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Market Assessment for Shale Oil

October 1979

MASTER

Prepared For
U.S. Department of Energy
Assistant Secretary for Fossil Energy
Division of Fossil Fuel Extraction

Under Contract No. ET-78-C-01-2628

DISCLAIMER

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Market Assessment for Shale Oil

October 1979

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Assistant Secretary for Fossil Energy
Division of Fossil Fuel Extraction
Washington, D.C. 20585

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TABLE of CONTENTS

Table of Contents (continued)

LIST of TABLES

LIST of FIGURES

PREFACE

The U.S. Department of Energy is actively pursuing economic and market assessments of shale oil towards commercial development of oil shale technology to help reduce the import of foreign oil. This report answers some of the key questions which face commercialization as viewed by the Pace Consultants & Engineers and Booz-Allen and Hamilton. The report addresses following questions:

1. What is the optimum mix of products that can be refined from shale oil based on economics, good refining practices, and logistics for the Northern Tier, Mid-Continent, Gulf Coast, Rocky Mountain, and West Coast regions? Determine the optimum slate of products using current market prices that can be refined from 100 percent shale oil by the typical refinery configuration of each region.

2. What are the required economic parameters which would allow refiners to process shale oil?

3. Where do the petroleum products testing facilities in the public and private sectors exist? Prepare a strategic plan for testing fuels and transportation products derived from shale oil relative to product specifications and performance.

4. Which refineries are the most logical processors of shale oil in terms of geography and refinery configuration? Also, identify the market demand issues based on the best shale oil product mix. Determine an optimum refinery for a new refining configuration for processing oil shale considering current prices.

5. Which specific refineries in the Northern Tier and Western Slope would likely desire to refine shale oil, and the capital costs these refineries would incur in modifying (if necessary) for the refining of shale oil? Identify refineries in each of the market areas mentioned previously which are logical shale oil processors.

6. If the shortage of domestic refining capacity is to be improved, what is industry's perspective towards processing shale oil and heavy oil along with domestic crude oil?

This report obviously does not answer all questions concerning, but it does represent the perceptions of one segment of the industry. Its value should be judged accordingly.

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EXECUTIVE SUMMARY

INTRODUCTION

The Pace Company Consultants & Engineers, Inc., under contract with the Department of Energy and Booz, Allen & Hamilton, assessed the technical, economic, and geographic factors involved in the utilization of shale oil.

The study projects an increase of shale oil production from 10,000 barrels per day in 1985 to 750,000 barrels per day in 2000. Shale oil's greatest market potential exists in the mid-continent and Rocky Mountain regions of the United States. Early emphasis will be in the mid-continent states that have the capability to receive and process a significant volume of raw market demand for distillate or residual fuels. The primary fuels expected to be produced from shale oil are diesel, distillate heating oils, kerosine-based (commercial) jet fuels, and residual fuels.

The market demand and other key issues which will have a significant impact on the volume and timing of shale oil introduced into the United States energy picture are outlined in this summary. A visual representation of this projected supply and demand framework is presented in Figure I. Figure II depicts the geographical breakdown of the U.S. into the five Petroleum Administration for Defense Districts that were used in this study.

FACTORS CONSTRAINING THE SUPPLY OF SHALE OIL

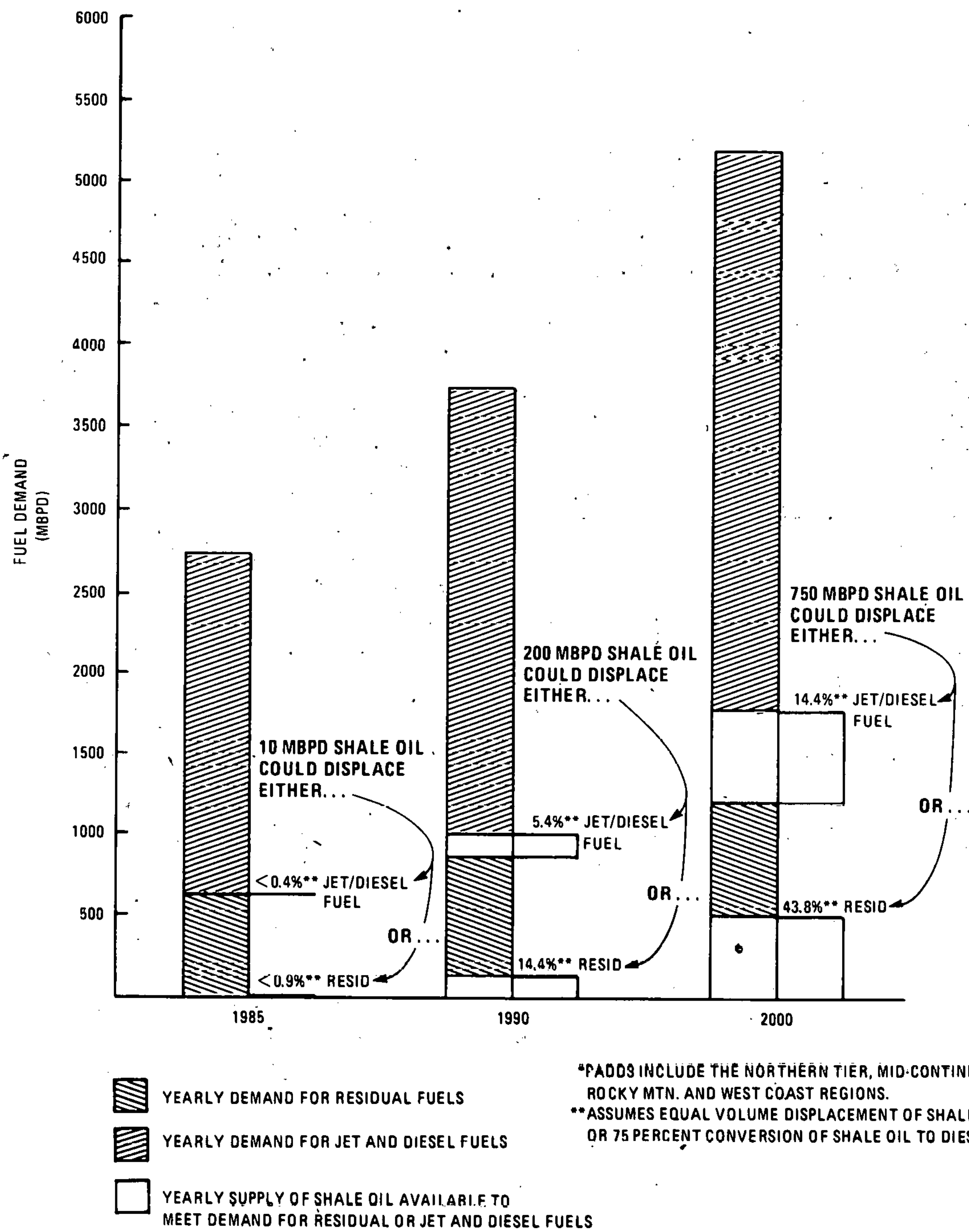
- Processing Restrictions

  - Eleven refineries in PADDs 2A and 2B have been identified as potential processors of shale oil. PADD 4 would require construction of major new refineries to allow processing of significant quantities of raw shale oil.

  - In many cases, refinery configurations will have to be modified and additional equipment acquired for processing shale oil. Specifically, hydrotreating capability required to produce transportation fuels exceeds the design limits of many existing refineries.

FIGURE I

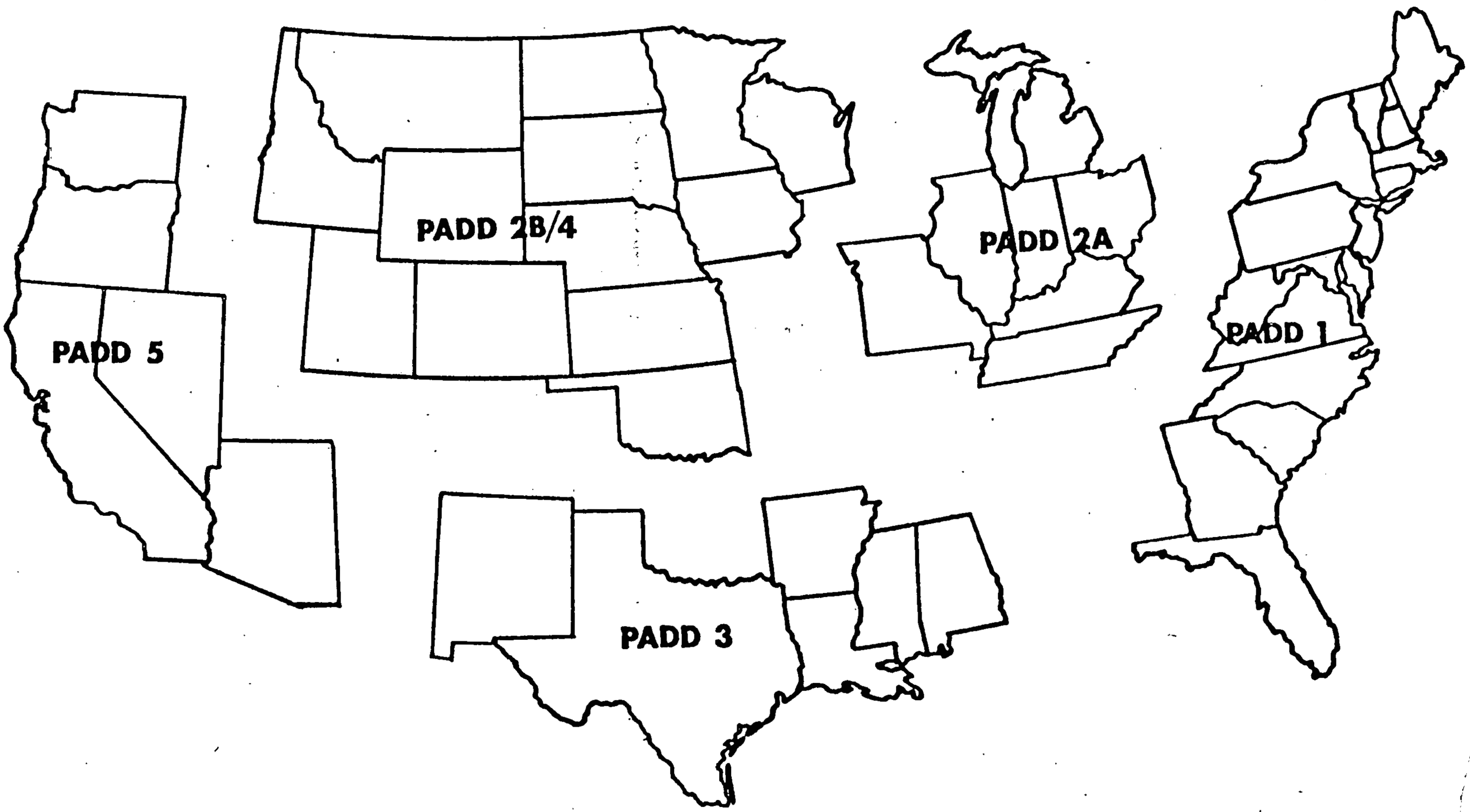
SHALE OIL CONTRIBUTION TO PROJECTED DEMANDS FOR DIESEL AND JET FUELS OR RESIDUAL FUELS IN PADDs 2A, 2B/4, 3, AND 5*



*PADDS INCLUDE THE NORTHERN TIER, MID-CONTINENT, GULF COAST, ROCKY MTN. AND WEST COAST REGIONS.
**ASSUMES EQUAL VOLUME DISPLACEMENT OF SHALE OIL FOR RESID OR 75 PERCENT CONVERSION OF SHALE OIL TO DIESEL/JET FUEL

FIGURE II

PETROLEUM ADMINISTRATION for DEFENSE DISTRICTS - PADD



- Many existing refineries which have the capability of processing raw shale oil can only handle small volumes unless additional sources of hydrogen can be employed. As the percentage of high nitrogen crude fed to these refineries increases, the quantity of surplus hydrogen will dwindle and so will the refineries' shale oil processing capability.

- Distribution Restrictions

  - Excess capacity in major pipeline systems, the northern system (between PADD 4 and PADDs 2A and 2B) and the southern system (between PADDs 3 and 5), is projected to be about 300,000 barrels per day. New pipelines will be needed for shale oil production in excess of this level.

  - Tie-ins with existing pipeline systems will require major expansions or additional feeder lines from the shale oil production site.

  - The existing crude oil pipeline system will encounter difficulties in handling raw shale oil's high viscosity, pour point, and contaminant levels.

  - Movement of many small volumes of shale oil to geographically dispersed locations will present logistical problems.

- Investment and Operating Costs for New Equipment

  - Investment and operating costs for processing raw shale oil could be minimized if there existed an availability of surplus hydrogen (about 2,000 std. cu. ft. per barrel of shale oil charged) and if the shale oil represents a small proportion of the refinery's total throughput.

  - At current prices, a 10,000 barrel per stream day shale oil hydrotreating facility could be constructed for approximately $40 million. Operating costs would vary from approximately $6.40 to $9.40 per barrel, depending on the availability of surplus hydrogen. If additional hydrogen generating equipment were needed, the investment cost would be greater. If the shale oil represents less than 2 percent of the refinery throughput and if sufficient hydrogen was available, it may be possible to process shale oil with no incremental investment.

- As the refiner attempts to process relatively larger percentages of shale oil, the required investment becomes larger. Approximately $120 million is required to construct a facility necessary to process 50,000 barrels per stream day of shale oil. Operating costs per barrel, however, would be less as hydrotreating severity could be tailored to the requirements of individual side stream fractions. These costs range from approximately $4.40 to $6.30 per barrel, again depending upon the availability of hydrogen.

- The upgrading of shale oil onsite or in a regional facility would allow the integration of syncrude into more existing refining and pipeline systems at a lesser cost and with minimum time delays. This is an option open to shale oil producers who may encounter downstream resistance in marketing raw shale oil, however, water availability and usage issues must be addressed.

DEMAND FOR SHALE OIL

. Short Term

- Until shale oil becomes established as a stable and consistent source of supply to refiners, the initial demand will be as boiler fuels. This initial consumption of shale oil in boilers could be reduced by the establishment of a Federal shale oil storage program which would ensure a supply that is dependable enough to allow continuous processing into transportation fuels. A stable supply is not likely to be encountered until after 1985 with no significant impact until 1990.

- Preliminary demand for shale oil as a refinery feedstock will come mainly from those refiners who are shale oil project sponsors wishing to refine shale oil in their own refineries, and secondly from refiners who are without assured crude oil supplies.

- Long Term

  - The greatest incremental demand for refined products between 1985 and 2000 will be in the form of diesel fuel and jet fuel, with the ability of shale oil to meet a significant portion of this demand by 1990. All of the PADDs examined exhibit this projected increase in commercial jet and diesel fuel demand.

  - A strong incremental demand for utility and industrial boiler fuel (resid) will also be experienced, particularly in PADD 2B/4.

  - The Department of Defense represents a significant potential demand (600 MBPD) for shale oil products. However, about 50 percent of this demand is accounted for by naphtha, a minimal product yield from shale oil.

  - Additional large-scale tests of raw shale oil in industrial or utility boilers are needed to develop techniques of nitrogen oxide emissions control.

A

INTRODUCTION

A

INTRODUCTION

Booz Allen and Hamilton, Inc., and The Pace Company Consultants & Engineers, Inc., assessed the technical, economic, and geographic factors involved in the utilization of shale oilfor the United States Department of Energy. Six tasks were defined covering various aspects of this subject. The first portion of this report gives brief answers to questions posed in these six tasks, along with references to detailed supporting material contained in the second portion of the report.

The issues analyzed in detail include:

- Shale oil characteristics of importance from a refining standpoint
- Current shale oil refining technology, including process descriptions and operating conditions
- Investment and operating costs for shale oil refining
- Potential products which can be produced from shale oil and a projection of the demand for these products
- Identification of refineries having the potential to process shale oil
- Limitations of the existing pipeline systems which could transport shale oil, as well as an evaluation of new pipeline requirements
- Refining industry outlook on processing shale oil
- Shale oil product testing requirements.

Included in an appendix are several abstracts of recent studies dealing with shale oil processing.

B

CONCLUSIONS

CONCLUSIONS

This study identified several key issues which will have a significant effect on the cost, timeliness, and ease with which shale oil can be introduced into the United States' refining system.

- The capacity of the existing refining industry to process raw shale oil is limited by the availability of surplus hydrogen for severe hydrotreating. Hydrotreating severity required to produce transportation fuels will exceed the design limits of existing units in many refineries. Those refineries which appear capable of processing raw shale oil can only handle small volumes at any one location and are geographically dispersed.

- The existing crude oil pipeline system will encounter difficulties in handling raw shale oil's high viscosity, pour point, and contaminant levels. In addition, major expansion of feeder lines will be required to allow movement of shale oil out of the oil shale region to tie-ins with existing major pipeline systems. Excess capacity in these major pipeline systems is projected to be about 300 thousand barrels per day. Shale oil production in excess of this level will require major new pipeline construction.

- The cost of processing raw shale oil as an alternate to petroleum crude oil is extremely variable and primarily dependent upon the percentage of shale oil run in the refinery, as well as the availability of excess hydrogen. If the shale oil represents relatively small proportions of the total throughput, many existing refiners could run it with the addition of only a whole shale oil hydrotreating unit. At current prices, a 10 thousand barrels per stream day shale oil hydrotreating facility could be constructed for $ 40 million. Operating costs would vary from $6.40 to $9.40 per barrel. The cost range is a function of hydrogen availability. If excess hydrogen is present in the refinery, its value is as fuel gas; however, if hydrogen must be manufactured, its cost is significantly higher. In the event that an existing refiner processed relatively large percentages of shale oil, substantially more equipment would have to be added. The most likely scheme would be to distill the shale oil and hydrotreat the individual fractions. Operating costs for such an operation would be $4.40 to $6.30 per barrel. Again, the range is a matter of hydrogen availability. The investment requirement to process 50 thousand barrels per stream day of shale oil in this manner is estimated at $ 120 million.

- A large fraction of any shale oil which is produced will be refined by the major oil companies who participate in the shale oil projects. These companies do not anticipate problems in processing the shale oil in their refineries.

- Shale oil produced for sale to independent refiners will initially be sold as boiler fuel because these refiners will require evidence of a stable and consistent source of supply before they will invest the capital to refine shale oil in their facilities. A federal shale oil storage program might be feasible to supplement the Strategic Petroleum Reserve. This would allow later processing to transportation fuels and eliminate the need to burn shale oil in boilers as an initial outlet for shale oil production.

- Shale oil upgrading onsite or in a regional facility would allow the integration of syncrude into the existing refining and pipeline systems at minimum cost and with minimal time delays.

- Based on refinery configurations, hydrogen supply, transportation systems, and crude availability, eleven refineries in Petroleum Administration for Defense Districts (PADDs) 2A and 2B have been identified as potential processors of shale oil. PADD 4 would require construction of major new refineries to allow processing of significant quantities of raw shale oil.

