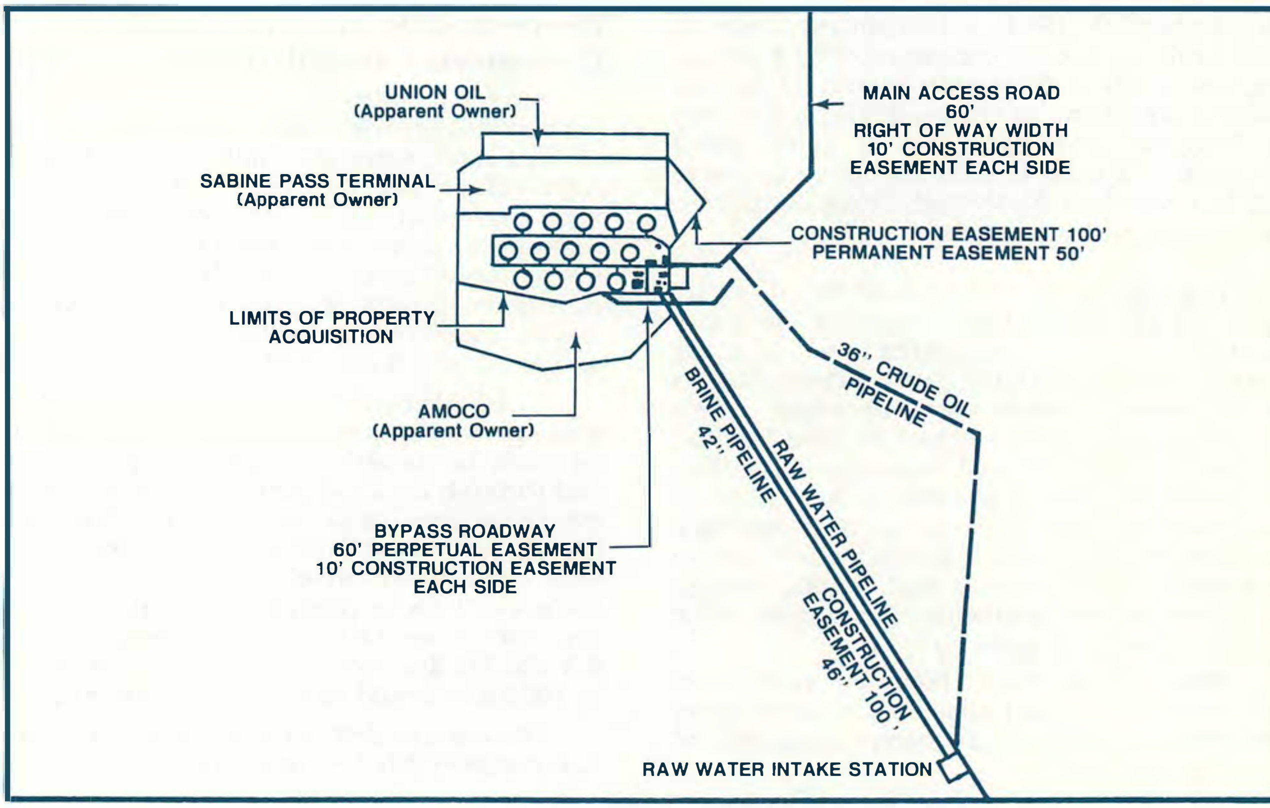

Figure 11. Big Hill Site.

TABLE 4

**SPR CRUDE OIL INVENTORY
(SEPTEMBER 30, 1984)**

Facility	Current Crude Oil Inventory (Millions of Barrels) Low Sulfur	High Sulfur	Total	Current Drawdown Capability (MB/D)	Current Complex Deliverability (MB/D)
Seaway Complex					
Bryan Mound	64.4	105.3	169.7	1,000	495*
Capline Complex					
Bayou Choctaw	18.3	28.3	46.6	240	880
Weeks Island	-	73.4	73.4	590	
Texoma Complex					
West Hackberry	78.4	37.0	115.4	1,100	1,120
Sulphur Mines	-	26.0	26.0	100	
Big Hill	-	-	-	0	
Total	**161.1**	**270.0**	**431.1**	**2,930**	**2,495**
Percentage	**37.4**	**62.6**	**100**		

*Limited to 400 MB/D unless the only refinery now connected to Seaway by pipeline takes more than its pro rata "share" of available SPR supplies. See discussion in Chapter Three.

TABLE 5

DOE DRAWDOWN TEST RESULTS

Date	Site	Drawdown Rate
July 1983	Bayou Choctaw/St. James	259 MB/D
November 1983	Bryan Mound	1,000 MB/D
May 1984	West Hackberry/Sun Terminal	1,000 MB/D

in view of the loss of the Texoma and Seaway pipeline capacity. Furthermore, the accuracy of the delivery rate is questionable because of the lack of deballasting facilities at the marine terminals servicing the storage sites. With the exception of very limited facilities at the Nederland terminal, the SPR terminals are not equipped with ballast treatment facilities. Significant delays could result if dirty ballast must first be discharged at another port or offloaded into barges prior to cargo loading.

The development of the Big Hill SPR storage capacity of 140 million barrels with a drawdown capability of nearly 1 MMB/D into the Sun terminal at Nederland, Texas, would further overtax the delivery rate of this terminal.

Figure 13 delineates the specifications for the seven crude oil types procured for SPR storage. To date, DOE has purchased these crude oils in a ratio of 65 percent high-sulfur to 35 percent low-sulfur.

TABLE 6

NPC CALCULATED MAXIMUM 1990 DRAWDOWN RATE (MB/D)

	Low-Sulfur Crude Oil*		High-Sulfur Crude Oil*		Oil Pipeline Capacity	
Facility	Full Cavern	Nearly Empty Cavern	Full Cavern	Nearly Empty Cavern	Low Sulfur	High Sulfur
Seaway Complex						
Bryan Mound	1,150	1,000	1,050	900	1,150	1,050
Capline Complex						
Bayou Choctaw	560	380	460	310	560	460
Weeks Island†	–	–	620	620	–	620
Texoma Complex						
West Hackberry	1,200	990	1,000	850	1,550	1,350
Sulphur Mines	–	–	100	100	–	100
Big Hill	1,200	820	980	680	1,300	1,100
Totals	**4,110**	**3,190**	**4,210**	**3,460**	**4,560**	**4,680**

*Without freshwater injection boosters or crude oil boosters.

†With crude oil boosters.

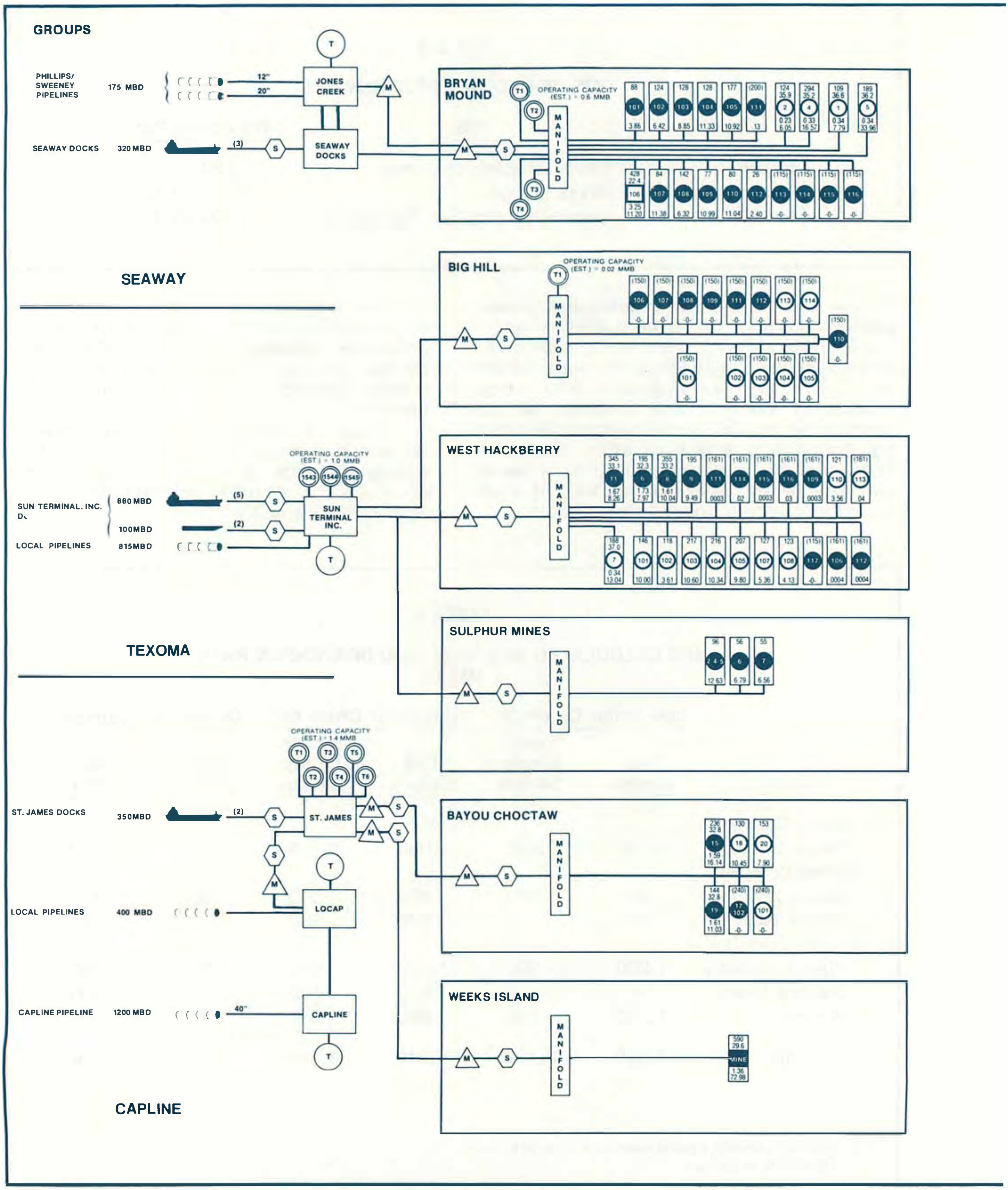

Figure 12. SPR System Schematic.

BRYAN MOUND INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SWEET	64.37	-0-	-0-	64.37
SOUR	-0-	83.63	-0-	83.63
MAYA	-0-	11.20	-0-	11.20
SUB TOTALS	64.37	94.83	-0-	159.20
			SITE TOTAL	159.20

BIG HILL INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SWEET	-0-	-0-	-0-	-0-
SUB TOTALS	-0-	-0-	-0-	-0-
			SITE TOTAL	-0-

WEST HACKBERRY INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SWEET	13.04	57.44	-0-	70.48
SOUR	35.76	0.05	-0-	35.81
SUB TOTALS	48.80	57.49	-0-	106.29
			SITE TOTAL	106.29

SULPHUR MINES INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SOUR	25.98	-0-	-0-	25.98
SUB TOTALS	25.98	-0-	-0-	25.98
			SITE TOTAL	25.98

BAYOU CHOCTAW INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SWEET	18.36	-0-	-0-	18.36
SOUR	27.17	-0-	-0-	27.17
SUB TOTALS	45.53	-0-	-0-	45.53
			SITE TOTAL	45.53

WEEKS ISLAND INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
WEEKS ISLAND SOUR	72.98	-0-	-0-	72.98
SUB TOTALS	72.98	-0-	-0-	72.98
			SITE TOTAL	72.98

CURRENT SPR INVENTORY SUMMARY				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	TOTAL IN MMB
SWEET	95.77	57.44	-0-	153.21
SOUR	88.91	83.68	-0-	172.59
MAYA	-0-	11.20	-0-	11.20
WEEKS ISLAND SOUR	72.98	-0-	-0-	72.98
SUB TOTALS	257.66	152.32	-0-	409.98
			SPR TOTAL	409.98

SITE DRAWDOWN RATES (MBD)				
CRUDE TYPE	PHASE I	PHASE II	PHASE III	CURRENT/ DEMON-STRATED
BM	387	1,054	1,054	1,000
BH	----	----	934	-0-
WH	402	1,402*	1,402*	1,000
SM	100	100*	100*	100
BC	240	480	480	240
WI	590	590	590	590
TOTALS	1,719	3,524	4,458	2,930**
YEAR CAPABILITY EXPECTED	1982	1988	1991	

*COMBINED DRAWDOWN RATE OF WH AND SM IS 1.4 MMBD.

**SEE NOTES 4 & 7

SPR PIPELINE SPECIFICATIONS				
LINE	P/L SIZE (IN.)	I.D. (IN.)	LENGTH (MI.)	VOLUMETRIC CAPACITY (MB)
BM	30	29.376	8.0	35.4
BH	36	35.376	26.0	166.9
WH	42	41.124	42.8	371.1
SM	16	15.500	15.9	19.6
BC	36	35.376	37.2	238.9
WI	36	35.124	67.2	425.3
			TOTAL PIPELINE VOLUME	1257.2

SPR CAVERNS BY PHASE			
SITE	PHASE I	PHASE II	PHASE III
BM	1, 2, 4, 5	101-112	113-116
BH	------	------	101-114
WH	6, 7, 8, 9, 11	101-116	117
SM	2/4/5, 6, 7	------	------
BC	15, 18, 19, 20	17/102	101
WI	MINE	------	------
PLANNED PHASED OIL STORAGE (MMB)	260	290	200

NOTES

1. BIG HILL IS IN THE CONSTRUCTION STAGE: PIPELINE TO SUN TEMINAL, INC. IS STILL IN PLANNING.
2. SULPHUR MINES IS CURRENTLY PLANNED AS A ONE-TIME DRAWDOWN SITE, DUE TO CAVERN GEOPHYSICAL CONSTRAINTS.
3. DRAWDOWN CONFIGURATIONS ARE DYNAMIC AND ILLUSTRATED PARAMETERS ARE SUBJECT TO CONTINUED CHANGE.
4. CURRENT CAVERN AND SITE DRAWDOWN RATES ARE BASED ON EROSION VELOCITY LIMITS OF 30 FT./SEC. IN OIL, WATER, AND BRINE SERVICES.
5. CAVERN CRUDE TYPES ARE LONG-TERM DESIGNATIONS, AND CURRENT FILL (BLANKET OIL) MAY NOT REFLECT FINAL USE.
6. TOTAL SPR INVENTORY, INCLUDING CAVERNS, TANKS, AND PIPELINES, IS 413,734,620 BARRELS.
7. CURRENT/DEMONSTRATED DRAWDOWN RATES REPRESENT 24-HOUR OPERATIONAL TESTS OF THEN-CURRENT CONFIGURATIONS AND CAPABILITIES.
8. ALL PHASE I TANK CAPACITIES, PIPELINE FILLS AND SITE MANIFOLDING (EXCEPT BIG HILL) ARE CONSIDERED AS AVAILABLE PHASE I STORAGE.

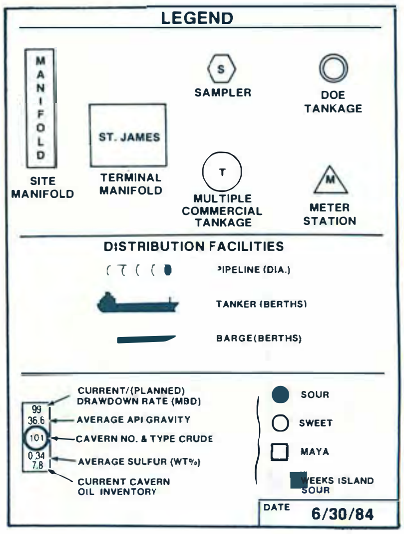

Figure 12. SPR System Schematic (Continued).

Courtesy of the Strategic Petroleum Reserve Office.

SPR CRUDE OIL SPECIFICATIONS (SPRO 1984 JUL)[a]

Characteristic	I	II	III	IV	V	VI	VII	Primary ASTM TEST METHOD[b]
API Gravity [°API]	30-45	40-45	30-40	34-40	36-41	26-45	22.0 Min.	D 1298
Total Sulfur [Wt.%], Max.	1.99	0.25	0.50	0.25	0.50	1.25	3.5	D 1552
Pour Point [°F (°C)], Max.	50 (10)	50 (10)	50 (10)	50 (10)	50 (10)	50 (10)	50 (10)	D 97
Salt Content [Lbs./1,000 Bbls.], Max.	50	50	50	50	50	50	50	D 3230
Viscosity [SUS @ 60 °F (cSt @ 15.6°C)], Max.	150 (32)	150 (32)	150 (32)	150 (32)	150 (32)	200 (43)	1500 (325)	D 445 & D 2161
[SUS @ 100 °F (cSt @ 37.8°C)], Max.	70 (13)	70 (13)	70 (13)	70 (13)	70 (13)	80 (16)	350 (75)	
Reid Vapor Pressure [Psia @ 100 °F (kPa @ 37.8 °C)], Max.	9.5 (65)	9.5 (65)	9.5 (65)	9.5 (65)	9.5 (65)	9.5 (65)	9.5 (65)	D 323
Total Acid Number [mg KOH/g], Max.	0.40	0.40	0.40	0.40	0.40	0.40	0.40	D 644
Water and Sediment [Vol.%], Max.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	D 473 & D 4006
Yields [Vol.%]								
Naphtha [<375 °F (<191 °C)]	24-30	35-42	21-29	29-36	30-38	15-20	10 Min.	
Distillate [375-620 °F (191-327 °C)]	17-31	21-35	23-37	31-45	19-33	24-27	15 Min.	D 2892 & D 1160
Gas Oil [620-1050 °F (327-566 °C)]	26-38	20-34	28-42	20-34	23-37	38-42	20 Min.	
Residuum [>1050 °F (>566 °C)]	10-19	4-9	7-14	0-5	7-14	15-20	50 Max.	

[a] Crude oil must be marketable, free of added chemicals or contaminants, and suitable for normal refinery processing.

[b] To the maximum extent practicable, the primary ASTM test methods listed are to be used in characterizing crude oil. While other methods may be used when the primary method is unavailable, the primary method is designated as the referee method in any disputes.

Figure 13. DOE Procurement Specifications for Each of the Seven SPR Crude Oil Types.

Chapter Two
Analysis Considerations and Procedures

Overview of Study Methodology

The bases for the study analysis were crude oil and product logistics balances for 1983 (actual), and for a 1990 nondisrupted case and 1990 disrupted case. The study methodology was designed to assess the capabilities of the SPR complexes, overland and marine distribution systems, and domestic refineries, in each of these three cases.

For the purposes of this study, U.S. refineries were segregated into 13 refining centers on the basis of location and accessibility to SPR oil. Historical data on crude oil and product imports and exports, refining capacity, refinery runs, and product slates were obtained from the EIA. Current overland crude oil and product distribution capacities and movement patterns (intra-PADD and inter-PADD) were defined. The current supply of U.S. and foreign flag marine tonnage capable of moving crude oil and petroleum products was quantified on the basis of published data. Waterborne distribution patterns were also identified, and trade route factors were generated to measure the current demand for tankers and barges in the domestic crude oil and product trades.

Crude oil and product logistics balances were projected to 1990 on the basis of published data and the judgment of the study participants. Refining input and output balances were derived through extrapolation of the 1983 data consistent with EIA's long range forecast of crude oil production, product demand, and imports. Levels of refining capacity in 1983 were projected to be more than adequate to meet 1990 product demand since future shutdowns were assumed to be offset by debottlenecking. The 1990 overland transportation system was assumed to be the same as in the 1983 case, with no changes in the existing pipeline network or capabilities. The future availability of U.S. and foreign flag tonnage was estimated using a number of assumptions regarding the scrapping of ships, new construction, and projected import levels. The 1983 factors used to estimate the tonnage requirements for various trade patterns were applied to the 1990 case.

To test the logistics capabilities of the SPR system, overland and marine distribution systems, and the domestic refining industry to draw down, distribute, and refine SPR crude oil at the maximum SPR design rate, a disruption scenario requiring a 4.5 MMB/D SPR drawdown was developed. The disruption logistics requirements were then overlaid on the projected 1990 facilities and systems to identify any potential bottlenecks or hindrances to the efficient distribution of 4.5 MMB/D of SPR oil.

To complete the study in a timely fashion, certain basic simplifying assumptions were necessary. The principal issue was the disruption scenario itself, which was structured to allow the testing of the SPR system at its maximum projected (1990) drawdown rate. The assumption of a total cutoff of virtually all crude oil and product imports eliminated the need for subjective assessments of which exporting countries might be involved or which types of crude oil would be affected. No attempt was made to assess the causes of a complete import cutoff or the likelihood of such an event occurring. Rather, the scenario was designed as a means by which the complex logistics involved in an SPR drawdown could be tested, without assessing the myriad potential geopolitical and military issues.

All of the information used in this analysis was obtained from the public domain or developed from the expertise of the study participants. The report is not a forecast of future market conditions or of a future disruption. The report is not intended to be a reiteration of previous studies, a refinery flexibility study, or an in-depth supply/demand analysis. Nor is the study intended to be a commentary on U.S. maritime policies. The report focuses on the achievability of maximum drawdown and use of SPR oil in a 1990 disruption, and the means by which this could be accomplished. Additional insight into possible alternative directions the study could have taken can be derived from the sensitivities noted in Chapter Three.

Definition of the 1983 Base Case

Identification of Refining Centers

The refining industry in the United States was divided into 13 refining centers according to common geographic location and accessibility to shipments of crude oil from the SPR. The refining centers are listed in Table 7 and a map of their locations is shown in Figure 14. A complete listing of the refineries in each refining center may be found in Appendix E.

TABLE 7

SUMMARY OF U.S. REFINING CENTERS

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

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

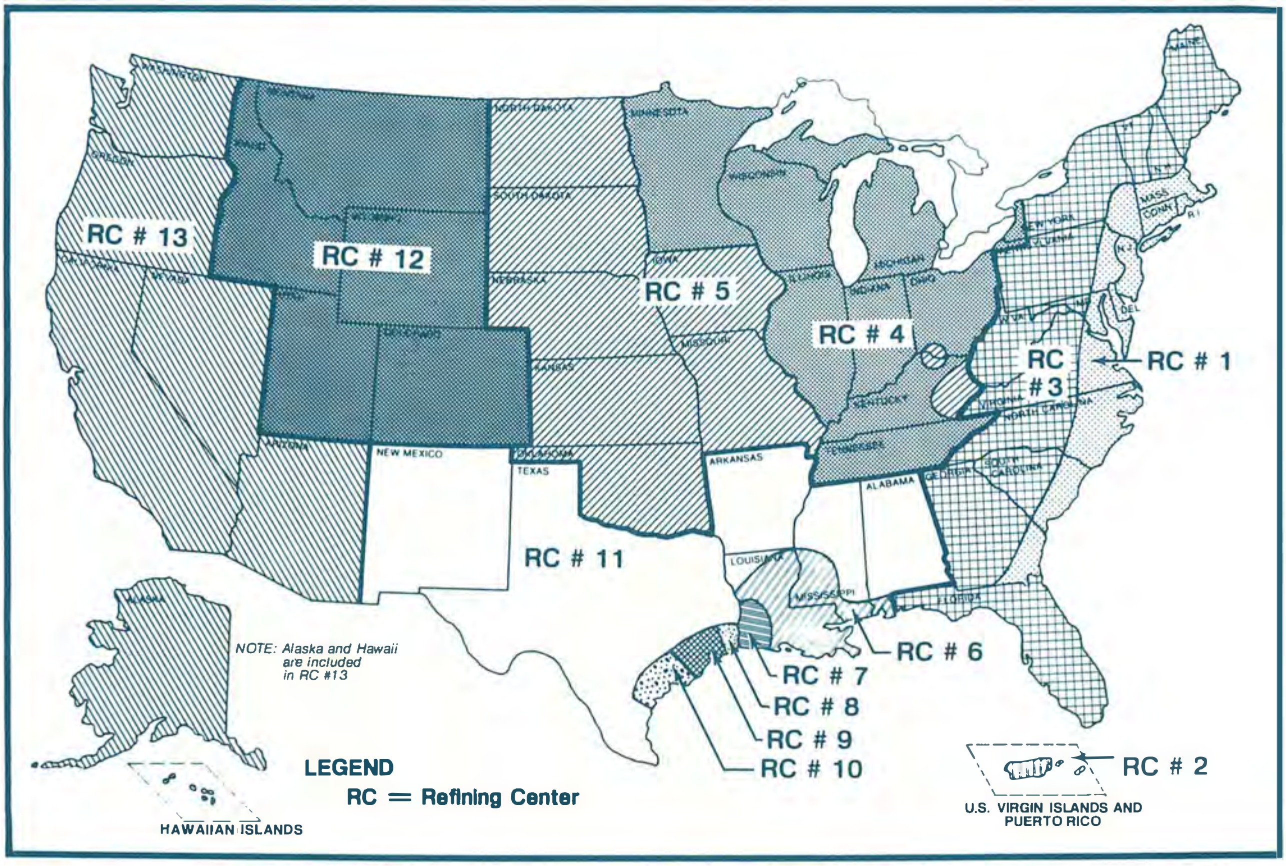

Figure 14. U.S. Refining Centers.

Refinery Inputs and Outputs—1983

The 1983 inputs and outputs for each refining center were developed from information routinely submitted by each refinery to the EIA on Form EIA-810 and Form EIA-820. This information includes actual 1983 refinery inputs and product outputs; projected capacities of refinery processing units for January 1, 1984, and January 1, 1985; and projected refinery inputs and product outputs for 1984 and 1985. The EIA aggregated the refinery specific information into the 13 refining centers for the NPC. (Data provided by the EIA may be found in Appendix E.) The data for each refining center covered all details needed for this study except crude oil input quality. The EIA data contain only weighted average sulfur content, weighted average API gravity, and receipts of Alaskan crude oil. Additional information on the quality of imported crude oil was obtained by the EIA from the Bureau of the Census, and was combined by refining center. (This information is shown in Appendix E.)

Based on these sources, the estimated distribution and composition of domestic crude oil production in 1983 are shown in Table 8. The input and output balances for each refining center in 1983 are presented in Table 9.

TABLE 8

DOMESTIC CRUDE OIL AND LEASE CONDENSATE QUALITY—1983*

	Production (MB/D)	Volume Percent Low Sulfur	Volume Percent High Sulfur
PADD I	80	57	43
PADD II	1,040	95	5
PADD III	4,180	72	28
PADD IV	570	44	56
PADD V	2,820	0	100
	8,690	**49**	**51**

*Numbers have been rounded.

TABLE 9

REFINERY INPUT/OUTPUT BY REFINING CENTER
1983 BASE CASE
(MB/D)

	Virgin Islands/ Puerto Rico	PADD I		
	Water Connected	Water Connected	Not Connected	Subtotal
Input				
Total Crude Oil & Lease Condensate	**422**	**944**	**47**	**991**
Domestic: Low Sulfur	–	–	44	44
High Sulfur	–	8	3	11
Alaskan & California OCS	130	140	–	140
Foreign: Low Sulfur	104	470	–	470
High Sulfur	195	348	–	348
Unidentified	(7)	(22)	–	(22)
Unfinished Oils	(27)	119	0	119
NGLs & Gasoline Blending Comp.	6	18	3	21
Total Input	**401**	**1,081**	**50**	**1,131**
Output				
Total Gasoline	106	542	12	554
Middle Distillates	111	281	16	297
Residual Fuel Oil & Asphalt	142	157	3	160
Other Products	47	152	16	168
Total Output	**406**	**1,132**	**47**	**1,179**
Net Processing Gain	(5)	(51)	3	(48)
Yields (%)*				
Total Gasoline	25.3	49.3	19.1	48.0
Middle Distillates	28.1	26.4	34.0	26.8
Residual Fuel Oil & Asphalt	35.9	14.8	6.4	14.4
Other Products	11.9	14.3	34.0	15.1
Total Yields†	**101.3**	**104.8**	**93.6**	**104.3**
Gross Crude Oil Distillation Input	439	953	47	1,000
Operable Capacity	737	1,446	57	1,503
Operating Rate (%)	59.6	65.9	82.1	66.5
Crude Sulfur (W. Avg.%)	0.98	0.98	0.30	0.94
API Gravity (W. Avg.)	29.12	31.32	41.61	31.80

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

TABLE 9 (Continued)

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

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

TABLE 9 (Continued)

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

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

TABLE 9 (Continued)

	PADD III (Continued)		
	Corpus Christi	Inland (Not Connected)	Subtotal
Input			
Total Crude Oil & Lease Condensate	**367**	**738**	**5,380**
Domestic: Low Sulfur	153	458	2,300
High Sulfur	–	247	1,031
Alaskan & California OCS	57	12	531
Foreign: Low Sulfur	93	18	628
High Sulfur	64	4	872
Unidentified	–	(1)	18
Unfinished Oils	46	31	197
NGLs & Gasoline Blending Comp.	22	57	352
Total Input	**435**	**826**	**5,929**
Output			
Total Gasoline	198	373	2,816
Middle Distillates	151	252	1,743
Residual Fuel Oil & Asphalt	34	82	472
Other Products	70	122	1,087
Total Output	**453**	**829**	**6,118**
Net Processing Gain	(18)	(3)	(189)
Yields (%)*			
Total Gasoline	42.6	41.1	44.2
Middle Distillates	36.6	32.8	31.3
Residual Fuel Oil & Asphalt	8.2	10.7	8.5
Other Products	16.9	15.9	19.5
Total Yields†	**104.4**	**100.4**	**103.4**
Gross Crude Oil Distillation Input	384	762	5,510
Operable Capacity	563	1,042	7,783
Operating Rate (%)	68.2	73.2	70.8
Crude Sulfur (W. Avg.%)	0.60	0.80	0.87
API Gravity (W. Avg.)	35.94	37.29	34.88

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

TABLE 9 (Continued)

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

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

Existing Distribution System—Overland

A supply/demand balance case was developed for each PADD and the U.S. Virgin Islands/Puerto Rico using actual 1983 data from the DOE's Energy Information Administration in the *Petroleum Supply Annual, 1983.* A summary of these supply/demand balances along with inter-PADD crude oil and product receipts and shipments is contained in Table 10. Corresponding crude oil movements are displayed in Figure 15. It should be noted that these balances treat liquified petroleum gas (LPG) as product and that LPG movements are included in the receipt and shipment data.

A brief discussion of petroleum logistics by PADD follows.

PADD I

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

Crude Oil. The only pipeline system capable of crude oil deliveries into PADD I is the

TABLE 10

SUPPLY/DEMAND BALANCE BY PADD—1983 BASE CASE (MB/D)

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

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

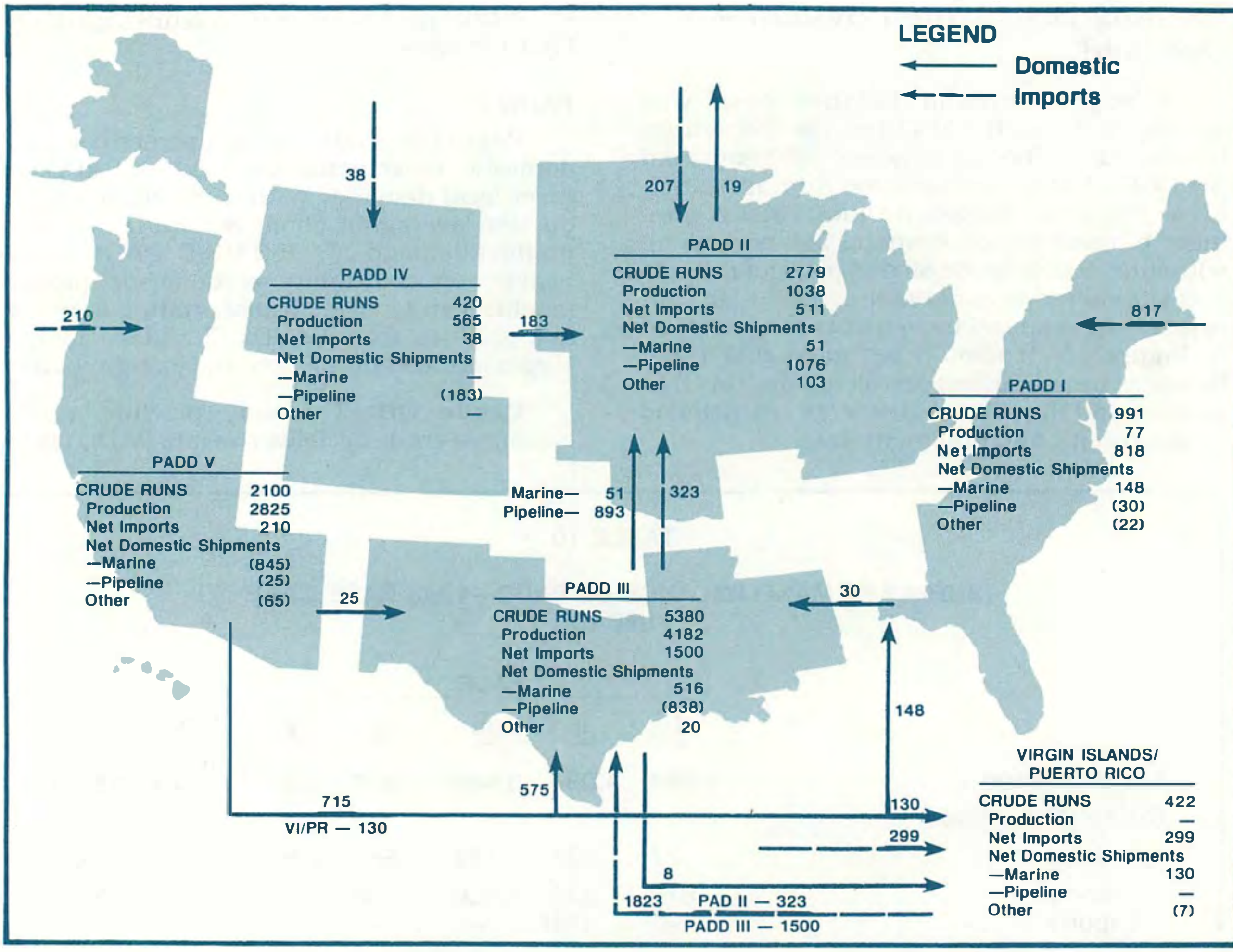

Figure 15. Actual Crude Oil Logistics (MB/D)—1983 Base Case.

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

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

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

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

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

U.S. Virgin Islands/Puerto Rico

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

PADD II

Crude Oil. During 1983, indigenous PADD II crude oil production represented only about 25 percent of PADD II product demand; hence this PADD is heavily dependent upon other areas to satisfy local demand. Crude oil movements to PADD II during 1983 are indicated in Table 11.

TABLE 11

CRUDE OIL MOVEMENTS INTO PADD II

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

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

PADD III

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

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

PADD IV

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

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

PADD V

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

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

A summary of crude oil production, refinery capacity, and product demand for all PADDs for 1983 is displayed in Figure 16.

Pipeline Systems

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

In the original SPR development plans, the Seaway and Texoma pipelines provided capability to transport SPR crude oil from the Bryan Mound site and the Texoma complex, respectively, to Midwest refiners through interconnection to other crude oil pipelines at Cushing, Oklahoma.

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

Figures 17 and 18 display the major inter-PADD crude oil and product pipelines as identified in the 1979 NPC study entitled *Storage and Transportation Capacities*.

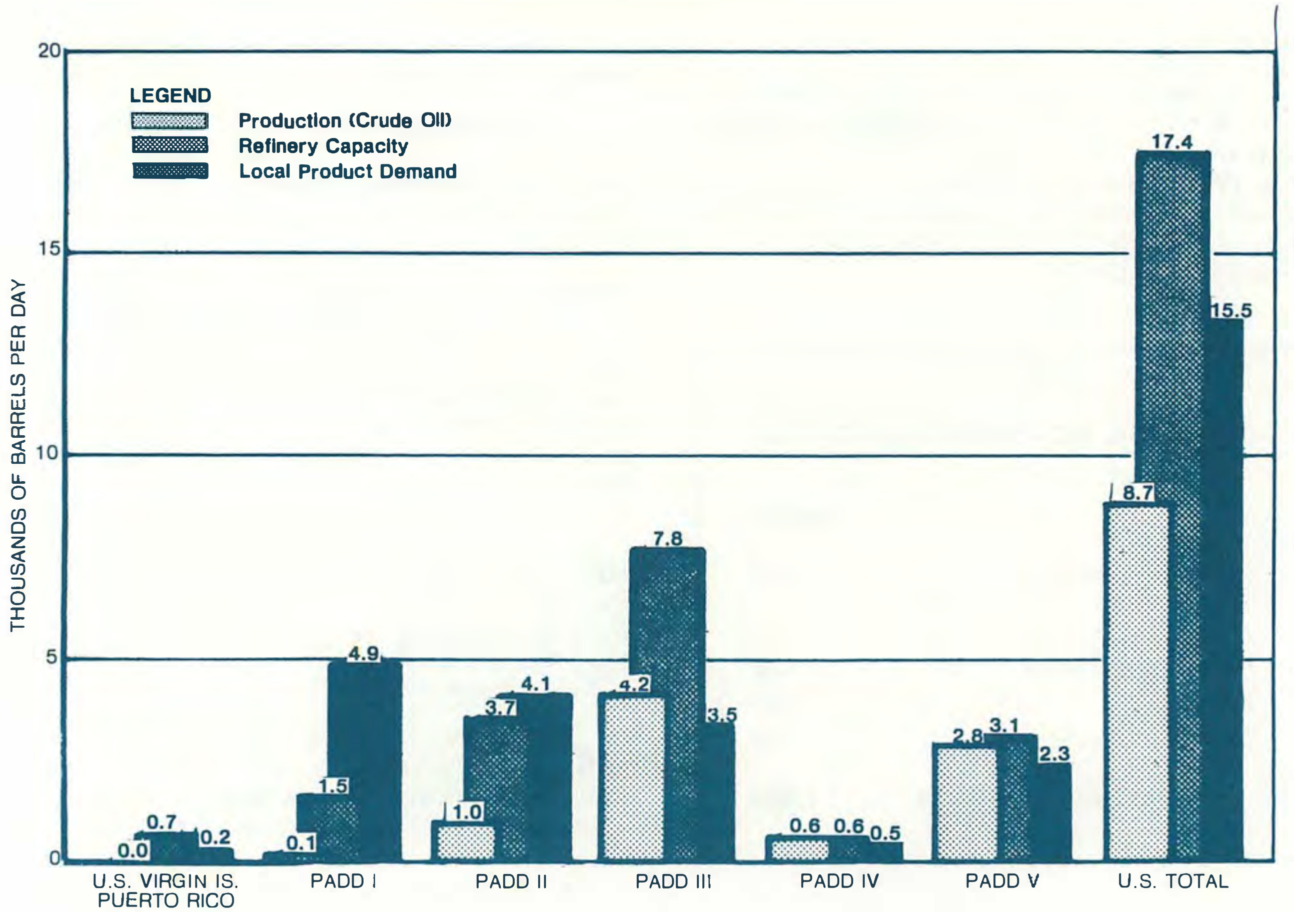

Figure 16. Summary of Crude Oil Production, Refining Capacity, and Product Demand (MMB/D)—1983.

Existing Distribution System—Marine

In order to assess the availability of U.S. flag tonnage for an emergency distribution of SPR crude oil stocks, the existing marine distribution requirements for domestic tankers and barges were examined. Demand estimates for U.S. flag vessels in 1983 were derived from the distribution data in Table 10. The existing fleet (June 1984) of domestic tankers and barges was allocated to specific trade routes based on general operating characteristics to develop the 1983 base case. The resulting 1983 supply/demand balance for U.S. flag tonnage was used as a projection base for the 1990 nondisrupted and disrupted cases.

1983 Supply of U.S. Flag Tankers and Barges

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

The Jones Act Fleet. The Jones Act is an amendment to the Merchant Marine Act of 1920, prohibiting the use of any but American-built, -owned, and -documented vessels in the carriage of cargo between points in the United States. Section 21, however, exempts the U.S. Virgin Islands and certain other noncontiguous U.S. points. As a result, foreign flag tankers are permitted to trade between the U.S. Virgin Islands and the U.S. mainland.

The Jones Act fleet, therefore, refers to the U.S. flag tankers that qualify to operate in the domestic oil trade. As illustrated in Table 12, the fleet has a total deadweight tonnage of approximately 10 million long tons. The most significant source of employment for Jones Act tankers in terms of cargo volume is the movement of Alaskan crude oil to domestic refining centers.

Waivers of the Jones Act are provided for to the extent that such waivers are deemed necessary in the interest of national defense. Waiver procedures are discussed in Appendix D.

The Subsidized Fleet. The Merchant Marine Act of 1936 provided a number of programs to help U.S. flag ships participate in the

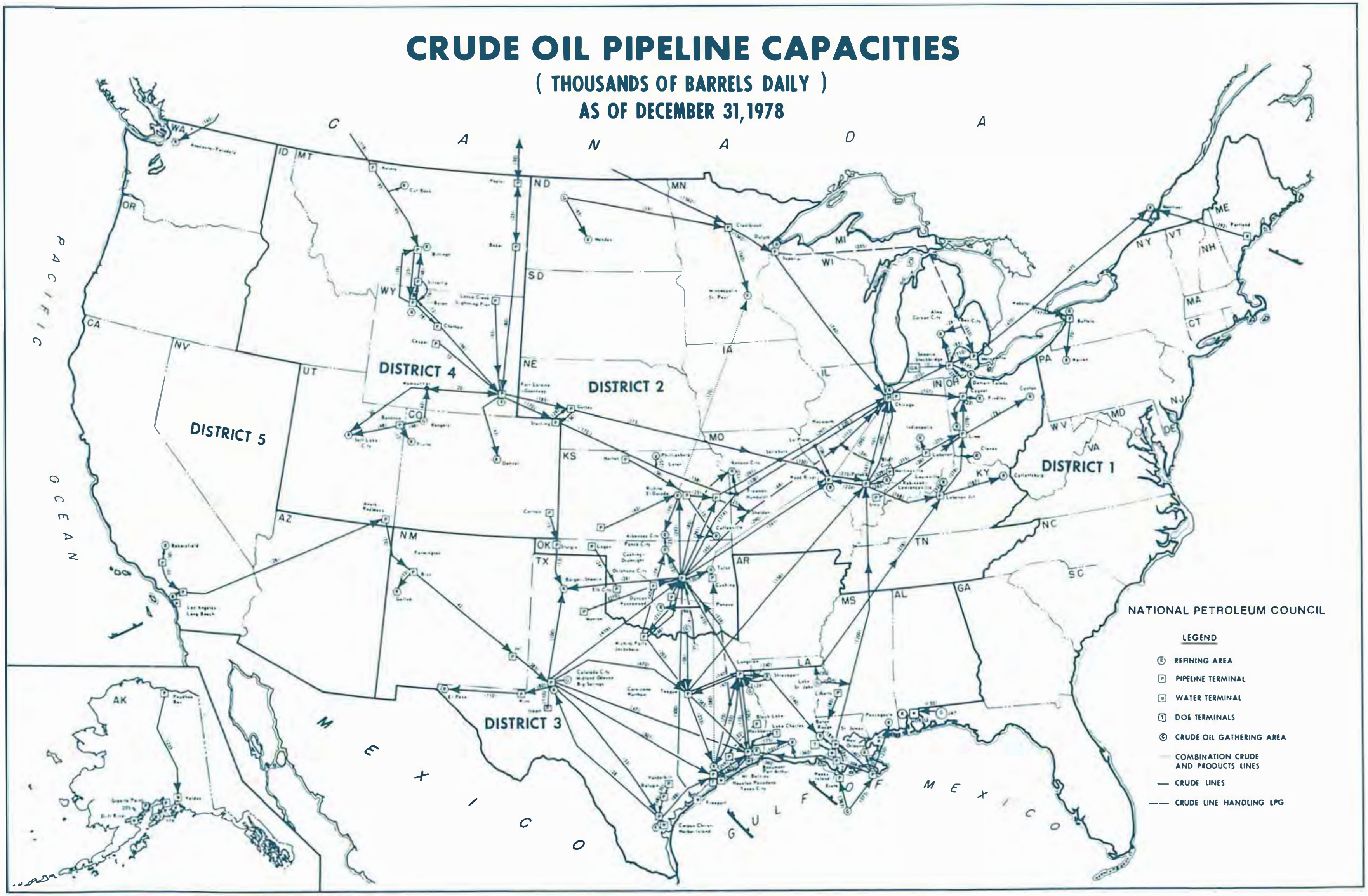

Figure 17. 1978 Crude Oil Pipelines.

NOTE: The Texoma and Seaway pipelines are no longer in crude oil service.

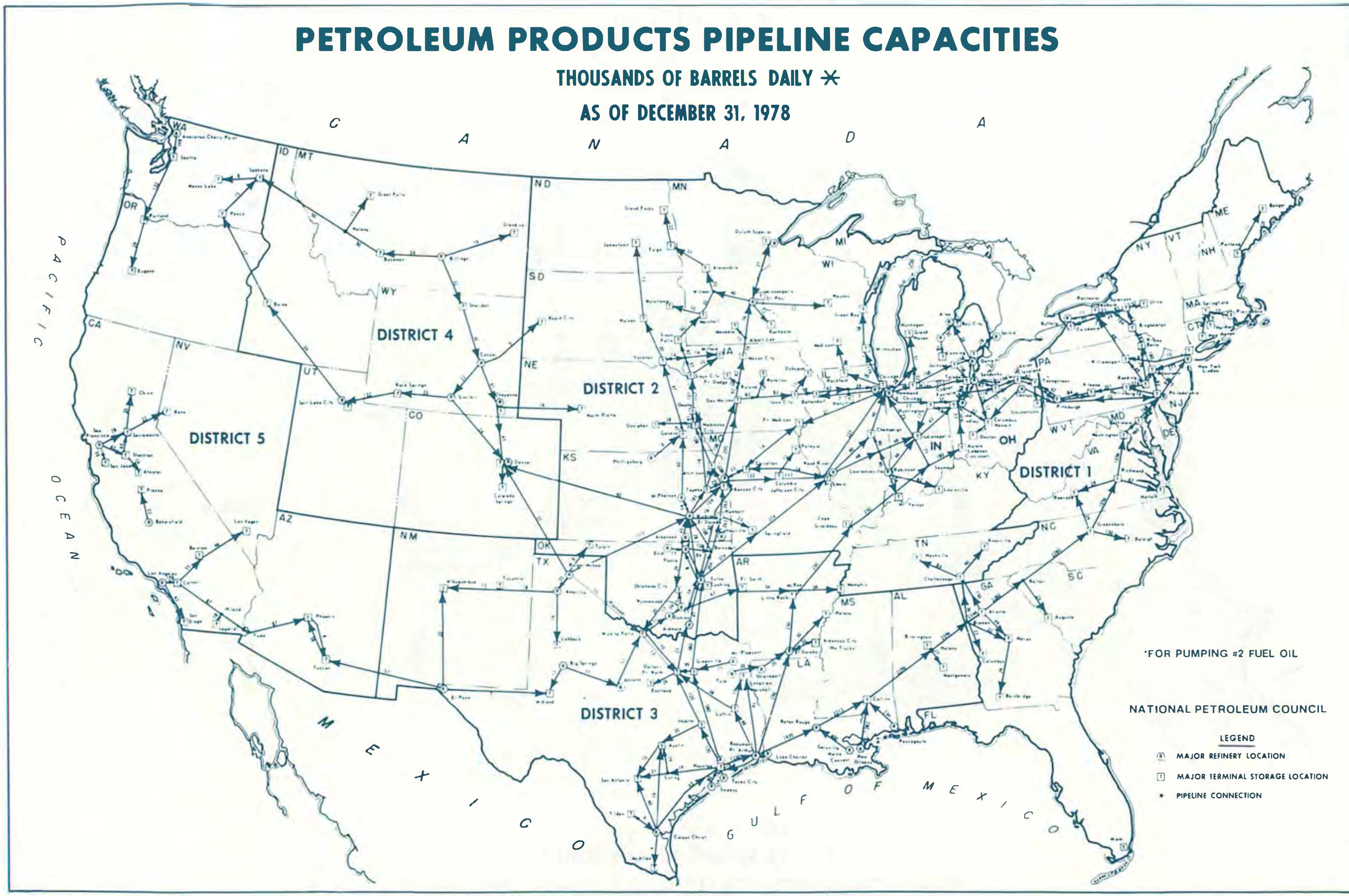

Figure 18. 1978 Petroleum Products Pipeline Capacities.

TABLE 12

SUPPLY OF U.S. FLAG TONNAGE AS OF JUNE 1984*

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

*For exclusions see Appendix D, Tables D-3 and D-4. Totals do not add due to independent rounding.

foreign commerce of the United States by subsidizing their cost to make them more competitive with foreign flag ships. Title V of the Merchant Marine Act of 1936 is the Construction Differential Subsidy program, which authorizes the Secretary of Commerce to make a grant for up to 50 percent of the cost of constructing ships in domestic shipyards, provided the owners of the subsidized ships agree to operate them solely on foreign trade routes as required by Section 506.

In 1970, the Merchant Marine Act of 1936 was amended to extend CDS to the construction of bulk vessels, including oil tankers. This amendment resulted in the construction of the CDS tanker tonnage listed in Table 12. These vessels have essentially three requirements: they must have been built in the United States; they must be manned by U.S. crews; and they must operate in foreign trades.

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

The Secretary of Transportation is authorized in Section 506 to grant permission to a CDS vessel to operate in the domestic trades for up to six months at a time. In determining whether to grant permission for domestic operation of a CDS vessel, the Secretary considers whether there are any vessels with domestic trading privileges which could accomplish what is proposed for the CDS vessel. Generally, if there are eligible vessels available, the requested domestic operation by the CDS vessel would not be authorized, since authorization would allow the CDS vessel to compete unfairly with the unsubsidized domestic vessel.

Under current policy, only CDS tankers of 100,000 DWT or more are considered for domestic operation permission and these only for service from Alaska to Panama. Since these carriers can operate under such permission for only six months at a time, 885,000 DWT, or about half of the total available supply of CDS tonnage over 100,000 DWT shown in Table 12, was used in the tanker supply assessment.

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

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

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

The demand for tankers and barges was derived for each specific distribution requirement, or trade route, by assigning factors to each trade route that could be used to convert daily throughput requirements developed by the study participants into DWT equivalents. Based on actual vessel operating experience, these factors were derived from average, round-trip voyage times, taking into consideration such things as routine delays, average load factors, weather, and other operational constraints. They were used to allocate sufficient deadweight tonnage to each trade that would provide a net carrying capacity to meet throughput requirements. These factors are listed in Tables 13, 14, and 15.

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

Refined product movements from PADD III to PADD I were assigned to both tankers and barges. The demand for barge tonnage in the distribution of refined products was derived by allocating a percentage of the total flow (see

TABLE 13

MARINE PLANNING FACTORS FOR CRUDE OIL DISTRIBUTION

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

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

TABLE 14

MARINE PLANNING FACTORS FOR PRODUCTS DISTRIBUTION BY TANKER

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

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

TABLE 15

MARINE PLANNING FACTORS FOR PRODUCTS DISTRIBUTION BY BARGE

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

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

Table D-6) to barges by region, as shown in Table 16.

TABLE 16

PERCENTAGE OF REFINED PRODUCT MOVEMENTS FROM PADD III TO PADD I BY BARGE—1983

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

The allocation for 1983 was based primarily on the experienced judgment of the study participants. For product movements to Florida, an average factor of 1.25 was used. This represents a simple average for Tampa and Jacksonville, as illustrated in Table 15. All other inter-PADD flows for both crude oil and refined products were assumed to be carried by tanker.

Exceptions to the above methodology were made in estimating the demand for tonnage for intra-PADD requirements for product distribution on the East and West Coasts, and for Military Sealift Command (MSC) requirements. The methodology used in estimating these demand segments is explained below.

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

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

Military Sealift Command Requirements. Since the MSC requirements represent a significant demand segment in the commercial market for Jones Act tankers, it was necessary to incorporate this demand in the overall tonnage balance in this study.

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

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

1983 Marine Balance and Assumptions

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

- Tankers in the over 100,000 DWT category are assumed to trade exclusively in the West Coast crude oil trades.
- Tankers in the 70,000–99,999 DWT category are assumed to trade primarily from the Chiriqui Grande Terminal in Panama to coastal refining centers in PADDs I and III. However, the vessels at the larger end of this category would be expected to move to the West Coast to the extent that a deficit exists in the supply of tankers over 100,000 DWT.
- Tankers in the 40,000–69,999 DWT category are assumed to trade from Chiriqui Grande and Puerto Armuelles (transiting the Panama Canal) to PADDs III and I, and from PADD III to PADD I.
- Tankers in the under 40,000 DWT category are assumed to trade exclusively in the coastal product trades.
- Barges in the over 50,000 barrel category are assumed to trade exclusively in the coastal and inter-PADD product trades.

Although it is recognized that there would be specific exceptions to the above assumptions, it was felt that the allocation was representative for the purposes of this study. The tanker and barge requirements for crude oil and product movements for 1983, by trade route, are shown in Tables 17 and 18.

The supply/demand balance for U.S. flag tonnage in the carriage of domestic crude oil and refined products in 1983 appears in Tables 19, 20, and 21.

TABLE 17

U.S. FLAG TANKER REQUIREMENTS FOR DOMESTIC CRUDE OIL DISTRIBUTION—1983 BASE CASE*

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

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

TABLE 18

U.S. FLAG TANKER/BARGE REQUIREMENTS FOR DOMESTIC PRODUCT DISTRIBUTION—1983 BASE CASE

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

*755 MB/D of the total PADD I marine receipts of 1,037 MB/D in Table 10 was estimated to have moved from PADD III to PADD I by water in 1983 (see Table D-7). Also included in PADD I receipts are 36 MB/D moving from Puerto Rico to the East Coast. The above distribution does not include 246 MB/D moving from the U.S. Virgin Islands that qualifies for foreign flag vessels.

TABLE 19

U.S. FLAG MARINE TONNAGE BALANCE FOR DOMESTIC CRUDE OIL DISTRIBUTION—1983 BASE CASE (MDWT)

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

TABLE 20

U.S. FLAG TANKERS UNDER 40,000 DWT BALANCE FOR DOMESTIC PRODUCT DISTRIBUTION 1983 BASE CASE (MDWT)

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	704.00
U.S. Gulf Coast—U.S. West Coast	110.00
U.S. West Coast—U.S. West Coast	500.00
U.S. East Coast—U.S. East Coast	150.00
Other:	
Military Sealift Command	400.00
Total Demand	**1,864.00**
Jones Act Supply:	
Ships 20,000-39,999 DWT	2,513.00
Total Supply	**2,513.00**
Surplus/(Deficit)	**649.00**

TABLE 21

**U.S. FLAG BARGES OVER 50,000 BARRELS
BALANCE FOR DOMESTIC PRODUCTS DISTRIBUTION
1983 BASE CASE
(MDWT)**

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

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

Definition of the 1990 Nondisrupted Case

1990 Supply/Demand Projections

Total U.S. 1990 supply/demand balances for crude oil and products were obtained from the Energy Information Administration's mid-price case as contained in Table A.15 of the *Annual Energy Outlook, 1983.* The outlook presents supply/demand balances through 1995 for three alternate price scenarios, termed the low-, mid-, and high-price cases. The mid-price supply/demand balance is used in this analysis for illustrative purposes only: its use should not be considered an endorsement of the mid-price projections.

A summary of 1990 supply/demand by PADD is shown in Table 22. Associated inter-PADD crude oil flows are shown in Figure 19.

Demand

Estimated actual PADD demands for 1983 were used as the basis for disaggregating the EIA forecast for 1990. It was assumed that the U.S. Virgin Islands/Puerto Rico demands would increase over the period at the same rate as the 50-state demands. Product demands by PADD were developed on the basis of 1983 actual product market shares. (For example, in 1983, 33.6 percent of gasoline demand was in PADD I, so for 1990, 33.6 percent of the projected total gasoline demand was distributed to PADD I.)

Production

Domestic crude oil and condensate production was projected to be 8,630 MB/D. Based on publicly available forecasts of production, certain adjustments were made to 1983 production patterns to estimate 1990 production by PADD. These are compared in Table 23.

The level and location of projected production have a significant impact on 1990 transportation logistics. For example, if domestic production were lower than projected, additional imports would be required to meet projected demand. Further, if production were lower on the West Coast, demand for U.S. flag tanker tonnage in west-to-east service would be lower. The impacts of varying levels of production on the 1990 cases are addressed as sensitivities in Chapter Three.

Crude Oil and Product Imports

Crude oil imports in 1990 were apportioned among PADDs based on the needs of individual refining centers. Product imports were apportioned among PADDs based on 1983 actual experience.

Crude Oil and Product Shipments/Receipts

Crude oil and product logistics movements for the 1990 nondisrupted case are based on 1983 experience adjusted for changes in local demand, refinery production, and imports. In

TABLE 22

PROJECTED SUPPLY/DEMAND BALANCE BY PADD
1990 NONDISRUPTED CASE
(MB/D)

	PADD						
	I	**II**	**III**	**IV**	**V**	**VI/PR***	**Total**
Local Demand	**5,340**	**4,410**	**3,810**	**550**	**2,510**	**240**	**16,860**
Crude Oil Supplies:							
Production	90	1,050	3,600	560	3,330	–	8,630
Imports†	910	1,110	2,320	40	220	270	4,870
Exports	–	–	–	–	–	–	–
Domestic Marine Shipments	–	–	(70)	–	(1,110)	–	(1,180)
Domestic Marine Receipts	140	70	800	–	–	170	1,180
Domestic Pipeline Shipments	(40)	–	(650)	(140)	(30)	–	(860)
Domestic Pipeline Receipts	–	790	70	–	–	–	860
Other	–	–	(50)	–	(110)	–	(160)
Product Supplies:‡							
Imports	1,040	220	270	20	120	110	1,780
Exports	(30)	(40)	(290)	–	(250)	–	(610)
Domestic Marine Shipments	(90)	(50)	(840)	–	–	(310)	(1,290)
Domestic Marine Receipts	1,070	170	50	–	–	–	1,290
Domestic Pipeline Shipments	(190)	(340)	(2,910)	(80)	–	–	(3,520)
Domestic Pipeline Receipts	2,180	1,000	160	80	100	–	3,520
Other§	260	430	1,350	70	240	–	2,350
Total Supplies	**5,340**	**4,410**	**3,810**	**550**	**2,510**	**240**	**16,860**
Memo: Crude Runs	1,100	3,020	6,020	460	2,300	440	13,340

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

developing these movements, capacity limitations of existing facilities were assumed to be unchanged from 1983.

Other

Other products included in the data are natural gas liquids production indigenous to each PADD, refinery gain, inventory build/draw, and other adjustments to balance.

It should be noted that, as in the 1983 case, product movements include shipments/receipts of natural gas liquids among PADDs.

Projected Refinery Inputs and Outputs

The 1990 nondisrupted refining input and output projection was based on changes in domestic crude oil production and refined products demand likely to occur between 1983 and 1990. Complete, detailed input and output balances, regionally divided, for the year 1990 were extrapolated from the 1983 data in a manner consistent with the EIA's overall, long-range forecast of crude oil production, product demand, and imports. The resulting projection of 1990 refinery operations is presented in Table 24.

The 1990 product outputs of the individual refining centers were obtained by subdividing the total requirements (United States plus the U.S. Virgin Islands and Puerto Rico) according to the 1983 geographic refinery production pattern. With minor exceptions, each refining center was assigned the same production share of each product it had in 1983. However, the

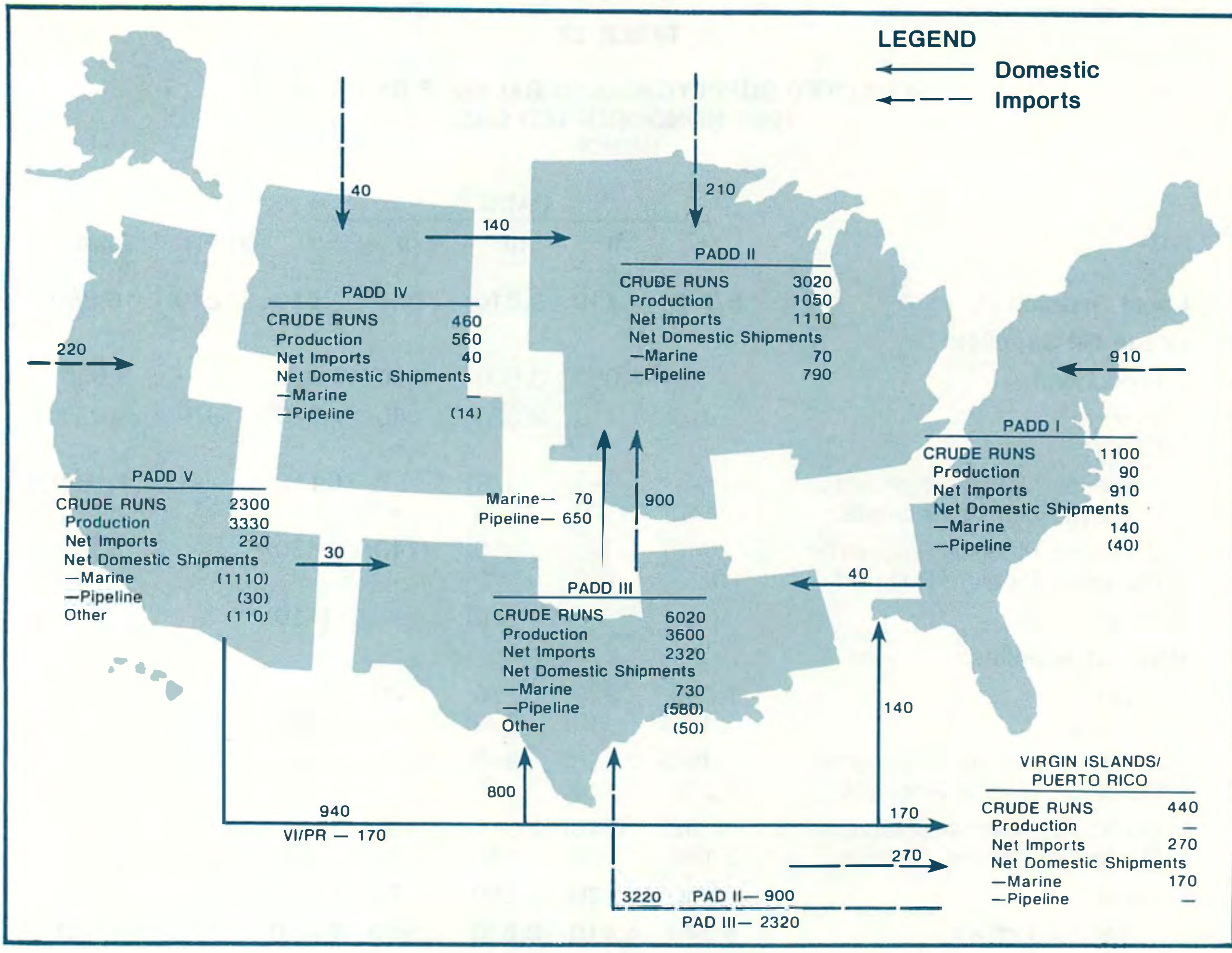

Figure 19. Crude Oil Logistics (MB/D)—1990 Nondisrupted Case.

TABLE 23

COMPARISON OF DOMESTIC CRUDE OIL AND LEASE CONDENSATE PRODUCTION—1983 AND 1990 (MB/D)

	1983 Actual	1990 Estimated	△
PADD I	80	90	10
PADD II	1,040	1,050	10
PADD III	4,180	3,600	(580)
PADD IV	570	560	(10)
PADD V*	2,820	3,330	510
Virgin Islands/ Puerto Rico	0	0	0
Total	**8,690**	**8,630**	**(60)**

*Alaska	1,710	1,840	130
California OCS	80	350	270
Other PADD V	1,030	1,140	110

TABLE 24

REFINERY INPUT/OUTPUT BY REFINING CENTER
1990 NONDISRUPTED CASE
(MB/D)

	Virgin Islands/ Puerto Rico	PADD I		
	Water Connected	Water Connected	Not Connected	Subtotal
Input				
Total Crude Oil & Lease Condensate	**435**	**1,055**	**50**	**1,105**
Domestic: Low Sulfur	–	–	47	47
High Sulfur	–	–	3	3
Alaskan & California OCS	170	147	–	147
Foreign: Low Sulfur	115	515	–	515
High Sulfur	150	393	–	393
Unidentified	–	–	–	–
Unfinished Oils	(28)	123	0	123
NGLs & Gasoline Blending Comp.	6	15	4	19
Total Input	**413**	**1,193**	**54**	**1,247**
Output				
Total Gasoline	104	529	11	540
Middle Distillates	118	370	19	389
Residual Fuel Oil & Asphalt	143	154	3	157
Other Products	53	194	19	213
Total Output	**418**	**1,247**	**52**	**1,299**
Net Processing Gain	(5)	(54)	2	(52)
Yields (%)*				
Total Gasoline	24.1	43.6	14.0	42.4
Middle Distillates	29.0	31.4	38.0	31.7
Residual Fuel Oil & Asphalt	35.1	13.1	6.0	12.8
Other Products	13.0	16.5	38.0	17.3
Total Yields†	**101.2**	**104.6**	**96.0**	**104.2**
Gross Crude Oil Distillation Input	453	1,065	50	1,115
Operable Capacity	614	1,446	57	1,503
Operating Rate (%)	73.8	73.7	87.7	74.2

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

TABLE 24 (Continued)

	PADD II		
	Capline Connected	Not Connected	Subtotal
Input			
Total Crude Oil & Lease Condensate	**2,219**	**803**	**3,022**
Domestic: Low Sulfur	821	681	1,502
High Sulfur	225	122	347
Alaskan & California OCS	58	–	58
Foreign: Low Sulfur	375	–	375
High Sulfur	740	–	740
Unidentified	–	–	–
Unfinished Oils	(5)	4	(1)
NGLs & Gasoline Blending Comp.	116	77	193
Total Input	**2,330**	**884**	**3,214**
Output			
Total Gasoline	1,258	475	1,733
Middle Distillates	668	292	960
Residual Fuel Oil & Asphalt	160	31	191
Other Products	342	114	456
Total Output	**2,428**	**912**	**3,340**
Net Processing Gain	(98)	(28)	(126)
Yields (%)*			
Total Gasoline	51.6	49.3	51.0
Middle Distillates	30.2	36.2	31.8
Residual Fuel Oil & Asphalt	7.2	3.8	6.3
Other Products	15.4	14.1	15.1
Total Yields†	**104.4**	**103.5**	**104.2**
Gross Crude Oil Distillation Input	2,271	817	3,088
Operable Capacity	2,727	958	3,685
Operating Rate (%)	83.3	85.3	83.8

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

TABLE 24 (Continued)

	PADD III			
	Lower Mississippi	Lake Charles	Beaumont, Port Arthur	Houston, Texas City
Input				
Total Crude Oil & Lease Condensate	**1,728**	**354**	**1,019**	**1,674**
Domestic: Low Sulfur	662	113	362	340
High Sulfur	–	50	161	294
Alaskan & California OCS	330	32	37	286
Foreign: Low Sulfur	166	43	123	311
High Sulfur	570	116	336	443
Unidentified	–	–	–	–
Unfinished Oils	25	9	13	76
NGLs & Gasoline Blending Comp.	101	13	30	102
Total Input	**1,854**	**376**	**1,062**	**1,852**
Output				
Total Gasoline	791	176	432	791
Middle Distillates	628	121	352	560
Residual Fuel Oil & Asphalt	144	12	98	99
Other Products	358	82	204	477
Total Output	**1,921**	**391**	**1,086**	**1,927**
Net Processing Gain	(67)	(15)	(24)	(75)
Yields (%)*				
Total Gasoline	39.4	44.9	39.0	39.4
Middle Distillates	35.8	33.3	34.1	32.0
Residual Fuel Oil & Asphalt	8.2	3.3	9.5	5.7
Other Products	20.4	22.6	19.8	27.3
Total Yields†	**103.8**	**104.1**	**102.3**	**104.3**
Gross Crude Oil Distillation Input	1,746	357	1,033	1,740
Operable Capacity	2,269	497	1,435	1,977
Operating Rate (%)	77.0	71.8	72.0	88.0

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

TABLE 24 (Continued)

	PADD III (Continued)		
	Corpus Christi	Inland (Not Connected)	Subtotal
Input			
Total Crude Oil & Lease Condensate	**416**	**825**	**6,016**
Domestic: Low Sulfur	126	469	2,072
High Sulfur	–	356	861
Alaskan & California OCS	79	–	764
Foreign: Low Sulfur	155	–	798
High Sulfur	56	–	1,521
Unidentified	–	–	–
Unfinished Oils	47	32	202
NGLs & Gasoline Blending Comp.	20	53	319
Total Input	**483**	**910**	**6,537**
Output			
Total Gasoline	193	364	2,747
Middle Distillates	188	312	2,161
Residual Fuel Oil & Asphalt	34	81	468
Other Products	88	156	1,365
Total Output	**503**	**913**	**6,741**
Net Processing Gain	(20)	(3)	(204)
Yields (%)*			
Total Gasoline	37.4	36.3	39.0
Middle Distillates	40.6	36.4	34.8
Residual Fuel Oil & Asphalt	7.3	9.5	7.5
Other Products	19.0	18.2	22.0
Total Yields†	**104.4**	**100.4**	**103.3**
Gross Crude Oil Distillation Input	435	852	6,163
Operable Capacity	563	1,042	7,783
Operating Rate (%)	77.3	81.8	79.2

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

TABLE 24 (Continued)

	PADD IV	PADD V	U.S. Total
Input			
Total Crude Oil & Lease Condensate	**461**	**2,297**	**13,336**
Domestic: Low Sulfur	219	–	3,840
High Sulfur	199	1,175	2,585
Alaskan & California OCS	–	899	2,038
Foreign: Low Sulfur	–	223	2,026
High Sulfur	43	–	2,847
Unidentified	–	–	–
Unfinished Oils	(17)	21	300
NGLs & Gasoline Blending Comp.	17	37	591
Total Input	**461**	**2,355**	**14,227**
Output			
Total Gasoline	216	961	6,301
Middle Distillates	182	772	4,582
Residual Fuel Oil & Asphalt	32	359	1,350
Other Products	41	386	2,514
Total Output	**471**	**2,478**	**14,747**
Net Processing Gain	(10)	(123)	(520)
Yields (%)*			
Total Gasoline	44.8	39.9	41.9
Middle Distillates	41.0	33.3	33.6
Residual Fuel Oil & Asphalt	7.2	15.5	9.9
Other Products	9.2	16.7	18.4
Total Yields†	**102.3**	**105.3**	**103.8**
Gross Crude Oil Distillation Input	467	2,335	13,621
Operable Capacity	560	3,115	17,263
Operating Rate (%)	83.4	75.0	78.9

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

resultant product slates, and relative levels of operation among the various refining centers differ in 1990 from 1983 because the individual products have divergent demand trends and geographic patterns. For example, the production of one of the fastest-growing products, petrochemical feedstocks, is concentrated in the Gulf Coast region. In general, the product slate reflects a shift toward less gasoline (41.9 versus 46.9 percent yield on crude oil), more middle distillate (33.6 versus 29.8 percent), and less residual fuel oil (9.9 versus 11.0 percent). This implies a reduced cracking requirement, but more bottoms conversion, as compared to the recent past.

The crude oil run levels within each refining center were proportioned according to the product output requirements. These crude oil runs were then compared to available capacity and found to be feasible in all instances. On average, the required operating rate of 13,621 MB/D is about 79 percent of existing, calendar-day crude oil distillation capacity. The highest individual operating rate among the 13 refining centers (Houston/Texas City) is a projected 88 percent, still well within demonstrated sustainable capacity.

No net increase in crude oil input capacity was assumed, although it is recognized that some debottlenecking of existing refineries may occur, probably offset by further shutdowns of older, less efficient plants. The locations affected by such future changes are difficult to predict; the only one specifically recognized is a 123 MB/D reduction in Puerto Rico's 1990 refining capacity versus 1983.

To establish the composition of the crude oil slates for each refining center, the historical distribution of domestic crude oil was followed. Surpluses from PADD V and PADD IV flow eastward and, of these, movement of Alaskan crude oil is the most significant. Disposition of the California Outer Continental Shelf (OCS) crude oil, because of its special quality, was assumed to be split between California refineries (150 MB/D) and Gulf Coast refineries (200 MB/D). Apart from Alaskan North Slope and the California OCS crude oil, aggregate domestic crude oil quality was assumed to remain constant between 1983 and 1990. Imports were flexed as necessary to balance both volume and quality needs of refineries. In the 1990 nondisrupted case, crude oil imports total 4,873 MB/D, including approximately 250 MB/D of exchanges with Canada for logistical and quality reasons.

Low-sulfur grades, i.e., crude oils containing no more than 0.5 wt.% sulfur, are expected to constitute 44 percent of the total crude oil refined in 1990. This recognizes the likely decline in the low-sulfur proportion, which was about 50 percent in 1982 and 48 percent in 1983, as a consequence of the changing refining industry configuration and world crude oil supply environment. Refiners' planned crude oil runs for 1985, as reported to the EIA, were taken as a reflection of the crude oil quality needs under foreseeable economic circumstances and upon completion of the present wave of refinery retrofitting.

The analysis discloses that, among refining centers, wide differences in the flexibility to refine different crude oil types will continue to exist. At one extreme are the PADD V refineries, which require less than 10 percent of their crude oil as low-sulfur grade. At the opposite extreme are the inland PADD I refineries, geared to 94 percent low-sulfur (domestic) supply. The refineries along the Atlantic and Gulf coasts, and the pipeline-connected PADD II refineries, have needs for low-sulfur crude oil in the 42–67 percent range. The 1990 refinery input projection allows for these individual crude oil slate differences.

1990 Projected Pipeline Distribution System

In projecting 1983 crude oil pipeline capabilities to 1990, it is assumed that there are no changes in existing pipeline capacities or their capabilities from year-end 1983. Importantly, the Seaway and Texoma pipelines are assumed to remain unavailable for SPR service as discussed elsewhere in this chapter. Further, no new pipelines are assumed to have been built, although several are now reportedly being planned (e.g., All-American, Pacific Texas, Transgulf). These pipelines are discussed in further detail in Appendix C.

The impacts of the above pipeline assumptions are noted in the sensitivity cases in Chapter Three.

Projected pipeline movements in the 1990 nondisrupted case were developed by considering the crude oil and product requirements in each PADD, 1983 actual logistics patterns, and the limitations of individual pipeline systems into or from each PADD.

1990 Projected Marine Distribution System

A 1990 supply/demand balance for U.S. flag tankers and barges was developed by applying the same methodology that was used for the 1983 balance. The 1990 demand for U.S. flag tonnage was derived from the 1990 crude oil and product supply/demand distribution data. On the supply side, a year-by-year inventory of tankers and barges was developed for the 1984–1990 period. The year-by-year breakdown (Table 25) was used to illustrate the impact of attrition on the various components of the fleet as a result of projected vessel scrapping and the Port and Tanker Safety Act of 1978 that will impact the carrying capacity of the fleet after 1985.

Scrapping Assumptions

The vessel scrapping rate used in projecting the supply of Jones Act tankers to 1990 is a key variable and was based purely on current economic factors. With the depressed tanker rates of the last two years, marginal tonnage has tended to be placed in long-term lay-up or scrapped. Many of the vessels in lay-up will require survey work and, in some cases, substantial overhauls in order to be put back in service.

There are several factors that could affect this projected scrapping schedule. It is possible that rising freight rates over the next few years would support the continued operation of some marginal tonnage. Also, individual oil companies may have strategic reasons to keep economically marginal, company-owned vessels trading. If this is the case, actual scrappage of Jones Act tankers could be significantly lower than the projections used in this study.

There are also potential market forces that could accelerate the scrapping of domestic tonnage. For example, if all CDS vessels were granted full Jones Act status, the existing surplus would increase. This would no doubt accelerate the scrapping of Jones Act tankers, as would the construction of proposed pipeline projects such as a major west-to-east crude oil pipeline.

Impact of Port and Tanker Safety Act of 1978

As of January 1, 1986, all product carriers under 40,000 DWT and over 15 years of age must have permanent, segregated ballast systems. The expected loss in carrying capacity is illustrated in Appendix D. By 1990, the impact on the Jones Act tanker fleet will probably be minimal, because it is assumed that most of the tankers affected by these regulations will have been scrapped. Therefore, although the Jones Act tankers under 40,000 DWT in 1990 will have a total registered deadweight tonnage of 939,000 DWT (see Table 25), the effective carrying capacity for the purpose of this study must be reduced by approximately 54,000 DWT to account for the impact of the Port and Tanker Safety Act of 1978. As a result, adjustments must be made to the available supply of domestic tankers under 40,000 DWT to reflect a 54,000 DWT reduction in Jones Act tonnage and a 33,000 DWT reduction in CDS tonnage.

Domestic Supply of Oceangoing Barges

The projected supply of domestic barges to 1990 is also listed in Table 25. Only those barges suitable for distribution (50,000 barrels or larger) have been included in the overall tonnage supply. It should be noted, however, that an additional half million deadweight tons is available from the lightering category (see Table D-3). This additional tonnage could be used for vessel topping off, lightering, or local PADD III distribution of SPR crude oil. Barges under 50,000 barrels in size have been excluded because they are primarily employed in the short haul coastal distribution of refined products and would be expected to remain in these trades during the disruption scenario.

New construction is projected to add an additional 600,000 DWT to the oceangoing segment of the domestic barge fleet as a partial replacement for tanker scrappings. This construction assumption is subject to the same market forces as scrapping and would be expected to vary as the vessel scrapping assumptions vary.

Foreign Flag Tanker Availability

An inventory of available foreign flag tankers suitable for loading at SPR facilities was estimated in the following manner. Vessel positioning data were analyzed for a two-month period in the first half of 1984 to determine the availability of foreign flag tankers (25,000 DWT to 159,999 DWT) in the proximity of the U.S. Gulf Coast. The data identified all foreign tankers calling at Caribbean, U.S. Gulf Coast, and U.S. East Coast ports. The data further identified those vessels that were U.S. controlled. The results appear in Table 26.

The data indicate that approximately 25 million DWT of foreign flag tankers were positioned in the proximity of the U.S. Gulf Coast during the two-month sample period. In the event of an emergency drawdown, this would mean approximately 12–13 million tons for the first 30-day cycle of the drawdown. The supply of foreign tonnage, based on 1984 data, would almost equal the size of the entire U.S. flag fleet.

Because the amount of foreign flag tonnage in the Gulf Coast at any given point was found to be a function of imports, 1990 import projections were examined to support the foreign tonnage supply used in Table 27. Import projections for PADD III in 1990 show an increase

TABLE 25

SUPPLY PROJECTION FOR U.S. FLAG TANKERS AND BARGES TO 1990*
(MDWT)

	1984	1985	1986	1987	1988	1989	1990
Jones Act Tankers:							
20,000-39,999 DWT	2,513	2,189	1,788	1,488	1,189	1,053	939
40,000-69,999 DWT	1,916	1,916	1,916	1,916	1,916	1,824	1,824
70,000-99,999 DWT	1,817	1,817	1,817	1,817	1,817	1,817	1,748
100,000-199,999 DWT	3,135	3,135	3,135	3,135	3,135	3,135	3,021
Over 200,000 DWT	450	450	450	868	868	868	868
Total	9,830	9,507	9,106	9,224	8,924	8,697	8,400
CDS Tankers:							
20,000-39,999 DWT	377	377	377	377	377	377	377
40,000-69,999 DWT	0	0	0	0	0	0	0
70,000-99,999 DWT	711	711	711	711	711	711	711
100,000-199,999 DWT	0	0	0	0	0	0	0
Over 200,000 DWT	1,774	1,774	1,774	1,774	1,774	1,774	1,774
Total	2,863	2,863	2,863	2,863	2,863	2,863	2,863
Barges:							
Over 50,000 Barrels	1,109	1,109	1,309	1,509	1,709	1,709	1,709
Grand Total	**13,802**	**13,479**	**13,278**	**13,596**	**13,496**	**13,269**	**12,972**

*Detailed assumptions are listed in Appendix D.

TABLE 26

FOREIGN FLAG TANKERS 25,000–159,999 DWT CALLING AT U.S. GULF COAST, EAST COAST, AND CARIBBEAN PORTS DURING MARCH/APRIL 1984

Vessel Size (MDWT)	Total		U.S. Controlled	
	No. of Vessels	MDWT	No. of Vessels	MDWT
25–40	136	4,565	30	1,032
40–50	26	1,148	2	90
50–60	46	2,539	6	311
60–70	44	2,827	3	201
70–80	18	1,392	12	940
80–90	54	4,602	8	668
90–100	20	1,919	1	99
100–120	10	1,097	1	112
120–140	26	3,411	4	518
140–160	16	2,338	2	307
Total	**396**	**25,838**	**69**	**4,278**

TABLE 27

ADJUSTED MARINE VESSEL SUPPLY—1990 NONDISRUPTED CASE (MDWT)

	Jones Act	CDS	Foreign Flag*
Tankers			
20,000–39,999 DWT	885†	344‡	2,283
40,000–69,999 DWT	1,824	–	3,257
70,000–99,999 DWT	1,748	711	3,957
100,000–200,000 DWT	3,021	0	3,423
Over 200,000 DWT	868	1,774	–
Total	8,346	2,829	12,920
Barges			
Over 50,000 barrels	1,709	–	–
Total Tonnage	**10,055**	**2,829**	**12,920**

*Available tonnage represents half of the supply in Table 26 for the first 30-day cycle. Tonnage does not reflect any adjustment for loss to segregated ballast.

†Represents 939 from Table 25 adjusted for 54 MDWT loss to segregated ballast.

‡Represents 377 from Table 25 adjusted for 33 MDWT loss to segregated ballast.

of approximately 50 percent over 1983. This indicates that an ample supply of foreign tonnage would be available for an emergency drawdown.