- Based on refining technology and projected product demands to the year 2000, shale oil will be best suited to the production of diesel fuel and jet fuel.

- Additional large-scale tests of raw shale oil in industrial or utility boilers are needed to demonstrate techniques of nitrogen oxide emissions control.

SUMMARY OF THE TASKS

TASK 1

Determine the optimum slate of products that can be refined from shale oil based on economics, good refining practices, and logistics for the Northern Tier, Mid-Continent, Gulf Coast, Rocky Mountain, and West Coast regions. Determine the optimum slate of products using current market prices that can be refined from 100 percent shale oil by the typical refinery configuration of each region.

Based on Pace's "Energy and Petrochemical Outlook to 2000," we have projected the demand for products which can be produced from shale oil between 1985 and 2000. This evaluation was conducted using a more conventional Petroleum Administration for Defense District (PADD) division in order to meet time constraints. An analysis was also made of shale oil refining technology (Section C), economics of refining (Section D), and refinery characteristics by PADD and transportation limitations (Section E). Based on these inputs, it was determined that in the short term, when the shale oil industry is operating with fluctuating shale oil production levels and qualities, the use of shale oil as a boiler fuel represents the most probable outlet for production. Once a longer-term, stable level of operation has been reached, shale oil will primarily be refined to meet substantial increases in demand for diesel and jet fuels.

A determination of "optimum" product slates given current product prices was not made because this would require the use of a refinery simulation model which can evaluate all of the processing trade-offs occurring in a typical refinery. While this can be done in the future, it would require substantially more time and manpower than was available for this study. It should be noted that at this time there is considerable doubt regarding the physical and chemical properties of shale oil which will be available for refining. These quality differences will have a strong effect on the optimum product slate produced by a given industry. Also, in our evaluation of the refining industry outlook for processing shale oil, we have assumed that refiners are planning to process shale oil along with conventional crude oils rather than utilize a 100 percent shale oil-dedicated facility.

TASK 2

What are the required economic parameters which would allow refiners to process shale oil?

In order for a refiner to process shale oil, it must be competitive with the alternate processing of petroleum crudes. The attractiveness of shale oil as a feed to a given refiner is heavily dependent on the configuration and current raw material and product slate of that refinery. A large refinery processing high sulfur crude oils would have in-place hydrotreating equipment which would allow running incremental barrels of shale oil with minimum expense. If the shale oil represented a very low percentage of total feed, it could probably be handled with the addition of only a whole shale oil hydrotreating unit and the necessary offsite facilities, such as tankage. Pace estimates the investment requirement (in 1979 dollars) to process 10 thousand barrels per day of raw shale oil at approximately $ 40 million.

When the shale oil proportion of total charge is large enough, hydrotreaters for the individual shale oil fractions will be required in order to protect catalyst in downstream existing units, such as catalytic reformers and fluid catalytic crackers. A likely configuration would be a shale oil distillation unit similar to a crude oil distillation unit and sidestream hydrotreaters for the naphtha, middle distillate, and gas oil fractions. Pace has estimated the investment requirement for a 50 thousand barrels per day shale oil distillation facility with sidestream hydrotreaters at $120 million.

What are the major impacts of processing increasing blends of shale oil on existing refining operations? Outline the specific economic and physical limitations of refining shale oil.

The properties of shale oil which lead to refining difficulties and the conditions required to refine shale oil in various processing units are discussed in detail in Section C. A summary of the major problems in refining shale oil is as follows:

- Trace metals (primarily arsenic) poison hydrotreating catalysts and must be removed from shale oil.

- High nitrogen content must be reduced to prevent poisoning of hydrocracking, catalytic reforming, and fluid catalytic cracking catalysts, and to meet product stability specifications. Denitrification requires severe hydroprocessing with resulting hydrogen consumption as high as two thousand standard cubic feet per barrel. Equipment limitations will prevent many refiners from being able to attain the required hydroprocessing severity with existing equipment.

- Olefins and diolefins in shale oil cause gum formation when exposed to air. The gums tend to deposit on heat exchange equipment in various processing units.

- Unless conversion processes such as hydrocracking and fluid catalytic cracking are used, the yield of gasoline from shale oil will be minimal.

The benefits resulting from shale oil refining are:

- Shale oil can be processed to produce high yields of diesel and jet fuel which will be in increasing demand between 1985 and 2000.

- Shale oil contains only a minimal bottoms fraction. Refiners whose capacity is limited by market limitation on bottoms product could achieve higher throughputs if they were otherwise able to process shale oil.

The economic implications of refining shale oil are:

- As the percentage of shale oil run in the refinery increases, investment requirements will also increase. With shale oil volumes representing very low percentages of the total throughput, the incremental operating cost for shale oil over crude would be $6.40 to $9.40. The cost of running high percentages of shale oil in a refinery will be $4.40 to $6.30.

What is the oil industry's perspective regarding utilization of 50 to 100 thousand barrels per day of shale oil by 1985 or sooner?

Refiners' perspectives towards shale oil refining are discussed in detail in Section H.

The following points need to be stressed in this regard:

- Barring a crash program by the federal government to develop shale oil, including suspension of many environmental siting, and permitting requirements, the chances that shale oil production will reach a level of 50 to 100 thousand barrels per day by 1985 or sooner are minimal.

- The refiners who will process the major portion of shale oil produced from currently envisioned projects will be the same companies who are developing oil shale. For these companies, the production of oil shale and the subsequent refining steps are integral operations. Our contacts with thes companies indicate that they are not anticipating unsolveable refining problems from shale oil. In some cases this results from onsite upgrading to produce a syncrude which can be handled by any refinery.

- Those oil shale projects faced with selling shale oil to outside refiners see a ready market to refiners without assured crude oil supplies. Once a continuous operating record is established for the oil shale projects, these refiners will invest the capital required to process shale oil because it represents a long-term, consistent source of supply.

- Small, independent refiners are likely to underestimate the processing requirements which shale oil will impose on their operations. Shale oil must be made available to these refiners on a small volume basis to allow them to assess its operational impacts on a laboratory, pilot plant, or small production run scale. These same refiners are likely to face capital limitations which will restrict their ability to modify their facilities to handle shale oil.

What market is best for shale oil utilization?

This issue is discussed in Section E. In summary, from both a market demand standpoint and a processing standpoint, shale oil will be of greatest value for the production of diesel and jet fuels in existing refineries. In the short term, shale oil can be used to replace conventional boiler fuels in utilities and industry, and liquid fuels in refineries.

Evaluate the reasonable options for utilizing small amounts of shale oil (less than 50 thousand barrels per day) which would likely be produced in the early stages of commercialization.

This primarily equates to a reliability of supply problem. Even at production volumes below 50 thousand barrels per day, shale oil would be in demand by refiners seeking an assured, long-term source of refinery feedstock. Large swings in production levels, including stop/start production, are likely during the initial stages of development of the oil shale industry. Under these conditions, the use of shale oil as boiler fuel represents the best outlet for initial production. Major uses of boiler fuel, such as utilities with oil-fired plants, can accommodate shale oil as a substitute fuel with minimal modifications. This approach is discussed in Section E.

An alternative approach to dealing with erratic shale oil production levels is the establishment of a stockpiling/storage program by the federal government as an addition or alternative to the Strategic Petroleum Reserve. This approach would have the advantage of reserving the initial shale oil production for higher priority end users such as transportation fuels rather than for boiler fuels. This program could continue even after the shale oil industry has established continuous and sustained production levels. Both storage in suitable geological formations and abandoned mines could be considered. Subsequent recovery of shale oil from the storage location would be problematical unless the raw shale oil had been processed to remove heavy ends and lower the pour point to substantially below storage temperature.

Determine the capital investments a refinery would face in order to process shale oil and associated costs of those investments as well as evaluating the incremental operating costs which such a refinery would incur as a result of refining shale oil.

We have estimated the investment for processing 10 thousand barrels per day of shale oil in an existing refinery where that volume represents a small portion of total crude charged. The onsite investment for the whole shale oil hydrotreater is estimated at $30 million, while offsite investments should total $10.0 million. The offsites investment includes tankage facilities for storage of raw shale oil. The cost to operate this facility would vary between $6.40 per barrel if adequate excess hydrogen were available in the plant to $9.40 per barrel charged if the hydrogen had to be manufactured.

Also studied was a facility to process 50 thousand barrels per day of shale oil where that volume would represent a significant portion of the refinery charge. Total onsite investment of $85 million includes the shale oil distillation facility and sidestream hydrotreaters for naphtha, distillate, and gas oil fractions. The offsites investment requirement would be $35 million, making the total investment $120 million. Total operating costs for the distillation and hydrotreating units would be $4.40 per barrel if the refinery could provide adequate hydrogen, or $6.30 per barrel if hydrogen generation facilities were required.

TASK 3

Identify petroleum products testing facilities in the public and private sectors and prepare a strategic plan for testing fuels and transportation products derived from shale oil relative to product specifications and performance.

This task is addressed in Section II of this report.

Is a product testing program or engine testing program required?

Without question the Department of Defense would require extensive testing of fuels to be used in military hardware. Of particular concern would be the performance of shale-derived fuels in military aircraft. Those areas of critical importance in jet fuels are summarized in Section C (Distillate Hydrotreating).

An integrated testing program would require not only full-scale combustor tests and ground tests of engines, but also flight-testing in aircraft to determine longer-term maintenance problems which might result from the use of shale oil.

The testing of shale oil-derived products in civilian applications would also be required, and would most likely be conducted by refiners in conjunction with the Coordinating Research Council.

Timing would be a major problem in any shale oil testing program. To conduct exhaustive tests on shale oil which is not typical of that which will be produced during commercial production will be of limited value. The same consideration applies to the methods of refining--unless the fuels to be tested are representative of those to be produced by commercial refining operations, the results will be of limited value. At the present time it is not possible to predict when shale oil production and processing will be well enough defined to start commercial scale end use testing programs.

Would the Department of Defense be able to perform the necessary test programs?

The Department of Defense has already conducted considerable research into the production, refining, and use of shale oil for military applications. This work has primarily been accomplished at the Air Force Aero Propulsion Laboratory at Wright-Patterson Air Force Base in Ohio, and at the Naval Air Propulsion Test Center in Trenton, New Jersey.

The Department of Defense will face problems in conducting engine tests in the near term because of the lack of shale oil which will be representative of long-term production. Although the Department of Defense can probably conduct the engine tests in-house, shale oil production and refining will have to be done on a contract basis.

TASK 4

Identify those refineries which are the most logical processors of shale oil in terms of geography and refinery configuration. Also, identify the market demand issues based on the best shale oil product mix. Determine an optimum refining configuration for a new refinery for processing shale oil considering current prices.

Determination of an optimum refining configuration for processing shale oil considering current product prices implies a knowledge of the current cost of shale oil to the refiner. This information is simply not available. Estimated costs of shale oil range between about $14 and $24 per barrel. This uncertainty reduces the value of a determination of an optimum processing configuration.

It is possible--given very tight constraints--to determine an optimum processing configuration. However, this requires specification of the following items at a minimum:

- Product slate requirements (volume and quality)
- Processing unit availability
- Raw material costs and qualities

In order to determine an optimum configuration from both an economic and processing standpoint, it would be necessary to utilize Pace's Refinery/Petrochemical Linear Programming (LP) Model to simulate refinery operations with shale oil. This can be done in the future, but neither the time nor manpower was available for this level of effort in this study.

Determine the capital investment requirements of modification to handle shale oil feedstock blends of 5 percent, 10 percent, 25 percent, 50 percent, and pure shale oil feed. Also determine operating cost increases resulting from shale oil processing.

The economics of shale oil processing are presented in Section D of this report. These questions are also addressed in the first, second, and last questions of Task 2.

Precise investment requirements at various levels of shale oil substitution for crude oil cannot be determined on a generalized basis. Each refinery in question would need to be analyzed for its current hydrotreating capabilities and feedstock qualities. We can, however, distinguish between an operation where the shale oil represented a small percentage of total feed and an operation in which the shale oil provided a significant portion of total refinery charge. The investment requirements for processing 10 thousand barrels per day of shale oil in low percentages are roughly $40 million. Facilities to process 50 thousand barrels per day, where that number represents a large portion of total feed, would require an investment of $120 million. When the shale oil is run in low percentages, the incremental operating cost over crude is simply the cost of running the shale oil hydrotreater, which would range from $6.40 to $9.40 per barrel. The alternate operation on large volumes of shale oil involves distillation and hydrotreating facilities. The distillation of shale oil would cost the same as distillation of crude; roughly $0.80 per barrel. The hydrotreating steps for the naphtha, distillate, and gas oil fractions total $3.60 to $5.50 per barrel of shale oil charged.

Determine the relative value of raw shale oil and upgraded shale oil in the five market areas mentioned in Task 1.

This question essentially asks for the incremental cost of shale oil hydrotreating to produce a syncrude suitable for use as a refinery feedstock. If a syncrude nitrogen content of 500 ppm is assumed (equating to 97.5 percent nitrogen removal from shale oil containing 2.0 weight percent nitrogen), no catalyst poisoning in a refiner's fluid catalytic cracking units would be anticipated. The cost of upgrading to this level is estimated to be \$6.40 to \$9.40 per barrel as discussed in Section D for whole shale oil hydrotreating.

The incremental cost to produce an upgraded shale oil or syncrude is of considerable importance. As discussed in Sections F and H of this report, many refiners lacking an assured crude supply would consider processing shale oil in their plants. However, many of these refiners operate small, widely dispersed plants lacking sufficient hydrogen supply, refining capacity, or ability to meet processing severity requirements. In addition, these plants might not be able to obtain raw shale oil because pipelines supplying the plants could not accommodate this material.

If the raw shale oil were upgraded on site or in a regional upgrading facility which might process shale oil from several projects, the syncrude could be processed by any refiner with essentially no modification of plant facilities. Thus, the cost of upgrading on site or in a regional facility would establish an upper limit on the incremental cost a large number of refiners would have to bear to refine shale oil.

The concept of a regional upgrading facility operating on a co-op or intermediate processor basis appears to have merit and should be further evaluated. The economics of scale of a centralized facility, along with the elimination of the stringent refining and transportation requirements of raw shale oil, would be major advantages.

What geographic market is best suited to process shale oil?

The availability of crude supplies, transportation facilities, refining capacity, and surplus hydrogen have all been analyzed in Section F to determine the answer to this question. Based on analysis of all factors, PADDs 2A and 2B appear to be the best suited for processing shale oil.

TASK 5

Identify specific refineries in the Northern Tier and Western Slope which would likely desire to refine shale oil, and the capital costs these refineries would incur in modifying (if necessary) for the refining of shale oil. Identify refineries in each of the market areas mentioned previously which are logical shale oil processors.

We have identified those refineries in PADDs 2A, 2B, 3, 4, and 5 which are logical processors of shale oil. This information is contained in Section F.

Several points should be emphasized. A multitude of refineries have the potential to process shale oil. For example: we evaluated 17 refineries in PADD 4 which had hydroprocessing facilities and a source of hydrogen. These refineries ranged in size from 5,300 barrels per day capacity to 52 thousand barrels per day. Because of the small size, each of these refineries would have very limited flexibility to accommodate raw shale oil. In addition, many of these independent refineries would not be in a position to make substantial capital investments to upgrade their facilities.

When these same refineries were analyzed to determine their potential hydrogen surplus, only one plant--Exxon's Billings, Montana refinery--was judged to have the potential to handle even a minimal amount of shale oil (9,500 barrels per day). The total potential for the PADD was 36,500 barrels per day apportioned among 16 plants. This clearly represents a tremendous distribution problem if shale oil production is commercialized at several hundred thousand barrels per day, and if a significant volume of shale oil is to be refined in PADD 4.

An upgraded shale oil could be processed in much larger volumes in PADD 4 as soon as it became available. The alternative will be for small refiners to wait until an assured long-term supply is available before making the investments required to process shale oil.

Given the present configuration of these refineries, determine the capital costs of modification and the costs of processing shale oil in the blends described above.

Because of time and manpower constraints we have not attempted to determine the modification and processing costs of the refineries identified above. This would require an in-depth analysis of current refinery crude slate and processing configurations, and could be done in the future if desired.

TASK 6

If the shortage of domestic refining capacity is to be improved, what is industry's perspective towards processing shale oil and heavy oil along with domestic crude oil?

Industry's outlook on processing shale oil is discussed in Section E as well as in Task 2, Item 3.

C

TECHNICAL ASPECTS OF REFINING

C

TECHNICAL ASPECTS OF REFINING

SHALE OIL CHARACTERISTICS

Comparison of Shale Oil And Conventional Crude Petroleum

Raw shale oil is a valuable source of hydrocarbons which can be used to supply any end use normally associated with conventional petroleum products. As with conventional crude oils, shale oil must be refined to remove undesirable contaminants and to meet product specifications. Conventional petroleum refining processes can in principle be used to upgrade shale oil; however, processing equipment, operating conditions, and catalysts may require modification to handle shale oil's peculiar raw material characteristics.

The properties of raw shale oil differ depending upon the type of retorting process used. The most significant differences are apparent between shale oils produced by surface retorting, and shale oils produced by in situ retorting.

Table C-1 lists the significant bulk properties of six raw shale oils produced by different retorting processes. The Tosco, Union, and Paraho processes employ surface retorting, and the Garret/OXY processes utilize in situ retorting. For comparison, the properties of four conventional petroleum crudes which will compete with shale oil for refining capacity are also shown. It can be seen from Table C-1 that shale oil generally has a low API gravity, a moderate sulfur content, and very high nitrogen and pour points compared with conventional crude oils.

Refining Characteristics

Each of these bulk parameters is of importance to a refiner. The API gravity gives a rough indication of whether the shale oil or crude oil contains large amounts of low boiling "light" components or high boiling "heavy" components. Shale oil's low API gravity indicates that the raw material is lacking in low boiling components which are typical of gasoline fractions. This is better illustrated in Figure C-1 which compares the volumes of naphtha, distillate, gas oil, and residuum recoverable from three shale oils and two petroleum crudes. This figure shows that raw shale oil contains small volumes of the gasoline, diesel, kerosine, and jet fuel fractions (naphtha and distillate) and large volumes of the fuel oil fraction (gas oil). This clearly illustrates the need for conversion processes such as coking, hydrocracking, and fluid catalytic cracking if a significant portion of the shale oil is to be used for transportation fuels.

As shown in Table C-2, shale oil from surface retorts will be lower in sulfur content than domestic production or imports through 1990. The sulfur content of shale oil has a direct influence on hydrogen consumption in a refinery, but from a processing standpoint it is of secondary importance. This occurs because shale oil is significantly easier to desulfurize than it is to denitrogenate. Therefore, denitrogenation controls refining severity and adequate desulfurization is readily accomplished during denitrogenation.

The nitrogen contents of raw shale oils are extremely high in comparison with petroleum crudes. The average nitrogen content of domestic crude oils is about 0.15 weight percent, which is an order of magnitude less than for shale oil. The nitrogen content of shale oil is of primary concern because many nitrogen compounds act as a catalyst poison in refinery processes which are used to upgrade shale oil. Secondarily, nitrogen compounds adversely affect the thermal stability of transportation fuels with resultant gum formation, and they also contribute to emissions of nitrogen oxide when the fuels are burned.

The high pour points which are characteristic of most raw shale oils present problems in transporting the shale oil to remote upgrading facilities. Special handling procedures such as the use of heated pipelines, pour point depressants, and onsite upgrading have all been suggested as means of alleviating this handling problem.

In addition to the bulk shale oil characteristics discussed above which are of major concern to the refiner, shale oil also contains appreciable concentrations of oxygen, arsenic, iron, and in some cases finely dispersed particulate matter. Typical concentrations of these materials in shale oil are as follows:

Oxygen (Weight Percent)	0.8-1.4
Arsenic (ppm)	18-33
Iron (ppm)	33-108
Bottom Sediment and Water (Volume Percent)	0.2-0.7

The oxygen compounds are removed during hydroprocessing and add to the hydrogen consumption during refining. Arsenic compounds accumulate on hydroprocessing catalysts and reduce their activity. It has also been shown that the arsenic, in the presence of the relatively high concentrations of iron in the shale oil, contributes to the formation of solid deposits in the hydroprocessing reactor. Equipment plugging due to such deposit formation has occurred in many of the laboratory-scale shale oil refining programs, as well as the 88 thousand barrel run recently completed by Sohio.

Depending upon the retorting method used, raw shale oil may contain significant amounts of mineral material as carry-over from the retorting process. These finely divided solids, along with entrained or emulsified water, show up in analyses for bottom sediment and water (BS&W). A solids removal step will be required prior to processing to prevent plugging of downstream refining processes.

SHALE OIL PROCESSING

Pretreatment

In order to process shale oil in a conventional refinery, provisions must be made to handle those requirements which are not typically dealt with in petroleum processing. We have termed these requirements as "pretreatment" when some type of processing is required to convert the shale oil into a suitable refinery feedstock. In some instances, pretreatment may include what the oil shale industry commonly refers to as upgrading. In the industry context, upgrading generally refers to onsite processing to produce a syncrude for pipelining to a remote refinery. Thus, upgrading represents extensive pretreatment which in actuality is the first stage of a two-stage refining scheme.

The question of whether to provide pretreatment/upgrading on site or at a remote location must be considered on a case-by-case basis. This is due not only to differences in raw shale oil properties, depending on the retorting process, but it is also dependent upon how and where the shale oil will be refined and/or used. For example: the initial module of Union Oil's Long Ridge Project represents raw shale oil handling at its simplest. The first module will produce about 9 thousand barrels per day of raw shale oil. Union plans to sell the shale oil from this first module for direct use as a boiler fuel in electric generating plants. The product will be shipped from the plant by rail. This end use and method of transportation require essentially no pretreatment (with the possible exception of solids removal).

The next stage of complexity in shale oil pretreatment is encountered when raw shale oil is to be transported by pipeline to a remote refinery for processing. The use of pipelines for transportation imposes two requirements:

- The facility must be designed to handle the high pour points of crude shale oil or the pour point must be reduced.
- The shale oil should be relatively free of solids.

It is readily apparent that raw shale oils having a pour point of 60°F to 85°F cannot be transported through pipelines where the average ground temperature may be 40°F to 50°F without special facilities or pour point modification. Several options exist to overcome the pour point problem. These include:

- Construction of shale oil-dedicated, high-volume heated pipelines
- Use of proprietary pour point depressants to lower the pour point of the raw shale oil

- Use of proprietary shale oil preparation techniques which essentially slurry wax crystals of high pour point shale oil fractions in a low pour point shale oil fraction
- Chemical conversion of the raw shale oil by processes such as coking to remove high pour point materials.

Solids removal can be accomplished by several techniques. Gravity settling at elevated temperatures will remove substantial amounts of both water and oil shale fines. The particulate matter in whole shale oil could also be removed with small-pore filters which are currently in use to remove particulates from crude oil residuum prior to hydrodesulfurization. This can also be accomplished by continuous centrifuges or electrostatic heater treaters. Most refineries are equipped to remove any additional fines which might remain entrained in the shale oil. This is normally accomplished in an electrostatic desalter which removes both particulate matter and water.

Refining

The technology of conventional petroleum refining has advanced to the point where the substitution of an alternate feedstock such as shale oil does not require state-of-the-art advances in technology.

Many options are possible for processing shale oil in a refinery. Very large refineries, which are typical of the Gulf Coast or Upper Mid-Continent (150 thousand barrels per day or greater capacity), have a wide variety of processing units and the resulting flexibility to process shale oil by several unit configurations. Unfortunately, most of the refineries which are typical of the Rocky Mountain States are relatively simple and will at best have one way in which to process shale oil. In the following discussion, descriptions of the major refining processes which can be used in shale oil refining are presented along with representative operating conditions when processing shale oil. Any given refinery will have several--if not all--of the processing units. This discussion will provide a basis to estimate the ability of a refinery to process shale oil.

Hydrotreaters

Hydrotreaters will play a major role in shale oil refining because they provide the means to remove the heteroatoms (sulfur, nitrogen, and oxygen) as well as arsenic. This is done in a hydrotreating unit such as that shown in the general schematic diagram of Figure C-2. The general flow schemes of hydrotreaters to treat naphtha, kerosene, or gas oils are similar. The feedstock is mixed with hydrogen, either before or after preheating, and passed through a guard reactor (not shown) which removes arsenic and iron, and prevents poisoning of the downstream hydrotreating catalyst. Most hydrotreating reactions are carried out below 800°F to minimize cracking, and the feed is usually heated to between 500°F and 800°F.

The reactor normally contains a fixed bed of catalyst pellets impregnated with nickel, carbon monoxide, molybdenum, or tungsten or combinations of these elements. Units which process heavy oil or resid often utilize an ebullated rather than a fixed bed of catalyst. In the presence of the hydrogen and catalyst, nitrogen, sulfur, and oxygen are converted to ammonia, hydrogen sulfide, and water, respectively. In addition, aromatics and olefins are saturated. Some conversion of heavy materials to lighter components also occurs. The degree to which these reactions proceed depends upon the conditions employed. The hydrotreater also provides facilities for recycling unused hydrogen back to the reactor, removal of the hydrogen sulfide, ammonia, and water by-products, and fractionation to produce the desired boiling range products.

The hydrogen which is consumed in the hydrotreater must either be supplied from other units in the refinery which produce by-product hydrogen, or a stand-alone hydrogen generation unit must be built. Many refineries operate with a balance between by-product hydrogen production and the consumption of hydrogen in hydrotreaters. If a change in feedstock is made, such as adding shale oil to the crude slate, the plant hydrogen balance may be significantly altered because of the greater hydrogen consumption required for shale oil hydrotreating.

Naphtha Hydrotreating

If high octane gasoline is to be produced from shale oil naphtha, the nitrogen content of the naphtha must be reduced to about 0.5 ppm or less in a naphtha hydrotreater. Higher nitrogen concentrations will lead to deactivation of the catalyst employed in the downstream catalytic reforming unit. Literature references to the conditions required for shale naphtha hydrotreating are generally limited to cases in which a blend of naphtha from coking and straight run naphtha is processed. Operating conditions reported sufficient to produce 1.5 ppm product nitrogen are 1,500 psig, 700°F, and 1.0 LHSV (liquid hourly space velocity). (The hydrogen consumption reported for these conditions was 627 standard cubic feet per barrel, which reflects a high hydrogen requirement to saturate the large concentrations of olefins produced during coking. Actual hydrogen consumption for a straight run naphtha would be considerably lower and is of little economic consequence if the naphtha is subsequently processed in a catalytic reformer. Under these circumstances, hydrogen consumed during denitrogenation is subsequently recovered from the reformer.) In actuality, the small volume of straight run naphtha available from raw shale oil fractionation would probably be blended with other naphtha streams in the refinery.

The hydrotreated naphtha could be blended to naphthenic type JP-4 military jet fuel, or undergo further processing to produce gasoline stocks.

Distillate Hydrotreating

The shale oil fractions boiling between about 380°F to 530°F are suitable components for jet fuel, diesel fuel, and fuel oil. The use of shale oil to produce jet fuels and marine diesel fuel has been of considerable interest, due in part because the Department of Defense would like to have a secure supply of military fuel for reasons of national security.

A complete discussion of all the characteristics and specifications required for an acceptable jet fuel is beyond the scope of this report. However, the major problem areas facing oil shale-derived jet fuels are as follows:

- Low hydrogen contents of jet fuels have been correlated with increased soot and smoke emissions. In addition to being an environmental problem, smoke emissions increase the vulnerability of military aircraft. The particulates in smoke are also responsible for the formation of a luminous flame which greatly increases the heat transfer by radiation to engine components.

- High fuel bound nitrogen contents translate to increased nitrogen oxide emissions. In addition, a relationship between the tendency for increased gum formation and poor storage/thermal stability with increased nitrogen content has been observed for shale oil-derived jet fuels.

- Olefinic content is important because the olefins are precursors of gum, which degrade thermal and storage stability.

- Aromatics, in addition to having a low hydrogen content and resulting smoke formation problems, cause elastomeric O-rings in fuel systems to swell. If aromatic concentrations are too high, swelling is excessive and the O-ring can expand out of its cavity. If aromatics are too low, swelling is not sufficient to effect a seal, and leakage occurs.

Under contract with the Air Force, Exxon has evaluated the hydrotreating conditions necessary to produce suitable jet fuels from shale oil distillate. Their laboratory work showed that acceptable jet fuels can be produced with nickel-molybdenum catalysts under moderately severe hydrotreating conditions of 700°F, 4,000 standard cubic feet per barrel treat gas rates, 1,200 psig, and one LHSV. Hydrogen consumption was approximately 1,050 standard cubic feet per barrel. Under these conditions, the sulfur content of Paraho-derived shale oil was reduced from 0.74 weight percent to less than 10 ppm. Nitrogen content was reduced from 1.16 weight percent to 5 ppm at the start of operations, and 40 to 100 ppm after a thirty-day run. (This decrease in nitrogen removal was caused by slow deactivation of the nickel-molybdenum catalyst for denitrogenation.)

From a refining standpoint, shale oil is a very good alternate feedstock for jet fuel type transportation fuels. One of its major drawbacks is that the volume of material boiling in the jet fuel range is limited.

If shale oil distillate is to be blended into fuel oil, the product specifications are significantly reduced and the distillate shale oil hydrotreater could operate under much less severe conditions. Thus, the production of jet fuels from shale oil distillates represents a "worst case" approach to refining of this particular stream.

Gas Oil Hydrotreating

The atmospheric and vacuum gas oils are blended in fuel oils or--depending on the refinery processing units available--are converted to lighter fuels in a hydrocracking or fluid catalytic cracking unit (FCCU). The amount of shale gas oil which could be blended into fuel oil would depend both on the size of the existing market for fuel oil and on the pour point of the fuel oil blend. Fuel oil based entirely on shale oil components would face potentially high nitrogen oxide emissions if substantial denitrogenation was not accomplished. The probable worst case requirement for gas oil denitrogenation is based on providing a suitable feed to a FCCU. Since basic nitrogen compounds act to temporarily deactivate cracking catalysts, the maximum nitrogen content for subsequent catalytic cracking would be about 1,500 ppm. The operating conditions required to denitrogenate atmospheric and vacuum gas oils would be similar to those required for whole shale oil hydrotreating. Reactor conditions of 745 °F, 1,850 psia hydrogen partial pressure (2,200 psig total pressure), 0.6 LHSV, and a gas treat rate of 5,000 standard cubic feet per barrel have been shown by Chevron to produce a hydrotreated gas oil nitrogen concentration of approximately 1,000 ppm. These tests were made on whole shale oil; a hydrogen consumption for the gas oil fraction alone was not available. Under these severe conditions, some hydrocracking of the shale oil fraction occurs.

Whole Shale Oil Hydrotreating

The technology which has been developed in residuum hydrodesulfurization makes it possible to hydrotreat whole shale oil without a prior fractionation step. This approach has been taken both on the laboratory scale, and in a recent 88 thousand barrel refining test done by Sohio. It is technically possible to increase the severity of this initial hydrotreating process to the point where the product oil contains one ppm of nitrogen. However, as discussed previously, a more reasonable approach seems to be to hydrotreat to about 1,500 ppm nitrogen product level to accommodate downstream processing catalyst deactivation requirements.

In laboratory tests, Chevron has hydrotreated whole Paraho shale oil at 745 °F, 2,200 psig total pressure (1,850 psia hydrogen partial pressure), 0.6 LHSV, 5,000 standard cubic feet per barrel recycle gas rate, with a nickel-tungsten catalyst to produce a 500 ppm nitrogen product. The gross hydrogen consumption was about 2,000 standard cubic feet per barrel. Union Oil has also reported on the product yields from hydrotreating whole shale oil produced in a Union retort. Although the reactor conditions were not specified, the hydrogen consumption was given as 1,500 standard cubic feet per barrel, and an indicated catalyst life of 1.5 years is expected.

Catalytic Reforming

If motor gasoline is to be produced from shale oil naphtha, a catalytic reforming unit would be used to increase the octane rating. The unleaded octane rating of hydrotreated shale oil naphthas ranges between 30 and 50. The catalytic reforming unit typically utilizes a platinum-impregnated catalyst to convert low octane components into high octane components with a net production of hydrogen. Figure C-3 is a schematic diagram of UOP's Platforming process, which is illustrative of catalytic reforming technology.

The pretreated feed and recycle hydrogen are heated to 925 °F to 975 °F before entering the first reactor. In the first reactor, the major reaction is the dehydrogenation of naphthenes to aromatics and--since this is strongly endothermic--a large drop in temperature occurs. To maintain the reaction rate, the gases are reheated before being passed over the catalyst in the second reactor. As the charge proceeds through the reactors, the reaction rates decrease, the reactors become larger, and the reheat needed lessens. Three reactors are usually sufficient to provide the desired degree of reaction, and heaters are needed before each reactor to bring the mixture up to reaction temperature. In practice, either separate heaters can be used or one heater can contain several separate coils. The reaction mixture from the last reactor is cooled and the liquid products condensed. The hydrogen-rich gases are separated from the liquid phase in a drum separator and the liquid from the separator is sent to a fractionator to be debutanized.

The hydrogen-rich gas stream is split into a hydrogen recycle stream and a net hydrogen by-product which is used in hydrotreating or hydrocracking operations, or as fuel.

From a refinery standpoint, operation of a catalytic reforming unit on hydrotreated shale oil naphthas should not require specialized equipment or operating procedures because virtually all of shale oil's troublesome components have been removed during hydrotreating. Laboratory tests have been conducted on catalytic reforming of shale oil naphtha which show that at 908 °F, 2.95 LHSV and 500 psig operating conditions, a 90.0 octane gasoline (RON, clear; 82.4 MON, clear) can be produced with a C_4+ volume yield of 83.8 percent. The net hydrogen production was 931 standard cubic feet per barrel.

Fluid Catalytic Cracking

The fluid catalytic cracking (FCC) process is widely used to convert heavy oils into more valuable gasoline and light products. Several types of FCC Units are in use, and Figure C-4 shows simplified flow diagrams of three process configurations.

The process employs a catalyst in the form of very fine particles which behave as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between the reaction zone and the regeneration zone, and acts as a vehicle to transfer heat from the regenerator to the oil feed and reactor. Average reactor temperatures are in the range of 870°F to 950°F, with oil feed preheat temperatures from 600°F to 850°F, and regenerator temperatures from 1,100°F to 1,300°F. Newer units are designed to take advantage of high activity zeolite catalysts which allow nearly all of the cracking reactions to take place in the riser which transports the catalyst/oil mixture to the reactor.

Control over the product slate is obtained by varying reactor temperature, the catalyst/oil ratio, and catalyst activity. This unit is very important in providing a refiner with the flexibility to produce a wide variety of products depending on seasonal and market conditions.

Hydrotreated shale gas oil is a desirable feedstock for fluid catalytic cracking because naphthenic materials (such as shale oil) are much more readily cracked than aromatic materials. The amount of carbon or coke which is deposited on the cracking catalyst also varies significantly with different types of feedstocks. Hydrotreated shale oil produces appreciably lower coke yields than hydrotreated Arabian gas oils at constant conversion and at similar feed nitrogen levels.

Chevron's experience in the catalytic cracking of hydrotreated shale oil and hydrotreated Arabian gas oil was as follows:

- At 930°F reactor temperature, hydrotreated Paraho shale oil with 1,300 ppm nitrogen was cracked to about the same conversion as the Arabian gas oil with 320 ppm nitrogen when the two stocks were cracked at constant severity.
- Coke yields for the shale oil are appreciably lower than those for the Arabian gas oil with 860 ppm nitrogen at reactor temperatures of 930°F and 975°F. The coke yields were the same at 975°F as when compared with a lower nitrogen Arabian gas oil (320 ppm nitrogen).
- Gasoline yields (C_5s/430°F) for 1,300 ppm nitrogen shale oil are intermediate to those obtained for the 320 and 860 ppm nitrogen Arabian gas oils at 930°F. At 975°F, the shale oil gasoline yields were equal to those of the 320 ppm nitrogen Arabian gas oil.
- The gasolines and cycle oils have properties which are similar to those obtained from petroleum gas oils.

In conclusion, the use of the fluid catalytic cracking process to produce a variety of light fuels from heavy shale oil fractions represents an attractive refining process to utilize shale oil.

Hydrocracking

The catalytic hydrocracking process performs a refining function which is similar to that of the fluid catalytic cracking process--it converts low value, heavy fractions to gasoline, jet fuels, and light fuel oil. By changing catalysts, processing conditions, and equipment configurations, the hydrocracking process can utilize distillate or residual feedstocks and can also provide a great deal of product slate flexibility to accommodate changing market conditions.

Shale oil might be processed in either a single stage or two-stage system. In a single stage system, the process flow is the same as for the second stage of a two-stage plant. Because hydrocracking catalyst is susceptible to poisoning by metallic salts, organic nitrogen, oxygen and sulfur compounds in the feedstock, the feed must be hydrotreated to remove these contaminants before hydrocracking. In a two-stage system, the first stage essentially acts to remove additional nitrogen from the feedstock.