Marine Supply Summary

- Under the 1990 nondisrupted case, U.S. flag tonnage is projected to decline by approximately 6 percent from the 1983 base case.
- Jones Act tonnage over 40,000 DWT is projected to remain essentially constant to 1990. A 1.6 million DWT decline is projected for Jones Act tankers in the 20,000–40,000 DWT size range.
- No significant new building of U.S. flag tankers is assumed during the 1983–1990 period beyond the two 209,000 DWT Jones Act Very Large Crude Carriers currently on order.
- CDS supply will remain constant at about 2.9 million DWT through 1990.
- The supply of barges over 50,000 barrels for coastal and inter-PADD distribution is projected to increase substantially as a partial replacement for tanker scrappings.

Balance for Crude Oil Distribution

Demand for tankers in the crude oil trades (Table 28) is projected to increase by approximately 1.5 million DWT from 1983 to 1990. An 850,000 DWT increase is the result of an increase in the flow of California OCS crude oil to PADD I and PADD III. The balance of the increase is required to distribute the projected increase in Alaskan North Slope production.

Table 29 shows the supply/demand balance for U.S. flag crude oil tankers based on the 1990 nondisrupted case crude oil distribution assumptions. The data indicate that, overall, the Jones Act supply of crude oil tankers will be in balance by 1990. However, the data indicate a shortage of Jones Act tankers over 100,000 DWT. This is consistent with the 1983 base case shown in Table 20 and indicates that the demand for crude oil tankers in 1990 on the West Coast will continue to attract vessels under 100,000 DWT. Therefore, the surpluses

TABLE 28

U.S. FLAG TANKER REQUIREMENTS FOR DOMESTIC CRUDE OIL DISTRIBUTION—1990 NONDISRUPTED CASE

	MB/D	Factor	MDWT
Non-SPR Crude Distribution:			
Valdez—			
U.S. West Coast	840.00	2.20	1,848.00
Puerto Armuelles	780.00	4.63	3,611.40
Hawaii	60.00	2.67	160.20
Puerto Armuelles—			
U.S. Gulf Coast/P.R.	0.00	2.43	0.00
U.S. East Coast	30.00	3.14	94.20
Chiriqui Grande*—			
U.S. Gulf Coast/P.R.	690.00	1.79	1,235.10
U.S. East Coast	60.00	2.37	142.20
U.S. Gulf Coast—			
U.S. East Coast	0.00	2.32	0.00
California—			
U.S. West Coast	0.00	0.68	0.00
U.S. Gulf Coast	150.00	5.13	769.50
U.S. East Coast	50.00	5.72	286.00
Total Requirement			**8,146.60**

*The TransPanama Pipeline is assumed to have a maximum throughput of 750 MB/D.

TABLE 29

U.S. FLAG TONNAGE BALANCE FOR DOMESTIC CRUDE OIL DISTRIBUTION—1990 NONDISRUPTED CASE (MDWT)

	Over 100 MDWT	70–99.9 MDWT	40–69.9 MDWT	Total
Supply				
Jones Act	3,889.00	1,748.00	1,824.00	7,461.00
CDS Waivers	885.00	0.00	0.00	885.00
Total Supply	**4,774.00**	**1,748.00**	**1,824.00**	**8,346.00**
Demand				
Alaskan North Slope—				
U.S. West Coast/Hawaii	2,008.20	0.00	0.00	2,008.20
Panama	3,611.40	0.00	0.00	3,611.40
Panama—				
U.S. Gulf Coast/P.R.	0.00	1,235.10	0.00	1,235.10
U.S. East Coast	0.00	0.00	236.40	236.40
California OCS—				
U.S. Gulf Coast	0.00	0.00	769.50	769.50
U.S. East Coast	0.00	0.00	286.00	286.00
U.S. Gulf Coast—				
U.S. East Coast	0.00	0.00	0.00	0.00
U.S. West Coast	0.00	0.00	0.00	0.00
Total Demand	**5,619.60**	**1,235.10**	**1,291.90**	**8,146.60**
Surplus/(Deficit)	**(845.60)**	**512.90**	**532.10**	**199.40**

in both the 70,000–99,999 DWT and 40,000–69,999 DWT categories shown in Table 29 would be expected to trade up and bring the fleet into balance.

Balance for Refined Product Distribution

Demand for tankers and barges for the inter-PADD movements of refined products (Table 30) is expected to remain fairly constant to 1990.

The supply/demand balance for U.S. flag tonnage in coastal and inter-PADD movements of refined products is illustrated in Tables 31 and 32.

Table 31 projects a shortfall in Jones Act tankers of approximately 800,000 DWT. This shortfall is due entirely to the calculated attrition in the supply of tankers in this category, which greatly exceeds a projected 200,000 DWT decline in demand by 1990.

In actual practice, however, one would expect that the projected shortfall of tankers under normal circumstances would not occur. As supply and demand approached equilibrium, market forces would result in a slowing of the scrapping rate, new construction, and/or changes in distribution patterns. Therefore, it is reasonable to assume that a disruption occurring in 1990 would probably not result in incremental demand on top of an existing significant imbalance in the supply and demand for U.S. tonnage in the product trades. For practical purposes, it should be assumed that the supply/demand balance for product tonnage will approach equilibrium in 1990.

The demand projections for barge tonnage in the distribution of refined products from PADD III to PADD I in 1990 was derived by allocating a percentage of the total flow to barges by region as shown in Table 33. These allocations were based primarily on estimates of the study participants.

The balance for U.S. flag oceangoing barges is projected to go from a slight deficit in the

TABLE 30

U.S. FLAG TANKER/BARGE REQUIREMENTS FOR DOMESTIC PRODUCT DISTRIBUTION—1990 NONDISRUPTED CASE

	MB/D	Factor	MDWT
Tankers			
U.S. Gulf Coast—U.S. East Coast	334.00	2.00	668.00
U.S. West Coast—U.S. West Coast	–	–	500.00
U.S. East Coast—U.S. East Coast	–	–	150.00
Total			**1,318.00**
Barges			
U.S. Gulf Coast—U.S. East Coast	463.00	1.25	579.00
U.S. West Coast—U.S. West Coast	–	–	212.00
U.S. East Coast—U.S. East Coast	–	–	700.00
Total	**797.00***		**1,491.00**

*797 MB/D of the total 1990 PADD I marine receipts of 1,070 MB/D in Table 22 is projected to move from PADD III to PADD I by water.

TABLE 31

U.S. FLAG TANKERS UNDER 40,000 DWT BALANCE FOR DOMESTIC PRODUCT DISTRIBUTION 1990 NONDISRUPTED CASE (MDWT)

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	668.00
U.S. Gulf Coast—U.S. West Coast	0.00
U.S. West Coast—U.S. West Coast	500.00
U.S. East Coast—U.S. East Coast	150.00
Other:	
Military Sealift Command	400.00
Total Demand	**1,718.00**
Jones Act Supply:	
Ships 20,000-39,999 DWT	885.00
Total Supply	**885.00**
Surplus/(Deficit)	**(833.00)**

TABLE 32

**U.S. FLAG BARGES OVER 50,000 BARRELS
BALANCE FOR DOMESTIC PRODUCT DISTRIBUTION
1990 NONDISRUPTED CASE
(MDWT)**

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	578.75
U.S. Gulf Coast—U.S. West Coast	-
U.S. West Coast—U.S. West Coast	212.00
U.S. East Coast—U.S. East Coast	700.00
Total Demand	**1,490.75**
Jones Act Supply:	
Barges Over 50,000 Barrels	1,709.00
Total Supply	**1,709.00**
Surplus/(Deficit)	**218.25**

1983 base case to a small surplus in 1990. This balance is very sensitive to the barge supply assumptions that assume a 600,000 DWT net increase between 1983 and 1990.

TABLE 33

**PERCENTAGE OF
REFINED PRODUCT MOVEMENTS FROM
PADD III TO PADD I BY BARGE—1990**

Region	Percentage
Florida	85
Other South Atlantic	45
Mid-Atlantic/New England	10

Inland Barging—1990

Current U.S. Coast Guard records of certified shallow draft tank barges were analyzed. These records indicate a total of 4,418 tank barges.

Forty-six tank barges were listed at over 40,000 barrels in capacity and were not used for the study since their size generally was not suitable for purely inland moves. At the other extreme, 1,020 tank barges of less than 5,000 barrels in capacity were not used in the study. Of this number, 780 were less than 2,500 barrels. Table 34 summarizes the inland tank barge fleet after the above deletions.

Included in the totals in Table 34 are approximately 450 tank barges suitable for crude and heavy oil. In the disruption scenario, numerous tank barges now in clean product service could be pressed into crude oil service, if necessary.

In general, inland equipment can be expected to have a useful life of at least 40 years with replating. Therefore, using 1990 as the critical year while ignoring inland equipment built prior to 1950 results in a 1990 estimate of 2,682 barges with approximately 43 million barrels of capacity. No attempt was made to differentiate between product and chemical capacity.

TABLE 34

ADJUSTED INLAND BARGE FLEET

Category	Number	Barrel Capacity (Thousands)
Petroleum	2,686	44,673
Various Chemicals	666	9,063
Total	**3,352**	**53,736**

Due to severely depressed demand for tank barges over the past few years, tank barge construction has dwindled to virtually zero. Without a dramatic surge in demand, there is little reason to assume significant additions to the fleet by 1990. Therefore, a usable fleet of around 3,000 tank barges would seem a reasonable assumption.

At this point, additional analysis is somewhat subjective since there is no central source that collects data on idle capacity, lay-up, scrapping, etc. After discussions with industry contacts, a consensus estimate was that perhaps 20 percent of the inland tank barge fleet was currently idle. Assuming this estimate to be a reasonable figure, and applying this factor evenly to both the number of tank barges and their capacity, the following estimate of the currently active fleet can be drawn:

(3,352 Barges) (80%) = 2,682 Barges

(53,736,000 Barrels) (80%) =
42,989,000 Barrels

Using data supplied by MarAd, shallow draft crude oil and product moves for two years (1980 and 1981) were analyzed in some detail. The data were further differentiated into all barrels reported and those moves assumed to be in only inland tank barges. Further analysis between inland tank barge availability and reported petroleum movements cannot be made. Even using liberal assumptions, only about one-half of the inland tank barge fleet can be justified by using published data on petroleum movements. In all probability, significant volumes are not being reported.

Chapter Three
Analysis of 1990 Disruption

Discussion of Disruption Scenario and Presentation of Data

In order to assess the capabilities of drawing down the SPR and delivering products derived from SPR crude oil to the marketplace, it was necessary to define a supply disruption scenario. Supply disruptions of various magnitudes could conceivably occur at any time from one or more of many possible circumstances. These circumstances could include:

- Military conflicts
- Political unrest in producing countries
- Selective embargoes
- Limited production quotas
- Terrorist activities
- Facilities/logistics accidents or upsets.

Further, depending upon circumstances, a disruption could affect the levels of crude oil and product imports to different degrees.

Rather than attempting to define and test a potentially infinite series of disruption scenarios, a base disruption case was developed that required SPR drawdown at the maximum rate at which SPR crude oil could physically be pumped from the salt dome caverns following completion of existing plans. The 4.5 MMB/D maximum sustainable drawdown rate is scheduled to be reached in 1990. Therefore, 1990 was chosen as the test year. (Maximum sustainable drawdown is defined as the rate that can be maintained for a 90-day period if not constrained by a specified ratio of high-sulfur and low-sulfur crude oils.)

The disruption scenario chosen to test the SPR at its maximum capabilities was a virtual elimination of crude oil and product imports into the United States and the U.S. Virgin Islands/Puerto Rico. *No attempt was made to identify circumstances that could create such a disruption, nor should any be construed.* The net impact of the import cutoff is a loss of 4.9 MMB/D crude oil and 1.2 MMB/D products.

Only one exception was made to the assumption that all imports cease during the disruption. It was assumed that Canadian crude oil imports continue on a barrel-for-barrel exchange basis, based on the probable continued utilization of crude oil pipelines from Canada into PADDs II and IV for logistical and quality purposes. Continuation of exchanges with Canada implies that the necessary export licenses could be obtained.

It was assumed in developing the 1990 disrupted case that it would be possible to draw down SPR crude oil at the 1990 planned 4.5 MMB/D maximum capability rate. The study then took the resultant flows of crude oil and product and superimposed them on projected 1990 facilities to identify distribution bottlenecks.

Table 35 summarizes the supply/demand balances for each PADD and the U.S. Virgin Islands/Puerto Rico in the 1990 disrupted case. Figure 20 displays the associated inter-PADD crude oil movements in the disrupted case. A description of factors considered in developing these balances follows.

Demand

In the 1990 disrupted case, it has been assumed that demand is uniformly restrained among regions. Differing degrees of consumption reductions can be expected for different

TABLE 35

SUPPLY/DEMAND BALANCE BY PADD—1990 DISRUPTED CASE
(MB/D)

	PADD I	PADD II	PADD III	PADD IV	PADD V	VI/PR*	Total
Local Demand	**4,840**	**4,000**	**3,450**	**510**	**2,270**	**220**	**15,290**
Crude Oil Supplies:							
Production	90	1,050	3,600	560	3,330	–	8,630
Imports†	–	210	–	40	–	–	250
Exports	(120)	(130)	–	–	–	–	(250)
Domestic Marine Shipments	–	–	(1,030)	–	(1,240)	–	(2,270)
Domestic Marine Receipts	1,260	70	270	–	200	470	2,270
Domestic Pipeline Shipments	(40)	–	(1,290)	(180)	(30)	–	(1,540)
Domestic Pipeline Receipts	–	1,470	70	–	–	–	1,540
SPR Crude Oil	–	–	4,500	–	–	–	4,500
Other	–	–	(70)	–	(170)	–	(240)
Product Supplies:‡							
Imports	–	–	–	–	–	–	–
Exports	–	–	–	–	–	–	–
Domestic Marine Shipments	(80)	(40)	(1,150)	–	(60)	(250)	(1,580)
Domestic Marine Receipts	1,380	160	40	–	–	–	1,580
Domestic Pipeline Shipments	(170)	(210)	(3,010)	(50)	–	–	(3,440)
Domestic Pipeline Receipts	2,250	980	140	70	–	–	3,440
Other§	270	440	1,380	70	240	–	2,400
Total Supplies	**4,840**	**4,000**	**3,450**	**510**	**2,270**	**220**	**15,290**
Memo: Crude Oil Runs	1,190	2,670	6,050	420	2,090	470	12,890

*Movements to/from the U.S. Virgin Islands/Puerto Rico (VI/PR) considered domestic.

†Does not include SPR fill additions; assumes Canadian imports/exports continue on exchange basis.

‡Includes refined products, LPG, and others.

§Includes LPG produced and used in each PADD, refinery gain, inventory draw/build, and other adjustments to balance.

products. For example, demand for distillate may drop more than demand for gasoline during a disruption because consumers may be able to reduce residential heating requirements to a greater extent than their driving. In consideration of these impacts, the Department of Energy developed demand elasticities of individual products.[1] They further developed individual product demands based on these elasticities. These results were used as a guide in the development of the disrupted case demands, which are displayed in Table 36.

[1]Letter from Howard G. Borgstrom (Director, Planning and Financial Management Division, Strategic Petroleum Reserve, DOE) to John H. Guy, IV, NPC, June 6, 1984.

However, the elasticity values were not found to be critical because refinery flexibility in the disrupted case appears ample to change the product mix significantly, if necessary.

In determining product demand by region, it was assumed that all areas of the country and the U.S. Virgin Islands/Puerto Rico uniformly restrain demand. It is acknowledged, however, that in a disruption of the magnitude postulated, with the sudden and total interruption of product imports, spot dislocations could occur, especially in areas dependent upon Canadian pipeline imports. This issue is treated further in the PADD II discussion in this chapter and as a sensitivity later in this chapter.

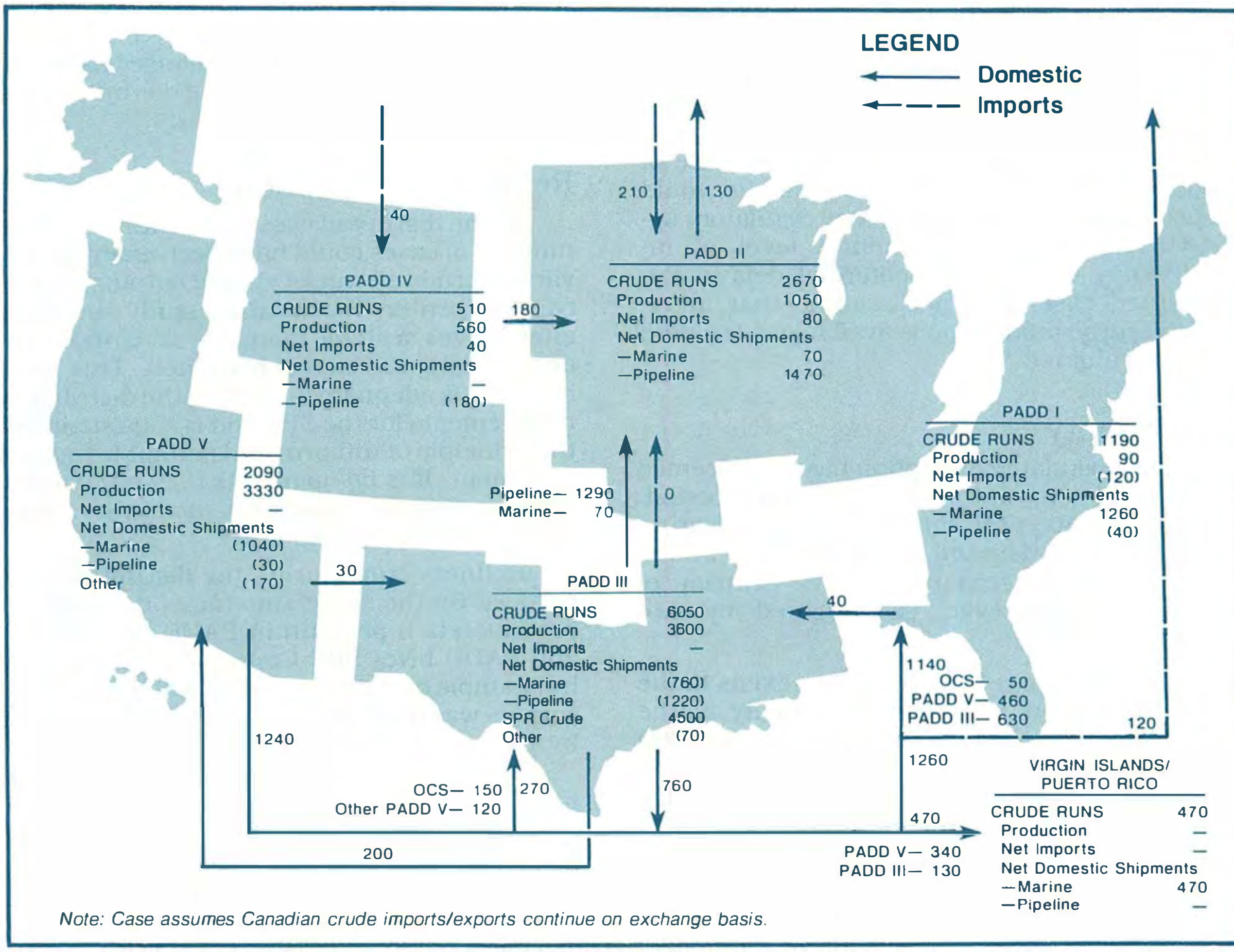

Figure 20. Crude Oil Logistics (MB/D)—1990 Disrupted Case.

TABLE 36

U.S. PRODUCT DEMANDS*—1990 CASES (MB/D)

	1990 Nondisrupted	1990 Disrupted	Percentage Decline
Gasoline	6,520	6,040	7.4
Middle Distillates	4,770	4,170	12.6
Residual Fuel Oil	1,700	1,520	10.6
Other†	3,870	3,560	8.0
	16,860	**15,290**	**9.3**

*Including the U.S. Virgin Islands and Puerto Rico.
†Includes NGLs, asphalts, and other refined products.

Production

Domestic field production was assumed to remain unchanged from the 1990 nondisrupted case. While capability currently exists to achieve an emergency temporary increase of about 325 MB/D,[2] attainment of this rate would depend upon receipt of necessary regulatory approval and some incremental level of investments. Given these potential delays, the disrupted case does not assume that incremental surge production is available in the time frame evaluated.

Seasonality

The postulated disruption has been deemed to occur during an "annual average" period. Depending upon the actual timing of a disruption, differing demand patterns could be expected due to seasonality. The impact of seasonality, however, is mitigated by two factors:

- Adequate refinery capacity exists in the projected 1990 case, especially at the relatively low operating rate in the 1990 disrupted case, to interchange heating oil and motor gasoline production for seasonal differences.
- Product distribution capability in the disrupted case (particularly in PADD III to PADD I pipelines) should be capable of increasing shipments to accommodate seasonal demand peaks. Approximately 380 MB/D of spare capacity in the major PADD III to PADD I pipelines exists in the disrupted case.

The effects of seasonality are noted in the sensitivity section of this chapter.

International Energy Program

No attempt was made to identify circumstances that would lead to the 1990 disrupted case, including circumstances affecting the United States' rights or obligations under the IEP supply-sharing mechanism. For a discussion of international considerations during a supply disruption, see *Emergency Preparedness for Interruption of Petroleum Imports into the United States*, National Petroleum Council, April 1981.

Exchanges

It was assumed that SPR crude oil would be freely exchangeable. However, assignability or exchanges prior to DOE delivery of oil has not been assumed. Tanker lot exchanges have been assumed to occur freely in the disrupted case, as they do normally.

Refinery Assumptions

In the disrupted case, a potentially infinite number of cases could have been examined for various crude oil run levels and outputs for each refining center. Rather than study the many alternatives, a single plausible set of input and output balances was constructed. This set of balances is adequate for testing the distribution requirements for the SPR and is consistent with the principle of uniform and equitable regional treatment. *It is by no means the only possible refinery balance scenario, nor even necessarily the most likely one.*

Refinery runs during the disruption were reduced by the same amount as demand (approximately 9 percent) in PADD IV, PADD V, and PADD I-Not SPR Connected. These areas have ample domestic crude oil and the resulting surplus was diverted to refining centers affected by the loss of crude oil imports.

To help relieve the East Coast product shortages resulting from the cessation of product imports, refinery runs in PADD I-SPR Connected and the U.S. Virgin Islands/Puerto Rico were increased to an operating rate corresponding to 80 percent of the existing 1983 capacity. In view of the projected low rates of utilization in the 1983–1990 predisruption, this level has been assumed to be a reasonable maximum operating rate for 1990. The assumed limit takes into account possible refinery shutdowns that may occur between now and 1990 and builds a reasonable degree of conservatism into the assumption regarding distribution capabilities required during a disruption.

The refinery runs in PADD II-Capline Connected and PADD II-Not SPR Connected were set to hold the clean product movements between PADD II and other PADDs constant between the 1990 nondisrupted case and the 1990 disrupted case. The result is that refining throughput in PADD II is reduced by 11.6 percent, a greater reduction than in other PADDs. This assumption, while not representing a most likely case, was made because it puts slightly more pressure on the refining and distribution systems in the PADD III refining centers, which are the most critical in the analyses.

The balance of crude oil runs required to meet the reduced demand levels during the disruption was assigned to the PADD III refining centers. PADD III's refinery operating level was increased from 79 percent of the 1983 capacity in the 1990 nondisrupted case to 80

[2]National Petroleum Council, *Emergency Preparedness for Interruption of Petroleum Imports into the United States*, April 1981.

percent of the 1983 capacity in the 1990 disrupted case.

The assumptions regarding available crude oil supply during the 1990 disruption produced a set of input and output balances that do not tax the capacity of the refining system. More refinery shutdowns could take place between now and 1990 without invalidating the study conclusions.

The loss of crude oil imports, and in some cases domestic crude oils, in each refining center has been assumed to be replaced by similar quality crude oil from the SPR. Therefore, if a refining center were running 40 percent low-sulfur crude oil from domestic and imported sources in the 1990 nondisrupted case, then that refining center was also assumed to run 40 percent low-sulfur crude oil from domestic and SPR sources in the 1990 disrupted case. This assumption requires that low-sulfur crude oil from the SPR be moved to PADD V to replace imports of low-sulfur Indonesian supplies.

Alaskan and California OCS crude oils that require movement from PADD V to the East have preferentially been run in PADD I-SPR Connected and the U.S. Virgin Islands/Puerto Rico. This movement helps to efficiently use the available tanker fleet and relieves some of the congestion in the busy PADD III Gulf Coast refining centers' ports. A sensitivity case noting this assumption can be found later in this chapter.

The product slates produced by the refining centers reflect the change in demand patterns that have been assumed to occur during a disruption and to partially offset the loss of product imports that are heavily oriented toward residual fuel oil. As a result of the assumed increase in heavy fuel oil production, utilization rates for coking and catalytic cracking units are lower than in the 1990 nondisrupted case. If demand for clear products should actually be higher than assumed, ample processing capacity would be available to meet this demand.

The 1990 disrupted case input and output balances for each refining center are shown in Table 37.

Overland Distribution Assumptions

As in the 1990 nondisrupted case, it is assumed that the proposed All American Pipeline (crude oil), Pacific Texas Pipeline (crude oil), and Transgulf Pipeline (products) would be unavailable for use; this assumption provides a more demanding test of capabilities to transport products and SPR crude oil during the postulated disruption. The impact of this assumption is treated as a sensitivity later in this chapter. Further, no incremental investments or enhancements in pipelines to increase capacity are assumed to have been made in the 1990 disrupted case relative to the 1990 nondisrupted case.

Transportation of crude oil and products among the PADDs and the U.S. Virgin Islands/Puerto Rico was determined by local demand, refinery requirements, and availability of supplies (with consideration for pipeline capacity limitations). The major PADD III to PADD I product pipelines were used to the maximum extent possible in the disrupted case to minimize demands on marine transportation.

Marine Transportation Assumptions

For the 1990 disrupted case, the participation of CDS tankers in the Jones Act trades was limited to six-month waivers for tankers over 100,000 DWT, consistent with current policy. Any change in this policy would have a significant impact on the scrapping assumptions used to estimate vessel inventories for 1990. No attempt was made to factor in increased demand on the U.S. flag tanker fleet due to an escalation of use by the Military Sealift Command during the disruption. It is impossible to anticipate the magnitude of any potential supply disruption and what the Department of Defense requirements may be for tanker capacity. This potentially large requirement for tonnage, particularly U.S. flag tonnage, could substantially increase reliance on foreign flag tonnage for SPR distribution. MarAd waiver procedures must be sufficiently flexible to accommodate the employment of such tonnage on the scale that might be required. Also, for any east-to-west movements during the disruption, it was determined that the TransPanama Pipeline could not be reversed.

Implications of Disruption Scenario and Recommendations

Distribution Considerations

The implications of the postulated 1990 disruption on logistics among PADDs are significant and are summarized in Figure 20. Distribution capabilities within each PADD were specifically evaluated to identify potential bottlenecks. SPR crude oil is required for all districts except PADD IV. Although PADD V has crude oil availability in excess of local refinery requirements, east-to-west low-sulfur crude oil movements are assumed in order to replace

TABLE 37

REFINERY INPUT/OUTPUT BY REFINING AREA
1990 DISRUPTED CASE
(MB/D)

	Virgin Islands/ Puerto Rico	PADD I		
	Water Connected	Water Connected	Not Connected	Total
Input				
Total Crude Oil & Lease Condensate	**471**	**1,146**	**46**	**1,192**
Domestic: Low Sulfur	–	–	43	43
High Sulfur	–	–	3	3
Alaskan & California OCS	347	510	–	510
SPR: Low Sulfur	124	560	–	560
High Sulfur	–	76	–	76
Unidentified	–	–	–	–
Unfinished Oils	(29)	92	0	92
NGLs & Gasoline Blending Comp.	5	17	3	20
Total Input	**477**	**1,255**	**49**	**1,304**
Output				
Total Gasoline	109	558	10	558
Middle Distillates	118	363	16	379
Residual Fuel Oil & Asphalt	185	258	4	262
Other Products	40	128	17	145
Total Output	**452**	**1,307**	**47**	**1,354**
Net Processing Gain	(5)	(52)	2	(50)
Yields (%)*				
Total Gasoline	23.5	43.7	15.2	41.9
Middle Distillates	26.7	29.3	34.8	29.5
Residual Fuel Oil & Asphalt	41.9	20.8	8.7	20.4
Other Products	9.1	10.3	37.0	11.3
Total Yields†	**101.1**	**104.2**	**95.7**	**103.2**
Gross Crude Oil Distillation Input	491	1,157	46	1,203
Operable Capacity	614	1,446	57	1,503
Operating Rate (%)	80.0	80.0	80.7	80.0

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

TABLE 37 (Continued)

	PADD II		
	Capline Connected	Not Connected	Total
Input			
Total Crude Oil & Lease Condensate	**1,971**	**696**	**2,667**
Domestic: Low Sulfur	797	590	1,387
High Sulfur	256	106	362
Alaskan & California OCS	69	–	69
SPR: Low Sulfur	265	–	265
High Sulfur	584‡	–	584‡
Unidentified	–	–	–
Unfinished Oils	(3)	3	0
NGLs & Gasoline Blending Comp.	132	87	219
Total Input	**2,100**	**786**	**2,886**
Output			
Total Gasoline	1,133	422	1,555
Middle Distillates	565	242	807
Residual Fuel Oil & Asphalt	205	40	245
Other Products	290	109	399
Total Output	**2,193**	**813**	**3,006**
Net Processing Gain	(93)	(27)	(120)
Yields (%)*			
Total Gasoline	50.9	47.9	50.1
Middle Distillates	28.7	34.6	30.3
Residual Fuel Oil & Asphalt	10.4	5.7	9.2
Other Products	14.7	15.6	15.0
Total Yields†	104.7	103.7	104.5
Gross Crude Oil Distillation Input	2,017	708	2,725
Operable Capacity	2,727	958	3,685
Operating Rate (%)	74.0	73.9	73.9

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

TABLE 37 (Continued)

	PADD III			
	Lower Mississippi	Lake Charles	Beaumont, Port Arthur	Houston, Texas City
Input				
Total Crude Oil & Lease Condensate	**1,780**	**370**	**1,063**	**1,676**
Domestic: Low Sulfur	689	116	372	350
High Sulfur	–	53	171	325
Alaskan & California OCS	88	–	–	85
SPR: Low Sulfur	164	47	134	302
High Sulfur	839	154	386	614
Unidentified	–	–	–	–
Unfinished Oils	18	6	7	52
NGLs & Gasoline Blending Comp.	114	15	32	121
Total Input	**1,912**	**391**	**1,102**	**1,849**
Output				
Total Gasoline	790	171	440	755
Middle Distillates	604	116	345	514
Residual Fuel Oil & Asphalt	251	38	160	250
Other Products	336	80	178	407
Total Output	**1,981**	**405**	**1,123**	**1,926**
Net Processing Gain	(69)	(14)	(21)	(77)
Yields (%)*				
Total Gasoline	37.6	41.5	38.1	36.7
Middle Distillates	33.6	30.9	32.2	29.7
Residual Fuel Oil & Asphalt	14.0	10.1	15.0	14.5
Other Products	18.7	21.3	16.6	23.6
Total Yields†	**103.8**	**103.7**	**102.0**	**104.5**
Gross Crude Oil Distillation Input	1,798	373	1,076	1,740
Operable Capacity	2,269	497	1,435	1,977
Operating Rate (%)	79.2	75.0	75.0	88.0

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

TABLE 37 (Continued)

	PADD III (Continued)		
	Corpus Christi	Inland (Not Connected)	Subtotal
Input			
Total Crude Oil & Lease Condensate	**413**	**753**	**6,055**
Domestic: Low Sulfur	129	428	2,084
High Sulfur	–	325	874
Alaskan & California OCS	25	–	198
SPR: Low Sulfur	150	–	797
High Sulfur	109	–	2,102
Unidentified	–	–	–
Unfinished Oils	32	21	136
NGLs & Gasoline Blending Comp.	24	64	370
Total Input	**469**	**838**	**6,561**
Output			
Total Gasoline	180	345	2,681
Middle Distillates	163	283	2,025
Residual Fuel Oil & Asphalt	66	81	846
Other Products	80	132	1,213
Total Output	**489**	**841**	**6,765**
Net Processing Gain	(20)	(3)	(204)
Yields (%)*			
Total Gasoline	35.1	36.3	37.3
Middle Distillates	36.6	36.6	32.7
Residual Fuel Oil & Asphalt	14.8	10.5	13.7
Other Products	18.0	17.1	19.6
Total Yields†	104.5	100.4	103.3
Gross Crude Oil Distillation Input	435	781	6,203
Operable Capacity	563	1,042	7,783
Operating Rate (%)	77.3	75.0	79.7

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

TABLE 37 (Continued)

		PADD IV	PADD V	U.S. Total
Input				
Total Crude Oil & Lease Condensate		**415**	**2,090**	**12,890**
Domestic:	Low Sulfur	196	–	3,710
	High Sulfur	181	1,092	2,512
	Alaskan & California OCS	–	794	1,918
SPR:	Low Sulfur	–	204	1,950
	High Sulfur	38	–	2,800‡
Unidentified		–	–	–
Unfinished Oils		(11)	12	200
NGLs & Gasoline Blending Comp.		19	37	670
Total Input		**423**	**2,139**	**13,760**
Output				
Total Gasoline		198	930	6,041
Middle Distillates		156	680	4,165
Residual Fuel Oil & Asphalt		41	326	1,905
Other Products		38	314	2,149
Total Output		**433**	**2,250**	**14,260**
Net Processing Gain		(10)	(111)	(500)
Yields (%)*				
Total Gasoline		44.3	42.5	41.0
Middle Distillates		38.6	32.4	31.8
Residual Fuel Oil & Asphalt		10.1	15.5	14.6
Other Products		9.4	14.9	16.4
Total Yields†		**102.5**	**105.3**	**103.8**
Gross Crude Oil Distillation Input		421	2,124	13,165
Operable Capacity		560	3,115	17,263
Operating Rate (%)		75.7	68.2	76.3

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

†Numbers may not add because of rounding.

‡Includes SPR and 250 MB/D Canadian imports. 130 MB/D of return exports to Canada through PADD II supplied by PADDs II and IV domestic production plus 120 MB/D supplied through PADD I.

low-sulfur imports. Various solutions to identified bottlenecks were then tested for feasibility. Since the three SPR complexes are located within PADD III, it is appropriate to begin with that region.

PADD III

Table 38 compares PADD III supply/demand balances between the nondisrupted and disrupted cases. As shown in the crude oil section of Table 38, the 2,320 MB/D of crude oil imports available in the nondisrupted case are reduced to zero in the disrupted case. Since all SPR sites are located in PADD III, the entire 4.5 MMB/D maximum design drawdown for the SPR is shown as entering the distribution system in PADD III. However, domestic shipments out of PADD III increase 1.6 MMB/D over the nondisrupted case, reflecting the distribution of SPR supplies to other PADDs. Specifically, marine shipments out of PADD III grow from 70 MB/D in the nondisrupted case to

1,030 MB/D in the disrupted case, an increase of 960 MB/D. Further, marine receipts into PADD III decline from 800 MB/D to 270 MB/D. Similarly, pipeline shipments of crude oil out of PADD III grow from 650 MB/D in the nondisrupted case to 1,290 MB/D in the disrupted case for a net increase of 640 MB/D.

Product imports into PADD III are also reduced to zero in the 1990 disrupted case. Product shipments out of PADD III, both marine and pipeline, rise from 3,750 MB/D (840 MB/D marine plus 2,910 MB/D pipeline) to 4,160 MB/D (1,150 MB/D marine plus 3,010 MB/D pipeline). Net product receipts from other PADDs decline by 30 MB/D.

The growth in PADD III product shipments to other PADDs reflects the need for products refined in that region to make up for the loss of imported products in other PADDs, primarily PADD I. As can be seen at the bottom of Table 38, total product supplies retained for consumption in PADD III declines 360 MB/D in the disrupted case.

As is evident from the discussion above, the adequacy of facilities within PADD III, both at the SPR sites themselves and elsewhere in the region, is the crucial issue in determining whether SPR reserves can be drawn down at the maximum design rate of 4.5 MMB/D and distributed to U.S. refiners to meet national needs during the postulated disruption. Deficiencies have been identified at each of the three SPR sites which, if not corrected, would prevent distribution of SPR crude oil at the 4.5 MMB/D maximum drawdown rate to the nation's refining centers as required to meet product demands.

The following discussion quantifies these distribution deficiencies and outlines recommendations to remedy them. The three complexes are addressed and analyzed in serial fashion. Capabilities at the Seaway and Capline

TABLE 38

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES—PADD III (MB/D)

	1990 Nondisrupted	1990 Disrupted	Δ
Local Demand	**3,810**	**3,450**	**(360)**
Crude Oil Supplies:			
Production	3,600	3,600	0
Imports	2,320	0	(2,320)
Exports	0	0	0
Domestic Marine Shipments	(70)	(1,030)	(960)
Domestic Marine Receipts	800	270	(530)
Domestic Pipeline Shipments	(650)	(1,290)	(640)
Domestic Pipeline Receipts	70	70	0
SPR Crude Oil	0	4,500	4,500
Other	(50)	(70)	(20)
Product Supplies:			
Imports	270	0	(270)
Exports	(290)	0	290
Domestic Marine Shipments	(840)	(1,150)	(310)
Domestic Marine Receipts	50	40	(10)
Domestic Pipeline Shipments	(2,910)	(3,010)	(100)
Domestic Pipeline Receipts	160	140	(20)
Other	1,350	1,380	30
Total Supplies	**3,810**	**3,450**	**(360)**
Memo: Crude Oil Runs	6,020	6,050	30

complexes are analyzed first. The Texoma complex, with over one-half the SPR's total planned drawdown capability, is treated as the swing complex in this analysis. That is, any SPR drawdown or distribution requirements that cannot be met by Seaway and Capline, even with distribution capacity enhancements, are supplied from the Texoma complex.

Further, in order to effectively test the adequacy of marine and pipeline distribution systems, refining center destinations for crude oil stored in each of the complexes were designated based on the refining center input/output balances presented earlier in this chapter. Efficiency of transportation logistics as well as quality requirements were considered in assigning destinations for SPR crude oil. It should be stressed that many distribution patterns for SPR crude oil are possible. The distribution patterns presented here represent only one possible scenario. In an actual disruption, SPR crude oil receipts by refining centers or individual refineries will depend, among other things, upon the outcome of the bidding process for SPR oil.

Seaway Complex. The Seaway complex currently consists of the Bryan Mound storage site with pipeline delivery connections to the Seaway dock at Freeport, Texas, for tanker loading, and to an existing pipeline supplying the Phillips refinery at Sweeny. Because the Seaway complex was originally designed to utilize the Seaway pipeline for crude oil distribution, the removal of that line from crude oil service has left the complex with unbalanced capacity.

To assess the extent of this imbalance and evaluate alternative solutions, drawdown and distribution at the Seaway complex was evaluated on the basis of current facilities with no subsequent investment. It was assumed that the Phase III design inventory for Bryan Mound would be 225 million barrels of low-sulfur and high-sulfur crude oils. Design drawdown rates at Seaway, as well as the Capline and Texoma complexes, were adjusted for a 20 percent redundancy factor. Total planned Seaway drawdown capability, and distribution capability *without further enhancements*, is shown in Table 39. Without further investment, only 402 MB/D of Seaway's 1,096 MB/D drawdown capacity can be distributed, leaving a distribution deficiency of 694 MB/D. Inadequate throughput capacity at the Seaway dock and the lack of alternative pipeline/marine distribution capacity are the main constraints.

The distribution pattern assumed for this analysis is shown at the bottom of Table 39. Distribution is relatively straightforward with the first priority being given to supplying the Sweeny refinery, the only refinery currently connected by pipeline to the complex. As noted above, the volumes that would actually move to Sweeny during a disruption would be determined by the outcome of an actual sale of SPR crude oil. However, for the purposes of this analysis, it was assumed that Sweeny received its pro rata share of demand for SPR crude oil in the Houston refining center based upon refinery capacity. (If Sweeny were to actually receive more SPR crude oil from Seaway, distribution capability at this complex would show a corresponding increase, up to the limits of the terminal's capacity.) The balance of the distribution from the Seaway complex is moved by water to adjacent refining centers and is constrained by Seaway dock capacity.

One means of utilizing the 694 MB/D spare drawdown capacity at Seaway would be to add marine loading capability at Freeport harbor, either at Seaway dock or through negotiations for the use of the existing Phillips' dock. This approach has drawbacks, however. Access to Freeport harbor is restricted by draft limitations and daylight berthing is required for vessels over 615 feet in length. In addition, DOE's contract for use of the Seaway dock expires in 1986 with no assurance of renewal.

An alternative is construction of a pipeline from Bryan Mound to the Houston/Texas City area. DOE has proposed this enhancement. The effect of this proposal on drawdown capacity utilization and distribution is shown in Table 40. The new pipeline, with *design* throughput capacity of 1 MMB/D, would connect Bryan Mound with an Arco pipeline terminal in Texas City, an input point to the pipeline network serving Houston/Texas City area refiners. (Reflecting the redundancy factor, the throughput capacity would be 833 MB/D.) The pipeline would provide access to some 400 MB/D marine loading capacity at Texas City. Further, Houston, a major refining center, has a potentially substantial demand for SPR crude oil, which with current facilities must be delivered entirely by water. Although not shown in Table 40, Houston also offers opportunities for marine outloading as a supplement to or, if necessary, a replacement for the Seaway dock. Further, a pipeline rather than marine transport would give some relief to the significant vessel tonnage demand and movement scheduling during a disruption. With addition of this new pipeline, distribution capability of the Seaway complex would be sufficient to fully utilize Bryan Mound drawdown capacity.

Since the SPR crude oil distribution pattern implicit in the 1990 disrupted case is only one of a spectrum of possible cases, it is important

TABLE 39

SEAWAY COMPLEX—1990 DISRUPTED CASE DELIVERABILITY SHORTFALL WITHOUT ENHANCEMENTS (MB/D)

Summary

Maximum design drawdown capacity (1,096 MB/D) not currently achievable due to:

- Limited dock capacity at the Seaway docks (320 MB/D)
- Limited Seaway terminal capacity (495 MB/D)
- Assumed limitation on demand at Sweeny refinery*

Drawdown Capacity

Maximum Design Drawdown	1,096
Distribution with Facilities Constraints	402
Unused Drawdown Capacity	694

	Throughput Capacity	Projected Utilization	Unused Capacity
Terminal Facilities			
Seaway Terminal	495	402	93
Transportation Facilities			
Sweeny Pipeline	175	82*	93
Seaway Docks	320	320	–
Total	**495**	**402**	**93**
Total Deliverability	**495**	**402**	**93**

	Low Sulfur	High Sulfur	Total SPR Crude
SPR Crude Oil Delivered			
Sweeny via Pipeline	27	55	82
Corpus Christi via Water	150	–	150
Houston via Water	170	–	170
Total	**347**	**55**	**402**

*Sweeny refinery SPR crude oil receipts assumed limited to pro rata share of total SPR supplies (82 MB/D).

in evaluating enhancement options to look for flexibility to respond to demand changes from the base case.

With the recommended pipeline enhancement at the Seaway complex, a reasonable level of flexibility is provided, as shown in the Transportation Facilities and SPR Crude Oil Delivered sections of Table 40. The existing Sweeny pipeline has a capacity of 93 MB/D in excess of assumed demand. The new pipeline to the Houston/Texas City area is assumed to supply 559 MB/D to local refineries. Dock loading at Texas City is assumed to be 135 MB/D (109 MB/D to Corpus Christi and 26 MB/D to PADD I). If local Houston/Texas City demand increases, 135 MB/D assumed to be loaded over the docks at Texas City can be diverted to area refineries; if local demand decreases, there is 265 MB/D of spare dock loading capacity available at Texas City to provide marine movements to other refining centers.

In summary, it is recommended that a pipeline with a design capacity of 1.0 MMB/D be constructed from Bryan Mound to Texas City

TABLE 40

SEAWAY COMPLEX—1990 DISRUPTED CASE DELIVERABILITY WITH NPC RECOMMENDED ENHANCEMENTS (MB/D)

Summary

Enhancement recommended:

- A 1 MMB/D pipeline* from Bryan Mound to Arco pipeline terminal at Texas City providing pipeline connection to Houston/Texas City area to supply local refiners and provide access to additional marine terminal capacity.

Drawdown Capacity	
Maximum Design Drawdown	1,096
Distribution with Enhancements	1,096
Unused Drawdown Capacity	0

	Throughput Capacity	Projected Utilization	Unused Capacity/ Flexibility
Terminal Facilities			
Seaway	495	402	93
Arco	694	694	–
Total	**1,189**	**1,096**	**93**
Transportation Facilities			
Sweeny Pipeline	175	82	93
Houston/Texas City Pipeline	833*	694	139
Texas City Docks (400 MB/D Capacity)			
Seaway Docks	320	320	–
Total	**1,328**	**1,096**	**232**
Total Deliverability	**1,189**	**1,096**	**93**

	Low Sulfur	High Sulfur	Total SPR Crude
SPR Crude Oil Delivered			
Sweeny via Pipeline	27	55	82
Houston via Pipeline	–	559	559
Corpus Christi via Pipeline & Water	–	109	109
PADD I via Pipeline & Water	–	26	26
Corpus Christi via Water	150	–	150
Houston via Water	170	–	170
Total	**347**	**749**	**1,096**

*Design capacity of the pipeline is 1.0 MMB/D; a 20 percent redundancy factor is used for assessing actual throughput capacity, resulting in the 833 MB/D shown under the facilities section (1.0 MB/D ÷ 1.2 = 833 MB/D).

to alleviate the capacity imbalance of the Seaway complex. This pipeline must have the flexibility to deliver both low-sulfur and high-sulfur crude oil, either by batching or parallel pipelines. It offers the advantages of:

- Fully utilizing Bryan Mound drawdown capacity
- Reducing excessive demand for marine tonnage during an actual disruption
- Providing SPR pipeline supply to a major refining center
- Offering flexibility to handle demand shifts
- Avoiding investment in dock facilities at a limited port.

It is vital, however, that such a pipeline project include all enhancements necessary to the Houston/Texas City area pipeline systems downstream of Arco's Texas City terminal to permit delivery of SPR crude oil to all refineries. This study effort concentrated on macro crude oil demands and did not attempt to identify the refinery-level micro enhancements needed to ensure that individual facilities could and would be serviced by the SPR. Such an effort must be undertaken by the SPR staff in conjunction with individual specialists on refinery oil movements. Similar case-by-case analyses are necessary and recommended for government/industry site interfaces at the Texoma and Capline complexes.

In addition, options to enhance marine loading capability through the existing interconnection with the Phillips refinery docks at Freeport should be considered to create additional flexibility.

Capline Complex. The Capline complex consists of the Bayou Choctaw and Weeks Island storage sites with pipeline connections to DOE's St. James terminal. The latter has the capability for pipeline deliveries to the Capline system and to two local refineries, Texaco at Convent and Marathon at Garyville. It also has facilities for marine loading.

As in the Seaway complex analysis, the initial distribution case prepared for the Capline complex assumed the 1990 disrupted case using current facilities with no further investment. This reflects a Phase III design inventory of 140 million barrels of low-sulfur and high-sulfur crude oils. Capline's total design drawdown rate is 1,070 MB/D (including the previously mentioned 20 percent redundancy). Table 41 summarizes the drawdown and distribution capabilities at the Capline complex without further investments. With current capacity constraints at the St. James terminal, 190 MB/D drawdown capacity cannot be used.

The Capline system was given priority in this analysis since it is now the only major delivery mode for SPR crude oil destined for PADD II refineries. In the case of local refineries, it must again be noted that actual deliveries will be dependent on results of SPR sales at the time of a disruption; for analytic purposes, however, delivery was apportioned to the Mississippi River region based on refining capacity. The effects of these loadings on available capacity are also shown in Table 41. Throughput capacity at the St. James terminal is the determining constraint. As shown in the Transportation Facilities section of Table 41, pipeline capacity to the Capline system and to local refineries is more than adequate to meet projected demand. There is also unused dock loading capacity at the Capline complex.

To maximize drawdown and distribution capacity at the Capline complex, it is recommended that throughput capacities at the St. James terminal be increased from 880 MB/D to 1,070 MB/D to match the drawdown capacity of the caverns at Weeks Island and Bayou Choctaw. DOE has already proposed such a modification.

The estimated impact of this enhancement is shown in Table 42. As can be seen, 166 MB/D of drawdown capacity remains unused, even after the recommended enhancements. This is due to two additional constraints assumed in this analysis. Specifically:

- Low-sulfur crude oil drawdown is assumed to be limited to the 90-day run-out rate
- High-sulfur crude oil drawdown is held to the capacity of the pipeline from Weeks Island.

If low-sulfur crude oil supplies were either increased, or drawn down more quickly, the remaining 166 MB/D spare capacity could be utilized. Alternatively, if the Bayou Choctaw line, which is assumed to move only low-sulfur crude oil, could be made available by running it in alternate low-sulfur and high-sulfur service, the full distribution capacity of the complex could also be realized. Dock loading capability is more than adequate to handle the additional drawdown.

Flexibility to accommodate demand changes exists in the Capline complex. For example, added Capline system demand of 201 MB/D could be met by supplying pipeline-connected Mississippi River refiners by marine tanker and barge. Further increase in Capline system demand can be handled by marine delivery direct to the Capline system's own dock. Since pipeline-connected Mississippi River refiners have the ability to receive by

TABLE 41

CAPLINE COMPLEX—1990 DISRUPTED CASE DELIVERABILITY SHORTFALL WITHOUT ENHANCEMENTS (MB/D)

Summary

Maximum design drawdown capacity (1,070 MB/D) cannot be achieved due to limited throughput capacity at the St. James terminal (880 MB/D).

Drawdown Capacity	
Maximum Design Drawdown	1,070
Maximum Distribution due to Facility Constraints	880
Unused Drawdown Capacity	190

	Throughput Capacity	**Projected Utilization**	**Unused Capacity**
Terminal Facilities			
St. James Terminal	880	880	–
Transportation Facilities			
Pipelines	840	838	2
Docks	350	42	308
Total	**1,190**	**880**	**310**
Total Deliverability	**880**	**880**	**–**

SPR Crude Oil Delivered	**Low Sulfur**	**High Sulfur**	**Total SPR Crude**
Capline to PADD II	265	372	637
Pipeline to Miss. River	33	168	201
Water to Miss. River	16	26	42
Total	**314**	**566**	**880**

water, this would be the most efficient means to deliver additional crude oil to those plants.

The recommended terminal enhancement would rectify the identified drawdown/distribution capacity imbalance in the complex, especially given its ample flexibility to deal with demand changes and the lack of other alternatives.

An additional recommendation for change in the Capline complex is discussed in the following section dealing with the Texoma complex.

Texoma Complex. The Texoma complex includes storage sites at West Hackberry, Sulphur Mines, and yet-to-be-completed Big Hill. All the sites are connected by pipeline to the Sun terminal at Nederland, which offers dock loading capability and pipeline delivery to local Beaumont/Port Arthur refineries. Phase III design inventory for the complex is 385 million barrels of high-sulfur and low-sulfur crude oils.

The Texoma complex, like the Seaway complex, was designed to supply SPR crude oil to a major pipeline (Texoma pipeline) linked to inland refiners. *With the sale and conversion of the Texoma pipeline to natural gas service, the complex is left with a major deficiency:* some 1,217 MB/D of drawdown capacity cannot be utilized, as shown at the top of Table 43. Even though some spare pipeline and vessel loading capacity exists, Texoma complex distribution is constrained to levels well below the maximum design drawdown rate by the lack of adequate terminal and dock facilities available to DOE at Sun's Nederland terminal. As currently configured, all SPR crude oil stored at Texoma must move through the Sun terminal at Nederland, whether the distribution mode is by pipeline or by water.

Texoma is the largest of the three SPR complexes and was treated as the swing supplier of SPR crude oil in this analysis. With Seaway drawdown and distribution capacity at 1,096 MB/D and Capline at 904 MB/D, drawdown and distribution capacity at Texoma is required to increase to 2,500 MB/D. Without any further enhancements at Texoma, that complex has a drawdown and distribution capacity of 1,120 MB/D, thus limiting total SPR drawdown and distribution to 3,120 MB/D, a shortfall of 1,380 MB/D from the 4.5 MMB/D design drawdown rate.

TABLE 42

CAPLINE COMPLEX—1990 DISRUPTED CASE DELIVERABILITY WITH NPC RECOMMENDED ENHANCEMENTS (MB/D)

Summary

Increase throughput capacity of St. James terminal by 190 MB/D (from 880 MB/D to 1,070 MB/D).

Drawdown Capacity

Maximum Design Drawdown	1,070
Maximum Distribution Capacity	1,070
Unused Drawdown Capacity	0

	Throughput Capacity	Projected Utilization	Unused Capacity/ Flexibility
Terminal Facilities			
St. James Terminal	1,070	904*	166
Transportation Facilities			
Pipelines	840	838	2
Docks	350	66	284
Total	**1,190**	**904**	**286**
Total Deliverability	**1,070**	**904**	**166**

	Low Sulfur	High Sulfur	Total SPR Crude
SPR Crude Oil Delivered			
Capline to PADD II	265	372	637
Pipeline to Miss. River	33	168	201
Water to Miss. River	16	50	66
Total	**314**	**590**	**904**

*Note: Two assumptions prevent utilization of the Capline complex at maximum drawdown and terminal throughput capacity, even after enhancements. First, low-sulfur crude oil drawdown is held to the 90-day run-out rate. If sufficient additional low-sulfur crude oil were located in this complex, the 90-day run-out rate could increase to fully utilize capacity. Second, high-sulfur distribution is limited to the capacity of the pipeline from Weeks Island. Even without relocation of future SPR fill, all Capline complex capacity could be utilized if the Bayou Choctaw line (now assumed to be low-sulfur crude oil *only*) could be made available to alternate high-sulfur and low-sulfur service, thereby utilizing the 166 MB/D indicated spare capacity.

TABLE 43

TEXOMA COMPLEX—1990 DISRUPTED CASE
DELIVERABILITY SHORTFALL WITHOUT ENHANCEMENTS
(MB/D)

Summary

Maximum design drawdown of 2,337 MB/D cannot by achieved due to:

- Limited capacity now available to DOE at Nederland (Sun) terminal (1,120 MB/D)*
- Limited dock loading capacity available to DOE (880 MB/D)*
- Limited pipeline deliverability

Drawdown Capacity

Maximum Design Drawdown	2,337
Maximum Distribution due to Facility Constraints	1,120
Unused Capacity	1,217

	Throughput Capacity	Projected Utilization	Unused Capacity
Terminal Facilities			
Nederland (Sun only)	1,120*	1,120	–
Transportation Facilities			
Sun Pipeline to Beaumont	679	427	252
Nederland (Sun Docks only)	880*	693	187
Total	**1,559**	**1,120**	**439**
Total Deliverability	**1,120**	**1,120**	**–**

	Low Sulfur	High Sulfur	Total SPR Crude
SPR Crude Oil Delivered			
Pipeline via Nederland to Beaumont	134	293	427
Water via Nederland to Miss. River	–	267	267
PADD I via Water	426	–	426
Total	**560**	**560**	**1,120**

*As described in Appendix C, there is some additional capacity at the Sun terminal and docks that could be made available to DOE with little investment or contractual obligation.

Two alternatives to correct this deficiency are identified:

- The addition of sufficient terminal, pipeline, and marine loading capability at Texoma to bring total distribution capacity to 2,500 MB/D with an additional 250 MB/D of spare capacity to provide flexibility to meet potential demand shifts.
- The shifting of SPR crude oil from the Texoma complex, either by physical relocation of future fill or by pipeline connections from current and planned sites, to the Capline area distribution points.

Table 44 summarizes the enhancements that would be required under the first alternative to bring distribution capability at the Texoma complex to 2,500 MB/D and to provide 250 MB/D of additional flexibility.

- Construction of a 9-mile, 26-inch-diameter pipeline from West Hackberry to the existing 22-inch-diameter Texas pipeline near Lake Charles. With a design capacity of 700 MB/D, this new pipeline would permit pipeline delivery to Lake Charles and Beaumont/Port Arthur refineries and would provide access to existing dock loading facilities at Lake Charles. This enhancement would also permit an increase of 100 MB/D in the maximum drawdown rate of the overall Texoma complex.
- Increase terminal and dock capacity available to DOE at Nederland by:
  - —Building a pipeline spur to connect the Big Hill storage site to the Texas Oil and Chemical terminal and docks (approximately four miles northwest of the Sun terminal). Design throughput capacity at the Texas Oil and Chemical facilities is 200 MB/D.
  - —Increasing terminal capacity available to DOE at Sun's Nederland terminal from 1,120 MB/D to a design capacity of 2,360 MB/D.
  - —Increasing dock capacity available to DOE at the Sun terminal (or elsewhere in Nederland) such that total Nederland dock capacity (including Texas Oil and Chemical docks) is 2,050 MB/D.

Table 44 also shows the distribution effects of adding these facilities. (Throughput capacities shown in the table reflect the 20 percent redundancy factor assumed for critical facilities.) The pipeline to the Lake Charles area (throughput capacity of 580 MB/D) provides an outlet for Texoma SPR stocks other than Nederland. This results in an increase in maximum design drawdown capability of the Texoma complex by freeing up capacity in the existing DOE pipeline connecting the West Hackberry and Sulphur Mines storage sites to Nederland and permitting higher combined drawdown rates from those two sites. The additional terminal and dock facilities at Nederland increase distribution capacity at that part of the complex from 1,120 MB/D to 1,710 MB/D (after accounting for the redundancy factor).

With these enhancements, distribution capacity at the Texoma SPR site would match the 2,500 MB/D design drawdown required, and spare distribution capacity of 250 MB/D (210 MB/D after accounting for the 20 percent redundancy factor) would be available to provide flexibility for future shifts in demand. This alternative, however, places a high premium on marine shipments from Nederland and requires nearly 1.5 MMB/D to be moved over the docks by either tanker or barge. Potential for delays due to scheduling problems, dock congestion, and issues associated with ballast treatment pose significant risks to achieving and maintaining this high throughput rate.

The second alternative alleviates much of the pressure on terminal and marine throughput at Nederland. Table 45 summarizes the effects on distribution requirements at the Texoma complex if 100 million barrels of Texoma SPR crude oil is made available to the Capline area. For the purposes of this example, it is assumed that 100 million barrels of storage capacity is relocated to the Capline area and drawn down at a rate of 700 MB/D. Of course, actual drawdown capability would depend upon the site selected and the facilities available. The 700 MB/D rate could also represent the throughput capacity of a pipeline connecting the Texoma storage sites to the Capline area. If fill is relocated, the required drawdown from Texoma would be reduced from 2.5 MMB/D to 1.8 MMB/D.

The enhancements required at the Texoma complex if future SPR fill is relocated would be as follows:

- Build a 9-mile, 26-inch-diameter pipeline with a design capacity of 700 MB/D from West Hackberry to the Lake Charles area (same enhancement as in the first alternative).
- Increase terminal and dock capacity available to DOE at Nederland by:
  - —Building a pipeline spur to connect the Big Hill storage site to the 200 MB/D Texas Oil and Chemical terminal and docks.
  - —Increasing terminal capacity available to DOE at Sun's Nederland terminal from 1,120 MB/D to a design capacity of 1,480 MB/D, and increasing dock capacity at the Sun terminal by 90 MB/D to a design capacity of 970 MB/D.

As can be seen in the example in Table 45, drawdown and distribution of Texoma complex inventories is at a revised maximum design capacity of 1.8 MMB/D and leaves about 215 MB/D (180 MB/D after the redundancy factor) of flexibility to accommodate potential demand shifts. Utilization requirements for Nederland

TABLE 44

TEXOMA COMPLEX—1990 DISRUPTED CASE DELIVERABILITY WITH NPC RECOMMENDED ENHANCEMENTS ASSUMING NO REALLOCATION OF TEXOMA SPR OIL TO THE CAPLINE COMPLEX AREA (MB/D)

Summary

Enhancements recommended are:

- A 9-mile, 700 MB/D design capacity pipeline from West Hackberry to the Texas pipeline near Lake Charles (permits delivery to local refineries and docks at Lake Charles and pipeline delivery to Beaumont/Port Arthur refineries). Also permits increase of 100 MB/D in Texoma drawdown rate.
- Increase Nederland terminal design capacity available to DOE from 1,120 MB/D to 2,560 MB/D.
- Increase dock capacity available at Nederland from 880 MB/D to 2,050 MB/D design capacity by building a pipeline spur to the Texas Oil and Chemical terminal and docks and increasing dock capacity available to DOE at Sun terminal.

Drawdown Capacity

Maximum Design Drawdown	2,500*
Distribution	2,500
Unused Capacity	0

	Throughput Capacity	Projected Utilization	Unused Capacity/ Flexibility
Terminal Facilities			
Nederland (Sun and TO&C)	2,130†	1,920	210
Lake Charles	580	580	–
Transportation Facilities			
New 26″ Pipeline to L. Charles	580	580	–
Lake Charles Docks (333)			
Texas 22″ Pipeline to Beaumont (247)			
Sun Pipeline to Beaumont	679	427	252
Nederland (Sun and TO&C) Docks	1,710	1,493	217
Total	**2,969**	**2,500**	**469**
Total Deliverability	**2,710**	**2,500**	**210**

SPR Crude Oil Delivered	Low Sulfur	High Sulfur	Total SPR Crude
Pipeline via Nederland to Beaumont	134	293	427
Pipeline to Lake Charles	–	154	154
Pipeline via Lake Charles to Beaumont	–	93	93
Water via Nederland to:			
Houston	105	–	105
Miss. River	115	338	453
PADD I	560	–	560
VI/PR	124	–	124
PADD V	204	–	204
Lake Charles	47	–	47

(Continued)

TABLE 44 (Continued)

	Low Sulfur	High Sulfur	Total SPR Crude
SPR Crude Oil Delivered (Cont.)			
Water via Lake Charles to:			
Miss. River	-	283	283
PADD I	-	50	50
Total	**1,289**	**1,211**	**2,500**

*DOE design drawdown capacity of 2,337 MB/D, plus 100 MB/D is 63 MB/D less than assumed here. DOE drawdown capacities include 20 percent redundancy factor, so 2,500 MB/D may well be achievable. If not, spare drawdown/deliverability capacity exists at Capline which, with scheduling flexibility, can be made available to make up this small shortfall in reaching total drawdown/distribution of 4.5 MMB/D.

†Capacities discounted from design capacity described above to reflect a 20 percent redundancy factor.

TABLE 45

TEXOMA COMPLEX—1990 DISRUPTED CASE DELIVERABILITY IF 100 MILLION BARRELS OF FUTURE FILL IS SHIFTED FROM TEXOMA TO THE CAPLINE AREA* (MB/D)

Summary

The enhancements required at the Texoma complex if future SPR fill is relocated from Texoma to the Capline complex (assuming a shift of at least 100 million barrels) are:

- Construction of a 9-mile, 700 MB/D pipeline from West Hackberry to Lake Charles area.
- Increase Nederland terminal capacity available to DOE from 1,120 MB/D to 1,680 MB/D.
- Increase dock capacity at Nederland from 880 MB/D to 1,170 MB/D by constructing a pipeline to Texas Oil and Chemical and increasing dock capacity available to DOE at Sun terminal by 90 MB/D.

Drawdown Capacity

Maximum Drawdown (Adjusted)	1,800
Distribution	1,800
Unused Capacity	0

	Throughput Capacity	Projected Utilization	Unused Capacity
Terminal Facilities			
Nederland (Sun and TO&C)	1,400†	1,220	180
Lake Charles	580†	580	-
Transportation Facilities			
New 26″ Pipeline to L. Charles	580†	580	-
Lake Charles Docks (333)			
Texas 22″ Pipeline to Beaumont (247)			
Sun Pipeline to Beaumont	679	427	252
Nederland (Sun and TO&C) Docks	973	793	180
Total	**2,232**	**1,800**	**432**
Total Deliverability	**1,980**	**1,800**	**180**

*It is assumed for purposes of this table that the 100 million barrels of shifted SPR oil would have a drawdown rate of 700 MB/D. The goal of reducing Texoma waterborne shipments could also be achieved by a 700 MB/D pipeline from Texoma to the Capline area.

†Capacities discounted from design capacity described above to reflect a 20 percent redundancy factor.

dock capacity would decrease significantly from nearly 1.5 MMB/D to a much more manageable level of about 800 MB/D. The physical enhancements recommended at the Texoma complex under this example are consistent with those DOE has proposed. If only these enhancements are made and future fill is not relocated, however, distribution capability at the complex would fall 520 MB/D short of the 2.5 MMB/D required.

Reallocating at least 100 million barrels of future SPR fill to the Capline complex would provide greater drawdown sustainability to Capline and to local refiners. The area of the Louisiana Offshore Oil Port's Clovelly salt dome storage provides several advantages as a potential location if a portion of future fill is physically relocated to the Capline area. (Figure 21 displays current LOOP interconnections to crude oil pipelines.) With the necessary new site development and interconnections, it would be possible for DOE to make deliveries into LOCAP/Capline and also to six other pipelines connected to the LOOP system that could otherwise receive SPR crude oil only via marine transportation. Location of fill in this area would also expand deliverability within the Capline complex. However, until a specific site is designated, it is not possible to assess what further enhancements, if any, would be required.

Making Texoma fill directly available to the Capline area would also provide greater distribution flexibility in meeting individual refiner's requirements for low-sulfur or high-sulfur crude oil from the SPR. It is recommended that DOE undertake a detailed economic evaluation of the alternatives of physically moving or pipeline connecting Texoma fill to the Capline complex area. If the apparent benefits prove cost effective, only the enhancements recommended by DOE would be required at the Texoma complex.

The effects of current deficiencies and the proposed enhancements at each of the SPR complexes are summarized in Tables 46 and 47. Table 46 assumes that lower Mississippi shipments of Texoma SPR oil are by water, while Table 47 shows the effect of relocating 100 million barrels of future Texoma fill to the Capline complex area.

PADD I

The required changes in PADD I crude oil and product logistics are displayed in Table 48, which compares the 1990 nondisrupted case to the 1990 disrupted case.

The following points are significant:

- In the disrupted case, crude oil runs increase about 8 percent over the nondisrupted case due to the loss of over 1.0

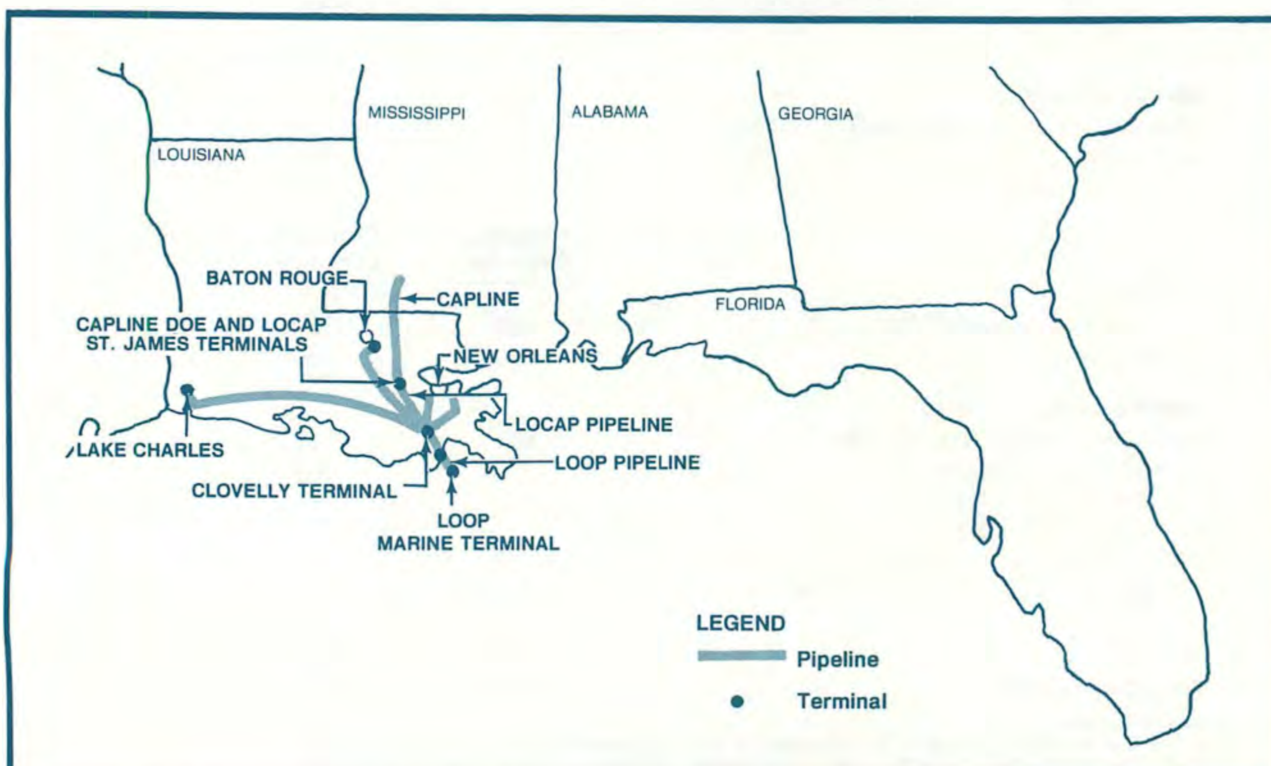

Figure 21. Louisiana Offshore Oil Port (LOOP) and Connecting Pipelines to Refineries.

TABLE 46

PLANNED SPR DELIVERABILITY/SHORTFALL—1990 DISRUPTED CASE WITHOUT SHIFT OF 100 MILLION BARRELS OF FUTURE SPR FILL TO CAPLINE (MB/D)

	Seaway		Capline		Texoma		Total SPR System	
	Need	Available Without Enhancement	Need	Available Without Enhancement	Need	Available Without Enhancement	Need	Available Without Enhancement
Corpus Christi	260	150	–	–	–	–	260	150
Houston/Texas City	810	250	–	–	110	–	920	250
Beaumont/Port Arthur	–	–	–	–	520	430	520	430
Lake Charles	–	–	–	–	200	–	200	–
Lower Miss.	–	–	260	240	740	270	1,000	510
PADD II	–	–	640	640	–	–	640	640
PADDs I, V, and VI/PR	30	–	–	–	930	420	960	420
Total	**1,100**	**400**	**900**	**880**	**2,500**	**1,120**	**4,500**	**2,400**
Shortfall	**700**		**20**		**1,380**		**2,100**	
Enhancements Recommended								
1 MMB/D pipeline to Houston/Texas City for local use and dock loading at Texas City	700		–		–		700	
Increase St. James terminal capacity	–		20		–		20	
700 MB/D pipeline to Lake Charles for local use, pipeline connection and dock loading	–		–		580		580	
Expand Nederland terminal and docks	–		–		800		800	
Total Enhancements	**700**		**20**		**1,380**		**2,100**	

TABLE 47

PLANNED SPR DELIVERABILITY/SHORTFALL—1990 DISRUPTED CASE WITH SHIFT OF 100 MILLION BARRELS OF FUTURE SPR FILL TO CAPLINE*
(MB/D)

	Seaway		Capline		Texoma		Total SPR System	
	Need	Available Without Enhancement	Need	Available Without Enhancement	Need	Available Without Enhancement	Need	Available Without Enhancement
Corpus Christi	260	150	–	–	–	–	260	150
Houston/Texas City	810	250	–	–	110	–	920	250
Beaumont/Port Arthur	–	–	–	–	520	430	520	430
Lake Charles	–	–	–	–	200	–	200	–
Lower Miss.	–	–	960	240	40	40	1,000	280
PADD II	–	–	640	640	–	–	640	640
PADDs I, V, and VI/PR	30	–	–	–	930	650	960	650
Total	**1,100**	**400**	**1,600**	**880**	**1,800**	**1,120**	**4,500**	**2,400**
Shortfall	**700**		**720**		**680**		**2,100**	
Enhancements Recommended								
1 MMB/D pipeline to Houston/Texas City for local use and dock loading at Texas City	700		–		–		700	
Shift 100 MB future SPR fill to Capline area	–		700		–		700	
Increase St. James terminal capacity	–		20		–		20	
700 MB/D pipeline to Lake Charles for local use, pipeline connection and dock loading	–		–		580		580	
Expand Nederland terminal and docks	–		–		100		100	
Total Enhancements	**700**		**720**		**680**		**2,100**	

*It is assumed for purposes of this table that the 100 million barrels of shifted SPR oil would have a drawdown rate of 700 MB/D. The goal of reducing Texoma waterborne shipments could also be achieved by a 700 MB/D pipeline from Texoma to the Capline area.

TABLE 48

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES—PADD I
(MB/D)

	1990 Nondisrupted	1990 Disrupted	△
Local Demand	**5,340**	**4,840**	**(500)**
Crude Oil Supplies:			
Local Production	90	90	-
Imports	910	-	(910)
Exports*	-	(120)	(120)
Domestic Marine Shipments	-	-	-
Domestic Marine Receipts	140	1,260	1,120
Domestic Pipeline Shipments	(40)	(40)	-
Domestic Pipeline Receipts	-	-	-
Other	-	-	-
Product Supplies:			
Imports	1,040	-	(1,040)
Exports	(30)	-	30
Domestic Marine Shipments	(90)	(80)	10
Domestic Marine Receipts	1,070	1,380	310
Domestic Pipeline Shipments	(190)	(170)	20
Domestic Pipeline Receipts	2,180	2,250	70
Other	260	270	10
Total Supplies	**5,340**	**4,840**	**(500)**
Memo: Crude Oil Runs	1,100	1,190	90

*Assumes Canadian imports/exports continue on exchange basis.

MMB/D of product imports. This increase in runs is necessary in spite of a 9.3 percent decline in local product demand. Crude oil runs in the disrupted case represent about 80 percent of current operable refinery capacity.

- To offset the loss of 900 MB/D of imported crude oil and meet increased refinery runs, domestic waterborne shipments of crude oil must increase by 1.1 MMB/D. Domestic marine tonnage would be required for this transportation under existing Jones Act provisions. Virtually all of this replacement crude oil must go to the Philadelphia and New York refining centers as these areas represent about 85 percent of PADD I's current (and projected) refining capacity. However, since net PADD receipts at refinery centers of waterborne crude oil increase only 100 MB/D over the nondisrupted case, dock capacity at PADD I refineries should be capable of handling this increased volume. PADD I docks demonstrated the capability of handling even higher volumes during the imports "peak" in the late 1970s.
- As seen in Table 48, local crude oil runs in the disrupted case meet only 1.2 MMB/D of PADD I's 4.8 MMB/D product demand. As a result, receipts of domestic products in PADD I must increase about 400 MB/D over nondisrupted levels. Table 49 displays the PADD I product volumetrics for the 1990 disrupted case.

Clean products pipeline capacity into PADD I is more than adequate to meet required movements. However, a portion of PADD I's clean product requirements from other PADDs will still need to be fulfilled by marine transportation, primarily to Florida and terminals along the U.S. southeast coast. PADD I pipeline and refinery facilities should be capable of handling the 70 MB/D increase in pipeline shipments and 90 MB/D in refinery runs shown in Table 48 for the disrupted case. (Appendix C contains an

TABLE 49

PADD I PRODUCT SUPPLY/DEMAND BALANCE 1990 DISRUPTED CASE (MB/D)

Local Product Demand	**4,840**
Supply	
Local refinery production	1,190
Domestic shipments	(250)
Domestic pipeline receipts (clean and NGLs)	2,250
Domestic marine receipts (clean)	710
Domestic residual fuel oil marine receipts	670
Other*	270
Total Supply	**4,840**

*Includes refinery gain.

estimate of pipeline deliverability in PADD I and a map displaying the location of the Colonial and Plantation pipelines and their respective capacities.)

- As noted earlier, the proposed Transgulf Pipeline is not assumed to be available. Should this line be in place by 1990, it would reduce marine clean products transportation requirements from Gulf Coast refineries to Florida. The sensitivity of this assumption to marine transportation requirements has been noted separately in this chapter.
- Because residual fuel oil accounts for about 70 percent of all product imports into PADD I, an imbalance occurs between local refinery production and demand in the disrupted case, resulting in significantly increased residual fuel oil marine shipment requirements. Table 50 summarizes these requirements. (Appendix C contains additional detail on residual fuel oil balances in 1990.) The projected levels of residual fuel oil product movement in the disrupted case would materialize, though only if SO_x emission limits are waived as explained later in this chapter.

Although significant changes in PADD I distribution patterns and sources would occur in the postulated disruption scenario, no pipeline enhancements are necessary.

U.S. Virgin Islands/Puerto Rico. Table 51 displays 1990 supply/demand balances for the U.S. Virgin Islands and Puerto Rico.

Although there are no pipeline logistics issues associated with supplying these territories, the following points are significant in comparing the 1990 nondisrupted and disrupted cases.

- Despite reduced local demand and reduced product shipments to the United States, crude oil runs would increase 30 MB/D to partially offset the loss of 100 MB/D of product imports.
- With the loss of crude oil imports, demand for marine movements of crude oil from the United States would increase 300 MB/D. Because movements to the U.S. Virgin Islands are exempt from Jones Act provisions, 240 MB/D of the increase would occur on foreign flag vessels, with 60 MB/D (additional movement to Puerto Rico) transported in Jones Act or appropriately waivered tonnage (CDS or foreign flag).

TABLE 50

RESIDUAL FUEL OIL MOVEMENTS INTO PADDs* (MB/D)

	PADD					
	I	II	III	IV	V	VI/PR
1990 Nondisrupted	140	30	(40)	–	(30)	(100)
1990 Disrupted	670	(40)	(470)	–	(30)	(130)

*Shipments in brackets.

TABLE 51

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES
U.S. VIRGIN ISLANDS/PUERTO RICO*
(MB/D)

	1990 Nondisrupted	1990 Disrupted	△
Local Demand	**240**	**220**	**(20)**
Crude Oil Supplies:			
Imports	270	–	(270)
Exports	–	–	–
Domestic Marine Shipments	170	470	300
Domestic Marine Receipts	–	–	–
Other	–	–	–
Product Supplies:			
Imports	110	–	(110)
Exports	–	–	–
Domestic Marine Shipments	(310)	(250)	60
Domestic Marine Receipts	–	–	–
Other	–	–	–
Total Supplies	**240**	**220**	**(20)**
Memo: Crude Oil Runs	440	470	30

*Movements to/from the United States and the U.S. Virgin Islands/Puerto Rico are considered domestic.

- Output of residual fuel oil would be increased almost 30 percent, providing additional residual fuel oil to meet PADD I requirements. Residual fuel oil movements from the U.S. Virgin Islands/Puerto Rico are estimated at 130 MB/D in the disrupted case.
- Marine product movements of 60 MB/D from the U.S. Virgin Islands to Puerto Rico are required to meet Puerto Rican demand. Existing law permits this movement to occur on foreign flag vessels, so there is no additional demand for Jones Act tonnage. (Appendix C contains a detailed balance for the individual territories for the 1983 and 1990 projected cases.)

No distribution enhancements are seen as necessary for PADD I and the U.S. Virgin Islands/Puerto Rico; a marine sensitivity addressing reduced delivery levels of PADD V crude oil to the Virgin Islands in the disrupted case is contained later in this chapter.

PADD II

PADD II is dependent upon oil movements from other PADDs to meet local crude oil and product requirements in both the 1990 projected cases. The required changes in PADD II crude oil and product logistics are displayed in Table 52.

The following points are significant in considering these balances:

- The normal supply patterns for PADD II lend themselves to relatively simple adjustments in the disrupted case. With the conversion of Seaway and Texoma pipelines to natural gas service, all the foreign crude oil imported into PADD II from overseas sources in the nondisrupted case must move into PADD II via the Capline system, with the exception of some very small quantities moving up the Mississippi River by barge. (Overland imports from Canada are a special case, which will be discussed later.) The Capline system has recently operated far below its capacity (1.2 MMB/D) and should be capable of handling imports that are landed in the Gulf Coast and shipped through PADD III in the 1990 nondisrupted case. Capline system shipments do not present a problem in the disrupted case as they would

TABLE 52

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES—PADD II
(MB/D)

	1990 Nondisrupted	1990 Disrupted	△
Local Demand	**4,410**	**4,000**	**(410)**
Crude Oil Supplies:			
Production	1,050	1,050	–
Imports*	1,110†	210	(900)
Exports*	–	(130)	(130)
Domestic Marine Shipments	–	–	–
Domestic Marine Receipts	70	70	–
Domestic Pipeline Shipments	–	–	–
Domestic Pipeline Receipts	790	1,470	680
Other	–	–	–
Product Supplies:			
Imports	220	–	(220)
Exports	(40)	–	40
Domestic Marine Shipments	(50)	(40)	10
Domestic Marine Receipts	170	160	(10)
Domestic Pipeline Shipments	(340)	(210)	130
Domestic Pipeline Receipts	1,000	980	(20)
Other	430	440	10
Total Supplies	**4,410**	**4,000**	**(410)**
Memo: Crude Oil Runs	3,020	2,670	(350)

*Assumes Canadian imports/exports continue on exchange basis.
†900 MB/D of PADD II imports are landed in PADD III and shipped on Capline.

decline approximately 16 percent from the nondisrupted case. Since the SPR caverns at Bayou Choctaw and Weeks Island can feed into the Capline system, a loss of waterborne crude oil imports can readily be covered from the SPR, with little or no effect on the receiving refineries on the north end of the Capline system.

- The outcome of a bidding process for crude oils available from the SPR cannot be predicted in advance of a disruption. Thus, it cannot be determined whether PADD II refiners will be successful bidders on enough crude oil to meet product demand in the district. Likewise, even if they bid successfully, it cannot be predicted whether their SPR procurements will be out of the caverns accessible to the Capline system, or from others requiring tanker movements to St. James. It is reasonable to assume that there will be exchanges available to place as much PADD II-bound SPR crude oil as possible at the origin of the Capline system without the necessity for high cost tanker movement.