A schematic diagram of a two-stage hydrocracker is shown in Figure C-5. The fresh feed is mixed with makeup hydrogen and recycle gas (high in hydrogen content) and passed through a heater to the first reactor. The reactor effluent goes through heat exchangers to a high pressure separator where the hydrogen-rich gases are separated and recycled to the first stage for mixing both makeup hydrogen and fresh feed. The liquid product from the separator is sent to a distillation column where the gasoline and lighter fractions are taken overhead and the bottoms used as feed to the second stage reactor. If jet fuel or diesel fuel is one of the products desired, the distillation column separation is made with the jet fuel or diesel fuel going overhead. The bottoms from the distillation column are mixed with recycle hydrogen and sent through a furnace to the second stage reactor. In the second stage reactor the temperature is maintained to bring the total conversion of the unconverted oil from the first stage and second stage recycle to 50 to 70 volume percent per pass. The second stage product is combined with the first stage product prior to fractionation.

Chevron has evaluated the single stage pilot plant hydrocracking of both a 650°F+ shale gas oil stream and a 625/850°F shale oil stream. The nitrogen content of both feeds was about 530 ppm. Operating conditions for the 625/850°F feedstock runs were 790°F reactor temperature, 1.0 LHSV, 2,150 psia hydrogen partial pressure (2,350 psig total pressure), 8,000 standard cubic feet per barrel recycle gas rate, and a recycle cut point of 550°F. The recycle oil stream was cracked to extinction. A 53 percent, 535°F conversion per pass was obtained with a chemical hydrogen consumption of about 1,250 standard cubic feet per barrel. The yields of C_5/180°F, 180/300°F, and 300/535°F products were approximately 14, 27, and 68 volume percent, respectively. This illustrates the potentially high yields of jet fuel components (300/535°F) which can be produced by shale oil hydrocracking.

Coking

Coking has been widely considered as a means for both partial upgrading of whole shale oil to produce a pipelineable material, and as a refining process to convert high boiling shale oil fractions to lighter materials. The delayed coking process was developed to minimize refinery yields of residual fuel oil by severe thermal cracking of high boiling stocks.

A schematic diagram of a delayed coking unit is shown in Figure C-6. Hot fresh feed is charged to the fractionator two to four trays above the bottom vapor zone. This quenches the vapor from the coke drums and preheats the fresh feed. Unvaporized fresh feed and condensed recycle are pumped from the bottom of the fractionator through the coker heater where they are partially vaporized, and then moved into one of two coke drums. The unvaporized portion of the heater effluent settles out in the coke drum where the combined effect of retention time and temperature causes the formation of coke. Vapors from the top of the coke drum return to the base of the fractionator. These vapors consist of steam and the products of the thermal cracking reaction--gas, naphtha, and gas oils.

When the coke drum in service is filled to a safe margin from the top, the heater effluent is switched to the empty coke drum and the full drum is isolated, steamed to remove hydrocarbon vapors, cooled by filling with water, opened, drained, and the coke removed.

The amount of coke formed during shale oil coking is dependent on the end boiling point of the coker distillate. As the coker distillate end point increases, less of the feedstock is converted to coke. Chevron found that when coking whole Paraho shale oil the amount of feed converted to coke was linear with the coker distillate end point. At 850°F end point, the coke yield was 7 weight percent. An end point of 650°F produced a coke yield of 22 percent. Delayed coking runs by Sohio on a 700°F+ Paraho shale oil fraction produced a coke yield in relatively good agreement with the Chevron results.

Delayed coking concentrates the nitrogen, arsenic, iron, and ash in the coke. The changes in concentration of these components between whole shale oil and coke are indicated as follows:

	Shale Oil Feed	Coke
Nitrogen (Weight Percent)	2.15	4.08
Arsenic (ppm)	27	190
Iron (ppm)	68	100
Ash (Weight Percent)	0.04	0.38

As would be expected, the coker distillate represents an improved feedstock for further refining because the coking operation has removed very heavy components and a significant portion of the contaminants. This improvement in quality is apparent from Table C-3 for coking of whole Paraho shale oil.

The major disadvantage of delayed coking in a refining system is that the yield of liquid products from a given volume of feed material is significantly reduced. Also, the high nitrogen coke is likely to have a low by-product value.

SUMMARY

The operating conditions described in this report as being sufficient to produce an end product of given specifications can serve as a rough guide to determine an existing refinery's shale oil processing capability. It should be evident from the preceding discussion that the refining industry has at its command a multitude of processes for upgrading and refining shale oil. Virtually any product which can be produced from conventional petroleum feedstocks can also be produced from shale oil. The availability of refining technology will not limit the integration of shale oil into the refining system.

The "optimum" method of refining shale oil is not discernable at this point. Considerable laboratory work has been done on the conditions required to produce various specification products using a variety of processes. A modern refinery is very complex with extensive mixing of intermediate streams and numerous processing units which are required to provide flexibility in meeting changing market demands. Given the diverse nature of the current data base, considerable effort would be required to develop a consistent set of information which incorporates differences in raw shale oil properties, processing methods, and product specifications. Only when such a unified body of information is available can an attempt be made to identify an "optimum" shale oil refining flowsheet. The economic implications of each refining process will also have to be well-defined before an optimum method can be identified.

FIGURE C-1

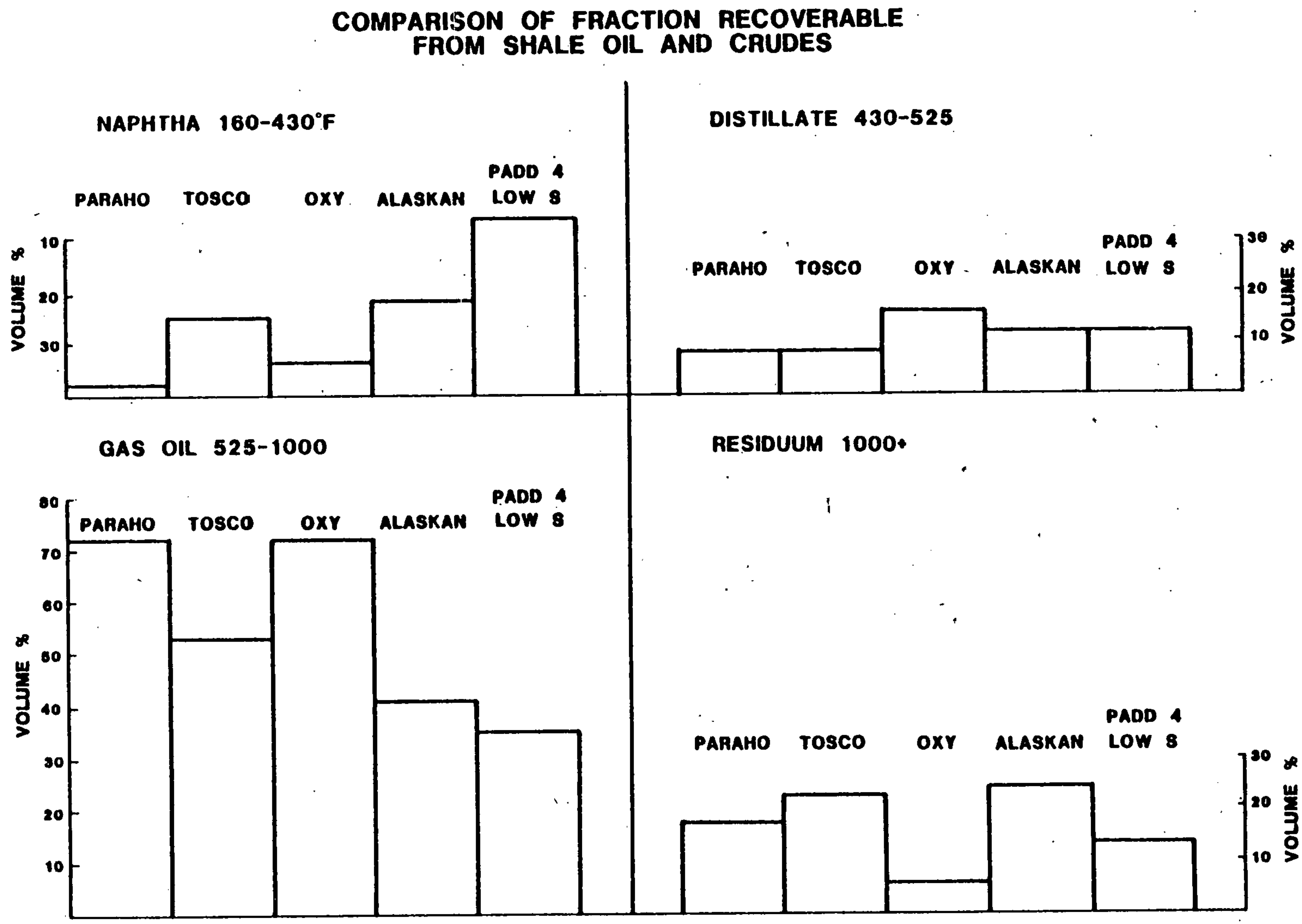

COMPARISON OF FRACTION RECOVERABLE FROM SHALE OIL AND CRUDES
NAPHTHA 160-430°F
PARAHO
TOSCO
OXY
ALASKAN
PADD 4 LOW S
VOLUME %
10
20
30
DISTILLATE 430-525
30
20
10
GAS OIL 525-1000
80
70
60
50
40
RESIDUUM 1000+

FIGURE C-2

GENERALIZED HYDROTREATER SCHEMATIC DIAGRAM

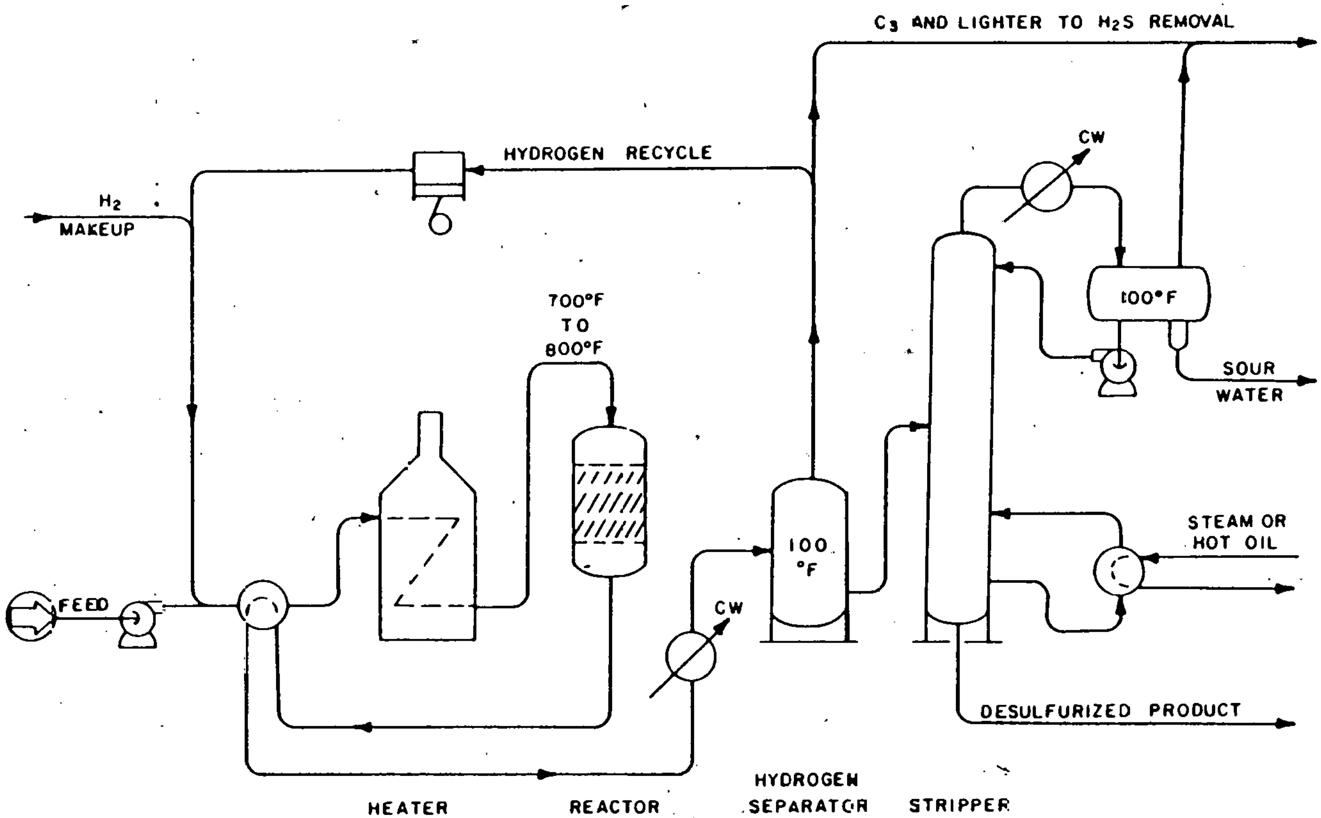


FIGURE C-3

GENERALIZED CATALYTIC REFORMING SCHEMATIC DIAGRAM

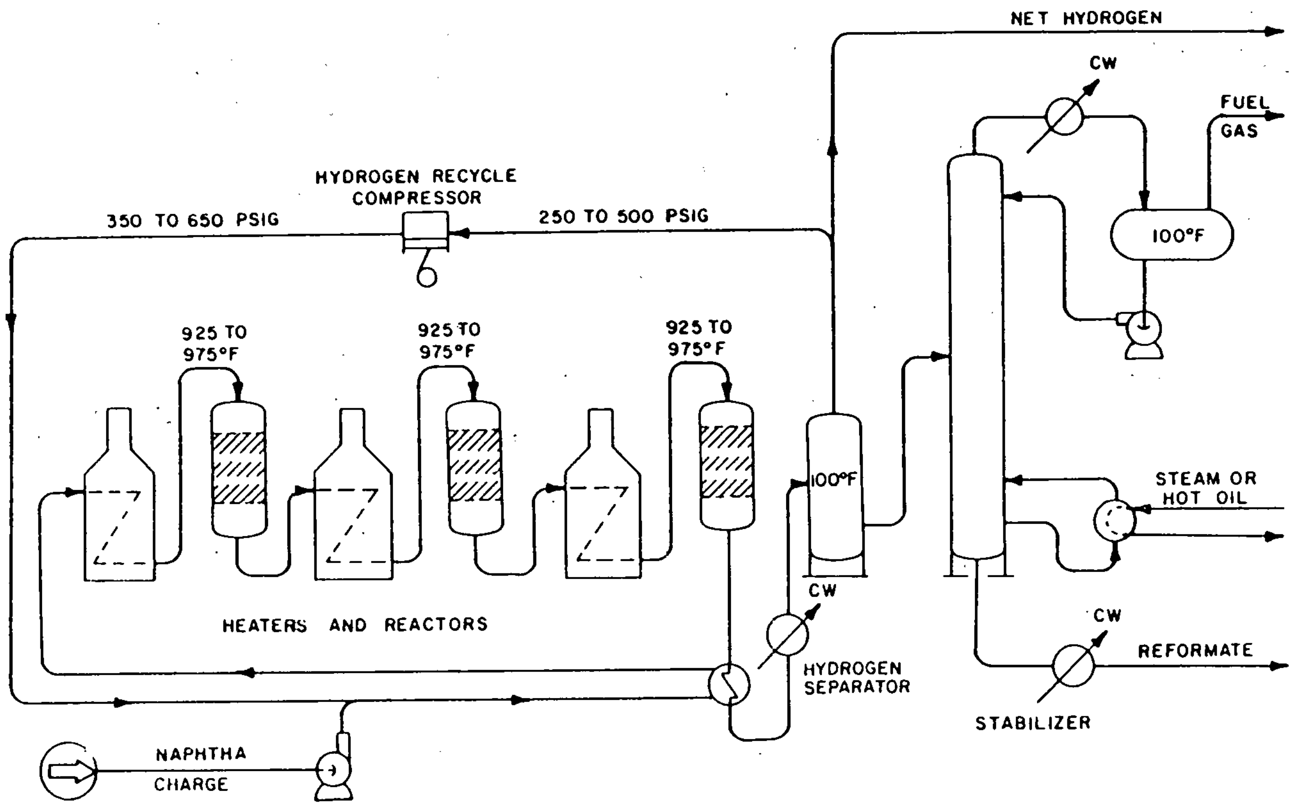


FIGURE C-4

FLUID CATALYTIC CRACKING UNIT CONFIGURATION

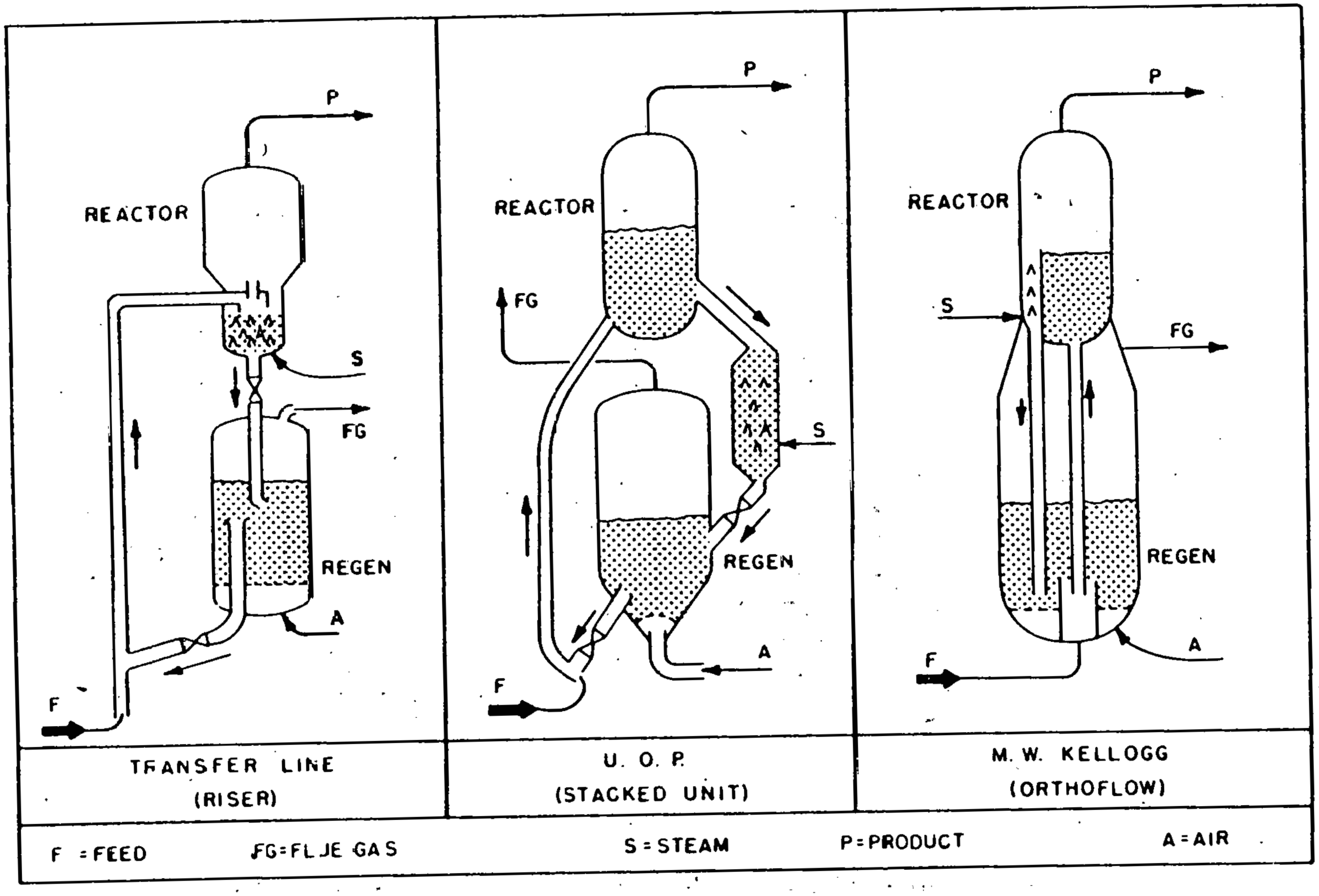


FIGURE C-5

GENERALIZED TWO-STAGE HYDROCRACKING SCHEMATIC DIAGRAM

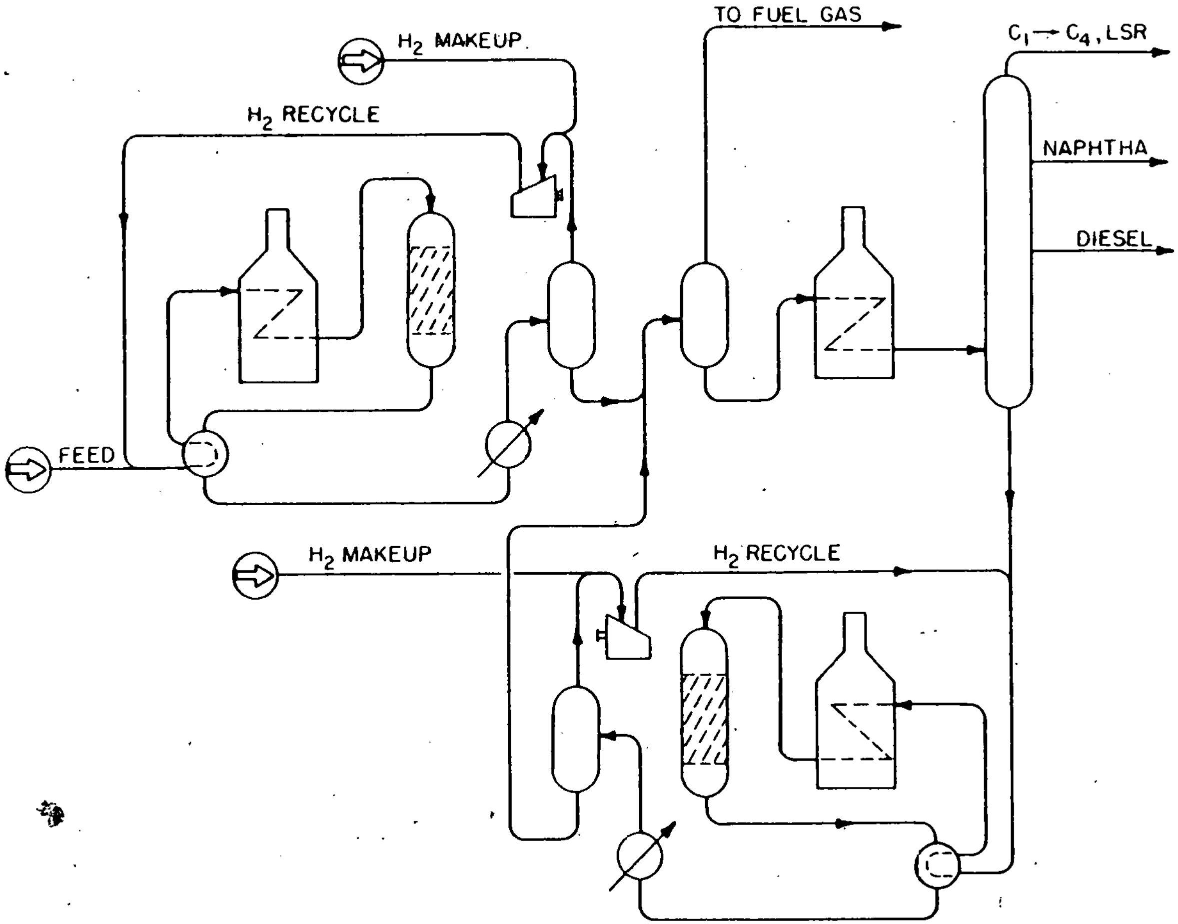


FIGURE C-6

GENERALIZED DELAYED COKING SCHEMATIC DIAGRAM

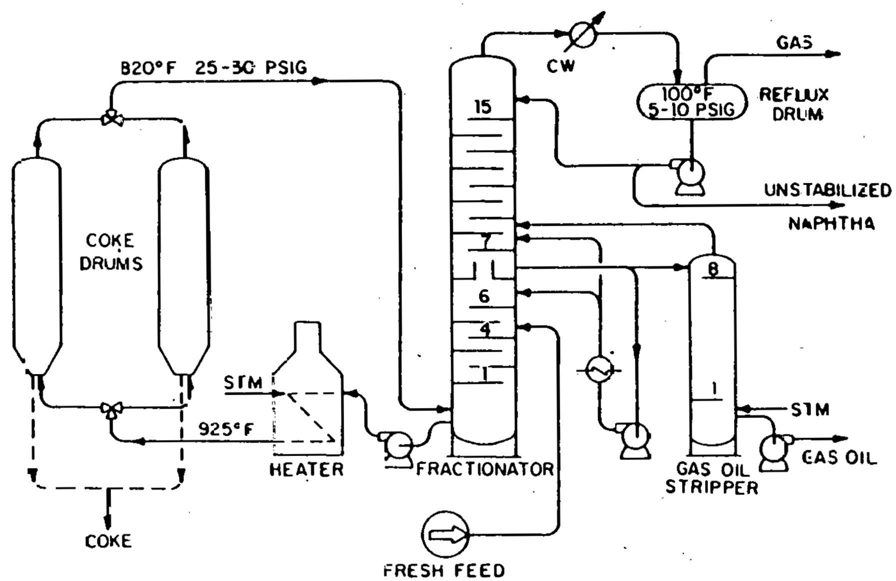


TABLE C-1

COMPARISON OF SHALE OIL AND CONVENTIONAL PETROLEUM PROPERTIES

	API Gravity	Sulfur (Wt. %)	Nitrogen (Wt. %)	Pour Point °F
Raw Shale Oils				
Tosco	21.0	0.67	1.85	70
Paraho Direct	19.3	0.71	2.00	85
Paraho Indirect	19.7	0.63	2.16	85
Garrett	25.0	0.64	1.30	50
Oxy	23.7-24.3	0.9-1.20	1.10-1.33	15-60
Union	22.2	0.80	1.80	60
Petroleum Crudes				
Alaskan North Slope	27.5	0.96	0.04*	30
PADD 4 Low Sulfur	39.0	0.18	0.03*	7
PADD 4 High Sulfur	26.2	2.25	0.01*	0
PADD 4 Asphaltic	23.0	2.70	0.01*	0

*Nitrogen contents for petroleum crudes based on 525°F to 1,000°F cuts.

TABLE C-2

PROJECTED SULFUR CONTENT OF DOMESTIC AND IMPORTED CRUDE OILS (Weight Percent Sulfur)

	1980	1985	1990
Domestic Production	0.79	0.84	0.82
Imports	0.83	0.99	0.94
Composite	0.80	0.90	0.89
Shale Oil			
Surface Retorts	0.6-0.7		
Oxy In Situ	0.9-1.2		

TABLE C-3

PROPERTY IMPROVEMENT RESULTING FROM DELAYED COKING OF WHOLE SHALE OIL

Type	Whole Shale Oil	Shale Oil Coker Distillate
Inspections		
Gravity (°API)	20.50	32.70
Sulfur (Wt. %)	0.63	0.61
Total Nitrogen (Wt. %)	2.15	1.75
Oxygen (Wt. %)	1.19	0.94
Arsenic (ppm)	26.50	6.30
Pour Point (ASTM, °F)	85	25
Iron (ppm)	68.00	0.40

D

SHALE OIL PROCESSING ECONOMICS

D

SHALE OIL PROCESSING ECONOMICS

Investment requirements and operating costs associated with refining whole shale oil cannot be precisely determined without specific details of the shale oil properties, processing capabilities of the existing refinery, and definition of the base charge and product slates.

Shale oil can be processed in conventional petroleum refining facilities if the high nitrogen content is reduced. Presence of nitrogen is of primary concern in the shale naphtha and gas oil streams due to its deactivation of catalyst in catalytic reformers and fluid catalytic crackers. Once the nitrogen content problem is resolved, investment requirements and operating costs for downstream units such as hydrocrackers, catalytic reformers, and fluid catalytic crackers are equivalent to those for crude oil streams.

Two basic options exist for handling shale oil in a refinery. Whole shale oil hydrotreating and subsequent blending into the crude oil charge is the simplest approach and should be acceptable when the volume of shale oil represents a small portion of the total feed. Distillation of the whole shale oil followed by separate hydrotreating of the naphtha, distillate, and gas oil sidestreams is the more complex and investment-intensive approach. This configuration allows hydroprocessing the components of shale oil to the extent required to protect downstream catalyst when the shale oil fraction is blended into the crude oil fraction. Thus, large volumes of raw shale oil could be handled.

Whole shale oil hydrotreating could be integrated with an existing refinery as shown in Figure D-1. Figure D-2 depicts the probable configuration employing whole shale oil distillation.

Economic considerations for each approach are discussed in the following sections. Table D-1 lists the bases for our economic calculations.

HYDROGEN ECONOMICS

Hydrogen consumption is the most significant factor in determining the cost of operating hydrotreaters. Excess hydrogen in refineries is burned as plant fuel; therefore, the lowest hydrogen value is based on its heat content. With fuel valued at $2.30 per million BTU, hydrogen is valued at $0.70 per thousand cubic feet. Typical refinery hydrogen streams are at relatively impure concentrations, and prior to compressing to the required level for the hydrotreating unit, a cryogenic enrichment step should be taken. The cost of such a process is estimated at $0.10 per thousand standard cubic feet, bringing the minimum hydrogen value to $0.80 per thousand standard cubic feet.

In a situation where no hydrogen is available, it must be purchased or produced onsite. Operating costs for a hydrogen plant, shown in Table D-2, indicate the value of manufactured hydrogen to be $2.30 per thousand standard cubic feet. This represents the maximum hydrogen cost to a refiner. A situation in which the quantity of excess hydrogen was inadequate and the balance was made up by manufactured hydrogen would result in an average price in the range of $0.80 to $2.30 per thousand standard cubic feet.

INVESTMENT FOR WHOLE SHALE OIL HYDROTREATING

As shown in Figure D-1, filtered whole shale oil would be hydrotreated and then blended into the crude charge prior to desalting. For a unit capable of hydroprocessing 10 thousand barrels per stream day, the onsite investment requirement is estimated at $30 million (including the filtration equipment). The offsite investment requirement is estimated at $10 million, and includes $1.3 million for tankage to handle 15 days of shale oil inventory. Other offsite requirements include utilities, distribution and production equipment, environmental facilities, roads, buildings, etc. The whole shale oil hydrotreater would operate at conditions very similar to an atmospheric crude oil residuum desulfurizer, and would require a correspondingly similar investment.

OPERATING COSTS FOR WHOLE SHALE OIL HYDROTREATING

Table D-3 details the actual consumptions and costs per barrel of feed for a whole shale oil hydrotreater. The total cost of operating the unit is between $6.40 and $9.40 per barrel charged. This range is due to the variable hydrogen cost which contributes $1.60 to $4.60 per barrel. No further costs would be attributed to processing shale oil as opposed to crude oil since our base assumption is that the whole shale oil hydrotreating approach would only be chosen when the shale oil portion of total feed was sufficiently low for the shale oil-derived stream to be safely blended with the corresponding crude oil fractions.

INVESTMENT FOR WHOLE SHALE OIL AND DISTILLATION AND SIDE STREAM HYDROTREATING

For this case a facility capable of handling 50 thousand barrels per stream day of shale oil was analyzed. Estimated investment requirements are detailed in the following table:

	$MM
Onsite	
50 MBPSD Atmospheric Distillation Unit	10.7
14 MBPSD Shale Naphtha Hydrotreater	7.6
5 MBPSD Shale Distillate Hydrotreater	6.1
25 MBPSD Shale Gas Oil Hydrotreater	58.9
Total Onsite	83.3
	(or about 85)
Offsite	
25 Days of Tankage	10.6
Other Offsites (30 Percent of Onsite)	25.0
Total Offsite	35.6
	(or about 35)
Total Investment	118.9
	(or about 120)

The investment for the shale oil distillation unit is equal to that for a crude oil distillation unit of the same capacity.

The shale oil side stream hydrotreaters require more investment than similar units for crude oil-derived streams. This is due to the high operating temperature and pressure, and (in some cases) lower space velocities for the shale oil units. The onsite investment required for crude oil fraction hydrotreaters is compared to that for shale oil fraction hydrotreaters in the following table. All units are sized to process 10 thousand barrels per stream day.

(Million Dollars)

	Naphtha	Distillate	Gas Oil
Crude Stream Unit	4.4	6.5	9.8
Shale Oil Stream Unit	6.0	9.8	28.9
Increased Investment For Shale Oil Stream (Percent)	36.4	50.8	194.9

The investment increase for shale oil hydrotreating is substantially higher for the heavier fractions due to the significantly higher severity required to reduce the nitrogen content of the heavier material.

OPERATING COSTS FOR SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING

The costs for operating each unit in the shale oil distillation/hydrotreating facility are shown in Table D-4. The total costs per barrel charged each unit are summarized as follows:

Total Operating Costs For Shale Oil Distillation And Hydrotreating Units
(Dollars Per Barrel)

Distillation Unit	0.80
Naphtha Hydrotreater	1.63 - 2.61
Distillate Hydrotreater	2.91 - 4.41
Gas Oil Hydrotreater	5.63 - 8.63

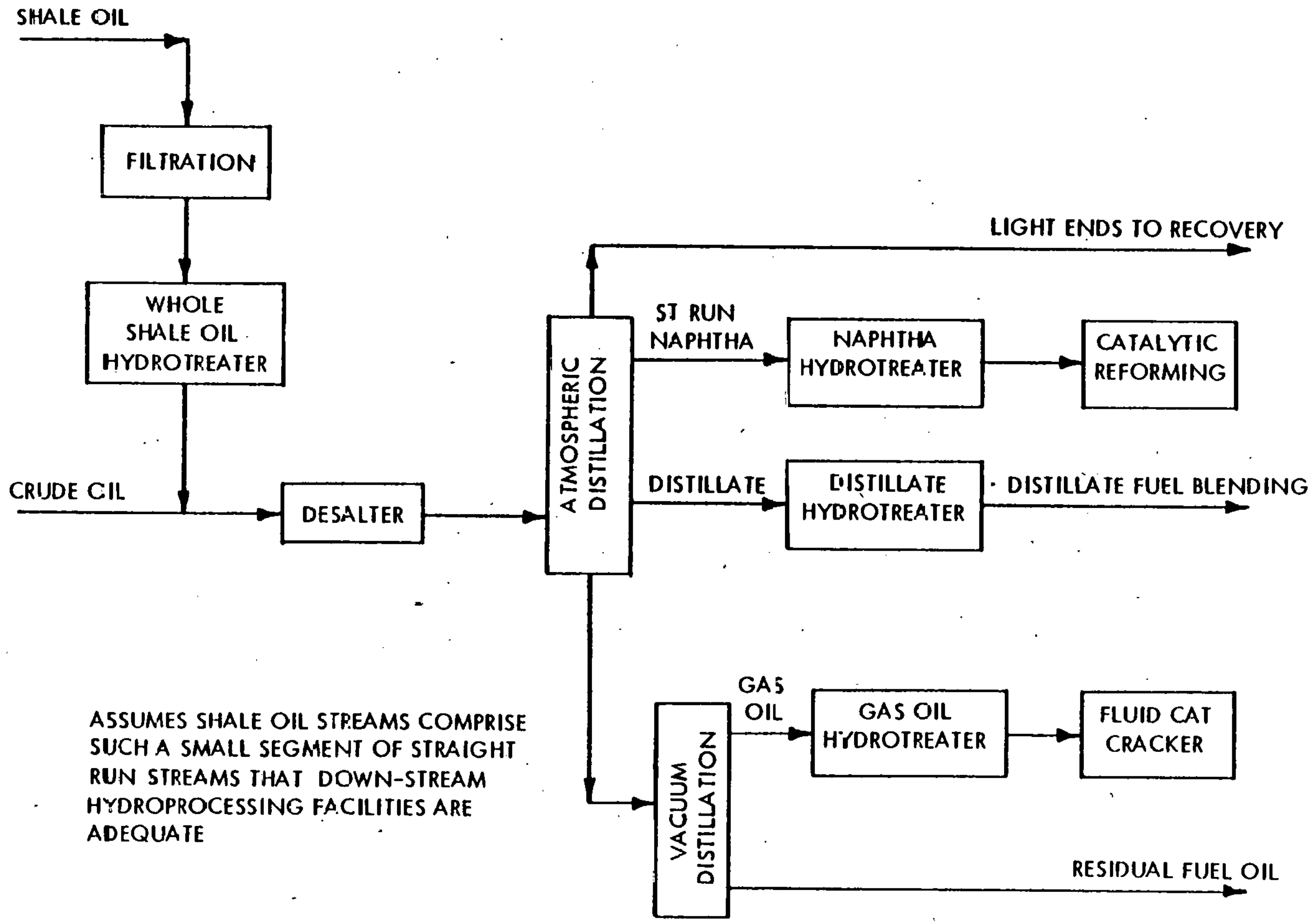
Table D-5 shows the consumption rates for each unit.

The cost of operating the distillation unit should not vary significantly from shale oil to crude oil feeds. Hydrotreater operating costs are higher for shale oil units. Table D-6 compares the cost to operate crude oil hydrotreating units with shale oil units of equal size.

The average total cost per barrel charged is $0.90 less for crude oil naphtha than for shale oil naphtha; $1.70 less for crude oil distillate; and $6.00 less for crude oil-derived gas oils. As with investments, the severity requirements for shale oil increase dramatically for the higher boiling range materials.