It is recognized that an alternative assumption could have been made for the PADD II refineries' operating level in the disrupted case. It might have been assumed that PADD II refineries would operate at 90.7 percent of their pre-disruption levels, since overall U.S. shortfall is 9.3 percent. This is the same assumption used in refinery balances for PADDs IV and V, which have refining capacity in close balance with product demand.

PADD II is somewhat different, however, in that considerable clean products (about 1.0 MMB/D) would normally move into PADD II from PADD III. The net transfer into PADD II is estimated in the nondisrupted case at 660

MB/D, taking into account the 340 MB/D of product moving from the district, largely into PADDs I and III. Most of these transfers across district occur in the Texas/Oklahoma and Ohio/Kentucky/West Virginia areas.

Therefore, to better check the flexibility of the SPR drawdown system, it was decided to hold these clean product transfers constant in the disrupted case, effectively pressuring refining and distribution systems in PADDs I and III. The impact of this assumption was to constrain refinery throughput in PADD II by an additional 70 MB/D, or an 11.6 percent reduction from the nondisrupted case. *However, this assumption in no way should be construed as a "recommended" distribution pattern, nor as even a "likely" case.*

Overland imports from Canada merit special attention. It seems reasonable that a supply disruption affecting the United States would affect Canada similarly, and therefore that nation would take action to preserve its own supply. Much of PADD II's northern tier supply is intertwined with the Canadian system. Indeed, the main crude oil pipeline from Western to Eastern Canada passes through PADD II.

For the disrupted case, it is assumed that the 250 MB/D of Canadian crude oil exports to the United States (210 MB/D of it to PADD II) would continue, but that the United States would pay back to Canada a like amount (130 MB/D through PADD II and 120 MB/D through PADD I).

Total disruption of imports of Canadian liquified petroleum gases could result in spot supply dislocations in PADD II. In 1983, Canadian imports into PADD II were over 130 MB/D and comparable import levels were assumed in 1990. Sudden disruption of these supplies as postulated in the 1990 disrupted case would require curtailed demand, fuel switching, and/or alternative supply acquisition by consumers affected. In an actual disruption, however, these imports would likely continue. This issue is treated as a sensitivity later in this chapter.

No pipeline enhancements for PADD II are required. It is possible to meet this area's requirements during the disrupted case with existing transportation facilities.

PADD IV

Unlike any of the other PADDs, the Rocky Mountain area has no waterborne shipment/receipt capability and all imports are by pipeline from Canada. Further, PADD IV is self-sufficient in oil supplies in all the cases evaluated. Table 53 displays 1990 supply/demand balances for PADD IV.

The following issues are significant in reviewing PADD IV logistics in the 1990 disrupted case:

- Crude oil runs are lower, reflecting reduced local demand. Imports of Canadian crude oil continue on an exchange basis in the disrupted case to satisfy logistics and quality requirements.
- PADD IV remains a net shipper of crude oil to other PADDs, primarily to Great Lakes refineries in PADD II. These movements increase in the disrupted case by approximately 40 MB/D.

Although PADD IV refiners cannot physically access SPR oil (they can purchase and exchange SPR crude oil), there are no identified distribution difficulties in PADD IV.

PADD V

PADD V has domestic crude oil production in excess of local refinery runs and demand. The required changes in PADD V crude oil and product logistics in the 1990 nondisrupted and disrupted cases are displayed in Table 54.

The following issues are significant in reviewing the above balances:

- Demand adjustments resulting from reduced nationwide product supplies will reduce PADD V demand by 240 MB/D. Refineries in PADD V will decrease runs to reflect reduced demand.
- Crude oil imports of 220 MB/D, typically high-quality Indonesian crude oil, would be disrupted, as well as product imports of 120 MB/D. As a result, marine movements of 200 MB/D low-sulfur crude oil from east-to-west are assumed to be required to replace the disrupted Indonesian crude oil. Product exports of 250 MB/D, however, would also be disrupted.
- As noted earlier, it has been assumed that the proposed west-to-east pipeline projects would not be available. As a result, west-to-east crude oil marine movements would increase from 1,100 MB/D to 1,240 MB/D, in line with the above mentioned east-to-west backhaul and lower PADD V refinery runs. The marine aspects of this requirement are discussed in the marine implications section of this chapter.

No pipeline enhancements are needed for PADD V. However, it is recognized that completion of a west-to-east pipeline would enhance PADD V distribution capabilities in the event of a supply disruption.

TABLE 53

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES—PADD IV (MB/D)

	1990 Nondisrupted	1990 Disrupted	△
Local Demand	550	510	(40)
Crude Oil Supplies:			
Production	560	560	–
Imports *	40	40	–
Exports	–	–	–
Domestic Pipeline Shipments	(140)	(180)	(40)
Domestic Pipeline Receipts	–	–	–
Other	–	–	–
Product Supplies:			
Imports	20	–	(20)
Exports	–	–	–
Domestic Pipeline Shipments	(80)	(50)	30
Domestic Pipeline Receipts	80	70	(10)
Other	70	70	–
Total Supplies	**550**	**510**	**(40)**
Memo: Crude Oil Runs	460	420	(40)

*Assumes Canadian imports/exports continue on exchange basis.

TABLE 54

COMPARISON OF 1990 SUPPLY/DEMAND BALANCES—PADD V (MB/D)

	1990 Nondisrupted	1990 Disrupted	△
Local Demand	**2,510**	**2,270**	**(240)**
Crude Oil Supplies:			
Production	3,330	3,330	–
Imports	220	–	(220)
Exports	–	–	–
Domestic Marine Shipments	(1,110)	(1,240)	(130)
Domestic Marine Receipts	–	200	200
Domestic Pipeline Shipments	(30)	(30)	–
Domestic Pipeline Receipts	–	–	–
Other	(110)	(170)	(60)
Product Supplies:			
Imports	120	–	(120)
Exports	(250)	–	250
Domestic Marine Shipments	–	(60)	(60)
Domestic Marine Receipts	–	–	–
Domestic Pipeline Shipments	–	–	–
Domestic Pipeline Receipts	100	–	(100)
Other	240	240	–
Total Supplies	**2,510**	**2,270**	**(240)**
Memo: Crude Oil Runs	2,300	2,090	(210)

Marine Distribution

This section of the study discusses the carrying capacity limitations that might be expected to impact the 1990 marine distribution system in the event of an emergency. The only change with respect to the vessel trading priorities identified for the 1990 nondisrupted case is that SPR crude oil moved to PADD V would be shipped directly by Panamax tankers. Transshipments via the terminal at Puerto Armuelles for east-to-west movements would not be feasible in the anticipated time frame. To test the maximum demand case, no backhauls or triangulations were assumed.

The PADD-by-PADD marine movements of crude oil and product are shown in Table 55.

Adjustments to Fleet Carrying Capacity

Operating Inefficiencies. In the basic tonnage balances for the 1990 nondisrupted case, normal operating inefficiencies such as deadfreight, time waiting for orders, weather delays, and multiple port discharges were taken into consideration in developing the planning factors used to derive tanker demand. However, it is inevitable that these operating inefficiencies will initially increase in the event of an emergency drawdown until the logistics network can adjust to the abnormal distribution requirements. The scheduling of vessels for the distribution of crude oil in a disruption would not necessarily present an unmanageable situation. Of greater concern are potential bottlenecks that might occur in the distribution and redistribution of refined products as they move down the logistics chain from large refinery shipments to small end users.

The disposition of crude oil tankers in the first half of 1984, and the apparent strategies within the oil industry with respect to the control of domestic tonnage, demonstrate that almost 90 percent of the vessels are under the control of oil companies at any given time.

TABLE 55

MARINE BALANCE BY PADD—1990 DISRUPTED CASE (MB/D)

	PADD						
	I	II	III	IV	V	VI/PR	Total Shipments
Crude Oil:							
PADD III	20	70	-	-	-	30[*]	(120)
PADD V							
OCS	50	-	150	-	-	-	(200)
Non-OCS	580[†]	-	120	-	-	340	(1,040)
SPR	610	-	1,274[‡]	-	200	100	(2,184)
Total Receipts	**1,260**	**70**	**1,544**	**-**	**200**	**470**	**(3,544)**
Products:							
PADD I	-	70[§]	10[¶]	-	-	-	(80)
PADD II	40[§]	-	-	-	-	-	(40)
PADD III							
Clean	590	90	-	-	-	-	(680)
Resid.	470	-	-	-	-	-	(470)
PADD IV							
Clean	-	-	-	-	-	-	-
Resid.	30	-	30	-	-	-	(60)
VI/PR							
Clean	120[*]	-	-	-	-	-	(120)
Resid.	130[*]	-	-	-	-	-	(130)
Total Receipts	**1,380**	**160**	**40**	**-**	**-**	**-**	**(1,580)**

*Foreign flag movements.
†Includes 120 MB/D for export to Canada in foreign flag tankers.
‡Local intra-PADD distribution by tanker and barge.
§Inland moves.
¶Backhaul assumed for tonnage balance.

In the first half of 1984, a total of 84 tankers over 40,000 DWT were employed in the distribution of domestic crude oil. Of these, 50 were owned by oil companies and 23 independently-owned tankers operated on term charters to oil companies for periods of one or more years. Only 11 tankers, or 13 percent, were in the spot market. Therefore, most of the U.S. flag tankers suitable for the domestic crude oil trades are at present under the control of oil companies. In the event of supply disruption, this should minimize inefficiencies caused by tanker owners and oil companies having different motives.

SPR Marine Terminal Facilities. Individual vessels making up the total carrying capacity of the domestic tanker and barge fleets vary in size. Therefore, it is necessary to evaluate the physical and operational characteristics of the vessel loading facilities to determine if the optimum fleet throughput is achievable. The planning factors that were used assume that vessels are fully loaded at the load port and dispatched within a reasonable amount of time. Any restrictions or limitations to the interface between the fleet and the SPR facilities could significantly reduce the throughput potential of the fleet.

It is believed that there now exist potentially significant limitations to achieving the over-the-dock throughput at the SPR terminals required in the event of a maximum drawdown.

The Act to Prevent Pollution from Ships, 1980, requires that adequate reception facilities be available at ports and terminals to receive materials that had previously been discharged at sea (Annex I, Regulation 12; Annex II, Regulation 7).

At the present time, the SPR terminals are not equipped with sufficient ballast treatment facilities. However, because of the uniqueness of the SPR program as a noncommercial operation, it might be appropriate to include special provisions in the regulations for emergency drawdown situations. The proposed rules currently have waiver provisions that permit a vessel to load at a terminal that does not have approved facilities, provided it is able to discharge ballast at another location that has approved facilities. However, since U.S. ports are not expected to have ballast reception facilities in place by 1990, significant delays could result if dirty ballast must first be discharged at another port or off-loaded into barges prior to cargo loading.

Current DOE estimates for sustainable loading rates do not include time for vessels to discharge dirty ballast. It is estimated that a worst case scenario requiring all vessel ballast water to be discharged into barges prior to loading cargo (up to 12 hours of additional time) could reduce the sustainable loading rates at the SPR terminals by as much as 30 percent.

However, it is recognized that building ballast treatment facilities at each of the SPR terminal sites might not be the most cost effective solution. Possible alternatives to be considered in a cost analysis are listed below:

- Expand the existing dock capacity sufficiently to compensate for the ballast constraints by connecting to nearby marine terminals.
- Examine the feasibility of pumping untreated ballast water directly to the storage site for injection into the caverns.
- Exempt vessels loading at the SPR terminals from the "Act to Prevent Pollution from Ships, 1980," during an emergency.

Marine Loading Facilities. As discussed in the earlier sections on PADD III distribution enhancements, significant dock throughput capacity will have to be added, especially in the Nederland area, to accommodate substantial crude oil movements to the lower Mississippi River refineries.

In addition to volume throughput deficiencies, the facilities appear to lack sufficient flexibility in that they are designed exclusively for loading tankers. This may not be practical when more than half of the waterborne distribution requirements call for local distribution within PADD III. The distribution data in Tables 40, 42, and 44 indicate that 1.3 MMB/D, or 60 percent, of the SPR crude oil that is projected to move by water is distributed locally within PADD III. If it is assumed that a substantial portion of this crude oil is to be distributed by barge, significant bottlenecks could occur.

As an example, the PADD III marine distribution requirements listed in Table 56 are expressed in terms of daily barge loading equivalents for typical 15,000-barrel inland barges and for 75,000-barrel oceangoing barges.

While the data in Table 56 are not intended to imply that all of the PADD III marine distribution must be moved in barges, they do raise significant doubt regarding the ability of the existing terminal facilities to accommodate sufficient barge traffic to sustain these high levels of over-the-dock throughput.

At the present time, the SPR system has very limited capacity to load barges. The Nederland terminal has three barge docks with a total capacity to load approximately 120 MB/D. Seaway and St. James have no barge

TABLE 56

PADD III BARGE LOADING REQUIREMENTS

Load Port	Discharge Port	MB/D	Barge Loadings/Day: Inland Barges	Barge Loadings/Day: Oceangoing Barges
Seaway	Corpus Christi	150	9	2.0
Seaway	Houston	170	11	2.3
Texoma	Miss. River	453	30	6.0
Texoma	Lake Charles	47	3	1.6
Texoma	Houston	105	7	0.4
St. James	Miss. River	66	5	–
Lake Charles	Miss. River	283	19	3.8
		1,274	91	16.1

docks. Therefore, it appears that berthing modifications to enhance barge loading should be carefully evaluated.

Detailed simulation studies, which are beyond the scope of this report, would be required to more adequately define the appropriate mix of inland barges, oceangoing barges, and tankers that might be required for the above distribution. Dock modifications should then be planned accordingly.

Vessel Length Restrictions. At the present time, vessels up to 940 feet in length can discharge crude oil at St. James. However, vessels over 750 feet in length require holding tugs to maintain the vessel in position because the distance between existing mooring dolphins is not adequate to moor larger vessels. Because of the potential danger of igniting hydrocarbon vapors vented during loading operations by having live tugs along side, a 750-foot length restriction is required for vessels that would be loading during a drawdown of SPR crude oil.

DOE has initiated a dock modification project for the installation of forward mooring buoys positioned to enable vessels up to 940 feet to tie up to the dock at St. James for crude oil loading. Such modifications at St. James would be beneficial.

Trading Status of CDS Tankers. An additional limitation to the availability of vessels could be the trading status of the CDS tonnage. Table D-6 illustrates the expected availability of these tankers in the event of an SPR drawdown. Although some time may be required to position these vessels, it was felt that all but three tankers, each under 40,000 DWT, would be available by the end of the second 30-day cycle.

Port Restrictions. The abnormal distribution patterns that would likely result from a disruption of crude oil and product imports into the United States might require vessels to call at ports where draft restrictions impose a limitation on cargo carrying capacity.

Inland Barging. Due to inadequate and possibly incomplete published data on inland tank barge movements, projections for the 1990 disrupted case are difficult. However, with an estimated 1990 fleet of approximately 3,000 tank barges, and an assumed 10 percent demand reduction in the disruption scenario, it was assumed that sufficient inland tank barge equipment would be available during a disruption. If necessary, equipment thus made available could be used for crude oil moves out of the SPR and in numbers that would probably exceed the barge loading capacity of the various terminals.

Military Requirements. The Voluntary Tanker Agreement authorized under Section 708 of the Defense Production Act of 1950, as amended, and administered by MarAd, provides for voluntary contributions of tanker tonnage at appropriate charter rates to the Department of Defense to meet national defense requirements. The Agreement creates a pool of privately owned tanker capacity for support of national defense activities. It provides for a close working relationship among the MarAd Administrators. The Department of Defense and the industry participants can meet military and economic needs through cooperative action at such time as the Agreement is activated.

Clearly, it is impossible to anticipate under what particular circumstances the Agreement might be activated. However, once activated it would substantially affect tanker tonnage availability and utilization. Thus, it is important that actions taken to draw down and distribute SPR oil be closely coordinated with other demands generated for tanker tonnage under the Voluntary Tanker Agreement. The recommendations in this report should be viewed in the context of the working relationship that would, of necessity, develop should the Agreement be activated.

Tonnage Balance for Crude Oil Distribution

The tanker requirements for crude oil distribution in the 1990 disrupted case is shown in Table 57. Overlaying the supply in 1990, the tonnage balance for the 1990 disrupted case is shown in Table 58. In the case of a disruption, the demand for U.S. flag tankers for non-SPR crude oil distribution is projected to decline by approximately 1.3 million DWT. This is primarily due to the fact that 330 MB/D of PADD V non-OCS crude oil is diverted from the Jones Act trades in the 1990 nondisrupted case to the U.S. Virgin Islands and Canada. As a result, it is assumed that this volume would be carried in foreign flag tankers.

The total waterborne throughput for SPR crude oil in Tables 40, 42, and 44 is estimated to be 2,212 MB/D. Of this total, 914 MB/D, or

TABLE 57

U.S. FLAG TANKER REQUIREMENTS FOR DOMESTIC CRUDE OIL DISTRIBUTION—1990 DISRUPTED CASE*
(MDWT)

	MB/D	Factor	MDWT
Non-SPR Crude Distribution			
Valdez—			
U.S. West Coast	710.00	2.20	1,562.00
Puerto Armuelles	580.00	4.63	2,685.40
Hawaii	60.00	2.67	160.20
Puerto Armuelles—			
U.S. Gulf Coast/P.R.	0.00	2.43	0.00
U.S. East Coast	0.00	3.14	0.00
Chiriqui Grande†—			
U.S. Gulf Coast/P.R.	120.00	1.79	214.80
U.S. East Coast	460.00	2.37	1,090.20
U.S. Gulf Coast—			
U.S. East Coast	20.00	2.32	46.41
California—			
U.S. West Coast	0.00	0.68	0.00
U.S. Gulf Coast	150.00	5.13	769.50
U.S. East Coast	50.00	5.72	286.00
Total Non-SPR Requirement			**6,814.51**
SPR Crude Distribution			
U.S. Gulf Coast—U.S. East Coast	610.00	2.32	1,415.20
U.S. Gulf Coast—U.S. West Coast	204.00	4.96	1,011.80
U.S. Gulf Coast—Puerto Rico	100.00	2.30	230.00
Total SPR Requirement			**2,657.00**
Total Crude Distribution Requirements			**9,471.51**

*The above distribution lists U.S. flag requirements only and does not show foreign flag movements to the U.S. Virgin Islands (370 MB/D) or Canada (120 MB/D).

†The TransPanama pipeline is assumed to have a maximum throughput of 750 MB/D.

TABLE 58

U.S. FLAG TONNAGE BALANCE FOR DOMESTIC CRUDE OIL DISTRIBUTION—1990 DISRUPTED CASE (MDWT)

	Over 100 MDWT	70–99.9 MDWT	40–69.9 MDWT	Total
Supply				
Jones Act	3,889.00	1,748.00	1,824.00	7,461.00
CDS Waivers	885.00	0.00	0.00	885.00
Total Supply	**4,774.00**	**1,748.00**	**1,824.00**	**8,346.00**
Demand				
Alaskan North Slope—				
U.S. West Coast/Hawaii	1,722.20	0.00	0.00	1,722.20
Panama	2,685.40	0.00	0.00	2,685.40
Panama—				
U.S. Gulf Coast/P.R.	0.00	214.80	0.00	214.80
U.S. East Coast	0.00	0.00	1,090.20	1,090.20
California—				
U.S. Gulf Coast	0.00	0.00	769.50	769.50
U.S. East Coast	0.00	0.00	286.00	286.00
U.S. Gulf Coast—				
U.S. East Coast	0.00	0.00	46.41	46.41
U.S. West Coast	0.00	0.00	0.00	0.00
Total Demand	**4,407.60**	**214.80**	**2,192.11**	**6,814.51**
SPR Requirement	–	–	2,657.00	2,657.00
Surplus/(Deficit)	366.40	1,533.20	(3,025.11)	(1,125.51)
Remaining CDS Tonnage*	889.00	711.00	–	1,600.00
Net Balance	1,255.40	2,244.20	(3,025.11)	474.49

*Assumes that the regulatory limit on domestic operation of CDS vessels of six months out of twelve is waived during the disruption.

about 40 percent, must be distributed by tanker to PADDs I and V.

The incremental demand for U.S. flag tankers that results from the SPR drawdown, assuming no backhauls or triangulations, is estimated to be approximately 2.7 million DWT. When the SPR inter-PADD requirements for U.S. flag tankers are combined with the non-SPR movements, the Jones Act fleet falls short by approximately 1.1 million DWT. Although an additional 1.6 million DWT of remaining CDS tonnage could be waived into the U.S. trade, some foreign tonnage might be required due to potential limitations in the appropriate size categories of the additional CDS supply. However, the projected balance in Table 58 indicates a minimal requirement for Jones Act waivers.

The projected balance is further reinforced by the fact that, in an actual disruption, substantial carrying capacity could be gained by more efficiently utilizing vessels in backhauls and triangular trading. For example, Table 57 shows 200 MB/D of California OCS crude oil moving east from PADD V to PADD III and 204 MB/D of SPR crude oil moving west from PADD III to PADD V. If 50 percent of the tankers in this trade backhaul crude oil, approximately 500,000 DWT of carrying capacity is freed.

Tonnage Balance for Refined Product Distribution

The demand for coastal and inter-PADD tanker and barge movements of refined products in the disrupted case is as shown in Table 59, and represents an increase of approximately 20 percent over the 1990 nondisrupted case. The increase is the result of the substantial volume of residual fuel oil movements into PADD I to replace imports (see Table 50).

Clean product movements from PADD III to PADD I in the disrupted scenario (590 MB/D) are allocated to tankers and barges using the 1990 breakdown listed in Table D-8. Residual fuel oil movements into PADD I from PADD III (470 MB/D) and PADD V (30 MB/D) are assumed to be carried by Jones Act tankers. The result is an increase of 848,000 DWT in the demand for product tankers, and a reduction of about 211,000 DWT in the demand for barges.

The distribution requirements under the 1990 disrupted case therefore generate a net incremental demand for tonnage over the 1990 nondisrupted case of 637,000 DWT for refined products distribution. However, the impact of this increase in demand falls entirely on the tanker fleet. The increased movement of residual fuel oil, which is assumed to be moved exclusively by tankers, essentially doubles the 833,000 DWT shortfall that appears in Table 31 to produce the 1.5 million DWT shortfall of Jones Act tankers in Table 60. For the purposes of this study, however, it is more meaningful to focus on the incremental demand of 637,000 DWT over the 1990 nondisrupted case. Under normal circumstances, one would expect that market forces would bring the supply and demand for product tonnage into balance by 1990.

The impact of the disruption on the supply/demand balance for domestic oceangoing barges is somewhat different. Lower product consumption results in a decline in the demand for barges of 211,000 DWT. The result is a surplus of 429,000 DWT, which most likely would move into the U.S. Gulf Coast for local SPR crude oil distribution, as shown in Table 61.

Refining Considerations

A major finding of the refinery analysis is that, barring a very sizeable loss of capacity from further plant shutdowns, there will be sufficient capacity available to process 4,500 MB/D of SPR oil in addition to domestic crude oil.

In the disruption scenario postulated in this study, the refineries operate at a gross pipestill input level of 13,165 MB/D. This corresponds to 76 percent of the operable capacity now existing. It is 456 MB/D, or 3.3 percent, less than the input level of the forecast normal situation in 1990. Although a simplifying assumption was made for study purposes—that overall refinery capacity would be little changed between now and 1990—that assumption does

TABLE 59

TANKER/BARGE REQUIREMENTS FOR U.S. FLAG DOMESTIC PRODUCT DISTRIBUTION—1990 DISRUPTED CASE

	MB/D	Factor	MDWT
Tankers			
U.S. Gulf Coast—U.S. East Coast	692.00	2.00	1,384.00
U.S. West Coast—U.S. West Coast	–	–	475.00
U.S. East Coast—U.S. East Coast	–	–	135.00
U.S. West Coast—U.S. East Coast	30.00	5.72	172.00
Total			**2,166.00**
Barges			
U.S. Gulf Coast—U.S. East Coast	368.00	1.25	460.00
U.S. Gulf Coast—U.S. West Coast	–	–	0.00
U.S. West Coast—U.S. West Coast	–	–	190.00
U.S. East Coast—U.S. East Coast	–	–	630.00
Total	**1,090.00**		**1,280.00**

not appear critical in the light of the indicated surplus. For the same reason, seasonal differences within the year are not expected to pose any particular difficulty.

Furthermore, the projected changes in product mix, both those occurring normally (a gradual shift of gasoline to distillate) and those occasioned by the disruption (a shift from light products to residual fuel oil), will help ease the burden on refiners' cracking and coking capacities. This leaves considerable flexibility to alter the product mix to suit consumer needs that develop during the emergency.

TABLE 60

SUPPLY/DEMAND BALANCE FOR U.S. FLAG TANKERS UNDER 40,000 DWT 1990 DISRUPTED CASE

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	1,384.00
U.S. Gulf Coast—U.S. West Coast	0.00
U.S. West Coast—U.S. West Coast	475.00
U.S. East Coast—U.S. East Coast	135.00
Other:	
Military Sealift Command	400.00
Total Demand	**2,394.00**
Jones Act Supply:	
Ships 20,000-39,999 DWT	885.00
Total Supply	**885.00**
Surplus/(Deficit)	(1,509.00)
CDS Supply 10,000-39,999 DWT*	227.00
Total Surplus/(Deficit)	**(1,282.00)**

*See Appendix D, Tables D-4 and D-6 for a discussion of the limitation on the supply of CDS tankers between 20,000-39,999 DWT; assumes that the regulatory limit on domestic operation of CDS vessels of six months out of twelve is waived during the disruption.

Low-Sulfur/High-Sulfur Crude Oil Fill Ratio

The "quality" or nature of the oil in the SPR must be a fundamental consideration if the utility of the Reserve for meeting refiners' requirements is to be maximized. Typically, a refinery's process configuration and equipment evolve over time along with the crude oil supply. The refinery and its crude oil supply are, in a sense, tailored to each other. Major changes in a refinery's crude oil slate can be accommodated, but only if given the time and money to modify plant facilities. Short-term substitutions are definitely limited. In addition to these physical limitations, there exist restraints imposed by economic, environmental, and other considerations.

TABLE 61

SUPPLY/DEMAND BALANCE FOR U.S. FLAG BARGES OVER 50,000 BARRELS 1990 DISRUPTED CASE

Domestic Product Movements:	
U.S. Gulf Coast—U.S. East Coast	460.00
U.S. Gulf Coast—U.S. West Coast	-
U.S. West Coast—U.S. West Coast	190.00
U.S. East Coast—U.S. East Coast	630.00
Total Demand	**1,280.00**
Jones Act Supply:	
Barges Over 50,000 Barrels	1,709.00
Total Supply	**1,709.00**
Surplus/(Deficit)	**429.00**

To cope with the loss of imports, each refiner will require a replacement crude oil suitable for processing by his existing equipment. In the disruption scenario under consideration, the primary crude oil quality concern is apt to be sulfur content. The resid content is of lesser concern because under disruption circumstances additional production of heavy fuel oil to make up for the loss of product imports would be advantageous.

The planned 1990 SPR inventory target of 35 percent low-sulfur/65 percent high-sulfur is unbalanced; a minimum low-sulfur fill level of 45 percent would be more appropriate to accommodate refinery crude oil input nominations in a disruption. As was shown in the analysis of SPR drawdown capability (with the proposed enhancements), it is possible to sustain a 90-day 4.5 MMB/D drawdown with the proposed 35 percent low-sulfur/65 percent high-sulfur ratio and still meet refinery nominations. *However, this does not imply that the 35 percent low-sulfur/65 percent high-sulfur ratio is* *appropriate*—rather it implies that there is flexibility to vary the ratios of low-sulfur and high-sulfur crude oils drawn down for a limited period.

The implication of this flexibility in the 1990 disrupted case is that after 90 days of sustained drawdown, high-sulfur crude oils in SPR storage would comprise almost 75 percent of the remaining strategic stockpile. Table 62 displays this effect. Continued drawdown following the first 90 days would result in increasingly high-sulfur crude oil "production" from the Reserve. Should the postulated disruption require SPR drawdown beyond 90 days, it would become increasingly difficult, and ultimately impossible, for refineries to meet the necessary product slate with the currently planned low-sulfur to high-sulfur ratio.

The average sulfur content of the Reserve is critical because for various reasons a substantial part of U.S. refining capacity is dependent on the availability of low-sulfur crude oil. Often, the metallurgy of the process equipment and the lack or inadequacy of desulfurization capacity dictate the crude oil selection. In other cases, sulfur dioxide emissions from the refinery are at regulatory limits. (For example, some California refineries may run Indonesian crude oil for this reason.) In still other instances, certain products from refining high-sulfur crude oil might be non-marketable, e.g., residual fuel oil from isolated inland refineries.

Although a low-sulfur crude oil can almost always be substituted for a high-sulfur type, the reverse is not always true. The substitution of high-sulfur crude oil for low-sulfur crude oil is limited by physical, environmental, and economic constraints. This study has relied on refiners' 1985 run projections as an expression of crude oil type requirements. It has not examined to what degree these crude oil preferences were governed by absolute physical limits as opposed to possibly changeable environmental controls or economic assumptions.

During a disruption, it may well be that some refineries could increase the percentage of high-sulfur crude oil, freeing up low-sulfur crude oil for others. Also, a higher proportion of high-sulfur crude oil could likely be accommodated by giving proportionally more crude oil to the refineries capable of running incremental high-sulfur crude oil, and less crude oil to refineries dependent on low-sulfur crude oil. However, this would be inconsistent with the study assumption that all regions will be treated uniformly and equitably. It is not known whether the low-sulfur crude oil requirements will decrease in the future as a result of further refinery conversions. Equally uncertain is the composition of domestic crude oil in the future, although the trend has been toward higher sulfur. If that trend continues, a counterbalancing shift in the composition of imports will probably be required, unless refinery modifications keep pace.

Given the uncertainties, it is better to err on the side of more low-sulfur crude oil, thereby retaining flexibility as much as possible. Having more than the minimal percentage of low-sulfur crude oil, which is universally usable, would increase refinery flexibility and relieve inevitable scheduling problems caused by rapid deployment of the Reserve. The added flexibility could materially help lessen the impact of the disruption, at the relatively minor (and recoverable) cost represented by the price premium for low-sulfur crude oil.

Therefore, it is recommended that the proportion of low-sulfur crude oil in the SPR be at least equal to the low-sulfur proportion of pro-

TABLE 62

ANALYSIS OF CRUDE OIL QUALITIES IN SPR FOLLOWING 90 DAY DRAWDOWN—1990 DISRUPTED CASE (Millions of Barrels)

	Low Sulfur	High Sulfur	Total
SPR inventory at initiation of drawdown	263	487	750
SPR crude drawn down over 90 days	(175)	(230)	(405)
SPR crude remaining in storage after 90 day drawdown	88	257	345
Percentage of Total	26%	74%	100%

jected crude oil imports. Thus, the 1990 disrupted case calls for at least 1,950 MB/D, or 43.3 percent, of the 4,500 MB/D SPR-supplied oil to be low-sulfur crude oil.

It is recognized that this conflicts with the DOE's present course of filling the SPR with only 35 percent low-sulfur crude oils and the rest with high-sulfur crude oils. About 430 million barrels of the 750 million barrel target have already been acquired on this basis. To rectify the imbalance, it will be necessary to immediately begin purchasing the remainder on the basis of at least 50 percent low-sulfur crude oil. Otherwise there is a risk that part of the Reserve will be ineffective in relieving the supply emergency. Fortuitously, market conditions now are especially favorable for purchasing low-sulfur crude oil.

The current fill formula was originated by the Federal Energy Administration, apparently on the basis of an analysis prepared in 1976 by Turner, Mason & Solomon, Consulting Engineers. That study's objective was to determine the best selection of crude oils to store as protection from a future (1980) embargo by the Organization of Arab Petroleum Exporting Countries. Their conclusions were specifically qualified by an assumption that no changes would occur in the geographic use pattern of other crude oil supplies, that is, the nonembargoed foreign and domestic crude oil. Total projected imports consisted of 49 percent low-sulfur crude oil. The Federal Energy Administration did not then contemplate the loss of *all* foreign oil imports into the United States, either directly or by diversion to our IEA allies. Whereas a 2:1 ratio of high-sulfur to low-sulfur crude oil is a suitable replacement of average Arab oil, it is not a suitable replacement of the overall average oil now imported by the United States, which includes considerable Nigerian, North Sea, and Indonesian supplies.

Though a disruption of lesser magnitude might not exhaust the entire Reserve, having a greater proportion in the most usable category would protect the national security for a longer time. A fact not to be overlooked is that the foreign crude oil most likely to be lost is, on average, lower in sulfur than the foreign crude oil most likely to be retained. Western Hemisphere crude oil, i.e., Mexican and Venezuelan, is all high-sulfur crude oil. The low-sulfur Eastern Hemisphere crude oils, such as North Sea, African, and Indonesian, are likely to be diverted to Western Europe and Japan.

It is true that in the particular disruption case studied, without changing the fill mix, the desired low-sulfur/high-sulfur proportions could be supplied for a limited period of some 90 days. Afterwards, deliveries would have to consist of almost entirely high-sulfur crude oil. This is not regarded as a viable option.

Notwithstanding the fulfillment of the crude oil quality requirement, a problem is presented by residual fuel oil sulfur specifications. It is clear that the incremental residual fuel oil to be supplied by U.S. refineries cannot match the tight sulfur specifications of imported residual fuel oil. About half of the latter is of 0.5 percent or lower sulfur content. It is contemplated that the residual fuel oil would be made available primarily by diversion of coker feedstock to fuel oil blending. However, typical coker charge is much too high in sulfur content to be blended to 0.5 percent sulfur No. 6 Oil, and desulfurization facilities for this product will not be available. A massive switch to low-sulfur crude oil, even if it were available, would be self-defeating because of the low resid yield characteristic of such crude oils.

The study assumes that the sulfur specifications of residual fuel oil will be waived as necessary, on a case-by-case basis. An alternate possibility in many instances will be substitution of other fuels, such as distillate fuel oil, by consumers of imported residual fuel oil.

Sensitivity Cases

The disruption scenario described earlier in this chapter is only one of a range of possible cases that could have been studied. In the interest of timely completion of this report and in order to test the drawdown capabilities of the Strategic Petroleum Reserve at a maximum rate of 4.5 MMB/D, only one distribution case was analyzed in detail. However, a number of key sensitivities were identified throughout the course of this study. Many of these sensitivities were given serious consideration with respect to the probability of their occurrence and the resulting impact on an SPR drawdown. Because of the number and complexity of these sensitivities, a matrix format was developed to provide an overview of those sensitivities that impact on an actual disruption (see Table 63).

The most significant sensitivities are those that vary the drawdown rate and timing of the disruption. For example, a maximum drawdown of 4.5 MMB/D prior to the completion of Phase III would not be possible. A partial drawdown of less than 4.5 MMB/D would present significantly fewer problems.

For the most part, with the exception of a disruption requiring less than a 4.5 MMB/D drawdown, the listed sensitivities have little or no impact on the SPR drawdown capabilities. Rather, these sensitivities primarily affect the

TABLE 63

SENSITIVITIES MATRIX

Sensitivity	Impact: SPR Drawdown at 4.5 MMB/D	Supply/Demand	Crude Runs	Marine Tonnage	Major Crude & Product Pipelines
1. Partial disruption requiring a drawdown rate less than 4.5 MMB/D.	Reduced drawdown.	Higher consumption due to increased supply.	Higher runs probable. Also increased crude quality flexibility probable.	Decline in demand for Jones Act tonnage as limited foreign flag imports continue	Increased throughputs in domestic lines (esp. Capline), reduced throughput in DOE pipelines and terminals.
2. Disruption occurs prior to 1990.	Reduced drawdown capability, esp. if prior to system enhancements.	More significant shortfall due SPR avails.	Correspondingly lower runs.	Lower drawdown result in reduced requirement for Jones Act tonnage.	Reduced crude and product shipments.
3. Disruption occurs post-1990.	None assuming system enhancements.	Greater shortfall due to increased dependence on imports.	Lower runs due to declining domestic production.	Uncertain, tonnage supply beyond 1990 not estimated.	Reduced crude and product shipments.
4. 200 MB/D lower domestic crude production in PADD V (increased crude imports in 1990 nondisrupted case).	None.	Declines 200 MB/D or 10.5% (vs. 9.3% base disruption.	Decline 200 MB/D	Lower demand for U.S. flag tonnage (1.2 MMDWT).	Slight decline in crude shipments, esp. in Capline to PADD II (~20 MB/D).

TABLE 63 (Continued)

Sensitivity	Impact: SPR Drawdown at 4.5 MMB/D	Supply/Demand	Crude Runs	Marine Tonnage	Major Crude & Product Pipelines
5. Significantly more refineries shut down because of increased product imports.	None.	None.	The same but at a higher operating factor (due to less refinery capacity available).	Uncertain; depends on location of refinery shutdowns.	Slight decline in domestic crude and product shipments.
6. Proposed west-to-east crude oil pipelines available for utilization.	None.	None.	None in total, but may shift crude disposition and qualities among refinery areas.	Decline 1.4 MMDWT, U.S. flag crude tonnage.	Increased throughput in Four Corners and new line. Nominal Capline impact.
7. Transgulf Pipeline (TGP) available for utilization (350 MB/D) products LA-FL.	None.	None.	May result in shift of runs among refinery areas to facilitate input to TGP pipeline.	Decline 0.4 MMDWT, Jones Act product tonnage.	May result in shift of crude shipments to accommodate shift in refinery runs.
8. Divert movements of 200 MB/D of Alaskan oil from the Virgin Islands to U.S. Gulf in 1990 disrupted case (assumes U.S. imports displaced to the Virgin Islands).	None.	None.	None.	Increased Jones Act tonnage required.	None.

TABLE 63 (Continued)

Sensitivity	Impact: SPR Drawdown at 4.5 MMB/D	Supply/Demand	Crude Runs	Marine Tonnage	Major Crude & Product Pipelines
9. Military Sea-lift demand due to military mobilization during disruption.	None.	Declines depending on disposition of crude by military.	Declines depending on disposition of crude by military, i.e., redistributed among refining areas.	Available Jones Act and subsidized tonnage for domestic civilian service declines.	Throughputs (esp. product pipelines) may decline depending on disposition of crude by military.
10. Vessel light loadings during disruption.	Increased number of vessel loadings may result in bottleneck, lowering drawdown rate.	Decline if drawdown rate declines.	Decline if drawdown rate declines.	Increased requirements for tonnage (crude and product oil).	Increase in SPR pipeline movements—nominal impact on indigenous domestic crude movements.
11. Loss of Canadian crude imports on exchange (250 MB/D).	None.	Localized shortage in affected areas.	Shift in runs from northern portions of PADD II to to southern PADDs II & III.	Decline in demand for foreign flag tonnage employed in exchange payback (Maine). May increase demand for inland waterway product tonnage to supply northern PADD II.	Increased shipments of crude from PADD III to PADD II, primarily in Capline. Increased product pipeline shipments to PADD II.

TABLE 63 (Continued)

	Sensitivity	Impact				
		SPR Drawdown at 4.5 MMB/D	Supply/Demand	Crude Runs	Marine Tonnage	Major Crude & Product Pipelines
12.	NGL imports from Canada into PADD II continue for logistics efficiency purposes.	None.	Would increase unless corresponding exchange of hydrocarbons with Canada occurred.	None.	None.	Reduced movements of NGLs to PADD II from other PADDs (primarily PADD III).
13.	Seasonality.	None.	Heating oil variance.	Product output composition altered.	Variance in demand for Jones Act tonnage.	Variance in product pipeline shipments.
14.	Electric utility fuel switching.	None.	Lower residual fuel oil requirement.	Shift to light products.	Reduce demand for residual shipments.	Increase pipeline movements of clean products.
15.	International sharing considerations.*	None.	Varies depending upon U.S. supply right or obligation.	Varies depending upon U.S. supply right or obligation.	Uncertain effect depending on cargo preference, treaties, etc.	Varies depending upon U.S. supply right or obligation.
16.	Availability of 325 MB/D of domestic surge production.	None.	Increases 325 MB/D.	Increases 325 MB/D.	Increases demand for Jones Act tonnage.	Increase in crude and product movements.

*For a detailed description of this issue, see *Emergency Preparedness for Interruption of Petroleum Imports into the United States,* NPC, 1981.

distribution capabilities of the pipeline and marine logistics systems. For example, the assumptions with respect to the volume of PADD V crude oil moving to the U.S. Virgin Islands in the disruption scenario are significant to the supply/demand balance for Jones Act tankers. The 1990 disrupted case assumes that 340 MB/D of PADD V crude oil is moved to the Virgin Islands in foreign flag tankers. If for some reason the additional domestic crude oil required in the Virgin Islands (due to the interruption of imports, approximately 270 MB/D) is supplied directly from the SPR or other PADD III sources, Jones Act tanker demand could increase by as much as 1.5 million DWT. This is so because more PADD V crude oil (approximately 240 MB/D) is required to move into the U.S. Gulf Coast in Jones Act tankers. Such a sensitivity could result in a shortfall in Jones Act tonnage of as much as 3 million DWT. Such a shortfall would undoubtedly require some participation of foreign flag tankers in the SPR drawdown.

Chapter Four
SPR Facility Operating and Maintenance Practices

Study participants visited each of the SPR sites and terminals and the SPR Project Management Office, and discussed SPR procedures with officials of the DOE. This chapter presents their findings.

Management and Contractual Arrangements

The operation and maintenance of the SPR facilities is contracted to a single private contractor on a competitive bid basis. The current contract has been held by Petroleum Operations Support Services, Inc. (POSSI) since January 18, 1983, and extends to December 31, 1984, with two one-year options. However, the DOE is accepting bids for a new type of contract that includes management of the SPR as well as operations and maintenance. This contract may begin as early as April 1, 1985. Total responsibility for the day-to-day operations and maintenance rests solely with the contractor. In addition, security is handled through a separate contractor that provides personnel for guards at the gates and on-site patrols within the cavern complex.

At each location, DOE maintains a small staff that typically includes a senior site representative and a resident engineer. The line of responsibility and authority between DOE and the contractor representative is not entirely clear. Although the contractor is responsible for the operations and maintenance at the sites, the contract states that:

> The contractor agrees that the Government Fee Determination Official shall determine to what extent the Contractor's performance warrants award of all, some portion of, or none of the award fee available for each evaluation period, and that such determination concerning the amount of award fee is absolutely binding on both parties and shall not be subject to appeal...

This appears to have created a situation where there is little consistency among the sites in day-to-day management. At some sites the contractor representative is clearly in charge, at others the DOE representative appears to be in charge, and at others there appears to be a joint effort.

Operations and Maintenance Procedures

It is evident that much could be gained in experience and training if a drawdown exercise were held at each storage site. This is the true test of whether equipment will operate as designed and whether personnel are able to line up the delivery functions properly. Although there have been approximately three test drawdowns from storage caverns into steel tank storage, the dock facilities have never been tested for their ability to deliver oil from SPR storage. However, they have been used extensively for filling the SPR, utilizing the same loading arms, mooring facilities, and pumps that would be used in a drawdown.

A computer drawdown model is utilized in the DOE SPR Project Management Office, but there is little evidence that the site operators themselves are totally familiar with the various options that might occur during an emergency.

Training should include dry runs of various operating combinations and drawdowns of low-sulfur versus high-sulfur crude oil so that operators will be familiar with lining up manifolds and pumps under various scenarios. Although basic procedure manuals are in place and current, it does not appear that operators are entirely familiar with them.

Pipeline Maintenance

The DOE has some 300 miles of pipeline to transport crude oil, raw water, and brine during leaching, filling, and drawdown. The following is an overview of the staffing practices, spare pipe, and availability of spare parts to maintain the pipeline network. Judging from discussions with site personnel, the maintenance program appears quite sound, although there is evidence that some of the corrosion monitoring programs have been slow in developing.

Organizationally, there are two POSSI pipeline maintenance crews consisting of four employees each, plus one employee at Bryan Mound. One crew works out of St. James while the other crew is located at Sulphur Mines. Each crew is responsible to the POSSI site supervisor. Technical assistance, which includes corrosion mitigation, is provided by the POSSI staff in New Orleans. The DOE Pipeline Manager, located at Weeks Island, plays a significant advisory role in the preparation and implementation of maintenance plans, for which POSSI has full responsibility.

POSSI pipeline maintenance employees have at least three years of experience. Each crew has a technician trained in the essentials of cathodic protection survey. Rights-of-way and valve maintenance are regular chores. Crews are also trained in fire fighting and spill control and maintain readiness through mock exercises.

Specialty contractors have been made a part of emergency preparedness plans. Pipeline contractors have been alerted throughout the SPR facility areas to provide needed response. T. D. Williamson of Tulsa would be made available to provide hot tapping and stoppel equipment in the event of a major repair.

Split sleeves, flanges, and clamps are available at St. James, Sulphur Mines, and Bryan Mound. The following spare pipe is available for crude oil service: St. James—3,000 feet, 36"; West Hackberry—2,500 feet, 42"; Bryan Mound—800 feet, 30"; Sulphur Mines—1,000 feet, 16". Spare pipe for both raw water and brine disposal lines is also available. The quantities of spare pipe for crude oil service are rather large. Pipeline failure/damage scenarios should be examined for each pipeline diameter to determine appropriate wall thickness and lengths. Steps should be taken to prevent corrosion through the use of external and internal coatings for the pipe retained in stock.

The corrosion mitigation program can be divided into two areas: prevention and detection. The prevention program is focused on cathodic protection for all pipelines and inhibitor injection/pigging for the crude oil lines. Periodic pipe to soil potential surveys are performed on the pipelines that are protected by sacrificial anodes along the main line and by deep-well anodes at the terminals. Inhibitor is injected into each crude oil line followed by regularly scheduled pigging to remove water.

Some internal corrosion in the crude oil lines has been found through the use of internal inspection tools. Plans are being made to internally inspect the 42-inch line from West Hackberry to the Sun terminal in Nederland. Ultrasonic probes have been used to measure pipe wall thickness externally on the brine disposal lines. The pipeline routes are inspected from the air once a week, and would be inspected more frequently during drawdown.

While it is apparent that most of the corrosion mitigation effort has been focused on the crude oil lines, this effort should be expanded to include the raw water intake and brine disposal lines to maintain a sustained operation. It is suggested that corrosion coupons using parent pipe be installed in the bottom quadrant of each raw water brine disposal line as a supplement to the ultrasonic measurements currently in use. Placing these in the bottom quadrant at a location giving representative flow conditions will help evaluate any corrosion activity in the line. On the Bayou Choctaw pipeline, corroded portions of line that affect the design throughput should be replaced.

Electrical Systems

The incoming power to all facilities is vulnerable to sabotage, but should be repairable by the various utilities in a reasonable period of time. For example, a Houston Lighting and Power source advised that Bryan Mound is receiving the best industrial service available, and that, unless several transmission towers were lost, it is unlikely that service could be interrupted for more than 24 hours.

According to the Excess Capacity report issued by DOE, all locations have from ½ to ⅔ spare transformer capacity, with the exception of Sulphur Mines, which has none. Also, one multiple 20 KVA system is being procured.

Power reliability generally is acceptable, except at West Hackberry. Extended power outages have occurred there, one of several weeks duration. DOE should take action to ensure that a reliable source of electric power is provided for the sites, because an outage could seriously affect the drawdown capabilities of a critical facility.

Custody Transfer

Considering the high cost of crude oil, meters offer greater accuracy, more flexibility in operations, and a potential reduction in manpower in not having to hand gauge quiet tanks. All meter installations appear to be well designed and in good condition but should be checked to determine that they conform to applicable API Standards. Where practical, existing meters should be used to provide greater accuracy and operational flexibility. It is not clear whether present manifolding would permit the meters to be used for both receipts and deliveries or whether some piping changes would be necessary to accomplish this.

A measurement procedure manual that outlines the operation and maintenance of each meter installation should be prepared and kept at each oil storage location. This manual should outline the methodology of meter proving, set acceptable meter factor variances between provings, and establish back-up measurement criteria such as tank gauges to minimize disputes between DOE and prospective purchasers in the event of a disagreement on measurement.

Deballasting

Drawdown by marine transportation of the SPR could be limited by the absence of any facility for handling ballast water at either the DOE's St. James terminal or the Seaway terminal. The Sun terminal at Nederland, Texas, has five tanker docks and three barge docks and would ordinarily be expected to be able to deliver up to 1.1 MMB/D by water. However, Sun terminal reports that their ballast water treatment facilities would limit their delivery of oil to ships to about 200 MB/D. This is insufficient for a maximum drawdown case, especially once Big Hill is operational. A study should be conducted to determine the most effective method of handling ballast during an SPR drawdown. Among the options are:

- Constructing ballast water treatment facilities at SPR marine terminals
- Tying into nearby marine terminals to increase dock utilization
- Injecting the ballast water discharged from the vessels into the caverns
- Exempting vessels loading at the SPR terminals from the "Act to Prevent Pollution from Ships, 1980," during an emergency.

Crude Oil Segregation

The DOE has been conscientious at all facilities in maintaining proper segregation between low-sulfur and high-sulfur crude oils. Additional segregations based on other crude oil characteristics would have been desirable. Most refineries, however, can process one or the other of the two segregations. Not knowing the actual types of crude oil contained in the blend of the delivery will pose a difficult problem for bidders, since more than one storage cavern will be used simultaneously depending on the required drawdown rate.

Also, none of the DOE sites are equipped to deliver more than one quality of crude oil to a terminal at a time. However, the sites where both low-sulfur and high-sulfur crude oils are stored have the ability to switch between low-sulfur and high-sulfur. Additionally, the proposed enhancements to the SPR will allow access to additional terminals, allowing flexibility to deliver more than one type of crude oil simultaneously.

Security

Comments relative to security of the SPR facilities should be viewed within the context that a comprehensive evaluation of DOE's security plans was impossible because of their classified nature. However, in a briefing by DOE officials, it was indicated that security precautions are enhanced whenever intelligence information indicates a greater than normal degree of risk. The prevailing security measures are designed to protect against infiltration and sabotage, but these measures are not evident at all sites or even at all aspects of a given site. Those sites where the salt dome is shared with other industrial concerns pose greater difficulty in maintaining tight security.

All well pads and pump pads are equipped with sophisticated intrusion detection and monitoring equipment. However, in each instance, i.e., well pad or pump pad, the area protected by the intrusion detecting equipment is limited. Additional provisions are warranted to provide additional security for the area outside of the well pads and pump pads but within the perimeter fence.

All storage sites, except Weeks Island, depend upon fresh water for drawdown. Without displacement water, oil in caverns is not available for drawdown. The intake structures for Sulphur Mines, West Hackberry, and Bryan Mound are outside the main DOE security fence, and, as such, they are vulnerable. Security for freshwater pumps and the power supply to run them is essential.

Warehousing

The warehouse space at Weeks Island is adequate and well organized. New warehouse space has been construced at St. James, Bayou Choctaw, and West Hackberry. The warehouse at Bryan Mound is poorly organized and was unfinished at the time that the study participants examined the site.

Sulphur Mines Site

The Sulphur Mines site is a high-cost facility, considering the volume of oil stored. Furthermore, this site is limited in its utility because it must deliver its oil through the same pipeline as West Hackberry. West Hackberry is intended to ultimately have 220 million barrels of crude oil at the end of Phase III. About 55 percent of this crude oil is planned to be high-sulfur. At a 1.4 MMB/D drawdown rate, West Hackberry will last approximately 160 days. The 1.4 MMB/D drawdown rate includes any drawdown from the Sulphur Mines site. Since Sulphur Mines contains high-sulfur crude oil, and high-sulfur crude oil will only be pumped 55 percent of the time, the advertised 100 MB/D drawdown rate for Sulphur Mines is misleading. The effective drawdown rate will be only about 55 MB/D, which means that the drawdown at Sulphur Mines will be less than one-half completed when West Hackberry has been depleted. Connection of the West Hackberry site to Lake Charles or the Texas pipeline could mitigate this drawback.

Chapter Five
SPR Sales

General Description of the Means of Selling SPR and Other Crude Oils

The crude oil supply system in the United States is a complex and dynamic process involving a diversity of participants and distribution facilities. This chapter discusses the means by which domestic refiners acquire and transport their crude oil supplies and deliver the refined products derived from them to customers nationwide. The system is complicated because crude oils have widely differing properties and qualities such as distillation yields, gravity, sulfur, and metal contaminants that affect refining values. Further, relative values of crude oils vary with particular refinery capabilities.

Participants

The following participants are involved in the crude oil supply chain:

- ***Producer***—Has a source of crude oil (well owner or royalty owner) but not necessarily the facilities to process it into products such as gasoline or heating oil. The only viable disposition of this oil by the independent producer is through outright sale to crude oil resellers or a refiner.
- ***Reseller***—Serves as an intermediate or broker between producers and refiners.
- ***Refiner***—May also be a producer, but typically relies partly or wholly on producers and/or resellers for crude oil supply. Refiners with owned crude oil production may have supplies in excess of their refining requirements and sell such supplies to other refiners or resellers.
- ***Importer***—As domestic crude oil production is not adequate to meet U.S. refinery requirements, some refiners and resellers may act as importers of foreign source crude oil.

Crude Oil Exchanges

While the previous description might suggest that crude oil transactions are simply a multitude of individual sales, the parties involved frequently engage in exchanges of crude oil to achieve certain efficiencies. The nature of the exchange and the objectives served vary, as noted below:

- Exchange crude oil of a particular quality for crude oil of a different quality, for the mutual benefit of the exchange participants, who may have differing refinery process configurations.
- Exchange crude oil at one location for the same or a different type of crude oil at another location to achieve transportation economies.
- Secure for an extended period (term trade) the economic benefits contemplated in the types of exchanges described above.
- Balance a perceived surplus in one time period against a perceived deficit in another time period (time trade).

- Eliminate the relative uncertainty of foreign flag marine transportation costs and risks by substituting a domestic supply movement.
- Defer the receipt of crude oil by trading domestic crude oil, which would begin to flow ratably over the month of supply, into foreign crude oil F.O.B. a loading port during the same month.

In short, crude oil exchanges are efficient mechanisms for balancing supply, enhancing raw material economics, and hedging risk.

The typical crude oil exchange consists of matching buy and sell agreements in which the parties invoice and pay each other (unless the invoices are netted out). In this manner, the respective cash flows of the parties are protected in the event that the buy and sell activities occur in different months or if, in a particular month, one party delivers a significantly greater quantity than does the other party.

A less common type of exchange is the barrel-for-barrel exchange in which only the crude oil, but no money, changes hands. This type of exchange is typically reserved for situations in which neither party's cash flow is impaired.

In the United States, virtually all refiners participate in crude oil exchanges regularly. In addition, scores of trading companies and purchaser/gatherer/resellers are active. Included among the trading companies are quite a few whose parent organizations are domiciled outside the United States.

Refiners, traders, and purchaser/gatherer/resellers all take risks in that they actually take title to the oil involved in an exchange transaction, albeit perhaps only momentarily as the same oil is traded away in yet another exchange. By contrast, another group that facilitates crude oil exchanges, the petroleum brokers, do not take the risk of title. Rather, the brokers seek to identify and bring together the parties to an exchange for a fee.

There are some 1,500–2,000 full-time personnel engaged in crude oil supply and trading in the United States. To that number must be added possibly another 100 brokers who deal exclusively in exchanges in the "cash market," as distinguished from the literally hundreds of brokers, floor traders, and others involved in the oil futures exchanges.

The crude oil traders and cash-market brokers maintain frequent contact with each other in an intensive effort to discern trading directions and make favorable trades. Through this process, a system of crude oil trades has developed that optimizes logistics. It should be noted that this huge, complex trading system involves not only U.S. domestic crude oils but foreign crude oils as well, either F.O.B. at their points of origin or delivered to destinations in many parts of the world.

Locales for Domestic Crude Oil Trading

Crude oil trades occur at numerous key locations in the contiguous 48 states. Table 64 displays a number of pipeline interconnection and water locations where many, but by no means all, domestic crude oil trades occur. Also shown are grades commonly traded at those points.

The vast majority of domestic pipeline crude oil bulk trades occurs at Cushing, Oklahoma; Midland, Texas; and St. James, Louisiana. The crude oils widely traded at those points are fungible and are large in volume.

The Los Angeles/Long Beach/Wilmington Harbor area is also an important trading center for arriving cargoes of Alaskan North Slope (ANS) crude oil or mixtures of California-produced and ANS crude oil. The other areas shown on Table 64, while of secondary importance in terms of the number of exchange transactions and quantities traded, are nevertheless important in optimizing raw material cost and quality.

Although crude oil exchanges are known to be widespread, precise data on volumes exchanged are not available. It is probably a fair estimate that at least half of the crude oil produced in the United States changes hands one or more times on its way from the wellhead to a refinery.

Plans for Sale of SPR Crude Oil

Two options are listed for sales of SPR oil. The basic method of distribution of SPR oil would be by price competitive sale with awards going to the highest bidders (although the Secretary may establish a minimum acceptable price). Under the current plan, sale would be open to any interested buyers. Buyers would be required to sign a standard sales agreement as a condition of bidding. Measures would be included in the sales agreement to ensure the financial and performance responsibilities of the successful buyers. The other distribution option is planned to be available only as a "last resort" measure. Under this option the

TABLE 64

CRUDE OIL TRADING CENTERS

Location	Crude Oil Types Traded
Cushing, OK	Mid-Continent Sweet (also loosely referred to as WTI), Oklahoma Sweet, WTS.
Midland, TX	WTI, WTS, occasional West Coast mixes moved via Four Corners and Texas-New Mexico pipelines.
Colorado City, TX	WTI, Scurry, WTS.
Longview, TX	E. Texas, WTI, Coastal Mix.
Corpus Christi, TX	S. Texas, WTI, WTS, ANS, Foreign, S. Texas Sour.
Houston, Port Arthur, Texas City, TX	WTI, WTS, E. Texas, ANS, Foreign.
St. James, LA	LLS, HLS, Eugene Island, LMS, ANS, Foreign.
Ft. Laramie/ Guernsey, WY	Rocky Mountain Sweet; Wyoming/ Montana Sour; Montana Mix.
Wood River, IL	Rocky Mountain Sweet; Wyoming/ Montana Sour; Montana Mix; Mid-Continent Sweet.
Patoka, IL	Mid-Continent Sweet; LLS, HLS, Eugene Island, LMS, ANS, Foreign.

Legend: WTI = West Texas Intermediate
WTS = West Texas Sour
ANS = Alaskan North Slope
LLS = Light Louisiana Sweet
HLS = Heavy Louisiana Sweet
LMS = Louisiana/Mississippi Sweet

Secretary may, in any calendar month, direct the distribution of up to 10 percent of the volume of SPR oil sold in that calendar month in a manner which the Secretary selects at his discretion. The price for such SPR oil would be the average price of SPR oil sold at the contemporaneous competitive sale, or at the most recent competitive sale if no contemporaneous competitive sale is held.

To facilitate the sales process defined in SPR Drawdown Plan Amendment No. 4, the DOE has developed Standard Sales Provisions containing contract terms and conditions that would be expected to appear in contracts by the government for sale of SPR crude oil. Specific SSP issues of concern as identified by study participants are discussed later in this chapter.

To promote the widest accessibility of participants to sales of SPR crude oil would require:

- Free exchangeability of SPR crude oil among all parties eligible to participate in a sale of SPR oil and freedom to move to any destination in the fifty states, Puerto Rico, and the U.S. Virgin Islands, or into Canada to facilitate assumed continuation of U.S./Canadian exchanges.
- A thorough understanding of the contents and mixture or stratification of each SPR storage facility, so that each prospective purchaser or exchanger would have a reasonable understanding of the nature of the oil to be sold. Quality issues regarding SPR oil are addressed later in this chapter.

Standard Sales Provisions

Primary Deterrents to an Effective Drawdown

The latest version of the Standard Sales Provisions for the sale of SPR crude oil (Appendix F) represents a significant achievement in that the SSPs are approaching the terms and conditions encountered in normal petroleum industry practice. The closer the SSPs come to this goal, the more efficiently and quickly sales of SPR crude oil will be accomplished. However, additional modifications can be made to SPR Drawdown Plan Amendment No. 4 and the SSPs to further improve the efficiency and effectiveness of the drawdown of SPR crude oil without compromising the national interest or the welfare of the general public.

Universe of Bidders

The SSPs, written in compliance with SPR Drawdown Plan Amendment No. 4, provide that price competitive sales of SPR crude oil will be open to *all* interested buyers. Allowing anyone to bid on SPR crude oil requires the DOE to have in place unnecessarily complicated procedures and excessive penalty provisions, magnifying the administrative burden for the DOE. More significantly, an unlimited universe of bidders has the potential to create distribution inefficiencies and introduce uncertainties in crude oil flow to the crude oil processors, resulting in unnecessary delays in providing the consumer with adequate supplies of petroleum products.

During the SPR Distribution Readiness Exercise (DIREX-B) "drawdown" test of the SPR, at a rate of 1.7 MMB/D, the DOE staff limited bids to a total of 23. In an actual emergency, with an unlimited universe of potential bidders, the total number of bids could greatly exceed the capabilities of the DOE staff.

Unlimited bidding may encourage purchasers to enter the system who lack expertise in petroleum refining, distribution, and marketing, making the system less efficient. A restricted list of purchasers will help ensure that SPR crude oil is processed in a timely fashion to meet the needs of the U.S. domestic market.

SPR Drawdown Plan Amendment No. 4 states:

> It is intended that the universe of eligible buyers will be as large as possible to ensure *efficient* distribution of SPR oil. [Emphasis added]

Therefore, to promote an efficient drawdown of the SPR and the timely distribution of petroleum products to consumers, it is recommended that SPR Drawdown Plan Amendment No. 4 be modified from the present position of being open "... to *all* interested buyers..." to a more restricted list of purchasers such as U.S. refiners, their purchasing agents, and/or traditional suppliers. Procedures should be established for pre-certification of qualified bidders. Since there are well over 150 such purchasers currently involved in this business activity, the necessary competition to ensure an acceptable bidding process will be provided. These purchasers have the necessary expertise to move crude oil out of the SPR expeditiously and to provide petroleum products to the general public on a timely basis in realization of the goal of the Energy Policy and Conservation Act to minimize the effects of any emergency disruption. It is recognized that exceptions to this bidding restriction may be required from time to time (e.g., due to the International Energy Agency or international defense commitments). Such exceptions could be approved on a case-by-case basis.

Jones Act Requirements

The SSPs require Jones Act vessels for any marine transportation of SPR crude oil (Section B.2). In the event of a maximum SPR drawdown, sufficient Jones Act tonnage may not be available. A contingency plan should be developed by MarAd well in advance of any emergency for expediting waivers of the Jones Act requirement. Jones Act waivers should be handled on a case-by-case basis. If the drawdown rate is such that case-by-case waivers cannot be administratively handled, a blanket waiver should be granted to CDS vessels enabling MarAd's contingency plan procedure to concentrate on case-by-case waivers of foreign flag tankers to participate in the SPR drawdown.

MarAd should develop, and have available to it, a standby procedure to allow blanket waivers of foreign flag vessels into the domestic trade in the event that case-by-case handling of foreign flag waivers exceeds the processing capabilities of MarAd's staff. This standby blanket waiver procedure should be invoked only if delays in distribution of SPR oil occur due to the processing under a case-by-case procedure for foreign flag vessels after the above steps have been taken to streamline the process to permit a blanket waiver for CDS vessels to enter the domestic trade. As noted elsewhere in this report, MarAd should develop an Industry Advisory Group to review its waiver procedures and to act as an industry clearing house during times of emergencies to assist MarAd in assessing vessel availability and requirements.

An alternative view to the recommendation for case-by-case Jones Act waivers is contained in Appendix D.

Damage Provisions

Damage provisions for nonperformance are too severe and one-sided. As currently written, the SSPs place the entire burden to perform upon the purchaser. The government's liability is limited (Section C.31). The government incurs no liability for termination of the contract (Section C.25) nor for failure of government subcontractors to perform. In contrast, a purchaser could incur severe liabilities (Section C.28) for his or his subcontractor's failure to perform. These damage provisions can be imposed even if the purchaser fails through no fault of his own, due to circumstances beyond his control.

The SSP liability provisions should be reconsidered to ensure that there will be no reluctance on the part of the petroleum industry to bid for SPR crude oil should an emergency situation develop. If crude oil is moved in accordance with a drawdown plan, there is no reason why one shipper who suffers delays should be held liable, if other shippers can be rescheduled to take his place. Section C.29 permits a purchaser to be excluded from future sales for an indeterminate period as a result of purchaser nonperformance. This should be sufficient incentive for a responsible purchaser to make every effort to perform. Both the purchaser and the DOE should be excused from the contract under conditions of force majeure—without liability.

The revised SSPs do not contain a demurrage clause. Such a clause should establish the reimbursement to the purchaser when delays occur due to the government's inability to perform at the specified time or rate.

Secondary Deterrents to an Effective Drawdown

Many provisions, while individually not of a magnitude to prevent effective SPR drawdown, might collectively be of such weight as to impede the process by administratively overburdening the DOE and/or bidders and unnecessarily confusing the procedures.

Two provisions that would severely impact the administration of the plan by DOE and/or bidders are:

- ***Section B.21—Financial Statements and Other Information.*** Financial statements for the most recent year and unaudited financial statements for the most recent quarter, along with a statement by bidder as to the intended disposition of the SPR oil, should be sufficient. The SSPs should make clear that no additional information will be required.

- ***Section C.6—Delivery and Transportation Schedule.*** Vessel schedules should be based on nominating the vessel to the SPR Office (SPRO) on a three-day window at least seven days prior to vessel arrival. SPRO would then confirm acceptance of this nomination or give alternate date(s). Nominations to SPRO could include "To Be Named" vessels. Confirmed vessel names would be provided to SPRO no later than 72 hours before the acceptance window. If a bidder is unable to acquire a Jones Act vessel, additional time should be allowed to obtain domestic operating permission for a CDS vessel or get a Jones Act waiver for a specific lifting.

The following provisions would cause confusion and create potential impediments to bidding. (The first two issues under this category could also become an administrative burden to DOE if DOE does not address them prior to an emergency.)

- ***Section B.3—Superfund Tax on SPR Petroleum (Caution to Offerers).*** The Internal Revenue Service has not taken the required steps as requested by DOE to determine what SPR crude oils are taxable when sold. Before an emergency occurs, it should be determined if and how the tax applies. Procedures should be worked out in advance for payment. If this cannot be done in advance of the Notice of Sale, all SPR crude oil should be automatically exempted from the Superfund Tax at the time of any competitive sale.

- ***Section B.4—Export Limitations and Licensing (Caution to Offerers).*** The SPR mix of domestic and foreign crude oil may create potential conflicts with U.S. export control laws. The commingled crude oils in the storage caverns are subject to different regulations. To alleviate any confusion, DOE should clarify whether SPR oil is domestic or foreign.

- ***Section C.11—Quality Differentials for Crude Oil.*** DOE has not developed and published the applicable specific price differentials to adjust for crude oil quality variations in deliveries. It is recommended that if the gravity of the crude oil delivered differs by more than ± 0.5 °API from the Notice of Sale specification:

—For all the crude oils stored in the SPR caverns other than Weeks Island: (1) Sweet crudes (not more than 0.5 percent sulfur content) should be adjusted for price per current prevailing petroleum industry practice based upon the API gravity scale for typical West Texas Intermediate crude oils; (2) Sour crudes (greater than 0.5 percent sulfur content) should be adjusted for price per current petroleum industry practice based upon the average API gravity scale for West Texas Sour crude oil.

The above gravity adjustments would be applied only to the difference between the actual gravity and the ± 0.5 °API allowed variation.

Should a sulfur adjustment scale for these crude oils become widely used by the petroleum industry, then a similar scale should be adopted for SPR crude oils.

—For crude oil stored at Weeks Island (from which deliveries may be more variable in quality), a quality bank program could be established similar to that of the Louisiana Offshore Oil Port, which provides for the calculation of a "Relative Crude Value" (RCV) for shippers' deliveries to and receipts from LOOP, with a monetary adjustment for the value difference. That difference multiplied by the barrels delivered by LOOP, multiplied by an "adjustment factor," reflects the quality settlement. The quality adjustment would be the difference between the RCV applicable to the published characteristics for the SPR crude oil offered for sale and the RCV applicable to the actual characteristics of the Weeks Island crude oils delivered.

It should be noted, however, that the LOOP quality adjustment formula is not endorsed as a general basis for determining relative crude oil values.

—In the event that a bidder is delivered the wrong type of crude oil (e.g., sour crude instead of sweet), which he cannot process, damages could be so great that adjustment and/or reconciliation should be handled on a case-by-case basis.

- ***Section C.17—Payment and Performance Guarantee.*** The payment and performance guarantees for either cash or credit purchases do not follow common business practice. The amount of the performance guarantee is excessive, in that the SSPs currently call for an advance cash payment for a contract over 31 days of 105 percent of contract value, or a letter of credit in the amount of 100 percent of the contract amount. Contracts for sale of oil from the Naval Petroleum Reserve call for a standby letter of credit to cover the value of the volume of 35 days of crude oil deliveries and terminates 60 days following final delivery under the contract. There is no reason why a similar practice should not be adopted by the SPR.
- The following Sections should be amended in the manner discussed below to conform more closely to standard business practice:

—*Section C.19.* Payment and Performance Letters of Credit—general requirements.

—*Section C.21.* Billing and Payment—with purchaser's letter of credit.

—*Section C.22.* Method of Payment—general.

—*Section C.25.* Government Options if Payment Is Not Received.

A standard irrevocable letter of credit issued by a commercial bank should provide the government with the required protection. This letter of credit should be written for the term of the contract plus 60 days and have a provision for cancellation at any time by the contracting officer. Authentication of the bank officer's signature should not be necessary.

Payment for deliveries should be made by purchaser via the FEDWIRE transfer of funds 10 calendar days after delivery date for marine transactions and for pipeline deliveries 10 calendar days after receipt of invoice which occurs in the month following a pipeline delivery. The letter of credit should be invoked only if payment is not made.

Testing of SPR Drawdown Capabilities and Procedures

A concern has often been expressed about the capability of the DOE plans and programs, as now constructed, to handle a supply disruption that results in SPR oil drawdown and distribution of the magnitude considered in this study. In fact, to expect SPR facilities and procedures to perform well without prior testing is unrealistic. An exercise to test the SPR plans and programs, the quality and quantity of the programs personnel, and the facilities of the entire Strategic Petroleum Reserve organization should be implemented. Such a test should be considered in two separate and distinct phases: (1) physical facility testing and (2) administrative testing.

Facilities Testing

To ensure physical deliverability of SPR oil to custody transfer points, oil recycling exercises or SPR crude oil deliveries to custody transfer points (docks, pipeline tankage) should be tested periodically. Actual sale of the oil would not be necessary to verify the physical capabilities of SPR drawdown.

An actual sale of SPR oil for test purposes is not the preferred method since the physical capability of SPR drawdown could be tested by exchanging SPR oil with title transfer for later replacement by the exchange partner. This test should be designed to demonstrate both marine and pipeline capabilities. An exchange in lieu of sale would avoid unnecessarily impacting the crude oil market and would remove the exposure to price changes for the replacement purchases.

Administrative Testing

To test the ability of current DOE programs and personnel to administratively coordinate and process SPR bids and information requirements from companies during drawdown, a test of these procedures should be conducted with petroleum industry participation. Petroleum industry personnel should be involved in all phases of such a test, including test planning and design. Parameters of such a test should include:

- DOE issuance of a postulated disruption scenario and a Notice of Sale
- Mock bidding on SPR crude oil by petroleum companies, including "paper" compliance with all SSP provisions
- Testing through two complete mock sales periods (see time line in Appendix F)
- Development of a procedure to evaluate and follow up on test results, including petroleum company input and participation
- Development of a contingency plan to allocate sufficient MarAd personnel to test the ability of the agency to administratively process a predetermined volume of Jones Act waivers in sufficient time to be responsive in an emergency situation.

The above recommendations are a compilation and synopsis of areas of concern identified by this study. Although not all-inclusive, they represent major shortcomings of SPR Drawdown Plan Amendment No. 4. Previous comments received on the SSPs should also be considered in the effort to design provisions that will facilitate the efficient and timely drawdown and sale of SPR crude oil.

Appendices

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

November 7, 1983

Mr. Robert A. Mosbacher
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Mosbacher:

One of the key initiatives which this Administration has taken in the area of energy security has been the rapid development and fill of the Strategic Petroleum Reserve (SPR). We currently expect the SPR inventory to reach half of the planned 750 million-barrel level within the coming months, and we are expanding our efforts to improve our planning on how to use the SPR during an energy supply emergency. Assuring the capability to distribute oil from the SPR in an effective and efficient manner is of major importance in this planning.

In several key studies over the past decade, the Council has provided outstanding leadership and advice to the Government on how to develop an emergency oil stockpile. In fact, most of the major features of the current SPR Plan, in terms of size, types of crude oil stored, storage method, and location, derive from National Petroleum Council studies prepared during and immediately after the 1973-74 Arab oil embargo. However, many changes have occurred in the U.S. petroleum industry since those initial studies, in terms of refinery capacity and location and crude oil distribution patterns.

Accordingly, I request the National Petroleum Council to undertake a new study addressing certain aspects of the Strategic Petroleum Reserve in the 1984-90 time frame. Areas of particular concern include: types of crude oil in storage in the SPR, taking into account latest and prospective U.S. refining capabilities and sources of supply; industry capabilities to transport oil from SPR storage sites to refineries; and any other aspect of the Government/industry relationship wherein the Council believes changes in our current plans for SPR distribution and composition would be warranted.

Because of the importance of this assignment, I would appreciate it if the Council gave this project very high priority and would work with the Department to establish a time schedule that results in completion of your study at the earliest, practical date.

Sincerely,

Donald Paul Hodel

DONALD PAUL HODEL

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

November 7, 1983

Mr. Robert A. Mosbacher
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Mosbacher:

A number of changes have occurred in worldwide oil logistics since the 1973-1974 oil embargo. The world tanker industry has retrenched in the face of a long-standing decline in oil demand and reduced tonnage requirements due to the increase in short-haul sources of supply and new pipeline construction.

The United States is much less dependent upon imports than in recent years, and now most of our imports are from Western Hemisphere, non-OPEC sources. However, changes in the structure of the worldwide tanker industry may be a consideration in emergency preparedness planning as, in times of a disruption of supplies, world tanker movement patterns are distorted at the same time that emergency petroleum movements may be required.

Accordingly, I request that the National Petroleum Council undertake a study addressing the question of the long-term availability and movement patterns of tankers worldwide. This study should examine the trends in tanker size, flag, and contract provisions, with a special consideration of the availability of tankers for any possible drawdown and distribution of Strategic Petroleum Reserve stocks. Other factors that may affect tanker availability in the 1984-90 time period, such as bunker fuel oil availability, environmental considerations, and Federal laws and regulations, should also be considered.

Because of the importance of this assignment, I would appreciate it if the Council gave this project very high priority and would work with the Department to establish a time schedule that results in completion of your study at the earliest, practical date.

Sincerely,

Donald Paul Hodel

DONALD PAUL HODEL

Description of the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- *Potential for Energy Conservation in the United States: 1978-1985* (1975)
- *Ocean Petroleum Resources* (1975)
- *Petroleum Storage for National Security* (1975)
- *Materials and Manpower Requirements* (1974, 1979)
- *Petroleum Storage & Transportation Capacities* (1974, 1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil and Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1984)
- *Enhanced Oil Recovery* (1976, 1984)

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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Appendix B
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Appendix C
Pipelines and Terminal Capacity

This appendix presents additional considerations regarding future pipeline capabilities. A number of potential shifts were identified in future crude oil and product pipeline markets, and their consideration in this report is discussed below.

All American Pipeline (Crude Oil)

The All American Pipeline Company is reportedly planning a heated oil pipeline system that would allow delivery of PADD V crude oils (heavy OCS crude oil and others) to the Gulf Coast.[1] The main line of this system would run from Emidio, California (near Bakersfield) to McCamey in West Texas. An extension would run from McCamey to Freeport, Texas, and the total line would be almost 1,680 miles long. In West Texas, three planned delivery points would allow access by Midwest and Southwest refiners to crude oils carried in this pipeline. Further, through interconnections at Cadiz, California, the transport capability of the existing Four Corners Pipeline would be enhanced from its current capacity of around 60 MB/D to an estimated 130 MB/D. Initial delivery capacity of the All American Pipeline would be around 300 MB/D. Figure C-1 displays the proposed route of the All American Pipeline.

This study has assumed that the proposed All American Pipeline is unavailable in 1990. This should in no way be construed as an assessment of the probability of project construction or completion; rather it provides a more rigorous test of 1990 west-to-east logistics capability during a supply disruption that may result in SPR drawdown.

Pacific Texas Pipeline (Crude Oil)

The Pacific Texas Pipeline Company is reportedly planning construction of a west-to-east 42-inch crude oil pipeline capable of carrying 900 MB/D.[2] This pipeline would run from Long Beach, California, and could interconnect with as many as 14 existing crude oil pipelines in the Midland, Texas area. Although this study has assumed that the Pacific Texas Pipeline is unavailable for utilization in 1990, this assumption should in no way be construed as an assessment of the probability of project construction or completion. Again, this assumption was made solely to provide a "worst case" logistics scenario in which it would be necessary to transport any PADD V crude oils from west to east either in the existing Four Corners Pipeline or in marine transportation. Figure C-2 displays the route of the proposed Pacific Texas Pipeline.

Transgulf Pipeline (Products)

The 1990 cases have not assumed that the proposed Transgulf product pipeline is available for use. This project entails conversion of a gas transmission pipeline between Baton Rouge and Port Everglades to clean products service. The pipeline has an estimated 350 MB/D capacity and offtake terminals at Lucedale, Mississippi, and at Tallahassee, Jacksonville, and Kissimmee, Florida.

[1] "All American Pipeline Work to Start in 1985," *Pipeline*, June 1984, p. 7.

[2] "Pacific Texas Plans 1,026-Mile Oil Line System," *Pipeline*, June 1984, p. 21.

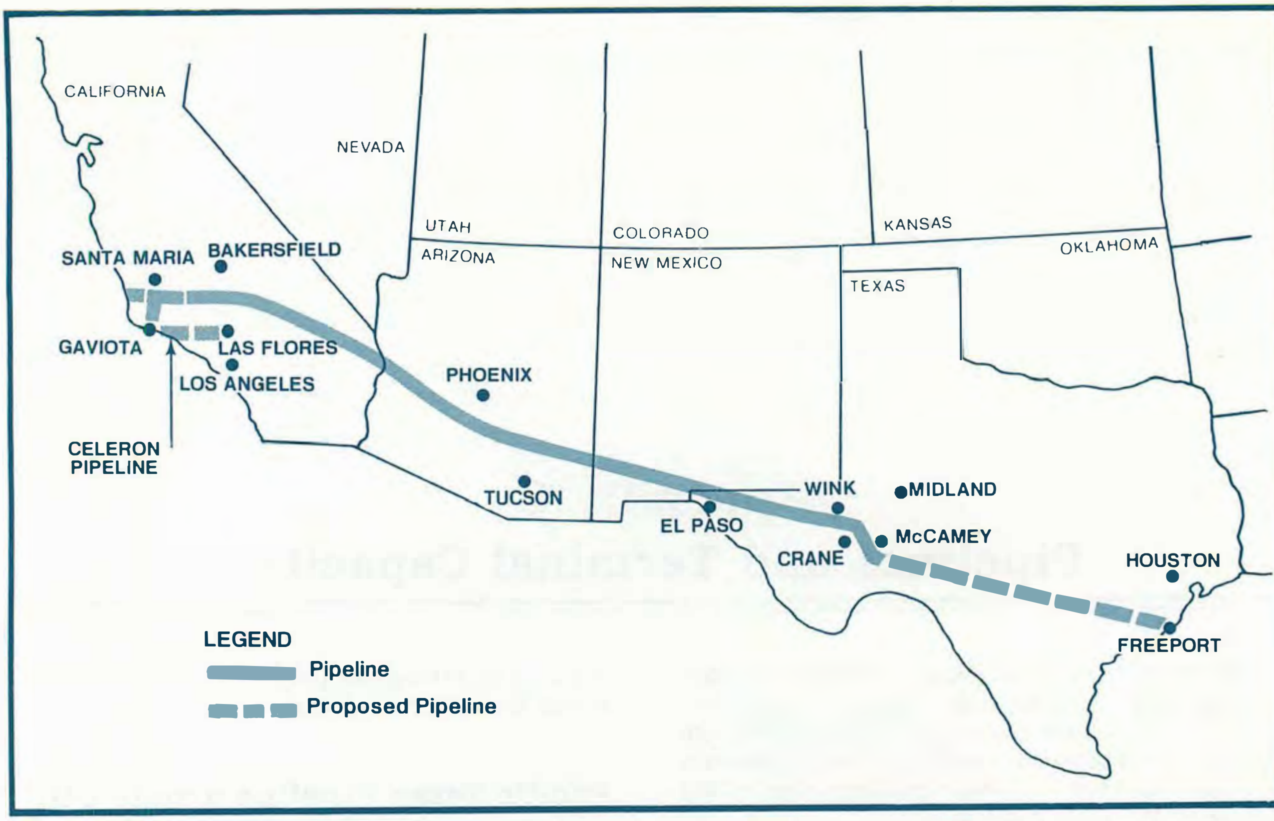

Figure C-1. Proposed All American Pipeline.