FIGURE D-1

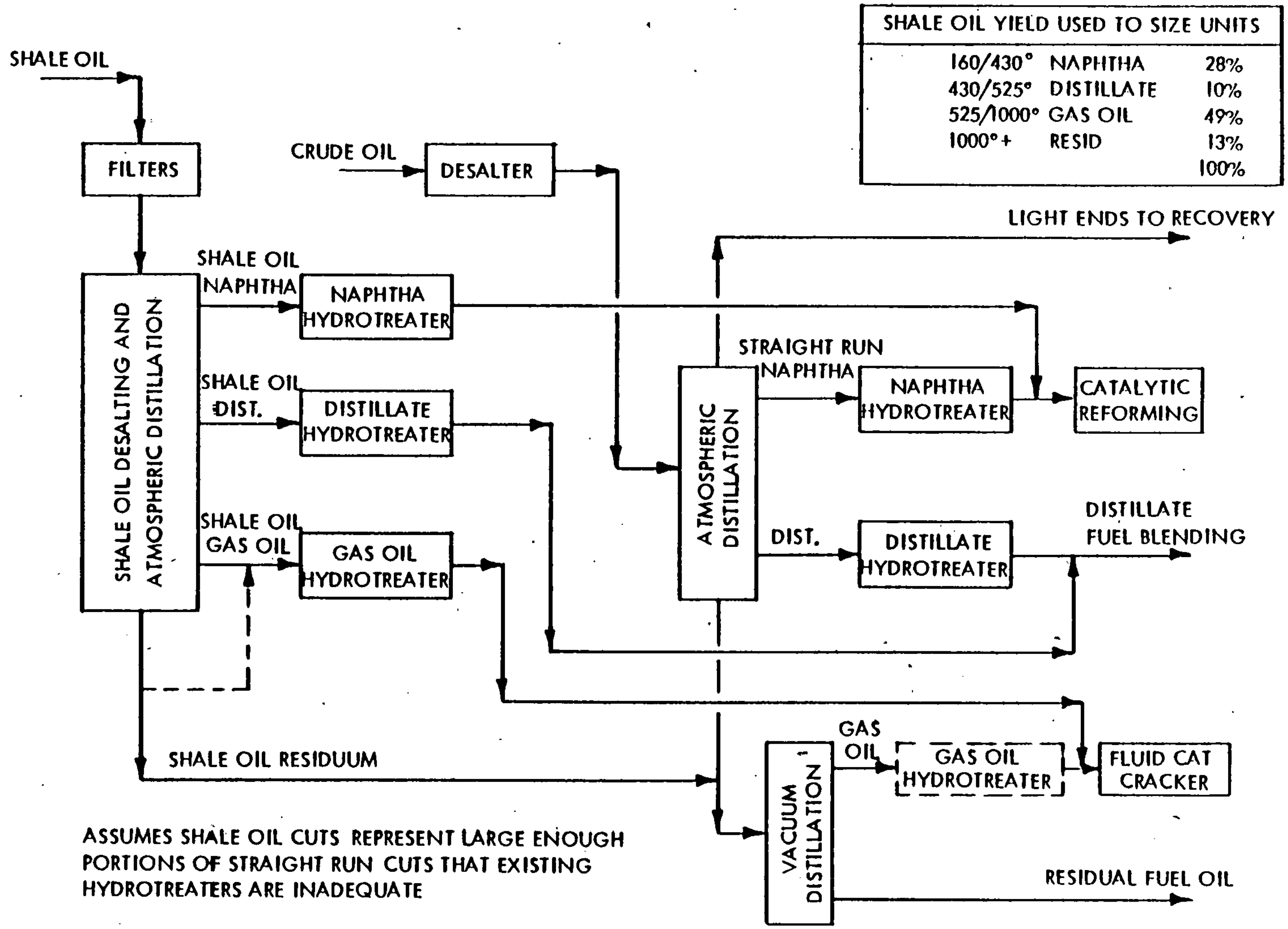
CONFIGURATION TO PROCESS SMALL PERCENTAGE OF
SHALE OIL IN AN EXISTING REFINERY



ASSUMES SHALE OIL STREAMS COMPRISE SUCH A SMALL SEGMENT OF STRAIGHT RUN STREAMS THAT DOWN-STREAM HYDROPROCESSING FACILITIES ARE ADEQUATE

FIGURE D-2

CONFIGURATION TO CHARGE LARGE PERCENTAGE OF SHALE OIL TO AN EXISTING REFINERY



ASSUMES SHALE OIL CUTS REPRESENT LARGE ENOUGH PORTIONS OF STRAIGHT RUN CUTS THAT EXISTING HYDROTREATERS ARE INADEQUATE

TABLE D-1

BASES FOR SHALE OIL PROCESSING ECONOMIC ANALYSIS

I. INVESTMENTS

A. Estimates for 1979 costs: Nelson's Construction Index=750.

B. Tankage investment estimated at $8.50 per barrel.

C. Other offsite investment taken as 30 percent of onsite investment.

II. OPERATING COST FACTORS

A. Salaries and wages estimated at 2.4 times direct labor. Direct labor rate is $8.50 per operator hour.

B. Fuel cost @ $2.25 per million BTUs.

C. Power cost @ $25.00 per thousand kilowatt hours.

D. Cooling water cost @ $0.01 per thousand gallons.

E. Maintenance taken as 2 percent of offsite + 4 percent of onsite investment per year.

F. Plant supplies estimated at 8 percent of maintenance.

G. Taxes and insurance estimated at 2 percent of total investment per year.

H. Depreciation based on 10 percent of total investment per year.

I. Before tax profit is 20 percent of total investment per year.

J. Stream day factor = 0.9.

TABLE D-2

HYDROGEN PLANT OPERATING COSTS
(Dollars Per Thousand Standard Cubic Feet)

Naphtha Feed ($0.43/Gallon)	0.87
Salaries and Wages	0.01
Fuel	0.72
Power	0.10
Cooling Water	0.01
Maintenance	0.05
Plant Supplies	-
Catalysts and Chemicals	0.03
Taxes and Insurance	0.03
Depreciation	0.15
Total Manufacturing Cost	1.97
	(or about 2.00)
Before Tax Profit (20 Percent Total Investment/Year)	0.33
	(or about 0.30)
Hydrogen Transfer Price	2.30

TABLE D-3

WHOLE SHALE OIL HYDROTREATING COSTS AND CONSUMPTION FACTORS

Investment Basis:

	$MM
10 MBPSD Shale Oil Hydrotreater	28.9
Offsite Investment	10.0
Total Investment	38.9
	(or about 40.0)

Operating Cost	$/Barrel
Fuel (73.7 MBTU/Bbl)	0.17
Power (6.2 KWH/Bbl)	0.16
Cooling Water (0.10 MGal/Bbl)	0.01
Salaries and Wages (3 Men/Shift)	0.15
Maintenance	0.41
Plant Supplies	0.03
Catalyst and Chemicals	0.19
Taxes and Insurance	0.24
Depreciation	1.14
Total Processing Cost Excluding Hydrogen	2.50
Hydrogen (2,000 SCF/Bbl)	1.60-4.60
Total Processing Cost	4.10-7.10
Before Tax Profit	2.27
	(or about 2.30)
Total Operating Cost	6.37-9.37
	(or about 6.40-9.40)

TABLE D-4

SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING OPERATING COSTS

Investment Basis:	$MM	
50 MBPSD Distillation Unit	10.7	
14 MBPSD Naphtha Hydrotreater	7.6	
5 MBPSD Distillate Hydrotreater	6.1	
25 MBPSD Gas Oil Hydrotreater	58.9	
Total Onsite	83.3	(or about 85)
Offsite Investment	35.6	(or about 35)
Total Investment	118.9	(or about 120)

	$/BBL OF FEED TO EACH UNIT			
	50 MBPSD Distilla-tion	14 MBPSD Naphtha Hydrotreater	5 MBPSD Distillate Hydrotreater	25 MBPSD Gas Oil Hydrotreater
Operating Costs				
Fuel	0.20	0.03	0.09	0.17
Power	0.01	0.05	0.04	0.16
Cooling Water	0.01	0.01	0.01	0.01
Salaries & Wages	0.15	0.10	0.10	0.10
Maintenance	0.04	0.08	0.17	0.34
Plant Supplies	0.01	0.01	0.01	0.03
Catalyst and Chemicals	0	0.03	0.03	0.15
Taxes and Insurance	0.02	0.05	0.10	0.19
Depreciation	0.12	0.25	0.52	0.96
Total Processing Cost Excluding Hydrogen	0.56	0.61	1.07	2.11
Hydrogen	-	0.52-1.50	0.80-2.30	1.60-4.60
Total Processing Cost	0.56	1.13-2.11	1.87-3.37	3.71-6.71
Before Tax Profit	0.24	0.50	1.04	1.92
Total Operating Cost	0.80	1.63-2.61	2.91-4.41	5.63-8.63
Approximately:		(1.60-2.60)	(2.90-4.40)	(5.60-8.60)

TABLE D-5

SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING CONSUMPTION FACTORS

	Distillation	Naphtha Hydrotreater	Distillate Hydrotreater	Gas Oil Hydrotreater
Fuel (MBTU/Bbl)	87.9	12.3	37.9	73.7
Power (KWH/Bbl)	0.24	2.0	1.43	6.2
Cooling Water (MGal/Bbl)	0.50	0.87	0.07	0.11
Operators Per Shift	3	2	2	2
Hydrogen (SCF/Bbl)	–	650	1,000	2,000

TABLE D-6

COMPARISON OF CRUDE OIL AND SHALE OIL SIDE STREAM HYDROTREATING (All Units 10 MBPSD)

	Whole	Naphtha		Distillate		Gas Oil	
	Shale Oil	Crude	Shale Oil	Crude	Shale Oil	Crude	Shale Oil
Investment ($MM)							
Onsite	28.93	4.4	6.0	6.5	9.8	9.8	28.9
Offsite	9.96	1.3	1.8	1.9	2.9	2.9	8.6
Total	38.89	5.7	7.8	8.4	12.7	12.7	37.5
Approximately:	(40)	(6)	(8)	(8)	(13)	(13)	(38)
Operating Costs ($/Bbl)							
Processing Cost Exc. Hydrogen	2.50	0.68	0.61	0.77	0.77	0.77	2.52
Hydrogen	1.60-4.60	0.08-0.23	0.52-1.50	0.08-0.23	0.80-2.30	0.16-0.46	1.60-4.60
Profit	2.27	0.32	0.47	0.51	0.77	0.77	2.27
Total Cost	6.37-9.37	1.08-1.23	1.60-2.58	1.36-1.51	2.34-3.84	1.70-2.00	6.39-9.39
Approximately:	(6.4-9.4)	(1.1-1.2)	(1.6-2.6)	(1.4-1.5)	(2.3-3.8)	(1.7-2.0)	(6.4-9.4)
Average Cost	7.87	1.16	2.09	1.44	3.09	1.85	7.89
Increase in Average Cost For Shale Oil Over Crude Oil Streams		-	0.93	-	1.65	-	6.04

E

PRODUCT SLATE AND END USE CONSIDERATIONS

E

PRODUCT SLATE AND END USE CONSIDERATIONS

PROJECTED SHALE OIL PRODUCTION LEVELS

In order to determine where shale oil will fit into the regional energy fuel demand picture, both the volume of shale oil available and the potential end use must be considered. As part of Pace's "Energy and Petrochemical Outlook to 2000," we have projected the volumes of shale oil likely to be produced between 1985 and 2000. Our projection is based on Cameron Engineers' knowledge of the shale oil industry in general, and planned or projected projects. These projections assume that an economic incentive such as the $3.00 per barrel shale oil tax credit will be promulgated, and that some relaxation of air quality standards will occur. The projections do not include allowance for a major federal program to develop shale oil on a crash basis. Our projections of shale oil production are as follows:

Year	Production (BPD)
1985	10,000
1987	100,000
1990	200,000
1995	500,000
2000	750,000

REGIONAL REFINED PRODUCT DEMANDS

As previously discussed, shale oil could be refined to produce essentially any fuel produced from conventional petroleum. However, it is our judgment that shale oil can be targeted toward four markets:

- Transportation fuels (gasoline, heavy naphtha/JP-4, Jet A, and diesel fuel)
- Liquid refinery fuel
- Number 2 fuel oil
- High sulfur fuel oils normally used by industry and utilities as boiler fuel.

These fuels represent the full spectrum of refining severity. The transportation fuels require the greatest amount of processing in order to meet strict product specifications and to minimize feedstock compatibility problems with processing catalysts. Number 2 fuel oil can be produced from a blend of petroleum fractions and partially upgraded shale oil. Liquid refinery fuels and utility boiler fuel (resids) provide the opportunity to use raw shale oil to displace heavy petroleum fractions which might be more suitable for upgrading to transportation fuels than raw shale oil.

Based on "The Pace Energy and Petrochemical Outlook to 2000," we projected the demand for the fuels identified above by PADDs for the years 1985, 1990, and 2000. Projections were not made for the period up to 1985 because of the probable lack of significant quantities of shale oil being available in that time frame. The results of these projections are shown in Figure E-1. In all cases the projected demand for premium leaded gasoline and heavy naphtha/JP-4 is less than 2 percent of the total demand for the other products, and therefore does not show up on the demand figures. The compound growth rates in fuel demands between 1985 and 2000 are given in Table E-1. It can be seen from this table that each PADD experiences the greatest increase in demand for diesel, Jet A, and resid. Unleaded gasoline also experiences a modest demand increase during this period. However, based on the requirement for a high aromatic content in order to meet minimum octane requirements, we do not feel that shale oil fractions would represent the most desirable feedstock for unleaded gasoline production. Allowing shale oil fractions to displace more aromatic conventional petroleum fractions which are not currently used in gasoline production appears to be a more logical use for the shale oil. A map of the United States showing the states in each PADD is shown on Figure E-2.

It can therefore be concluded that diesel fuel and Jet A will be the fuels experiencing the greatest incremental demands in all of the PADDs which were examined. A strong incremental demand for utility and industrial boiler fuel (resid) will also be experienced, particularly in PADD 2B/4 and 3.

It is important to maintain a perspective regarding the impact which shale oil will have in displacing or supplementing petroleum feedstocks to refineries. By comparing the projected shale oil production rates presented previously with the aggregated demand for petroleum products in PADDs 2A, 2B/4, 3, and 5 indicates that shale oil could supply the following percentages of refined product demand in 1985, 1990, and 2000:

Potential Total Refined Product Demand Supplied by Shale Oil
(Percent)*

PADD	1985	1990	2000
2A	0.29	5.73	17.26
2B/4	0.52	9.82	32.78
3	0.32	5.80	17.95
5	0.36	7.13	20.82
Aggregate	0.09	1.70	5.20

*Assumes total shale oil production would be consumed by each PADD.

It can be seen that even if the total shale oil production projected for a given year were consumed in a given PADD, shale oil's contribution would be minor until after 1990. By 2000, the total shale oil production would have a significant impact on any given PADD, but the impact on the aggregated demand of the PADDs would still be relatively minor. However, if this same comparison is made assuming that 75 percent of the raw shale oil production can be converted to diesel and jet fuel (corresponding to Chevron's estimated production from a grass roots hydrotreating/hydrocracking refinery), or that the raw shale oil would displace high sulfur resid, the impact of shale oil is much more significant (Table E-2).

If shale oil is used to displace high sulfur resid as a boiler fuel, it can have a significant impact on any given PADD by 1990 and can supply over 40 percent of the projected aggregate demand for resid in 2000. With conversion of shale oil to jet fuel and diesel fuel, a significant impact would be observed in any given PADD in 1990, and on the aggregate demand by 2000.

POTENTIAL PRODUCTS FROM SHALE OIL

During the initial years of production, shale oil will be produced in low volumes and on an intermittent basis due to startup and shutdown of a limited number of production modules. Until production reaches a sustained level which can be relied on by a given refinery, shale oil will not represent a desirable feedstock. It is during these initial years when production is getting underway that the use of raw shale oil as boiler fuel could provide a valuable outlet for supplies which are unpredictable from both a timeliness and quality standpoint.

Considerable doubt still exists as to whether shale oil can be burned directly or blended with petroleum fuel oils without excessive emissions of nitrogen oxides and/or particulates. A large-scale test firing of shale oil/fuel oil blends was conducted in 1976 by Southern California Edison in a 45 megawatt boiler. The boiler was equipped with six front-face mounted oil burners arranged in two rows, and rated at 85 million BTUs per hour each. Shale oil was blended in various proportions with low sulfur fuel oil before its combustion in the boiler so that the sulfur content of the fuel blend did not exceed 0.5 percent. The fuel handling system for the test boiler was modified to achieve the blending of the shale and low sulfur oils in the piping network. The fuel piping was arranged to either supply the shale oil blends to all six burners or to the bottom row burners only. Emission of air contaminants was determined when the shale oil blend was burned in all six burners (tank blending) and when the oil blend was burned in the bottom row of burners only, followed by the combustion of low nitrogen fuel in the upper burners. The segregation of the high and low nitrogen fuels in two independent fuel systems was termed "dual fuel combustion."

These tests showed that in order to meet a nitrogen oxide emission restriction of 225 ppm which applies in Southern California, a blend of up to 17 percent shale oil (1.98 weight percent nitrogen) could be burned using specially designed low nitrogen oxide burners and staged combustion techniques. If a shale oil blend was to be burned in the bottom row of the burner and natural gas burned in the upper row, a blend of up to 58 percent shale oil could be used and still meet the emission restriction.

These results are particularly significant when interpreted in light of the recently passed Utility and Industrial Fuel Use Act. This Act is intended to minimize the use of natural gas and petroleum in new and existing power plants and major fuel burning installations. The Act provides, however, for an exemption from the prohibition against the use of natural gas or oil if a mixture of gas or oil and an alternate fuel (such as shale oil) is used. Although the regulations implementing the Act are not finalized, it is very possible that if raw shale oil can be combusted without nitrogen oxide problems, it would be in demand by those installations facing an expensive conversion from natural gas or oil-fired equipment to coal-fired equipment.

In our judgment this is a critical area which needs to be explored further because the use of raw shale oil as utility fuel could provide an important and useful outlet for this material during the early developmental stages of the shale oil industry. Specifically, additional large-scale tests on raw shale oil combustion in boilers of different design and size need to be performed.

FIGURE E-1

PROJECTED DEMANDS FOR FUEL BY PADD

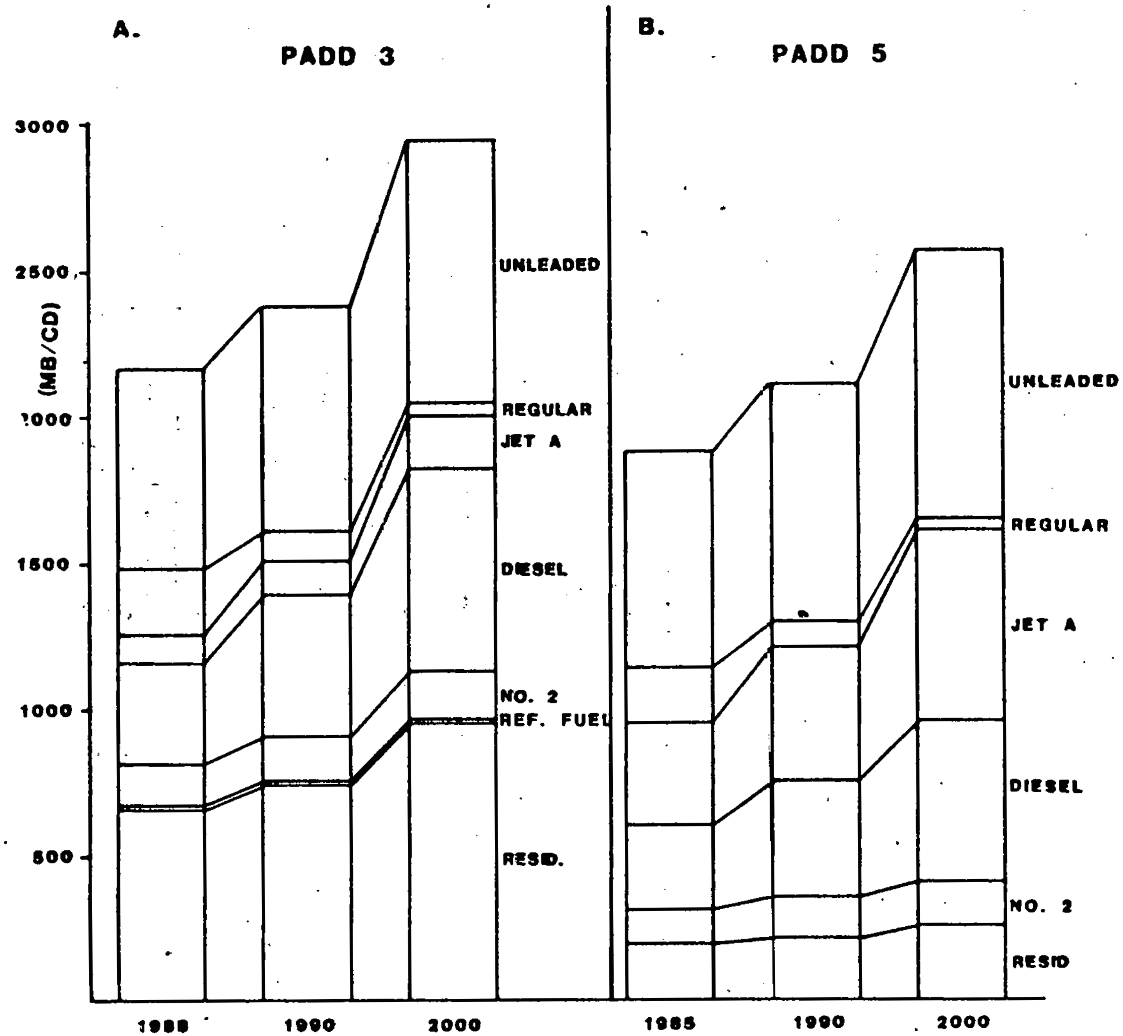


FIGURE E-1 - Continued

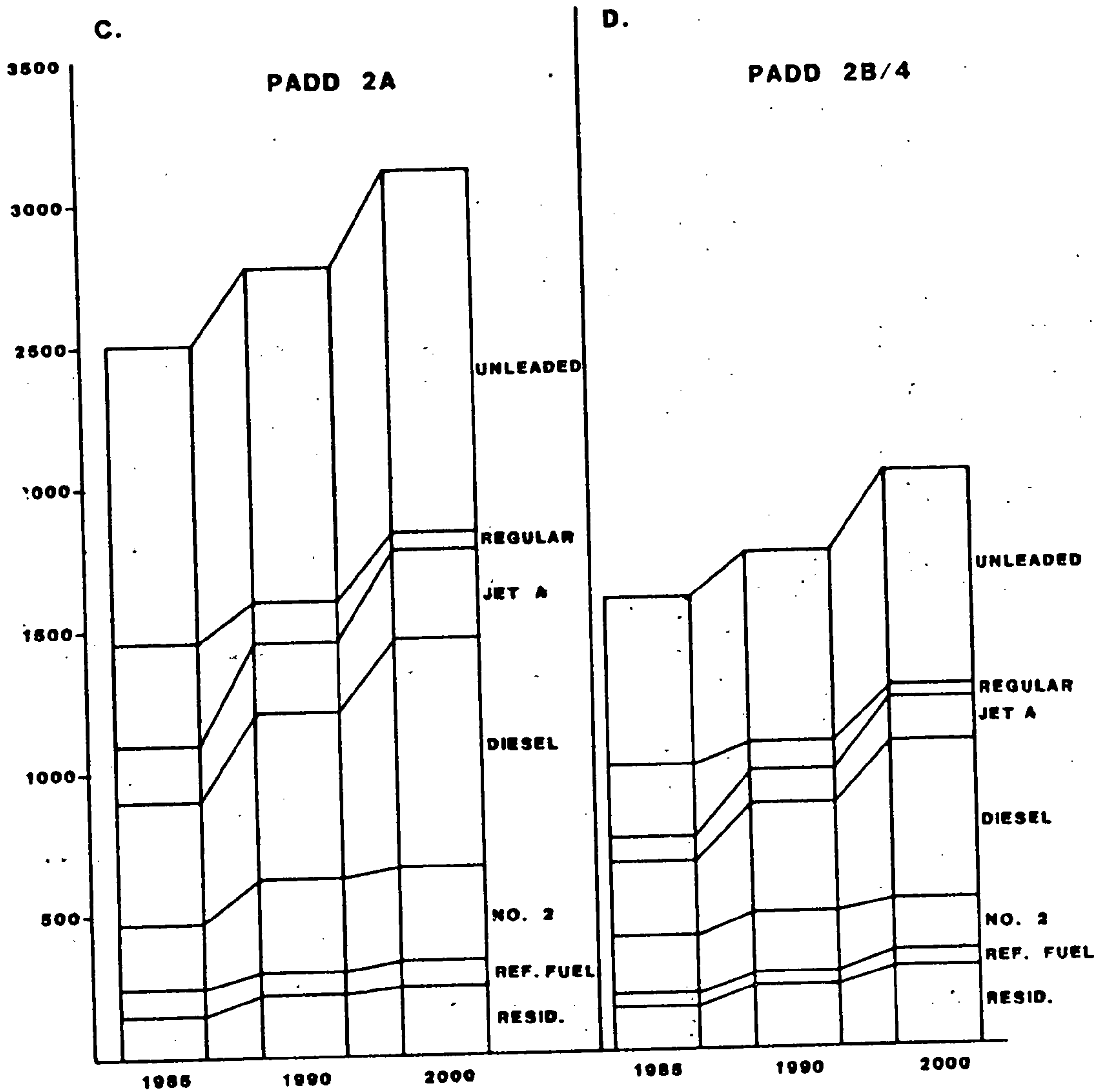


FIGURE E-2

PETROLEUM ADMINISTRATION for DEFENSE DISTRICTS - PADD

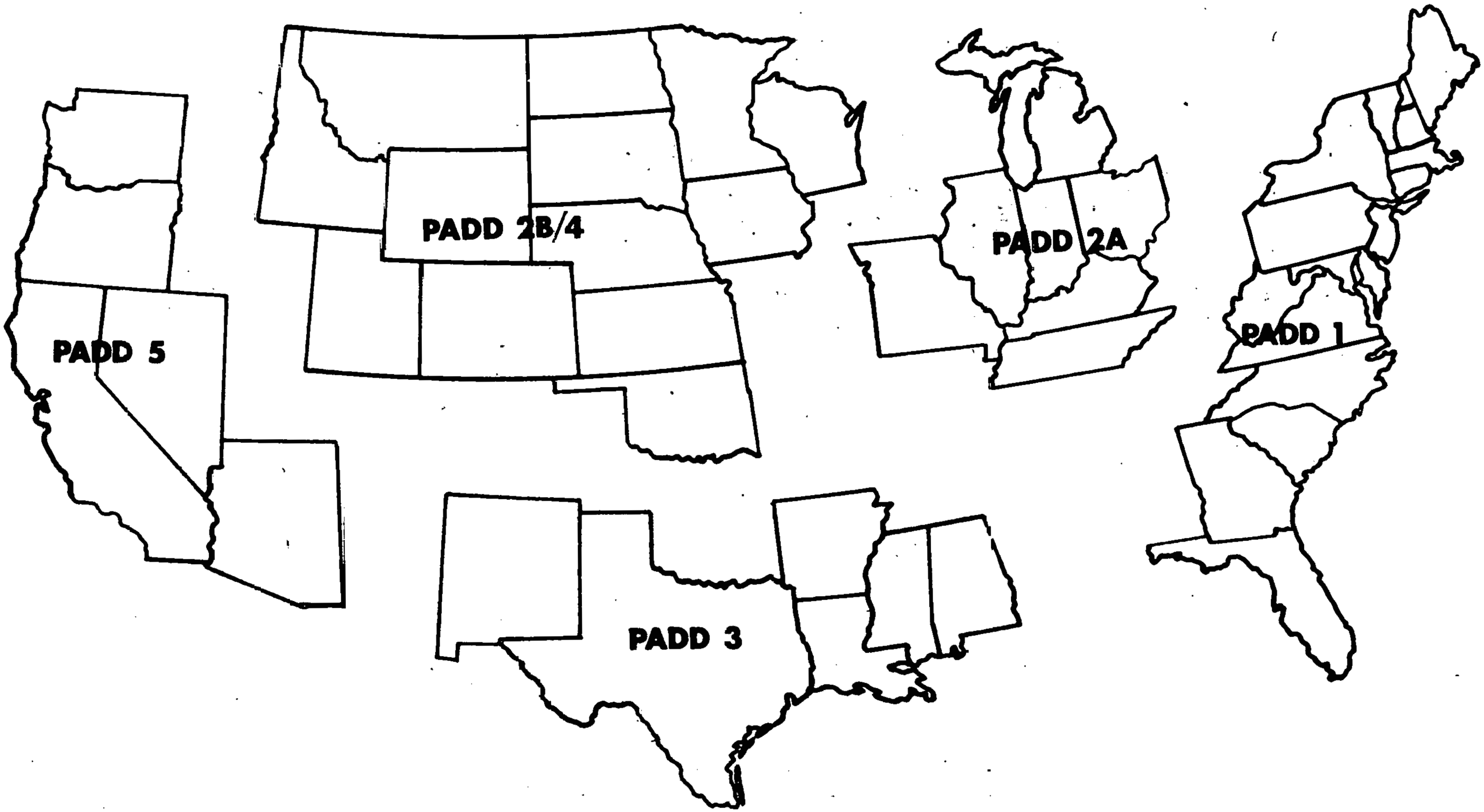


TABLE E-1

GROWTH RATES IN FUEL DEMAND
BY PADD
(Percent)

	PADD			
	2A	2B/4	3	5
Resid	2.78	4.51	2.44	1.51
Refinery Fuel	-	-	-	-
No. 2 Fuel Oil	2.24	(1.00)	1.12	1.85
Diesel	4.45	5.03	4.73	4.69
Jet A	3.20	4.06	4.69	4.11
Regular Gasoline	(12.69)	(12.31)	(12.05)	(12.02)
Unleaded Gasoline	1.29	1.70	1.78	1.51

TABLE E-2

RESID OR DIESEL FUEL/JET FUEL SUPPLIED BY SHALE OIL (Percent)

	PADD 2A	2B/4	3	5	Aggregate
Resid*					
1985	6.37	6.80	1.52	5.13	0.86
1990	88.9	89.7	27.2	94.8	14.4
2000	316	263	79	307	43.8
Diesel Fuel/Jet Fuel*					
1985	1.22	2.12	1.73	1.19	0.37
1990	18.2	30.2	25.0	17.5	5.4
2000	50.3	78.5	64.7	46.9	14.4

*Assumes equal volume displacement of shale oil for resid, or 75 percent conversion of shale oil to diesel/jet fuel.

F

REFINING INDUSTRY CAPABILITIES

F

REFINING INDUSTRY CAPABILITIES

REGIONAL CHARACTERIZATION OF EXISTING PLANTS

Raw shale oil will require large volumes of hydrogen to produce specification fuel. The amount of hydrogen required is estimated at about 2,000 standard cubic feet per barrel of raw shale oil. A review of each of the 264 refineries located in PADDs 2A, 2B, 3, 4, and 5 was conducted to determine:

- If existing facilities were capable of refining shale oil to end products
- Which refineries had a surplus of hydrogen above that required by existing refinery units
- Shale oil refining capacity based on surplus hydrogen.

The refineries evaluated are listed in Table F-1.

Shale oil refining capability was based on whether a refinery had catalytic reforming, catalytic hydrorefining, and/or catalytic hydrotreating units. Those refineries which did not have such units were eliminated. Hydrogen balances for refineries with shale oil capability were estimated by adding hydrogen production from catalytic reformers and hydrogen generators, and subtracting hydrogen demand by catalytic hydrotreating, catalytic hydrorefining, and catalytic cracking units.

Raw shale oil refining capacity was determined by dividing the daily surplus hydrogen by the hydrogen demand of raw shale oil (2,000 standard cubic feet per barrel of crude oil). Table F-2 lists those refineries in PADDs 2A, 2B, 3, 4, and 5 with raw shale oil capacities of 10,000 barrels per day or more, and shows the estimated hydrogen surplus.

Table F-2 shows that based on estimated hydrogen surplus, the refineries with a shale oil capacity of 10 thousand barrels per day or more could refine nearly 760 thousand barrels per day of raw shale oil. However, it would be incorrect to conclude from these statistics that ample hydrogen will be available for raw shale oil processing at projected shale oil production rates in 1990 and 2000. The explanation of this apparent paradox is that hydrogen surplus is keyed to the quality of crude oil supply. Supplies of light, low sulfur crude oils are declining, and supplies of heavier, higher sulfur crude oils are required to make up the difference. The heavier, higher sulfur crude oils such as Alaskan North Slope will consume considerably more hydrogen with resultant loss in hydrogen surplus.

An additional problem is immediately apparent from Table F-2. No refinery within the five PADDs reviewed has the hydrogen surplus to refine raw shale oil at a rate of 50 thousand barrels per day or more (a level generally considered to be the output of a single commercial oil shale facility). PADD 5 has the highest per refinery raw shale oil capacity, but excess Alaskan North Slope crude oil in the PADD lowers the potential for a shale oil market. The low per refinery raw shale oil capacity will require the distribution of projected shale oil production by 1990 and 2000 to numerous refineries.

A final consideration is that the severity of shale oil processing imposes stringent restrictions on equipment design and hydrogen purity. Shale oil denitrogenation requires high pressure operation of hydroprocessing facilities which are nearer to hydrocracking requirements than conventional hydrotreating requirements. In our survey of refineries with hydroprocessing facilities it was not possible to determine if existing equipment could operate under sufficiently severe conditions to denitrogenate shale oil. Also, in many cases the excess hydrogen produced by catalytic reformers might not be of high enough purity to meet hydroprocessing requirements. This occurs because the pressure required for denitrogenation is based on hydrogen partial pressure. If the available excess hydrogen is of low purity, the total hydroprocessing pressure must be increased to satisfy the hydrogen partial pressure requirements. This could in turn cause the total pressure requirement to exceed the pressure rating of existing equipment.

In summary, the refineries listed in Table F-2 appear capable of processing shale oil when hydrogen availability is the only variable considered. To more accurately assess shale oil refining capability will require a much more in-depth analysis of projected changes in crude slate for each refinery, and an assessment of existing process unit capabilities.

REFINERY ACCESS TO
CONVENTIONAL PETROLEUM SUPPLIES

As the production of shale oil increases with the startup of additional projects, the pipeline transportation system will have to be expanded to transport raw shale or syncrude to remote refining centers, or to transport refined products to demand centers. The transportation system will be a critical link in the ultimate usage of oil shale.

Up until this time most of the effort expended on oil shale development has dealt with the logistics and technology of mining and processing. When commercial projects get underway, existing pipelines will quickly reach their design capacity, and expansion or new pipeline construction will be required. As was discussed in the section of this report dealing with shale oil characteristics, shale oil's high pour point will require special considerations for existing or new pipelines. The use of existing petroleum pipelines will require either an upgraded shale oil or syncrude, or use of flow improving additives. New shale oil pipelines can be designed from the start to accommodate shale oil's high pour point.

Since pipeline transportation will be critical to oil shale's orderly development, we have briefly examined the constraints and requirements of both flow improving additives (pour point depressants) and new shale oil-dedicated pipelines.

Flow Improving Additives

The use of chemical additives to modify flow properties of waxy crude oils is very much an art rather than a science. Each particular system or feedstock must be tested with candidate flow improving additives because of the inability to translate results between different systems or feedstocks. Considerable effort by many companies has been made to develop additives, which by modifying the wax crystal structure result in a marked change in the flow properties. Furthermore, these same additives reduce the thixotropic effects (the tendency of a gel to liquefy under vibration, and solidify at rest) of the fluid. In the general case these additives can seldom be justified due to the high cost of the treatment compared with the alternative of a good pipeline system design. However, there are a number of situations in which the use of these additives can be justified:

- Injection of an additive prior to a scheduled shutdown so as to avoid the use of flushing oil.
- Addition to the oil during a difficult restart operation when the system may remain cold until flow is fully established.
- Transportation of an oil with flow characteristics more severe than those for which the system was originally designed.
- Transportation of crude oil in an existing buried, uninsulated, conventional crude oil pipeline.

In designing a pipeline system it costs very little to make provisions for the injection of an additive for use in the above listed situations. For satisfactory results, it is desirable to ensure that all the wax is brought into solution prior to additive treatment. This usually entails heating to 90°F to 130°F.

The use of flow characteristics improvers currently appears to be limited by the available excess capacity of the existing pipeline system which could be devoted to shale oil transport.

Existing Pipeline Systems

Two existing crude oil pipeline systems have the potential to transport raw or upgraded shale oil: the northern system and the southern system are shown in Figure F-1. The ability of both systems to handle projected shale oil production by 1985, 1990, and 2000 is subject to existing and projected throughput of conventional crude oil and the various proposals to move Alaskan North Slope crude oil from ports on the West Coast to areas of need (PADDs 2B and 2A). Both systems would require construction of connecting lines and expansions to connect with Piceance Creek oil shale facilities and to increase available capacity. A description of the two existing crude oil pipeline systems follows.

Northern System

The northern system was developed to move crude oil from the states of Montana, Wyoming, Colorado, and Utah to refineries located in those states, and to export crude oil production in excess of refining capacity to PADDs 2A and 2B. Canadian crude oil was transported via the system into PADDs 2A and 2B. Curtailment of Canadian imports has in some cases increased available capacity in the system.

Chevron

Chevron Oil Company operates a crude oil pipeline that originates at Rangely, Colorado and terminates at Salt Lake City, Utah. The line consists of two 10-inch pipelines, each 160 miles long with a capacity of 105 thousand barrels per day and a throughput of 100 thousand barrels per day. Although existing available capacity is relatively small, declining domestic crude oil production and/or expansion of the line could increase available capacity significantly.