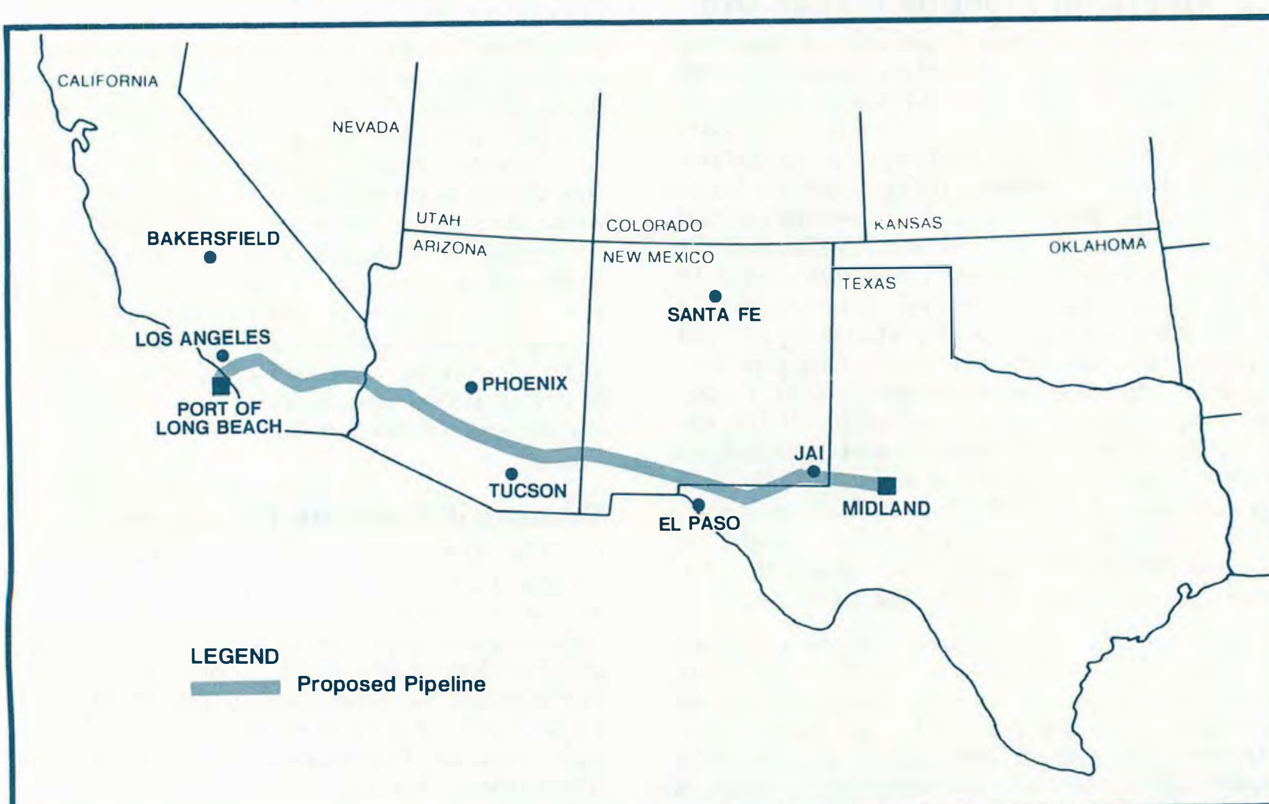

Figure C-2. Proposed Pacific Texas Pipeline.

Current projections by the Transgulf Pipeline Company are that the pipeline will be operational by late 1986. Should this line be in place by 1990, its net impact would be to reduce marine clean products transportation requirements from Gulf Coast refineries to Florida. The assumption that this pipeline is unavailable for utilization should in no way be construed as an assessment of the probability of the project's construction or completion. Figure C-3 displays the route of the proposed Transgulf Pipeline.

PADD I Product Movements

In the disrupted case, local PADD I crude oil runs meet only about 1.2 MMB/D of PADD I's 4.8 MMB/D product demand; receipts of domestic products in PADD I increase by about 400 MB/D over nondisrupted levels. To define how much of these increased domestic product movements can occur in each of the two transportation modes (pipeline/marine), product pipeline capacities were defined. Based on reported capacities, Table C-1 displays

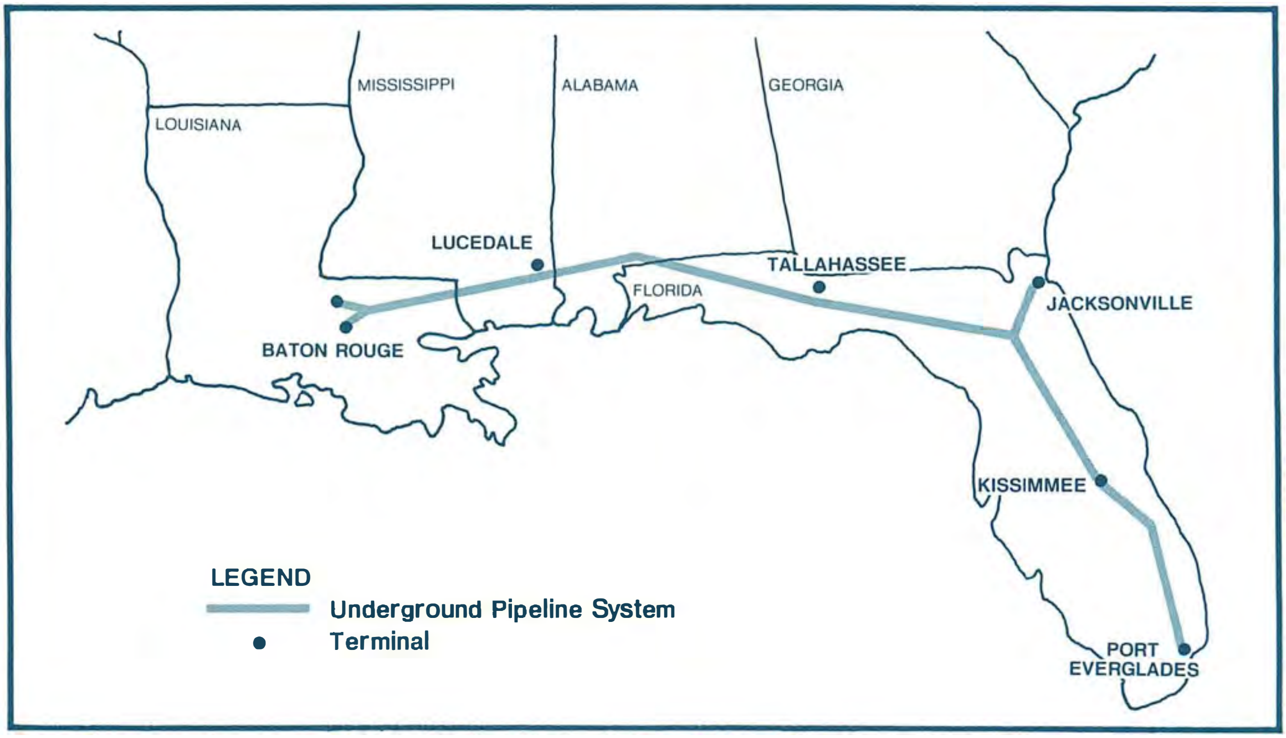

Figure C-3. Transgulf Pipeline.

TABLE C-1

PRODUCT PIPELINE CAPACITIES

	New England	Mid-Atlantic	South Atlantic	Florida	Total
Clean Products					
Colonial	-	1,010	903	-	1,913
Plantation	-	-	416	-	416
Other	-	112	-	-	112
Total	**-**	**1,122**	**1,319**	**-**	**2,441**
LPG/NGL					
Dixie	-	-	146	-	146
Texas Eastern	-	44	-	-	44
Total	**-**	**44**	**146**	**-**	**190**

estimated maximum quantities of products deliverable by pipeline into PADD I by region.

These capacities are the upper limit of product movements by pipeline into PADD I, with additional product demands to be met by marine transportation. There do not appear to be any pumping or terminal constraints along Colonial or Plantation that would preclude attainment of these delivery rates.

Texoma Complex

The Sun Nederland terminal has five ship docks, three barge docks, plus connections to six pipelines. Present terminal tankage, manifolding, and piping arrangements are very flexible in permitting various combinations for deliveries to docks and pipelines to ensure most efficient utilization.

DOE'S present contract ensures the use of one ship dock plus an additional dock if not in service. In the event of a disruption and/or contractual changes with DOE, a minimum throughput case has been developed for combined ship/barge loadings and pumping to pipelines. Minimum available loading on water for DOE movements is calculated to be 1,120 MB/D. Calculations for various pumping configurations are shown in the following tabulations.

Based on the total 1,320 MB/D rate (shown in Table C-2) with 400,000 barrel ships, the equivalent of 3.35 ship docks will be in use each day for total Sun and DOE volumes. Based on the 1,120 MB/D rate for DOE with 400,000 barrel ships, the equivalent of 2.8 ship docks will be in use for DOE volumes only.

TABLE C-2

SHIPS AND BARGE LOADING (MB/D)

DOE	#1 Booster	720
	#2 Booster	720
Sun	3 Cargo Booster Pumps	480
	Rotation Pump	720
		2,640
% Industry Acceptable Dock Utilization		50%
		1,320
Deduct Volume for Sun's Commercial and Industry-Related Business		200
Net Loading Available for DOE		**1,120**

Appendix D
Marine Transportation

This appendix presents additional information with respect to the U.S. maritime laws, policies, and procedures that were briefly discussed in Chapters Two and Three, as well as data and assumptions used in estimating the 1990 supply and availability of U.S. flag tankers and barges. An alternative view to the study's recommendation for case-by-case waivers of the Jones Act during a supply disruption is also presented in this appendix.

The Jones Act

In 1920, Senator Wesley L. Jones of Washington, Chairman of the Senate Commerce Committee, added an amendment to the Merchant Marine Act of 1920 (Section 27) that prohibited the use of any but American-built, -owned, and -documented vessels in the carriage of cargo between points in the United States. Such carriage included the coastwise, intercoastal, and noncontinguous trades. Section 27 of the Act, together with similar laws covering fishing, passenger transport, towing, and dredging, are today commonly known as the "cabotage laws." However, Section 21 exempts the U.S. Virgin Islands and certain other noncontiguous U.S. points from Jones Act restrictions. As a result, foreign flag tankers are permitted to trade between the Virgin Islands and the U.S. mainland.

The Jones Act fleet operates in the domestic trades that are protected by the cabotage laws that prohibit non-U.S. vessels from trading between U.S. ports. As illustrated in Table 12 in Chapter Two, the Jones Act tanker fleet has a total deadweight of approximately 10 million tons. The most important source of employment for the Jones Act fleet in terms of cargo volume is in the movement of Alaskan crude oil to domestic refinery centers.

Jones Act Waivers

Public law 81-891, 64 Stat. 1120, which was enacted on December 27, 1950, provides that the head of each department responsible for the administration of navigation laws is directed to waive compliance with such laws upon the request of the Secretary of Defense to the extent deemed necessary in the interest of national defense by the Secretary of Defense. The same department heads are authorized to waive compliance—either on their own initiative or on the written recommendation of the head of any other government agency—whenever they deem that such action is necessary in the interest of national defense.

The effect of the law has been to require or allow certain administrative waivers of the Jones Act—one of the navigation laws—by the Department of the Treasury. Since 1950, 132 administrative waivers have been granted; 104 of those were for the direct benefit of the Department of Defense, the St. Lawrence Seaway Development Corporation, or the Federal Aviation Administration.

Upon receipt of a request by industry for a specific waiver of the Jones Act, the Treasury Department, through its U.S. Customs Service, will contact: The Department of Defense (DOD) for its views as to whether the proposed shipment(s) would be in the interest of national defense; the Maritime Administration (MarAd), Department of Transportation, for an independent assessment of the availability of Jones Act vessels for the shipment(s); and other relevant government agencies to determine their views on the matter.

If a non-DOD request for a waiver is initiated through some other government agency (the Department of Energy, for example), that agency determines whether or not it wishes to act as an advocate. If it does choose advocacy, the agency must persuade the Treasury Department (specifically, the Assistant Secretary for Enforcement and Operations) that the waiver would be in the interest of national defense. The Treasury Department would also solicit the views of DOD and MarAd.

Waiver requests initiated by DOD are routinely granted since the law so directs. On other requests, the views of DOD as to whether the waiver is necessary in the interest of national defense are given considerable weight by the Treasury Department. However, it is also possible for a national defense interest argument by another agency to be persuasive with the Treasury Department. If MarAd finds a qualified U.S. vessel available for the shipment(s), the Treasury Department would be reluctant to grant any non-DOD initiated waiver, since there could understandably be strong opposition from affected U.S. operators.

The Subsidized Fleet

The Merchant Marine Act of 1936 provided a number of programs to help U.S. flag ships participate in the foreign commerce of the United States by subsidizing their cost to make them more competitive with foreign flag ships. Title V of the Merchant Marine Act of 1936 (46 U.S.C., S. 1151.) is the Construction Differential Subsidy (CDS) program, which authorizes the Secretary of Commerce to make a grant for up to 50 percent of the cost of constructing ships in domestic shipyards, provided the owners of the subsidized ships agree to operate them solely on foreign trade routes as required by Section 506.

In 1970 the Merchant Marine Act of 1936 was amended to extend CDS to the construction of bulk vessels, including oil tankers. This amendment resulted in the construction of the CDS tanker tonnage listed in Table 12. These vessels have essentially three requirements: they must have been built in the United States; they must be manned by U.S. crews; and they must operate in foreign trades.

Domestic Operation of CDS Vessels

As U.S.-built, -owned, and -flagged vessels, tankers built with CDS are not excluded from the domestic trades by the Jones Act. However, Title V, Section 506 of the Merchant Marine Act of 1936 does place domestic trading restrictions on these vessels since they were built with government subsidies to participate exclusively in the foreign commerce of the United States.

The Secretary of Transportation is authorized in Section 506 to grant permission to a CDS vessel to operate in the domestic trades for up to six months at a time. The vessel's owner must repay to the Secretary of Transportation a pro rata share of the CDS for the period of domestic operations.

In determining whether to grant permission for domestic operation of a CDS vessel, the Secretary considers whether there are any vessels with domestic trading privileges which could accomplish what is proposed for the CDS vessel. Generally, if there are eligible vessels available, the requested domestic operation by the CDS vessel would not be authorized, since authorization would allow the CDS vessel to compete unfairly with the unsubsidized domestic vessel.

Under current policy, only CDS tankers of 100,000 DWT or more are considered for domestic operation permission and these only for service from Alaska to Panama. The Very Large Crude Carriers operated under such permissions at any one time represent half of the total available supply of CDS tonnage over 100,000 DWT shown in Table 12. They account for the 885,000 DWT of available CDS tonnage used in the tanker supply assessment.

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

The Act to Prevent Pollution from Ships, 1980

The Act to Prevent Pollution from Ships, 1980 (33 U.Sc. 1901–1911) implemented the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the 1978 Protocol relating thereto. MARPOL 73/78 is a broad-ranging international initiative to reduce both accidental and operational pollution from ships. It is an evolutionary outgrowth of the International Convention for the Prevention of Pollution of the Sea by Oil, 1954 (OILPOL), which was last amended in 1969.

MARPOL 73/78 added equipment requirements to help reduce oil pollution from ships, and added separate annexes aimed at controlling pollution from chemical tankers, packaged harmful substances, sewage, and garbage. All of the annexes (with the exception of Annex III, related to packaged harmful substances) contain requirements that adequate reception facilities be provided at ports and terminals.

In addition to expanding the scope to include substances other than oil, MARPOL 73/78 represents a basic change in pollution control philosophy from OILPOL. It is widely perceived that the OILPOL scheme of relying purely on pollutant discharge standards was not working, primarily because of the difficulties of enforcing such standards on the high seas. Under MARPOL 73/78, the discharge standards are supported by ship equipment requirements that make enforcement and ship operator compliance easier, and by the requirements for reception facilities that reduce the delays and other burdens of discharging pollutants ashore.

The Act to Prevent Pollution from Ships, 1980, requires that adequate reception facilities be available at ports and terminals to receive materials that had previously been discharged at sea (Annex I, Regulation 12; Annex II, Regulation 7).

The SPR terminals are not equipped with sufficient ballast treatment facilities. Therefore, because of the uniqueness of the SPR program as a noncommercial operation, it might be appropriate to include special provisions in the regulations for emergency drawdown situations. The proposed rules currently have waiver provisions that will permit a vessel to load at a terminal that does not have approved facilities provided, if it is able to discharge ballast at another location that has approved facilities. However, since U.S. ports are not expected to have ballast reception facilities in place by 1990, significant delays could result if dirty ballast must first be discharged at another port or off-loaded into barges prior to cargo loading.

Impact of Port and Tanker Safety Act of 1978

As of January 1, 1986, all product carriers under 40,000 DWT and over 15 years of age must have permanent, segregated ballast systems. The expected loss in carrying capacity is illustrated in Tables D-1 and D-2. The data explain the derivation of the adjustments that were made to the supply of Jones Act and CDS tonnage under 40,000 DWT in Table 25. Table 27 reflects the 1990 carrying capacity adjustments of 54,133 DWT for Jones Act vessels and 33,216 DWT for CDS vessels as a result of segregated ballast requirements.

Projected 1990 Tonnage Supply

The 1990 tonnage supply estimates were arrived at by adjusting the 1983 base fleet for year-by-year additions and deletions due to new construction and vessel scrapping. Tables D-3 and D-4 summarize the net adjustments to each segment of the tanker fleet for the period 1984 to 1990. Table D-5 presents the yearly adjustments used in estimating the available barge tonnage.

Certain key assumptions are presented that define the makeup of the 1983 fleet base. Certain vessels and vessel types were excluded for a variety of reasons. Detailed scrapping assumptions are also presented.

Availability of CDS Tankers

In determining the availability of CDS vessels for an emergency drawdown, certain assumptions were made with respect to CDS tankers. Since these vessels are active in the foreign trades, some estimation had to be made regarding their availability in the U.S. Gulf Coast. Table D-6 estimates availability and timing and lists the assumptions used.

Demand Estimates for Product Tonnage

The demand for tankers and barges was derived for each trade by assigning factors to convert daily throughput requirements into deadweight ton equivalents. However, for refined product movements from PADD III to PADD I, it was first necessary to allocate the total product movement to tankers and barges. Table D-7 presents the allocation for both the 1983 base case and the 1990 nondisrupted case.

For the 1990 disruption, the same method was used to allocate clean product movements from PADD III to PADD I. Of the total 710 MB/D of clean product receipts in PADD I (Table 49), approximately 120 MB/D is shipped from the U.S. Virgin Islands/Puerto Rico, leaving 590 MB/D moving in Jones Act vessels from the U.S. Gulf Coast. Table D-8 presents the clean product allocation to tankers and barges.

The residual fuel oil movements into PADD I in the disrupted case (Table D-9) were combined with the clean product requirements and presented in Table 59. The residual fuel oil movements were assigned exclusively to tankers with the exception of the 40 MB/D inland movement from PADD II to PADD I shown in Table D-9. As a result, 470 MB/D of residual fuel oil and 222 MB/D of clean products must move in Jones Act tankers from PADD III to PADD I for a total of 692 MB/D.

Two potential bottlenecks arise as a result of these shipping requirements.

- There may not exist adequate Jones Act tonnage to accommodate an increase of over 500 MB/D of residual fuel oil movements.
- Shipping delays and/or dock congestion may increase in the disrupted case in PADD III created by increased residual fuel oil throughput requirements. However, PADD I pipeline and refinery facilites should be capable of adequately handling the 70 MB/D increase in pipeline shipments and 90 MB/D in refinery runs in the disrupted case.

SCRAPPING SCENARIO*

A. CATEGORIES

Category I	a) All vessels originally built prior to 1955
Category II	a) All *non-IGS* vessels originally built 1955–1965 and less that 40,000 DWT
	b) All *IGS* vessels originally built 1955–1965 and less than 33,000 DWT
Category III	a) All *IGS* vessels originally built 1950–1965 and 33,000–40,000 DWT, unless rebuilt since 1980.
	b) All *non-IGS* vessels originally built 1950–1965 and greater than 40,000 DWT (one vessel).
	c) All *non-COW* vessels originally built 1950–1965 and 40,000–70,000 DWT (two vessels).

B. SCRAPPING SCHEDULE†

Category I	25 vessels/724,428 DWT
(2nd half) 1984	11 vessels/323,087 DWT
1985	14 vessels/401,341 DWT
Category II	19 vessels/599,534 DWT
1986	10 vessels/299,767 DWT
1987	9 vessels/299,767 DWT
Category III	11 vessels/524,128 DWT
1988	6 vessels/262,064 DWT
1989	5 vessels/262,064 DWT
Total	**55 vessels/1,848,090 DWT**

*This assumes no Alaska Export and no CDS Payback; each would cause substantially greater scrapping.

†These estimates reflect general assumptions recognizing that specific exceptions will occur. Some of these vessels might go into "Ready Reserve" rather than scrap.

TABLE D-1

IMPACT OF SEGREGATED BALLAST TANKER REQUIREMENTS
JONES ACT FLEET

	20–29.9	30–34.9	35–39.9	Total
No. of Ships Affected	21	25	20	
Scrapped through 1/1/86	(14)	(10)	(1)	
No. of Ships in Service 1/1/86	7	15	19	
Avg. DWT Loss/Ship (LT)	× 3,075	× 4,595	× 3,647	
Deduction (DWT) 1/1/86	21,525	68,925	69,293	159,743
No. Scrapped during 1986	(3)	(6)	(1)	
No. of Ships in Service 1/1/87	4	9	18	
Avg. DWT Loss/Ship (LT)	× 3,075	× 4,595	× 3,647	
Deduction (DWT) 1/1/87	12,300	41,355	65,646	119,301
No. Scrapped during 1987	(3)	(5)	(1)	
No. of Ships in Service 1/1/88	1	4	17	
Avg. DWT Loss/Ship (LT)	× 3,075	× 4,595	× 3,647	
Deduction (DWT) 1/1/88	3,075	18,380	61,999	83,454
No. Scrapped during 1988	(0)	(2)	(2)	
No. of Ships in Service 1/1/89	1	2	15	
Avg. DWT Loss/Ship	× 3,075	× 4,595	× 3,647	
Deduction (DWT) 1/1/89	3,075	9,190	54,705	66,970
No. Scrapped during 1989	(0)	(2)	(1)	
No. of Ships in Service 1/1/90	1	0	14	
Avg. DWT Loss/Ship	× 3,075	× 4,595	× 3,647	
Deduction (DWT) 1/1/90	3,075	0	51,058	54,133

Assumptions:

- All vessels less than 40,000 DWT that do not have appropriate SBT must comply.
- All owners will select SBT in lieu of COW.
- The following cargo cubic capacities will be sacrificed to provide SBT:
  20,000-29,999—55,000 barrels
  30,000-34,999—65,000 barrels
  35,000-39,999—75,000 barrels

TABLE D-2

IMPACT OF
SEGREGATED BALLAST TANKER REQUIREMENTS
CDS FLEET

a) No. of Ships	7
b) Canal DWT	247,596
c) Total Cargo Tank Capacity	2,090,000
d) Lost Cargo Tank Capacity	7 × 75,000 = 525,000
e) Cubic Available	1,565,000
f) Crude Capacity	214,380 LT
g) Cargo Lost	33,216 LT (or 13%)

Assumptions:

- Each vessel loses 75,000 barrels except three with COW.
- No scrapping.

TABLE D-3

UNSUBSIDIZED FLEET PROJECTION

Year	20–40 MDWT No.	20–40 MDWT DWT*	40–70 MDWT No.	40–70 MDWT DWT	70–100 MDWT No.	70–100 MDWT DWT	100–200 MDWT No.	100–200 MDWT DWT	200+ MDWT No.	200+ MDWT DWT	Total No.	Total DWT(%)
6/84	76	2,512,500	38	1,916,033	23	1,816,908	21	3,135,300	2	449,528	160	9,830,269 (100%)
1/85	65	2,189,413									149	9,507,182 (97%)
1/86	51	1,788,072									135	9,105,841 (93%)
1/87	41	1,488,305							4	867,528	127	9,224,074 (94%)
1/88	32	1,188,538									118	8,924,307 (91%)
1/89	28	1,052,888	36	1,824,062							112	8,696,686 (88%)
1/90	25	939,075	36	1,824,062	22	1,748,014	20	3,021,500	4	867,528	107	8,400,179 (85%)

*To account for DWT loss due to SBT after 1/1/86, make the following deductions for each date: 1/86 (159,743) (not cumulative); 1/87 (119,301); 1/88 (83,454); 1/89 (66,970); 1/90 (54,133).

TABLE D-4

SUBSIDIZED FLEET PROJECTION

Year	20–40 MDWT No.	20–40 MDWT DWT	40–70 MDWT No.	40–70 MDWT DWT	70–100 MDWT No.	70–100 MDWT DWT	100–200 MDWT No.	100–200 MDWT DWT	200+ MDWT No.	200+ MDWT DWT	Total No.	Total DWT(%)
Assume 1986 Constant	10	377,232*	–		8	711,396	–		7	1,774,419	25	2,863,047

*To account for SBT loss, deduct 33,216 DWT.

Assumptions:

- Excluded chemical tankers in dedicated trades and with substantial contract obligations.
- Included large (greater than 35,000) fully integrated ITBs.
- Excluded vessels less than 20,000 DWT.
- Excluded vessels currently to be sold for scrap.
- Included newbuilding (*Exxon Baytown*) delivery 6/84.
- Excluded "Ready Reserve Fleet" and MSC lifetime chartered vessels.
- Excluded two subsidized ULCCs that are in deep layup in the Far East.
- Excluded two converted LNG ships that are dimensionally difficult and often in grain overseas.
- Excluded two subsidized 90,000 DWT vessels to be converted to hospital ships—*Rose City* and *Worth*.
- Excluded National Defense Reserve Fleet vessels (Ref. MarAd letter dated 5/24/84).
- Inventory attrition does not include operating attrition or losses due to casualties.

TABLE D-5

BARGE INVENTORY PROJECTION BY YEAR, 1983–1990
(MDWT)

Category I: Vessels Suitable for Lightering Only

	1983	1984	1985	1986	1987	1988	1989	1990
Beginning Inventory	537	537	537	520	520	520	520	520
Fleet Additions	–	–	–	–	–	–	–	–
Retirements	–	–	17	–	–	–	–	–
Year-End Balance	537	537	520	520	520	520	520	520

Category II: Vessels Suitable for Distribution Service Only

	1983	1984	1985	1986	1987	1988	1989	1990
Beginning Inventory								
Additions	(All suitable for distribution are assumed							
Retirements	also suitable for lightering)							
Year-End Inventory								

Category III: Vessels Suitable for Distribution and Lightering

	1983	1984	1985	1986	1987	1988	1989	1990
Beginning Inventory	1,109	1,109	1,109	1,109	1,309	1,509	1,709	1,709
Additions	–	–	–	200	200	200	–	–
Retirements	–	–	–	–	–	–	–	–
Year-End Inventory	1,109	1,109	1,109	1,309	1,509	1,709	1,709	1,709

Assumptions:

- Barges of less than 50,000 barrels are not suitable for lightering nor for distribution because of small size and dock utilization constraints.
- Most barges of 50,000–100,000 barrels will be suitable for lightering and distribution.
- Vessels are scrapped at age 25 years.
- Retirements are based on barge age only, since tugs can be replaced (except for ITBs).
- New buildings: Total of 10 vessels of 20,000 DWT each are delivered each year from 1986 to 1988. No new vessels delivered in any other year except those already on order.
- Any vessel on U.S. Atlantic or Gulf Coast is potentially available. Vessels on Pacific Coast are kept there because transit times encourage movement of only tankers to U.S. Gulf Coast, with barges continuing West Coast service. Panama transit not a factor. Interim outfitting for lightering does not constrain use of vessels. Hoses temporary fendering available.

TABLE D-6

AVAILABILITY OF CDS SHIPS

No.	Vessels	Total DWT	Available by end of: First Month	Second Month	Not Available
7	VLCC	1,774,419	5	2	–
8	Medium	711,396	6	2	–
10	Product Size	377,232	4	3	3

VLCCs *7 Vessels*
- Assume 5 are available within 30 days
- Assume remaining 2 are available during second 30 days (probably near Persian Gulf for SPR)

80–90s *8 Vessels*
- Assume 6 are available within 30 days
- Assume remaining 2 are available during second 30 days

35–40s *10 Vessels*
- Assume 4 are available within 30 days
- Assume 3 are available within second 30 days
- Assume 3 *not* available (usually due to Navy charters)

TABLE D-7

PADD III TO PADD I PRODUCT DISTRIBUTION BY TANKER AND BARGE
1983 BASE CASE AND 1990 NONDISRUPTED CASE

		Total (MB/D)	Percentage of Movements By Barge	By Barge (MB/D)	By Tanker (MB/D)
	1983 Base Case*				
80%	Florida	400	70%	280	120
	Other South Atlantic (North of Florida)	186	35%	65	121
20%	Mid-Atlantic/ New England	147	5%	7	140
	Total U.S. Gulf Coast– U.S. East Coast Movements	**733**		**352**	**381**
	1990 Nondisrupted Case*				
80%	Florida	400	85%	340	60
	Other South Atlantic (North of Florida)	238	45%	107	131
20%	Mid-Atlantic/ New England	159	10%	16	143
	Total U.S. Gulf Coast– U.S. East Coast Movements	**797**		**463**	**334**

*80 percent of 1983 PADD III to PADD I product movements to South Atlantic region; 20 percent to Mid-Atlantic and New England. Same break to be assumed for 1990, although potential exists for South Atlantic to increase its share; Florida to remain constant at 400 MB/D in 1990.

TABLE D-8

PADD III to PADD I PRODUCT DISTRIBUTION BY TANKER AND BARGE—1990 DISRUPTED CASE

	1990 Disrupted Case*	Total (MB/D)	Percentage of Movements By Barge	By Barge (MB/D)	By Tanker (MB/D)
80%	Florida	360	85%	306	54
	Other South Atlantic (North of Florida)	112	45%	50	62
20%	Mid-Atlantic/ New England	118	10%	12	106
	Total U.S. Gulf Coast– U.S. East Coast Movements	**590**		**368**	**222**

*80 percent of 1990 PADD III to PADD I product movements to South Atlantic region; 20 percent to Mid-Atlantic and New England; Florida at 360 MB/D to reflect demand reduction.

TABLE D-9

RESIDUAL FUEL OIL MOVEMENTS AMONG PADDs*
(MB/D)

	PADD					
	I	II	III	IV	V	VI/PR
1990 Nondisrupted Case	140	30	(40)	–	(30)	(100)
1990 Disrupted Case	670	(40)	(470)	–	(30)	(130)

*Shipments in brackets.

Current Tanker Fleet

Tables D-10 and D-11 list the fleet of unsubsidized and subsidized tankers, respectively, as of June 1984. The unsubsidized fleet consists of 160 vessels with a cumulative tonnage of 9,830,269 DWT. There were 25 vessels in the subsidized tanker fleet with a cumulative tonnage of 2,863,047 DWT.

TABLE D-10

UNSUBSIDIZED TANKER FLEET AS OF JUNE 1984

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
20,777	Suzanne	44	572	75	31	79.3	19,277	173,000	(1)
24,513	Scorpio	44(61)	605	75	33	85	23,013	204,000	(1)
25,088	Coastal Florida	44(68)	584	74	33	–	23,588	–	(1)
25,682	David D. Irwin	42(61)	631	75	34	90.5	24,182	219,000	(1)
25,728	Texaco Massachusetts	63	605	78	35	90.8	24,228	208,000	(1)
25,786	Texaco Georgia	64	605	78	35	90.8	24,286	208,000	(1)
25,930	Texaco Minnesota	43(64)	615	74	32	90.8	24,430	218,000	(1)
26,371	Cove Spirit	54	588	83	34	92	24,871	–	(2)
26,550	Texaco Maryland	63	605	78	35	90.8	25,050	208,000	(1)
26,550	Texaco Rhode Island	64	605	78	34	90.8	25,050	208,000	(1)
26,564	Texaco Montana	65	605	78	34	90.8	25,064	208,000	(1)
26,581	Texaco Mississippi	44(64)	615	74	33	90.8	25,081	218,000	(1)
26,912	Frio	45(62)	634	75	34	91.1	25.412	228,000	(2)
27,241	Exxon Galveston	78	523	95	39	111.3	25,741	195,000	(3)
27,600	Texas Trader	44(69)	634	74	33	92.9	26,100	232,000	(1)
27,615	American Trader	43(67)	634	74	33	92.9	26,115	232,000	(2)
27,770	Amoco Delaware	44(71)	634	74	33	78.5	26,270	237,000	(1)
28,583	Exxon Chester	52	628	83	34	94.4	27,083	225,000	(1)
28,642	Commanche	54	605	84	35	–	27,142	–	(1)
28,703	Pecos	50	628	83	34	98	27,203	233,000	(1)
28,808	Beaujolais (Ex. NY Getty)	54	628	83	34	98	27,308	225,000	(2)
30,369	Guadalupe	45(78)	684	74	33	–	28,869	223,000	(2)
30,590	Colorado	44(72)	675	74	32	–	29,090	261,000	(1)
30,806	Gulf Pride	59	645	84	35	105.8	29,306	250,000	(2)
30,806	Gulf Solar	59	645	84	35	105.8	29,306	250,000	(1)
30,806	Gulf Spray	60	645	84	35	105.8	29,306	250,000	(1)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
30,806	Gulf Supreme	61	645	84	35	105.8	29,306	250,000	(1)
30,806	Chablis (Ex. Gulf Oil)	60	645	84	35	105.8	29,306	250,000	(1)
30,806	Montrachet (Ex. Gulf Crest)	59	645	84	34	105.8	29,306	250,000	(1)
31,145	Mobil Fuel	57	645	84	35	105	29,645	–	(1)
31,816	Arco Endeavor	58	641	84	35	–	30,316	–	(3)
31,828	Western Sun	54	641	85	34	105	30,328	251,000	(4)
31,857	Dina	58	641	84	35	105.3	30,357	246,000	(3)
31,878	Cove Mariner	55	641	84	34	–	30,378	–	(4)
31,884	Medina (Ex. Del. Sun)	53	641	84	35	105	30,384	246,000	(1)
31,905	Mobil Aero	59	641	84	36	105	30,405	254,000	(1)
31,991	Cove Navigator	51	660	85	36	106.8	30,491	253,000	(1)
32,741	Concho	45(70)	619	84	32	101	31,241	280,000	(2)
34,090	Philadelphia Sun	81	612	90	33	110	32,590	–	(5)
34,124	Pennsylvania Trader	62	670	83	36	108.8	32,624	269,000	(3)
34,400	New York Sun	80	612	90	37	110	32,900	–	(5)
34,723	Gulf King	57	661	90	36	116.2	33,223	275,000	(1)
34,723	Gulf Knight	58	661	90	34	116.2	33,223	275,000	(1)
34,723	Tropic Sun	57	661	90	36	115.5	33,223	–	(3)
34,770	Texaco Wisconsin	58	661	90	36	115.4	33,270	264,000	(1)
34,780	St. Emillion (Ex. Banner)	56	661	90	35	116.2	33,280	267,000	(1)
34,930	Neches	58	661	90	36	116.3	33,430	–	(1)
34,975	Cove Sailor	59	661	90	36	–	33,475	281,000	(3)
35,079	Mission Santa Clara	57	661	90	36	116	33,579	–	(3)
36,958	Martha Ingram (Integrated Tug Barge)	71	620	87	36	111	35,458	270,000	(1)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
37,034	Carole Ingram (Integrated Tug Barge)	72	631	87	36	110	35,534	294,000	(1)
37,276	Eclipse	71	672	89	36	116.3	35,776	303,000	(1)
37,276	Falcon Princess	72	672	89	36	116.3	35,776	303,000	(1)
37,807	Ogden Charger	69	660	90	37	117	36,307	328,000	(3)
37,807	Ogden Leader	69	660	90	37	117	36,307	328,000	(3)
37,814	Overseas Valdez	68	660	90	37	117	36,314	328,000	(1)
37,814	Overseas Vivian	69	660	90	37	117	36,314	328,000	(1)
37,814	Overseas Alice	68	660	90	37	117	36,314	328,000	(1)
37,853	Ogden Willamette	69	660	90	37	117	36,353	297,000	(3)
37,853	Ogden Champion	69	660	90	37	117	36,353	334,000	(3)
37,853	Ogden Wabash	69	660	90	37	117	36,353	297,000	(3)
37,884	Valley Forge	69	660	90	37	117	36,384	328,000	(1)
38,238	Spirit of Liberty	68	660	90	37	117	36,738	328,000	(1)
39,060	Texaco California	54(73)	712	90	38	126	37,560	359,000	(1)
39,289	Chevron Arizona	77	650	96	34	129	37,789	270,000	(4)
39,304	Chevron Colorado	76	650	96	37	129	37,804	270,000	(4)
39,363	Chilbar	59(81)	666	102	37	126	37,863	298,000	(2)
39,366	Charleston	56(80)	645	102	36	–	37,866	–	(3)
39,366	Texaco Connecticut	53(71)	712	90	38	126	37,866	359,000	(4)
39,368	Washington Trader	59	712	93	38	118	37,868	336,000	(4)
39,373	Texaco New York	53(72)	712	90	38	126	37,873	359,000	(1)
39,374	Fredericksburg	58(81)	627	84	34	121	37,874	311,000	(3)
39,789	Chevron Louisiana	77	650	96	37	129	38,289	270,000	(4)
39,789	Chevron Oregon	75	651	96	37	129	38,289	269,000	(4)
39,789	Chevron Washington	76	650	96	37	129	38,289	269,000	(4)
39,838	Overseas Aleutian	53(71)	675	90	38	120	38,338	–	(1)

Subtotal (20,000–39,999 DWT): 2,512,500 DWT (76 ships)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
40,631	Exxon Washington	57	715	93	39	126	37,800	–	(5)
40,642	Exxon Lexington	58	715	93	39	126	37,811	–	(5)
40,872	Exxon Jamestown	57	715	93	39	126	38,041	–	(5)
41,320	Seabulk Challenger (Integrated Tug Barge)	75	581	95	37	125	39,280	–	(2)
41,948	Texaco Florida	56(71)	712	90	38	126	40,448	–	(3)
42,595	Coast Range	81	658	100	36	130	41,095	–	(4)
42,595	Blue Ridge	81	658	100	37	132	41,095	–	(4)
42,595	Sierra Madre	82	658	100	36	130	41,095	–	(4)
42,595	Eileen Ingram	82	658	100	39	121.6	41,095	–	(4)
42,595	Hunter Armistead	83	658	100	39	121.6	41,095	–	(4)
47,075	Jacksonville (Integrated Tug Barge)	82	691	95	41	133.5	40,961	372,000	(4)
47,075	Groton (Integrated Tug Barge)	82	691	95	41	133.5	40,961	372,000	(4)
47,075	New York (Integrated Tug Barge)	83	691	95	41	133.5	40,961	372,000	(4)
47,075	Baltimore (Integrated Tug Barge)	83	691	95	41	133.5	40,961	372,000	(4)
49,430	Mt. Vernon Victory	61	740	102	40	144	44,681	–	(5)
49,298	Mobil Meridian	61	736	102	40	143	46,082	–	(6)
49,339	Cove Trader	59	736	102	40	142	44,635	–	(5)
49,395	Mount Washington	63	737	102	39	144	46,374	–	(5)
50,852	Ogden Dynachem	81	629	106	38	137	48,852	–	(4)
50,011	Potomac Trader	83	658	106	39	–	–	–	(5)
50,023	Chesapeake	64	658	106	39	144	46,502	–	(1)
50,035	Delaware Trader	82	658	106	39	–	–	–	(5)
50,063	Petersburg	63	736	102	40	144	44,814	–	(6)
50,116	Chesapeake Trader	82	658	106	39	–	–	–	(5)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
50,136	Montpelier Victory	62	737	102	40	144	44,887	–	(5)
50,852	Ogden Hudson	82	629	106	38	137	48,852	–	(5)
51,196	Exxon Baltimore	60	740	102	40	150.6	45,798	–	(5)
51,196	Exxon Boston	60	740	102	40	150.6	45,798	–	(5)
53,288	Arco Heritage	63	745	102	41	150.8	46,076	–	(5)
53,453	Texas Sun	60	745	102	41	150	46,269	–	(5)
53,463	Pennsylvania Sun	59	745	102	41	150	46,279	–	(5)
57,884	Baltimore Trader	55(71)	800	102	40	159.1	52,295	–	(5)
62,005	Overseas Alaska	70	731	105	43	159	50,694	–	(4)
62,005	Overseas Arctic	71	731	105	43	159	50,694	–	(4)
62,115	Golden Gate	70	731	105	43	158.9	50,809	–	(4)
65,000	Exxon Baytown	84	779.6	106	–	–	–	–	(4)
68,894	Overseas Natalie	61	860	104	46	181.2	49,347	–	(4)
69,306	Cove Liberty	54(74)	826	106	43	170	56,942	–	(5)

Subtotal (40,000–69,999 DWT): 1,916,003 DWT (38 ships)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Air Draft (Feet)	Vessel Description
70,213	Chevron Mississippi	72	810	105	44	178.8	56,204	–	(4)
70,213	Chevron California	72	810	105	44	178.8	56,204	–	(4)
70,378	Arco Sag River	72	810	105	43	179	58,503	–	(5)
70,459	Sansinena II	71	810	105	44	179	56,436	–	(6)
70,459	Arco Prudhoe Bay	71	810	105	44	179	55,829	–	(5)
71,054	Cove Leader	59	822	104	47	167.5	51,205	–	(6)
71,508	Exxon New Orleans	65	800	116	42	184.2	–	–	(4)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Air Draft (Feet)	Vessel Description
71,540	Exxon Houston	64	800	116	42	184.2	–	–	(4)
75,649	Exxon Baton Rouge	70	810	125	41	201.2	–	–	(6)
75,649	Exxon Philadelphia	70	810	125	41	201.2	–	–	(4)
75,649	Exxon San Francisco	69	810	125	41	201.2	–	–	(6)
80,569	Sohio Resolute	71	811	125	44	202	–	–	(4)
80,735	America Sun	70	818	125	44	202	–	125	(5)
80,739	Glacier Bay	70	811	125	43	202	–	–	(3)
80,773	Sohio Intrepid	71	811	125	44	202	–	–	(3)
81,000	Adonnis	66(83)	822	124	42	–	–	–	(6)
81,116	Ogden Yukon	73	811	125	44	202	–	–	(6)
87,506	Point Vail	(81)	806	120	47	194	–	–	(5)
89,590	Arco Texas	(81)	899	105	48	195	64,580	–	(5)
90,393	Overseas New York	77	894	106	49	195.4	62,991	153	(5)
90,515	Overseas Washington	78	894	106	49	195.4	63,113	153	(5)
90,564	Overseas Ohio	77	894	106	49	195.4	63,162	153	(5)
90,637	Overseas Chicago	77	894	106	49	195.4	63,235	153	(5)
Subtotal (70,000–99,999 DWT): 1,816,908 DWT (23 ships)									
113,800	Manhattan	62	1,006	132	53	289	–	–	(6)
120,478	Overseas Juneau	73	883	138	52	253.9	–	–	(5)
120,585	Arco Anchorage	73	883	138	52	253.9	–	148	(5)
120,585	Arco Fairbanks	74	883	138	52	253.9	–	148	(5)
120,585	Arco Juneau	74	883	138	52	253.9	–	148	(5)
121,739	Overseas Boston	80	855	133	55	–	–	–	(5)
122,805	Tonsina	78	869	136	55	–	–	–	(5)
122,850	Kenai	78	869	136	55	244.4	–	172	(5)

*Tons per inch immersion.

TABLE D-10 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Air Draft (Feet)	Vessel Description
123,997	Prince William Sound	75	869	136	55	209.1	–	–	(6)
124,468	Mobil Arctic	72	930	132	55	251.3	–	153	(5)
136,156	Ogden Columbia	(83)	889	145	56	–	–	–	(5)
172,775	Exxon North Slope	78	906	173	57	317	–	157	(5)
172,775	Exxon Benicia	79	906	173	57	317	–	157	(5)
173,380	Atigun Pass	77	906	173	55	317.2	–	179	(5)
173,380	Keystone Canyon	78	906	173	57	317.2	–	179	(5)
173,619	Brooks Range	78	906	173	57	317.2	–	–	(5)
173,619	Thompson Pass	78	906	173	57	317.2	–	–	(5)
182,204	B. T. Alaska	78	953	166	59	334	–	–	(5)
188,500	B. T. San Diego	78	953	166	59	334	–	–	(5)
188,500	Arco Alaska	79	953	166	55	330.8	–	148	(5)
188,500	Arco California	80	926	166	59	330.8	–	148	(5)

Subtotal (100,000–199,999 DWT): 3,135,300 (21 ships)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Vessel Description
224,428	Bay Ridge-PD Back CDS	78	1,070	144	70	–	(6)
225,100	Stuyvesant-PD Back CDS	74	1,098	144	70	333	(6)

Subtotal (200,000–299,999 DWT): 449,528 DWT (2 ships)

*Tons per inch immersion.

TABLE D-10 (Continued)

UNSUBSIDIZED TANKER FLEET SUMMARY

Category	Number of Ships	DWT
20,000- 39,999 DWT	76	2,512,500
40,000- 69,999 DWT	38	1,916,003
70,000- 99,999 DWT	23	1,816,908
100,000-199,999 DWT	21	3,135,300
200,000-299,999 DWT	2	449,528
Grand Total	**160**	**9,830,269**

VESSEL DESCRIPTION

(1): Vessel not fitted with inert gas system (IGS); no crude oil wash (COW); no segregated ballast tanks (SBT).
(2): No IGS; no COW; does have SBT.
(3): IGS in place; no COW; no SBT.
(4): IGS in place; no COW; does have SBT.
(5): IGS in place; COW in place; does have SBT.
(6): IGS in place; COW in place; no SBT.

TABLE D-11

SUBSIDIZED TANKER FLEET AS OF JUNE 1984

Vessel Size (DWT)	Vessel Name	Year Built	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Vessel Size (Barrels)	Vessel Description
35,100	Patriot	76	711.25	84.0	34.5	117.8	33,600	308,000	(1)
35,100	Ranger	76	711.25	84.0	34.5	117.8	33,600	308,000	(1)
35,100	Courier	77	711.25	84.0	34.5	117.8	33,600	308,000	(1)
35,100	Rover	77	711.25	84.0	34.5	117.8	33,600	308,000	(1)
39,232	Mormacstar	75	689	90	35	123.3	37,732	286,000	(3)
39,232	Mormacsun	76	689	90	35	123.3	37,732	286,000	(3)
39,232	Mormacsky	77	689	90	35	123.3	37,732	286,000	(3)
39,712	Coronado	73	689	90	35	123.2	38,212	270,000	(6)
39,712	Cherry Valley	74	689	90	35	123.2	38,212	270,000	(6)
39,712	Chelsea	75	689	90	35	123.2	38,212	270,000	(6)

Subtotal (30,000–39,999 DWT): 377,232 DWT (10 ships)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Air Draft (Feet)	Vessel Description
82,199	Ultramar	73	892.5	106	45.87	193	62,366	160	(5)
82,199	Ultrasea	74	892.5	106	45.87	193	62,366	160	(5)
89,700	Golden Endeavor	74	892	106	49	195.3	62,319	–	(5)
90,000	Golden Monarch	75	894	106	49	195.3	62,319	–	(5)
91,800	Chestnut Hill	76	894	106	49	195.4	64,406	134	(6)
91,800	Kittanning	77	894	106	49	195.3	64,419	134	(6)
91,849	American Heritage	76	894	106	49	195.4	64,455	–	(5)
91,849	Beaver State	76	894	106	49	195.9	64,390	–	(6)

Subtotal (80,000–99,999 DWT): 711,396 DWT (8 ships)

*Tons per inch immersion.

TABLE D-11 (Continued)

Vessel Size (DWT)	Vessel Name	Year Built (Rebuilt)	Length (Feet)	Beam (Feet)	Draft (Feet)	TPI*	Canal Cargo Capacity (DWT)	Air Draft (Feet)	Vessel Description
226,100	Brooklyn	74	1,094	144	70	333	–	118	(6)
226,100	Williamsburg	74	1,095	144	70	333	–	118	(6)
264,073	Massachusetts	75	1,100	178	67	–	–	–	(6)
264,073	New York	76	1,100	178	67	–	–	–	(6)
264,073	Maryland	76	1,100	178	67	–	–	–	(6)
265,000	Arco Spirit	77	1,100	178	67	–	–	–	(5)
265,000	Arco Independence	76	1,100	178	67	–	–	–	(5)

Subtotal (200,000–299,999 DWT): 1,774,419 DWT (7 ships)

SUBSIDIZED TANKER FLEET SUMMARY

Category	Number of Ships	DWT
30,000– 39,999 DWT	10	377,232
80,000– 99,999 DWT	8	711,396
200,000–299,999 DWT	7	1,774,419
Grand Total	**25**	**2,863,047**

VESSEL DESCRIPTION

(1): Vessel not fitted with inert gas system (IGS); no crude oil wash (COW); no segregated ballast tanks (SBT).
(2): No IGS, no COW; does have SBT.
(3): IGS in place; no COW; no SBT.
(4): IGS in place; no COW; does have SBT.
(5): IGS in place; COW in place; does have SBT.
(6): IGS in place; COW in place; no SBT.

*Tons per inch immersion.

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MINORITY REPORT BY PACIFIC RESOURCES, INC., (PRI) REGARDING JONES ACT WAIVERS IN THE EVENT OF A SUPPLY DISRUPTION

With the exception of one problem area, this report should improve a great deal the operations of our Strategic Petroleum Reserve (SPR). It should also increase general public appreciation of the important and unique role the SPR will play in the event of a national supply disruption.

We are unable to concur, however, in that portion of the report which indicates that an immediate blanket waiver of the Jones Act is unnecessary in the event of a supply disruption. As the largest fuel supplier to Hawaii, PRI has had experience in seeking rare Jones Act waivers, and we are far from confident that a case-by-case waiver procedure will permit anyone to obtain necessary transportation services during a crisis. The lack of an immediate blanket waiver could mean that PRI and other independent refiners not owning Jones Act tankers may be unable to make timely bids for SPR crude because of the uncertainty of a waiver and the unavailability of Jones Act vessels at reasonable rates.

Jones Act tankers are scarce. Page 3-61 of the report* states as much: "In the first half of 1984, a total of 84 tankers over 40,000 DWT were employed in the distribution of domestic crude oil. Of these, 50 were owned by oil companies and 23 independently-owned tankers operated on term charters to oil companies for periods of one or more years. Only 11 tankers, or 13%, were in the spot market." In short, most Jones Act tankers are controlled by large, integrated oil companies and only 11 tankers would be potentially available for use by PRI and other independent refiners.

The President may not order drawdown and distribution of the SPR unless he finds that the action is necessary because of a severe energy supply disruption which, among other requirements, "is or is likely to be, of significant scope and duration, and of an emergency nature." In circumstances which would meet this definition, it is

*Page 92 of this final report.

impossible for us to believe that we and other independent refiners will be able to obtain Jones Act shipping necessary to transport SPR crude. Such an emergency would render meaningless predictions of tanker availability based upon today's adverse tanker industry economics. When that crisis occurs, and predictions go awry, as they will, we do not want the government to cite this study's findings in refusing to implement a blanket Jones Act waiver.

We reject the argument that a blanket waiver could lead to court challenges and prevent efficient tanker utilization during a crisis. Presidential decisions made in the face of emergency conditions are traditionally given wide latitude by the courts, and the decision for a blanket waiver if an emergency occurs would rest with the President. Legal questions will arise regardless of whether a blanket waiver is provided or not; they are likely to be resolved, however, after the crisis has passed and transportation pursuant to the blanket waiver has occurred. PRI and other independent refiners without Jones Act ships will look forward to joining the Administration in supporting the justification for the blanket waiver after the supply emergency has passed.

When the Department of Energy published its regulations governing the SPR's Standard Sales Provisions (SSPs) on January 20, 1984, the Supplementary Information described in some detail the matter of Jones Act waiver requirements, and left open the question of blanket waiver, stating "the potential seriousness of the problem is recognized." (Federal Register, Janaury 20, 1984, p. 2696). The President's Comprehensive Energy Emergency Response Procedures report to Congress on December 31, 1982 and the DIREX-B Assessment team also seem to contemplate a need for a Jones Act blanket waiver.

The SSP regulations point out the importance of this question to independent refiners who rely on marine access to the SPR: "The issue will arise at the time of solicitation of offers to buy SPR oil, because it bears upon the ability to submit such an offer (putting at risk first the offer guarantee and subsequently the payment and performance guarantee) depending on whether the offeror has access to a U.S. flag vessel." Thus, the availability of a blanket waiver may determine whether PRI and other independent refiners are able to bid for SPR supplies. The significant geographic isolation of Hawaii from the SPR will undoubtedly cause substantial difficulties even if a blanket waiver is secured. If the report leads to abandonment of public and government support for a blanket waiver, however, Hawaii may be unable to use the reserve at all.

We appreciate Committee and staff efforts to alter original draft language in an attempt to meet some of our objections. The final product, however, is not responsive, and the issue is of vital importance. It is not enough to state that "Jones Act waivers, if necessary, should be expeditiously handled on a case-by-case basis" and to add as an afterthought that "MarAd should develop, and have available to it, a standby blanket waiver procedure for foreign flag vessels, for use in the event that the case-by-case waiver process results in delays in SPR distribution..." By that time, PRI and our largest customers, Hawaiian oil consumers and the Department of Defense, will be out of luck -- and oil. If an emergency occurs, we will need an automatic Jones Act blanket waiver to meet their requirements.

Appendix E
Refinery Operations

This appendix presents the base data that were utilized in the refinery analyses. The 13 U.S. refining areas developed by the NPC for this study are presented on pages E-2 through E-13 and list each refinery in an area and its operable and operating capacity. Pages E-14 through E-17 present refinery process facilities projected, by the industry, to be in place by January 1, 1984 and 1985. Crude oil import data are presented on pages E-18 through E-32 and list, by refining area, the quantity of crude oil imports by country, average sulfur, and average gravity. Pages E-33 through E-54 present data on refinery inputs, product slates, and refinery process facilities for 1982 and 1983.

NPC REFINING AREAS
BY REFINERY

REFINING AREA NO. 1
PADD I
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
0	68,000	68,000	Amerada Hess Corp.	Sewaren Refinery	Port Reading	NJ
125,000	0	125,000	Atlantic Richfield Co.	Philadelphia Refinery	Philadelphia	PA
41,850	0	41,850	Cibro Pet. Prod. Inc.	Albany Refinery	Albany	NY
140,000	0	140,000	Getty Refg & Mrktg Co.	Delaware Refinery	Delaware City	DE
174,100	0	174,100	Gulf Oil Corp.	Philadelphia Refinery	Philadelphia	PA
99,700	0	99,700	Mobil Oil Corp.	Paulsboro Refinery	Paulsboro	NJ
80,000	88,000	168,000	Chevron U.S.A. Inc.	Perth Amboy Refinery	Perth Amboy	NJ
14,200	0	14,200	Chevron U.S.A. Inc.	Baltimore Refinery	Baltimore	MD
24,000	0	24,000	Amoco Oil Co.	Savannah Refinery	Savannah	GA
53,000	0	53,000	Amoco Oil Co.	Yorktown Refinery	Yorktown	VA
100,000	0	100,000	Exxon Company U.S.A.	Bayway Refinery	Linden	NJ
168,000	0	168,000	BP Oil Inc.	Marcus Hook Refinery	Marcus Hook	PA
44,400	0	44,400	Seaview Petroleum Co.	Paulsboro Refinery	Paulsboro	NJ
155,000	0	155,000	Sun Company Inc.	Marcus Hook Refinery	Marcus Hook	PA
90,000	0	90,000	Texaco Inc.	Eagle Point Refinery	Westville	NJ

REFINING AREA NO. 2
U.S VIRGIN ISLANDS AND PUERTO RICO
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
515,000	0	515,000	Amerada Hess Corp.	Novic Refinery	St. Croix	VI
0	123,495	123,495	Commonwealth Oil Ref. Co.	Ponce Refinery	Ponce	PR
24,500	11,500	36,000	Gulf Oil Corp.	Bayamon Refinery	San Juan	PR
0	0	0	Phillips P R Core Inc.	Rafael Durand-Stanley	Guyama	PR
85,000	0	85,000	Sun Company Inc.	Puerto Rico Refinery	Yabucoa	PR

REFINING AREA NO. 3
PADD I
(NOT CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
6,800	0	6,800	Ashland Oil Inc.	Freedom Refinery	Freedom	PA
3,000	0	3,000	G.N.C. Energy Corp.	Greensboro Facility	Greensboro	NC
0	200	200	American Ref. Group Inc.	Indianola Facility	Indianola	PA
15,700	0	15,700	Pennzoil Company Inc.	Rouseville Refinery	Oil City	PA
0	0	0	Quaker St. Oil Refg. Corp.	Emlenton Refinery	Emlenton	PA
6,700	0	6,700	Quaker St. Oil Refg. Corp.	Mckean Refinery	Smethport	PA
4,500	0	4,500	Quaker St. Oil Refg. Corp.	Ohio Valley Refinery	St. Marys	WV
9,515	0	9,515	Quaker St. Oil Refg. Corp.	Congo Refinery	Newell	WV
6,841	0	6,841	Witco Chemical Corp.	Bradford Petroleum Div.	Bradford	PA
2,700	0	2,700	Young Refining Corp.	Douglasville Refinery	Douglasville	GA

REFINING AREA NO. 4
PADD II
(CAPLINE CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
47,500	0	47,500	Clark Oil & Refg. Corp.	Wood River Refinery	Hartford	IL
57,000	0	57,000	Clark Oil & Refg. Corp.	Blue Island Refinery	Blue Island	IL
189,150	24,250	213,400	Ashland Oil, Inc.	Catellettsburg Refinery	Catellettsburg	KY
0	64,000	64,000	Ashland Oil, Inc.	Buffalo Refinery	Tonawanda	NY
66,000	0	66,000	Ashland Oil, Inc.	Canton Refinery	Canton	OH
0	20,400	20,400	Ashland Oil, Inc.	Findlay Refinery	Findlay	OH
25,200	0	25,200	Ashland Oil, Inc.	Louisville Refinery	Louisville	KY
67,143	0	67,143	Ashland Oil, Inc.	St. Paul Park Refinery	St. Paul	MN
12,900	0	12,900	Gladieux Refining Inc.	Fort Wayne Refinery	Fort Wayne	IN
21,200	0	21,200	Indiana Frm Br Coop Assn	Mt. Vernon Refinery	Mt. Vernon	IN
133,000	0	133,000	Koch Industries	Pine Bend Refinery	Rosemount	MN
2,700	0	2,700	Lakeside Refining Co.	Kalamazoo Refinery	Kalamazoo	MI
3,000	0	3,000	Crystal Refining Co.	Carson City Refinery	Carson City	MI
7,900	0	7,900	Laketon Asphalt Ref. Co.	Laketon Refinery	Laketon	IN
120,000	75,000	95,000	Marathon Oil Co.	Robinson Refinery	Robinson	IL
68,500	0	68,500	Marathon Oil Co.	Detroit Refinery	Detroit	MI
180,000	0	180,000	Mobil Oil Corp.	Joliet Refinery	Joliet	IL
39,000	0	39,000	Murphy Oil Corp.	Superior Refinery	Superior	WI
43,200	0	43,200	Rock Island Ref. Corp.	Indianapolis Refinery	Indianapolis	IN
283,000	0	283,000	Shell Oil Co.	Wood River Refinery	Wood River	IL
376,000	0	376,000	Amoco Oil Co.	Whiting Refinery	Whiting	IN
168,000	0	168,000	Standard Oil Co. of Ohio	Lima Refinery	Lima	OH
80,000	40,000	120,000	Standard Oil Co. of Ohio	Toledo Refinery	Toledo	OH
118,000	0	118,000	Sun Company Inc.	Toledo Refinery	Toledo	OH
54,000	30,000	84,000	Texaco Inc.	Lawrenceville Refinery	Lawrenceville	IL
40,000	0	40,000	Total Petroleum Inc.	Alma Refinery	Alma	MI
151,000	0	151,000	Union Oil Co. of CA	Chicago Refinery	Lemont	IL
60,000	0	60,000	Coral Petroleum Inc.	Warren Refinery	Warren	PA

REFINING AREA NO. 5
PADD II
(NOT CONNECTED, FORMERLY SEAWAY OR TEXOMA CONNECTED)

Operating	Idle	Total Operable	Corporation	Name	City	State
27,982	0	27,982	Derby Refining Co.	N. Wichita Refinery	N. Wichita	KS
118,500	15,500	134,000	Conoco	Ponca City Refinery	Ponca City	OK
56,500	0	56,500	Farmland Industries Inc.	Coffeyville Refinery	Coffeyville	KS
80,577	0	80,577	Getty Refg. & Mrktg. Co.	El Dorado Refinery	El Dorado	KS
0	0	19,000	Hudson Refining Co.	Cushing Refinery	Cushing	OK
31,200	18,800	50,000	Mobil Oil Corp.	Augusta Refinery	Augusta	KS
54,000	0	54,000	Natl. Corp. Refg. Assn.	McPherson Refinery	McPherson	KS
33,250	0	33,250	Pester Refining	El Dorado Refinery	El Dorado	KS
85,000	0	85,000	Sun Company Inc.	Tulsa Refinery	Tulsa	OK
42,500	0	42,500	Total Petroleum Inc.	Arkansas City Refinery	Arkansas City	KS
7,500	0	7,500	Allied Materials Corp.	Stroud Refinery	Stroud	OK
0	26,400	26,400	Farmland Industries Inc.	Phillipsburg Refinery	Phillipsburg	KS
0	600	600	Kentucky Oil & Refg. Co.	Betsy Lane Refinery	Betsy Lane	KY
0	1,000	1,000	Kentucky Oil & Refg. Co.	Plant #2 Troy Div.	Troy	IN
1,000	0	1,000	Moreco Energy Inc.	McCook Refinery	McCook	IL
9,200	0	9,200	Oklahoma Refining Co.	Cyril Refinery	Cyril	OK
9,800	0	9,800	Oklahoma Refining Co.	Custer Refinery	Thomas	OK
5,500	0	5,500	Somerset Refinery, Inc.	Somerset Refinery	Somerset	KY
56,000	0	56,000	Amoco Oil Co.	Mandan Refinery	Mandan	ND
12,000	0	12,000	Tonkawa Refg. Co.	Arnett Refinery	Arnett	OK
53,800	0	53,800	Union Pacific Corp.	Enid Refinery	Enid	OK
26,500	0	26,500	Dorchester Gas Corp.	Mt. Pleasant Refinery	Mt. Pleasant	TX
43,700	0	43,700	Gulf Oil Corp.	Cincinnati Refinery	Cleves	OH
45,000	0	43,000	Kerr-McGee Corp.	Wynnewood Refinery	Wynnewood	OK
45,000	31,500	76,500	Atlas Processing Co.	Shreveport Refinery	Shreveport	LA
18,100	0	18,100	South Hampton Co.	Silsbee Refinery	Silsbee	TX
46,000	0	46,000	La Gloria Oil & Gas Co.	Tyler Refinery	Tyler	TX
47,000	0	47,000	Tosco Corp.	Duncan Refinery	Duncan	OK
38,500	8,500	47,000	Tosco Corp.	El Dorado Refinery	El Dorado	AR
49,500	12,500	62,000	Total Petroleum	Ardmore Refinery	Ardmore	OK

REFINING AREA NO. 6
MISSISSIPPI RIVER REFINERIES
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
255,000	0	255,000	Marathon Oil Co.	Garyville Refinery	Garyville	LA
140,000	0	140,000	Texaco Inc.	Convent Refinery	St. James Parish	LA
0	0	0	Clark Oil & Refg. Corp.	Mt. Airy Refinery	Mt. Airy	LA
49,500	0	49,500	Delta Refining Co.	Memphis Refinery	Memphis	TN
0	7,900	7,900	Vicksburg Refining Inc.	Vicksburg Refinery	Vicksburg	MS
199,100	0	199,100	Gulf Oil Corp.	Alliance Refinery	Belle Chasse	LA
0	19,300	19,300	McTan Refining Corp.	St. James Refinery	St. James	LA
0	300,000	300,000	GHR Energy Corp.	GoodHope Refinery	GoodHope	LA
20,000	0	20,000	Texas Napco	St. James Refinery	St. James	LA
0	28,356	28,356	International Processors	St. Rose Refinery	St. Rose	LA
0	20,600	20,600	Ergon Refining Inc.	Vicksburg Refinery	Vicksburg	MS
90,200	0	90,200	Murphy Oil Corp.	Meraux Refinery	Meraux	LA
218,200	0	218,200	Shell Oil Co.	Norco Refinery	Norco	LA
114,000	0	114,000	Tenneco Oil Co.	Chalmette Refinery	Chalmette	LA
45,000	0	45,000	Placid Refining Co.	Port Allen Refinery	Port Allen	LA
419,000	36,000	455,000	Exxon Company U.S.A.	Baton Rouge Refinery	Baton Rouge	LA
26,600	0	26,600	Mobile Bay Refg. Co.	Chickasaw Refinery	Chickasaw	AL
80,000	0	80,000	LA Land And Exploration	Mobile Refinery	Saraland	AL
25,000	0	25,000	Marion Corp.	Theodore Refinery	Theodore	AL
280,000	0	280,000	Chevron U.S.A. Inc.	Pascagoula Refinery	Pascagoula	MS

REFINING AREA NO. 7
LAKE CHARLES REFINERIES
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
14,000	0	14,000	CPL Oil & Refining Inc.	Lake Charles Refinery	Lake Charles	LA
297,000	23,000	320,000	Cities Service Co.	Lake Charles Refinery	Lake Charles	LA
156,500	0	156,500	Conoco	Lake Charles Refinery	West Lake	LA
7,400	0	7,400	Mallard Resources	Gueydan Refinery	Gueydan	LA
46,000	11,400	57,400	Hill Petroleum Co.	Krotz Springs Refinery	Krotz Springs	LA
11,000	0	11,000	Celeron Oil & Gas	Mermentau Refinery	Mermentau	LA

REFINING AREA NO. 8
BEAUMONT-PORT ARTHUR-PORT NECHES REFINERIES
(PIPELINE/WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
90,000	0	90,000	Am. Petrofina Co. of TX	Port Arthur Refinery	Port Arthur	TX
268,400	144,300	412,700	Gulf Oil Corp.	Port Arthur Refinery	Port Arthur	TX
0	50,000	50,000	Independent Refining Corp.	Winnie Refinery	Winnie	TX
0	30,000	30,000	Erickson Refining Corp.	Port Neches Refinery	Port Neches	TX
277,400	57,600	335,000	Mobil Oil Corp.	Beaumont Refinery	Beaumont	TX
242,000	160,000	402,000	Texaco Inc.	Port Arthur Refinery	Port Arthur	TX
31,000	160,000	31,000	Texaco Inc.	Port Neches Refinery	Port Neches	TX
120,000	0	120,000	Union Oil Co. of CA	Beaumont Refinery	Nederland	TX

REFINING AREA NO. 9
HOUSTON-TEXAS CITY REFINERIES
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
119,600	0	119,600	Texas City Refining Inc.	Texas City Refinery	Texas City	TX
232,000	0	232,000	Atlantic Richfield Co.	Houston Refinery	Houston	TX
65,000	0	65,000	Charter International Oil Co.	Houston Refinery	Houston	TX
100,000	0	100,000	Crown Central Petr. Corp.	Pasadena Refinery	Houston	TX
3,250	0	3,250	Eddy Refining Co.	Houston Refinery	Houston	TX
0	2,000	2,000	Petromax	Houston Facility	Houston	TX
49,000	20,500	69,500	Marathon Oil Co.	Texas City Refinery	Texas City	TX
0	12,300	12,300	Petraco-Valley Oil & Ref.	Houston Refinery	Houston	TX
285,000	0	285,000	Shell Oil Co.	Deer Park Refinery	Deer Park	TX
415,000	0	415,000	Amoco Oil Co.	Texas City Refinery	Texas City	TX
427,000	67,000	494,000	Exxon Corp.	Exxon Refinery	Baytown	TX
175,000	0	175,000	Phillips Petroleum Co.	Sweeny Refinery	Sweeny	TX

REFINING AREA NO. 10
CORPUS CHRISTI REFINERIES
(WATER CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
110,400	18,400	128,800	Coastal States Petrochem	Corpus Christi Refinery	Corpus Christi	TX
105,400	0	105,000	Gulf States Oil & Refg. (Koch)	Corpus Christi Refinery	Corpus Christi	TX
63,000	41,000	104,000	Southwestern Refg. Co. Inc. (Kerr McGee)	Corpus Christi Refinery	Corpus Christi	TX
30,000	0	30,000	Union Refining	Ingelside Refinery	Ingelside	TX
0	19,320	19,320	Saber Refining Co.	Corpus Christi Refinery	Corpus Christi	TX
155,000	15,000	170,000	Champlin Petroleum Co.	Corpus Christi Refinery	Corpus Christi	TX
33,300	0	33,300	Quintana Petrochemical	Corpus Christi Refinery	Corpus Christi	TX

REFINING AREA NO. 11
PADD III
(NOT CONNECTED TO SPR OR FORMERLY SEAWAY CONNECTED)

Operating	Idle	Total Operable	Corporation	Name	City	State
71,100	0	71,100	Diamond Shamrock Corp.	McKee Refinery	Sunray	TX
95,000	0	95,000	Phillips Petroleum Co.	Borger Refinery	Borger	TX
20,000	0	20,000	Texaco Inc.	Amarillo Refinery	Amarillo	TX
29,000	0	29,000	Amerada Hess Corp.	Purvis Refinery	Purvis	MS
60,000	0	60,000	Am. Petrofina Co. of TX	Big Spring Refinery	Big Spring	TX
8,000	0	8,000	Canal Refining Co.	Church Point Refinery	Church Point	LA
3,200	1,200	4,400	Calumet Refining Co.	Princeton Refinery	Princeton	LA
6,500	0	6,500	Claiborne Gasoline Co.	Lisbon Refinery	Lisbon	LA
3,000	0	3,000	B-T Energy Corp.	Louisville Refinery	Louisville	KY
3,200	0	3,200	Crystal Oil Co.	Stephens Refinery	Stephens	AR
0	0	0	Dorchester Gas Corp.	Cargray Refinery	White Deer	TX
1,500	5,000	6,500	Conoco	Acadia Gasoline Plant	Egan	LA
33,274	0	33,274	Monsanto-Conoco	Texas City Refinery	Alvin	TX
1,500	0	1,500	Flint Ink Corp.	San Antonio Refinery	San Antonto	TX
28,500	0	28,500	Navajo Refining Co.	Artesia Refinery	Artesia	NM
9,900	0	9,900	Howell Hydrocarbons Inc.	San Antonio Refinery	San Antonio	TX
18,000	0	18,000	Giant Industries Inc.	Ciniza Refinery	Gallup	NM
33,500	0	33,500	Hunt Oil Co.	Tuscaloosa Refinery	Tuscaloosa	AL
7,800	0	7,800	Kerr-McGee Corp.	Dubach Refinery	Dubach	LA
7,800	0	7,800	Cotton Valley Solvents	Cotton Valley Refinery	Cotton Valley	LA
4,600	1,280	5,880	MacMillian Ring-Free Oil	Norphlet Refinery	Norphlet	AR
10,000	0	10,000	Liquid Energy Corp.	Bridgeport Refinery	Bridgeport	TX
550	0	550	Shore Inc.	Kilgore Refinery	Kilgore	TX
3,200	0	3,200	Port Petroleum	Stonewall	Stonewall	LA

REFINING AREA NO. 11 (Continued)

Operating	Idle	Total Operable	Corporation	Name	City	State
15,000	0	15,000	Pioneer Refining Ltd.	Nixon Refinery	Nixon	TX
1,000	0	1,000	Petrolite Corp.	Kilgore Refinery	Kilgore	TX
42,750	0	40,750	Pride Refining Inc.	Abilene Refinery	Abilene	TX
40,000	0	40,000	Sigmor Refg. Co.	Three Rivers Refinery	Three Rivers	TX
30,600	0	30,600	Shell Oil Co.	Odessa Refinery	Odessa	TX
36,100	0	36,100	Southern Union Refg Co.	Lovington Refinery	Lovington	NM
76,000	0	76,000	Chevron U.S.A. Inc.	El Paso Refinery	El Paso	TX
16,800	0	16,800	Plateau Inc.	Bloomfield Refinery	Bloomfield	NM
26,100	0	26,100	Tesoro Petroleum Corp.	Carrizo Springs Refinery	Carrizo Springs	TX
4,750	0	4,750	Thriftway Oil Co.	Bloomfield Refinery	Farmington	NM
0	1,184	1,184	Thriftway Oil Co.	Graham Refinery	Graham	TX
17,000	0	17,000	Texaco Inc.	El Paso Refinery	El Paso	TX
20,000	0	21,000	Amber Refining Inc.	Fort Worth Refinery	Fort Worth	TX
3,000	2,800	5,800	Southland Oil Co.	Lumberton Refinery	Lumberton	MS
11,000	0	11,000	Southland Oil Co.	Sandersville Refinery	Sandersville	MS
0	9,500	9,500	Vulcan Refining Co.	Cordova Refinery	Cordova	AL
4,000	1,500	5,500	Warrior Asph Co. AL Inc.	Holt Refinery	Holt	AL
6,700	2,700	9,400	Cross Oil & Refining Co.	Smackover	Smackover	AR

REFINING AREA NO. 12
PADD IV REFINERIES
(NOT CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
0	8,000	8,000	Caribou Four Corners Inc.	Woods Cross Refinery	Woods Cross	UT
12,500	0	12,500	Crysen Refining Co.	Woods Cross Refinery	Woods Cross	UT
32,500	0	32,500	Conoco	Denver Refinery	Commerce City	CO
48,500	0	48,500	Conoco	Billings Refinery	Billings	MT
0	1,500	1,500	Silver Eagle Oil Inc.	ULA Barge Refinery	La Barge	WY
33,650	7,800	41,450	Farmers UM Control Exch Inc.	Laurel Refinery	Laurel	MT
26,000	0	26,000	Asamera Oil U.S. Inc.	Denver Refinery	Denver	CO
13,100	0	13,000	Gary Western Co.	Denver Refinery	Fruita	CO
25,000	0	25,000	Husky Oil Co.	North Salt Lake Refinery	North Salt Lake	UT
28,800	0	28,800	Husky Oil Co.	Cheyenne Refinery	Cheyenne	WY
4,700	0	4,700	Kenco Refining Inc.	Wolf Point Refinery	Wolf Point	MT
12,555	0	12,555	Wyoming Refining Co.	New Castle Refinery	New Castle	WY
24,500	0	24,500	Little Am. Refg. Co.	Casper Refinery	Evansville	WY
54,000	0	54,000	Sinclair Oil Corp.	Sinclair Refinery	Sinclair	WY
5,600	0	5,600	Flying J. Inc.	Cutbank Refinery	Cutbank	MT
0	6,000	6,000	Morrison Petroleum Co.	Woods Cross Refiney	Woods Cross	UT
200	0	200	Mountaineer Refining Co.	La Barge Refinery	La Barge	WY
25,000	0	25,000	Phillips Petroleum Co.	Woods Cross Refinery	Woods Cross	UT
45,000	0	45,000	Chevron U.S.A. Inc.	Salt Lake Refinery	Salt Lake City	UT
39,000	0	39,000	Amoco Oil Co.	Salt Lake City Refinery	Salt Lake City	UT
48,000	0	48,000	Amoco Oil Co.	Casper Refinery	Casper	WY
45,000	0	45,000	Exxon Company U.S.A.	Billings Refinery	Billings	MT
7,500	0	7,500	Plateau Inc.	Roosevelt Refinery	Roosevelt	UT
6,300	0	6,300	Simmons	Great Falls Refinery	Great Falls	MT

REFINING AREA NO. 13
PADD V REFINERIES
(WATER OR NOT CONNECTED TO SPR)

Operating	Idle	Total Operable	Corporation	Name	City	State
21,000	0	21,000	Marlex Oil & Refg. Co.	Long Beach Refinery	Los Angeles	CA
178,000	27,000	205,000	Atlantic Richfield Co.	Carson Refinery	Carson	CA
126,000	0	126,000	Atlantic Richfield Co.	Cherry Point Refinery	Ferndale	WA
20,000	0	20,000	Atlantic Richfield Co.	North Slope Refinery	Anchorage	AK
21,400	0	21,400	Kern County Refinery	Bakersfield Refinery	Bakersfield	CA
85,000	0	85,000	Pacific Refining Co.	Hercules Refinery	Hercules	CA
26,000	14,500	40,500	Pacific Oasis Corp.	Paramount Refinery	Paramount	CA
9,500	0	9,500	Conoco	Santa Maria Refinery	Santa Maria	CA
41,600	0	41,600	Edgington Oil Co. Inc.	Long Beach Refinery	Long Beach	CA
4,000	0	4,000	Oxnard Refinery	Oxnard Refinery	Oxnard	CA
0	9,000	9,000	Anchor Refining Co.	McKittrick Refinery	McKittrick	CA
29,500	0	29,500	Fletcher Oil & Refg. Co.	Wilmington Refinery	Carson	CA
51,500	0	51,500	Gulf Oil Corp.	Santa Fe Springs Refinery	Santa Fe Springs	CA
10,000	0	10,000	Demenno Resources	Irvine Refinery	Irvine	CA
4,750	0	4,750	Huntway Refining Co.	Encino Refinery	Encino	CA
3,700	0	3,700	Thagard Oil Co.	South Gate Refinery	South Gate	CA
11,000	0	11,000	MacMillian Ring-Free Oil	Long Beach Refinery	Signal Hill	CA
71,500	0	71,500	Mobil Oil Corp.	Ferndale Refinery	Ferndale	WA
123,500	0	123,500	Mobil Oil Corp.	Torrance Refinery	Torrance	CA
0	0	0	ECO Petroleum/Marlex	Long Beach Refinery	Signal Hill	CA
11,070	0	11,070	Sound Refining Inc.	Tacoma Refinery	Tacoma	WA
44,120	0	44,120	Powerine Oil Co.	Santa Fe Springs Refinery	Santa Fe Springs	CA
91,000	0	91,000	Shell Oil Co.	Anacortes Refinery	Anacortes	WA
91,400	0	91,400	Shell Oil Co.	Martinez Refinery	Martinez	CA
93,000	0	93,000	Shell Oil Co.	Wilmington Refinery	Carson	CA
22,000	0	22,000	Chevron U.S.A. Inc.	Kenai Refinery	Kenai	AK
390,000	15,000	405,000	Chevron U.S.A. Inc.	El Segundo Refinery	El Segundo	CA
		365,000	Chevron U.S.A. Inc.	Richmond Refinery	Richmond	CA
		48,000	Chevron U.S.A. Inc.	Honolulu Refinery	Honolulu	HI

REFINING AREA NO. 13 (Continued)

Operating	Idle	Total Operable	Corporation	Name	City	State
		15,000	Chevron U.S.A. Inc.	Willbridge Refinery	Portland	OR
		5,500	Chevron U.S.A. Inc.	Richmond Beach Refinery	Richmond Beach	WA
		106,000	Exxon Company U.S.A.	Benicia Refinery	Benicia	CA
		48,500	Tesoro Petroleum Corp.	Kenai Refinery	Kenai	AK
		78,000	Texaco Inc.	Puget Sound Refinery	Anacortes	WA
60,000	15,000	75,000	Texaco Inc.	Los Angeles Refinery	Wilmington	CA
		126,000	Tosco Corp.	Avon Refinery	Martinez	CA
		16,170	Golden Eagle Refg Co. Inc.	Carson Refinery	Carson	CA
		24,000	U.S.A. Petrochem Corp.	Ventura Refinery	Ventura	CA
		41,000	Union Oil Co. of CA	Santa Maria Refinery	Arroyo Grande	CA
		70,000	Union Oil of CA	San Francisco Refinery	Rodeo	CA
86,500	21,500	108,000	Union Oil of CA	Wilmington Refinery	Wilmington	CA
		60,000	Champlin Petroleum Co.	Wilmington Refinery	Wilmington	CA
		21,400	U.S. Oil & Refining Co.	Tacoma Refinery	Tacoma	WA
		6,750	Huntway Refining Co.	Van Nuys Refinery	Van Nuys	CA
6,000	0	6,000	Arizona Fuels Corp.	Fredonia Refinery	Fredonia	AZ
27,000	0	27,000	Independent Valley	Bakersfield Refinery	Bakersfield	CA
38,000	19,600	57,600	Getty Refining & Mktg.	Bakersfield Refinery	Bakersfield	CA
45,000	0	45,000	North Pole Refining Co.	North Pole Refinery	North Pole	AK
17,300	0	17,300	Beacon Oil	Hanford Refinery	Hanford	CA
4,500	0	4,500	Nevada Refining Co.	Tonopah Refinery	Tonopah	NV
21,400	0	21,400	Newhall Refining Co. Inc.	Newhall Refinery	Newhall	CA
10,000	0	10,000	San Joaquin Refg. Co.	Oildale Refinery	Bakersfield	CA
26,000	0	26,000	Chevron U.S.A. Inc.	Bakersfield Refinery	Bakersfield	CA
12,000	0	12,000	Sunland Refining Corp.	Bakersfield Refinery	Bakersfield	CA
38,800	0	38,000	Tosco Corp.	Bakersfield Refinery	Bakersfield	CA
0	0	0	Witco Chemical Corp.	Golden Bear Refining	Bakersfield	CA

PROJECTED OPERABLE CAPACITY OF PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1984
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY										
	CRUDE DISTILL-ATION	VACUUM DISTILL-ATION	THERMAL CRACKING	CATALYT-IC CRACKING FRESH	CATALYT-IC CRACKING RECYCLED	CATALYT-IC REFORMI-NG	CATALYT-IC HYDROCR-ACKING	CATALYT-IC HYDROTR-EATING	ALKYLAT-ION	AROMATI-CS/ISOM-ERIZATI-ON	ASPHALT
REFINING AREA											
01 (1 + 2)	2225900	1035700	143780	601300	88100	563100	90000	1503600	67800	93672	149200
02 (3)	62275	23180	.	.	.	11450	4440	17300	.	.	.
03 (5)	1014133	293460	102100	382000	35900	239350	8190	295600	92200	27045	31883
04 (6)	2140418	944500	333200	645800	48300	448500	138700	985500	139300	42500	89600
05 (9)	2087000	883000	198000	763000	76700	516115	82000	1605400	111200	105575	17000
06 (8)	1539400	575000	87500	417500	52500	317500	52000	680350	47400	36800	11400
07 (7)	517000	136500	122600	180600	0	117200	.	260700	39000	2300	.
08 (10)	631400	241000	54200	201500	5500	164600	.	447600	39200	51800	2000
09 (11)	1114964	298318	41800	282900	32525	216440	0	392700	68300	47950	71526
10 (12)	619950	195010	31500	190400	32600	118150	10900	240800	30580	9500	32650
11 (13)	3341690	1523900	526800	699700	49850	679130	401400	1427137	132700	27300	116158
12 (4)	2865120	1135000	197300	1030200	72400	752700	127500	1429700	184900	63700	213810
TOTAL	18159250	7284568	1838780	5394900	494375	4144235	915130	9286387	952580	508142	735227

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED OPERABLE CAPACITY OF PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1984
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY			
	LUBRICATING OILS	HYDROGEN	PETROLEUM COKE	TOTAL
REFINING AREA				
01 (1 + 2)	36600	11133	15051	6624936
02 (3)	16632	5	.	135282
03 (5)	13500	9	18494	2553864
04 (6)	17400	277	43800	6017795
05 (9)	49100	235	22500	6516825
06 (8)	45700	60	14625	3877735
07 (7)	7000	.	30800	1413700
08 (10)	.	80	13460	1852340
09 (11)	17140	444	5930	2590937
10 (12)	1830	26	7350	1521246
11 (13)	21792	1002	99020	9047579
12 (4)	22800	131	52700	8147961
TOTAL	249494	13402	323730	50300200

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED OPERABLE CAPACITY OF PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1985
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY										
	CRUDE DISTILL-ATION	VACUUM DISTILL-ATION	THERMAL CRACKING	CATALYT-IC CRACKING FRESH	CATALYT-IC CRACKING RECYCLED	CATALYT-IC REFORMI-NG	CATALYT-IC HYDROCR-ACKING	CATALYT-IC HYDROTR-EATING	ALKYLAT-ION	AROMATI-CS/ISOM-ERIZATI-ON	ASPHALT
REFINING AREA											
01 (1 + 2)	2154700	1058400	182500	613300	88100	580270	89000	1550600	72000	96877	162100
02 (3)	63133	21900	.	.	.	11420	4440	19576	.	.	2400
03 (5)	962883	283000	100000	355500	26400	219300	8190	353040	84300	26245	31950
04 (6)	2247741	1040900	351700	662300	48300	445500	173700	1022000	149700	23914	105100
05 (9)	2043000	889000	198000	758000	76700	514500	94000	1685900	111200	107175	17700
06 (8)	1414400	604200	81500	420000	52500	305500	47000	658450	50600	52595	11400
07 (7)	508500	146000	122400	180600	0	118400	30000	284500	26200	0	0
08 (10)	566500	244000	56000	198700	2800	147500	10000	458600	42700	44800	10000
09 (11)	1108860	298570	43300	286400	39525	211300	0	399400	67800	48250	73599
10 (12)	597550	201000	28600	190900	33800	111800	12100	234300	30380	9500	38000
11 (13)	3347545	1591700	558800	703450	50550	676330	397656	1452772	129800	28500	135991
12 (4)	2850920	1148700	252700	1022700	72900	721800	168500	1446000	184800	61500	218410
TOTAL	17865732	7527370	1975500	5391850	491575	4063620	1034586	9565138	949480	499356	806650

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED OPERABLE CAPACITY OF PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1985
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY			
	LUBRICATING OILS	HYDROGEN	PETROLEUM COKE	TOTAL
REFINING AREA				
01 (1 + 2)	30600	114	32960	6711521
02 (3)	16877	5	.	139751
03 (5)	14120	9	19529	2434466
04 (6)	17400	330	66170	6354755
05 (9)	51100	415	37300	6583990
06 (8)	44600	60	24910	3767715
07 (7)	9000	28	30800	1456428
08 (10)	.	80	14350	1796030
09 (11)	17522	372	6830	2601728
10 (12)	1830	27	9650	1499437
11 (13)	26800	1033	115330	9216257
12 (4)	21800	191	68568	8239489
TOTAL	251649	2664	426397	50851567

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=01 -- PADD 1 -- SPR WATER CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
ARCO PHILADELPHIA	ALGERIA		15,777	0.11	44.2
ARCO PHILADELPHIA	INDONESIA	MEDIUM	199	0.12	35.5
ARCO PHILADELPHIA	MEXICO	MAYAN	7,661	3.62	22.6
ARCO PHILADELPHIA	NETHERLANDS		1,038	1.61	33.1
ARCO PHILADELPHIA	NIGERIA	LIGHT	1,127	0.12	42.5
ARCO PHILADELPHIA	SAUDIA ARABIA	LIGHT	573	1.45	36.1
ARCO PHILADELPHIA	OMAN		2,406	0.90	34.6
ARCO PHILADELPHIA	TUNISIA		1,016	0.09	43.4
CIBRO ALBANY	VENEZUELA	HEAVY	991	3.54	10.6
GETTY DELAWARE CITY	ALGERIA		329	0.19	44.4
GETTY DELAWARE CITY	GABON	GAMBA	733	0.23	31.7
GETTY DELAWARE CITY	GABON	MANDJI	3,627	1.14	29.7
GETTY DELAWARE CITY	INDONESIA	HEAVY	359	0.00	0.00
GETTY DELAWARE CITY	INDONESIA	MEDIUM	1,880	0.14	34.8
GETTY DELAWARE CITY	IRAN		2,172	1.62	31.5
GETTY DELAWARE CITY	MEXICO	MAYAN	11,786	3.28	22.4
GETTY DELAWARE CITY	SAUDIA ARABIA	HEAVY	7,219	3.08	26.9
GETTY DELAWARE CITY	SAUDIA ARABIA	LIGHT	273	2.60	33.3
GETTY DELAWARE CITY	SAUDIA ARABIA	MEDIUM	808	2.46	30.2
GETTY DELAWARE CITY	EGYPT	BELAYIM	2,365	2.21	26.4
GETTY DELAWARE CITY	EGYPT	SUEZ BLEND	501	1.70	31.3
GETTY DELAWARE CITY	VENEZUELA	HEAVY	3,674	2.66	11.3
GETTY DELAWARE CITY	VENEZUELA	MEDIUM	4,484	2.24	18.2
GULF PHILADELPHIA	ALGERIA		432	0.02	43.4
GULF PHILADELPHIA	ANGOLA		12,307	0.13	33.3
GULF PHILADELPHIA	CONGO		1,784	0.35	27.1
GULF PHILADELPHIA	ZAIRE		5,269	0.12	31.4
GULF PHILADELPHIA	INDONESIA		314	0.09	22.2
GULF PHILADELPHIA	ECUADOR	ORIENTE	678	0.54	29.5
GULF PHILADELPHIA	GABON	GAMBA	2,644	0.40	31.5
GULF PHILADELPHIA	GABON	LUCINA	2,211	0.10	39.9
GULF PHILADELPHIA	INDIA		3,642	0.16	39.4
GULF PHILADELPHIA	INDONESIA	MEDIUM	2,233	0.08	34.7
GULF PHILADELPHIA	NIGERIA	MEDIUM	4,530	0.19	37
GULF PHILADELPHIA	NORWAY	STATFJORD	603	0.26	39.5
GULF PHILADELPHIA	TRINIDAD		169	0.56	26.3
GULF PHILADELPHIA	UNITED KINGDOM	MEDIUM	6,349	0.22	38.2
DELTA NEW YORK IMPORTS	UNITED KINGDOM	MEDIUM	852	0.00	38.3
MOBIL PAULSBORO	GUATAMALA		173	2.50	26.7
MOBIL PAULSBORO	MEXICO	BLENDED	461	1.70	24.3
MOBIL PAULSBORO	NORWAY	EKOFISK	543	1.70	42.1
MOBIL PAULSBORO	SAUDIA ARABIA	LIGHT	15,926	1.57	33.3
CHEVRON PERTH AMBOY	MEXICO	BLENDED	382	2.68	25
CHEVRON PERTH AMBOY	MEXICO	ISTHMUS	2,607	1.47	32.1
CHEVRON PERTH AMBOY	MEXICO	MAYAN	7,428	2.86	22.5
CHEVRON PERTH AMBOY	SAUDIA ARABIA	HEAVY	547	2.47	27.7
CHEVRON PERTH AMBOY	SAUDIA ARABIA	LIGHT	727	1.38	35
CHEVRON PERTH AMBOY	OMAN		766	0.94	35
CHEVRON PERTH AMBOY	DUBAI		377	1.70	31.1
CHEVRON PERTH AMBOY	VENEZUELA	HEAVY	4,618	4.80	10.4
CHEVRON BALTIMORE	VENEZUELA	HEAVY	705	4.75	10.2

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=01 -- PADD 1 -- SPR WATER CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
AMOCO SAVANNAH	VENEZUELA	HEAVY	5,611	5.00	10.7
AMOCO YORKTOWN	ALGERIA		1,474	0.11	43.9
AMOCO YORKTOWN	MEXICO	MAYAN	172	2.88	12
AMOCO YORKTOWN	NIGERIA	LIGHT	210	0.09	40.6
AMOCO YORKTOWN	NORWAY	EKOFISK	453	0.16	42.5
AMOCO YORKTOWN	SAUDIA ARABIA	LIGHT	0	1.92	40.6
AMOCO YORKTOWN	TRINIDAD		3,596	0.27	33.3
AMOCO YORKTOWN	SHARJA		453	0.10	50
AMOCO YORKTOWN	UNITED KINGDOM	MEDIUM	1,511	0.30	38.1
AMOCO YORKTOWN	VENEZUELA	HEAVY	5,731	2.84	12.3
AMOCO YORKTOWN	VENEZUELA	MEDIUM	194	2.88	25.6
EXXON BAYWAY	MEXICO	BLENDED	460	2.97	24.5
EXXON BAYWAY	MEXICO	MAYAN	4,271	3.19	22.6
EXXON BAYWAY	SAUDIA ARABIA	HEAVY	850	2.48	27.8
EXXON BAYWAY	SAUDIA ARABIA	MEDIUM	238	2.80	29.5
SOHIO MARCUS HOOK	ANGOLA		129	0.00	33.2
SOHIO MARCUS HOOK	BRAZIL		364	0.09	38.1
SOHIO MARCUS HOOK	CAMEROUN	KOLE	5,690	0.29	33.7
SOHIO MARCUS HOOK	INDIA		454	0.12	39.2
SOHIO MARCUS HOOK	NIGERIA	LIGHT	4,305	0.11	42.4
SOHIO MARCUS HOOK	NIGERIA	MEDIUM	5,439	0.15	36.3
SOHIO MARCUS HOOK	NORWAY	EKOFISK	7,026	0.17	42.3
SOHIO MARCUS HOOK	NORWAY	STATFJORD	3,204	0.30	38.7
SOHIO MARCUS HOOK	PERU		396	0.57	28.9
SOHIO MARCUS HOOK	UNITED KINGDOM	MEDIUM	13,423	0.34	37.3
SEAVIEW PAULSBORO	CHINA		1,084	0.07	31.7
SEAVIEW PAULSBORO	VENEZUELA	HEAVY	3,041	2.58	11.8
SUN OIL MARCUS HOOK	ALGERIA		2,530	0.06	42.5
SUN OIL MARCUS HOOK	CAMEROUN	KOLE	1,641	0.21	33.8
SUN OIL MARCUS HOOK	INDIA		487	0.17	38.4
SUN OIL MARCUS HOOK	INDONESIA	MEDIUM	1,029	0.09	35.1
SUN OIL MARCUS HOOK	NIGERIA	HEAVY	818	0.22	27.2
SUN OIL MARCUS HOOK	NIGERIA	LIGHT	3,025	0.13	42.2
SUN OIL MARCUS HOOK	NIGERIA	MEDIUM	486	0.16	35.8
SUN OIL MARCUS HOOK	NORWAY	EKOFISK	1,025	0.13	42.3
SUN OIL MARCUS HOOK	NORWAY	STATFJORD	100	0.27	38.2
SUN OIL MARCUS HOOK	PERU		1,495	0.57	27.5
SUN OIL MARCUS HOOK	TUNISIA		535	0.03	43.1
SUN OIL MARCUS HOOK	UNITED KINGDOM	LIGHT	1,560	0.13	43.1
SUN OIL MARCUS HOOK	UNITED KINGDOM	MEDIUM	27,783	0.34	36.8
SUN OIL MARCUS HOOK	VENEZUELA	LIGHT	480	0.17	35.4
TEXACO EAGLE POINT	ALGERIA		878	0.10	63.8
TEXACO EAGLE POINT	ANGOLA		1,896	0.11	34.5
TEXACO EAGLE POINT	INDONESIA	HEAVY	550	0.21	21.1
TEXACO EAGLE POINT	INDONESIA	MEDIUM	21,592	0.09	35.7
TEXACO EAGLE POINT	NIGERIA	MEDIUM	654	0.13	36.1
TEXACO EAGLE POINT	UNITED KINGDOM	MEDIUM	1,415	0.30	36.7
NPCD			290,033		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

------------------------ NPC DISTRICT=02 -- US CARIBBEAN- SPR WATER CONNECTED ------------------------------

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
GULF BAYAMON	CONGO		563	0.38	27.5
GULF BAYAMON	ZAIRE		562	1.05	29.3
GULF BAYAMON	ECUADOR	ORIENTE	2,308	1.03	29
GULF BAYAMON	GABON	MANDJI	317	0.83	29.6
GULF BAYAMON	IRAN		1,698	1.73	30.4
GULF BAYAMON	MEXICO	BLENDED	30	1.29	28.1
GULF BAYAMON	MEXICO	MAYAN	69	3.21	22.1
GULF BAYAMON	NIGERIA	MEDIUM	45	0.46	33.8
SUN OIL PUERTO RICO	ANGOLA		1,927	0.24	31.6
SUN OIL PUERTO RICO	ECUADOR	ORIENTE	6,460	0.47	29.7
SUN OIL PUERTO RICO	GABON	MANDJI	1,771	0.75	30.2
SUN OIL PUERTO RICO	INDONESIA	HEAVY	381	0.00	26.7
SUN OIL PUERTO RICO	INDONESIA	MEDIUM	497	0.00	35.4
SUN OIL PUERTO RICO	IRAN		2,853	0.46	32.4
SUN OIL PUERTO RICO	PERU		1,169	0.24	26.1
SUN OIL PUERTO RICO	UNITED KINGDOM	MEDIUM	1,473	0.19	37.2
SUN OIL PUERTO RICO	UNITED KINGDOM	SOUR	475	1.21	33.3
NPCD			22,598		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

-------------------------------- NPC DISTRICT=04 -- PADD 2 -- SPR + CAPLINE CONNECTED --------------------------------

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
APEX OIL WOOD RIVER	VENEZUELA	HEAVY	183	2.80	11.2
APEX OIL BLUE ISLAND	ALGERIA		2,884	0.06	63.5
APEX OIL BLUE ISLAND	INDONESIA	MEDIUM	149	0.09	35.7
APEX OIL BLUE ISLAND	IRAN		421	1.60	30.8
APEX OIL BLUE ISLAND	MEXICO	MAYAN	9,880	3.00	22.7
APEX OIL BLUE ISLAND	NIGERIA	LIGHT	525	0.07	41.8
APEX OIL BLUE ISLAND	TRINIDAD		340	0.30	14.6
APEX OIL BLUE ISLAND	EGYPT	SUEZ BLEND	440	1.30	31.6
APEX OIL BLUE ISLAND	VENEZUELA	HEAVY	118	2.80	11
APEX OIL BLUE ISLAND	VENEZUELA	MEDIUM	569	1.73	19.2
ASHLAND OIL CATLETTSBURG	CANADA	HEAVY	70	2.23	24.5
ASHLAND OIL CATLETTSBURG	IRAN		3,810	1.54	32,9
ASHLAND OIL CATLETTSBURG	IRAQ		1,896	2.04	35.4
ASHLAND OIL CATLETTSBURG	MEXICO	ISTHMUS	5,536	1.52	32.9
ASHLAND OIL CATLETTSBURG	MEXICO	MAYAN	4,276	3.14	22.5
ASHLAND OIL CATLETTSBURG	NIGERIA	LIGHT	549	0.14	42.1
ASHLAND OIL CATLETTSBURG	SAUDIA ARABIA	LIGHT	2,826	1.70	31.7
ASHLAND OIL CATLETTSBURG	SAUDIA ARABIA	MEDIUM	1,340	2.60	29.7
ASHLAND OIL CATLETTSBURG	EGYPT	SUEZ BLEND	914	1.18	31.8
ASHLAND OIL CATLETTSBURG	UNITED KINGDOM	MEDIUM	3,430	0.33	36.6
ASHLAND OIL ST. PAUL PARK	CANADA	HEAVY	577	1.74	24.2
GLADIEUX FT WAYNE	CANADA	HEAVY	1,403	0.20	29
KOCH PINE BEND	CANADA	HEAVY	45,578	2.80	0.00
KOCH PINE BEND	MEXICO	MAYAN	273	0.00	0.00
MARATHON ROBINSON	CAMEROUN	KOLE	2,888	0.32	32.5
MARATHON ROBINSON	CANADA	HEAVY	4,428	0.93	26.5
MARATHON ROBINSON	CONGO		3,097	0.36	27
MARATHON ROBINSON	NIGERIA	HEAVY	525	0.17	28.1
MARATHON ROBINSON	UNITED KINGDOM	MEDIUM	1,022	0.40	36.9
MOBIL JOLIET	CANADA	HEAVY	8,599	0.57	23.2
MOBIL JOLIET	ECUADOR	ORIENTE	222	0.95	29.1
MOBIL JOLIET	GUATAMALA		1,140	1.79	28.6
MOBIL JOLIET	MEXICO	BLENDED	412	3.20	24.3
MOBIL JOLIET	MEXICO	MAYAN	7,437	3.27	22.5
MURPHY SUPERIOR	CANADA	FEDERATED	256	0.53	37.2
MURPHY SUPERIOR	CANADA	HEAVY	1,856	2.54	24.2
SHELL WOOD RIVER	ALGERIA		198	0.04	62.2
SHELL WOOD RIVER	CAMEROUN	KOLE	345	0.37	34.5
SHELL WOOD RIVER	INDONESIA	HEAVY	1,784	0.19	28.1
SHELL WOOD RIVER	MEXICO	ISTHMUS	515	2.40	33.6
SHELL WOOD RIVER	MEXICO	MAYAN	2,414	3.45	22.5
SHELL WOOD RIVER	NIGERIA	HEAVY	2,312	0.20	29.3
SHELL WOOD RIVER	NORWAY	EKOFISK	357	0.16	43.4
SHELL WOOD RIVER	SAUDIA ARABIA	HEAVY	482	3.05	27.7
SHELL WOOD RIVER	SAUDIA ARABIA	LIGHT	3,026	1.80	33.6
SHELL WOOD RIVER	OMAN		3,638	0.73	34.7
AMOCO WHITING	CANADA	HEAVY	6,089	2.23	26.6
AMOCO WHITING	TRINIDAD		419	0.27	33.5
AMOCO WHITING	EGYPT	SUEZ BLEND	0	1.52	31.8
SUN OIL TOLEDO	CANADA	FEDERATED	474	0.53	38.4
SUN OIL TOLEDO	CANADA	HEAVY	2,464	0.13	32.4

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=04 -- PADD 2 -- SPR + CAPLINE CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
SUN OIL TOLEDO	NIGERIA	LIGHT	496	0.11	41.9
SUN OIL TOLEDO	NIGERIA	MEDIUM	1	0.00	32
SUN OIL TOLEDO	TUNISIA		564	0.04	43
TOTAL ALMA	CANADA	HEAVY	54	0.00	34.7
UNION OIL CHICAGO	CANADA	HEAVY	3,553	2.84	25.3
UNITED WARREN	CANADA	FEDERATED	3,607	0.54	38
UNITED WARREN	CANADA	HEAVY	2,214	0.00	0.00
NPCD			154,878		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=05 -- PADD 2 -- NOT SPR CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
TEXAS EASTERN TYLER	ALGERIA		1,370	0.21	43.4
TEXAS EASTERN TYLER	NIGERIA	MEDIUM	534	0.12	36.9
TEXAS EASTERN TYLER	NORWAY	EKOFISK	500	0.14	43.1
TEXAS EASTERN TYLER	UNITED KINGDOM	MEDIUM	2,607	0.32	38.2
TEXAS EASTERN TYLER	UNITED KINGDOM	SOUR	379	0.53	39.9
TOSCO DUNCAN	ALGERIA		40	0.00	64
TOSCO DUNCAN	VENEZUELA	MEDIUM	2,123	2.27	17.1
NPCD			7,553		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=06 -- PADD 3 -- LOWER MISSISSIPPI RIVER

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
APEX OIL MT AIRY	NIGERIA	HEAVY	506	0.20	28.3
APEX OIL MT AIRY	UNITED KINGDOM	MEDIUM	467	0.31	36.2
GULF ALLIANCE	ALGERIA		519	0.08	44
GULF ALLIANCE	ANGOLA		2,900	0.38	32.3
GULF ALLIANCE	CONGO		399	0.45	27.2
GULF ALLIANCE	ZAIRE		922	0.13	31.4
GULF ALLIANCE	ECUADOR	ORIENTE	274	1.08	29.1
GULF ALLIANCE	GABON	GAMBA	35	0.10	31.3
GULF ALLIANCE	GABON	LUCINA	612	0.10	39.9
GULF ALLIANCE	GABON	MANDJI	1,073	1.09	29.9
GULF ALLIANCE	NIGERIA	HEAVY	1,142	0.25	28.9
GULF ALLIANCE	NIGERIA	MEDIUM	1,054	0.12	35.8
MARATHON GARYVILLE	CAMEROUN	KOLE	684	0.34	32.5
MARATHON GARYVILLE	CONGO		322	0.37	26.8
MARATHON GARYVILLE	GABON	MANDJI	1,134	0.76	28.6
MARATHON GARYVILLE	IRAN		943	1.54	29.9
MARATHON GARYVILLE	MEXICO	BLENDED	15,140	2.14	27
MARATHON GARYVILLE	MEXICO	ISTHMUS	975	1.52	33.3
MARATHON GARYVILLE	MEXICO	MAYAN	2,231	3.26	22.5
MARATHON GARYVILLE	SAUDIA ARABIA	LIGHT	4,869	2.04	31.9
MARATHON GARYVILLE	SAUDIA ARABIA	MEDIUM	10,435	2.26	30.2
MARATHON GARYVILLE	UNITED ARAB EMIRATE		885	1.79	33.3
MARATHON GARYVILLE	EGYPT	SUEZ BLEND	1,336	1.58	32.1
DELTA MEMPHIS	IRAN		533	0.00	33.4
DELTA MEMPHIS	UNITED KINGDOM	LIGHT	936	0.00	42.7
DELTA MEMPHIS	UNITED KINGDOM	MEDIUM	5,108	0.00	37.4
ERGON VICKSBURG	VENEZUELA	MEDIUM	2,334	2.14	16.3
MURPHY MERAUX	NIGERIA	LIGHT	554	0.05	42.5
MURPHY MERAUX	NORWAY	EKOFISK	1,307	0.14	43.1
MURPHY MERAUX	UNITED KINGDOM	MEDIUM	3,178	0.40	35.8
PLACID PORT ALLEN	UNITED KINGDOM	MEDIUM	949	0.34	37.7
SHELL NORCO	ALGERIA		2,499	0.05	63.8
SHELL NORCO	ANGOLA		98	0.26	32.4
SHELL NORCO	CAMEROUN	KOLE	2,117	0.40	34
SHELL NORCO	GABON	GAMBA	355	0.10	31.3
SHELL NORCO	NIGERIA	HEAVY	151	0.26	29.3
SHELL NORCO	NIGERIA	LIGHT	504	0.08	41.8
SHELL NORCO	UNITED KINGDOM	MEDIUM	1,199	0.29	32
PACIFIC OASIS IMPORTS	INDONESIA	LIGHT	99	0.00	44.8
CHEVRON PASCAGOULA	ANGOLA		1,288	1.58	32
CHEVRON PASCAGOULA	INDONESIA	HEAVY	622	0.79	23.5
CHEVRON PASCAGOULA	INDONESIA	MEDIUM	7,180	0.09	35
CHEVRON PASCAGOULA	KUWAIT		498	2.80	28.2
CHEVRON PASCAGOULA	MEXICO	ISTHMUS	2,326	1.90	32.3
CHEVRON PASCAGOULA	MEXICO	MAYAN	4,333	1.59	22.8
CHEVRON PASCAGOULA	NIGERIA	HEAVY	6,126	0.18	28.7
CHEVRON PASCAGOULA	NIGERIA	MEDIUM	3,004	0.14	35.5
CHEVRON PASCAGOULA	SAUDIA ARABIA	HEAVY	18,773	2.80	27.5
CHEVRON PASCAGOULA	SAUDIA ARABIA	LIGHT	13,596	1.77	32.8
CHEVRON PASCAGOULA	SAUDIA ARABIA	MEDIUM	11,043	2.37	30.4
CHEVRON PASCAGOULA	UNITED KINGDOM	MEDIUM	2,307	0.31	37.1

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=06 -- PADD 3 -- LOWER MISSISSIPPI RIVER

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
EXXON BATON ROUGE	MEXICO	ISTHMUS	2,238	1.59	34
EXXON BATON ROUGE	MEXICO	MAYAN	1,806	3.18	22.5
EXXON BATON ROUGE	ABU DHABI		403	0.86	38.1
TENNECO CHALMETTE	BOLIVIA		655	0.04	59.2
TENNECO CHALMETTE	IRAN		350	1.44	33.6
TENNECO CHALMETTE	NIGERIA	HEAVY	1,578	0.13	28.8
TENNECO CHALMETTE	NIGERIA	MEDIUM	499	0.12	37.2
TENNECO CHALMETTE	SAUDIA ARABIA	LIGHT	338	1.94	33.1
TEXACO CONVENT	ALGERIA		1,126	0.05	63.8
TEXACO CONVENT	INDONESIA	HEAVY	1,036	0.21	22.9
TEXACO CONVENT	NIGERIA	HEAVY	1,599	0.19	29.4
TEXACO CONVENT	NIGERIA	LIGHT	971	0.07	43
TEXACO CONVENT	NIGERIA	MEDIUM	16,887	0.14	36.1
TEXACO CONVENT	SAUDIA ARABIA	LIGHT	480	0.13	34.8
TEXACO CONVENT	UNITED KINGDOM	LIGHT	421	0.18	42.9
TEXACO CONVENT	UNITED KINGDOM	MEDIUM	5,080	0.35	37
TEXACO CONVENT	VENEZUELA	LIGHT	511	0.30	37.2
NPCD			177,852		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=07 -- PADD 3 -- LAKE CHARLES

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
CONOCO-DUPONT LAKE CHARLES	ECUADOR	ORIENTE	349	0.00	28.7
CONOCO-DUPONT LAKE CHARLES	IRAN		433	1.60	31.2
CONOCO-DUPONT LAKE CHARLES	MEXICO	MAYAN	357	3.00	22.9
CONOCO-DUPONT LAKE CHARLES	SAUDIA ARABIA	HEAVY	395	3.21	28.2
CONOCO-DUPONT LAKE CHARLES	EGYPT	SUEZ BLEND	403	1.30	31.6
CONOCO-DUPONT LAKE CHARLES	VENEZUELA	HEAVY	1,486	5.40	10.4
CONOCO-DUPONT LAKE CHARLES	VENEZUELA	MEDIUM	3,941	4.25	17.8
HILL KROTZ SPRING	ALGERIA		1,166	0.04	19.8
HILL KROTZ SPRING	NIGERIA	LIGHT	754	0.05	43.2
HILL KROTZ SPRING	NORWAY	EKOFISK	498	0.00	43.1
HILL KROTZ SPRING	TRINIDAD		442	0.25	32.8
HILL KROTZ SPRING	UNITED KINGDOM	LIGHT	528	0.00	43
HILL KROTZ SPRING	UNITED KINGDOM	MEDIUM	3,038	0.19	37.2
SOUTHLAND LAKE CHARLES	ANGOLA		704	0.15	33
SOUTHLAND LAKE CHARLES	ZAIRE		364	1.30	33
SOUTHLAND LAKE CHARLES	ECUADOR	ORIENTE	5,679	0.94	29.4
SOUTHLAND LAKE CHARLES	GABON	GAMBA	382	0.11	32
SOUTHLAND LAKE CHARLES	GABON	MANDJI	181	1.26	29
SOUTHLAND LAKE CHARLES	IRAN		1,763	1.40	33.3
SOUTHLAND LAKE CHARLES	KUWAIT		249	2.88	29.7
SOUTHLAND LAKE CHARLES	MEXICO	MAYAN	6,204	2.80	21.1
SOUTHLAND LAKE CHARLES	NIGERIA	HEAVY	785	0.18	28.8
SOUTHLAND LAKE CHARLES	SAUDIA ARABIA	HEAVY	1,494	2.80	19.2
SOUTHLAND LAKE CHARLES	SAUDIA ARABIA	MEDIUM	699	2.57	30.2
SOUTHLAND LAKE CHARLES	DUBAI		878	1.68	32.3
SOUTHLAND LAKE CHARLES	UNITED KINGDOM	MEDIUM	1,536	0.36	25
SOUTHLAND LAKE CHARLES	UNITED KINGDOM	SOUR	513	1.10	36
SOUTHLAND LAKE CHARLES	VENEZUELA	HEAVY	185	2.30	13
NPCD			35,409		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=08 -- PADD 3 -- BEAUMONT-PT ARTHUR

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
PETROFINA PORT ARTHUR	ECUADOR	ORIENTE	2,172	0.60	24.4
PETROFINA PORT ARTHUR	IRAN		2,512	1.02	32.1
GULF PORT ARTHUR	ANGOLA		697	0.16	32.2
GULF PORT ARTHUR	CAMEROUN	KOLE	449	0.55	21.9
GULF PORT ARTHUR	CONGO		1,014	0.32	27.3
GULF PORT ARTHUR	ZAIRE		140	0.14	31.4
GULF PORT ARTHUR	ECUADOR	ORIENTE	4,218	0.92	29.2
GULF PORT ARTHUR	GABON	LUCINA	281	0.22	39.7
GULF PORT ARTHUR	GABON	MANDJI	5,508	1.36	28.7
GULF PORT ARTHUR	MEXICO	BLENDED	817	2.07	25.9
GULF PORT ARTHUR	MEXICO	ISTHMUS	3,379	2.13	33.7
GULF PORT ARTHUR	MEXICO	MAYAN	5,722	2.80	22.5
GULF PORT ARTHUR	NIGERIA	MEDIUM	884	0.20	37
GULF PORT ARTHUR	PERU		386	0.40	27
GULF PORT ARTHUR	TRINIDAD		128	0.43	26.4
GULF PORT ARTHUR	EGYPT	SUEZ BLEND	247	1.52	31.5
GULF PORT ARTHUR	UNITED KINGDOM	MEDIUM	1,117	0.32	37
MOBIL BEAUMONT	INDONESIA	LIGHT	567	0.05	54.2
MOBIL BEAUMONT	MEXICO	ISTHMUS	5,003	1.46	33.7
MOBIL BEAUMONT	MEXICO	MAYAN	84	3.81	22.3
MOBIL BEAUMONT	NIGERIA	MEDIUM	511	0.15	33.4
MOBIL BEAUMONT	SAUDIA ARABIA	LIGHT	2,832	1.10	36.4
TEXACO PORT ARTHUR	ALGERIA		4,961	0.06	58.7
TEXACO PORT ARTHUR	ECUADOR	ORIENTE	250	0.90	29.6
TEXACO PORT ARTHUR	INDONESIA	HEAVY	251	0.21	21.3
TEXACO PORT ARTHUR	INDONESIA	MEDIUM	8,088	0.09	35.5
TEXACO PORT ARTHUR	MEXICO	BLENDED	2,123	3.00	24.4
TEXACO PORT ARTHUR	MEXICO	ISTHMUS	6,613	1.55	33.2
TEXACO PORT ARTHUR	MEXICO	MAYAN	7,955	3.00	22.8
TEXACO PORT ARTHUR	SAUDIA ARABIA	HEAVY	1,744	2.25	27.6
TEXACO PORT ARTHUR	SAUDIA ARABIA	LIGHT	2,639	2.14	32.6
TEXACO PORT ARTHUR	SAUDIA ARABIA	MEDIUM	1,638	2.49	30.1
TEXACO PORT ARTHUR	UNITED ARAB EMIRATE		305	1.65	22
TEXACO PORT ARTHUR	VENEZUELA	LIGHT	481	1.93	32.5
TEXACO PORT ARTHUR	VENEZUELA	MEDIUM	248	2.40	16.9
UNION OIL BEAUMONT	NIGERIA	HEAVY	2,835	0.30	28.5
UNION OIL BEAUMONT	NIGERIA	MEDIUM	1,496	0.50	35.7
NPCD			80,294		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=09 -- PADD 3 -- HOUSTON-TEXAS CITY

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
AGWAY TEXAS CITY	ALGERIA		308	0.09	45.9
AGWAY TEXAS CITY	ANGOLA		2,639	0.12	32.2
AGWAY TEXAS CITY	CAMEROUN	KOLE	1,265	0.29	34
AGWAY TEXAS CITY	CANADA	HEAVY	382	0.98	35.1
AGWAY TEXAS CITY	ZAIRE		990	0.12	31.7
AGWAY TEXAS CITY	ECUADOR	ORIENTE	365	0.99	29.4
AGWAY TEXAS CITY	INDIA		4,022	0.15	39.4
AGWAY TEXAS CITY	NIGERIA	HEAVY	925	0.18	29.9
AGWAY TEXAS CITY	NIGERIA	LIGHT	3,851	0.11	41.7
AGWAY TEXAS CITY	NIGERIA	MEDIUM	798	0.13	35.6
AGWAY TEXAS CITY	NORWAY	EKOFISK	1,205	0.13	42.6
AGWAY TEXAS CITY	SAUDIA ARABIA	LIGHT	325	0.10	41.2
AGWAY TEXAS CITY	UNITED KINGDOM	MEDIUM	2,193	0.28	39.3
ARCO HOUSTON	ALGERIA		4,180	0.19	60.7
ARCO HOUSTON	MEXICO	ISTHMUS	307	1.53	31.6
ARCO HOUSTON	MEXICO	MAYAN	13,557	3.56	22.2
ARCO HOUSTON	SHARJA		500	0.10	49.7
CHARTER HOUSTON	ECUADOR	ORIENTE	388	0.90	29.9
CHARTER HOUSTON	GUATAMALA		410	0.94	28.9
CHARTER HOUSTON	IRAN		1,664	1.76	33.4
CHARTER HOUSTON	TRINIDAD		187	0.56	26.3
CHARTER HOUSTON	VENEZUELA	LIGHT	516	1.16	32.9
CROWN CENTRAL PASADENA	ALGERIA		677	0.11	39.9
CROWN CENTRAL PASADENA	ANGOLA		686	0.06	31.4
CROWN CENTRAL PASADENA	CAMEROUN	KOLE	401	0.50	33.4
CROWN CENTRAL PASADENA	INDIA		600	0.12	39
CROWN CENTRAL PASADENA	NIGERIA	HEAVY	497	0.18	28.6
CROWN CENTRAL PASADENA	NIGERIA	LIGHT	659	0.09	42.5
MARATHON TEXAS CITY	NIGERIA	HEAVY	1,368	0.13	28.5
PHILLIPS SWEENEY	BOLIVIA		247	0.07	58.6
PHILLIPS SWEENEY	GABON	MANDJI	1,392	1.05	29.9
PHILLIPS SWEENEY	IRAN		515	1.60	30.7
PHILLIPS SWEENEY	IVORY COAST		1,893	0.47	32.1
PHILLIPS SWEENEY	NIGERIA	LIGHT	6,435	0.12	42.2
PHILLIPS SWEENEY	NIGERIA	MEDIUM	251	0.10	37.6
PHILLIPS SWEENEY	NORWAY	EKOFISK	2,018	0.15	43.1
PHILLIPS SWEENEY	SAUDIA ARABIA	HEAVY	528	2.73	27.3
PHILLIPS SWEENEY	SAUDIA ARABIA	MEDIUM	331	2.51	30.9
PHILLIPS SWEENEY	VENEZUELA	MEDIUM	5	2.70	20
SHELL DEER PARK	ALGERIA		2,764	0.05	55.6
SHELL DEER PARK	MEXICO	BLENDED	92	2.61	24.9
SHELL DEER PARK	MEXICO	ISTHMUS	1,335	1.34	33.7
SHELL DEER PARK	MEXICO	MAYAN	14,552	2.88	22.4
SHELL DEER PARK	NIGERIA	LIGHT	1,036	0.06	42.2
SHELL DEER PARK	NORWAY	EKOFISK	302	0.17	43
SHELL DEER PARK	SAUDIA ARABIA	HEAVY	572	2.33	27.6
SHELL DEER PARK	SAUDIA ARABIA	LIGHT	1,713	1.26	36.1
SHELL DEER PARK	SAUDIA ARABIA	MEDIUM	1,946	2.05	30.3
SHELL DEER PARK	OMAN		1,944	0.94	35
SHELL DEER PARK	EGYPT	SUEZ BLEND	1,968	1.57	31.5
SHELL DEER PARK	UNITED KINGDOM	LIGHT	523	0.19	42.4

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

---------------------------- NPC DISTRICT=09 -- PADD 3 -- HOUSTON-TEXAS CITY ------------------------------

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
AMOCO TEXAS CITY	ALGERIA		3,339	0.03	60.1
AMOCO TEXAS CITY	ANGOLA		751	0.18	32.5
AMOCO TEXAS CITY	CHINA		1,016	0.18	32.3
AMOCO TEXAS CITY	KUWAIT		1,314	2.90	27.5
AMOCO TEXAS CITY	MEXICO	MAYAN	23,701	3.08	22.5
AMOCO TEXAS CITY	NIGERIA	LIGHT	549	0.08	42.8
AMOCO TEXAS CITY	NIGERIA	MEDIUM	1,024	0.13	35.8
AMOCO TEXAS CITY	NORWAY	EKOFISK	1,505	0.16	43.4
AMOCO TEXAS CITY	SAUDIA ARABIA	HEAVY	1,820	2.66	27.5
AMOCO TEXAS CITY	SAUDIA ARABIA	LIGHT	332	2.63	34
AMOCO TEXAS CITY	TRINIDAD		18,816	0.26	33.2
AMOCO TEXAS CITY	SHARJA		688	0.10	49
AMOCO TEXAS CITY	UNITED KINGDOM	MEDIUM	8,778	0.30	35.7
AMOCO TEXAS CITY	VENEZUELA	LIGHT	136	2.88	27.8
AMOCO TEXAS CITY	VENEZUELA	MEDIUM	504	2.88	26.2
EXXON BAYTOWN	MEXICO	ISTHMUS	4,303	1.68	34.1
EXXON BAYTOWN	MEXICO	MAYAN	426	2.66	23
EXXON BAYTOWN	SAUDIA ARABIA	LIGHT	1,012	1.74	34.7
EXXON BAYTOWN	UNITED ARAB EMIRATE		412	1.50	22.1
EXXON BAYTOWN	ABU DHABI		1,452	1.69	22.1
EXXON BAYTOWN	UNITED KINGDOM	MEDIUM	515	0.30	38
NPCD			160,623		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=10 -- PADD 3 -- CORPUS CHRISTI

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
COASTAL CORPUS CRISTI	ALGERIA		5,304	0.01	62.6
COASTAL CORPUS CRISTI	BOLIVIA		211	0.01	59.1
COASTAL CORPUS CRISTI	ZAIRE		472	0.12	31.4
COASTAL CORPUS CRISTI	ECUADOR	ORIENTE	2	1.05	27.7
COASTAL CORPUS CRISTI	IRAN		145	2.66	27.9
COASTAL CORPUS CRISTI	IRAQ		1,089	2.65	27.9
COASTAL CORPUS CRISTI	ITALY		0	0.94	30
COASTAL CORPUS CRISTI	KUWAIT		145	2.66	27.9
COASTAL CORPUS CRISTI	MEXICO	MAYAN	6,335	2.56	22.3
COASTAL CORPUS CRISTI	SAUDIA ARABIA	HEAVY	495	3.05	26.4
COASTAL CORPUS CRISTI	VENEZUELA	HEAVY	4,003	2.71	11.4
COASTAL CORPUS CRISTI	VENEZUELA	LIGHT	713	1.53	30.3
COASTAL CORPUS CRISTI	VENEZUELA	MEDIUM	1,886	1.67	21
KERR-MCGEE CORPUS CHRISTI	ALGERIA		685	0.24	24.7
KERR-MCGEE CORPUS CHRISTI	NIGERIA	HEAVY	3,913	0.20	23.7
KERR-MCGEE CORPUS CHRISTI	NIGERIA	LIGHT	566	0.00	42.1
KERR-MCGEE CORPUS CHRISTI	NIGERIA	MEDIUM	4,138	0.10	36.1
KERR-MCGEE CORPUS CHRISTI	UNITED KINGDOM	MEDIUM	4,334	0.15	37.9
KOCH CORPUS CHRISTI	ECUADOR	ORIENTE	345	0.90	29.4
KOCH CORPUS CHRISTI	INDIA		477	0.20	38.6
KOCH CORPUS CHRISTI	MEXICO	MAYAN	549	0.00	0.00
KOCH CORPUS CHRISTI	NIGERIA	LIGHT	919	0.10	43.1
KOCH CORPUS CHRISTI	NIGERIA	MEDIUM	392	0.10	37.5
KOCH CORPUS CHRISTI	NORWAY	EKOFISK	495	0.20	43
SABER CORPUS CRISTI	UNITED KINGDOM	MEDIUM	1	0.48	33.8
SABER CORPUS CRISTI	VENEZUELA	HEAVY	1,751	2.34	10.4
CHAMPLIN CORPUS CHRISTI	ALGERIA		1,963	0.32	43.5
CHAMPLIN CORPUS CHRISTI	ANGOLA		368	0.15	32.9
CHAMPLIN CORPUS CHRISTI	CAMEROUN	KOLE	567	0.00	27.3
CHAMPLIN CORPUS CHRISTI	CANADA	HEAVY	420	0.94	32.9
CHAMPLIN CORPUS CHRISTI	ECUADOR	ORIENTE	1,291	0.29	29.7
CHAMPLIN CORPUS CHRISTI	GABON	MANDJI	527	1.26	29
CHAMPLIN CORPUS CHRISTI	INDIA		4,279	0.05	24.5
CHAMPLIN CORPUS CHRISTI	IRAN		94	1.40	33.5
CHAMPLIN CORPUS CHRISTI	NIGERIA	LIGHT	554	0.07	42
CHAMPLIN CORPUS CHRISTI	NIGERIA	MEDIUM	1,060	0.16	38.4
CHAMPLIN CORPUS CHRISTI	NORWAY	STATFJORD	512	0.18	35.8
CHAMPLIN CORPUS CHRISTI	TRINIDAD		495	0.00	0.00
CHAMPLIN CORPUS CHRISTI	UNITED KINGDOM	MEDIUM	3,477	0.24	33
CHAMPLIN CORPUS CHRISTI	VENEZUELA	MEDIUM	2,879	2.37	17.8
NPCD			57,853		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=11 -- PADD 3 -- NOT SPR CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
DIAMOND SHAMROCK 3 RIVERS	NIGERIA	LIGHT	1,037	0.07	43.2
DIAMOND SHAMROCK 3 RIVERS	NIGERIA	MEDIUM	510	0.13	36.5
DIAMOND SHAMROCK 3 RIVERS	UNITED KINGDOM	MEDIUM	732	0.27	38.1
DORCHESTER CARGRAY	ECUADOR	ORIENTE	519	0.90	29.3
INDEPENDENT PT NECHES	ECUADOR	ORIENTE	0	1.34	17.6
ARCHEM IMPORTS	CANADA	FUEL OIL	1	0.00	60
ARCHEM IMPORTS	CANADA	HEAVY	0	0.00	0.00
NPCD			2,800		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=12 -- PADD 4 -- NOT SPR CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
CONOCO-DUPONT BILLINGS	CANADA	FEDERATED	7,123	0.50	39.3
CONOCO-DUPONT BILLINGS	CANADA	HEAVY	1,247	1.91	28.9
FARMERS UNION LAUREL	CANADA	FEDERATED	1,080	1.34	38.6
FARMERS UNION LAUREL	CANADA	FUEL OIL	732	0.33	65.5
FARMERS UNION LAUREL	CANADA	HEAVY	2,918	2.11	27.8
WESTCO CUTBANK	CANADA	FUEL OIL	36	0.54	65.8
WESTCO CUTBANK	CANADA	HEAVY	9	0.54	29.7
EXXON BILLINGS	CANADA	FUEL OIL	155	0.00	65.7
SIMMONS GREAT FALLS	CANADA	FEDERATED	609	0.00	38.8
SIMMONS GREAT FALLS	CANADA	FUEL OIL	76	0.00	65.9
NPCD			13,986		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=13 -- PADD 5 -- SPR CONNECTED

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
ARCO CARSON	ALGERIA		399	0.24	64.3
COASTAL HERCULES	BOLIVIA		247	0.10	58.8
COASTAL HERCULES	INDONESIA	LIGHT	773	0.02	54.5
COASTAL HERCULES	MALAYA		462	0.10	47.1
CONOCO-DUPONT SANTA MARIA	INDONESIA	MEDIUM	227	0.00	35.4
CONOCO-DUPONT SANTA MARIA	PERU		368	0.00	34.1
MOBIL FERNDALE	INDONESIA	LIGHT	1,864	0.07	54.4
CRYSEN TACOMA	VENEZUELA	HEAVY	781	2.25	11.9
POWERINE SANTA FE SPRINGS	ECUADOR	ORIENTE	350	1.20	29
POWERINE SANTA FE SPRINGS	INDONESIA	LIGHT	157	0.03	42
SHELL ANACORTES	CANADA	FEDERATED	2,159	0.29	41.5
SHELL ANACORTES	CANADA	HEAVY	.	.	32.3
SHELL ANACORTES	INDONESIA	LIGHT	362	0.02	53.4
SHELL ANACORTES	PERU		418	0.74	27.6
SHELL WILMINGTON	ECUADOR	ORIENTE	698	1.58	28.9
SHELL WILMINGTON	INDONESIA	LIGHT	248	0.01	55
CHEVRON EL SEGUNDO	BRUNEI		251	0.09	65
CHEVRON EL SEGUNDO	INDONESIA	HEAVY	1,318	0.17	21.1
CHEVRON EL SEGUNDO	INDONESIA	LIGHT	1,789	0.15	52.2
CHEVRON EL SEGUNDO	INDONESIA	MEDIUM	14,993	0.08	35.6
CHEVRON RICHMOND	BRUNEI		147	0.09	65.9
CHEVRON RICHMOND	INDONESIA	LIGHT	145	0.02	54.1
CHEVRON RICHMOND	INDONESIA	MEDIUM	11,793	0.09	34.4
CHEVRON HONOLULU	INDONESIA	HEAVY	200	0.09	20.8
CHEVRON HONOLULU	INDONESIA	MEDIUM	8,770	0.09	35.7
TEXACO PUGET SOUND	CANADA	FEDERATED	909	0.47	41.5
TEXACO PUGET SOUND	INDONESIA	LIGHT	2,124	0.04	53.7
TEXACO PUGET SOUND	INDONESIA	MEDIUM	11,557	0.08	35.5
TEXACO PUGET SOUND	MALAYA		468	0.11	32.5
TEXACO LOS ANGELES	INDONESIA	MEDIUM	634	0.11	35
GOLDEN EAGLE CARSON	INDONESIA	LIGHT	227	0.00	43.4
UNION OIL WILMINGTON	INDONESIA	LIGHT	2,346	0.03	42.8
UNION OIL WILMINGTON	INDONESIA	MEDIUM	4,347	0.09	33.2
CHAMPLIN WILINGTON	CANADA	HEAVY	450	1.20	34.5
TIME OIL TACOMA	VENEZUELA	HEAVY	902	3.22	11.4
THIRFTY SANTA FE SPRINGS	BRUNEI		199	0.06	35.2
THIRFTY SANTA FE SPRINGS	INDONESIA	LIGHT	300	0.00	58
THIRFTY SANTA FE SPRINGS	INDONESIA	MEDIUM	1,809	0.08	33.5
NPCD			75,190		

1983 US CRUDE OIL IMPORTS BY COUNTRY
RECEIVED BY REFINERIES IN EACH NPC DISTRICT
THOUSANDS OF BARRELS

NPC DISTRICT=SPR IMPORTS

REFINER	COUNTRY OF ORIGIN	CRUDE STREAM	VOLUME (1000 BBL)	PERCENT SULFUR	API GRAVITY
SPRO IMPORTS	ECUADOR	ORIENTE	337	1.02	29.1
SPRO IMPORTS	MEXICO	ISTHMUS	976	1.50	33.4
SPRO WEST HACKBERRY	ALGERIA		1,335	0.06	42.2
SPRO WEST HACKBERRY	MEXICO	ISTHMUS	13,353	1.46	32.9
SPRO WEST HACKBERRY	NIGERIA	LIGHT	451	0.04	42.6
SPRO WEST HACKBERRY	NIGERIA	MEDIUM	4,334	0.10	36.2
SPRO WEST HACKBERRY	NORWAY	EKOFISK	550	0.21	43.2
SPRO WEST HACKBERRY	UNITED KINGDOM	MEDIUM	21,991	0.30	36.8
SPRO WEST HACKBERRY	UNITED KINGDOM	SOUR	498	0.55	36.1
SPRO BRYAN MOUND	MEXICO	ISTHMUS	36,289	1.49	33.4
SPRO BRYAN MOUND	MEXICO	MAYAN	771	3.43	22.1
SPRO BRYAN MOUND	SAUDIA ARABIA	LIGHT	1,097	1.85	32.7
SPRO BRYAN MOUND	OMAN		3,008	0.99	34.7
SPRO BRYAN MOUND	EGYPT	SUEZ BLEND	297	1.22	31
NPCD			85,285		
			1,164,355		

Refinery Input of Crude Oil and Petroleun Products, 1982
By Strategic Petroleum Reserve Refining Area
(Thousand Barrels, except Where Noted)

	(1 + 2) 01	(3) 02	(5) 03	(6) 04	(9) 05	(8) 06	(7) 07	(10) 08	(11) 09	(12) 10	(13) 11	(4) 12	TOTAL
CRUDE OIL (incl. lease cond)	576449	18157	303840	600339	539429	312732	112660	136378	263479	151814	737486	719213	4471976
NATURAL GAS LIQUIDS													
Nat. Gasoline & Isopen	0	246	11082	2816	11113	11153	1181	1027	14081	1168	3311	6945	64123
Unfrac. Stream	0	0	0	0	0	0	0	8	0	0	0	0	8
Plant Condensate	0	0	229	0	7254	263	0	707	3472	896	96	1380	14297
Liquefied Petro. Gases	2916	0	13090	19275	11036	4525	4528	3944	9089	4365	9770	27085	109623
Ethane	0	0	0	715	0	660	0	0	0	1	0	2	1378
Propane	1	0	38	627	0	0	0	0	0	69	2	625	1362
Butane	950	0	6646	12874	8944	946	2819	2173	3547	3553	6136	16145	64733
Butane-Propane Mix	0	0	0	273	0	715	108	326	225	72	74	48	1841
Ethane-Propane Mix	0	0	0	45	0	0	0	1	0	0	0	0	46
Isobutane	1965	0	6406	4741	2092	2204	1601	1444	5317	670	3558	10265	40263
OTHER LIQUIDS													
Other Hydro. & Alcohol	1127	337	59	2031	2290	2334	260	521	204	759	6516	2688	19126
Unfinished oils (net)	28796	-131	6434	17748	27900	8175	6923	6369	11028	-4662	5490	8158	122228
Motor Gas Blend Comp(net)	4364	1315	55	28506	11760	-159	263	1523	-5141	545	4441	16780	64252
Av. Gas Blend Comp (net)	-5	0	-4	11	162	-98	0	0	-876	0	24	7	-779
TOTAL INPUT	613647	19924	334785	670726	610944	338925	125815	150477	295336	154885	767134	782256	4864854
Crude Oil Distillation													
Gross input (daily avg.)	1611	50	842	1730	1551	882	309	349	783	422	2068	2047	12650
Operable Cap. (Daily avg.)	2528	66	1085	2318	2206	1397	501	644	1058	614	3146	2755	18323
Operating Ratio (percent)	63.7	77.0	77.6	74.7	70.3	63.2	61.7	54.2	74.0	68.7	65.8	74.3	69.0
Crude Oil Qualities													
Sulfur Content, W.Avg.	1.07	0.26	0.54	0.79	1.10	0.89	0.94	0.49	0.77	0.84	1.00	0.99	0.92
API Gravity, W.Avg.	31.25	41.64	37.96	33.28	33.23	35.70	36.97	35.87	36.82	36.18	25.91	34.70	33.00
REFINERY RECEIPTS OF ALASKAN CRUDE OIL	102278	0	6628	47192	57035	10165	6293	16323	2685	0	294956	13311	556866

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

Refinery Input of Crude Oil and Petroleun Products, 1982
By Strategic Petroleum Reserve Refining Area
(Thousand Barrels, except Where Noted)

	(1 + 2) 01	(3) 02	(5) 03	(6) 04	(9) 05	(8) 06	(7) 07	(10) 08	(11) 09	(12) 10	(13) 11	(4) 12	TOTAL
LIQUEFIED REFINERY GASES	17383	-5	5810	10768	19234	3038	2316	2275	4730	847	13416	20410	100222
For Pchem Use	4257	-5	586	1874	11529	1264	1138	-2	239	-71	2184	2124	25117
For Other Use	13126	0	5224	8894	7705	1774	1178	2277	4491	918	11232	18286	75105
Ethane	0	0	0	0	961	0	89	0	0	4	123	293	1470
Petrochem Use	0	0	0	0	961	0	89	0	0	0	3	0	1053
Other Use	0	0	0	0	0	0	0	0	0	4	120	293	417
Propane	13623	0	7023	11165	18214	2791	3006	2014	4102	1756	10073	20014	93781
Petrochem Use	3682	0	561	1175	7864	1264	950	77	0	32	1555	2125	19285
Other Use	9941	0	6462	9990	10350	1527	2056	1937	4102	1724	8518	17889	74496
Butane	3450	-5	-1213	-156	-670	247	-878	222	279	-712	2787	111	3462
Petrochem Use	575	-5	25	529	2328	0	0	41	66	10	626	0	4195
Other Use	2875	0	-1238	-685	-2998	247	-878	181	213	-722	2161	111	-733
Butane-Propane Mix	310	0	0	-241	609	0	99	159	205	-88	433	-7	1479
Petrochem Use	0	0	0	170	256	0	99	0	29	0	0	0	554
Other Use	310	0	0	-411	353	0	0	159	176	-88	433	-7	925
Isobutane Petrochem Use	0	0	0	0	120	0	0	-120	144	-113	0	-1	30
Finished Motor Gasoline	256665	5289	188155	321874	296173	152834	64896	64156	132323	82558	343125	448698	2356746
Finished Leaded	107496	3989	110413	163448	113424	63093	31735	24859	73394	53471	156617	211630	1113569
Finished Unleaded	149169	1300	77742	158426	182749	89741	33161	39297	58929	29087	186508	237068	1243177
Finished Aviation Gasoline	111	0	366	1371	1034	1626	0	18	76	322	2339	934	8197
Naphtha-type jet fuel	7679	385	5167	4134	1289	4712	712	6678	13890	4835	18390	6371	74242
Kerosene-type jet fuel	19739	0	7913	64958	22465	31001	13547	4367	9411	5987	76039	35916	291343
Kerosene	5912	171	333	13984	13545	705	1	330	905	558	2030	7146	45620
Distillate Fuel Oil	128242	6115	88908	115502	132463	66343	21607	45382	68320	40539	119109	150938	983468
Residual Fuel Oil	113932	386	8547	68079	41344	30275	6395	10858	15722	4301	122436	31881	454156
Naphtha < 400	9223	0	980	923	17967	12005	559	1834	11630	11	2384	2066	59582
Other Oils > 400	262	0	7	31313	36051	1320	1872	1902	3605	0	4697	16224	97253
Special Naphthas	-60	221	2007	140	6265	2414	0	-29	3557	55	1315	2543	18428
Lubricants	4497	4497	4316	4391	9235	10812	2804	0	2560	277	4624	5631	53644
Wax	643	967	357	350	685	677	419	0	511	103	737	114	5563
Petroleum Coke	13657	0	10900	16529	16831	9625	4367	3796	5079	3769	38594	26391	149538
Marketable	4861	0	6241	9152	7687	4215	2748	1880	2047	2085	29022	15411	85349
Catalyst	8796	0	4659	7377	9144	5410	1619	1916	3032	1684	9572	10980	64189
Asphalt & Road Oil	24220	443	7140	13071	2995	2190	0	251	14904	7041	17613	30164	120032
Still Gas	24693	682	13335	24615	28404	18394	5832	5262	10391	5969	39413	30526	207516
Petrochem. Use	387	0	0	1036	3152	1890	0	0	59	187	708	15	7434
Other Use	24306	682	13335	23579	25252	16504	5832	5262	10332	5782	38705	30511	200082
Miscellaneous Products	8640	315	681	2963	2789	540	3195	7859	1844	256	2325	1045	32452
Fuel Use	1255	15	285	0	89	12	3185	0	7	134	276	-230	5028
Non-fuel use	7385	300	396	2963	2700	528	10	7859	1837	122	2049	1275	27424
TOTAL PRODUCTION	635438	19466	344922	694965	648769	348511	128522	154939	299458	157428	808586	816998	5058002
Processing Gain (-)/loss (+)	-21791	458	-10137	-24239	-37825	-9586	-2707	-4462	-4122	-2543	-41452	-34742	-193148

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Refinery Input of Crude Oil and Petroleun Products, 1982
By Strategic Petroleum Reserve Refining Area
(Thousand Barrels, except Where Noted)

	(1 + 2) 01	(3) 02	(5) 03	(6) 04	(9) 05	(8) 06	(7) 07	(10) 08	(11) 09	(12) 10	(13) 11	(4) 12	TOTAL
CRUDE OIL (incl. lease cond)	498605	17137	265504	567018	557498	323738	112576	134089	269445	153280	766515	748812	4414217
NATURAL GAS LIQUIDS													
Nat. Gasoline & Isopen	328	299	11001	3348	12772	6657	1980	1303	14917	1188	3128	7000	63921
Unfrac. Stream	0	0	0	85	0	0	0	84	0	0	0	0	169
Plant Condensate	0	0	146	0	6302	0	0	500	2491	759	0	1207	11405
Liquefied Petro. Gases	1470	0	11584	16119	10457	2210	2793	3729	8484	3968	6697	24925	92436
Ethane	0	0	0	846	8	0	0	0	0	9	0	7	870
Propane	11	0	26	610	15	0	0	1	27	103	75	670	1538
Butane	415	0	5984	7790	7852	103	1547	1905	3311	2372	4532	15720	51531
Butane-Propane Mix	0	0	48	1292	128	312	10	346	232	904	280	25	3577
Ethane-Propane Mix	0	0	0	0	0	0	0	0	0	0	0	0	0
Isobutane	1044	0	5526	5581	2454	1795	1236	1477	4914	580	1810	8503	34920
OTHER LIQUIDS													
Other Hydro. & Alcohol	1070	0	410	2698	2324	1581	151	273	239	160	5101	5276	19283
Unfinished oils (net)	33748	68	1458	8589	27867	3851	3149	16835	11336	-6349	7189	-1705	106036
Motor Gas Blend Comp(net)	5910	630	8002	19386	10410	142	300	2101	-5485	704	-38	8187	50249
Av. Gas Blend Comp (net)	-30	0	-1	7	0	6	0	0	0	-1	-12	66	35
TOTAL INPUT	541101	18134	298104	617250	627630	338185	120949	158914	301427	153709	788580	793768	4757751
Crude Oil Distillation													
Gross input (daily avg.)	1392	47	739	1569	1587	898	310	384	762	426	2133	2099	12352
Operable Cap. (Daily avg.)	2183	57	958	2269	1977	1435	497	563	1042	560	3115	2727	17386
Operating Ratio (percent)	63.8	82.1	77.2	69.2	80.3	62.6	62.4	68.2	73.2	76.2	68.5	77.0	71.0
Crude Oil Qualities													
Sulfur Content, W.Avg.	0.98	0.30	0.55	0.77	1.04	0.85	1.07	0.60	0.80	0.95	0.99	1.01	0.91
API Gravity, W.Avg.	30.71	41.61	37.79	33.72	34.22	35.80	34.38	35.94	37.29	35.39	25.74	35.05	33.05
REFINERY RECEIPTS OF ALASKAN CRUDE OIL	83739	0	413	50753	73632	9471	7865	20814	4217	0	308095	15797	574796

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Refinery Input of Crude Oil and Petroleun Products, 1982
By Strategic Petroleum Reserve Refining Area
(Thousand Barrels, except Where Noted)

	(1 + 2) 01	(3) 02	(5) 03	(6) 04	(9) 05	(8) 06	(7) 07	(10) 08	(11) 09	(12) 10	(13) 11	(4) 12	TOTAL
LIQUEFIED REFINERY GASES	15710	0	5506	23363	24730	2514	2356	4220	3907	1468	14577	22518	120869
For Pchem Use	4519	0	580	10623	13689	1623	680	1076	544	32	2415	2599	38380
For Other Use	11191	0	4926	12740	11041	891	1676	3144	3363	1436	12162	19919	82489
Ethane	86	0	23	13	5427	0	86	0	0	5	-3	0	5637
Petrochem Use	0	0	0	13	3198	0	12	0	0	0	0	0	3223
Other Use	86	0	23	0	2229	0	74	0	0	5	-3	0	2414
Propane	13393	0	6494	12456	20061	1237	2928	3908	3596	1942	9945	22082	98042
Petrochem Use	3898	0	541	1047	9728	894	668	1063	345	0	1679	2420	22283
Other Use	9495	0	5953	11409	10333	343	2260	2845	3251	1942	8266	19662	75759
Butane	1868	0	-1016	10843	-1476	1277	-658	-54	-79	-306	3938	284	14621
Petrochem Use	621	0	39	9563	585	729	0	13	182	6	736	0	12474
Other Use	1247	0	-1055	1280	-2061	548	-658	-67	-261	-312	3202	284	2147
Butane-Propane Mix	363	0	5	51	540	0	0	366	373	-199	697	-27	2169
Petrochem Use	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Use	363	0	5	51	540	0	0	366	373	-199	697	-27	2169
Isobutane Petrochem Use	0	0	0	0	178	0	0	0	17	26	0	179	400
Finished Motor Gasoline	236241	4196	177420	294489	302443	154905	63962	72291	135817	80395	357183	469858	2349200
Finished Leaded	86960	2784	102374	129356	124711	63596	23452	27984	69780	50199	155476	210469	1047141
Finished Unleaded	149281	1412	75046	165133	177732	91309	40510	44307	66037	30196	201707	259389	1302059
Finished Aviation Gasoline	146	0	349	1564	1087	1109	0	115	146	306	2228	1000	8050
Naphtha-type jet fuel	6799	506	4266	3846	-5	8691	1354	5719	15434	4570	17454	6917	75551
Kerosene-type jet fuel	17510	0	8009	61082	28035	35276	12478	6226	9146	7345	82346	38616	306069
Kerosene	4406	324	336	13925	14650	106	-187	69	745	404	2149	5629	42556
Distillate Fuel Oil	114282	5298	72928	106100	126072	56575	20914	43028	66897	41002	125799	144986	923881
Residual Fuel Oil	84396	534	4625	36122	33647	33125	4310	12038	12752	3650	112009	23181	360389
Naphtha < 400	8926	0	1004	3438	8060	8749	-115	3908	15146	0	1588	5290	55994
Other Oils > 400	73	0	29	30528	44189	1503	3442	2806	1775	2	6484	1904	92735
Special Naphthas	726	283	2172	486	7737	2552	16	6	2240	39	1096	3183	20536
Lubricants	5686	4094	3881	5766	10072	9502	2987	0	4075	319	4215	5182	55779
Wax	820	827	356	428	695	678	478	0	810	111	701	197	6101
Petroleum Coke	13436	0	8866	18529	17168	9500	5129	4593	4870	3518	38494	29202	153305
Marketable	4470	0	5617	11278	7362	4367	3646	2717	1725	1586	29890	16773	89431
Catalyst	8966	0	3249	7251	9806	5133	1483	1876	3145	1932	8604	12429	63874
Asphalt & Road Oil	24759	475	6591	16880	3690	2430	0	450	17115	7913	19932	35463	135698
Still Gas	23772	390	10934	21502	27849	17904	6001	5998	10213	5728	42151	33197	205639
Petrochem. Use	2543	0	0	671	2729	2269	0	0	56	274	660	20	9222
Other Use	21229	390	10934	20831	25120	15635	6001	5998	10157	5454	41491	33177	196417
Miscellaneous Products	3850	410	683	1989	3250	573	2829	3911	1363	390	2072	1345	22665
Fuel Use	1016	166	166	444	139	0	2815	0	0	60	325	15	5146
Non-fuel use	2834	244	517	1545	3111	573	14	3911	1363	330	1747	1330	17519
TOTAL PRODUCTION	561538	17337	307955	640037	653369	345692	125954	165378	302451	157160	830478	827668	4935017
Processing Gain (-)/loss (+)	-20437	797	-9851	-22787	-25739	-7507	-5005	-6464	-1024	-3451	-41898	-33900	-177266

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CRUDE OIL DISTILLATION CAPACITY
JANUARY 1, 1983

	CRUDE OIL DISTILLATION CAPACITY				CRUDE OIL DISTILLATION CAPACITY	
	BARRELS PER CALENDAR DAY		BARRELS PER STREAM DAY		BARRELS PER CALENDAR DAY	BARRELS PER STREAM DAY
	OPERATING	IDLE	OPERATING	IDLE	TOTAL	TOTAL
REFINING AREA						
01 (1 + 2)	1933750	290995	2045900	321000	2224745	2366900
02 (3)	55756	200	61500	275	55956	61775
03 (5)	867509	93800	912173	99560	961309	1011733
04 (6)	1958100	423556	2045300	435559	2381656	2480859
05 (9)	1870850	101800	1993500	107166	1972650	2100666
06 (8)	1046900	441900	1095400	486000	1488800	1581400
07 (7)	474900	23000	492000	25000	497900	517000
08 (10)	466700	123720	483000	138400	590420	621400
09 (11)	973924	65164	1041462	75294	1039088	1116756
10 (12)	537405	23300	592550	25400	560705	617950
11 (13)	2933460	192600	3130235	216900	3126060	3347135
12 (4)	2465893	253650	2600320	264800	2719543	2865120
TOTAL	15585147	2033685	16493340	2195354	17618832	18688694

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CRUDE OIL DISTILLATION CAPACITY
JANUARY 1, 1984

	CRUDE OIL DISTILLATION CAPACITY				CRUDE OIL DISTILLATION CAPACITY	
	BARRELS PER CALENDAR DAY		BARRELS PER STREAM DAY		BARRELS PER CALENDAR DAY	BARRELS PER STREAM DAY
REFINING AREA	OPERATING	IDLE	OPERATING	IDLE	TOTAL	TOTAL
01 (1 + 2)	1920350	112200	2032700	122000	2032550	2154700
02 (3)	54706	3200	57800	3833	57906	61633
03 (5)	845207	54150	894483	59000	899357	953483
04 (6)	1886000	165756	1962000	178741	2051756	2140741
05 (9)	1903850	22500	2018500	24500	1926350	2043000
06 (8)	1134900	208100	1193000	221400	1343000	1414400
07 (7)	463000	27000	479000	29500	490000	508500
08 (10)	443800	95400	462000	104000	539200	566000
09 (11)	928654	112230	983958	127067	1040884	1111025
10 (12)	528605	28000	565650	30200	556605	595850
11 (13)	2859170	266320	3039853	294100	3125490	3333953
12 (4)	2495443	214600	2626920	224000	2710043	2850920
TOTAL	15463685	1309456	16315864	1418341	16773141	17734205

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OPERABLE PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1983
(BARRELS PER STREAM DAY,EXCEPT WHERE NOTED)

	FACILITIES CAPACITY										
	CRUDE DISTILL-ATION	VACUUM DISTILL-ATION	THERMAL CRACKING	CATALYT-IC CRACKING FRESH	CATALYT-IC CRACKING RECYCLED	CATALYT-IC REFORMI-NG	CATALYT-IC HYDROCR-ACKING	CATALYT-IC HYDROTR-EATING	ALKYLAT-ION	AROMATI-CS/ISOM-ERIZATI-ON	ASPHALT
REFINING AREA											
01 (1 + 2)	2366900	1097700	153780	641300	92100	614100	90000	1569100	72300	107372	149200
02 (3)	61775	23180	.	.	.	12850	4440	17300	.	.	.
03 (5)	1011733	292660	99100	375500	29750	241350	8190	298600	91770	27045	30873
04 (6)	2480859	1075500	382200	754300	48300	450700	138700	852500	143700	42500	88400
05 (9)	2100666	883000	198000	763000	76700	516115	82000	1605400	111200	107175	17200
06 (8)	1581400	609000	91500	417500	52500	321500	50000	645350	47400	37100	11400
07 (7)	517000	122000	45500	180600	0	112000	.	210000	37500	2300	.
08 (10)	621400	256000	31200	160000	5500	149600	.	304500	39200	51800	2000
09 (11)	1116756	298308	41800	282900	32525	211280	0	385600	68300	46950	63415
10 (12)	617950	195010	31500	190400	32600	117250	4900	240800	30580	9500	32650
11 (13)	3347135	1513900	523800	698700	49850	674130	392400	1383172	132700	27300	113688
12 (4)	2865120	1135000	177300	990200	72400	765700	127500	1423700	189900	63700	213810
TOTAL	18688694	7501258	1775680	5454400	492225	4186575	898130	8936022	964550	522742	722636

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OPERABLE PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1983
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY			
	LUBRICATING OILS	HYDROGEN (MMCFD)	PETROLEUM COKE	TOTAL
REFINING AREA				
01 (1 + 2)	35800	133	15051	7004836
02 (3)	16632	5	.	136182
03 (5)	13100	9	18094	2537774
04 (6)	17400	182	43800	6519041
05 (9)	49100	235	22500	6532291
06 (8)	45700	60	14625	3925035
07 (7)	7000	.	8750	1242650
08 (10)	.	40	13460	1634700
09 (11)	16804	444	5930	2571012
10 (12)	1830	20	7350	1512340
11 (13)	21792	1057	99020	8978644
12 (4)	22800	131	47200	8094461
TOTAL	247958	2316	295780	50688966

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OPERABLE PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1984
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY										
	CRUDE DISTILL-ATION	VACUUM DISTILL-ATION	THERMAL CRACKING	CATALYT-IC CRACKING FRESH	CATALYT-IC CRACKING RECYCLED	CATALYT-IC REFORMI-NG	CATALYT-IC HYDROCR-ACKING	CATALYT-IC HYDROTR-EATING	ALKYLAT-ION	AROMATI-CS/ISOM-ERIZATI-ON	ASPHALT
REFINING AREA											
01 (1 + 2)	2154700	1058400	172500	568300	88100	580270	89000	1550600	65000	96877	162100
02 (3)	61633	21900	.	.	.	11420	4440	19576	.	.	2400
03 (5)	953483	282600	96500	353400	26400	219300	8190	345540	84300	26245	31950
04 (6)	2140741	964500	333700	642800	48300	445500	138700	987000	138700	23914	103900
05 (9)	2043000	889000	198000	758000	76700	514500	82000	1686400	111200	107175	17700
06 (8)	1414400	604200	81500	420000	52500	305500	47000	658450	50100	39395	11400
07 (7)	508500	146000	122400	180600	0	118400	30000	266000	39000	2300	0
08 (10)	566000	244000	55500	198700	2800	147500	10000	458600	40700	44800	10000
09 (11)	1111025	296570	43300	286400	39525	212700	0	397100	67800	46250	72888
10 (12)	595850	200900	30700	190900	33800	114100	12100	237500	30380	9500	38000
11 (13)	3333953	1591700	545800	702950	50550	665630	396900	1452772	132800	28500	133491
12 (4)	2850920	1148700	251700	1022200	72900	746200	148500	1452000	184800	61500	217010
TOTAL	17734205	7448470	1931600	5324250	491575	4081020	966830	9511538	944780	486456	800839

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OPERABLE PETROLEUM REFINERIES
BY STRATEGIC PETROLEUM RESERVE REFINING AREA, JANUARY 1, 1984
(BARRELS PER STREAM DAY, EXCEPT WHERE NOTED)

	FACILITIES CAPACITY			
	LUBRICATING OILS	HYDROGEN (MMCFD)	PETROLEUM COKE	TOTAL
REFINING AREA				
01 (1 + 2)	36600	114	29460	6652021
02 (3)	16877	5	.	138251
03 (5)	13720	9	19529	2461166
04 (6)	17400	268	60800	6046223
05 (9)	51100	275	37300	6572350
06 (8)	44600	60	24910	3754015
07 (7)	9000	28	27800	1450028
08 (10)	.	80	14350	1793030
09 (11)	17628	372	6830	2598388
10 (12)	1830	27	9650	1505237
11 (13)	17000	1033	111430	9164509
12 (4)	21800	191	65743	8244164
TOTAL	247555	2462	407802	50379382

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	01 (1 + 2)		02 (3)		03 (5)		04 (6)		05 (9)		06 (8)
	YEAR		YEAR		YEAR		YEAR		YEAR		YEAR
	1983	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983
PRODUCT											
CRUDE OIL INCL. LEASE CONDENSATE	1485107	1501309	48700	49200	795279	811618	1631795	1684309	1508678	1553882	870450
LOW SULFUR CRUDE OIL	607272	603815	46000	46200	644946	662967	1082998	907440	629010	645450	402700
MEDIUM SULFUR CRUDE OIL	67524	65500	.	.	97000	96900	40800	71600	78654	130500	80200
HIGH SULFUR CRUDE OIL	810311	831994	2700	3000	53333	51751	507997	705269	801014	777932	387550
NATURAL GAS LIQUIDS	5125	4480	1372	1372	34675	35121	47806	51277	116424	118100	31659
OTHER HYDROCARBONS	1567	1400	1922	2429	6172	5635	8900	13000	39968	36743	7290
UNFINISHED OILS	217396	211590	3170	3365	22716	24211	105529	121886	112669	117491	78601
GASOLINE BLENDING COMPONENTS	8014	13031	5543	5543	47924	29446	55648	59934	66330	67593	5286
TOTAL	1717209	1731810	60707	61909	906766	906031	1849678	1930406	1844069	1893809	993286

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA											
	06(8)	07(7)		08(10)		09(11)		10(12)		11(13)		
	YEAR	YEAR		YEAR		YEAR		YEAR		YEAR		
	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983	1984	
PRODUCT												
CRUDE OIL INCL. LEASE CONDENSATE	1027840	313315	408600	373397	418664	789417	833423	438948	459305	2205934	2248247	
LOW SULFUR CRUDE OIL	442200	202859	170600	238629	210324	439433	468426	218073	238146	304547	220855	
MEDIUM SULFUR CRUDE OIL	41000	1415	50250	52201	74000	49317	69397	109880	109995	541518	628592	
HIGH SULFUR CRUDE OIL	544640	109041	187750	82567	134340	300667	295600	110995	111164	1359869	1398800	
NATURAL GAS LIQUIDS	33139	20910	20700	24580	35792	128200	128709	12633	13122	27680	23160	
OTHER HYDROCARBONS	22290	1500	1500	18660	19780	5189	10350	3966	4112	37742	38340	
UNFINISHED OILS	74021	22857	27977	72941	89753	61607	64925	7121	6986	193379	194241	
GASOLINE BLENDING COMPONENTS	5406	2594	.	13471	21590	14704	11882	8961	9051	40198	44312	
TOTAL	1162696	361176	458777	503049	585579	999117	1049289	471629	492576	2504933	2548300	

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA	
	12(4)	
	YEAR	
	1983	1984
PRODUCT		
CRUDE OIL INCL. LEASE CONDENSATE	2140182	2196739
LOW SULFUR CRUDE OIL	1117731	1148046
MEDIUM SULFUR CRUDE OIL	158357	168067
HIGH SULFUR CRUDE OIL	864094	880626
NATURAL GAS LIQUIDS	85111	83800
OTHER HYDROCARBONS	3500	3051
UNFINISHED OILS	41730	35734
GASOLINE BLENDING COMPONENTS	53848	47793
TOTAL	2324371	2367117

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	01 (1 + 2)		02 (3)		03 (5)		04 (6)		05 (9)		06 (8)
	YEAR		YEAR		YEAR		YEAR		YEAR		YEAR
	1983	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983
PRODUCT											
UNFINISHED OILS	36530	40603	443	517	2524	2524	55011	53727	38423	37888	30968
GASOLINE BLENDING COMPONENTS	0	0	1000	1000	3381	3640	9374	9545	9979	10127	817
FINISHED MOTOR GASOLINE	682281	677800	15014	15309	532804	523835	797276	835761	846501	844415	394341
FINISHED LEADED GASOLINE	266790	246257	9515	9443	311563	280791	332792	321340	318593	313496	147374
FINISHED UNLEADED GASOLINE	415491	431543	5499	5866	221241	243044	464484	514421	527908	530919	246967
JET FUEL	48825	62304	960	960	33024	38349	207336	207938	66332	71271	132986
JET FUEL-NAPHTHA	12348	24903	960	960	12775	14005	12064	12310	5700	5700	29100
JET FUEL-KEROSENE	36477	37401	.	.	20249	24344	195272	195628	60632	65571	103886
KEROSENE	21096	21355	2208	2328	4751	6182	20033	19903	42055	42050	6900
DISTILLATE FUEL OIL	341356	332957	13604	14093	209588	209122	325721	349152	356723	367937	152622
RESIDUAL FUEL OIL	320216	320084	2457	2585	15980	17063	159355	155884	95404	102482	81497
ASPHALT & ROAD OIL	71248	76311	.	.	14520	13825	27313	32047	7392	7400	8350
LUBRICATING OILS	21784	22366	13319	12318	12372	12890	11100	11100	32881	33049	35257
WAX	2574	2598	2817	2939	1166	1185	800	800	2848	2848	2910
PETROLEUM COKE	7727	7299	.	.	16624	16160	36107	46292	21900	21900	15937
SPECIAL NAPHTHAS	210	80	820	845	6766	7310	11392	14260	20048	20745	24160
LIQUEFIED PETROLEUM GASES	43021	46738	.	.	18091	18365	34932	46523	90649	87957	29569
ALL OTHER PRODUCTS	103446	107653	6975	6906	27349	28322	184914	180899	272078	292311	89601
TOTAL	1700314	1718148	59617	59800	898940	898772	1880664	1963831	1903213	1942380	1005915

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	06(8)	07(7)		08(10)		09(11)		10(12)		11(13)	
	YEAR	YEAR		YEAR		YEAR		YEAR		YEAR	
PRODUCT	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983	1984
UNFINISHED OILS	62508	2771	4927	16190	17960	28155	30476	13116	11751	209117	204951
GASOLINE BLENDING COMPONENTS	817	0	0	12830	9160	46657	18926	4124	4124	33742	32545
FINISHED MOTOR GASOLINE	463751	194757	222097	227976	266258	371065	408283	226389	237577	1017464	1015418
FINISHED LEADED GASOLINE	181889	69095	63499	72245	84546	191292	213550	143275	147445	442019	423685
FINISHED UNLEADED GASOLINE	281862	125662	158598	155731	181712	179773	194733	83114	90132	575445	591733
JET FUEL	129486	45552	55855	38781	47270	77945	80888	35944	40121	279415	283082
JET FUEL-NAPHTHA	29100	4169	3080	18420	25520	43740	43165	15027	19156	51600	51844
JET FUEL-KEROSENE	100386	41383	52775	20361	21750	34205	37723	20917	20965	227815	231238
KEROSENE	6900	.	.	7000	7000	3317	3410	3200	3200	44339	39769
DISTILLATE FUEL OIL	219402	70993	64592	108203	119478	203550	217054	114262	120156	321057	322793
RESIDUAL FUEL OIL	112017	2266	685	33008	45422	44084	46669	13913	13915	315705	348619
ASPHALT & ROAD OIL	10130	0	0	0	0	46059	53726	21582	22328	58804	61734
LUBRICATING OILS	37947	5850	6000	0	0	12064	14196	850	850	15340	15640
WAX	1600	843	900	0	0	2157	2310	560	560	2800	2700
PETROLEUM COKE	15937	9619	26543	5332	11277	5435	5450	4652	4652	84590	85450
SPECIAL NAPHTHAS	24670	375	375	0	0	14609	17714	150	150	7399	7689
LIQUEFIED PETROLEUM GASES	30769	8375	14459	9279	12968	45348	47477	9285	9988	29477	33007
ALL OTHER PRODUCTS	63136	11796	62966	35973	43403	94094	96495	10691	10458	105729	111107
TOTAL	1179070	353197	459399	494572	580196	994539	1043074	458718	479830	2524978	2564504

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA 12(4)	
	YEAR	
PRODUCT	1983	1984
UNFINISHED OILS	12238	12143
GASOLINE BLENDING COMPONENTS	5998	5871
FINISHED MOTOR GASOLINE	1342032	1364135
FINISHED LEADED GASOLINE	598908	582196
FINISHED UNLEADED GASOLINE	743124	781939
JET FUEL	116374	131903
JET FUEL-NAPHTHA	22433	21613
JET FUEL-KEROSENE	93941	110290
KEROSENE	33283	26135
DISTILLATE FUEL OIL	413682	432957
RESIDUAL FUEL OIL	87884	89297
ASPHALT & ROAD OIL	88459	77236
LUBRICATING OILS	18871	19500
WAX	400	400
PETROLEUM COKE	34763	35694
SPECIAL NAPHTHAS	10860	10910
LIQUEFIED PETROLEUM GASES	57923	58398
ALL OTHER PRODUCTS	128651	127636
TOTAL	2351418	2392215

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	01 (1 + 2)		02 (3)		03 (5)		04 (6)		05 (9)		06 (8)
	YEAR		YEAR		YEAR		YEAR		YEAR		YEAR
	1984	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984
PRODUCT											
CRUDE OIL INCL. LEASE CONDENSATE	1460149	1480696	47995	47166	713448	733812	1666850	1811170	1601643	1633296	902761
LOW SULFUR CRUDE OIL	649442	626100	45216	44166	621484	622323	983060	868140	647098	635800	365581
MEDIUM SULFUR CRUDE OIL	56166	69426	.	.	35845	42315	25000	25000	80700	84700	55491
HIGH SULFUR CRUDE OIL	754541	785170	2779	3000	56119	69174	658790	918030	873845	912796	481689
NATURAL GAS LIQUIDS	3467	4900	950	950	38615	38969	29789	29992	119388	119718	29650
OTHER HYDROCARBONS	8100	7800	.	.	1026	1510	38880	41132	38864	38986	4675
UNFINISHED OILS	203473	190262	3960	3960	34973	38612	110702	104210	136708	131347	56685
GASOLINE BLENDING COMPONENTS	14424	15396	1835	1925	26468	25091	56185	54560	49100	49100	17527
TOTAL	1689613	1699054	54740	54001	814530	837994	1902406	2041064	1945703	1972447	1011298

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	06(8)	07(7)		08(10)		09(11)		10(12)		11(13)	
	YEAR	YEAR		YEAR		YEAR		YEAR		YEAR	
	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984	1985
PRODUCT											
CRUDE OIL INCL. LEASE CONDENSATE	923775	398675	394190	427237	429480	801211	821943	452769	464063	2305491	2356561
LOW SULFUR CRUDE OIL	439580	176613	174096	287380	289623	458499	467197	227826	220040	249831	229028
MEDIUM SULFUR CRUDE OIL	47000	2983	2983	19700	19700	54926	54896	92189	103300	515279	552776
HIGH SULFUR CRUDE OIL	437195	219079	217111	120157	120157	287786	299850	132754	140723	1540381	1574757
NATURAL GAS LIQUIDS	42951	17093	17132	18665	18665	129299	124068	12812	12179	27168	28691
OTHER HYDROCARBONS	4793	1041	800	15210	17210	8771	8837	3245	3312	38660	49560
UNFINISHED OILS	75708	27006	30382	134115	134115	43840	41546	10306	9329	200486	187173
GASOLINE BLENDING COMPONENTS	8044	259	700	18928	18748	20944	22643	9824	9229	37392	42524
TOTAL	1055271	444074	443204	614155	618218	1004065	1019037	488956	498112	2609197	2664509

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY INPUT
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA 12(4) YEAR 1984	REFINING AREA 12(4) YEAR 1985
PRODUCT		
CRUDE OIL INCL. LEASE CONDENSATE	2154068	2191961
LOW SULFUR CRUDE OIL	1168896	1182070
MEDIUM SULFUR CRUDE OIL	193405	192178
HIGH SULFUR CRUDE OIL	791767	817713
NATURAL GAS LIQUIDS	68332	71165
OTHER HYDROCARBONS	6644	6500
UNFINISHED OILS	59150	56368
GASOLINE BLENDING COMPONENTS	35374	35970
TOTAL	2323568	2361964

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	01 (1 + 2)		02 (3)		03 (5)		04 (6)		05 (9)		06 (8)
	YEAR		YEAR		YEAR		YEAR		YEAR		YEAR
	1984	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984
PRODUCT											
UNFINISHED OILS	59084	53710	356	356	9371	8977	50629	64131	85147	85861	20422
GASOLINE BLENDING COMPONENTS	928	800	1000	1000	5891	5891	4806	5444	5581	5890	800
FINISHED MOTOR GASOLINE	642527	649521	10719	10370	460022	469240	881126	937524	871181	892775	425252
FINISHED LEADED GASOLINE	211635	205885	6744	6243	257179	231276	351586	355658	332336	339561	165477
FINISHED UNLEADED GASOLINE	430892	443636	3975	4127	202843	237964	529540	581866	538845	553214	259775
JET FUEL	74786	75555	1390	1390	40025	41936	219534	225610	88895	86800	117778
JET FUEL-NAPHTHA	24119	24945	1390	1390	14856	15011	10900	15900	0	0	20021
JET FUEL-KEROSENE	50667	50610	.	.	25169	26925	208634	209710	88895	86800	97757
KEROSENE	17964	17186	991	951	994	1024	18746	18243	39036	38200	4500
DISTILLATE FUEL OIL	316001	319065	13425	13156	195798	199176	343724	386524	331705	334913	145336
RESIDUAL FUEL OIL	301305	293306	1325	1297	20671	21260	104780	112543	111699	109463	76302
ASPHALT & ROAD OIL	81415	82710	1397	1500	17236	17828	39665	40947	8100	8100	10733
LUBRICATING OILS	21551	20584	12555	12219	11234	12296	15300	15300	33900	33900	35944
WAX	1086	923	2871	2790	1063	1152	1300	1300	3000	3000	1735
PETROLEUM COKE	24935	27165	.	.	14779	15107	50319	57383	34424	34700	21977
SPECIAL NAPHTHAS	.	.	769	769	3589	3669	5943	7166	22955	23282	8214
LIQUEFIED PETROLEUM GASES	43708	45797	.	.	15130	16155	49271	54641	100395	99943	38650
ALL OTHER PRODUCTS	120122	137661	6862	6963	30781	33036	184919	194762	271045	281780	137694
TOTAL	1705412	1723983	53660	52761	826584	846747	1970062	2121518	2007063	2038607	1045337

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA										
	06(8)	07(7)		08(10)		09(11)		10(12)		11(13)	
	YEAR	YEAR		YEAR		YEAR		YEAR		YEAR	
	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984	1985
PRODUCT											
UNFINISHED OILS	45247	12660	7400	29726	29726	28560	24559	9883	9628	266217	251078
GASOLINE BLENDING COMPONENTS	800	0	0	6452	6452	3538	2936	5706	5714	24502	29085
FINISHED MOTOR GASOLINE	461162	233160	239402	254237	254237	409884	429271	240347	241762	1064464	1081071
FINISHED LEADED GASOLINE	165858	59029	57800	153523	153523	205926	215106	145269	142552	420340	396814
FINISHED UNLEADED GASOLINE	295304	174131	181602	100714	100714	203958	214165	95078	99210	644124	684257
JET FUEL	102637	44285	43018	50876	51400	79767	80046	42683	45824	281521	288556
JET FUEL-NAPHTHA	15900	4500	4500	20000	20000	45607	44308	16115	16369	43671	47829
JET FUEL-KEROSENE	86737	39785	38518	30876	31400	34160	35738	26568	29455	237850	240727
KEROSENE	4500	1300	1300	.	.	5495	5719	1680	1450	11019	11323
DISTILLATE FUEL OIL	183957	73540	72424	121887	122590	203053	212209	122418	122770	378674	390198
RESIDUAL FUEL OIL	66411	0	0	43139	43234	36943	36318	13692	13906	301754	311723
ASPHALT & ROAD OIL	14636	0	0	1759	1759	49273	50566	23935	25546	62542	67875
LUBRICATING OILS	30455	5452	5452	.	.	13595	14306	940	940	18140	22640
WAX	1735	819	819	.	.	2456	2455	700	700	2600	3000
PETROLEUM COKE	21977	25456	27006	13050	13050	5009	4955	7401	7321	91408	90578
SPECIAL NAPHTHAS	8050	0	0	3652	3652	12644	12361	140	140	8049	8372
LIQUEFIED PETROLEUM GASES	38850	14467	14345	8302	8302	54829	47223	7369	7685	35198	34883
ALL OTHER PRODUCTS	114449	62333	65223	72163	75018	85359	92711	13468	12806	127218	137799
TOTAL	1094866	473472	476389	605243	609420	990405	1015635	490362	496192	2673306	2728181

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

PROJECTED REFINERY PRODUCTION
BY STRATEGIC PETROLEUM RESERVE REFINING AREA
(BARRELS PER CALENDAR DAY)

	REFINING AREA	
	12(4)	
	YEAR	
	1984	1985
PRODUCT		
UNFINISHED OILS	27441	26786
GASOLINE BLENDING COMPONENTS	5544	4611
FINISHED MOTOR GASOLINE	1320038	1342063
FINISHED LEADED GASOLINE	540965	537703
FINISHED UNLEADED GASOLINE	779073	804360
JET FUEL	135169	139036
JET FUEL-NAPHTHA	25300	25570
JET FUEL-KEROSENE	109869	113466
KEROSENE	24083	22813
DISTILLATE FUEL OIL	416315	436525
RESIDUAL FUEL OIL	63273	63687
ASPHALT & ROAD OIL	83466	86774
LUBRICATING OILS	18430	18430
WAX	360	360
PETROLEUM COKE	58774	59368
SPECIAL NAPHTHAS	8590	8590
LIQUEFIED PETROLEUM GASES	69058	66493
ALL OTHER PRODUCTS	150027	149660
TOTAL	2380568	2425196

NOTE: NPC Refining Center number designations were changed after DOE provided these data. Final NPC Refining Center numbers are shown in parentheses.

Appendix F
The Standard Sales Provisions

Appendix F presents a time chart for marine vessel scheduling derived from the Standard Sales Provisions (SSPs), and a copy of the SSPs.

The time chart is included to illustrate the number of complex tasks that must be completed in a limited period of time, by both the purchaser of SPR crude oil and by DOE. The chart also shows the overlapping nature of the sales cycles.

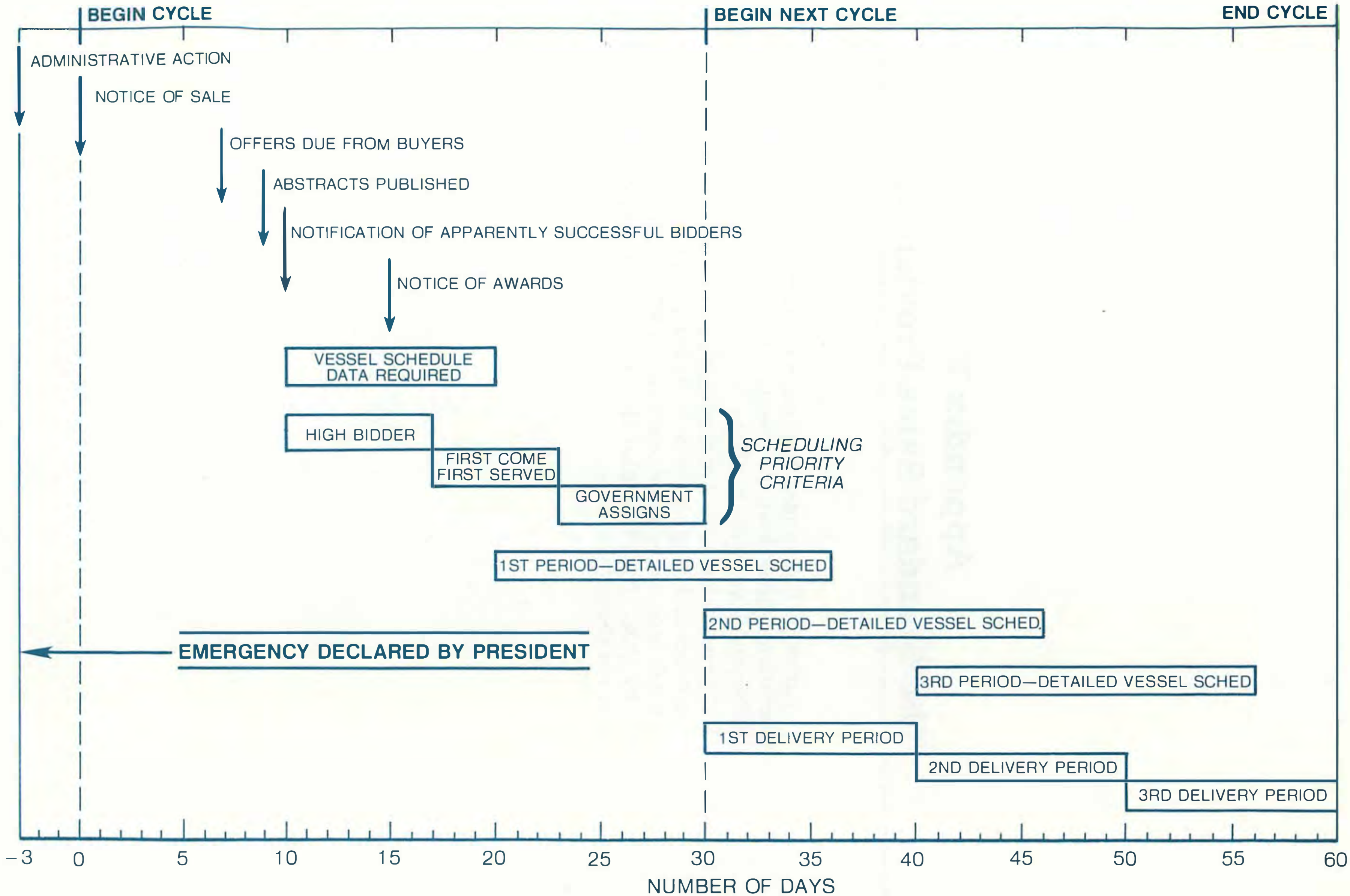

Figure F-1. Time Line for Vessel Scheduling.

federal register

Friday
January 20, 1984

Part VIII

Department of Energy

10 CFR Part 625

Sale of Strategic Petroleum Reserve; Standard Sales Provisions

DEPARTMENT OF ENERGY

10 CFR Part 625

Sale of Strategic Petroleum Reserve Petroleum; Standard Sales Provisions

AGENCY: Procurement and Assistance Management Directorate, Assistant Secretary for Management and Administration, Department of Energy.

ACTION: Interim appendix to final rule; request for further comment.

SUMMARY: On December 21, 1983 (48 FR 56538), the Department of Energy (DOE) published in the **Federal Register** a final rule governing price competitive sales of petroleum from the Strategic Petroleum Reserve (SPR) in the event that the SPR is drawn down to respond to a severe energy supply interruption or to meet obligations of the United States under the Agreement on an International Energy Program (IEP). This final rule provided for the publication in the **Federal Register**, as an appendix thereto, of Standard Sales Provisions (SSPs) containing or describing contract clauses, terms and conditions of sale, and performance and financial responsibility measures, which may be applicable to a particular sale of SPR petroleum. On June 15, 1983, draft SSPs were published in the **Federal Register** for public comment. After consideration of these and other comments, DOE has revised the SSPs and now adopts them on an interim final basis for use in the event that an emergency should occur. DOE also solicits further written comments with respect to these SSPs.

DATES: Comments on the SSPs are requested by March 20, 1984. The effective date of the SSPs is January 20, 1984.

ADDRESSES: Send comments to: Lynn Warner, MA-453.1, Department of Energy, Room 1J-015, 1000 Independence Avenue, SW., Washington, D.C. 20585.

FOR FURTHER INFORMATION CONTACT:

Marcia L. Morris, Procurement and Assistance Management Directorate, Department of Energy, Room 1I-018, 1000 Independence Avenue, SW., Washington, D.C. 20585; (202) 252-8871;

Fred A. Hutchinson, Strategic Petroleum Reserve, Environmental Protection, Safety, and Emergency Preparedness, Department of Energy, Room 3E-042, 1000 Independence Avenue, SW., Washington, D.C. 20585; (202) 252-4734; and

E. Grant Garrison, Office of Assistant General Counsel, International Trade and Emergency Preparedness, Department of Energy, Room 6A-141, 1000 Independence Avenue, SW., Washington, D.C. 20585; (202) 252-2900.

SUPPLEMENTARY INFORMATION:

I. Background

A. The Strategic Petroleum Reserve Drawdown Plan

In the Energy Emergency Preparedness Act of 1982 (EEPA), Pub. L. 97-229, Congress required that a new "Drawdown" (Distribution) Plan, establishing procedures for the sale of oil from the SPR during a drawdown in response to a severe energy supply interruption or to meet IEP obligations, be transmitted to the Congress. The EEPA provided that this amendment to the SPR Plan would take effect on the date transmitted, without Congressional review. The new Distribution Plan, SPR Plan Amendment No. 4, was transmitted to Congress on December 1, 1982, and took effect on that date. The new Plan provided that the principal method of distributing SPR oil will be price competitive sale.

On March 16, 1983, DOE published a notice of proposed rulemaking (48 FR 11125) to establish a framework for implementing the policies and procedures set out in Amendment No. 4. For a discussion of the statutory authority for the SPR, the regulatory background of the proposed rule, and the SPR's physical facilities, *see* the preamble to the proposed rule at 48 FR 11125.

B. The Final Rule

The purpose of the rule is to facilitate the sales process during a drawdown of the SPR by providing for the establishment of Standard Sales Provisions (SSPs), containing contract terms and conditions developed in accordance with the rule which, it is expected, will be contained in contracts for the sale of SPR petroleum. The rule calls for the publication of the SSPs in the **Federal Register** and the Code of Federal Regulations as an appendix to the rule. The rule also provides for the periodic review and republication of the SSPs in the **Federal Register**, including any revisions to such Provisions.

Upon a Presidential decision to draw down the SPR, DOE would issue a Notice of Sale, announcing the amounts, types, and locations of the SPR petroleum to be sold, the delivery points and other pertinent information. The rule provides that the Secretary of Energy or his designee would specify in the Notice of Sale, by referencing the **Federal Register** and the Code of Federal Regulations in which the latest version of the SSPs was published, which of the terms and conditions in the SSPs would or would not apply to a particular sale. In the Notice of Sale, the Secretary also could revise such terms and conditions, or add new ones which would apply to that particular sale. Offerors, as part of their offers for SPR petroleum, would agree to all contractual provisions and financial and performance responsibility measures made applicable by the Notice of Sale, and comply with the responsibility measures in accordance with the Notice of Sale. The rule provides that no contract could be awarded to an offeror who had not unconditionally agreed to all contractual provisions and responsibility measures made applicable by the Notice of Sale. It is expected that the terms and conditions set out in the SSPs and made applicable by the Notice of Sale will not be part of the contract documents as such, but rather will be incorporated by reference; the rule so provides.

Time may be of the essence in a severe energy supply interruption. Failure to achieve the desired SPR drawdown rate could lessen the beneficial effect of an SPR drawdown. Buyers who default on their sales contracts could undermine achivement of the desired drawdown rate, with potentially adverse consequences for the economy or the national security. Consequently, in order to assure that the drawdown objectives of the SPR are achieved and that only responsible offerors are awarded contracts, the rule provides that the Secretary may exclude a firm from participating in any future sale of SPR petroleum when that firm had previously offered to buy SPR oil, was awarded a contract, and failed to take delivery of the petroleum in accordance with the terms of the contract. This exclusion would be in addition to any remedies for breach which may be provided for in the contract of sale. The ineligibility would not come into effect until after the firm had been given an opportunity to submit information or argument in opposition to the ineligibility, which the Secretary must consider before making the purchaser ineligible for future award of SPR sales contracts. The ineligibility would continue for the length of time determined by the Secretary as appropriate under the circumstances. The rule provides that at his discretion the Secretary may permit any such firm that petitions for reinstatement, to participate in future SPR sales. In addition to the remedies available to the Government under the contract and under this rule, a purchaser who defaults on a contract also may be subject to debarment procedures in accordance with other applicable DOE regulations.

C. Proposed Standard Sales Provisions

1. *General Sales Objectives.* On June 15, 1983, proposed SSPs were published in the **Federal Register** (48 FR 27482) for public comment. The new SPR Distribution Plan, SPR Plan Amendment No. 4, provides that price competitive sales of SPR petroleum will be open to all interested buyers. Amendment No. 4 also provides for performance and financial responsibility measures in the SPR oil sales process, to reduce the risk that a buyer of SPR oil might fail to meet its contractual obligations to the Government. The procedures and provisions contained in the proposed SSPs were designed to balance and achieve both of these objectives.

In order to maximize competition by the widest possible universe of offerors, DOE made the draft SSPs as unrestricted and nonjudgemental as possible. As required by Amendment No. 4, price was to be the determining factor in the award of SPR petroleum sale contracts.

In order to reduce the risk of purchases by persons who lack the capability or intent to take timely delivery of SPR petroleum, or the financial wherewithal to pay for it, the proposed SSPs required that: (1) A firm transportation plan showing an ability to move the oil must be submitted by an offeror before it is awarded a contract, and (2) binding guarantees of the offeror's full payment and performance under the contract must be agreed to by each offeror as a precondition to contract award. The measures included in the draft SSPs to ensure the offeror's fulfillment of its responsibilities included:

1. Requirement for offer guarantee;
2. Requirement for letter of credit or cash deposit to guarantee payment and performance;
3. Assessment of liquidated damages for failure to lift oil in accordance with the contract; and
4. Possible termination for default.

An offer or agreement to acquire SPR oil thus would involve a substantial commitment to the implementation of SPR drawdown and distribution in a manner consistent with the purposes of the SPR.

2. *General Sales Procedures.* Under the draft SSPs published for comment on June 15, the SPR sales process started with the issuance of a Notice of Sale, followed by the submission of offers by prospective buyers. The Notice of Sale announcing the sale of SPR petroleum would indicate the amount, characteristics and location of the petroleum being sold, the delivery dates and the procedures for submitting offers, as well as providing other information pertinent to a particular sale; in addition, it would specify what contractual provisions and performance and financial responsibility measures were applicable. The Government would evaluate the offers and award SPR sales contracts to those offerors making the highest priced responsive offers, who had provided the necessary assurances of performance and financial responsibility.

Over the course of an SPR drawdown, a number of Notices of Sale may be issued, each covering a sales period of 1 to 2 months. Initially, Notices of Sale issued during SPR drawdown could allow an extremely short lead time for offers and deliveries. Under the proposed SSPs, it was contemplated that offerors might be given as little as 7 days from the issuance of the Notice of Sale until offers were due, and as little as 15 days from the time of such issuance until oil delivery started, with a less compressed schedule becoming more feasible after the initial stages of drawdown. Because of the possible short lead times, the proposed SSPs provided for the establishment of a list of prospective offerors, to whom the Government would furnish copies of all Notices of Sale.

The next step in the sales process was the preparation by prospective purchasers of their offers, which must be submitted before a time specified in the Notice of Sale. The proposed SSPs required that the offeror: unconditionally accept all terms and conditions made applicable to that sale by the Notice of Sale; include an offer guarantee; and offer at least the minimum price specified in the Notice of Sale.

Following the receipt of offers, the Government would evaluate the offers to select the "apparently successful" offerors. Offers were to be for prespecified amounts of petroleum (termed "delivery line items"), at given delivery points, on designated delivery dates, as set out in the Notice of Sale. Offerors would not have been permitted to alter a specified quantity, delivery point, or date. Offers for a particular delivery line item would have been ranked from highest to lowest, with the offeror making the highest offer, being selected as the apparently successful offeror. In the event that no offers were received for a particular item, the proposed SSPs established a procedure for selecting an apparently successful offeror for that item without soliciting further offers.

Under the proposed SSPs, all apparently successful offerors would have been required, within as little as 72 hours, to provide details of firm transportation arrangements for the crude oil, as well as either a letter of credit or a cash deposit as a guarantee of performance and of payment of amounts due under the contract. Upon timely receipt of those items, and upon a final determination by the Contracting Officer that the offer was responsive and the offeror responsible, the Government would issue the Notice of Award.

3. *Purchaser Performance and Financial Responsibility.* As mentioned above, the proposed SSPs established four major measures to assure purchaser performance and financial responsibility: (1) The offer guarantee, (2) the payment and performance guarantee, (3) liquidated damages, and (4) termination for default remedies.

a. Offer Guarantee

Under the proposed SSPs, the offeror was required to submit with its offer a guarantee that the offer would remain valid for 10 days after the date set for receipt of offers. This guarantee could take the form of an offer bond on the Government's Standard Form 24, a certified or cashier's check, or a cash deposit to a special DOE account. The maximum amount of the required guarantee was $10 million or 30 percent of the total of all of the bidder's offers for SPR petroleum line items, whichever was less. The offer guarantee was to be available for offset against any damages, including lost revenue on resale of the petroleum, incurred by the Government when an apparently successful offeror failed to provide the required payment and performance guarantee, or otherwise failed to execute the contract.

b. Payment and Performance Guarantee

In order to assure that the Government received payment for oil delivered or for other amounts due under the contract in connection with the buyer's performance, such as liquidated damages or other damages for breach of contract, apparently successful offerors were required to provide a payment and performance guarantee prior to contract award. This could be in the form of either a letter of credit or an advance cash payment.

The letter of credit was to be for 115 percent of the contract, and was to be issued by a bank that participates in the Federal Reserve Bank FEDWIRE system. It would be an irrevocable clean letter of credit, in the form specified in the proposed SSPs, with payment by draft accompanied by a statement of an authorized Government official either that payment was due for oil delivered, or that payment was due for liquidated or other damages.

After delivering the SPR petroleum to the purchaser, DOE would prepare a delivery report on a Department of Defense Standard Form DD-250, and a message containing the draft and the prescribed statement of an authorized Government official. The message containing the draft and prescribed statement could be sent by the SPR's New Orleans Project Management Office to the New Orleans Branch of the Atlanta Federal Reserve Bank for wire transmittal to the bank which issued the letter of credit. That bank must wire the funds thus drawn upon to the U.S. Department of the Treasury Account at the New York Federal Reserve Bank by the next business day after receipt of the draft. Copies of the invoice and the DD-250 would be mailed to the contractor and to the bank.

As an alternative to submitting a letter of credit, under the proposed SSPs the apparently successful offeror could submit an advance cash payment by wire transfer to a special DOE account, in an amount of 45 days' billings under the contract plus 15 percent of the total contract amount, or 115 percent of the entire contract amount, whichever is less. DOE would invoice the purchaser after each delivery, and if the amount remaining due under the contract exceeded the amount of the advance payment, the purchaser would make payment by wire transfer to the U.S. Department of the Treasury account. The cash guarantee would be applied as a credit against the final invoice.

c. Liquidated Damages

To provide compensation for the damages incurred by the Nation from a failure by purchasers to fully honor SPR petroleum sales contracts, the proposed SSPs imposed liquidated damages on buyers' unexcused failure to comply with the contractually agreed delivery schedules. These damages were to be in an amount equal to one percent of the contract price per barrel of undelivered petroleum, for each day or fraction thereof that a purchaser is late in accepting the petroleum, up to a maximum of 30 days. Liquidated damages would not be assessed unless the tardiness was due to causes for which the contractor was responsible.

In addition to being liable for liquidated damages, a purchaser who, without valid excuse, failed to take delivery of SPR petroleum in accordance with a contract to buy, also could be liable to the Government for the Government's lost receipts in the event that the purchaser's contract was terminated for default, and the petroleum was sold to another buyer at a lower price.

d. Termination for Default

The proposed SSPs provided that in the event that the purchaser failed, without valid excuse, to make payment in accordance with the SSPs, to accept delivery under the terms of the SSPs, or to comply with any other provision of the SSPs within 5 working days after written notice of such failure, the Contracting Officer could terminate the contract in whole or in part. Should the Government exercise its right of termination, it could sell any contracted-for and undelivered petroleum, holding the original purchaser liable for the difference between the contract price and any lesser price obtained for the sale of the crude, as well as for any applicable liquidated damages.

If there were insufficient time to decide whether a failure or refusal to lift SPR oil was due to a reason for which the contractor was culpable, DOE initially could elect to terminate the contract, before determining whether there was a basis to declare a default. The Contracting Officer promptly would proceed to examine the facts, and could convert the termination to one for default at any time within 10 days from the termination.

e. Other Performance and Financial Responsibility Measures

In addition to the performance and financial responsibility measures contained in the draft SSPs, the SPR sales rule on competitive SPR sales provides a mechanism for excluding purchasers from future participation in SPR sales in the event of their nonperformance. The only other bases in the proposed SSPs upon which the Contracting Officer could make a finding of nonresponsibility were a failure of an apparently successful offeror to submit a transportation plan showing its ability to take timely delivery of the SPR petroleum and move it to its destination, or evidence of an offeror's conduct or activity which: (i) Represented a violation of law or regulation, or Executive Order having the force and effect of law, or (ii) showed a lack of integrity or willingness to perform, and would substantially diminish the Contracting Officer's confidence in the offeror's performance.

II. Discussion of Major Comments

The interim final SSPs have been substantially revised as a result of the public comment process and of independent analysis and study by DOE. In August 1983 DOE conducted a test exercise of the SPR drawdown management system, called "DIREX-B," which involved a simulated use of the draft SSPs. As part of that test, an independent assessment team made up of DOE personnel and other Government personnel, supported by industry consultants, reviewed the entire exercise and recommended changes to the draft SSPs. In addition, discussions held by DOE with industry, particularly with operators and owners of the terminals and pipelines connected to SPR facilities, have contributed to an understanding of how best to achieve the SPR's drawdown objectives.

The most significant changes in the proposed SSPs published on June 15 are revision of the line item schedules and the method for evaluating offers and, related to that change, elimination of the requirement for a transportation plan. There also have been a number of changes to the purchaser payment and performance responsibility measures. However, the basic principles discussed above with respect to these responsibility measures have been retained in the revised SSPs. A provision-by-provision discussion of changes which have been made in the published draft SSPs follows this discussion of the major comments.

Comments on the proposed SSPs were requested through September 16, 1983. Written comments were received from 30 different organizations including major oil refiners, small oil refiners, oil industry trade associations, a chemical manufacturers trade association, a banking trade association, and two States. The specific comments received from these respondents, or made by the DIREX-B assessment team, are discussed below in three categories: (1)

general comments on the SSPs; (2) comments in response to the specific questions asked in the preamble to the proposed SSPs; and (3) comments on the SPR Distribution Plan, SPR Plan Amendment No. 4.

A. General Comments on the SSPs

A major finding of the DIREX–B assessment team was that while the sales procedures of the draft SSPs were likely to accomplish the sale of SPR petroleum, the rigid transportation requirements of the draft SSPs would detract from the success of any SPR drawdown and distribution. The assessment team recommended a sales process which gave industry greater flexibility in determining lot sizes, delivery dates and transportation methods, rather than having DOE dictate them. Two commenters also proposed similar changes to the sales method. Another five commenters suggested that the sales method at least be changed to permit greater flexibility as to delivery dates. As recommended, DOE has adopted a significantly different and more flexible approach to awarding SPR oil sale contracts through price competitive sale, which is further explained in the provision-by-provision discussion which follows this discussion of the major comments.

The oil sale system proposed on June 15 was a fragmented, yet rigid one, in which offerors had to offer on numerous small lots of oil, fixed by the Government, to be lifted at such times and by such methods as the Government specified. The system we propose today allows high offerors to choose the volume of their purchases, and to pick the method and timing of delivery.

Under the draft SSPs published on June 15, there were 16 master line item schedules, two for each of the eight SPR crude oil streams in storage,* consisting of one master line item covering petroleum to be delivered to each major common carrier pipeline connected to a storage site, and one master line item covering petroleum to be delivered by vessel or by private pipeline. Each master line item had up to 31 delivery line items corresponding to the days of the month. The Notice of Sale would have specified a quantity of oil to be available on a particular day for delivery via the delivery method specified by the master line item. Alternate offers would not have been permitted, nor would an offeror's changing of quantities, dates or delivery methods.

Under the revised SSPs, there will be only eight master line items, one for each of the eight crude oil streams stored in the SPR. The Notice of Sale will not specify the method by which the oil must be delivered, the delivery date, or the quantity, except to establish a minimum required purchase quantity. Instead, the offeror must indicate the proposed delivery method, and for vessel deliveries, a delivery period (although alternate offers may be made for different delivery periods and methods). Offerors may submit offers on more than one master line item, but may not make alternate offers on different master line items. Specific delivery dates are to be worked out by mutual agreement between the Government and the successful offerors, with the highest offerors being given first choice as to delivery dates. *See* SSP No. C.6. DOE will rank all offers on a master line item, and award contracts to those submitting the highest offers, regardless of delivery method. However, DOE will not award more petroleum to be transported by a particular delivery method than DOE estimates can be delivered by that method. The SPR oil sale contract will specify the delivery method, and the delivery method can be altered only by contract modification. Provision No. C.16 does provide that DOE will grant such modification whenever the modification does not interfere with the transportation plans of other purchasers. For a detailed discussion of the sales process, *see* the discussions in the following section, and SSP Nos. B.14, B.15, B.16, B.19, B.20 and the Instructions to Exhibit A of the interim final SSPs.

The DIREX–B assessment team further recommended elimination of the transportation plan, as they concluded that the performance and payment responsibility measures provide sufficient assurance that only those capable of accepting delivery of the petroleum would submit offers, and that the plan therefore was superfluous as an assurance of purchaser responsibility. The assessment team also found that it was likely that purchasers would be unable to provide firm transportation plans, including final destination, within the time required. The assessment team recommended that the scheduling of deliveries be achieved by discussions between the parties, such arrangements to be as flexible as possible. Nineteen comments from the public also were received objecting to various aspects of the draft SSPs' requirements for transportation plans.

As a result of the comments received, DOE has eliminated the transportation plan. Transportation arrangements are to be worked out by agreement between the parties in accordance with SSP No. C.6. However, while DOE no longer will require a transportation plan from every purchaser, DOE, in SSP No. B.21, has reserved the right to request information on an offeror's plans for transporting the petroleum, in order to obtain assurance that the offeror does not plan to transport the petroleum in violation of either the cabotage laws or U.S. export control laws.

Twenty comments were received recommending that the SSPs allow purchasers more time to meet SPR oil acquisition and delivery requirements. Of particular concern was the time allowed by the SSPs for the buyer's submission of a payment and performance guarantee, and for arrangement of transportation. The DIREX–B assessment team likewise recommended that additional time be allowed the buyer for making transportation arrangements. The proposed SSPs were based upon an assumed 15-day lead time from the issuance of the Notice of Sale until deliveries commenced. As revised, the SSPs which we publish today assume a 30-day lead time from the Notice of Sale until the delivery month which would allow longer for the submission of the guarantee and for the making of transportation arrangements; DOE expects to have oil deliveries start on the 1st day of a calendar month, to the maximum extent practicable, so as to coincide with normal industry practice and with pipeline requirements. Provision No. B.20 now provides at least 5 days for submission of the payment and performance guarantee, and with a 30-day lead time DOE estimates that, assuming offers are required to be submitted 7 days after the issuance of the Notice of Sale (as provided in Provision No. B.5), apparently successful offerors will have approximately 20 days to make transportation arrangements before the delivery month is to commence.

Eighteen comments were received urging, in case of an SPR drawdown, waiver of the "Jones Act," 46 U.S.C. 883, which has the effect of requiring that SPR crude delivered between ports in the U.S. be carried in U.S.-flag vessels. The comments expressed a concern that there were not sufficient tankers in the U.S.-flag fleet to meet the transportation requirements of an SPR drawdown. Five of the 18 recommended waiver of the

*The eight SPR crude oil streams, each of which is available only at a single location, are:

SPR Bryan Mound Sweet; SPR Bryan Mound Sour; SPR Bryan Mound Maya; SPR West Hackberry Sweet; SPR West Hackberry Sour (includes Sulphur Mines oil); SPR Bayou Choctaw Sweet; SPR Bayou Choctaw Sour; SPR Weeks Island Sour.

The locations of these crude streams are listed in SSP No. B. 14.

Jones Act when the Notice of Sale is issued so that firms without assured access to U.S.-flag vessels may offer. The potential seriousness of the problem is recognized. The President's Comprehensive Energy Emergency Response Procedures report to Congress on December 31, 1982, found that: "It may become necessary in case of a Presidential finding of a 'severe energy supply interruption,' to waive the U.S.-flag shipping requirement of the Jones Act (46 U.S.C. 883) so that the bidding for SPR oil which is to be moved by ocean carrier will not be limited to those bidders having advance assurance of the use of U.S.-flag ships. The Customs Service and the Maritime Administration are agreed that authority for such a blanket waiver presently exists under Pub. L. 81–891, 64 Stat. 1120." The DIREX–B assessment team also recommended advance waiver of the Jones Act. The issue will arise at the time of the solicitation of offers to buy SPR oil, because it bears upon the ability to submit such an offer (putting at risk first the offer guarantee and subsequently the payment and performance guarantee), depending on whether the offeror has access to a U.S.-flag vessel. In the event of a blanket waiver, the appropriate provisions in the SSPs would be amended to reflect the existence of such waiver. However, as no advance waiver decision has been made, the cautions to offerors in SSPs No. B.2 and No. C.3 regarding compliance with the Jones Act have been retained.

Eighteen comments were received objecting to various aspects of the draft SSPs' payment terms. In addition, the DIREX–B assessment team also recommended amendment of the payment terms. Plan Amendment No. 4 calls for the use of payment guarantees to assure that payment is received for petroleum delivered, and DOE believes that such measures are necessary to protect the public's investment in the SPR. However, a number of provisions have been amended so as to ease the payment terms imposed by the draft SSPs. In Provision No. C.17, the letter of credit has been reduced from 115 percent of the contract amount to 100 percent of the contract amount; the advance payment by wire cash deposit has been reduced from 115 percent to 105 percent of the contract amount. Provision No. C.19 now requires that the Contracting Officer authorize the cancellation of the letter of credit within 30 days of final payment under the contract, so that letters of credit no longer need to be valid for a full year. Provision No. C.18 makes clear that the level of available funds in the payment and performance guarantee need only be maintained at a level sufficient to cover the contract amount of petroleum remaining to be delivered. There should be no need for replenishment of the guarantee unless the Government has to draw against the guarantee for amounts due under the contract for extraordinary charges, such as liquidated damages.

A number of comments reflected an understanding that payment for oil would be due immediately upon its delivery to the buyer. However, that will not be the case for SPR oil purchasers who choose to use a letter of credit as the means of payment. The only time period specified in the billing and payment procedures for purchasers using the letter of credit, SSP No. C.21, is that the purchaser's bank must transfer the funds due to the Government's account at the Federal Reserve Bank of New York, the next business day after receipt of the Government's draft. Before that draft is issued, however, a number of events must occur: the delivery documentation must be completed by the Government's Quality Assurance Representative, the documentation forwarded to the New Orleans Project Management Office, the invoice prepared and, assuming wire transmittal of the Government's draft, the draft presented to the Federal Reserve Bank for transmittal to the purchaser's bank. DOE estimates that this process may take from 5 to 7 days from the time delivery is completed until the payment is transferred to the Government's account.

Twelve comments were received objecting to the use of the offer guarantee. The draft SSPs required that each offeror submit with its offer, either a cash wire deposit, a certified check or a Government Standard Form 24 Bid Bond, in the amount of 30 percent of the offer or $10 million, whichever was less, as an offer guarantee. The Government could draw against the offer guarantee for any damages incurred by the Government arising from a winning offeror's refusal to enter into a contract in accordance with the terms of the offer. The offer guarantee is necessary to assure that offers are submitted only by persons who have the intent and capability to take delivery of SPR oil and that drawdown is not delayed by the processing of frivolous offers. However, the DIREX–B assessment team likewise recommended a lower offer guarantee, and DOE has concluded that this objective could be satisfied by a lower offer guarantee than previously proposed. Provision No. B.9 of the revised SSPs requires an offer guarantee of 5 percent of the amount of the offer or $10 million, whichever is less. The revised SSPs also added a fourth acceptable guarantee, a standby irrevocable letter of credit. These changes should substantially lower the cost of offering to buy SPR petroleum, while retaining an assurance that only offerors with a serious intent and an adequate capability submit offers on SPR petroleum. However, DOE specifically seeks comments from State governments and other commenters, as to whether there are any potential purchasers who would be unable to comply with any of the four offer guarantee mechanisms, cash wire deposit, certified check, offer bond, or letter of credit.

DOE received 11 comments that the proposed liquidated damages were too high. As explained above, a failure to honor SPR petroleum sales contracts could hinder attainment of the desired SPR drawdown rate, with possible adverse effects on the Nation. The liquidated damages are compensation for the damages incurred by the country when a buyer fails to comply with the contractually agreed schedule. Therefore, the revised SSPs continue to impose liquidated damages of one percent of the contract amount for each day of *unexcused* delay in accepting delivery of the petroleum, up to a maximum cumulative liability of 30 percent. However, one change has been made which will reduce the potential extent of liability for liquidated damages. For vessel deliveries, the originally proposed SSPs would have imposed liquidated damages for each day of delay until delivery was completed; but SSP No. C.28 of the interim final SSPs only imposes liquidated damages until the buyer's vessel presents its notice of readiness. It should be emphasized that liquidated damages would be imposed only for delays that are *not excused* by SSP No. C.26. A contractor will not be held liable if the vessel presents its notice of readiness during the delivery window or if the nonperformance is caused by events beyond the control and without the fault of the contractor or its subcontractors. For example, where one commenter argued that it would be unfair to hold a purchaser liable for the actions of a vessel's master in refusing to bring a vessel into a channel for reasons of safety, in fact a purchaser would not be liable under the SSPs, so long as the vessel's master was acting reasonably.

Another seven comments objected to the termination for convenience clause. The right of termination for convenience of the Government is a standard Government contract provision. It also is standard Government contract procedure to compensate contractors whose contracts are terminated for the convenience of the Government for costs incurred by the contractor in performance of the contract. While the draft SSPs authorized a termination for the convenience of the Government, the draft SSPs did not provide for any payment to the terminated SPR purchaser for costs incurred by that purchaser in preparing to accept delivery of the petroleum. The DIREX–B assessment team recommended that the SSPs compensate SPR oil purchasers in the event that the Government exercises its right of termination. The revised SSPs now provide for the compensation of terminated contractors in some circumstances. If the purchaser fails to comply with the terms of the contract, SSP No. C.26(c)(1) still authorizes the termination of the contract for the convenience of the Government, without liability of the Government to the purchaser, even if such failure was beyond the control and without the fault of the purchaser. But, in any other termination for convenience, the Government will be liable to the purchaser for any reasonable cost incurred by the purchaser in preparing to accept delivery of the petroleum. Under no circumstances will the Government be liable for consequential damages or lost profits as the result of a termination for convenience of the Government.

Five comments were received recommending that the minimum vessel load rate of 20,000 barrels per hour established by the SSPs be lowered. The DIREX–B assessment team recommended permitting the use of barges where the necessary facilities were available. Due to facility constraints at the marine terminals interconnected to the SPR storage sites, achievement of desired SPR drawdown rates necessitates the use of vessels with loading rates in excess of 20,000 barrels per hour in most instances. Provision No. C.46 has been amended to permit two exceptions. The use of barges with a loading rate of 5,000 barrels per hour at the Sun Terminal barge docks is now permitted. In addition, barges may be used at the Seaway Terminal and tankers with loading rates of less than 20,000 barrels per hour may be used at all terminals, so long as the use of such barges and tankers is limited to circumstances where a smaller vessel is needed to complete loading of contract quantities and such use does not interfere with liftings by the other purchasers.

Five comments recommended that the Notice of Sale establish a maximum purchase quantity to preclude the possibility of a single purchaser, or a small number of purchasers, buying all of the SPR petroleum. The interim final SSPs will not set a maximum purchase quantity because it would be contrary to the philosophy of Plan Amendment No. 4 that price competition should be the sole determinant of how the petroleum is to be distributed.

B. Responses to Questions Asked in the Draft SSPs Notice

The preamble to the draft SSPs asked nine questions related to the SSPs. The nine questions are set forth below with a discussion of the comments received.

1. Do prospective offerors need any additional information on specifications for SPR petroleum, beyond that contained in Exhibit D of the SSPs?

Fourteen commenters requested additional information, while three commenters indicated that no further information was required. The revised Exhibit D will provide more detailed characteristics on each crude oil stream. This information is generated as part of the SPR's continuing petroleum sampling and analysis program. The actual analysis is performed by the National Institute for Petroleum and Energy Research, formerly the U.S. Department of Energy's Bartlesville Energy Technology Center. Whenever the SSPs are revised, the latest available information will be included in a revised Exhibit D to be published in the **Federal Register**. The Notice of Sale also will provide any revisions subsequent to the last publication of this information in the **Federal Register**. However, it should be noted that because of the complexity of the testing program and the length of time required to receive the results, DOE does not intend to analyze all crude oil streams just before issuance of the Notice of Sale; rather, it will provide whatever data happens to be the most recent data available.

2. Do the proposed gravity and sulfur adjustments (see Provision No. C.7) accurately reflect the possible quality differentials between SPR specifications and any nonconforming petroleum which may be delivered?

Eleven comments were received indicating disagreement with the gravity and sulfur adjustments established in the draft SSPs. The draft SSPs proposed a price adjustment of 7 cents per barrel for each degree that the API gravity of the crude oil actually delivered to the purchaser varied from the API gravity specified in the contract (increase price as API gravity increases, decrease price as API gravity decreases). The price adjustment for sulfur was 7 cents per barrel for each tenth of one percent that the total sulfur content (percent by weight) varied from the specific contract sulfur content (increase price as sulfur content decreases, decrease price as sulfur content increases). Nine of the 11 comments indicated that the sulfur and gravity adjustments should reflect the difference in the value of various crude oils as determined by the market. However, those comments recommending specific numbers were widely disparate; thus, a determination of the market value will not be easy. Five comments indicated that because, at least in theory, sulfur and gravity adjustments reflect market differentials, those adjustments ought to be determined at the time of drawdown. DOE agrees, and the provision on gravity and sulfur adjustments, SSP No. C.11 of the interim final SSPs, therefore does not have a specific figure, but rather provides that the Notice of Sale will establish the price adjustments. Before issuing the Notice of Sale, DOE will analyze the then-existing differentials between the various types of crude to arrive at the sulfur and gravity adjustments to be used for the sale of SPR petroleum.

3. Absent events outside of the tanker master's control, can purchasers provide, 5 days prior to a tanker's estimated arrival time, a 1-day window for the tanker's arrival?

In response to this question, five commenters answered that it would be possible to provide a firm delivery date 5 days in advance, while six indicated that it would not be possible. Four of the latter six said that it would be possible to provide a firm date 3 days in advance of arrival. The revised SSPs in Provision No. C.7 provide that the delivery window shall be as announced in the Notice of Sale, but shall not be less than a 3-day window. The purchaser still is required to establish a firm arrival date 3 days prior to vessel arrival.

4. What should be the smallest and largest quantity of SPR barrels sold as a single delivery line item? While administrative convenience would be served by selling large lot sizes, DOE seeks comments on the extent to which small sized lots may be needed by prospective offerors.

Fourteen comments were received in response to this question. None addressed the extent to which small sized lots should be offered by the SPR. The recommended minimum sized lots were from 10,000 to 100,000 barrels for pipelines, 40,000 to 60,000 barrels for barges, and 200,000 barrels for tankers. Maximum recommended lot sizes were 300,000 to 500,000 barrels for tankers. However, with the revision of the sales process, DOE no longer will expect to establish lot sizes in the Notice of Sale.

Under Provision No. B.15 of the revised SSPs, the Notice of Sale will establish minimum offer quantities. Separate minimum quantities will be established for tanker deliveries, barge deliveries, and pipeline deliveries. As discussed above, facilities for loading barges are limited, and SSP No. C.7 limits their use accordingly.

5. A transportation plan (Exhibit C of the proposed SSPs) is proposed to be required prior to contract award in order to assure the timely movement of SPR petroleum. Are there likely to be any circumstances where it is unreasonable to require such a plan before award?

Nineteen comments were received raising objections to various aspects of the previously proposed requirements for transportation plans. As a result of public comments and of the recommendations of the DIREX–B assessment team, DOE has eliminated the transportation plan. Transportation arrangements are to be worked out by agreement between the parties in accordance with SSP No. C.6.

6. It is intended that the transportation plan be accepted by the Contracting Officer so long as it shows credible arrangements consistent with the terms of the Notice of Sale for timely movement of the SPR petroleum to be awarded. Are there additional specific questions which could be asked on Exhibit C to further mechanize the Contracting Officer's review of transportation plans?

As explained above, the transportation plan has been eliminated.

7. For tanker and pipeline shipments, what minimum lead time is required from the date of SPR contract award until the time of delivery to the buyer of SPR oil? Please specify what assumptions about tanker or pipeline capacity availability your answer is based on.

For U.S.-flag tankers, the comments indicated a lead time of 2 to 6 weeks. For foreign-flag tankers, the comments indicated a lead time of 1 to 4 weeks. For common carrier pipelines, the comments asserted that most pipeline tariffs required notice by no later than the 25th day of the month prior to the month of delivery, but that if the pipelines were subject to prorationing, a 30 to 60-day lead time prior to the month of delivery could be required. Based on these comments and on other discussions with industry (including operators of terminals to be used in SPR drawdown), and on DOE's analysis, DOE decided that in revising the SSPs it should assume that the Notice of Sale would be issued at least 30 days prior to the start of SPR oil deliveries, and that if practicable, deliveries should commence on the 1st day of the next calendar month. In order to avoid selling more SPR petroleum for delivery by pipeline than the particular pipeline can transport, thereby throwing the pipeline into prorationing, DOE hopes to work closely with the pipelines to determine how much SPR petroleum the pipelines can accept, and will limit SPR oil deliveries via pipeline accordingly.

8. Will Forms DD-250 and DD-250-1 at Exhibit I (of proposed SSPs) provide adequate documentation of delivery?

Of the 11 comments received on this question, eight indicated that these forms provided adequate delivery documentation. The revised SSPs rely on these forms. Provision Nos. C.12 and C.13 have been amended to make clear that the purchaser has the right to have a representative present at ocean vessel loading, to conduct independent tests of quantity and quality.

9. DOE has under consideration the question of need for additional SSPs concerning ship and dock demurrage. What other SSPs, if any, may be needed?

Eight comments were received recommending that the Government reimburse the purchaser for demurrage incurred due to the fault of the Government; two other comments were received stating that demurrage should be the responsibility of the purchaser. The revised SSPs do not contain a demurrage provision. However, DOE is continuing to study possible ways of dealing with demurrage and other issues concerning vessel arrival and loading.

The only other suggestions received in response to this question were that limits be imposed on the potential universe of buyers of SPR oil. These suggestions are discussed next.

C. Comments on SPR Plan Amendment No. 4

A number of comments suggested changes in the SSPs which, if made, would contravene SPR Plan amendment No. 4. Thirteen comments recommended that SPR oil be sold only to domestic refiners. Five comments recommended that the oil be sold by a method other than competitive bidding. Three suggested that government agencies be precluded from buying SPR oil.

Section 161(c) of the Energy Policy and Conservation Act explicitly provides that drawdown and distribution must be in accordance with the SPR Plan in effect at that time. Consequently, DOE cannot adopt any SSPs that are inconsistent with SPR Plan Amendment No. 4.

SPR Plan Amendment No. 4 provides that "all interested buyers will be eligible to bid for and purchase SPR oil, including Federal agencies." (page 13) The Plan also provides that "[e]xcept where the distribution of oil is directed by the Secretary, * * * the purchase of SPR oil will be determined solely by price competitive sale." (page 14)

III. The Interim Final Standard Sales Provisions

A. Major Revisions

After consideration of the public comments received on the draft SSPs, the recommendations of the DIREX–B drawdown exercise assessment team, and other lessons learned by DOE in the DIREX–B exercise and through consultations with industry, DOE has concluded that the draft SSPs should be substantially revised. Public comments again are sought on the revised SSPs because of these substantial revisions. However, DOE is adopting the revised SSPs, as an interim final appendix to the final sales rule (48 FR 56538). These SSPs thus will be available for use in the event that a drawdown of the SPR occurs before any subsequent revision of the SSPs is published in the **Federal Register.** If future comments indicate the need for further revision of the interim final SSPs, DOE will republish the revised SSPs in their entirety, along with DOE's responses to those comments.

The most significant revisions in the draft SSPs published on June 15 concern the change to a much more flexible approach to selling SPR petroleum and determining logistical arrangements. This change has impacted provisions of the draft SSPs concerning line item schedules, the transportation plan, the evaluation of offers, and delivery arrangements.

The draft SSPs published on June 15 involved a highly structured oil sales system which was predicated upon the view that the SPR's drawdown rate could be maximized, within the context of a price competitive contract award system, by having the Government designate when and how specified quantities of oil that were offered for sale would be shipped. Offerors would have had to submit separate offers for all of the individual, predetermined oil shipments they wished to compete for, with no flexibility as to amount, timing or transportation mode. The winning offer prices could have differed from one lot of oil to another. Under the SSPs we adopt today on an interim final basis, high offerors for SPR oil generally would be allowed, in the order of their price offers, to decide how much of the oil listed under a master line item they wished to buy, and to choose how and when to move it. The comments received on our draft SSPs from the DIREX–B assessment team and from the public suggest that the system proposed on June 15 was too rigid and the pattern of offered shipments too fragmented. We believe that the method reflected in the interim final SSPs is a more realistic way of selling oil, with no less prospect of achieving the desired drawdown rate.

Under the scheme established by the draft SSPs , there were 16 master line item schedules. These included, for each of the eight SPR crude oil streams in storage,* one master line item covering petroleum to be delivered to a major common carrier pipeline, and one master line item covering petroleum to be delivered by vessel or by private pipeline. Each master line item had up to 31 delivery line items corresponding to the days of the month. When DOE issued a Notice of Sale, the delivery line items included therein would have specified set quantities of petroleum to be delivered on particular dates for movement by prescribed transportation modes. Offerors were prohibited from changing the quantity of crude oil under a line item or proposing alternate dates or delivery modes. Alternate offers were not permitted. A transportation plan was required from each apparently successful offeror, in order to obtain assurance that the offeror was planning to move the petroleum in accordance with terms (quantity, date and transportation method) established by the delivery line items.

Under the interim final SSPs, there now are only eight master line items, one for each of the eight SPR crude streams. Under each master line item, instead of up to 31 delivery line items, the revised SSPs have only five delivery line items, one for petroleum to be moved by major common carrier, one for other pipeline deliveries, and three for vessel deliveries. The pipeline delivery line items cover a delivery period of a month, while each vessel delivery line item covers a delivery period of a third of a month.

The Notice of Sale will specify the total amount of a particular crude stream to be sold, but will not designate the method by which the oil must be delivered, the delivery date or the amount, except to establish a minimum required purchase quantity. Instead, the offeror must indicate the desired purchase volume and the proposed delivery method, and for vessel deliveries the offeror must choose one of the three delivery periods; however, alternate offers may be made for different delivery periods and methods. A transportation plan will not be required. Specific delivery dates are to be worked out by mutual agreement between the Government and the winning offerors, with the highest offerors, in the order of their offered prices, being given preference in the selection of delivery dates.

Use of this bid structure will enable DOE to endeavor to award the SPR's oil sale contract to the highest offerors on a master line item, regardless of a bidder's preference as to delivery method or delivery period. Thus, it will be the order of price offers which determines how the SPR oil is moved, rather than a Government choice between different transportation modes.

The only limitation on this principle will be physical: there are facility constraints which may put a ceiling on the movement of SPR petroleum by an individual transportation method. Therefore, DOE will not award contracts against a delivery method in excess of DOE's estimate as to how much oil can be moved by that transportation method during the delivery period. Before drawdown, DOE will consult with the relevant pipelines and terminals to make estimates of their maximum transportation capabilities. These estimates will be indicated in the Notices of Sale. Once a delivery method appears to be fully subscribed, all other offers on that delivery method will be rejected, even if those offers contain higher offer prices than offers on other delivery methods. High offerors affected by such limits can preserve their opportunity to win SPR contracts by indicating their willingness to accept alternatives in the event a delivery method is oversubscribed; however, they must so indicate on their offers, as DOE will not contact them to solicit a change in their offers. The SPR petroleum sales contract will specify the agreed delivery method, but DOE intends to be as flexible as possible in allowing later changes in the transportation method.

There follows a provision-by-provision discussion of other noteworthy changes in the draft SSPs published on June 15.

B. Revised Provisions

SSP No. A.2 Definitions:

1. The term "work day" was changed to "business day."

2. The term "delivery period" has been defined.

3. The term "line item" has been redefined consistent with the new offer evaluation procedures.

4. The term "notification of apparently successful offeror" has been defined to highlight it as an event in the evaluation and award process.

5. The term "petroleum" has been redefined, consistent with the definition in the final sales rule.

6. The term "vessel" has been defined to be either a tanker or a barge. This term is used except where the context clearly requires use of tanker or barge.

SSP No. A.6 Offeror's list for sales of petroleum:

Reference to a telegraphic Notice of Sale has been removed; however, an option remains open to the Government to issue the Notice of Sale by telegram.

SSP No. B.2 Requirements of the Jones Act for U.S.-flag vessels—caution to offerors:

The reference to a transportation plan has been deleted. A caution regarding construction differential subsidy tankers has been added.

SSP No. B.4 Export limitations and licensing—caution to offerors:

The reference to a transportation plan has been deleted.

SSP No. B.5 Preparation of offers:

1. This provision was retitled.

2. Reference to the telegraphic Notice of Sale has been deleted.

SSP No. B.6 Submission of offers and modification of previously submitted offers:

1. Reference to telegraphic offers has been deleted.

2. Paragraph (g) has been added stating that DOE does not anticipate having a public opening of offers, but will post an abstract of offers and the winning offers in a public place within 48 hours of the time set for receipt of offers.

SSP No. B.8 Late offers, modification of offers, and withdrawal of offers:

1. This is draft SSP No. B.9, renumbered.

2. DOE now will accept an offer modification or withdrawal of offer received after the date set for receipt of offers if it was mailed by the third calendar day prior to such receipt date. However, late offers still will be considered only if mailed by the fifth day prior to the receipt date.

SSP No. B.9 Offer guarantee:

1. This is draft SSP No. B.24, renumbered.

2. The amount of the offer guarantee has been changed from "$10 million or

*The SPR's Bryan Mound Sweet, Bryan Mound Sour, Bryan Mound Maya, West Hackberry Sweet, West Hackberry Sour, Bayou Choctaw Sweet, Bayou Choctaw Sour, and Weeks Island Sour.

30 percent of the total offer, whichever is less" to "$10 million or 5 percent of the total offer, whichever is less."

3. Offerors now may submit a standby letter of credit as an offer guarantee. It must conform without exception to Exhibit H, Offer Guarantee, Letter of Credit, and be valid for 21 days past the date set for receipt of offers.

4. Cash deposit or check offer guarantees will be returned to unsuccessful offerors 5 business days after expiration of the offeror's acceptance period or 3 business days after award of contracts on delivery line items bid by the offeror, whichever is first. Bonds and letters of credit will be returned only on written request.

SSP No. B.12 Language of offers and contracts:

This new provision, recommended by the DIREX–B assessment team, requires that all contracts and contract correspondence be in English.

SSP No. B.14 SPR petroleum streams and delivery points:

1. This is draft SSP No. B.18, renumbered and retitled.

2. Information has been added on the crude oil streams available at each delivery point.

SSP No. B.15 Notice of Sale line item schedule—petroleum quantity, quality, and delivery:

1. This is draft SSP No. B.14, renumbered.

2. This provision has been rewritten to reflect the revised line item schedule and sales process discussed above.

SSP No. B.16 Line item information to be provided in the offer:

1. This is draft SSP No. B.16, retitled.

2. This provision has been revised to conform to the new sales procedures.

SSP No. B.17 Mistake in offer:

This new provision establishes a procedure for dealing with various possible errors in an offer, including obvious clerical errors, multiplication errors, and discrepancies between the quantities indicated by the offer on master line items and delivery line items.

SSP No. B.18 Proper form for offer submission:

This new clause states that the Notice of Sale may require that, for an offer to be valid, it must be submitted only on a certain form or forms. Such forms may be:

(a) The master line items schedules 001 through 008 in Exhibit A;

(b) A sheet similar to the sample Data Entry Sheet in Exhibit A;

(c) Other forms provided with the Notice of Sale; or

(d) Any combination of the above.

If the Notice of Sale requires submission of an offer on specified forms, failure to use such forms will result in the offer being rejected as nonresponsive.

SSP No. B.19 Evaluation of offers:

A definition of "minor informality or irregularity" has been added.

SSP No. B.20 Procedure for evaluation of offers:

1. As discussed above, this provision has been rewritten in accordance with the new sales procedures.

2. Draft SSP No. B.20 had a two-phase sales process. Phase II was to be used to sell delivery line items not awarded in Phase I. This now has been eliminated.

3. Under the draft provision, if tied offers occurred, a single offer was selected for award. Under the revised procedures, the petroleum will be divided among the tied offers on a pro rata basis.

4. Reference to the transportation plan has been deleted from the determination of responsibility.

SSP No. B.21 Financial statement and other information:

1. This is draft SSP No. B.12, renumbered and retitled.

2. Language was added allowing the Government to request information from the offeror regarding the offeror's plans for use of the petroleum, the status of requests for export licenses, the offeror's plans for complying with the Jones Act, etc., to assure that the offeror intends to comply with the terms of the contract.

SSP No. B.22 Resolicitation procedures on unsold petroleum:

1. This is draft SSP No. B.21, renumbered and retitled.

2. As revised to conform to the new sales process, this provision states that if petroleum already awarded becomes available and priced offers have expired, the Contracting Officer may at his option offer the petroleum to the highest offeror on that master line item which:

(a) Had not received its maximum master line item quantity,

(b) Offered to take delivery by a delivery method which has remaining capacity, and

(c) Had indicated a willingness to accept the delivery line item quantity available for award.

The pertinent offeror may, at its option, accept or reject that petroleum at the price originally offered; and if that offeror rejects the petroleum, it will be offered to the next highest offeror, etc. If not resold in this fashion, the Contracting Officer may either resolicit offers or add the petroleum to the next sales cycle.

SSP No. B.24 Line item information to be provided in the Notice of Award:

This is draft SSP No. B.17, renumbered and retitled.

SSP No. B.25 Contract documents:

This is draft SSP No. B.8, renumbered and retitled.

SSP No. B.26 Purchaser's representative:

This new provision requires that each offeror designate an agent and an alternate agent as points of contact. Each agent must have a U.S. address and telephone number, and speak English.

SSP No. B.27 Procedures for selling to other U.S. Government agencies:

This is draft SSP No. B.25, renumbered.

SSP No. B.28 Information gathered for statistical purposes:

This is draft SSP No. C.1, renumbered.

SSP No. C.1 Certification of independent price determination:

This is draft SSP No. C.2, renumbered.

SSP No. C.2 Transportation certification:

This new provision was paragraph (a) of draft SSP No. B.22.

SSP No. C.3 Certification of compliance with the Jones Act and the U.S. export control laws:

This is draft SSP No. C.4, renumbered.

SSP No. C.4 Storage of SPR petroleum:

This new provision states that continued storage of a purchaser's oil in an SPR storage facility after the end of the delivery period established by the Notice of Sale is not permitted. Such storage for purchasers would only be allowed if specifically authorized by the Secretary of Energy and provided for in the Notice of Sale or in the sales contract.

SSP No. C.5 Environmental compliance:

This is draft SSP No. C.10, renumbered and retitled.

SSP No. C.6 Delivery and transportation scheduling:

This new provision establishes procedures discussed above for making transportation arrangements. Delivery dates shall be established by mutual agreement of the parties with the highest offerors being given preference, provided that those offerors contact the SPR Project Management Office to arrange delivery dates within 7 days of notification of apparently successful offerors. After 7 days, requests will be handled on a first-come, first-served basis.

SSP No. C.7 Delivery and acceptance of crude oil:

1. This is draft SSP No. C.8, renumbered.

2. The Notice of Sale shall establish the delivery window, but such window shall be not less than 3 days.

3. The Notice of Sale also shall establish the quantity of petroleum to be

delivered in a loading window. While it is likely that DOE will establish a minimum quantity for tanker loading of 200,000 barrels, DOE is not interconnected to dock facilities with sufficient throughput capabilities to enable it to meet its maximum drawdown rate if all the oil was loaded on tankers in 200,000 barrel quantities, and each tanker was given a 3-day window. Therefore, the Notice of Sale will provide a procedure for equitably dividing the available loading windows among all purchasers, if necessary.

4. The draft SSPs required that all vessels have a minimum load rate of 20,000 barrels per hour. This provision now permits the use of barges with load rates not less than 5,000 barrels per hour at the Sun Terminal barge docks. In addition, where feasible, and with the consent of the Government, the purchasers may use barges at Seaway Terminal to complete loading of contract quantities.

5. This provision continues to require that tankers shall have a minimum average load rate of not less than 20,000 barrels per hour, except that it has been amended to provide that, where feasible and with the consent of the Government, tankers with less than 20,000 barrels per hour may be used to complete loading of contract quantities.

6. Tankers shall be allowed 36 hours of berth time. As recommended by the DIREX–B assessment team, a discussion of the commencement of berth time and allowable berth time has been added, as well as a discussion of procedures for early and late arriving vessels.

7. This provision has been revised to permit final pipeline delivery arrangements to be provided to the SPR Project Management Office on the last day of the month preceding the month of delivery. However, the purchaser also must contact the Project Management Office at least 10 days prior to the start of the delivery period to make arrangements for delivery dates in accordance with SSP No. C.16.

SSP No. C.8 Purchaser liability for excessive berth time:

This is draft SSP No. C.11, renumbered.

SSP No. C.10 Acceptance of quality:

1. This is draft SSP No. C.6, renumbered.

2. As recommended by the DIREX–B assessment team, this language has been amended to clarify the rights of the parties. While the Government will guarantee the quality of the crude, the provision requires that the purchaser accept the crude oil delivered, regardless of its characteristics. It also provides that in the event that the API gravity falls below, or the sulfur content exceeds the standards set out in Exhibit E, the purchaser has the option of accepting the differentials specified in SSP No. C.11, or renegotiating the contract price.

SSP No. C.11 Quality differential for crude oil:

1. This is draft SSP No. C.7, renumbered.

2. The fixed dollar amounts per degree API and tenth of a percent sulfur have been deleted. Differentials for sulfur and gravity will be as specified in the Notice of Sale.

SSP No. C.12 Determination of quantity of petroleum:

In response to comments received. the revised provision has corrected the citations to the API *Manual of Petroleum Measurement Standards,* which will be followed by DOE in determining the quantity of petroleum delivered.

SSP No. C.13 Determination of quality of petroleum:

1. In response to comments received, the references cited in the provision have been corrected.

2. As recommended by the DIREX–B assessment team, the language has been changed to make clear that the purchaser may have a third party witness and verify testing simultaneously with the Government Quality Assurance Representative. Such services, however, shall be for the account of the purchaser.

SSP No. C.15 Contract amount estimated for crude oil:

1. This is draft SSP No. C.18, renumbered.

2. This provision now reads that due to conditions of loading and shipping, the quantity of oil delivered may vary by +15 percent more or less than the scheduled delivery quantity. This is a change from +15 percent.

SSP No. C.16 Contract modification—alternate delivery method:

This new provision establishes the prerequisites for granting a purchaser's request for a change in delivery method. Such a change must be made by written modification to the contract.

SSP No. C.17 Payment and performance guarantee:

1. This is draft SSP No. C.15. renumbered.

2. Apparently successful offerors must furnish an acceptable payment and performance guarantee within as short a time as 5 business days after notification by the Contracting Officer. This is an increase from 3 business days established by the draft SSPs.

3. The purchaser must maintain a satisfactory payment and performance guarantee in full force and effect to the Contracting Officer's satisfaction until final payment under the contract. Failure to do so may result in termination of the purchaser's contract for default.

4. As discussed above the amount of the required payment and performance guarantee has been changed to the following:

(a) If the purchaser elects to make advance payment on a contract which is 31 days or less, the advance payment shall be 105 percent of the contract amount in advance;

(b) If the purchaser elects to make advance payment on a contract which is longer than 31 days, the advance payment shall be equal to 31 days' deliveries plus 5 percent of the entire contract amount; or

(c) If the purchaser elects to furnish a letter of credit conforming to the requirements of Provision No. 21 and Exhibit H, the letter of credit shall be in the amount of 100 percent of the contract amount, regardless of the length of the contract period.

SSP No. C.18 Replacement of funds in the performance guarantee:

1. This is draft SSP No. C.16, renumbered.

2. Payment and performance guarantees must be maintained at the following revised minimum levels:

(a) Letter of credit at 100 percent of the contract price of the petroleum remaining to be delivered;

(b) Advance payment on a contract of 31 days or less, 105 percent of the contract price of the petroleum remaining to be delivered.

(c) Advance payment on a contract for more than 31 days, at the lesser of 100 percent times 31 days' deliveries plus 5 percent of the total contract price or 105 percent of the contract price of the petroleum remaining to be delivered.

SSP No. C.19 Payment and performance letters of credit, general requirements:

1. This is draft SSP No. C.17, renumbered and retitled.

2. The provision has been amended to clarify which hanks may issue a letter of credit. It has been amended to indicate that only the bank acting as agent for a syndicate issuing the letter of credit need be a participant in FEDWIRE.

3. The provision regarding the evidence required that the bank official signing the letter of credit had authority to do so has been amended. A copy of the corporate minutes authorizing the signature is acceptable evidence, but other evidence may be acceptable as well.

4. The requirement for furnishing to various entities copies of letters of credit over $100 million, has been deleted.

5. Letters of credit shall be cancelled within thirty days after final payment under the contract.

SSP No. C.22 Method of payment—general:

Payments in amounts less than $1,000 will be by check made out to "U.S. Department of Energy." This is a change from "Treasurer of the United States."

SSP No. C.26 Termination:

Provision No. C.26(c)(1) has been changed to provide that termination shall be without liability of the Government only if such termination arises out of causes specified in C.26(a)(1) or C.26(b)(1). For any other termination for convenience, the Government shall be liable for reasonable costs incurred by the purchaser in preparing to perform the contract, but under no circumstances shall the Government be liable for consequential damages or lost profits as a result of such termination. This is a change from previous language under which the Government assumed no liability for termination for convenience.

SSP No. C.28 Liquidated damages:

1. Liquidated damages for petroleum lifted by ocean vessel will be assessed if the tanker has not arrived at the roads and the vessel's master has not presented a notice of readiness by 11:59 on the last day of the delivery window established under Provision No. C.6. Liquidated damages shall continue until the vessel presents its notice of readiness.

2. For petroleum to move by pipeline, if delivery arrangements have not been made by the last day of the month prior to the delivery month, liquidated damages shall commence on the 1st day of the delivery month until such delivery arrangements are completed; if delivery arrangements have been made, then liquidated damages shall begin on the first scheduled delivery date if delivery is not commenced.

SSP No. C.30 Government options in case of impossibility of performance:

This is draft SSP No. C.32, renumbered.

SSP No. C.36 Disputes:

Both C.36(d)(2) and C.36(e)(3) now require payment of interest at rates set by the Secretary of Treasury.

Exhibit A Schedule Line Items:

The master line items in this exhibit have been revised as discussed above, and instructions for filling out the schedules have been added. This exhibit also now includes a sample of a data entry sheet. The Notice of Sale may require offerors to fill in a similar sheet as part of their offers.

Exhibit C Sample Offer:

This is draft Exhibit E, revised and retitled.

Exhibit D SPR Crude Oil Stream Characteristics:

The information contained in this exhibit has been substantially expanded from the information provided in draft Exhibit D.

Exhibit E SPR Crude Oil Stream Minimum Quality:

This exhibit sets forth the guaranteed minimum quality for each SPR crude oil stream, formerly contained in draft Exhibit D.

Exhibit F SPR Delivery Point Data:

This information was contained in draft Exhibit D.

Exhibit G Offer Bond—Standard Form 24:

A copy of the offer bond has been added to the exhibits.

Exhibit H Offer Guarantee—Letter of Credit:

As discussed above, a letter of credit offer guarantee has been added to the exhibits. All such offer guarantees must conform exactly to the wording specified in Exhibit H.

Exhibit I Payment and Performance Guarantee—Letter of Credit:

This payment and performance guarantee letter of credit has had a number of revisions. The letter of credit uses the term "about" to establish the amount of the letter of credit which, under Uniform Code Customs and Practice for Documentary Credits, indicates that the letter of credit is valid for up to the stated amount plus 10 percent. Because of the requirements of the FEDWIRE system, DOE has added two statements to the letter of credit to accompany wire drafts. The limited and rigid format of wire messages restricts the length of such statements and precludes the use of the longer statements contained in the draft SSP letter of credit. The longer statements are retained in this letter of credit for all non-wire drafts.

IV. Procedural Matters

A. Comments procedures

You are invited to participate in this proceeding by submitting information, views, or arguments with respect to the interim final Standard Sales Provisions. Comments should be submitted no later than [insert date 60 days from date of publication] to the address indicated in the "ADDRESSES" section of this preamble and should be identified on the outside envelope and on the document with the designation: "Sales Provisions for Strategic Petroleum Reserve Petroleum." Ten copies should be submitted. All comments received will be available for public inspection in the DOE Reading Room, Room 1E-190, James Forrestal Building, 1000 Independence Avenue, SW., Washington, D.C. 20585, between the hours of 8:00 a.m. and 4:00 p.m., Monday through Friday, except Federal holidays.

Any information or data submitted which you consider to be confidential must be so identified and submitted in writing, one copy only. We reserve the right to determine the confidential status of such information or data and to treat it according to our determination.

DOE does not intend to hold a hearing in connection with its inquiry on these matters. DOE intends to review the SSPs annually. If the comments received indicate the need for further revision of the interim final SSPs, DOE will republish the revised SSPs in their entirety, along with DOE's responses to the comments received.

B. Effective date

As of January 20, 1984, the effective date of the SPR sales rule, 10 CFR Part 625, these SSPs are adopted, on an interim basis, for use in the price competitive sale of SPR petroleum.

C. Paperwork Reduction Act

The forms used in the sale of the SPR petroleum have been cleared by the Office of Management and Budget in accordance with the Paperwork Reduction Act, until March 31, 1984, under control number 1901-0261.

List of Subjects in 10 CFR Part 625

Administrative practice and procedure, Oil and gas reserves, Strategic and critical materials, Strategic Petroleum Reserve.

(Federal Energy Administration Act of 1974, Pub. L. 93-275 (15 U.S.C. 761); Department of Energy Organization Act, Pub. L. 95-91 (42 U.S.C. 7101); Energy Policy and Conservation Act, Pub. L. 94-163 (42 U.S.C. 6201))

Issued in Washington, D.C., January 3, 1984.

Berton J. Roth,

Director, Procurement and Assistance Management Directorate.

PART 625—[AMENDED]

10 CFR Part 625 is amended by adding the following Appendix A to read as follows:

Appendix A to Part 625—Standard Sales Provisions

Index

Section A—General Pre-Sale Information

Section A—General Pre-Sale Information

A.1 List of abbreviations:

(a) *DLI*: Delivery Line Item.
(b) *DOE*: Department of Energy.
(c) *EPCA*: Energy Policy and Conservation Act, Pub. L. 94-163 (42 U.S.C. 6201 *et seq.*).
(d) *MLI*: Master Line Item.
(e) *NA*: Notice of Acceptance.
(f) *NS*: Notice of Sale.
(g) *SSPs*: Standard Sales Provisions.
(h) *SPR*: Strategic Petroleum Reserve.
(i) *SPR/PMO*: Strategic Petroleum Reserve/Project Management Office.

A.2 Definitions:

(a) *Business Day.* The term "business day" means any day except Saturday, Sunday or a U.S. Government holiday.

(b) *Contract.* The term "contract" means the sales contract under which the purchaser buys SPR petroleum from the Government. It is composed of the NS, the NA, the successful offer, and the SSPs which are incorporated by reference.

(c) *Contracting Officer.* The term "Contracting Officer" means the person executing sales contracts on behalf of the Government, and any other Government employee properly designated as Contracting Officer. The term includes the authorized representative of a Contracting Officer acting within the limits of his authority, except as may be otherwise provided in the contract.

(d) *Delivery Period.* The term "delivery period" means a given period of time during which a designated quantity of petroleum will be sold. For *pipeline delivery,* a delivery period is 1 month. For *vessel delivery* the delivery period may be one of two 10-day periods or a third period of 10 days (more or less) in the month, e.g., the 1st through the 10th, the 11th through the 20th, and the 21st to the end of the month.

(e) *Department of Energy.* The term "Department of Energy" means the agency established by Pub. L. 95-91, 42 U.S.C. Section 7101 *et seq.* and any component thereof including the SPR Office.

(f) *Government.* The term "Government," unless otherwise indicated in the text, means the United States Government.

(g) *Headquarters Senior Procurement Official.* The term "Headquarters Senior Procurement Official" means the Director, Headquarters Procurement and Assistance Management Directorate, DOE, or his duly authorized representative.

(h) *Line Item.* The term "line item" means a numbered listing of petroleum available for purchase by the offeror. Each *master line item* has a quantity estimate of a particular stream of crude oil to be sold. There are eight *master line items,* one for each of the eight crude oil streams that SPR has in storage. Each master line item contains five *delivery line items* each of which specifies the delivery method and the delivery period. (See Exhibit A, Schedule Line Item.)

(i) *Notice of Acceptance (NA).* The term "Notice of Acceptance" means the document which is signed by the Government to accept the purchaser's offer to create a contract.

(j) *Notification of Apparently Successful Offeror.* The term "notification of apparently successful offeror" means the communication, written or oral, by the Contracting Officer to an offeror that it will be awarded a contract under a master line item if it is determined that the offer is responsive and the offeror is responsible. The Contracting Officer shall furnish a proposed contract number to be used by the offeror for identification on the offeror's payment and performance guarantee.

(k) *Notice of Sale (NS).* The term "Notice of Sale" means the document announcing the sale of SPR petroleum, the amount, characteristics and location of the petroleum being sold, the delivery period and the procedures for submitting offers. The NS will specify what contractual provisions and financial and performance responsibility measures are applicable to that particular sale of petroleum and provide other pertinent information. (See Exhibit B, Sample Notice of Sale)

(l) *Offeror.* The term "offeror" means any person or entity (including a Government agency) which submits an offer in response to a NS.

(m) *Petroleum.* The term "petroleum" means crude oil, residual fuel oil, or any refined product (including any natural gas liquid, and any natural gas liquid product) owned or contracted for by DOE and in storage in any permanent SPR facility, temporarily stored in other storage facilities, or in transit to such facilities (including petroleum under contract but not yet delivered to a loading terminal).

(n) *Price Competitive Sale.* The term "price competitive sale" used in connection with a sale of SPR petroleum means one in which contract awards are made to the highest responsible offerors which submit offers responsive to the SSPs and the NS.

(o) *Project Manager.* The term "Project Manager" means the chief operating officer of the SPR/PMO. He is the duly authorized representative of the Secretary of Energy for the sale of petroleum from the Reserve.

(p) *Project Management Office.* The term "Project Management Office" means the collective staff of the SPR Office in Louisiana and Texas.

(q) *Purchaser.* The term "purchaser" means any person or entity (including a Government agency) which enters into a contract with DOE to purchase SPR petroleum.

(r) *Secretary.* The term "Secretary" means the Secretary of Energy or his duly authorized representative.

(s) *Standard Sales Provisions (SSPs).* The term "Standard Sales Provisions" means a set of terms and conditions of sale, which may contain or describe financial and performance responsibility measures, for petroleum sold from the Strategic Petroleum Reserve. These SSPs constitute the "standard sales agreement" referenced in the Strategic Petroleum Reserve "Drawdown" (Distribution) Plan, Amendment No. 4 to the SPR Plan.

(t) *Strategic Petroleum Reserve.* The term "Strategic Petroleum Reserve" means that program of the Department of Energy established by Title I, Part B of EPCA.

(u) *Strategic Petroleum Reserve Office.* The term "Strategic Petroleum Reserve Office" means the Deputy Assistant Secretary for the SPR and the collective staff reporting to him.

(v) *Vessel.* The term "vessel" means either a tankship or a barge.

A.3 *Standard Sales Provisions:*

(a) These Standard Sales Provisions (SSPs) contain pre-sale information, sales solicitation provisions, and sales contract provisions setting forth terms and conditions of sale, including purchaser financial and performance responsibility measures, or descriptions thereof. The NS may specify which of such terms and conditions shall apply to a particular sale of such petroleum, and it may specify any revisions therein and any additional provisions which shall be applicable to that sale. (See Exhibit B, Sample Notice of Sale)

(b) *All offerors must,* as part of their offers for SPR petroleum in response to a NS, *agree without exception to all provisions of the SSPs which the NS makes applicable to the particular sale.* The Government will not award a contract to an offeror which has failed to so agree.

(c) The applicable provisions of the SSPs will be incorporated into the sales contracts by referring in the NS to the SSPs.

A.4 *Application of the Standard Sales Provisions:* These SSPs apply to all price competitive sales of petroleum from the SPR.

A.5 *Periodic Revisions of the Standard Sales Provisions:* DOE will review the SSPs periodically and republish them in the **Federal Register,** with any revisions. When a NS is issued, it will cite the **Federal Register** and the Code of Federal Regulations in which the latest version of the SSPs was published. Offerors are cautioned that it may take two years for a version of the SSPs published in the Federal Register to be published in the Code of Federal Regulations. Therefore, some applicable SSPs may be published only in the **Federal Register.** Interested persons may obtain a copy of the current SSPs by writing to the address set forth in Provision No. A.8.

A.6 *Offerors List for Sales of Petroleum:* (a) The SPR/PMO will maintain a list of those potential offerors which wish to receive a NS whenever such a document is issued. Signatories to the Basic Sales Agreement (BSA) which was intended to be utilized in SPR sales, but which no longer applies to such sales, will automatically be included unless they ask, in writing, to be excluded. They should update the information required by (c) below. In order to assure that prospective offerors will receive the NS or offer form in timely fashion, all potential offerors are encouraged to submit the information in (c) as soon as possible. *A NS may be issued with as little as a week or less allowed for the receipt of offers.* While the Government will use its best efforts to supply copies of the NS to persons not on the list who request the NS at the time an SPR petroleum sale is announced, this may not always be feasible in light of the short amount of time available before offers must be received.

(b) Any firm or individual may send a written request to be on the list to the following address: U.S. Department of Energy, Strategic Petroleum Reserve, Project Management Office, Procurement Division, Mail Stop EP 5501, 900 Commerce Road East, New Orleans, Louisiana 70123. Telephone Number (504) 734-4341.

(c) The request should be in writing and should include the following information:

Name of firm
Mailing address
City, State, Zip Code
Name of authorized agent and alternate authorized agent
Telephone numbers for agent and alternate including area code
TWX number/code
Telecopier brand name and model number
Is telecopier automatic or operator controlled?
Telephone number for telecopier transmission including area code
Telephone number for verification of message receipt including area code
Dunn's Number

A.7 *Publicizing the Notice of Sale:*

(a) The NS will be sent to persons whose names are on the offerors list referenced in Provision No. A.6. Potential offerors may send a representative to the SPR/PMO to obtain a copy of the NS.

(b) The NS will be sent to firms requesting it when a sale is announced. Firms may request the NS by telephone or in writing to the telephone number or address in Provision No. A.6 above.

(c) A DOE press release, which will include the salient features of the NS, will be available to any news agency.

(d) At the option of the SPR Project Manager, advertisements may be placed in the *Commerce Business Daily* and commercial publications likely to reach interested parties. The advertisements will contain the salient features of the NS and a name and telephone number at the SPR/PMO to call for further information.

A.8 *Issuing office for the Standard Sales Provisions and Notice of Sale Copies of the SSPs:* After publication in **Federal Register,** and copies of the NS, when one is issued, may be obtained from the following address: U.S. Department of Energy, Strategic Petroleum Reserve, Project Management Office, Procurement Division, Mail Stop EP 5501, 900 Commerce Road East, New Orleans, Louisiana 70123.

A.9 *Penalty for false statements in offers to buy SPR petroleum:* A penalty for making false statements is imposed in the False Statements Act, 18 U.S.C. 1001, which provides:

Whoever, in any matter within the jurisdication of any department or agency of the United States knowingly and willfully falsifies, conceals or covers up by any trick, scheme, or device a material fact, or makes any false, ficticious or fraudulent statements or representations, or makes or uses any false writing or document knowing the same to contain any false, ficticious or fraudulent statement or entry, shall be fined not more than $10,000 or imprisoned not more than 5 years, or both.

Section B—Sales Solicitation Provisions

B.1 *Requirements for a valid offer—caution to offerors:* A valid offer to purchase SPR petroleum must meet the following conditions:

(a) The offer guarantee in an amount adequate to guarantee the offer must be received prior to the time set for the receipt of offers (See Provision No. B.9);

(b) The offer must be on the proper forms if such forms are specified under Provision No. B.18;

(c) The offer must be received prior to the time set for receipt of offers;

(d) Any amendments to the NS which explicitly require acknowledgement of receipt must be properly acknowledged; and

(e) The offeror must agree without exception to all provisions of the SSPs which the NS makes applicable to a particular sale, as well as to all provisions in the NS.

B.2 *Requirements of the "Jones Act" for U.S.-flag vessels—caution to offerors:* The "Jones Act," 46 U.S.C. 883, prohibits the transportation of any merchandise, including SPR petroleum, by water or land and water, on penalty of forfeiture thereof, between points within the United States (excluding the Virgin Islands) in vessels other than vessels built in and documented under laws of the United States, and owned by United States citizens, unless the prohibition has been waived by the Secretary of the Treasury. Further, certain U.S.-flag vessels built with construction differential subsidies are precluded by Section 506 of the Merchant

Marine Act of 1936 (46 U.S.C. 1156) from participating in U.S. coast-wise trade, unless such prohibition has been waived by the Secretary of Commerce, the waiver being limited to a maximum of 6 months in any given year.

B.3 *"Superfund" tax on SPR petroleum—caution to offerors:* The Hazardous Substance Response Revenue Act of 1980, Pub. L. 96-510, 26 U.S.C. 4611 *et seq.* imposes a tax (the "Superfund" tax) of 0.79 cent a barrel on: (1) crude oil received at a United States refinery and (2) petroleum products (including crude oil) entered into the United States for consumption, use or warehousing unless it can be established that the tax has already been paid with respect to such petroleum. The Government already has paid the tax on some of the oil imported and stored in the SPR. However, no tax has been paid on imported oil stored in the SPR prior to the effective date of this Act, or on domestic oil stored in the SPR. Because various crude oils have been commingled in the SPR, upon drawdown of the SPR it will not be possible for DOE to provide information to purchasers of SPR crude oil as to which oil already has been taxed and which oil has not. DOE has requested that the Internal Revenue Service develop a method to designate the oil on which the taxes have been paid; until such time as procedures are developed, or the tax expires, offerors are advised that all SPR oil either received at a U.S. refinery, used or exported may be subject to the Superfund tax.

B.4 *Export limitations and licensing—caution to offerors:* Offerors for SPR petroleum are put on notice that SPR crude oils subject to different export control laws have been commingled in storage. Export of SPR crude oil is subject to U.S. export control laws, the provisions of which differ depending on the source of the crude oil proposed to be exported. For example, imported crude oil stored in the SPR may be exported pursuant to applicable Department of Commerce "Short Supply Controls," 15 CFR Part 377, if: the export is part of a transaction resulting in the importation of refined products of a quantity and quality not less than would be derived from domestic refining; the products are to be sold at prices no higher than the lowest prices at which they could have been sold by the nearest capable U.S. refinery; and for compelling economic or technological reasons beyond the exporter's control, the crude oil cannot reasonably be processed in the U.S. (15 CFR 377.6(d)(1)(vii)). However, there are somewhat more stringent, independent statutory tests to be met as preconditions to the export of certain other crude oils stored in the SPR, including Alaskan North Slope (ANS) and Naval Petroleum Reserves (NPR) oil. *See* section 7(d) of the Export Administration Act of 1979, 50 U.S.C. App. 2406(d) (ANS oil) and 10 U.S.C. 7430(e) (NPR oil); *see also* 30 U.S.C. 185(u) (oil shipped across a Mineral Lands Leasing Act Section 28(u) right-of-way) and 43 U.S.C. 1354(a) (OCS oil).

B.5 *Issuance of the Notice of Sale:* In the event petroleum is sold from the SPR, the Government will issue a NS containing all of the pertinent information necessary for the offeror to prepare a priced offer. *A NS may be issued with as little as a week or less allowed for the receipt of offers.* Offerors are expected to examine the complete NS document, and to become familiar with the SSPs cited therein. Failure to do so will be at the offeror's risk.

B.6 *Submission of offers and modification of previously submitted offers:*

(a) Unless otherwise provided in the NS, offers must be submitted to the Government by mail or hand-delivery. Direct cash deposits as offer guarantees will be sent by wire.

(b) Unless otherwise provided in the NS, offers may be modified or withdrawn by mail, telegram, or mailgram, provided that the mail, telegram, or mailgram is received at the designated office prior to the hour and date specified for receipt of offers.

(c) Envelopes containing offers and any material related to offers shall be plainly marked on the outside; "RE: SALE OF PETROLEUM FROM STRATEGIC PETROLEUM RESERVE. OFFERS ARE DUE (insert time of opening), LOCAL NEW ORLEANS, LA TIME ON (insert date of opening). MAIL ROOM MUST MARK DATE AND TIME OF RECEIPT ON FACT OF THE ENVELOPE."

(d) The envelope shall be marked with the full name and return address of the offeror.

(e) Offers being sent by mail and modifications being sent by mail, telegram, or mailgram must be received at the address specified in the NS.

(f) Handcarried offers brought to the SPR/PMO in New Orleans, Louisiana on the day set for receipt of offers, or any day prior to that day, shall be taken by the offeror to the place specified in the NS. This includes mail being delivered by a delivery service. Handcarried offers shall be placed in the bid box on Saturdays, Sundays, and U.S. Government holidays or after business hours on business days.

(g) Public opening of offers is not anticipated unless otherwise indicated in the NS. An abstract of offers will be prepared and posted along with copies of the apparently successful offers in a prominent place for public viewing no later than 48 hours after the specified time and date for the receipt of offers.

B.7 *Acknowledgment of amendments to a Notice of Sale:* When an amendment to a NS requires acknowledgment of receipt, receipt by an offeror must be acknowledged: (a) By signing and returning the amendment, or (b) by letter, mailgram, or telegram in either case to be sent to the address specified in the NS. Such acknowledgment must be received prior to the hour and date specified for receipt of offers.

B.8 *Late offers, modifications of offers, and withdrawal of offers:*

(a) Any offer received at the office designated in the NS after the exact time specified for receipt will be considered only if it is received before award is made and only under the following conditions:

(1) It was sent by registered or certified mail not later than the fifth calendar day prior to the date specified for the receipt of offers (e.g., an offer submitted in response to a NS requiring receipt of offers by the 20th of the month must have been mailed by the 15th or earlier); or,

(2) It was sent by mail, telegram or mailgram if authorized, and it is determined by the Government that the late receipt was due solely to mishandling by the Government after receipt at the Government installation.

(b) Any modification or withdrawal of an offer is subject to the same conditions as in (a) above, except that it shall be mailed not less than the third calendar day prior to the date specified for receipt of offers. An offer may also be withdrawn in person by an offeror or its authorized representative, provided the representative's identity is made known and the representative signs a receipt for the offer, but only if the withdrawal is made prior to the exact time set for receipt of offers.

(c) The only acceptable evidence to establish:

(1) The date of mailing of a late offer, modification, or withdrawal sent either by registered or certified mail is the U.S. Postal Service postmark on either: (i) The envelope or wrapper, or (ii) the original receipt from the U.S. Postal Service. If neither postmark shows a legible date, the offer, modification or withdrawal shall be deemed to have been mailed late. (The term "postmark" means a printed, stamped, or otherwise placed impression, exclusive of a postage meter machine impression, that is readily identifiable without further action as having been supplied and affixed on the date of mailing by employees of the U.S. Postal Service. Therefore, offerors should request the postal clerk to place a hand cancellation bull's-eye "postmark" on both the receipt and the envelope or wrapper.)

(2) The time of receipt at the Government installation is the time/date stamp of such installation on the offer's wrapper or other documentary evidence of receipt maintained by the installation.

(d) Notwithstanding (a) and (b) of this provision, a late modification of an otherwise successful offer which makes its terms more favorable to the Government will be considered at any time it is received, and may be accepted.

B.9 *Offer guarantee:*

(a) Each offeror must submit an acceptable offer guarantee. The offer guarantee must be received at the place specified for receipt of offers prior to the time and date set for receipt of offers.

(b) An offeror's failure to submit a timely, acceptable guarantee will result in rejection of its offer.

(c) The amount of the offer guarantee is 10 million dollars or 5 percent of the total offer, whichever is less. The total offer is the sum of the offer's maximum potential contract amounts for all master line items.

(d) Each offeror must submit one of the following types of offer guarantees with its offer:

(1) An offer bond executed on U.S. Government Standard Form 24 (See Exhibit G);

(2) A certified or cashier's check payable to the U.S. Department of Energy, drawn on a U.S. Bank;

(3) A wire cash deposit to a special SPR/PMO account. All wire deposit costs will be borne by the offeror; or

(4) A letter of credit from a U.S. depository institution conforming without exception to the contents required by Exhibit H, Offer Guarantee—Letter of Credit. If a letter of credit is chosen, all costs will be borne by the offeror.

(e) If the offeror, a surety company or bank forwards the offer guarantee separately from the offer, the envelope shall clearly say "OFFER GUARANTEE OF (Name of Company)" and shall be clearly marked in accordance with Provision No. B.6(c).

(f) The offeror shall be liable for any amount lost by the Government due to the difference between its offer and the resale price, and for any additional resale costs incurred by the Government in the event that the offeror:

(1) Withdraws its offer within 10 days following the date set for receipt of offers;

(2) Withdraws its offer after having agreed to extend its acceptance period; or

(3) Having received a notification of apparently successful offeror, fails to furnish an acceptable payment and performance guarantee within the time limit specified by the Contracting Officer

The offer guarantee shall be used toward offsetting such difference. Use of the offer guarantee for such recovery shall not preclude recovery by the United States of damages in excess of the amount of the offer guarantee caused by such failure of the offeror.

(g) Letters of credit and bid bonds furnished as offer guarantees must be valid for at least 21 calendar days after the date set for the receipt of offers.

(h) Offer guarantees (except offer bonds and letters of credit) will be returned to an unsuccessful offeror 5 business days after expiration of the offeror's acceptance period or 3 business days after award of contracts for delivery line items on which the offeror submitted a price, whichever is first, except as provided in (i) below, and to a successful offeror upon receipt of a satisfactory performance and payment guarantee. Offer bonds (Standard Form 24) and letters of credit will be returned only upon written request. Where the offer guarantee was a wire cash deposit, a cashier's check or a certified check, it may be applied toward advance payment.

(i) If an offeror defaults on its offer, the Government will hold the offer guarantee so that damages can be assessed against it.

B.10 *Explanation requests from offerors:* Offerors may request explanations regarding meaning or interpretation of the NS from the individual and telephone number indicated in the NS. On complex and/or significant questions, the Government reserves the right to have the offeror put the question in writing by mail, telegram or mailgram. Explanation or instructions regarding complex or significant issues will be given to prospective offerors only as an amendment to the NS.

B.11 *Currency for offers:* Prices shall be stated and amount shall be paid in U.S. dollars.

B.12 *Language of offers and contracts:* All offers in response to the NS and all modifications of offers shall be in English. All contracts awarded as a result of the NS and all modifications to such contracts shall be in English. All correspondence between offerors or purchasers and the Government shall be in English.

B.13 *Proprietary data:* If any information submitted in connection with a sale is considered proprietary, that information should be so marked, and an explanation provided as to the reason such data should be considered proprietary. Any final decision as to whether the material so marked is proprietary will be made by the Government. All DOE Freedom of Information Act regulations governing the release of proprietary data shall apply.

B.14 *SPR crude oil streams and delivery points:*

(a) The geographical locations of the terminals and docks interconnected with permanent SPR storage locations, the SPR crude oil streams available at each location and the delivery points for those streams are as follows (See also Exhibit D, SPR Crude Oil Stream Characteristics, and Exhibit F, SPR Delivery Point Data):

Geographical location	Delivery points	Crude oil streams
Freeport, Texas	Jones Creek Tank Farm, or Seaway Docks	SPR Bryan Mound Sweet, SPR Bryan Mound Sour
Freeport, Texas	Seaway Docks	SPR Bryan Mound Maya.
Nederland, Texas	Sun Terminal, or Sun Docks	SPR West Hackberry Sweet, *SPR West Hackberry Sour
St. James, Louisiana	LOCAP Terminal, or DOE St. James Docks	SPR Bayou Choctaw Sweet, SPR Bayou Choctaw Sour, SPR Weeks Island Sour

*Includes petroleum stored at the SPR's Sulphur Mines site.

(b) The NS may change delivery points and it may also include additional or alternate facilities utilized in connection with Government contracts for the purchase of petroleum to fill the SPR. These facilities may include loading terminals or transshipment terminals. Alternately, the Government or its contractor may provide the transportation to the purchaser's facility, for example, when the petroleum is in transit to the SPR at time of sale.

(c) The NS may specify facility operator, contract information for scheduling delivery of cargoes purchased, and applicable port data/restrictions (see Exhibit F, SPR Delivery Point Data, for additional information).

B.15 *Notice of Sale line item schedule—petroleum quantity, quality, and delivery:*

(a) Unless the NS provides otherwise, the master line items (MLI) and delivery line items (DLI) for sales contracts are as provided in Exhibit A, Schedule Line Items, to these SSPs. Currently, there are eight master line items in Exhibit A, one for each of the eight crude oil streams that the SPR has in storage.

(b) Each master line item contains five delivery line items, each of which specifies the delivery method and the delivery period.

(1) DLI–A covers crude to be transported by the major common carrier pipeline (Seaway, Texoma or Capline) connected to the site storing the particular SPR petroleum offered on that master line item over the period of a month.

(2) DLI–B covers petroleum to be transported by other pipelines connected to the SPR site over the period of a month.

(3) The last three cover petroleum to be transported by vessels: DLI–C, covering vessels to be loaded from the first through the tenth of the month; DLI–D, vessels to be loaded from the eleventh through the twentieth; and DLI–E, vessels to be loaded from the twenty-first through the last day of the month.

(c) The NS will state the total estimated number of barrels to be sold on each master line item. An offeror may offer to buy all or part of the petroleum offered on a master line item. In making awards, the Contracting Officer shall attempt to achieve award of the exact quantities offered by the NS, but may vary the estimated master line item quantities ±10 percent in order to match the delivery line item offers received.

(d) The NS will specify a minimum quantity for each delivery line item. To be responsive, an offer on a delivery line item must be for a quantity which is at least the Government's specified minimum.

(e) The NS will specify the maximum quantity which could be sold on each of the five delivery line items. This maximum is not an indication of the amount of petroleum that, in fact, will be sold on that delivery line item. Rather, it represents DOE's best estimate of the maximum amount of the particular SPR crude oil stream that can be moved by that transportation system over the delivery period. The total DOE estimated DLI maximums may exceed the total number of barrels to be sold on that master line item, as the NS delivery line estimates represent estimated transportation capacity, not what DOE is offering to sell. Where necessitated by facility constraints, DLI–B may be combined with either DLI–A or DLI–C, D, and E for the purpose of determining estimated transportation capacity.

(f) The NS will not specify what portion of the petroleum which the Government offers on a master line item will, in fact, be sold on any given delivery line item. Rather, the highest priced offers received on the master line item will determine the delivery line items against which the offered petroleum is sold.

(g) DOE will not sell petroleum on a delivery line item in excess of the delivery line item maximum; however, DOE reserves the right to revise its estimates up to the time of award and to award contracts in accordance with its revised estimates. Offerors are cautioned that: DOE cannot guarantee that such capacity is available; offerors should undertake their own analyses of available transportation capacity; and each apparently successful offeror is wholly responsible for arranging all transportation other than terminal arrangements at the terminals listed in Provision No. B.14. Such terminal arrangements shall be made in accordance with Provision No. C.6. A purchaser against one delivery line item cannot change transportation modes without prior written permission from the Government, although such permission will be given wherever possible, in accordance with Provision No. C.16.

(h) Exhibit D, SPR Crude Oil Stream Characteristics, contains current available characteristics for each SPR crude oil stream. This data will change as more crude oil is stored in the SPR. Prospective offerors are cautioned that the NS will provide, to the maximum extent practicable, the actual characteristics as to each stream offered.

(i) In the preparation of offers, offerors must specify at least one delivery line item (i.e., transportation mode), but may make offers on more than one delivery line item. Unless otherwise specified in the NS, offerors also may make alternate offers on different delivery line items under a single master line item; e.g., the offer may state, either DLI–A, via major common carrier, or DLI–D, via vessel loaded from the 11th through 20th, or DLI–E, via vessel loaded from the 21st through the end of the month.

(j) Offerors may submit more than one offer on a master line item.

(k) An offeror also may specify a minimum DLI quantity that the offeror would accept on a delivery line item. The Government will award less than the offer's maximum DLI quantity, only if after consideration of all higher offers, the remaining quantity available on a delivery line item is less than the offer's maximum DLI quantity. If the offeror specifies no minimum, the Government will evaluate the offer as though the offeror had specified the Government's minimum quantity.

(l) Each offeror, if determined to be an apparently successful offeror on a delivery line item, agrees to enter into a contract for the purchase of a quantity of petroleum (the quantity to be specified in the contract and to be within the minimum and maximum quantities stated in the offer) and to take delivery of that petroleum in accordance with the terms of that contract.

(m) The NS may establish a minimum acceptable price. Offers less than such price shall be rejected as nonresponsive.

B.16 *Line item information to be provided in the offer:* The following information will be provided to the Government by the offeror in its offer on each master line item, in the exact form as that set forth on the master line item schedule in Exhibit A (See also Exhibit C, Sample Offer):

(a) Master line item number

(b) Quantity offered for that master line item. The offeror shall state the maximum quantity sought for that crude type. Offerors are cautioned that alternate offers on different master line items are not permitted; e.g., the offer may not state, either 1,000,000 barrels of SPR West Hackberry sweet or 1,000,000 barrels of SPR West Hackberry sour. DOE will award the maximum MLI quantity to the offerors with the highest unit prices until award of the maximum MLI quantity to the next lowest offeror would cause the total of the awards to exceed either the quantity offered for sale on the master line item or the maximum transportation capability specified for a particular delivery line item. In that event, where practicable DOE will award a lesser amount to the apparently successful offeror sufficient to bring the total quantity awarded up to the quantity offered by the Government on that line item. However, DOE reserves the right to vary the quantity offered by ±10 percent in order to match the offers received. (See minimum acceptable quantity discussed in (e) below.)

(c) Delivery line item quantity. The offeror shall state the number of barrels which the offeror will accept on each delivery line item, i.e., by the delivery mode and during the delivery period specified. The quantity stated on a single delivery line item shall not exceed the maximum MLI quantity. The offeror shall designate a quantity on at least one delivery line item, but may designate quantities on more than one delivery line item. If the offeror is willing to accept alternate delivery methods or delivery periods, the total of its designated delivery line item quantities would exceed its maximum MLI quantity; otherwise, the total of its designated delivery line item quantities should equal its maximum MLI quantity.

(d) Delivery line item unit price and total price. The offeror shall provide the price per barrel for each delivery line item for which the offeror has designated a desired quantity, as well as the total price (quantity times price). DOE will award on the basis of highest unit price first. For offerors that will accept alternate delivery line items, if the offeror offers a higher price for one delivery line item, that item shall be awarded first. If the offeror has the same price for two or more delivery line items, it may indicate its first choice, second choice, etc., for award of those items; if the offeror does not indicate a preference, DOE may select the delivery line items to be awarded at its discretion. Prices may be stated in hundredths of a cent ($0.0001). The Government shall drop from the offer and not consider any numbers of less than one one-hundredth of a cent.

(e) Minimum quantity acceptable. The offeror may indicate the minimum quantity the offeror will accept on a delivery line item. The offeror may indicate that the minimum acceptable quantity is the maximum quantity sought by the offeror. DOE will award less than the maximum quantity proposed by the offeror only if the offer is for greater than the amount of petroleum remaining to be sold on the line item. If the offeror does not indicate a minimum quantity, the minimum quantity shall be the minimum quantity indicated in the NS.

(f) Any other data required by the NS.

B.17 *Mistake in offer:*

(a) After opening and recording the offers, the Contracting Officer shall examine all apparently successful offers for mistakes. In case of apparent mistakes and in cases where the Contracting Officer has reason to believe a mistake may have been made, he shall request from the offeror a verification of the offer, calling attention to the suspected mistake The Contracting Officer may telephone the offeror and confirm the request by telegram. The Contracting Officer may set a limit of as little as 6 hours for telephone response, with any required written documentation to be received within as little as 2 business days.

(b) If no response is received, the Contracting Officer may determine that no error exists and proceed with offer evaluation.

(c) If the offeror alleges a mistake, the matter will be resolved as provided in (d) and (e) below.

(d) The Contracting Officer may correct any error apparent on the face of the offer prior to award in accordance with (1) through (3) below if he has first obtained from the offeror verbal verification, to be confirmed in writing, of the offer actually intended.

(1) Price discrepancy: An offer for a delivery line item must contain the unit price per barrel being offered and the quantity to which the unit price applies. The offer for a delivery line item should contain an extension price which is the total of the quantity desired multiplied by the unit price offered. If there is a discrepancy between the unit price and the extension price, the unit price will govern and be recorded as the offer, unless it is clearly apparent on the face of the offer that there has been a clerical error, in which case the Contracting Officer can correct the offer.

(2) Quantity discrepancy: In case of conflict between the master line item quantity and the delivery line item quantity, the lesser quantity will govern.

(3) Any other type of error will be resolved in accordance with (e) below.

(e) The Head of the Procuring Activity will make administrative determinations described in (1) through (3) below in connection with mistakes in offers alleged after opening and recording of offers and before award. No such determination shall be used to make a non-responsive offer responsive. The authority for such determinations is in addition to that contained in (d) above.

(1) The Head of the Procuring Activity may determine that an offeror shall be permitted to withdraw its offer without penalty under the offer guarantee, where the offeror requests permission to do so and clear and convincing evidence establishes the existence of a mistake.

(2) The Head of the Procuring Activity may determine that an offeror may correct the offer and refuse to permit the offeror to withdraw its offer if the evidence is clear and convincing both as to the existence of a mistake and as to the offer actually intended, and if the offer, both as uncorrected and corrected, is an apparently successful offer.

(3) The Head of the Procuring Activity may determine that an offeror may correct its offer where the offeror requests permission to do so and clear and convincing evidence establishes both the existence of an error and the offer actually intended. However, if such correction would result in displacing one or more higher acceptable offers, the Head of the Procuring Activity shall not so determine

unless the existence of the mistake and the offer actually intended are ascertainable substantially from the NS and offer itself. If the evidence is clear and convincing only as to the mistake, but not as to the intended offer, the Head of the Procuring Activity may determine to permit the offeror to withdraw its offer in whole or in part, if only part of the offer is affected, without penalty under the offer guarantee.

B.18 *Proper form for offer submission:* The NS may require that for an offer to be valid, it must be submitted only on a certain form or forms. Such forms may be:

(a) The master line item schedules 001 through 008 in Exhibit A;

(b) A sheet similar to the Sample Data Entry Sheet in Exhibit A;

(c) Other forms provided with the NS; or

(d) Any combination of the above. If the NS requires submission of an offer on specified forms, failure to use such forms will result in the offer being rejected as non-responsive.

B.19 *Evaluation of offers:*

(a) The Contracting Officer will be the determining official as to whether an offer conforms to the SSPs and the NS. The Contracting Officer will award to the highest responsible offeror which submits an offer responsive to the SSPs and the NS. The Government reserves the right to reject any or all offers and to waive minor informalities or irregularities in offers received.

(b) A minor informality or irregularity in an offer is an inconsequential defect the waiver or correction of which would not be prejudicial to other offerors. Such a defect or variation from the strict requirements of the NS is inconsequential when its significance as to price, quantity, quality or delivery is negligible.

B.20 *Procedures for evaluation of offers:* DOE will array all price offers on a master line item from highest to lowest for award evaluation regardless of delivery line item. However, DOE will award against the delivery line items and will not award a greater quantity on a delivery line item than the Government's estimate (which is subject to change up to the time of award) of the maximum quantity that can be moved by the delivery method. Selection of the apparently successful offer involves the following steps:

(a) Any offers below the minimum acceptable price, if any minimum price has been established for the sale, will be rejected as being nonresponsive.

(b) All other offers on each master line item will be arrayed, for award consideration, from highest delivery line item price to lowest delivery line item price.

(c) The highest offers will be reviewed for responsiveness to the terms of the NS.

(d) In the event the highest offer does not take all the crude available on the master line item, the next highest offer will be selected until all of the petroleum offered on the master line item is taken. In the event that acceptance of an offer against a delivery line item would result in the sale of more petroleum than the Government estimates can be delivered by the specified delivery method, the Government will not award the full amount of the offer, but rather that portion which the Government estimates can be delivered, provided such portion exceeds the offer's minimum DLI quantity. In the event that the quantity remaining is less than the offeror's minimum DLI quantity, the Contracting Officer shall proceed to the next highest offer.

(e) In the event of tied offers, the total of which exceed the remaining quantity offered on a line item, the remaining quantity shall be divided proportionately using the following formula:

$$\frac{\text{barrels remaining X each individual offeror's maximum quantity}}{\text{total of the tied offerors' designated maximum quantities}}$$

In the event that a single tied offeror's share falls below the offeror's minimum acceptance quantity, that quantity will be awarded to the other tied offerors. If the share of more than one of the tied offers falls below their respective minimum acceptable quantity, then those tied offers shall be arrayed by a drawing of lots, conducted by the Contracting Officer. In the order of their drawing, the Contracting Officer shall then include in his division as many of those offerors as will not cause any offeror's share to fall below its minimum acceptable quantity.

(f) Determinations of responsibility of potential purchasers before each award will be made by the Contracting Officer. Compliance with required payment and performance guarantees will effectively assure a finding of responsibility of offerors, except where: (i) The offeror is on either DOE's or the Federal Government's list of debarred, ineligible and suspended bidders; or (ii) evidence, with respect to an offeror, comes to the attention of the Contracting Officer of conduct or activity which represents a violation of law or regulation (including an Executive Order having the force and effect of law); or (iii) evidence is brought to the attention of the Contracting Officer of past activity or conduct of the offeror which shows a lack of integrity (including actions inimical to the welfare of the United States) or willingness to perform, so as to substantially diminish the Contracting Officer's confidence in the offeror's performance under the proposed contract. Apparently successful offerors will be contacted by telephone and advised to provide to the Contracting Officer, within five business days or such other longer time as the Contracting Officer shall determine, a letter of credit (See Exhibit I, Payment and Performance Guarantee—Letter of Credit) or advance payment as specified in the NS or SSPs.

(g) Award on each delivery line item will be made to the highest responsible offerors which submit offers responsive to the SSPs and the NS and which have provided the required letter of credit or advance payment.

B.21 *Financial statements and other information:* (a) After receipt of offers but prior to making award, the Government reserves the right to ask for the audited financial statements for offeror's most recent fiscal year and unaudited financial statements for the most recent quarters. This statement package must contain a balance sheet and profit and loss statement for the periods covered thereby. A certification by a principal accounting officer that there have been no material changes in financial condition since the date of the audited statements, and that these present the true financial condition as of the date of the offer, shall accompany the statements. If there has been a change, the amount and nature of the change must be specified and explained in the unaudited statements and a principal accounting officer shall certify that they are accurate. The Contracting Officer must receive the data within 2 business days of a telephone request to the offeror.

(b) The Government also reserves the right to require information from the offeror regarding its plans for use of the petroleum, the status of requests for export licenses, plans for complying with the Jones Act, etc. The information must be received within 3 business days of a telephone request.

B.22 *Resolicitation procedures on unsold petroleum:*

(a) In the event that petroleum offered on a master line item remains unsold after evaluation of all offers, the Contracting Officer may issue an amendment to the NS, resoliciting offers on these delivery line items from all interested parties. Evaluation procedures for these delivery line items shall follow the procedures set forth in Provision No. B.20. The Government reserves the right to change the master line items to offer different SPR crude oil streams for the purpose of such resolicitation.

(b) In the event that for any reason petroleum which has been awarded becomes available to the Government for resale, the Contracting Officer may use the following procedures:

(1) If priced offers remain valid in accordance with Provision No. B.23, the petroleum will go to the next highest arrayed offer.

(2) If offers have expired in accordance with Provision No. B.23, the Contracting Officer at his option may offer the petroleum to the highest offeror for that master line item which: (i) had not received its maximum MLI quantity; (ii) had offered to take delivery by a delivery method which has remaining capacity; and (iii) had stated a minimum DLI quantity that was less than the quantity available for award. The pertinent offeror may, at its option, accept or reject that petroleum at the price originally offered, and if that offeror rejects the petroleum, it will be offered to the next highest offeror, etc.

(3) If the petroleum is not then resold, the Contracting Officer may at his option proceed to amend the NS to resolicit offers for that petroleum or add the petroleum to the next sales cycle.

B.23 *Offeror's certification of acceptance period:*

(a) By submission of an offer, the offeror certifies that its priced offer will remain valid for 10 calendar days after the date set for the receipt of offers.

(b) By mutual agreement of DOE and the offeror, an individual offeror's acceptance period may be extended for a longer period.

B.24 *Line item information to be provided in the Notice of Acceptance:* The following information will be provided to the purchaser by the Government on the NA for each master line item and/or delivery line item if the offeror is awarded a contract:

(a) Identification of SPR crude oil streams awarded;

(b) Delivery line item number;

(c) Total quantity awarded on the master line item and on each delivery line item;

(d) Price in U.S. dollars per specified unit, i.e., barrels;

(e) Extended total price offer for that line item;

(f) Delivery point;

(g) Delivery period; and

(h) Any other data necessary to the sales contract.

B.25 *Contract documents:* If an offeror is successful, the Government will make award using a NA signed by the Contracting Officer. The NA will identify the items, quantities, prices and delivery method which the Government is accepting. Attached to the NA will be the NS and the successful offer. Provisions from Section C of the SSPs will be made applicable through incorporation by reference in the NS. The Contracting Officer also shall provide the purchaser with an information copy of the then-current SSPs as published in the Federal Register. If time constraints require it, the Government may accept the offeror's offer by an electronic notice, such as telegram or telegraph, and the contract award shall be effective upon issuance of such notice. The electronic notice will be followed by a mailing of full documentation as described above.

B.26 *Purchaser's representative:* As part of its offer, each offeror shall designate an agent and an alternate agent as a point of contact for any telephone calls or correspondence from the Contracting Officer. Any such agent shall have a U.S. address and telephone number and shall speak English.

B.27 *Procedures for selling to other U.S. Government agencies:*

(a) If a U.S. Government agency submits an offer for petroleum in a price competitive sale, that offer will be arrayed for award consideration in accordance with Provision No. B.20, Procedures for evaluation of offers. If a U.S. Government agency is an apparently successful offeror, award and payment will be made exclusively in accordance with statutory and regulatory requirements governing transactions between agencies, and the U.S. Government agency will be responsible for complying with these requirements within the time limits set by the Contracting Officer.

(b) U.S. Government agencies are exempt from all guarantee requirements, but must complete all transportation arrangements for moving the petroleum. They must also fill out and submit any required information for statistical purposes. No failure by a U.S. Government agency to comply with any of the requirements of these SSPs shall provide a basis for challenging a contract award to the U.S. Government agency.

B.28 *Information gathered for statistical purposes.* The Contracting Officer, at his discretion, may in the NS require the offeror to submit the information called for in Exhibit L, Information for Statistical Purposes. That information may be used for analytical purposes, but will have no effect on contract evaluation and award.

Section C Sales Contract Provisions

C.1 *Certification of independent price determination:*

(a) By submission of an offer, the offeror certifies that in connection with the offer:

(1) The prices in the offer have been arrived at independently, without consultation, communication, or agreement, for the purpose of restricting competition, as to any matter relating to such prices, with any other offeror or with any competitor;

(2) Unless otherwise required by law, the prices which have been quoted in the offer have not been knowingly disclosed by the offeror and will not knowingly be disclosed directly or indirectly by the offeror prior to award, to any other offeror or to any competitor; and

(3) No attempt has been made or will be made by the offeror to induce any other person or firm to submit or not to submit an offer for the purpose of restricting competition.

(b) Each person signing the offer certifies that:

(1) He is the person within the offeror's organization responsible for the decision as to the prices being offered, and that he has not participated, and will not participate, in any action contrary to (a)(1) through (a)(3) above; or

(2) (i) He is not the person in the offeror's organization responsible within that organization for the decision as to the prices being offered, but that he has been authorized in writing to act as agent for the persons responsible for such decision in certifying that such persons have not participated, and will not participate, in any action contrary to (a)(1) through (a)(3) above, and as their agent does hereby so certify; and (ii) he has not participated, and will not participate, in any action contrary to (a)(1) through (a)(3) above.

(c) An offer will not be considered for award where (a)(1), (a)(3), or (b) above has been deleted or modified. Where (a)(2) above has been deleted or modified, the offer will not be considered for award unless the offeror furnishes with the offer a signed statement which sets forth in detail the circumstances of the disclosure and unless it is determined that such disclosure was not made for the purpose of restricting competition.

C.2 *Transportation certification:* By submission of an offer, the offeror represents that it, or another party with which it has a resale or exchange agreement, can take timely delivery of the total maximum MLI quantities for which a priced offer has been submitted.

C.3 *Certification of compliance with the "Jones Act" and the U.S. export control laws:* By submission of this offer, the offeror certifies that it will comply with the "Jones Act," 46 U.S.C. 883, regarding use of United States-flag vessels in the transportation of oil between points within the United States, and with any applicable U.S. export control laws affecting the export of SPR petroleum. Failure to comply will be considered to be a failure to comply with the terms of any contract containing these SSPs and may result in termination for default in accordance with Provision No. C.26. Purchasers who have failed to comply with the Jones Act or the export control laws in SPR sales may be found to be non-responsible in the evaluation of offers under Provision No. B.20 of the SSPs. Those purchasers may also be subject to proceedings to make them ineligible for future awards in accordance with 10 CFR Part 625.

C.4 *Storage of SPR petroleum:* Continued storage of purchasers' oil in the SPR storage facility after the end of the delivery periods specified in the contracts is not currently permitted in these SSPs. Such storage for purchaser will only be allowed if specifically authorized by the Secretary of Energy and provided for in the NS or in the sales contract. Allowing petroleum to remain in storage as the result of failure to complete delivery arrangements may result in assessment of liquidated damages under Provision Nos. C.26 through C.28 unless such failure is excused by those provisions.

C.5 *Environmental compliance:*

(a) Vessels to be used for the transportation of petroleum purchased from the SPR will comply with all applicable rules and regulations, including The Ports and Waterways Safety Act, The Federal Water Pollution Control Act of 1972, The Oil Pollution Control Act of 1961, and other applicable statutes, rules and regulations, including the following: Parts 151, 153, 157, and 159, of Title 33 and Parts 30–38 and 542 of Title 46 of the Code of Federal Regulations.

(b) The purchaser will employ in the performance of this contract only vessels whose owners are parties to the Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution (TOVALOP) or who carry equivalent liability coverage.

(c) All crude oil transfer operations in performance of the purchase will be in accordance with the guidelines detailed in the International Oil Tanker Safety Guide, and U.S. Coast Guard Regulations, and the "Ship to Ship Transfer Guide" of the International Chamber of Shipping Oil Companies International Marine Forum.

(d) Failure to comply with all environmental requirements will be considered a failure to comply with the terms of any contract containing these SSPs, and may result in termination for default in accordance with Provision No. C.26.

C.6 *Delivery and transportation scheduling:* After notification of the apparently successful offerors, but at least 10 days prior to the start of the one-third of a month delivery period for all deliveries to be moved by vessel, or at least 10 days prior to the start of the 30-day delivery period for pipeline deliveries, each apparently successful offeror or purchaser shall contact the PMO for the purpose of determining the delivery schedule within the delivery periods during which the purchaser is to take the petroleum. Requests for firm delivery windows for vessels or delivery dates for pipelines received by the PMO within 7 business days after issuance of the notification of apparently successful offers shall be handled in descending order, highest offer first. Such requests received after that time shall be handled on a first-come, first-served basis. If successful offerors do not make timely acceptable arrangements, delivery windows and dates will be assigned by the PMO 7 days prior to the start of the delivery period. The PMO point of contact is: Crude Oil Programming Division, Strategic Petroleum Reserve, Project Management Office, Department of Energy, 900 Commerce Road East, New Orleans, LA 70123 (504) 734-4974.

C.7 *Delivery and acceptance of petroleum:*

(a) The purchaser, at its expense, shall make all necessary arrangements to accept delivery of and transport the SPR petroleum, except for terminal arrangements which shall be coordinated with the Government. The Government will deliver and the purchaser will accept said petroleum at delivery points listed in the NS. Title and risk of loss shall pass to the purchaser at such delivery points in accordance with Provision No. C.9. The purchaser also shall be responsible for meeting any delivery requirements imposed at those points including complying with the rules, regulations, and procedures contained in applicable port/terminal manuals or other applicable documents such as pipeline tariffs on file with the Federal Energy Regulatory Commission.

(b) The following vessel loading conditions shall apply:

(1) Upon receipt of the NA, the purchaser shall furnish the SPR/PMO with an estimated schedule of planned vessel arrivals in accordance with Provision No. C.6, Delivery and transportation scheduling.

(2) The length of the loading window shall be as established in the NS, but shall not be less than a 3-day window. The minimum quantity to be lifted during a single loading window will also be established in the NS.

(3) Tankers shall have a minimum average load rate of 20,000 barrels per hour (BPH). Barges with a load rate of not less than 5,000 BPH shall be permitted at the Sun Terminal barge docks. With the consent of the Government, the purchaser may use tankers with load rates of less than 20,000 BPH, or barges at Seaway Terminal, in order to complete loading of contract quantities, if such use does not interfere with the Government's obligations to other parties.

(4) At least 10 days in advance of each scheduled arrival date, unless the NA specifies another time, the purchaser shall furnish the SPR/PMO with vessel nominations specifying: (i) name and size of vessel; (ii) estimated date of arrival, to be narrowed to a firm date not later than 3 days prior to vessel arrival; (iii) quantity to be loaded and contract number; and (iv) other relevant information requested in writing by the Contracting Officer. Once established, changes in such nomination details may be made by mutual agreement of the parties, to be confirmed by the Government in writing. The purchaser shall be entitled to substitute another vessel of similar size for any vessel so nominated, subject to the Government's approval. The Government should be given at least 4 days notice prior to the first day of the loading window of any such substitution. The Government shall make a reasonable effort to accept any nomination for which notice has not been given in strict accordance with the above provisions.

(5) The purchaser shall arrange to have its vessel notify the SPR/PMO of the expected hour of arrival 72, 48 and 24 hours in advance, and after the first notice, to advise of any variation of more than 4 hours. When the vessel is not more than 6 hours from the load port and is ready to load, a Notice of Readiness shall be tendered by the tanker's Master and promptly confirmed in writing to the SPR/PMO and the terminal responsible for coordination of crude oil loading operations. Such notice shall be effective only if given during customary terminal operating hours.

(6) The Government shall use its best efforts to berth the purchaser's vessel as soon as possible after receipt of the Notice of Readiness.

(7) Standard hose and fittings for loading shall be provided by the Government.

(8) Tankers shall be allowed berth time of 36 hours as defined below:

(i) Berth time shall commence immediately upon each vessel's arrival at berth and it shall continue until loading of the vessel is completed and the cargo hoses have been removed. In addition, allowable berth time will be increased by the amount of any delay occurring subsequent to the commencement of berth time and resulting from causes due to adverse weather conditions, strikes, labor disputes, events of force majeure and the like.

(ii) For all hours of berth time which elapse in excess of the purchaser's allowable berth time for loading provided for above, the purchaser shall be liable for dock demurrage penalties and also shall be subject to the conditions of Provision No. C.8.

(9) If the vessel is tendered for loading on a date earlier than the scheduled loading window and other vessels are loading or have already been scheduled for loading prior to the purchaser's vessel, the purchaser's vessel shall await its turn and berth time shall not commence until the vessel moors alongside. If the vessel is tendered for loading later than 2400 hours on the last day of the scheduled delivery window, the Government will use its best efforts to have the vessel loaded as soon as possible in its proper turn with other scheduled vessels, under the circumstances prevailing at the time.

(c) The following pipeline delivery conditions shall apply:

(1) Prior to the last day of the month preceding the month of delivery, the purchaser shall furnish the SPR/PMO with the following information: (i) confirmation of the pipeline's acceptance of the amount of the petroleum proposed to be delivered in the next month; (ii) an estimated schedule (consistent with the terms of the contract) for delivery of the petroleum to the pipeline; and (iii) the name and telephone number of the pipeline point of contact with whom the SPR/PMO should coordinate the petroleum delivery.

(2) Once established, the pipeline delivery schedule can only be changed with the Government's prior written consent.

C.8 *Purchaser liability for excessive berth time:* The Government reserves the right to direct a marine vessel loading SPR petroleum at a delivery point specified in the NS, to vacate its SPR berth, should such vessel, through its operational inability to receive oil at the average rates provided for in Provision No. C.7(b)(3), cause the berth to be unavailable for an already scheduled follow-on vessel. Furthermore, should a breakdown of the vessel's propulsion system prevent its getting under way on its own power, the Government may cause the vessel to be removed from the berth with all costs to the account of the purchaser.

C.9 *Title and risk of loss:* Unless otherwise provided in the NS, title to and risk of loss for petroleum purchased from the Government will pass to the purchaser at the delivery point as follows:

(a) For vessel shipment—when the petroleum passes the loading equipment connections of the dock facility to the vessel's permanent hose connection.

(b) For pipeline shipment—when the petroleum passes the permanent flange connecting the terminal to the commercially owned pipeline.

(c) For in-transit shipments—when the petroleum passes the permanent flange of the vessel manifold upon discharge into a marine terminal facility or another vessel.

(d) Terms for other SPR petroleum outside the U.S. will be given in the NS if they are applicable to the sale.

C.10 *Acceptance of crude oil:* The NS shall provide current available characteristics on each SPR crude oil stream offered for sale as shown in Exhibit D, SPR Crude Oil Stream Characteristics. Except as provided hereafter, the Government assumes no responsibility for deviations in quality and the purchaser shall accept the crude oil delivered.

(a) In the event that either the API gravity or total sulfur content (percent by weight) of the crude oil delivered does not fall within the plus or minus (±) limits specified in the NS, but is above the minimum API gravity and below the maximum sulfur level shown in Exhibit E, SPR Crude Oil Stream Minimum Quality, the price shall be adjusted in accordance with Provision No. C.11, Quality differentials for crude oil.

(b) In the event that the crude oil delivered has an API gravity below or a total sulfur content above the respective levels shown in Exhibit E, the purchaser shall accept the crude oil delivered and either pay the contract price adjusted in accordance with Provision No. C.11, or request renegotiation of the contract price. Unless the purchaser submits a written request for renegotiation of the contract price to the Contracting Officer within 10 days from the date of delivery, the purchaser shall be deemed to have accepted the adjustment of the price in accordance with Provision No. C.11. Should the purchaser request a renegotiation of the price and the parties are unable to agree as to that price, the dispute shall be settled in accordance with Provision No. C.36, Disputes.

C.11 *Quality differentials for crude oil:* The NS will specify price adjustments applicable to the crude oil streams offered for sale. The price adjustments will be made for variations in API gravity and total sulfur content (percent by weight) of the crude oil delivered from the crude oil stream characteristics as established by the NS as follows:

(a) The contract price per barrel shall be increased by the amount set forth in the NS for each whole degree API gravity that the crude oil delivered exceeds the upper limit of that crude oil stream's API gravity as established by the NS and decreased by the amount set forth in the NS for each whole degree API gravity that the crude oil delivered falls below the lower limit.

(b) The contract price per barrel shall be increased by the amount set forth in the NS for each one-tenth of 1 percent that the total sulfur content falls below the lower limit of that crude oil stream's total sulfur content as established by the NS and decreased by the amount set forth in the NS for each one-tenth of 1 percent of total sulfur content that the crude oil delivered exceeds the upper limit.

C.12 *Determination of quantity of petroleum:*

(a) Quantities will be determined from certified opening and closing Government tank gauge reports or delivery meter reports. All volumetric measurements will be converted to net dry barrels at 60°F using API *Manual of Petroleum Measurement Standards,* Chapter 11.1, *Volume Correction Factors,* (1980) (ASTM D1230) (IP 200). Table 5A—*Generalized Crude Oils, Correction of Observed API Gravity to API Gravity at 60°F,* Table 6A—*Generalized Crude Oils, Correction of Volume to 60°F Against API Gravity at 60°F,* or latest edition, and by deducting sediment and water (S&W) as determined from the composite all levels samples taken from the delivery tanks and free water.

(b) The quantity determination shall be made and certified by the Government's authorized contractor responsible for loading operations, and witnessed by the Government Quality Assurance Representative at the delivery point. The purchaser shall have the right to have representatives present at the loading and sampling. Should the purchaser arrange for additional inspection services to witness quantity determinations, such services will be for the account of the purchaser. Any disputes shall be settled in accordance with Provision No. C.36, Disputes. Should the purchaser opt not to provide such additional services, then the Government findings shall be binding on the purchaser.

C.13 *Determination of quality of petroleum:*

(a) The quality determination of the crude oil delivered to purchaser shall be made either from a composite of samples taken from all levels of the delivery tanks or from a composite of line samples. Tests to be performed by the Government or its authorized contractor are:

(1) API *Manual of Petroleum Measurement Standards,* Chapter 10.4, Pub. 2542, *Methods of Test for Water and Sediment in Crude Oils,* 1970 (ASTM D96) or latest edition; or API *Manual of Petroleum Measurement Standards,* Chapter 10.1, *Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method,* first edition, 1981 (ASTM D473) (IP53), or latest edition, and API *Manual of Petroleum Measurement Standards,* Chapter 10.2, *Determination of Water in Crude Oil by Distillation,* first edition, 1981 (ASTM D4006) (IP358), or latest edition.

(2) ASTM D1552, *Sulfur in Petroleum Products (High Temperature Method),* latest edition, ASTM D2622, *Sulfur in Petroleum Products (X-Ray Spectagraphic Method),* latest edition, or ASTM D129, *Sulfur in Petroleum Products (General Bomb Method),* latest edition.

(3) API *Manual of Petroleum Measurement Standards,* Chapter 9.1, *Hydrometer Test Method for Density, Relative Density, (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products,* first edition, 1981 (ASTM D1298) or latest edition.

(4) ASTM D445, *Kinematic Viscosity of Transparent and Opaque Liquids,* latest edition.

(b) The purchaser may arrange for additional services to witness and verify testing simultaneously with the Government Quality Assurance Representatives. Such services, however, will be for the account of the purchaser. Any disputes will be settled in accordance with Provision No. C.36. Should the purchaser opt not to provide such additional services, then the Government findings will be binding on the purchaser.

C.14 *Delivery documentation:* The quantity and quality determination shall be documented on the appropriate Department of Defense Petroleum Shipping and Inspection Report, DD250 (Pipeline) for delivery points identified in Provision No. B.14, or DD250–1 (Tanker/Barge) (see Exhibit K for copies of the forms). Copies of the completed DD250 or DD250–1, with applicable supporting documentation (i.e., metering tickets or tank measurements) will be furnished to the purchaser and/or the purchaser's authorized representative upon completion of delivery. They will serve as the basis for invoicing and/or reconciliation invoicing for the sale of petroleum as well as for invoicing such associated services as may be provided for in the contract.

C.15 *Contract amount estimated for crude oil:* The contract amount stated in the award documents for crude oil is an estimate. The per barrel unit price is subject to adjustments based on the sulfur content and API gravity characteristics of the crude oil actually delivered. In addition, due to conditions of loading and shipping, the quantity may vary by ± 5 percent more or less than the scheduled delivery quantity.

C.16 *Contract modification—alternate delivery methods:* A purchaser may request a change in delivery method after the issuance of the NA. Such requests may be made either orally or in writing, but will require written modification of the contract by the Contracting Officer. Such modifications will be permitted by the Government if it is determined that the change in delivery method does not interfere with the delivery plans of other purchasers, and the purchaser agrees to pay all increased terminalling costs incurred by the Government because of such modification. The NS may establish a per barrel rate for such increased costs.

C.17 *Payment and performance guarantee:*

(a) The purchaser must furnish an acceptable payment and performance guarantee before the Government will execute the NA. During the notification of apparently successful offeror, the Contracting Officer will inform the offeror by telephone that the guarantee is due within a period which may be as short as 5 business days, and give the offeror a provisional contract number to use if the guarantee is a letter of credit. The Contracting Officer may, at his discretion, send a confirming telegram of the notification, but the timeliness of receipt for the guarantee is determined by the date of the telephone call.

(b) The payment and performance guarantee must be either: (1) advance payment by a cash wire deposit or (2) a letter of credit. All wire deposit and letter of credit costs will be borne by the purchaser.

(c) A purchaser electing advance payment must so indicate in its offer. Payment must be made in accordance with Provision No. C.22 as follows:

(1) If the contract period is 31 days or less, the purchaser shall pay 105 percent of the contract amount in advance.

(2) If the contract period is longer than 31 days, the purchaser shall pay in advance an amount equal to 31 days of deliveries plus 5 percent of the entire contract amount.

(d) A purchaser not electing to provide an advance payment must provide a letter of credit, conforming to the requirements of Provision No. C.19, and Exhibit I, Payment and Performance Guarantee—Letter of Credit, equal to 100 percent of the contract amount.

(e) The purchaser shall maintain such payment and performance guarantee in full force and effect to the Contracting Officer's satisfaction until final payment under the contract. Failure to do so may result in termination of the purchaser's contract for default in accordance with Provision No. C.26, Termination.

(f) The Contracting Officer or his designee may draw against this payment and performance guarantee at any time after the first delivery for any monies due under the contract for petroleum delivered and at any time for any other monies owing to the Government under the contract, no matter how the debt to the Government arose.

C.18 *Replacement of funds in the payment and performance guarantee:*

(a) If the SPR/PMO (which may act through its Finance Division), with the approval of the Contracting Officer draws against the letter of credit, or makes charges against the advance payment, for monies owed the Government for liquidated damages or other funds due the Government, the SPR/PMO or its Finance Division shall notify the purchaser within 24 hours of the fact of such withdrawal or charge and the amount thereof. The Government shall dispatch such notification by U.S. Express Mail, U.S. Mail or telegraphic means. Purchaser is deemed to have received a mailed notice on the second day after its dispatch and to have received telegraphic notice the day after its dispatch.

(b) Payment and performance guarantees must be maintained at the following minimum levels:

(1) Letter of credit at 100 percent of the contract price of the petroleum remaining to be delivered;

(2) Advance payment, on a contract for 31 days or less, at 105 percent of the contract price of the petroleum remaining to be delivered; and

(3) Advance payment, on a contract for more than 31 days, at the lesser of 100 percent times 31 days delivery plus 5 percent of the total contract price or 105 percent of the contract price of the petroleum remaining to be delivered.

(c) In the event that a draw against the payment and performance guarantee causes the amount to fall below the levels specified in (b), the purchaser shall, within 5 business days after it is deemed to have received notification in (a), replenish the amount necessary to increase the remaining payment and performance guarantee to the levels specified in (b). Such replenishment shall be made either by the wire transfer of funds in accordance with Provision No. C.22, or by the provision of a new letter of credit or amendment of the old letter of credit. If such replenishment is not made within 5 business days, the Contracting Officer may withhold deliveries under the contract on the 6th business day with no prior notice to the purchaser, and/or the Contracting Officer may terminate the contract in whole or in part on the 6th business day without prior notice to the purchaser. Such termination would be for default in accordance with Provision No. C.26, Termination.

C.19 *Payment and performance letters of credit—general requirements*

Letters of credit must meet the following criteria:

(a) If a letter of credit is from a single depository institution, including a branch or an agency of a foreign bank, (hereinafter referred to as "bank") that bank must maintain an account with any Federal Reserve Bank or Branch (Fed) and be a participant in the Fed's FEDWIRE funds transfer system. If the letter of credit is issued by a syndicate of banks, only the institution acting as agent for the syndicate and responsible for honoring the drafts drawn under the letter of credit must maintain a Fed account and be a participant in FEDWIRE.

(b) Each letter of credit must conform without exception to the standard letter of credit provided as Exhibit I, Payment and Performance Guarantee—Letter of Credit. The Government does not require information concerning the bank's agreement with its customer. Therefore, *any* language in the letter of credit in addition to that specified in Exhibit I shall cause the letter of credit to be unacceptable and shall be cause for rejection of the offeror's offer.

(c) In addition to the letter of credit, the purchaser or its bank shall provide to the Contracting Officer evidence that the bank official signing the letter of credit is authorized to do so, such as copies of the appropriate page of the bank's signature book, certified copies of the corporate minutes authorizing the signature or other appropriate evidence.

(d) As set forth in Exhibit I, a letter of credit must provide for the presentment of drafts against the letter of credit by wire and for payment to the Government by wire transfer of funds over FEDWIRE.

(e) Within 30 calendar days after final payment under the contract, the Contracting Officer shall authorize the cancellation of the letter of credit.

C.20 *Billing and payment—with purchaser's advance payment:*

(a) If the offeror has notified the Government in its offer that it elects to pay in advance, the following procedures will be applicable. If the contract delivery period is 31 days or less, and if the purchaser has fully paid in advance, delivery documentation will be provided to the purchaser in accordance with Provision No. C.14 after each delivery. No invoices will be issued until the last delivery under the contract, at which time a reconcilation billing will be made in accordance with paragraph (c) below.

(b) If the contract delivery period is more than 31 days, and the offeror has notified the Government in its offer that it elects to give an advance payment, delivery documentation will be provided in accordance with Provision No. C.14, and the purchaser will then be billed monthly for crude oil delivered. Payments on all but the last month will be in accordance with paragraph (e) below. The advance payment will be credited against the last month's deliveries, and a reconciliation billing will be made by the Government to the purchaser in accordance with paragraph (c) below.

(c) On every contract with an advance payment there will be a reconciliation billing by the Government after final delivery under the contract. If money is due from the purchaser to the Government, an invoice will be issued to the purchaser (see paragraph (e) below). If money is due the purchaser, a Treasury check will be issued in accordance with TFRM–Treasury Fiscal Requirements Manual.

(d) Invoices may be issued at any time to the purchaser for other monies due and payable under the contract. These would include, but are not limited to, interest due the Government, liquidated damages, amounts owing for any services provided for under the contract, and the difference between the sale price and resale price as defined in Provision No. C.26, Termination, and Provision No. C.27, Other Government remedies.

(e) In accordance with the delivery documentation and the contract, the Contracting Officer shall determine the amount of any invoice and shall provide invoices to the purchaser by U.S. Express Mail, U.S. Mail or telegraphic invoice. A purchaser is deemed to have received a mailed invoice on the second day after its dispatch. Telegraphic invoices are deemed to have been received on the day after dispatch. All invoices payable by the purchaser must be paid in accordance with Provision No. C.22 and received no later than close of business, 5 business days after the purchaser is deemed to have received them.

C.21 *Billing and payment—with purchaser's letter of credit:*

(a) All purchasers not electing advance payment shall provide a letter of credit in accordance with Provision No. C.19.

(b) All costs associated with the letter of credit will be borne by the purchaser. Payments of sight drafts drawn against that letter of credit shall be made by wire transfer of funds over FEDWIRE to the U.S. Treasury Department account at the Federal Reserve Bank in New York in accordance with the letter of credit.

(c) After delivery of the SPR petroleum and completion of the delivery documentation, the Contracting Officer shall determine the amount of the invoice in accordance with the contract and the delivery documentation.

(d) Upon completion of the invoice, the SPR/PMO Finance Division shall prepare a wire message requesting a wire transfer of funds in accordance with the letter of credit and deliver it to the New Orleans Branch of the Federal Reserve Bank in Atlanta for transmittal over the FEDWIRE system to the bank issuing the letter of credit. A request for wire transfer of funds is regarded as a draft under the letter of credit issued by the bank. The bank shall use the wire transfer procedures specified in the letter of credit to transfer the invoiced funds to the Government.

(e) The SPR/PMO Finance Division shall provide copies of the invoices and the draft to the purchaser and the bank by U.S. Express Mail or U.S. Mail.

(f) In the event that the bank refuses to honor the wire draft against the letter of credit, the purchaser shall be responsible for paying any interest due from the day the wire message requesting a transfer of funds is transmitted to the bank.

(g) Within 30 calendar days after final payment under the contract, the Contracting Officer shall authorize the cancellation of the letter of credit.

C.22 *Method of payments—general:*

(a) Notwithstanding any other clause of the contract, the Government may invoice the purchaser at any time for payment of monies due under the contract. If the invoice is for money, the payment of which is delinquent, interest on the money shall accrue from the date of the delinquency and not from the deemed date of receipt by purchaser of the invoice.

(b) All amounts payable by the purchaser in excess of $1,000.00 shall be by wire transfer as a deposit to the account of the U.S. Treasury through FEDWIRE. Certain information which must be included on each wire transfer is specified in Exhibit J, Instruction Guide for Funds Transfer.

(c) Payments in amounts less than $1,000.00 shall be by check made out to "U.S. Department of Energy." Such payments will be sent to the SPR/PMO Finance Division, with documentation to identify the payer and purpose of the payment.

(d) The Government may designate another place, different timing, or another method of payment after reasonable written notice to the purchaser.

(e) No payment due the Government hereunder shall be subject to reduction or set-off for any claim of any kind against the United States arising independently of the contract.

(f) If a purchaser disagrees with the amounts claimed by the Government to be due from the purchaser on any invoice, the purchaser shall pay immediately the amount billed in the invoice, and notify the Contracting Officer of the basis for its disagreement. Any request for adjustment under this provision must be asserted within 10 days of the date the purchaser is deemed to have received the objectionable invoice; provided, however, that if the Contracting Officer decides that the facts justify such action, he may receive and act upon any such objection asserted at any time prior to final payment under this contract. Failure to agree to any adjustment shall be a dispute, and purchaser shall file a claim promptly in accordance with Provision No. C.36, Disputes.

C.23 *Currency for payment of contract:* Payment for all amounts due under the contract shall be made in U.S. dollars only.

C.24 *Interest:* All amounts due from and payable by the purchaser or its bank must be paid in accordance with the provisions governing such payments. Amounts not paid in accordance with such provisions shall bear interest from the date due until the date payment is received by the Government. Interest shall be computed on a daily basis. The interest rate shall be in accordance with the Current Value of Funds rate as indicated in the Treasury notice published in the Federal Register, Vol. 48, No. 208, on October 26, 1983, at page 49571, or as subsequently amended quarterly by the Department of The Treasury in Bulletins to the Treasury Fiscal Requirements Manual and in the Federal Register.

C.25 *Government options if payment is not received:*

(a) All amounts due from and payable by the purchaser or by the bank issuing the purchaser's letter of credit must be paid by the deadlines set by the provisions governing them.

(b) If any amount owed to the Government is not paid within the time deadlines specified by the applicable provisions, the Contracting Officer may, at his discretion, take any of the actions listed in (1) through (5) below. The Contracting Officer may take these steps simultaneously or in any sequence he deems appropriate. The Contracting Officer may, with or without prior notice to the purchaser:

(1) Invoice the purchaser for the amount on which payment is delinquent or provide written notice that payment is delinquent;

(2) Draw against the letter of credit for all amounts due and delinquent;

(3) Apply any advance payment received against the amount due and delinquent;

(4) Withhold all or any part of future deliveries under the contract; and/or

(5) Terminate the contract, in whole or in part, for purchaser default, in accordance with Provision No. C.26, by sending written notice of such default termination to the purchaser.

(c) Any disputes will be settled by the Contracting Officer in accordance with Provision No. C.36, Disputes.

C.26 *Termination:*

(a) *Immediate termination.* (1) The Contracting Officer may terminate this contract in whole or in part, without liability of the Government, by written notice to the purchaser effective upon its being deposited in the U.S. Postal System addressed to the purchaser as provided in Provision No. C.34, Notices, in the event that the purchaser either notifies the Contracting Officer that it will not be able to accept, or fails to accept, any delivery line item in accordance with the terms of the contract. Such notice shall invite the purchaser to submit information to the Contracting Officer as to the reasons for the failure to accept the delivery line item in accordance with the terms of the contract.

(2) Within 10 business days after the issuance of the notice of termination, the Contracting Officer may determine that such termination was a termination for default under subparagraph (b)(1)(ii). In the absence of information which persuades the Contracting Officer that the purchaser's failure to accept the delivery line item was excusable, the fact of such failure may be the basis for the Contracting Officer determining the purchaser to be in default, without first determining under subparagraphs (b)(2) and (b)(3) whether such failure was excusable under the terms of the contract. The Contracting Officer shall promptly give the purchaser written notice of such determination.

(3) Any termination other than one determined to be a termination for default in accordance with subparagraph (a)(2) and paragraph (b) shall be a termination for the convenience of the Government without liability of the Government.

(b) *Termination for Default.* (1) Subject to the provisions of subparagraphs (b)(2) and (b)(3), the Contracting Officer may terminate the contract in whole or in part for purchaser default, without liability of the Government, by written notice to the purchaser, effective upon its being deposited in the U.S. Postal System, addressed to the purchaser as provided in Provision No. C.34, Notices in the event that:

(i) The Government does not receive payment in accordance with any payment provision of the contract;

(ii) The purchaser fails to accept delivery of petroleum in accordance with the terms of the contract; or

(iii) The purchaser fails to comply with any other term or condition of the contract within 5 business days after the purchaser is deemed to have received written notice of such failure from the Contracting Officer.

(2) Except with respect to defaults of subcontractors, the purchaser shall not be determined to be in default or be charged with any liability to the Government under circumstances which prevent the purchaser's acceptance of delivery hereunder due to causes beyond the control and without the fault or negligence of the purchaser as determined by the Contracting Officer. Such causes shall include but are not limited to:

(i) Acts of God or the public enemy;

(ii) Acts of the Government of the United States, acting in its sovereign or contractual capacity;

(iii) Fires, explosions or other catastrophes; or

(iv) Strikes.

(3) If the failure to perform is caused by the default of a subcontractor, and if such default arises out of causes beyond the control of the purchaser and its subcontractor, and without the fault or negligence of either of them, the purchaser shall not be determined to be in default or to be liable for any excess costs for failure to perform, unless the supplies or services to be furnished by the subcontractor were obtainable from other sources in sufficient time to permit the purchaser to meet the delivery schedule.

(4) In the event that the contract is terminated in whole or in part for default, the purchaser shall be liable to the Government for:

(i) The difference between the contract price on the contract termination date and any lesser price the Contracting Officer obtained upon sale of the petroleum; and

(ii) Liquidated damages as specified in Provision No. C.28 and paragraph (5) below.

(5) In the event that the Government exercises its right of termination for default as provided in this paragraph (b), then the purchaser shall be liable to the Government for liquidated damages in an amount as set forth in Provision No. C.28, as fixed, agreed, liquidated damages. In no event shall liquidated damages be assessed for more than 30 days.

(6) In the event that the Government exercises its right of termination for default, and it is later determined that the purchaser's failure to perform was excused in accordance with subparagraphs (2) and (3), the rights and obligations of the parties shall be the same as if such termination was a termination for convenience without liability of the Government under paragraph (c).

(c) *Termination for convenience.* (1) In addition to any other right or remedy provided for in the contract, the Government may terminate this contract at any time in whole or in part whenever the Contracting Officer shall determine that such termination is in the best interest of the Government. Such termination shall be without liability of the Government if such termination arises out of causes specified in (a)(1) or (b)(1) above, acts of the Government in its sovereign capacity, or causes beyond the control and without the fault or negligence of the Government. For any other termination for convenience, the Government shall be liable for such reasonable costs incurred by the purchaser in preparing to perform the contract, but under no circumstances shall the Government be liable for consequential damages or lost profits as the result of such termination.

(2) The purchaser will be given immediate written notice of any decrease of petroleum deliveries greater than 5 percent, or of termination, under this paragraph (c). The termination or reduction shall be effective upon its notice being deposited in the U.S. Postal System unless otherwise specified in the notice. The purchaser is deemed to have received a mailed notice on the second day after its dispatch. A telegraphic notice is deemed to be received on the day after dispatch.

(3) Termination for the convenience of the Government shall not excuse the purchaser from liquidated damages accruing prior to the effective date of the termination

(d) Nothing herein contained shall limit the Government in the enforcement of any legal or equitable remedy which it might otherwise have, and a waiver of any particular cause for termination shall not prevent termination for the same cause occurring at any other time or for any other cause.

(e) In the event that the Government exercises its right of termination, as provided in paragraphs (a), (b), or (c)(1) above, the Contracting Officer may sell, upon such terms and conditions as he deems appropriate, any undelivered petroleum.

(f) The Government's ability to deliver petroleum under another contract on the date on which the defaulted purchaser was scheduled to accept delivery, shall not excuse a purchaser that has been defaulted for failure to perform in accordance with the contract, from either liquidated damages or the difference between the contract price and any lesser price obtained on resale.

(g) Any disagreement with respect to the amount due the Government for either resale costs or liquidated damages shall be deemed to be a dispute and will be decided by the Contracting Officer pursuant to Provision No. C.36, Disputes.

(h) As used in this Provision No. C.26, the term "subcontractor" or "subcontractors" includes subcontractors at any tier.

C.27 *Other Government remedies:*

(a) The Government's rights under this provision are in addition to any other right or remedy available to it in law or by virtue of this contract.

(b) The Government may, without liability on its part, withhold deliveries hereunder if payment is not made in accordance with this contract.

(c) If the purchaser fails to take delivery of a delivery line item in accordance with the terms of the contract, but the Government does not elect to terminate that item for default under Provision No. C.26, the purchaser nonetheless shall be liable to the Government for liquidated damages in the amount set forth in Provision No. C.28 as fixed, agreed and liquidated damages for each calendar day of delay or fraction thereof until such time as it accepts delivery of the petroleum, or until the contract is terminated for the convenience of the Government, whichever occurs sooner. In no event shall such damages be assessed for longer than 30 days. No purchaser that fails to perform in accordance with the terms of the contract shall be excused from liability for liquidated damages by virtue of the fact that the Government is able to deliver petroleum under another contract on the date which the non-performing purchaser was scheduled to accept delivery.

C.28 *Liquidated damages:*

(a) In case of failure on the part of the purchaser to perform within the time fixed in the contract or any extension thereof, the purchaser shall pay to the Government liquidated damages in the amount of 1 percent of the contract price of the undelivered petroleum per calendar day of delay or fraction thereof in accordance with paragraph (b) of Provision No. C.26, Termination for purchaser default, and paragraph (c) of Provision No. C.27, Other Government remedies.

(b) As provided in (a) above, liquidated damages will be assessed for each day or fraction thereof a purchaser is late in performing in accordance with the contract with respect to the delivery of petroleum sold under this contract, unless such tardiness is excused under the term of this contract. For petroleum to be lifted by vessel, damages will be assessed in the event that the vessel has not commenced loading by 11:59 p.m. on the last day of the delivery window established under Provision No. C.6, Delivery and transportation scheduling, unless the vessel has arrived at the roads and its Master has presented a notice of readiness to the Government or its agents. Liquidated damages shall continue until the vessel presents its notice of readiness. For petroleum to be moved by pipeline, if delivery arrangements have not been made by the last day of the month prior to delivery, liquidated damages shall commence on the 1st day of the month until such delivery arrangements are completed; if delivery arrangements have been made, then liquidated damages shall begin on the first scheduled delivery date if delivery is not commenced and shall continue until delivery is commenced.

(c) Any disagreement with respects to the amount of liquidated damages due the Government will be deemed to be a dispute and will be decided by the Contracting Officer pursuant to Provision No. C.36, Disputes.

C.29 *Failure to perform SPR contracts:* In addition to the usual debarment procedures, 10 CFR § 625.3, provides that:

(a) In addition to any remedies available to the Government under the Contract of Sale, in the event that a purchaser fails to perform in accordance with applicable SPR petroleum sale contractual provisions, and such failure is not excused by those provisions, the Headquarters Senior Procurement Official or his designee, at his discretion, may make such purchaser ineligible for future awards of SPR petroleum sales contracts.

(b) No purchaser shall be made ineligible for the award of any SPR sales contract prior to notice and opportunity to respond in accordance with the requirements of this subsection:

(1) Upon the determination that a purchaser is to be considered for ineligibility, the purchaser shall be sent by certified mail return receipt requested, the following:

(i) Notification that the Headquarters Senior Procurement Official is considering making the purchaser ineligible for future awards;

(ii) Identification of the SPR sales contract which the purchaser failed to comply with, along with a brief description of the events and circumstances relating to such failure;

(iii) Advice that the purchaser may submit in writing for consideration by the Headquarters Senior Procurement Official in determining whether or not to impose ineligibility on the purchaser, any information or argument in opposition to the ineligibility; and

(iv) Advice that such information or argument in opposition to the ineligibility must be submitted within a certain time in order to be considered by the Headquarters Senior Procurement Official, such time to be not less than 21 days.

(2) After the elapse of the time period established under subsection (1) for receipts of the purchaser's response, the Headquarters Senior Procurement Official at his discretion, and after consideration of the purchaser's written response, if any, may make the purchaser ineligible for future award of SPR petroleum sales contracts. Such ineligibility shall continue for the time period determined by the Headquarters Senior Procurement Official as appropriate under the circumstances.

(3) The purchaser shall be notified of the Headquarters Senior Procurement Official's decision.

(c) Any purchaser who has been excluded from participating in any SPR sale under (a) may request that the Headquarters Senior Procurement Official reconsider the purchaser's ineligibility. The Headquarters Senior Procurement Official at his discretion may reinstate any such purchaser to eligibility for future competitive sales.

C.30 *Government options in case of impossibility of performance:*

(a) In the event that the Government is unable to deliver petroleum contracted for to the purchaser due either to events beyond the control of the Government, including actions of the purchaser, or to acts of the Government, its agents, its contractors or subcontractors at any tier, the Government at its option may do either of the following:

(1) Terminate for the convenience of the Government under Provision No. C.26; or

(2) Offer different SPR crude oil streams or delivery times to the purchaser in substitution for those specified in the contract.

(b) In the event that a different SPR crude oil stream than originally contracted for is offered to the purchaser, the contract price will be negotiated between the parties. In no event shall the negotiated price be less than the minimum acceptable price established for same or similar crude oil streams in the most recent NS.

(c) The Government's obligation in such circumstances is to use its best efforts, and the Government under no circumstances shall be liable to the purchaser for damages arising from its failure to offer alternate SPR petroleum or delivery times.

(d) If the parties are unable to reach agreement as to price, crude oil streams or delivery times, the Government may terminate the contract for the convenience of the Government under Provision No. 26(c).

C.31 *Limitation of Government liability:* The Government's obligation under these SSPs and any resultant contract is to use its best efforts to perform in accordance therewith. The Government under no circumstances shall be liable thereunder to the purchaser for the conduct of its contractors or subcontractors or for indirect, consequential, or special damages arising from its conduct; neither shall the Government be liable thereunder to the purchaser for any damages due in whole or in part to causes beyond the control and without the fault or negligence of the Government, including but not restricted to, acts of God or public enemy, acts of the Government acting in its sovereign capacity, fires, floods, earthquakes, explosions, or other catastrophes, or strikes.

C.32 *[Reserved]*

C.33 *Purchaser's responsibility:* For petroleum to be delivered from permanent

SPR storage sites, the Government shall provide, at no cost to the purchaser, transportation by pipeline from the SPR storage sites to the supporting terminal facility specified in the master line item and, for vessel loadings, a safe berth and loading facilities sufficient to deliver petroleum to the vessel's permanent hose connection. The purchaser agrees to assume responsibility for, to pay for, and to hold the Government harmless for any other costs associated with terminal, port, vessel and pipeline services necessary to receive and transport the petroleum, including but not limited to vessel or port demurrage, tank storage charges and port charges incurred in the transportation of SPR petroleum sold under a contract incorporating this provision. The purchaser also agrees to assume responsibility for, to pay for and to hold the Government harmless for any liability, including consequential or other damages, incurred or occasioned by the purchaser, its agent, subcontractor at any tier, assignee or any subsequent purchaser, in connection with movement of petroleum sold under a contract incorporating this provision.

C.34 *Notices:*

(a) Any notices required to be given by one party to the contract to the other *in writing* shall be forwarded to the addressee, prepaid, by U.S. registered, return receipt requested, mail, telegram, or TWX. Each party shall give the other written notice of any change of address.

(b) Notices to the purchaser shall be forwarded to the purchaser's address as it appears in the offer and in the contract.

(c) Notices to the Contracting Officer shall be forwarded to the following address: U.S. Department of Energy, Strategic Petroleum Reserve, Project Management Office, Procurement Division, Mail Stop EP-5501, 900 Commerce Road East, New Orleans, Louisiana 70123.

C.35 *SPR/Project Management Office representative for contract administration:* The SPR/PMO representative for each sale and the representative's telephone number will be provided in the NS. After award of a contract, the SPR/PMO representative for each contract and the representative's telephone number will be provided in the NA.

C.36 *Disputes:*

(a) This contract is subject to the Contract Disputes Act of 1978 (41 U.S.C. Section 601 *et seq.*). If a dispute arises relating to the contract, the purchaser may submit a claim to the Contracting Officer, who shall issue a written decision on the dispute in the manner specified in 41 CFR 1-1.318.

(b) "Claim" means:

(1) A written request submitted to the Contracting Officer;

(2) For payment of money, adjustment of contract terms, or other relief;

(3) Which is in dispute or remains unresolved after a reasonable time for its review and disposition by the Government; and

(4) For which a Contracting Officer's decision is demanded.

(c) In the case of dispute requests or amendments to such requests for payment exceeding $50,000, the purchaser shall certify at the time of submission as a claim, as follows:

I certify that the claim is made in good faith, that the supporting data are accurate and complete to the best of my knowledge and belief and that the amount requested accurately reflects the contract adjustment for which the purchaser believes the Government is liable.

Purchaser's Name ______________________

Signature ______________________

Title ______________________

(d) The Government shall pay to the purchaser, interest:

(1) On the amount found due to the purchaser on claims submitted under this clause;

(2) At the rates fixed by the Secretary of the Treasury;

(3) From the date the amount is due until the Government makes payment.

(e) The purchaser shall pay to the Government, interest:

(1) On the amount found due to the Government and unpaid on claims submitted under this clause;

(2) At the rates fixed by the Secretary of the Treasury;

(3) From the date the amount is due until the purchaser makes payment.

(f) The decision of the Contracting Officer shall be final and conclusive and shall not be subject to review by any forum, tribunal, or Government ageny unless an appeal or action is commenced within the times specified by the Contract Disputes Act of 1978.

(g) The purchaser shall comply with any decision of the Contracting Officer and at the direction of the Contracting Officer shall proceed diligently with performance of this contract pending final resolution of any request for relief, claim, appeal, or action related to this contract.

C.37 *Assignment:* The purchaser shall not make or attempt to make any assignment of a contract which incorporates these SSPs or any interest therein contrary to the provisions of Federal law, including the Anti-Assignment Act (41 U.S.C. 15), which provides:

No contract or order, or any interest therein, shall be transferred by the party to whom such contract or order is given to any other party, and any such transfer shall cause the annulment of the contract or order transferred, so far as the United States are concerned. All rights of action, however, for any breach of such contract by the contracting parties, are reserved to the United States.

C.38 *Order of precedence:* In the event of an inconsistency between the terms of the various parts of this contract, the inconsistency shall be resolved by giving precedence in the following order:

(a) The NA and written modifications thereto;

(b) The NS;

(c) Those provisions of the SSPs (as published in the **Federal Register**, made applicable to the contract by the NS;

(d) The instructions to Exhibit A, Schedule Line Items; and

(e) The successful offer.

C.39 *Gratuities:*

(a) The Government, by written notice to the purchaser, may terminate the right of the purchaser to proceed under this contract if it is found, after notice and hearing, by the Secretary or his duly authorized representative, that gratuities (in the form of entertainment, gifts, or otherwise) were offered by or given by the purchaser, or any agent or representative of the purchaser, to any officer or employee of the Government, with a view toward securing a contract or securing favorable treatment with respect to the awarding, amending, or making of any determinations with respect to the performing of such contract; *provided,* that the existence of the facts upon which the Secretary or his duly authorized representative makes such findings shall be in issue and may be reviewed in any competent court.

(b) In the event that this contract is terminated as provided in paragraph (a) hereof, the Government shall be entitled: (1) to pursue the same remedies against the purchaser as it could pursue in the event of a breach of the contract by purchaser, and (2) as a penalty in addition to any other damages to which it may be entitled by law, to exemplary damages in an amount (as determined by the Secretary or his duly authorized representative) which shall not be less than three nor more than 10 times the cost incurred by the purchaser in providing any such gratuities to any such officer or employee.

(c) The rights and remedies of the Government provided in this clause shall not be exclusive and are in addition to any other rights and remedies provided by law or under this contract.

C.40 *Officials not to benefit:* No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

Exhibits

A—Schedule Line Items
B—Sample Notice of Sale
C—Sample Offer
D—SPR Crude Oil Stream Characteristics
E—SPR Crude Oil Stream Minimum Quality
F—SPR Delivery Point Data
G—Offer Bond—Standard Form 24
H—Offer Guarantee—Letter of Credit
I—Payment and Performance Guarantee—Letter of Credit
J—Instruction Guide for Funds Transfer
K—DD Form 250 and DD Form 250-1
L—Information for Statistical Purposes

Exhibit A—Schedule Line Items

Instructions for Exhibit A

(Caution to offerors: The master line items shall be completed in accordance with the SSPs. In any conflict between these instructions and the SSPs, the SSPs shall take precedence.)

1. Master Line Item: There is a separate master line item schedule for each crude oil stream offered for sale. Offerors may bid on more than one master line item, but may not make alternate bids on separate master line items (i.e., the offer may not state 1,000,000 barrels from either MLI 001, or MLI 002).

2. Maximum MLI Quantity: Offers shall state here the number of barrels which the offeror seeks to purchase on the master line item, regardless of delivery method. The maximum MLI quantity shall be not less than the Government's minimum quantity as stated in the NS.

3. Maximum DLI Quantity: Offers shall state on each delivery line item, the number of barrels which the offeror will accept by the delivery method and during the delivery period established for that delivery line item. An offer may indicate a willingness to accept alternate delivery methods or delivery periods. An offeror may fill in all, part or none of the maximum MLI quantity on any particular delivery line item. A total of all the offer's maximum DLI quantitites should total at least the maximum MLI quantity, but could exceed the maximum MLI quantity if the offeror is willing to accept alternate delivery methods or periods. For example, the offer could state:

MLI: 001
Maximum MLI Quantity: 1,000,000 barrels
Maximum DLI Quantities:
DLI 001C: 1,000,000 barrels
DLI 001D: 1,000,000 barrels
DLI 001E: 1,000,000 barrels

This would indicate that the offeror wanted one million barrels of Bryan Mound sweet to be delivered to its vessels either from the 1st through the 10th, the 11th through 20th, or 21st through the end of the month.

4. Unit Price: The offer shall state the offered price per barrel for each delivery line item for which the offer indicated a maximum DLI quantity. The offer may state different unit prices for different delivery line items. DOE will award the highest price first. Prices may be stated to one one-hundredths of a cent ($0.0001), but in no smaller fraction thereof. The offer may state the same price for one or more delivery line items.

5. Total Price: The offer shall state the total price (maximum DLI quantity times unit price) on each delivery line item for which the offer indicated a maximum DLI quantity.

6. Delivery Preference: Where the offer has the same unit price for two or more delivery line items, the offer may indicate the offeror's order of preference for delivery method and period (1st, 2nd, 3rd, etc.). If the offer does not indicate a preference, DOE will select the delivery line item to be awarded at its discretion.

7. Minimum DLI Quantity: The offer may indicate the minimum amount which the offeror is willing to accept on a delivery line item. The Government only will award less than the offer's maximum DLI quantity if an offer is otherwise successful, but the quantity which the Government has available for award is less than said maximum DLI quantity. The offer may indicate that the minimum DLI quantity is the same as the maximum DLI quantity. If the offer does not indicate a minimum DLI quantity, the offer's minimum DLI quantity shall be deemed to be the minimum offer quantity established by the NS.

Master Line Item No. 001 (Instruction 1)
Bryan Mound Sweet (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—Jones Creek Tank Farm, Freeport, TX
(b) Vessel—Seaway Terminal docks, Freeport, TX
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
001A		bbls delivered to Seaway pipeline over the period of sale	@$	$		
001B		bbls delivered to other pipeline(s) over the period of sale	@$	$		
001C		bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
001D		bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
001E		bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 002 (Instruction 1)
Bryan Mound Sour (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—Jones Creek Tank Farm, Freeport, TX
(b) Vessel—Seaway Terminal docks, Freeport, TX
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
002A		Bbls delivered to Seaway pipeline over the period of sale	@$	$		
002B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
002C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
002D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
002E		Bbls delivered to vessel(s) from the 21st through the last day of the month	@$	$		

Master Line Item No. 003 (Instruction 1)
Bryan Mound Maya (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—Jones Creek Tank Farm, Freeport, TX
(b) Vessel—Seaway Terminal docks, Freeport, TX
Maximum MLI Quantity———Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
003A		Bbls delivered to Seaway pipeline over the period of sale	@$	$		
003B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
003C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
003D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
003E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 004 (Instruction 1)
West Hackberry Sweet (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—Sun Terminal, Nederland, TX
(b) Vessel—Sun Terminal docks, Nederland, TX
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
004A		Bbls delivered to Texoma pipeline over the period of sale	@$	$		
004B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
004C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
004D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
004E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 005 (Instruction 1)
West Hackberry Sour (See Exhibit D, SPR Crude Oil Stream Characteristics) (Includes oil stored at the SPR's Sulphur Mines site)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—Sun Terminal, Nederland, TX
(b) Vessel—Sun Terminal docks, Nederland, TX
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
005A		Bbls delivered to Texoma pipeline over the period of sale	@$	$		
005B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
005C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
005D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
005E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 006 (Instruction 1)
Weeks Island Sour (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—LOCAP Terminal, St. James, LA
(b) Vessel—St. James Terminal docks, St. James, LA
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
006A		Bbls delivered to Capline pipeline over the period of sale	@$	$		
006B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
006C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
006D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
006E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 007 (Instruction 1)
Bayou Choctaw Sweet (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipeline—LOCAP Terminal, St. James, LA
(b) Vessel—St. James Terminal docks, St. James, LA
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
007A		Bbls delivered to Capline pipeline over the period of sale	@$	$		
007B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
007C		Bbls delivered to vessel(s) from the 1st through the 10th day of the month.	@$	$		
007D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
007E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

Master Line Item No. 008 (Instruction 1)
Bayou Choctaw Sour (See Exhibit D, SPR Crude Oil Stream Characteristics)
Delivery Points: (See Exhibit F, SPR Delivery Point Data)
(a) Pipelines—LOCAP Terminal, St. James, LA
(b) Vessel—St. James Terminal docks, St. James, LA
Maximum MLI Quantity ——— Barrels (Instruction 2)

Delivery line item No.	Maximum DLI quantity (Instruction 3)		Unit Price (Instruction 4)	Total price (Instruction 5)	Delivery preference (Instruction 6)	Minimum DLI quantity (Instruction 7)
008A		Bbls delivered to Capline pipeline over the period of sale	@$	$		
008B		Bbls delivered to other pipeline(s) over the period of sale	@$	$		
008C		Bbls delivered to vessel(s) from the 1st through the 10th day of the mo th.	@$	$		
008D		Bbls delivered to vessel(s) from the 11th through the 20th day of the month.	@$	$		
008E		Bbls delivered to vessel(s) from the 21st through the last day of the month.	@$	$		

BILLING CODE 6450-01-M

Sample Data Entry Sheet (Subject to Change)

OFFER

LEGENDS: MLI = MASTER LINE ITEM NUMBER
LEGENDS: DLI/P = DELIVERY LINE ITEM/PREFERRED
LEGENDS: UP$$ = UNIT PRICE (U.S. $)/DLI

MAXQ = MAXIMUM QUANTITY BID/MLI
DESQ = DESIRED QUANTITY BID/DLI
MINQ = MINIMUM QUANTITY BID/DLI

FOR DOE USE ONLY

(BBL : 1000)

MLI 001 MAXQ

DLI/	P	UP$$	DESQ	MINQ
001A				
001B				
001C				
001D				
001E				

MLI 002 MAXQ

DLI/	P	UP$$	DESQ	MINQ
002A				
002B				
002C				
002D				
002E				

MLI 003 MAXQ

DLI/	P	UP$$	DESQ	MINQ
003A				
003B				
003C				
003D				
003E				

MLI 004 MAXQ

DLI/	P	UP$$	DESQ	MINQ
004A				
004B				
004C				
004D				
004E				

MLI 005 MAXQ

DLI/	P	UP$$	DESQ	MINQ
005A				
005B				
005C				
005D				
005E				

MLI 006 MAXQ

DLI/	P	UP$$	DESQ	MINQ
006A				
006B				
006C				
006D				
006E				

MLI 007 MAXQ

DLI/	P	UP$$	DESQ	MINQ
007A				
007B				
007C				
007D				
007E				

MLI 008 MAXQ

DLI/	P	UP$$	DESQ	MINQ
008A				
008B				
008C				
008D				
008E				

SIGNATURE: OFFEROR or AGENT

FOR DOE USE ONLY

OFFEROR NAME

OFFEROR ADDRESS

OFFEROR CITY/PROVINCE

OF ST

OFFEROR ZIP CODE

OFFEROR COUNTRY

OFFEROR PHONE NUMBER

OF SZ

OFFEROR BOND

AGENT/ALTERNATE NAME

AGENT ADDRESS

AGENT CITY/PROVINCE

AG ST

AGENT ZIP CODE

AGENT COUNTRY

AGENT PHONE NUMBER

BILLING CODE 6450-01-C

DO NOT DETACH

Exhibit B—Sample Notice of Sale (NS)

(If the NS is sent by telegram, it could look substantially as shown below. If the NS is sent by mail, a Standard Form 33 will be included as a cover sheet.)

1. NS No. DE–NS–~~96~~–84P010001 is issued (date) for sale of Strategic Petroleum Reserve (SPR) crude oil. All references to "Provision No." refer to the Standard Sales Provisions (SSPS) published in the Federal Register (date). All provisions are applicable to this sale except that provision No(s). (give number or numbers) are changed to read: (give changes). Additional provisions are hereby added (give new numbers which do not duplicate others in SSPs) which read: (give text).

2. Offers and offer guarantees must be received by 12 noon local time on (date) at addresses for mailed and handcarried offers given in SSPS; (or)

2. Offers and offer guarantees must be received by 12 noon local time on (date) at (address) for mailed offers and (address) for handcarried offers.

3. Information for statistical purposes of Exhibit L of SSPS (is) (is not) required; (or)

3. Only item Nos. (give numbers) of Exhibit L of SSPs are required.

4. Direct Questions regarding NS to (name of individual), telephone (504) 734–4220. Collect calls will not be accepted.

5. Applicable quality differentials are:

A. All Sweet Crude Oil
API Gravity ——————
Sulfur ——————
B. Bayou Choctaw Sour
API Gravity ——————
Sulfur ——————
C. Bryan Mound Maya
API Gravity ——————
Sulfur ——————

6. Minimum acceptable prices for offered crude oils are: Bayou Choctaw Sweet, West Hackberry Sweet, and Bryan Mound Sweet ——— dollars per barrel ($ ——/bbl); Bayou Choctaw Sour, ——— dollars per barrel ($——/bbl); Bryan Mound Maya ——— dollars per barrel ($——/bbl).

7. Master Line Item (MLI) numbers given herein refer to those schedules attached as Exhibit A of the SSPs. Specifics of MLIs are given in Exhibit A. The quantities for each MLI offered for sale are as follows: MLI 001———bbls; MLI 002 not offered this sale; MLI 003———bbls; MLI 004———bbls; MLI 005 not offered this sale; MLI 006 not offered this sale; MLI–007———bbls; MLI 008——— bbls.

8. Offerors must give names, addresses and telephone numbers, including area codes, for authorized representative and alternate representative of the offeror with whom the government may conduct any necessary discussions.

9. Minimum quantities which will be awarded for each delivery line item are as follows:

10. Delivery line items maximums, i.e., DOE's best estimates of the maximum amount of petroleum that can be moved by each delivery line item transportation system over the delivery period, are as follows (see provision No. B.14 of the SSPs):

11. Minimum quantities to be loaded per vessel delivery window are as follows:

12. Consideration to be paid for alteration of contract delivery modes in accordance with provision No. C.16 is as follows:

Exhibit C—Sample Offer

Name of Offeror ——————————

(The following provides general guidance only. The offer must include all forms required by the Notice of Sale; any additional information required by the Notice of Sale may be in any suitably arranged written document. The offeror has total responsibility for the accuracy and completeness of its offer.)

1. We acknowledge receipt of Notice of Sale (NS) No. DE–NS–84P010001 issued (date).

2. We acknowledge receipt, if applicable, of the following:

Amendment No.	*Date Issued*
001	
002	
etc.	

3. We agree without exception to all provisions of the Standard Sales Provisions (SSPs) which the NS makes applicable to this sale as well as to all provisions in the NS and all amendments to the NS. We understand that our offer is not valid without this agreement.

4. We understand that our offer is not valid unless we submit an offer guarantee in the amount of $10 million or 5 percent of our total offer, whichever is less. The offer guarantee must reach you prior to the date and time set for receipt of offers.

a. The amount of our offer guarantee is (check one)

——$10 million
——5% of our total offer, not to exceed $———

b. The form of our offer guarantee is (check one)

——A cash deposit to the special SPR/PMO account
——A cashier's or certified check payable to the Treasurer of the United States
——A Standard Form (SF) 24, entitled "Bid Bond"
——An irrevocable standby letter of credit (Exhibit H to the SSPs)

c. Our offer guarantee was forwarded (check one)

——By wire transfer
——In this envelope with our offer
——By our bank under a separate cover
——By our surety company under a separate cover

d. If we submitted a cash deposit or cashier's or certified check, and, if we are an apparently successful offeror, (check one)

——We want the amount of the offer guarantee applied toward the advance payment or cash guarantee.
——We intend to furnish a letter of credit for a financial guarantee and want the cash returned as soon as the letter of credit is approved by DOE.
——We will furnish the entire amount of the advance payment or cash guarantee by a new cash wire deposit. We want the original cash offer guarantee returned as soon as the new cash deposit is received.

5. The NS —— did, —— did not require any information for statistical purposes from Exhibit L. It is attached if required.

6. Our offers on available crude oil for Master Line Items Nos. ——— are as attached (see Exhibit A).

(Or if authorized in NS)

Our offers on available crude oil are:
Master line item No. ——— Maximum MLI Quantity ——— bbls

Delivery line item No.	Maximum DLI quantity	Unit price	Total price	Delivery preference	Minimum DLI quantity

By signing the SF–33, I certify that:
I am
Name, ——————————
Title ——————————
of
Name of company, etc. ——————

I am the authorized agent of the offeror, in proof of which I submit a power of attorney or other enabling documents.

All offerors will supply the following information:

Name of firm
Mailing address
City, State, Zip Code
Name of authorized agent and alternate
Address of authorized agent and alternate
Telephone number for authorized agent and alternate, including area code
TWX number (if any)
Telecopier brand name and model number (if any)
Telephone number, including area code, for telecopier transmission
Is telecopier automatic or operator control?
Telephone number, including area code, for telecopier verification of message receipt
Dunn's number (if any)

BILLING CODE 6450-01-M

Exhibit D—SPR Crude Oil Stream Characteristics

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Bryan Mound Sweet

TERMINAL Seaway Terminal, Freeport, Texas

WHOLE CRUDE:

Specific Gravity 0.844
API Gravity 36.2 ± 1.0
Sulfur, Wt. % 0.32 ± 0.05
Nitrogen, Wt. % 0.099
Carbon Residue, Wt. % 2.6
Pour Point, °F 35

UOP "K" Factor 11.65
Org. Cl, ppm TBD*
O.D. Color 9100
H_2S, ppm <1.0

RVP, psi 7.8 max.
Neutralization No. <0.14
Mercaptans, ppm 8.4
SUS Viscosity (cSt)
77 °F 53 (8.28)
100 °F 42 (4.88)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	6.2	8.8	13.2	14.8	14.0	26.2	14.3
Wt. %	4.9	7.8	12.4	14.8	14.5	28.8	16.9
Specific Gravity	0.662	0.733	0.789	0.826	0.856	0.908	0.979
API Gravity	82.4	61.5	47.9	39.3	33.8	24.3	13.1
Sulfur, Wt. %				0.06	0.23	0.45	1.07
Mercaptans, ppm	7.4	14	26	33			
Cetane Index				45.8	52.1		
Aniline Point, °F				143.0	165.8	192.6	
SUS Visc., °F: 77				36	–	–	
100				34	42	–	
130				–	38	130	
180				–	–	62	
Cloud Point, °F					30	100	
Freeze Point, °F				-35.0			
Nitrogen, Wt. %					0.008	0.093	0.461
Carbon Residue, Wt. %						–	16.56

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Bryan Mound Sour

TERMINAL Seaway Terminal, Freeport, Texas

WHOLE CRUDE:

Specific Gravity	0.859			RVP, psi	5.0 max.
API Gravity	33.2 ± 1.0			Neutralization No.	<0.15
Sulfur, Wt. %	1.71 ± 0.10	UOP "K" Factor	11.85	Mercaptans, ppm	43
Nitrogen, Wt. %	0.103	Org. Cl, ppm	TBD*	SUS Viscosity (cSt)	
Carbon Residue, Wt. %	4.74	O.D. Color	13,900	77 °F	51 (7.68)
Pour Point, °F	<5	H_2S, ppm	<1.0	100 °F	44 (5.51)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	5.2	8.0	15.8	13.5	13.0	26.1	18.3
Wt. %	4.0	6.7	14.1	12.8	12.9	28.0	21.4
Specific Gravity	0.656	0.718	0.771	0.818	0.855	0.920	1.003
API Gravity	84.2	65.6	52.0	41.5	34.0	22.3	9.6
Sulfur, Wt. %				0.29	1.01	2.23	3.88
Mercaptans, ppm	20	33	126	56			
Cetane Index				49.8	52.4		
Aniline Point, °F				147.0	158.0	175.5	
SUS Visc., °F: 77				34	–	–	
100				32	39	–	
130				–	35	88	
180				–	–	50	
Cloud Point, °F					18	94	
Freeze Point, °F				-31			
Nitrogen, Wt. %					0.004	0.090	0.399
Carbon Residue, Wt. %						0.52	22.20

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Bryan Mound Maya

TERMINAL Seaway Terminal, Freeport, Texas

WHOLE CRUDE:

Specific Gravity 0.921
API Gravity 22.1 + 0.5
Sulfur, Wt. % 3.25 + 0.22
Nitrogen, Wt. % 0.357
Carbon Residue, Wt. % 10.5
Pour Point, °F <5

UOP "K" Factor 11.71
Org. Cl, ppm 3.6
O.D. Color 51,200
H_2S,ppm <1.0

RVP, psi 3.8
Neutralization No. 0.21
Mercaptans, ppm 53
SUS Viscosity (cSt)
100 °F 340 (73.4)
130 °F 171 (36.55)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	4.7	4.2	10.7	9.7	11.7	22.1	35.8
Wt. %	3.4	3.2	9.0	8.7	11.1	22.4	41.1
Specific Gravity	0.665	0.718	0.769	0.823	0.869	0.935	1.057
API Gravity	81.0	65.6	52.5	40.4	31.3	19.8	2.4
Sulfur, Wt. %				1.11	2.26	3.01	5.12
Mercaptans, ppm	15	203	352	3			
Cetane Index				47.8	48.1		
Aniline Point, °F				144.7	152.6	174.2	
SUS Visc., °F: 77				34	–	–	
100				32	42	–	
130				–	37	126	
180				–	–	60	
Cloud Point, °F					26	100	
Freeze Point, °F				-29.2			
Nitrogen, Wt. %					0.052	0.201	0.789
Carbon Residue, Wt. %						0.17	25.6

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR West Hackberry Sweet

TERMINAL Sun Terminal, Nederland, Texas

WHOLE CRUDE:

Specific Gravity	0.840			RVP, psi	6.2
API Gravity	37.0 ± 0.5			Neutralization No.	0.14
Sulfur, Wt. %	0.34 ± 0.05	UOP "K" Factor	11.90	Mercaptans, ppm	7.4
Nitrogen, Wt. %	0.105	Org. Cl, ppm	TBD*	SUS Viscosity (cSt)	
Carbon Residue, Wt. %	2.19	O.D. Color	8100	77 °F 45	(5.82)
Pour Point, °F	25	H_2S,ppm	<1.0	100 °F 39	(3.94)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5– 175°F	175°– 250°F	250°– 375°F	375°– 530°F	530°– 650°F	650°– 1000°F	Residuum
Vol. %	6.9	9.2	14.6	15.2	17.0	23.5	11.5
Wt. %	5.5	8.1	13.8	15.3	17.7	25.9	13.7
Specific Gravity	0.663	0.733	0.779	0.829	0.859	0.913	0.985
API Gravity	82.1	61.5	50.2	39.1	33.3	23.5	12.2
Sulfur, Wt. %				0.09	0.26	0.46	1.13
Mercaptans, ppm	15	32	92	26			
Cetane Index				45.6	51.3		
Aniline Point, °F				146.9	167.1	192.2	
SUS Visc., °F: 77				34	–	–	
100				33	43	–	
130				–	38	117	
180				–	–	58	
Cloud Point, °F					34	115	
Freeze Point, °F				-31.3			
Nitrogen, Wt. %					0.010	0.109	0.548
Carbon Residue, Wt. %						–	16.27

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR West Hackberry Sour

TERMINAL Sun Terminal, Nederland, Texas

WHOLE CRUDE:

Specific Gravity	0.860			RVP, psi	5.3 max.
API Gravity	33.1 ± 1.0			Neutralization No.	<0.12
Sulfur, Wt. %	1.71 ± 0.10	UOP "K" Factor	12.02	Mercaptans, ppm	19
Nitrogen, Wt. %	0.105	Org. Cl, ppm	TBD*	SUS Viscosity (cSt)	
Carbon Residue, Wt. %	4.04	O.D. Color	TBD	77 °F	59 (10.05)
Pour Point, °F	<30	H_2S, ppm	<1.0	100 °F	53 (8.28)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	5.6	7.6	16.2	14.3	12.9	24.1	17.7
Wt. %	4.4	6.5	14.8	13.9	13.1	26.3	21.0
Specific Gravity	0.661	0.721	0.773	0.822	0.863	0.924	1.011
API Gravity	82.6	64.8	51.6	40.7	32.5	21.6	8.5
Sulfur, Wt. %				0.36	1.12	2.26	3.84
Mercaptans, ppm	20	45	83	65			
Cetane Index				48.3	50.0		
Aniline Point, °F				143.2	157.6	180.0	
SUS Visc., °F: 77				34	–	–	
100				33	42	–	
130				–	37	124	
180				–	–	60	
Cloud Point, °F					21	86	
Freeze Point, °F				-22.4			
Nitrogen, Wt. %					0.015	0.104	0.362
Carbon Residue, Wt. %						TBD	20.29

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Bayou Choctaw Sweet

TERMINAL SPR St. James Terminal, St. James, Lousiana

WHOLE CRUDE:

Specific Gravity	0.844			RVP, psi	5.6
API Gravity	36.2 ± 1.0			Neutralization No.	0.09
Sulfur, Wt. %	0.35 ± 0.05	UOP "K" Factor	12.19	Mercaptans, ppm	27
Nitrogen, Wt. %	0.098	Org. Cl, ppm	TBD*	SUS Viscosity (cSt)	
Carbon Residue, Wt. %	2.8	O.D. Color	TBD	77 °F	55 (8.91)
Pour Point, °F	35	H_2S, ppm	<1	100 °F	49 (7.06)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5-175°F	175°-250°F	250°-375°F	375°-530°F	530°-650°F	650°-1000°F	Residuum
Vol. %	5.6	9.0	13.6	13.5	14.1	24.6	16.7
Wt. %	4.8	8.0	12.8	13.5	14.5	27.0	19.6
Specific Gravity	0.661	0.734	0.781	0.825	0.851	0.903	0.976
API Gravity	82.5	61.4	49.8	40.0	34.8	25.2	13.5
Sulfur, Wt. %				0.08	0.22	0.46	1.05
Mercaptans, ppm	14.5	22	40	53			
Cetane Index				47.1	53.7		
Aniline Point, °F				146.5	167.5	190.3	
SUS Visc., °F: 77				42	-	-	
100				39	41	-	
130				-	37	102	
180				-	-	55	
Cloud Point, °F					26	99	
Freeze Point, °F				-35			
Nitrogen, Wt. %					0.006	0.091	0.492
Carbon Residue, Wt. %						-	15.2

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Bayou Choctaw Sour

TERMINAL SPR St. James Terminal, St. James, Lousiana

WHOLE CRUDE:

Specific Gravity 0.871
API Gravity 31.0 ± 1.0
Sulfur, Wt. % 1.76 ± 0.10
Nitrogen, Wt. % 0.138
Carbon Residue, Wt. % 4.50
Pour Point, °F 5

UOP "K" Factor 11.84
Org. Cl, ppm TBD*
O.D. Color TBD
H_2S, ppm <1.0

RVP, psi 5.30 max.
Neutralization No. <0.12
Mercaptans, ppm 18
SUS Viscosity (cSt)
77 °F 67 (12.28)
100 °F 52 (8.10)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	6.0	6.9	15.8	15.4	12.2	24.9	17.7
Wt. %	4.6	5.8	14.3	14.9	12.4	27.0	20.9
Specific Gravity	0.664	0.724	0.773	0.824	0.867	0.929	1.017
API Gravity	81.5	63.9	51.5	40.3	31.7	20.9	7.7
Sulfur, Wt. %				0.44	1.26	2.19	3.85
Mercaptans, ppm	TBD	TBD	TBD	TBD			
Cetane Index				47.6	48.8		
Aniline Point, °F				TBD	TBD	TBD	
SUS Visc., °F: 77				34	-	-	
100				32	43	-	
130				-	38	137	
180				-	-	63	
Cloud Point, °F					24	85	
Freeze Point, °F				TBD			
Nitrogen, Wt. %					0.025	0.133	0.478
Carbon Residue, Wt. %						0.15	21.5

* TO BE DETERMINED

U. S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
CRUDE OIL ANALYSIS

Data current as of December 1, 1983,
but subject to change

STREAM SPR Weeks Island Sour

TERMINAL SPR St. James Terminal, St. James, Louisiana

WHOLE CRUDE:

- Specific Gravity 0.878
- API Gravity 29.7° ± 0.5°
- Sulfur, Wt. % 1.39 ± 0.10
- Nitrogen, Wt. % 0.173
- Carbon Residue, Wt. % 5.17
- Pour Point, °F <5
- UOP "K" Factor 11.78
- Org. Cl, ppm <1
- O.D. Color 28,840
- H_2S, ppm <1.0
- RVP, psi 4.9
- Neutralization No. 0.09
- Mercaptans, ppm 16
- SUS Viscosity (cSt)
  - 77 °F 76 (14.65)
  - 100 °F 58 (9.76)

DISTILLATION TO 1000°F:

Fraction	1	2	3	4	5	6	7
Cut Temperature	C5–175°F	175°–250°F	250°–375°F	375°–530°F	530°–650°F	650°–1000°F	Residuum
Vol. %	4.3	6.6	12.5	12.6	15.8	25.4	21.7
Wt. %	3.3	5.5	11.2	12.0	15.8	27.0	25.3
Specific Gravity	0.659	0.729	0.778	0.829	0.868	0.927	1.014
API Gravity	83.1	62.7	50.5	39.3	31.5	21.2	8.0
Sulfur, Wt. %				0.31	1.02	1.70	3.14
Mercaptans, ppm	18	23	50	8.1			
Cetane Index				45.9	48.5		
Aniline Point, °F				141.6	156.1	173.1	
SUS Visc., °F: 77				34	–	–	
100				32	44	–	
130				–	38	131	
180				–	–	61	
Cloud Point, °F					29	105	
Freeze Point, °F				-33.6			
Nitrogen, Wt. %					0.015	0.126	0.541
Carbon Residue, Wt. %						0.18	20.65

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F-40

Exhibit E—SPR Crude Oil Stream Minimum Quality

[Data as of Dec. 1, 1983, and subject to change]

	Minimum API gravity	Maximum total sulfur (percent by weight)
Bryan Mound Sweet	33.0	0.50
Bryan Mound Sour	30.0	2.00

[Data as of Dec. 1, 1983, and subject to change]

	Minimum API gravity	Maximum total sulfur (percent by weight)
Bryan Mound Maya	21.0	3.50
West Hackberry Sweet	33.0	0.50
West Hackberry Sour	30.0	2.00
Bayou Choctaw Sweet	33.0	0.50
Bayou Choctaw Sour	30.0	2.00

[Data as of Dec. 1, 1983, and subject to change]

	Minimum API gravity	Maximum total sulfur (percent by weight)
Weeks Island Sour	26.0	1.90

Crude oil delivered by the SPR to the purchaser that does not meet either the above API gravity minimum or the above total sulfur content maximum will be accepted by the purchaser with the price adjusted in accordance with Provision Nos. C.10 and C.11.

Exhibit F—SPR Delivery Point Data

Terminal:	Seaway Terminal Freeport, Texas	Sun Terminal, Inc., Nederland, Texas	DOE St. James Terminal, St. James, Louisiana
Delivery Points:	(1) Seaway Terminal Marine Dock Facility [1] (2) Jones Creek Tank Farm (Seaway or other pipeline)	(1) Sun Terminal Marine Dock Facility [5] (2) Sun Terminal (Texoma or other pipelines)	(1) St. James Terminal Marine Dock Facility [8] (2) Locap Terminal (Capline or other pipelines)
Marine Dock Facility Data (as of Oct. 12, 1983) (A)			
Number of Berths.	3	5	2
Maximum LOA.	[2] 750 foot	1,000 foot	750
Maximum Beam.	107 foot	145 foot	None
Maximum Draft (B).	37 foot	40 foot fresh water	[9] 39 foot
Maximum Air Draft.	NA	136	153 foot
Maximum Deadweight tons (C).	[3] 60,000 deadweight tons	[6] 147,000 deadweight tons	[10] 123,000 deadweight tons
Barging capability.	[4] Yes	[7] [3] Yes	No

[1] No deballasting facilities are available.
[2] Maximum LOA 615 foot during hours of darkness.
[3] Deadweight tons can be larger if draft, LOA and beam restrictions are met. Maximum at dock 1 is 50,000 deadweight tons. Terminal permission is required for less than 32,000 deadweight tons.
[4] Only dock No. 1 has barge loading capability.
[5] No deballasting facilities are available.
[6] 85,000 deadweight tons or larger are limited to daylight transit. Maximum deadweight tons may be larger if draft, LOA and beam restrictions are met and the pilots agree to bring vessel in.
[7] There are 2 crude barge docks; Docks A and B with maximum draft of 15 foot Ship dock No. 1 available if scheduling permits.
[8] No deballasting facilities are available.
[9] St. James Terminal draft is 42 foot at the dock. Draft at the bar at the mouth of the Mississippi is 39 foot for 100,000 deadweight tons or over; 40 foot for under 100,000 deadweight tons.
[10] Larger deadweight tons can be accommodated with terminal approval.

A. Contractor shall be responsible for confirming that proposed vessels can be accommodated by terminals, harbors and channels involved.
B. Maximum draft is subject to varying limitations at river and harbor entrances due to tidal variances.
C. Maximum DWT is theoretical berth handling capability; however, contractors must be aware that harbor and channel physical constraints are the controlling factor as to ship size, and are varying.

BILLING CODE 6450-01-M

EXHIBIT G - OFFER BOND

STANDARD FORM 24 JUNE 1964 EDITION GENERAL SERVICES ADMINISTRATION FED. PROC. REG. (41 CFR) 1-16.801	**BID BOND** *(See Instructions on reverse)* 24-103	DATE BOND EXECUTED *(Must not be later than bid opening date)*
PRINCIPAL *(Legal name and business address)*		TYPE OF ORGANIZATION *("X" one)* ☐ INDIVIDUAL ☐ PARTNERSHIP ☐ JOINT VENTURE ☐ CORPORATION STATE OF INCORPORATION
SURETY(IES) *(Name and business address)*		

PENAL SUM OF BOND					BID IDENTIFICATION	
PERCENT OF BID PRICE	AMOUNT NOT TO EXCEED				BID DATE	INVITATION NO.
	MILLION(S)	THOUSAND(S)	HUNDRED(S)	CENTS	FOR *(Construction, Supplies or Services)*	

KNOW ALL MEN BY THESE PRESENTS, That we, the Principal and Surety(ies) hereto, are firmly bound to the United States of America (hereinafter called the Government) in the above penal sum for the payment of which we bind ourselves, our heirs, executors, administrators, and successors, jointly and severally: *Provided*, That, where the Sureties are corporations acting as co-sureties, we, the Sureties, bind ourselves in such sum "jointly and severally" as well as "severally" only for the purpose of allowing a joint action or actions against any or all of us, and for all other purposes each Surety binds itself, jointly and severally with the Principal, for the payment of such sum only as is set forth opposite the name of such Surety, but if no limit of liability is indicated, the limit of liability shall be the full amount of the penal sum.

THE CONDITION OF THIS OBLIGATION IS SUCH, that whereas the Principal has submitted the bid identified above.

NOW, THEREFORE, if the Principal, upon acceptance by the Government of his bid identified above, within the period specified therein for acceptance (sixty (60) days if no period is specified), shall execute such further contractual documents, if any, and give such bond(s) as may be required by the terms of the bid as accepted within the time specified (ten (10) days if no period is specified) after receipt of the forms by him, or in the event of failure so to execute such further contractual documents and give such bonds, if the Principal shall pay the Government for any cost of procuring the work which exceeds the amount of his bid, then the above obligation shall be void and of no effect.

Each Surety executing this instrument hereby agrees that its obligation shall not be impaired by any extension(s) of the time for acceptance of the bid that the Principal may grant to the Government, notice of which extension(s) to the Surety(ies) being hereby waived; provided that such waiver of notice shall apply only with respect to extensions aggregating not more than sixty (60) calendar days in addition to the period originally allowed for acceptance of the bid.

IN WITNESS WHEREOF, the Principal and Surety(ies) have executed this bid bond and have affixed their seals on the date set forth above.

PRINCIPAL			
Signature(s)	1 *(Seal)*	2 *(Seal)*	*Corporate Seal*
Name(s) & Title(s) *(Typed)*	1	2	

INDIVIDUAL SURETIES		
Signature(s)	1 *(Seal)*	2 *(Seal)*
Name(s) *(Typed)*	1	2

CORPORATE SURETY(IES)					
SURETY A	Name & Address		STATE OF INC	LIABILITY LIMIT	*Corporate Seal*
	Signature(s)	1.	2.		
	Name(s) & Title(s) *(Typed)*	1	2		

CORPORATE SURETY(IES) (Continued)					
SURETY B	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1	2		
	Name(s) & Title(s) (Typed)	1	2		
SURETY C	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1	2		
	Name(s) & Title(s) (Typed)	1	2		
SURETY D	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1.	2.		
	Name(s) & Title(s) (Typed)	1	2.		
SURETY E	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1	2		
	Name(s) & Title(s) (Typed)	1	2		
SURETY F	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1	2		
	Name(s) & Title(s) (Typed)	1	2.		
SURETY G	Name & Address		STATE OF INC	LIABILITY LIMIT	Corporate Seal
	Signature(s)	1	2		
	Name(s) & Title(s) (Typed)	1	2.		

INSTRUCTIONS

1. This form is authorized for use whenever a bid guaranty is required in connection with construction work or the furnishing of supplies or services. There shall be no deviation from this form without approval by the Administrator of General Services.

2. The full legal name and business address of the Principal shall be inserted in the space designated "Principal" on the face of this form. The bond shall be signed by an authorized person. Where such person is signing in a representative capacity (e.g., an attorney-in-fact), but is not a member of the firm, partnership, or joint venture, or an officer of the corporation involved, evidence of his authority must be furnished.

3. The penal sum of the bond may be expressed as a percentage of the bid price if desired. In such cases, a maximum dollar limitation may be stipulated (e.g., 20% of the bid price but the amount not to exceed ________ dollars).

4. (a) Corporations executing the bond as sureties must be among those appearing on the Treasury Department's list of approved sureties and must be acting within the limitations set forth therein. Where more than a single corporate surety is involved, their names and addresses (city and State) shall be inserted in the spaces (Surety A, Surety B, etc.) headed "CORPORATE SURETY(IES)", and in the space designated "SURETY(IES)" on the face of this form only the letter identification of the Sureties shall be inserted.

(b) Where individual sureties execute the bond, they shall be two or more responsible persons. A completed Affidavit of Individual Surety (Standard Form 28), for each individual surety, shall accompany the bond. Such sureties may be required to furnish additional substantiating information concerning their assets and financial capability as the Government may require.

5. Corporations executing the bond shall affix their corporate seals. Individuals shall execute the bond opposite the word "Seal"; and, if executed in Maine or New Hampshire, shall also affix an adhesive seal.

6. The name of each person signing this bid bond should be typed in the space provided.

BILLING CODE 6450-01-C

Exhibit H—Offer Guarantee—Letter of Credit

Procurement Division
Mail Stop EP-5501
Project Management Office
Strategic Petroleum Reserve
U.S. Department of Energy
900 Commerce Road East
New Orleans, Louisiana 70123

To the Strategic Petroleum Reserve Drawdown Sales Coordinator:

By order of our customer (name and address of offeror) we hereby establish in the U.S. Department of Energy's favor an irrevocable Letter of Credit, Numbered ——, for an amount not to exceed U.S. $———, effective immediately as an offer guarantee for the offer of our customer dated ——— in response to the U.S. Department of Energy's Notice of Sale dated ——— for the sale of Strategic Petroleum Reserve petroleum. Liability under this Letter of Credit shall commence upon the date set by the Notice of Sale, including any amendments thereto, for receipt of offers and expires on the twenty-first day therefter. We agree that our obligation shall not be impaired by any extensions of the date set for receipt of offers, notice of such extension being hereby waived; provided, that such waiver of notice shall not apply to extensions extending more than thirty (30) calendar days beyond the period originally established for receipt of offers.

Funds under this Letter of Credit are available to the U.S. Department of Energy by its draft or drafts drawn on ourselves and accompanied by a manually signed statement of a duly authorized official of the U.S. Department of Energy stating the following:

This drawing of U.S. $——— — (U.S. dollar amount expressed in word form) against your Letter of Credit numbered ——, dated ——— is due the U.S. Government because of the failure of (name of offeror) to honor its offer to enter into a contract for the purchase of petroleum from the Strategic Petroleum Reserve, in accordance with the U.S. Government's Notice of Sale dated ——— and the applicable Standard Sales Provisions (10 CFR Part 625, Appendix A).

Upon receipt of the U.S. Department of Energy's draft and accompanying statement, either by hand or registered mail, return receipt requested at our office located at ———, we will honor the draft and make payment by 3 p.m. Eastern Standard Time of the next business day following receipt of the draft by wire transfer to the account of the U.S. Treasury through the Federal Reserve Communications System. Each wire transfer shall be formatted in accordance with prescribed Treasury requirements as shown in Exhibit J of the Standard Sales Provisions, 10 CFR Part 626, Appendix A.

This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (1974 Revision, International Chamber of Commerce Publication No. 290) and except as may be inconsistent therewith, to the Uniform Commercial Code in effect on the date of issuance of this Letter of Credit in the State in which the issuer's head office within the United States is located.

Address all communications regarding this Letter of Credit to (address and any applicable reference)

Yours Truly,

Authorized Signature ———————

Exhibit I—Payment and Performance Guarantee—Letter of Credit

Procurement Division
Mail Stop EP-5501
Project Management Office
Strategic Petroleum Reserve
U.S. Department of Energy
900 Commerce Road East
New Orleans, Louisiana 70123

To the Strategic Petroleum Reserve Drawdown Sales Coordinator:

By order of our customer (name and address) we hereby establish in the U.S. Department of Energy's favor an irrevocable Letter of Credit, Numbered ——, for about U.S. $——— — (the U.S. dollar amount expressed in word form) effective immediately and expiring at our office located at (address) three hundred and sixty-five (365) days from the date of issuance of this Letter of Credit, relative to an offer by our customer dated (date), to purchase Strategic Petroleum Reserve petroleum. Liability under this Letter of Credit shall commence upon acceptance by the U.S. Government of our customer's offer and the award to our customer of a contract for the delivery of Strategic Petroleum Reserve petroleum.

Funds under this Letter of Credit are available to the U.S. Department of Energy by its draft or drafts drawn on ourselves. Except in the case of a draft presented by wire, such draft or drafts shall be accompanied by either a written statement of a duly authorized official of the U.S. Department of Energy stating that:

This drawing is due the U.S. Department of Energy under your Letter of Credit number ——— in payment for —— barrels of petroleum sold to (customer's name) under contract number ——— at a price of $——– per barrel (plus or minus) a sulfur differential price adjustment of —— tenths of one percent at $——— per one tenth of one percent per barrel and (plus or minus) a gravity differential of —— degrees at $——— per degree API per barrel, for a total amount due of $——— — (U.S. dollar amount expressed in word form). The U.S. Government's invoice and supporting standard form DD250 is attached,

or a written statement of a duly authorized official of the U.S. Department of Energy that:

This drawing is due the U.S. Department of Energy under your Letter of Credit number ——— because of the failure of (customer's name) to accept delivery of petroleum under contract number ——— at the time specified in the contract, resulting in damage due under the contract of $——— — (U.S. dollar amount expressed in word form)

or both.

We will honor drafts presented by wire provided that each such draft contains either a statement that:

$——– is now due the U.S. DOE under your Letter of Credit ——— for (customer's name), including $——— due for —— bls of oil sold at $——— per bl, with adjustments of ± —— tenths @ $0.——— sulfur and ± ——— degrees @ $0.——— gravity, and $——— due for delivery damages,

or a statement that:

This drawing is now due the U.S. Department of Energy under your Letter of Credit ——— because of the failure of (customer's name) to accept delivery of petroleum at the time specified under the contract, resulting in damages due of $———,

or other wire message containing the relevant information.

The wire draft should include our FEDWIRE number and other information pertinent to a request for a wire transfer of funds over FEDWIRE, as follows: ————. The U.S. Government's invoice (including supporting documents) shall be forwarded to us by regular mail.

The U.S. Department of Energy may make multiple drawings totalling up to the amount of funds indicated in the first paragraph as available under this Letter of Credit.

Upon receipt of the U.S. Department of Energy's draft and accompanying statement, we will honor the draft and make payment by 3 p.m. Eastern Standard Time of the next business day following receipt of the draft, by wire transfer of funds over FEDWIRE to account number 021030004 of the U.S. Treasury through the Federal Reserve Communications System. Each wire transfer of funds shall be formatted in accordance with prescribed U.S. Treasury requirements as shown in Exhibit J of the Standard Sales Provisions, 10 CFR Part 626, Appendix A.

This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (1974 Revision, International Chamber of Commerce Publication No. 290) and except as may be inconsistent therewith, to the Uniform Commercial Code in effect on the date of issuance of this Letter of Credit in the state in which the issuer's head office within the United States is located.

Address all communications regarding this Letter of Credit to (address and any applicable reference)

Yours Truly,

Authorized Signature ———————

Exhibit J—Instruction Guide for Funds Transfer—Messages to Treasury

The following instructions provide specific information which is required so that a funds (wire) transfer message can be transmitted to the Department of Treasury. The funds transfer message format is shown in Attachment 1. A narrative description of each item on the funds transfer message follows:

Line 1

Item 1—*Priority Code*—The priority code will be provided by the sending bank. (Note: Some Federal Reserve district banks may not require this item.)

Line 2

Item 2—*Treasury Department Code*—The 9-digit identifier "021030004" is the routing symbol of the Treasury. This item is a constant and is required for all funds transfer messages sent to Treasury.

Item 3—*Type Code*—The type code will be provided by the sending bank (will be a 10 or 12).

Line 3

Item 4—*Sending Bank Code*—This 9-digit identifier will be provided by the sending bank.

Item 5—*Class*—The class field may be used at the option of the sending bank. (Note: Some Federal Reserve Districts prohibit use of this field.)

Item 6—*Reference Number*—The reference member will be inserted by the sending bank to identify the transaction.

Item 7—*Amount*—The amount must include the dollar sign and the appropriate punctuation including cents digits. This item will be inserted by the sending bank.

Line 4

Item 8—*Sending Bank Name*—The telegraphic abbreviation which corresponds to Item 4 will be provided by the sending bank.

Line 5

Items 9, 10, and 11—*Treasury Department Name, Agency Location Code, Agency Number*—This item is of critical importance. It must appear on the funds transfer message in the precise manner as stated to allow for the automated processing and classification of funds transfer message to Treasury for credit to the Department of Energy. This item is comprised of a rigidly formatted, left justified, nonvariable sequence of characters as follows:

Treas NYC/(89000201) DEPT. OF ENERGY (SPRO)

Item 12—*Payment Identification*—The payment identification should be furnished by the remitter in the following manner:

Lines 6 and 7

The constant "Payment for the Sale of Crude Oil Under Contract # ———. DD 250 # ——— will be inserted.

Line 8

The constant "Deposit Account 89X0233" will be inserted.

Important Note: Line Nos. 2 and 5 are edited by the Federal Reserve Bank. If the wire transfer message is not formatted as prescribed above, the message will be rejected by the FED Bank and returned to the sending bank.

Sample of Funds Transfer Message Format for SPR Oil Sales

02

To	Type
021030004	10

From	Class	Ref	Amount
011000390		0650	$500,000.00

Ordering Bank and Related Data

FIRST BOS

TREAS NYC/(89000201) DEPT OF ENERGY (SPRO)

PAYMENT FOR THE SALE OF CRUDE OIL UNDER

CONTRACT # DD 250 #

DEPOSIT ACCOUNT 89X0233

Attachment 1 to Exhibit J

BILLING CODE 6450-01-M

MATERIAL INSPECTION AND RECEIVING REPORT

1. PROC. INSTRUMENT IDEN(CONTRACT) (ORDER) NO.

EXHIBIT K

6. INVOICE NO.

DATE

7. PAGE OF

8. ACCEPTANCE POINT

2. SHIPMENT NO.

3. DATE SHIPPED

4. B/L

TCN

5. DISCOUNT TERMS

9. PRIME CONTRACTOR CODE

10. ADMINISTERED BY CODE

11. SHIPPED FROM *(If other than 9)* CODE

FOB:

12. PAYMENT WILL BE MADE BY CODE

13. SHIPPED TO CODE

14. MARKED FOR CODE

15. ITEM NO.	16. STOCK/PART NO. DESCRIPTION *(Indicate number of shipping containers - type of container - container number.)*	17. QUANTITY SHIP/REC'D *	18. UNIT	19. UNIT PRICE	20. AMOUNT

21. PROCUREMENT QUALITY ASSURANCE

A. ORIGIN

☐ PQA ☐ ACCEPTANCE of listed items has been made by me or under my supervision and they conform to contract, except as noted herein or on supporting documents.

DATE SIGNATURE OF AUTH GOVT REP

TYPED NAME AND OFFICE

B. DESTINATION

☐ PQA ☐ ACCEPTANCE of listed items has been made by me or under my supervision and they conform to contract, except as noted herein or on supporting documents.

DATE SIGNATURE OF AUTH GOVT REP

TYPED NAME AND TITLE

22. RECEIVER'S USE

Quantities shown in column 17 were received in apparent good condition except as noted.

DATE RECEIVED SIGNATURE OF AUTH GOVT REP

TYPED NAME AND OFFICE

* If quantity received by the Government is the same as quantity shipped, indicate by (✔) mark, if different, enter actual quantity received below quantity shipped and encircle.

23. CONTRACTOR USE ONLY

DD FORM 250 1 NOV 68 REPLACES EDITION OF 1 AUG 67 WHICH MAY BE USED

TANKER/BARGE MATERIAL INSPECTION AND RECEIVING REPORT	1. TANKER/BARGE ☐ LOADING REPORT ☐ DISCHARGE REPORT	2. INSPECTION OFFICE	3. REPORT NUMBER
4. AGENCY PLACING ORDER ON SHIPPER, CITY, STATE AND/OR LOCAL ADDRESS *(Loading)*		5. DEPARTMENT	6. PRIME CONTRACT OR P.O. NUMBER
7. NAME OF PRIME CONTRACTOR, CITY, STATE AND/OR LOCAL ADDRESS *(Loading)*			8. STORAGE CONTRACT
9. TERMINAL OR REFINERY SHIPPED FROM, CITY, STATE AND/OR LOCAL ADDRESS			10. ORDER NUMBER ON SUPPLIER
11. SHIPPED TO: *(Receiving Activity, City, State and/or Local Address)*			12. B/L NUMBER
			13. REQN. OR REQUEST NUMBER / 14. CARGO NUMBER
15. VESSEL		16. DRAFT ARRIVAL FORE AFT	17. DRAFT SAILING FORE AFT
18. PREVIOUS TWO CARGOES FIRST LAST		19. PRIOR INSPECTION	
20. CONDITION OF SHORE PIPELINE		21. APPROPRIATION *(Loading)*	22. CONTRACT ITEM NUMBER
23. PRODUCT		24. SPECIFICATIONS	

25. STATEMENT OF QUANTITY	LOADED	DISCHARGED	LOSS/GAIN	PER CENT
BARRELS *(42 Gals) (Net)*				
GALLONS *(Net)*				
TONS *(Long)*				

26. STATEMENT OF QUALITY

TESTS	SPECIFICATION LIMITS	TEST RESULTS

27. TIME STATEMENT	DATE	TIME
NOTICE OF READINESS TO LOAD DISCHARGE		
VESSEL ARRIVED IN ROADS		
MOORED ALONGSIDE		
STARTED BALLAST DISCHARGE		
FINISHED BALLAST DISCHARGE		
INSPECTED AND READY TO LOAD DISCHARGE		
CARGO HOSES CONNECTED		
COMMENCED LOADING DISCHARGE		
STOPPED LOADING DISCHARGING		
RESUMED LOADING DISCHARGING		
FINISHED LOADING DISCHARGING		
CARGO HOSES REMOVED		
VESSEL RELEASED BY INSPECTOR		
COMMENCED BUNKERING		
FINISHED BUNKERING		
VESSEL LEFT BERTH *(Actual/Estimated)*		

28. REMARKS *(Note in detail cause of delays such as repairs, breakdown, slow operation, stoppages, etc.)*

29. COMPANY OR RECEIVING TERMINAL

(Signature)

30. I CERTIFY THAT THE CARGO WAS INSPECTED, ACCEPTED AND LOADED/DISCHARGED AS INDICATED HEREON.

(Date) *(Signature of Authorized Government Representative)*

31. I HEREBY CERTIFY THAT THIS TIME STATEMENT IS CORRECT.

(Master or Agent)

DD FORM 1 MAR 68 250-1

REPLACES DD FORM 250-1, 1 JUL 65, WHICH MAY BE USED.

BILLING CODE 6450-01-C

U.S. Department of Energy

Exhibit L—Information for Statistical Purposes

[Check *one* for each statement.]

1. The offeror certifies that it is a small business concern as defined in accordance with Section 3 of the Small Business Act (15 U.S.C. 632). 1. — Yes or — No
2. The offeror certifies that it is a small business concern (as set forth in 1. above) and is owned and controlled by socially and economically disadvantaged individuals. Such a firm is defined as one— 2. — Yes or — No

a. which is at least 51 percent owned by one or more such individuals or, in the case of publicly-owned business, at least 51 percent of the stock is owned by such individuals;
b. whose management and daily business operations are controlled by one or more such individuals; and
c. which certifies concerning ownership and control in accordance with Section 3 below.

3. The offeror certifies that he or she is a minority individual in accordance with 3a below or that he or she is socially and economically disadvantaged in accordance with Section 3b or 3c. Socially and economically disadvantaged individuals are defined as: 3. — Yes or — No

a. United States citizens who are Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans, or other specified minorities;
b. any other individual found to be disadvantaged pursuant to Section 8(a) of the Small Business Act (15 U.S.C. 637); or
c. any other individual defined by the Small Business Administration as socially and economically disadvantaged for purposes relating to other sections of the Small Business Act.

4. The offeror certifies that it is a woman-owned business. A woman-owned business is a business which is at least 51 percent owned, controlled, and operated by a woman or women. "Controlled" is defined as exercising the power to make policy decisions. "Operated" is defined as actively involved in the day-to-day management. 4. — Yes or — No

(Businesses which are publicly-owned, joint stock associations or business trusts are exempted from answering this question. Exempted businesses may voluntarily represent whether they are, or are not, woman-owned if this information is available.)

5. The offeror certifies that it is a labor surplus area concern. (For definition of "labor surplus area concern," see 41 CFR Section 1–1.801). 5. — Yes or — No
6. The offeror states that it operates as:

(Check one or more as applicable)

——An individual
——A partnership
——A joint venture
——A nonprofit or not-for-profit organization
——Corporation
——An educational institution
——A hospital
——A State or local Government agency
——A U.S. Government agency
——A foreign government or foreign government agency

7. The offeror is incorporated in *(U.S. State or foreign country)* or, if not incorporated, is a resident of *(U.S. State or foreign country)*, and has its principal place of business in *(city and U.S. State or foreign country)*.
8. The offeror is owned or controlled by a parent entity. 8. — Yes or — No

A parent entity for the purposes of this clause is an entity which either owns the offeror or controls the activities and basic business policies of the offeror. To own another company means the parent entity must own at least a majority (more than 50 percent) of the voting rights in the company. To control another entity, such ownership is not required; if another entity is able to formulate, determine, or veto basic business policy decisions of the offeror, such other entity is considered the parent entity of the offeror. This control may be exercised through the use of dominant minority voting rights, proxy voting, contractual arrangements or otherwise.

9. If the answer to 8. above is "yes," the offeror will fill in below the name of the controlling entity, the main business address of that entity, and the telephone number thereof.

Failure to execute all parts of the representations/certifications given above at the time an offer is submitted shall be regarded as a minor informality and the offeror shall be permitted to satisfy the requirement prior to award.

(OMB control number 1901–0261)

[FR Doc. 84–738 Filed 1–19–84; 8:45 am]

BILLING CODE 6450–01–M

ENERGY EMERGENCY PREPAREDNESS ACT
OF 1982

(Public Law 97-229)

A REPORT TO THE CONGRESS:

STRATEGIC PETROLEUM RESERVE DRAWDOWN PLAN

AMENDMENT NO. 4

THE PRESIDENT
OF THE UNITED STATES

THE SECRETARY
U.S. DEPARTMENT OF ENERGY

DECEMBER 1, 1982

TABLE OF CONTENTS

INTRODUCTION

The purpose of this Strategic Petroleum Reserve (SPR) Plan Amendment is to provide a new SPR Drawdown Plan, setting forth the procedure for the drawdown, sale and distribution of SPR oil in the event of a severe energy supply interruption. It replaces Amendment No. 3 and Chapter VII of the Strategic Petroleum Reserve Plan, and supersedes all prior SPR Distribution Plans. References in this Amendment to the "Secretary" are to the Secretary of Energy (or the successor to the authority of the Secretary of Energy over drawdown, sale and distribution of SPR oil).

LEGISLATIVE BACKGROUND

The creation of the Strategic Petroleum Reserve was authorized by the Energy Policy and Conservation Act of 1975 (EPCA), Public Law 94-163, which was signed into law on December 22, 1975. The EPCA authorized the acquisition and storage of substantial quantities of petroleum which might be used to diminish U.S. vulnerability to the effects of a severe energy supply interruption, or to carry out U.S. obligations under the International Energy Program (IEP).

As required by the EPCA, the Strategic Petroleum Reserve Plan was transmitted to the Congress as Energy Action No. 10 on February 16, 1977, and became effective April 10, 1977. Chapter VII of the Plan discussed and identified the major objectives, criteria and other factors to be considered in developing the details of a SPR distribution process. Subsequently, SPR Plan Amendment No. 1, accelerating the SPR development schedule, was transmitted to the Congress by the Federal Energy Administration (FEA) as Energy Action No. 12 on May 25, 1977, and became effective on June 20, 1977. Plan Amendment No. 2, Energy Action DOE No. 2, authorizing expansion of the SPR to 1 billion barrels, became effective on June 13, 1978. Plan Amendment No. 3, Energy Action DOE No. 5, a Distribution Plan setting forth the method of drawdown and distribution of the Reserve, became effective on November 16, 1979. This SPR Drawdown Plan (Plan Amendment No. 4) supplants SPR Plan Amendment No. 3.

This Amendment is transmitted pursuant to sections 154 and 159 of the EPCA (42 U.S.C. Sections 6234 and 6239) and section 4(c) of the Energy Emergency Preparedness Act of 1982 (EEPA), Public Law 97-229, signed into law on August 3, 1982. The EEPA requires the submission of an SPR "Drawdown" (Distribution) Plan Amendment by December 1, 1982. Section 154(e)(12) of the EPCA requires inclusion in the Strategic Petroleum Reserve Plan of "a Distribution Plan setting forth the method of drawdown and distribution of the Reserve." Section 161(b) provides that "no drawdown and distribution of the Reserve may be made except in accordance with the provisions of the Distribution Plan contained in the Strategic Petroleum Reserve Plan which has taken effect pursuant to section 159(a)." Section 159(d) authorizes amendments to the SPR Plan to be transmitted to Congress with explanations of their need.

In accordance with section 4(c) of the EEPA, this Amendment No. 4 will take effect on the date it is transmitted to the Congress and will not be subject to the Congressional review prescribed by section 159(e) of the EPCA.

This SPR Plan Amendment No. 4 contains, to the maximum extent practicable, the assessments, estimates, evaluations, and other information required by EPCA section 159(d). The revision of the SPR Distribution Plan in this Amendment will be more in line with the normal workings of the marketplace, in that the primary method of distribution of SPR oil will be by price competitive sale. Therefore, the procedure outlined in this Amendment is expected to have reduced economic costs and enhanced economic benefits over the previous SPR Distribution Plan. The environmental impact of the SPR program has not been significantly changed by this Plan Amendment.

SPR DRAWDOWN CONDITIONS

Section 161(d) of the EPCA stipulates that drawdown and distribution of the SPR may not be made unless the President finds such actions are required due to "a severe energy supply interruption or by obligations of the United States under the International Energy Program." A severe energy supply interruption is defined in the EPCA under section 3(8) as a national energy supply shortage which the President determines:

- Is, or is likely to be, of significant scope and duration, and of an emergency nature;
- May cause major adverse impact on national safety or the national economy; and
- Results, or is likely to result, from an interruption in the supply of imported petroleum products, or from sabotage or an act of God.

The IEP referred to in section 161(d) is the Agreement on an International Energy Program (IEP) signed by the United States on November 18, 1974. This Agreement authorizes, under specific conditions, an emergency program among participating countries pursuant to which each member country receives its share of world-wide crude oil supplies available to IEP member countries. The existence of IEP obligations can serve as a basis for authorizing an SPR drawdown. However, there is no requirement that the SPR be drawn down and used to satisfy these obligations.

Section 161(e) of the EPCA provides additional guidance regarding implementation of the SPR program. It provides as follows:

> (e) The Secretary may, by rule, provide for the allocation of any petroleum product withdrawn from the Strategic Petroleum Reserve in amounts specified in (or determined in a manner prescribed by) and at prices specified in (or determined in a manner prescribed by) such rules. Such price levels and allocation procedures shall be consistent with the attainment, to the maximum extent practicable, of the objectives specified in section 4(b)(1) of the Emergency Petroleum Allocation Act of 1973.

Such regulations have been adopted and appear at 10 C.F.R. Part 220. They currently apply only to "any allocation of SPR crude oil, other than distribution by price competition." However, it is the policy of this Administration that the pricing and allocation of energy supplies shall be determined to the maximum extent possible by the workings of the market-place, and competitive sales which are not subject to these regulations will be the primary method of distributing SPR oil. Non-competitive distribution is provided for in this Amendment only as a limited, extraordinary option. The regulations at 10 C.F.R. Part 220 will be reviewed and any appropriate revisions will be proposed in light of this policy or as may be necessary to conform the regulations to the oil sale methodology provided for in this Amendment with respect to non-price competitive distribution.

These regulations shall remain inapplicable to sales by price competition. The Secretary may also promulgate such other regulations with respect to sales by price competition as he deems appropriate and are consistent with this Amendment.

CHAPTER I

SUMMARY OF THE AMENDMENT

This Amendment describes how SPR crude oil will be drawn down, sold and distributed. The existing SPR Distribution Plan and Chapter VII of the SPR Plan are superseded in their entirety by this SPR Plan Amendment.

WHEN AND HOW THE SPR WILL BE USED

The President will decide, consistent with section 161(d) of the EPCA, when to use the SPR and at what rate. It does not seem feasible or appropriate at this time to establish a specific "trigger" or formula which will automatically determine if the SPR is to be used and at what interval and rate because of the wide range of unpredictable conditions which might characterize an energy supply interruption.

Use of the SPR will be part of a total interruption response and the extent of its use is likely to change throughout the course of an interruption. Any oil that is under contract for delivery to the SPR or in transit to SPR sites at the time of emergency drawdown will be considered as SPR oil and will be disposed of consistent with this Amendment.

DOE is developing a SPR Distribution Management Manual (DMM) which will be a prime source for procedural guidance for responding to a severe energy supply interruption and for making recommendations to the Secretary and the President on use of the SPR. Factors which will be considered in developing recommendations on SPR use will include the nature of the interruption, the alternative response measures available, and the size and drawdown capability of the SPR. The DMM and associated procedures will be tested in 1983.

DISTRIBUTION OF PETROLEUM AMONG REFINERS AND OTHER USERS

The primary purpose of the SPR sales and distribution process will be to provide additional supplies of petroleum to domestic energy markets on a timely basis, to substitute for supplies interdicted due to a major fuel supply disruption. The SPR oil distribution process is intended primarily to supplement national petroleum supplies. This Distribution Plan describes the means by which SPR oil will be distributed into the U.S. oil supply system.

SPR OIL DISTRIBUTION FACILITIES

The SPR's permanent storage facilities are currently being developed and filled in three phases. Phase I involved the construction and fill of facilities to utilize existing storage capacity of approximately 250 million barrels (MMB) at five salt dome sites located in the Gulf Coast areas of Louisiana and Texas. Phase II involves the expansion of three of these sites by a total of 290 MMB through the process of "solution mining" (leaching). Phase III involves the development of additional storage capacity of up to approximately 210 MMB, by adding an additional site at Big Hill, Texas, and by expanding storage capacities at the West Hackberry and Bryan Mound SPR storage sites.

PHYSICAL DISTRIBUTION

The DOE will be responsible for moving SPR oil to the terminals or other delivery points specified by the government at schedules agreed to with the purchasers of the oil. At the delivery points, title to the oil will transfer to the recipients, and they will assume responsibility for moving the oil to refineries. The SPR sites connect with terminal systems which provide a capability for moving SPR oil by pipeline, tanker, or barge to most U.S. refiners who now receive oil from overseas sources.

SELECTION OF BUYERS AND SALES PRICE OF SPR OIL

There will be two options for selection of buyers of SPR oil. The basic method of distribution of SPR oil will be by price competitive sale with awards going to the highest bidders (although the Secretary may establish a minimum acceptable price). The sale would be open to all interested buyers, who will be required to sign a standard sales agreement as a condition of bidding. Measures will be included in the sales agreement to assure the financial and performance responsibilities of the successful buyers. It is intended that the universe of eligible buyers will be as large as possible to ensure efficient distribution of SPR oil.

The other distribution option is planned to be available only as a "last resort" measure. Under this option the Secretary may, in any calendar month, direct the distribution of up to 10 percent of the volume of SPR oil sold in that calendar month in a manner which the Secretary selects at his discretion. The price for such SPR oil will be the average price of SPR oil sold at the contemporaneous competitive sale, or at the most recent competitive sale if no contemporaneous competitive sale is held.

CHAPTER II

WHEN AND HOW THE RESERVE WILL BE USED

THE ROLE OF THE SPR IN RESPONDING TO A SEVERE ENERGY SUPPLY INTERRUPTION

The SPR will only be used to protect vital national interests of the U.S. (e.g. foreign policy, national security, the economy), where threatened by a major supply disruption which the President has determined to be a "severe energy supply interruption," or as necessary to fulfill "obligations of the United States under the international energy program," as defined in EPCA section 3(7).

At its current size, the SPR is an effective response measure which DOE could employ to offset the effects of an interruption of petroleum supplies. As the size of the SPR increases, so too will its ability to mitigate the impacts of interruptions. To maximize the value of the SPR, however, drawdown decisions must be based on estimates of how long the interruption may last, the likelihood of subsequent interruptions, and whether there will be opportunities to refill the SPR between interruptions.

OBJECTIVES OF SPR USE

Specific use objectives must be considered in determining the rate, timing, volume, sales procedures, and other similar factors of a drawdown. Different supply shortages and economic conditions will mandate different responses, and suggest a wide variety of SPR use objectives. Some objectives may not be compatible, and may even be mutually exclusive. Below is a partial list of SPR use objectives:

- Supplement domestic oil supplies and thus reduce economic and social costs.
- Enhance or augment national security and/or foreign policy goals.
- Assist in meeting IEP and other commitments.

POLICY CONSIDERATIONS PERTAINING TO SPR USE

Decisions regarding the use of the SPR, as well as other response measures, would be influenced by several international and domestic policy considerations, such as:

International Considerations

- The perceived effects of the supply interruption, its likely depth and duration, and its expected effect.
- The extent to which diplomatic or other actions are likely to resolve the circumstances which precipitate the supply interruption, and the probable time frame for resolution.
- The degree, if any, to which the SPR is to be used to support the U.S. commitment under the IEP.
- The role of the SPR in meeting national security concerns.

Domestic Considerations

- The extent to which consumers can reduce petroleum use during a supply interruption.
- The need for additional crude oil supplies in the initial period of a supply interruption.
- The amount of oil stored in the SPR and its drawdown capability.
- Projected Gross National Product, employment, price and inflation impacts of the interruption, and the potential for the SPR and other non-SPR response measures to reduce these impacts.
- The desirability of maintaining some portions of the SPR as "insurance" against an unexpectedly long interruption, or a gradual deepening of an interruption.

DRAWDOWN RATE

As the SPR becomes larger, the Government's flexibility in using it will be increased. Decisions concerning the drawdown of the SPR may seek a relatively high drawdown rate in the first several months of a major interruption to support U.S. foreign policy objectives. As the SPR is used, drawdown rates may be reduced to conserve remaining supplies. The adjustment would likely be gradual to minimize the economic hardships and disruptions induced by greater shortages of petroleum.

On the other hand, the SPR might be drawn down at lower rates over the course of the disruption. This might alleviate the worst impacts of a shortage and would retain a higher reserve as insurance against the worsening of an interruption, or prolonged periods of instability and an increase in the likelihood of subsequent interruptions. As a general rule, the presumption will be made that the most efficient allocation of oil over time will be made by the market.

CHAPTER III

CAPABILITIES TO MOVE SPR OIL

SUMMARY OF THE PHYSICAL DISTRIBUTION SYSTEM

In developing the SPR distribution system, storage sites have been located in areas that are highly accessible to major commercial distribution systems, including interstate pipelines and marine port and terminal facilities. These locations permit SPR crude oil to be introduced rapidly into the normal U.S. crude oil distribution system, if petroleum supplies to the United States are interrupted.

About 60 percent of the crude oil imported by the United States in 1981 entered through the Gulf Coast ports. A significant portion of this crude oil is transferred inland through three major interstate pipelines originating in the Gulf Coast. The three pipelines are the Seaway and Texoma Pipelines, both terminating at Cushing, Oklahoma, and the Capline Pipeline, which terminates at Patoka, Illinois. Many smaller pipelines further distribute crude oil from these major pipelines throughout the Midwest. SPR facilities are connected to these pipeline systems.

The SPR storage system is designed to make maximum use of existing and planned private distribution facilities, rather than developing facilities exclusively for SPR use. Since expeditious adjustments will be required to the regular schedules of affected ports, terminals, and pipelines to accommodate the necessary changes in physical distribution patterns, the potential for successful implementation of response measures will be maximized by industry performing these functions, with the Government supporting industry, as appropriate.

During a drawdown, the SPR oil in the storage sites will be moved through connecting pipelines to supporting terminals where transfer of ownership will take place. The Government's role will end at this point and the buyers will assume distribution responsibility. This storage configuration provides the capability to distribute SPR crude oil (directly, or by exchanges) through the pipelines to local and inland refineries, for across marine terminal docks to barges and tankers for delivery to refineries or to other facilities accessible by waterborne means on the Gulf Coast, the East Coast, the West Coast and the noncontiguous areas of the country.

The portion of the national distribution system through which SPR oil can move has a great deal of flexibility and redundancy ensuring that it is capable of meeting a variety of demands. Information associated with the distribution systems that the SPR interfaces with must be kept current. Through a system of analytical methods, the SPR distribution capabilities are continuously assessed to assure appropriate configurations exist. Should it become apparent that enhancements to the SPR distribution system are necessary because demand patterns have changed or commercial facilities have been modified, potential enhancements will be identified and incorporated as appropriate. Some of the key parameters that are maintained in order to establish the bounds in the capability are current utilization of foreign crude by refineries that have access to SPR oil be either interstate pipeline or local pipeline, over-the-dock capability with different ship availability assumptions, and expected demand patterns by refinery groups as a function of current source of crude.

U.S. CRUDE OIL DISTRIBUTION SYSTEM

The crude oil distribution system in the U.S. is a complex network of pipelines, tanker routes, inland waterways, terminals, and rail lines which has been adapted to the petroleum logistical needs of the country and is operated efficiently and economically by the petroleum and transportation industries. This system serves the major refining centers of the country. The SPR system has been developed to facilitate access to the refining centers through this system.

The use of the SPR may be activated by several different types of interruption situations, the most likely of which is an interruption of petroleum supplies from foreign sources. The highest volume users of imported crude oil are the regions of the U.S. most readily served by the SPR: the Midwest, the Gulf Coast, and the East Coast. The bulk of imported crude enters the country through Gulf Coast terminals (about 60 percent), with substantial imports also entering through terminals in the East Coast as well as Puerto Rico and the Virgin Islands.

While Gulf Coast refineries process significant amounts of the foreign crude which enters through Gulf Coast terminals, there is also a substantial flow of this oil through the Gulf Coast-to-Midwest pipeline system (and, to a lesser extent, the inland waterway system). Most of the foreign crude that is processed by Midwestern refineries flows initially through the three major common carrier pipelines (i.e., the Seaway, Texoma, and Capline Pipelines) that are linked to the SPR storage complexes in the Gulf Coast area.

It is expected that SPR oil will be distributed mainly by means of pipeline to Midwestern refineries and by pipeline and waterborne transport to Gulf Coast and East Coast refineries, with the needs of more remote refineries, such as those located in non-contiguous areas, served by voluntary displacement of shipments of uninterrupted supplies that were originally destined for delivery at Gulf Coast terminals.

GOVERNMENT AND PRIVATE SECTOR TRANSPORTATION RESPONSIBILITIES

During a drawdown the SPR oil will be moved from storage sites through connecting pipelines to the supporting terminals, where transfer of ownership will take place. The Government's role will end at this point and the buyers will assume distribution responsibility.

Buyers will assume distribution control at the point of transfer of ownership at the SPR and commercial terminals, or at other points of delivery in the case of oil not withdrawn from storage sites. Terminal and pipeline operations and shipping arrangements are expected to be the responsibility of the buyers and the energy transportation and distribution industry, with Government assistance only where appropriate and requested. Possible diversions and exchanges are intended to be the responsibility of the recipients.

Because the SPR distribution system depends on the use of the private oil distribution system used by refiners under normal conditions, it is necessary that buyers make arrangements for the movement of the SPR oil from the terminal sites.

CHAPTER IV

CONTRACTING AND SALES: BUYERS SELECTION AND PRICING

SUMMARY

Experience has demonstrated that Government intervention in the marketplace, in the form of allocation and price controls, has a negative impact on our Nation's ability to cope with severe energy supply interruptions. The failure of allocation and price controls, recognized even by many of those charged with implementing and enforcing them, has led this Administration to conclude that market mechanisms must be relied upon to respond to severe energy shortages most efficiently and effectively. Consistent with the its market-oriented approach, the Administration intends to use the SPR during an energy crisis in a manner which simulates the operation of the marketplace as closely as possible, and which interferes with the marketplace as little as possible.

An important consideration in the process of selling SPR oil is an assurance that sale and delivery schedules can be met. This becomes more essential as the drawdown rate increases. The DOE must rely on the buyers to make the necessary decisions and arrangements to move the oil from the terminals. Measures will be developed which will assure that the financial and performance responsibility of the successful buyers will be met. For example, these might include contractual provision for liquidated damages, irrevocable letters of credit, performance bonds, etc. Through such measures DOE may reduce the risk of purchases by persons who lack the capability or intent to take timely delivery of SPR oil, or the financial ability to pay for SPR oil.

Operational constraints considered in sales procedures may vary according to the drawdown rate, the nature of the interruption, and the necessity to integrate SPR withdrawal with other response measures. The difficulty of logistic problems will, as a general rule, tend to be related to the size and percentage of capacity represented by the drawdown rate.

As discussed in Chapter III, the drawdown of the SPR will rely primarily on the use of existing private facilities to move the oil to refineries. These private facilities include crude oil pipelines, tanker and barge docks, tankers, and barges. These facilities must be used in conjunction with continued movements of domestic oil and uninterrupted imported oil. Because of the interrelationships of these oil movements, it is essential that the demonstrated expertise of the private petroleum industry be used to manage the total oil movement.

COMPETITIVE SALES

The process of selecting buyers to purchase SPR oil in price competitive sales will generally consist of two steps. The timing and sequence of each of these steps will be determined by the Secretary, although actual drawdown of SPR oil may not occur until after the Presidential finding under section 161 of the EPCA has been made. In order to achieve efficient distribution of the SPR oil, the universe of eligible buyers will not be restricted, except insofar as necessary to assure performance and payment. Thus, all interested buyers will be eligible to bid for and purchase SPR oil, including Federal agencies. The two steps are:

1. ISSUANCE OF NOTICE OF SALE

The Secretary will issue a Notice of Sale (NS) requesting that bids be submitted for SPR oil. This NS may specify the quantity, the quality, and the location of oil available, any restrictions or minimum or maximum volumes for each purchaser which the Secretary considers necessary in light of logistic considerations, the sales period, any special transportation restrictions, and such other information or requirements as are deemed appropriate and are authorized by this Amendment.

The NS will also require that all bidders must agree to the terms and conditions of the DOE's standard sales agreement as a condition to their offers. In addition, it may advise offerors of the measures being taken to assure their financial or performance capability. The NS (or the standard sales agreement) may specify measures to assure performance and payment (such as liquidated damages, storage charges, irrevocable letters of credit, performance bonds, advance payment in whole or in part) and/or requirements or conditions for buyers who do not take delivery on schedule or who fail to meet other terms and conditions of the bidding procedures or the standard sales agreement, and will specify such other information or requirements as the Secretary deems appropriate and are consistent with this Amendment.

In the NS, the Secretary will incorporate provisions designed to enhance and ensure the maximum competitiveness of sales. It is intended that the NS and the sales agreement will include terms and conditions consistent with the purpose of this Amendment to implement drawdown of SPR oil primarily by price competitive sale open to all interested bidders.

2. SELECTION OF PURCHASERS FROM QUALIFYING BIDDERS

Except where the distribution of SPR oil is directed by the Secretary pursuant to this Amendment, the purchase of SPR oil will be determined solely by price competitive sale, with the oil being sold to the highest eligible bidders. At or before the time of offer, all buyers must sign the DOE's standard sales agreement which will set forth all of the provisions regarding the sale. The sales agreement is designed to expedite the process of selling and distributing SPR oil, and assuring performance under resulting awards. Provisions covered in a sales agreement may include such subjects as liability of the parties, payment procedures, crude oil quality differential pricing, and inspection and acceptance procedures, irrevocable letters of credit, performance bonds and/or other requirements or provisions which the Secretary may determine to be necessary or appropriate to assure performance and payment. Provisions in the sales agreement may be modified or deleted, as the Secetary may deem appropriate for a particular sale, through changes noted in the NS for that sale. Prior to award, successful bidders must provide financial and performance assurances which will guarantee their capability to carry out the contract.

DIRECTED SALES

Under the most extreme of circumstances the Secretary may direct in any calendar month the distribution of up to 10 percent of the volume of the SPR oil sold in that calendar month, in such manner as he determines at his discretion. The price for such SPR oil will be the average price of SPR oil sold at the contemporaneous competitive sale, or at the most recent competitive sale if no contemporaneous competitive sale is held. Contracting and related documents used in directed sales will be based on those employed in price competitive sales, subject to such modifications as the Secretary may in his discretion determine to be necessary or appropriate to reflect the directed nature of these sales.

REMOVAL OR STORAGE OF SPR OIL

Under some circumstances, it may be in the national interest for the Secretary to permit a successful bidder for SPR oil to leave the oil which has been purchased in storage at the SPR facilities for some period of time. A storage fee will be charged for such storage, and specific procedures and conditions for such storage may be established by the Secretary and may be reflected in the standard sales agreement. Similarly, the Secretary may require successful bidders to agree to timely removal of purchased oil from SPR facilities.

PRICING OF SPR OIL

The principal method of pricing SPR oil will be by competitive sale with the oil sold to the highest eligible bidders. The Secretary may establish a minimum acceptable price. In the case of SPR oil the distribution of which is directed by the Secretary, the price for such SPR oil will be the average price of SPR oil sold at the contemporaneous competitive sale, or at the most recent competitive sale if no contemporaneous competitive sale is held. This authority, if exercised, applies to up to 10 percent of the volume of SPR oil sold in any calendar month.

Appendix H

U.S. DEPARTMENT OF ENERGY

STRATEGIC PETROLEUM RESERVE
DISTRIBUTION ENHANCEMENTS FACT SHEET

BACKGROUND

The SPR Office has been reviewing current SPR distribution capabilities and criteria.

Findings of the internal SPR study can be summarized as follows:

- The SPR is planned to have a maximum initial (90-day) site drawdown capability of 4.5 MMB/D upon completion of the 750 MMB system, now planned for 1990.

- However, SPR distribution capabilities will be limited to a maximum future rate of 2.4 MMB/D unless we change our plans.

We have concluded, after examining many alternatives, that the following enhancements are warranted.

- Bryan Mound (Seaway Distribution Complex)

  -- Build a 42-inch (1.0 MMB/D) pipeline connection from the Bryan Mound site to a commercial terminal in the Texas City area, less than 50 miles away. This would permit direct shipment of SPR crude oil to Houston area refineries by pipeline as well as added tanker outloading capability (at least 400 MB/D) in the Gulf of Mexico. This pipeline would expand future Bryan Mound distribution capabilities to over one million barrels per day, in line with the drawdown capabilities we expect to have at that site when oil fill is complete in 1986.

  -- Construct a direct pipeline interconnection between DOE's pipeline to the Seaway Docks and Phillip's Terminal pipeline.

- West Hackberry (Texoma Distribution Complex)

  -- Construct a 26-inch 700 MB/D tie-in to the Lake Charles, Louisiana area, including access to both CITGO and CONOCO marine terminals. This would provide both overland access to refineries in this vicinity and also added tanker outloading capability.

-- Upgrade existing Sun Terminal piping manifolds to increase the distribution capability of the Sun Terminal.

- Big Hill (Texoma Distribution Complex)

-- Construct a 30-inch pipeline spur from the Big Hill-to-Sun Terminal pipeline to the Texas Oil and Chemical Marine Terminal in the Beaumont, Texas area.

The benefits of these enhancements are:

- Maximum initial distribution rate of at least 4.0 MMB/D for 750 MMB system, 3.5 MMB/D for 610 MMB system (Phase I and II).

- 93 percent of SPR inventory can be deployed in 6 months throughout the 1987-1991 period.

- About half of the existing SPR inventory can be deployed in 3 months from 1987 to completion.

- Improvement is made in both first and second quarter drawdown rates.

- Improves system balance in the 1990-1991 period by accommodating the increase in both inventory levels and drawdown rates associated with Big Hill development.

- Overall flexibility is increased in all time periods through overland access to the Lake Charles refinery area and additional marine transportation through a fifth ship channel (Calcasieu).

The distribution capability achieved through these enhancements is conservatively estimated. A level of redundancy of approximately 20 percent was assumed as an allowance for refinery demand variances, terminal operation delays, and other factors. Thus, an actual distribution rate in excess of 4.0 MMB/D may be achievable.

We are confident that these enhancement represent a mix of the greatest benefits at the least cost.

Glossary

NOTE: *The definitions below refer to the context in which words are used in this report.*

ANS—Alaskan North Slope.

backhaul—the movement of marine cargo on the return leg of a voyage rather than returning with ballast.

ballast—seawater that is taken into the cargo tanks of a tanker to submerge the vessel to a proper stability or draft.

Capline Complex—those DOE and privately owned facilities directly required to facilitate drawdown of the Bayou Choctaw and Weeks Island SPR sites. This includes the DOE pipelines that tie into the DOE St. James terminal.

CDS—*see* Construction Differential Subsidy Program.

clean products—refers to all petroleum products other than residual fuel oil.

Construction Differential Subsidy (CDS) Program—established under the Merchant Marine Act of 1936, the CDS program provides for the subsidization of the cost of U.S. flag ships to make them more competitive with foreign flag ships and encourage their participation in the foreign commerce of the United States.

crude oil washing (COW)—vessel tank washing procedure that consists of using recycled crude oil from the cargo system as a washing medium to remove clingage from cargo tanks after discharge. Fixed rotating guns within the cargo tanks are used to spray crude oil on tank tops and sides.

deadfreight—the portion of a vessel's cargo carrying capacity that is not used due to light loading of cargo.

deadweight ton (DWT)—the number of long tons (2,240 pounds) of cargo, stores, and bunkers that a vessel can carry. It is the difference between the long tons of water a vessel displaces in its "light" and loaded condition. A vessel's cargo capacity is less than its total deadweight tonnage.

demurrage—detention of a vessel by charterer, owner, or loading/unloading facility beyond the time allowed for a vessel to load and discharge cargo. Generally a fixed charge, per hour or per day, is agreed to in advance as compensation for such detention.

DOD—U.S. Department of Defense.

DOE—U.S. Department of Energy.

drawdown—the removal of crude oil from SPR storage caverns.

draft—*see* vessel draft.

DWT—*see* deadweight ton.

EEPA—Energy Emergency Preparedness Act.

EIA—Energy Information Administration.

EPCA—Energy Policy and Conservation Act.

F.O.B.—*see* Freight On Board.

Freight On Board (F.O.B.)—the point at which transportation costs begin to be incurred.

high-sulfur crude oil—crude oil with a sulfur content of greater than 0.50 weight percent, commonly referred to as sour crude oil.

IEA—International Energy Agency.

IEP—International Energy Program.

Inert Gas Systems (IGS)—process whereby inert gas is pumped into the cargo tank space of a vessel to control the composition of the atmosphere in the tank to reduce the risk of explosion.

lightering—removing partial or full cargo from a large vessel and conveying it from ship to shore.

LNG tankers—vessels designed to carry liquified methane in bulk.

LOOP—Louisiana Offshore Oil Port.

low-sulfur crude oil—crude oil with a sulfur content of 0.50 weight percent or less, commonly referred to as sweet crude oil.

LPG—liquified petroleum gas.

MarAd—U.S. Maritime Administration.

MB/D—thousand barrels per day.

MDWT—thousand deadweight tons.

MMB/D—million barrels per day.

MMDWT—million deadweight tons.

MSC—Military Sealift Command.

Notice of Readiness—notice served by the master of the vessel to the charterer, informing him of the readiness of the vessel to load according to the terms of the charter.

NPC—National Petroleum Council.

OCS—Outer Continental Shelf; in this report, OCS refers to the Outer Continental Shelf offshore California.

PADD—Petroleum Administration for Defense District.

Panamax tankers—tankers that are capable of transiting the Panama Canal (which imposes a width restriction at 106 feet), generally in the 50–90 MDWT size range.

POSSI—Petroleum Operations Support Services, Inc.

RCV—relative crude value.

redundancy—in this report, factors applied to drawdown and distribution estimates to provide flexibility in the SPR system; also used in DOE planning.

re-positioning—a ballast leg voyage to position a vessel for participating in another trade.

SBT—segregated ballast tanker.

Seaway Complex—those DOE and privately owned facilities directly required to facilitate drawdown of the Bryan Mound SPR site. This complex includes the Phillips (formerly Seaway) pipeline connecting the Bryan Mound SPR site to the Phillips (formerly Seaway) docks at Freeport, Texas.

segregated ballast—ballast water introduced into a tank that is completely segregated from cargo oil and fuel oil systems; the tank is permanently dedicated to the carriage of ballast. The capacity of the segregated system must be sufficient to provide adequate stability for safe operation of the vessel without using cargo tanks for ballast.

SPR—Strategic Petroleum Reserve.

SPRO—Strategic Petroleum Reserve Office.

SSPs—Standard Sales Provisions.

tanker—vessel designed to carry full loads of liquid cargo in bulk such as crude oil, refined petroleum products, and petrochemicals.

Texoma Complex—those DOE and privately owned facilities directly required to facilitate drawdown of the Sulphur Mines, West Hackberry, and Big Hill SPR sites. This includes the DOE pipelines connecting these sites to Sun Terminal at Nederland, Texas.

topping off—completing the loading of a vessel that was not fully loaded at the dock because of draft restrictions. Topping off can occur outside of the load port via small vessels, or at another loading port.

TPI—tons per inch immersion.

vessel draft—the depth, in feet and inches, of a vessel below the waterline, measured vertically to the lowest part of the hull, propellers, or other projecting point.

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