Amoco

Amoco pipelines originate at Rangely, Colorado (10-inch) and near Craig, Colorado (8-inch). The 10-inch line connects with the 8-inch line crossing southern Wyoming, which terminates in Salt Lake City, Utah and at Fort Laramie, Wyoming. The Fort Laramie terminus includes a connection with the major 20-inch Amoco line from Elk Basin, Wyoming to Freeman, Missouri.

The 8-inch line from Craig, Colorado crosses the southern Amoco line and terminates near the Amoco line in Casper, Wyoming. The Amoco line across southern Wyoming is operating at capacity to Salt Lake City (40 thousand barrels per day), and slightly below capacity to Fort Laramie, Wyoming (29 thousand barrels per day with 25 thousand barrels per day throughput). If this Amoco system in Wyoming and Colorado were expanded to handle large volumes of shale oil, it would provide access to several other pipeline systems which supply both major and minor refining centers. Possible tie-ins are listed in the following table. Once the shale oil reaches the Midwest via the Amoco, Platte, or Arapahoe pipelines, other pipeline connections could transport the shale oil to refineries in PADDs 2A and 2B having the available processing facilities.

Pipeline	Terminals	Excess Capacity (BPD)
Amoco (20-inch)	Elk Basin, Wyoming to Freeman, Missouri	45,000
Platte	Byron, Wyoming to Wood River, Illinois	120,000
Conoco	Gurnsey, Wyoming to Denver, Colorado	18,000
Arapahoe	Gurley, North Dakota to Humboldt, Kansas	100,000
	Total	283,000

Many of these alternatives may be affected by potential flow of Alaskan North Slope crude oil from the proposed Northern Tier pipeline. However, shale oil could supply the secondary market or southern markets of the proposed Northern Tier pipeline with about 280 thousand barrels per day through existing pipeline systems, allowing more of the Alaskan North Slope crude oil to be delivered in the northern portions of PADDs 2A and 2B. In addition, the Amoco system allows access to the refineries in Utah, Wyoming, and Montana which are currently running below capacity because of curtailment of Canadian imports and declining local production.

Southern System

The southern system (see Figure F-1) was developed to move crude oil from the Four Corners area to Long Beach, California and the Midland, Texas area. However, the western stretch from Long Beach to the Four Corners area is currently moving 28 thousand barrels per day of Alaskan North Slope crude oil from Long Beach to the Four Corners area. Due to the limited refining capacity along the West Coast and the excesses of Alaskan North Slope crude oil, shale oil markets will probably be located in West Texas or the Gulf Coast. This delivery system would increase flow to PADD 3, but is not expected to aid areas of PADD 2A and 2B which are suffering from Canadian import curtailments.

Pure Oil Pipeline

The Pure Oil Pipeline originates in Lisbon, Utah and terminates at Aneth, Utah. The rated capacity is 50 thousand barrels per day and throughput is 35 thousand barrels per day. Construction of pipelines from the Piceance Creek basin to Lisbon, Utah and expansion of the Pure Oil Pipeline would allow shale oil to be transported to the south, where it could enter the Texas/New Mexico pipeline.

Texas/New Mexico Pipeline

This pipeline originates at Aneth, Utah and terminates at Port Arthur, Texas. The line has a capacity of 100 thousand barrels per day and a throughput of 80 thousand barrels per day. Expansion of this line would allow transportation of significant volumes of shale oil from the Pure Oil pipeline at Aneth to West Texas and the Gulf Coast. However, increased deliveries of Alaskan North Slope crude oil by way of the Arco Four Corners pipeline would decrease capacity available for shale oil.

In summary, the existing crude oil pipeline system has the potential to move about 300 thousand barrels per day of shale oil to the Gulf Coast and Midwestern refining centers. Utilization of this excess capacity will require major expansion or new construction of feeder lines from the oil shale region to the Platte, Amoco, and Arapahoe lines to the north, and the Texas/New Mexico line to the south. Utilization of this available capacity is also dependent on the rate of decline of local conventional crude oil production and shipments of Alaskan North Slope crude oil from the proposed Northern Tier pipeline. Once shale oil production reaches 300 thousand barrels per day, major new pipelines will be required to handle any additional production.

In the short term, existing lines which originate in the shale oil region appear wholly inadequate to handle shale oil production levels in excess of 50 thousand barrels per day.

New Shale Oil Pipelines

It is apparent from the discussion on shale oil characteristics that there may be a considerable difference between the pour point of shale oil retorted by in situ or surface technologies. Since considerable doubt exists regarding the viability of in situ technology, evaluation of future new pipeline constraints should address the "worst case" conditions encountered with high pour point surface retorted shale oils.

In order to better define the economic burdens which a new shale oil-dedicated pipeline would impose on a developing industry, we have made a rough estimate of the costs and requirements of a pipeline having a capacity of 40 to 180 thousand barrels per day. This size range was chosen because it provides flexibility for gradual increases in capacity which will be a requirement of a developing industry, yet will allow for reasonable economics of scale at full capacity.

In the absence of rheological data and the time to make a proper design study, the following must be regarded as an intelligent assessment of known conditions based on actual experience of an 18-inch insulated pipeline designed for the separate transportation of heavy waxy crude oil (and of residual fuels of 120°F pour point).

The properties of the heavy crude oil are similar in general terms to shale oil as can be seen from the following table:

	Heavy Crude Oil	Shale Oil
Gravity (°API)	25	20
Specific Gravity at 60°F	0.9024	0.934
Viscosity		
@ 100°F C.S.	17.0	38.0
@ 122°F C.S.	11.4	22.5
@ 210°F C.S.	4.0	5.1
Pour Point (°F)	95	85

The shale oil pipeline was assumed to start at Rifle, Colorado and to proceed via Kansas City to Chicago, serving a number of Midwestern refineries. The Rifle/Kansas City distance is about 750 miles, and Kansas City to Chicago is roughly 450 miles, giving a total distance of 1,200 miles. An 18-inch diameter pipeline was chosen which, at maximum capacity, would have a throughput of 140 thousand barrels per day at a maximum permissible design pressure of 1,200 psig. A ground temperature of 30°F at four feet depth was assumed.

At Rifle, the shale oil would be heated to 180°F and an appropriate number of reheating and pumping stations would be provided to ensure one of the following criteria:

- Increasing capacity to 140 thousand barrels per day to Kansas City, or
- Extending the pipeline to Chicago at a throughput (to Chicago) of 140 thousand barrels per day, with 180 thousand barrels per day in the Kansas City section as far as McPherson, Kansas.

For all throughputs of between 40 and 140 thousand barrels per day to Kansas City, the initial heating and pumping station at Rifle would be required, followed by four pump booster and reheat stations to raise the oil temperature from 85°F to 180°F. The total cost of this sytem including rights-of-way, insulated line, five pump and heater stations, flow metering, instrumentation, and communication equipment, but excluding all tankage and breakout systems would be approximately $230 to $300 million. Link-up to heater stations would be designed for full throughput of 140 thousand barrels per day, but with provision for operation at the reduced throughput at 40 thousand barrels per day. Only a small reduction in investment for the initial operation at 40 thousand barrels per day is possible by omitting some of the booster pumps and drivers.

The extension of the pipeline to Chicago for a throughput of 140 thousand barrels per day would require the provision of three booster and heater stations which, together with the insulated pipeline and other facilities as described for the Kansas City section, would require an investment of a further $140 to $180 million. Operation of this section at 100 thousand barrels per day would be possible with 40 thousand barrels per day disposed of before Kansas City. A full 140 thousand barrels per day delivered to Chicago with a further 40 thousand barrels per day delivered as far as the concentration of refineries in the Wichita, El Dorado, Augusta/McPherson area would be possible to give a total offtake out of Rifle of 180 thousand barrels per day. This could be attained with the provision of two booster stations without heaters at an incremental cost of around $5 million.

The total cost of the shale oil-dedicated pipeline to Chicago is thus $370 to $480 million. It is apparent that the cost of pipeline systems which have largely been ignored in discussions of the cost of shale oil production can represent a very significant additional expense. Pipeline construction lead time can also present problems. The upgraded shale oil pipeline proposed for the Colony Project (which would transport shale oil from Rifle, Colorado to Lisbon, Utah) required an Environmental Impact Statement which took over three years to complete.

AREAS WITH CRUDE OIL AND REFINING CAPACITY DEFICITS

Shale oil production has the potential of supplementing domestic crude oil production and reducing at least a portion of our requirement for imported foreign crude oil. The question arises regarding what area (PADDs 2A, 2B, 3, 4, or 5) could most benefit by the projected production of shale oil. Table F-3 is a comparison of actual and projected production, existing refinery capacity, and actual and projected demand for refined products. From Table F-3, both PADD 2A and 2B will experience the greatest need for supplemental crude oil. Curtailment of Canadian crude oil imports has increased the deficit of supply versus demand for refined products. PADDs 2A and 2B could benefit most from shale oil production, and projected demand for refined products indicates a need for increased refining capacity. New refining capacity (single or multiple plants) totalling nearly 200 thousand barrels per day is indicated as needed by 1990 in PADDs 2A and 2B. This shortfall between product demand and refining capacity has historically been met by imports of refined products (primarily from PADD 3).

PADD 4, although currently an exporter of crude oil, is an importer of refined products--predominantly from PADDs 2B and 3. New refinery capacity in PADD 4 could reduce product imports from outside the region, and shale oil production could supplement declining local crude oil production and the loss of Canadian imports. Shale oil would aid refineries in Montana and Wyoming that have been affected by the Canadian curtailments.

New refining capacity in southeastern Wyoming which would refine shale oil and produce refined products for Montana, Wyoming, North Dakota, South Dakota, Nebraska, Western Kansas, and Colorado could reduce or nearly eliminate the demand of refined products from PADDs 2B and 3. These displaced refined products could then be routed to make up the product deficits in the northern PADDs 2A and 2B areas. A refinery with production capacity of over 100 thousand barrels per day is indicated by Table F-3 as necessary by 1990 in the PADD 4 area to bring capacity and product demand into balance.

SUMMARY

The review of potential shale oil transportation systems, market areas, and existing refinery shale oil capability has led to the following conclusions:

- Based on estimated hydrogen surplus, no existing refineries in PADD 4 appear capable of denitrification of shale oil volumes of at least 10 thousand barrels per day. Eleven refineries in PADDs 2A and 2B could process 10 thousand barrels per day more of raw shale oil, and have aggregate capacity of about 186 thousand barrels per day. Although a relatively high shale oil capacity exists in these two PADDs, shale oil refining would be divided among eleven different refineries, which can be expected to complicate raw shale oil distribution problems. These refineries are listed in Table F-2. Shale oil upgrading at the oil shale processing site would permit refining at virtually any refinery.

- Examination of existing pipelines originating near the Piceance Creek Basin oil shale area indicate that they are inadequate to handle shale oil production levels in excess of 50 thousand barrels per day. Major expansions of feeder lines would allow transportation of nearly 300 thousand barrels per day to PADDs 2A, 2B, and 3 refineries. The highest existing potential for shale oil pipeline capacity is the northern system (Amoco). Expansion of this system's feeder lines would allow shipment of nearly 285 thousand barrels per day to the PADDs 2A and 2B refineries through the Amoco, Platte, and Arapahoe pipelines. Pipelining of raw shale oil will require heating and increased pump capacity or the addition of viscosity improvers. Alternatives to existing pipelines would include construction of new pipelines designed to meet the high pour point/high viscosity characteristics of raw shale oil.

- Based on comparisons of crude oil supply, total refining capacity, and demand for refined products, PADDs 2A, 2B, and 4 are areas of greatest shale oil market potential. Curtailment of Canadian imports has resulted in lower crude oil input for many refineries in these PADDs. Construction of the proposed Northern Tier pipeline would help eliminate the shortfall, but shale oil could supplement Alaskan North Slope crude oil in secondary or southern market areas to the proposed pipeline.

- When all of these factors are considered together, only the refineries listed in PADDs 2A and 2B appear to have the capability to receive and process significant volumes of raw shale oil. Although PADD 4 does not currently have the capability to process significant volumes of shale oil, it would be a logical contender for major new refinery construction which could handle shale oil.

- If onsite or regional shale oil upgrading were practiced, the resulting syncrude could be processed in essentially any existing refinery and transported in any existing pipeline system. This would also prevent costly duplication of high severity processing equipment by many small refiners dispersed over a wide area. This would allow integration of shale oil production into the nation's refining system with minimum cost and delay.

FIGURE F-1

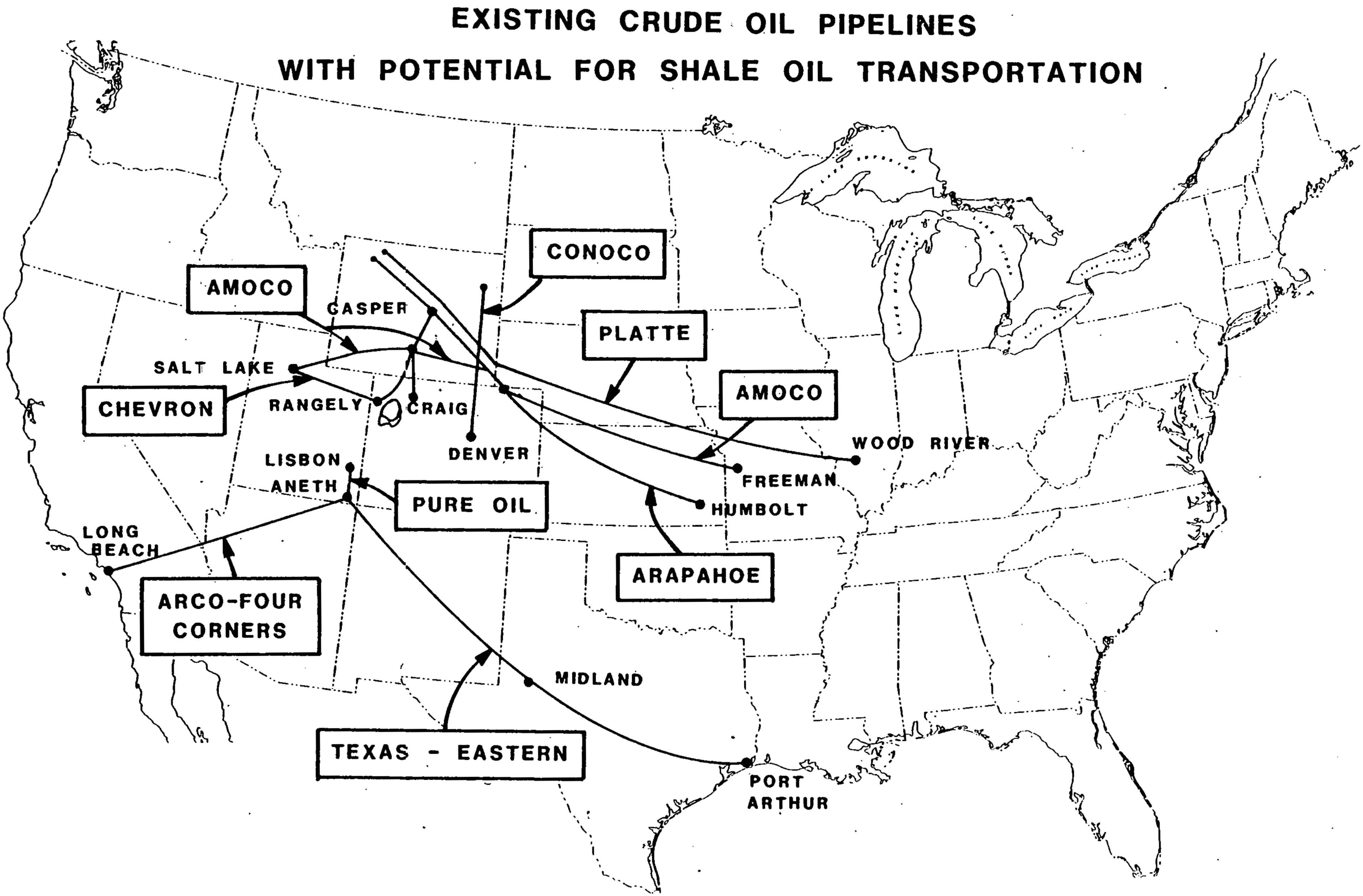

EXISTING CRUDE OIL PIPELINES
WITH POTENTIAL FOR SHALE OIL TRANSPORTATION
CONOCO
AMOCO
CASPER
PLATTE
SALT LAKE
AMOCO
CHEVRON
RANGELY
CRAIG
DENVER
WOOD RIVER
LISBON
ANETH
FREEMAN
PURE OIL
HUMBOLT
LONG BEACH
ARAPAHOE
ARCO-FOUR CORNERS
MIDLAND
TEXAS - EASTERN
PORT ARTHUR

TABLE F-1

REFINERIES EVALUATED FOR SHALE OIL REFINING CAPABILITY

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking Fresh feed	Cat cracking Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/ isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
ALABAMA																
Hunt Oil Co.—Tuscaloosa	28,500	29,900	15,000	.....	......	....	[2]5,500	...	[2]9,000	[2]6,000 [4]5,500	......	......	......	10,000	......	.....
Louisiana Land & Exploration Co.—Saraland	41,300	40,000	.....	......	......	....	......	....	......	......	......	......	......	......	......	.....
Mobile Bay Refining Co.—Chickasaw	28,000	21,000	......	......	......	....	[2]3,000	...	......	[1]3,000	......	......	......	......	......	.....
Mobil Bay Refining Co.—Chickasaw	28,000	30,000	......	.....	......	....	......	....	......	......	......	......	......	......	......	.....
Vulcan Refining Co.—Cordova	10,600	11,400	5,500	......	....	....	......	....	......	.....	......	......	.....	5,000	......	.....
Warrior Asphalt Co. of Alabama Inc.—Holt	2,875	3,000	......	......	......	....	......	...	......	.....	......	......	......	1,500	......	.....
Total	130,475	135,300	20,500	......	......	....	8,500	...	9,000	14,500	......	......	.....	16,500	......	.....
ARIZONA																
Arizona Fuels Corp.—Fredonia	6,000	5,400	3,500	......	.....	....	......	....	......	......	......	......	......	......	......	.....
ARKANSAS																
Berry Petroleum, Division of Crystal Oil Co.—Stevens	2,942	3,000	2,000	......	......	....	.....	....	......	......	......	......	......	......	......	.....
Cross Oil & Refining Co. of Arkansas—Smackover	8,600	8,750	3,100	......	......	....	.....	....	......	[6]1,200	......	......	1,500	1,500	[1]2.9	.....
Macmillan Ring-Free Oil Co.—Norphlet	4,400	4,500	3,000	......	......	....	......	....	......	......	......	......	1,950	1,500	......	.....
Tosco Corp.—El Dorado	47,000	48,300	17,000	......	[1]15,500	3,000	5,750	....	......	[1]7,500 [4]3,300 [6]1,100	[1]4,500	......	800	3,750	......	.....
Total	62,942	64,550	25,100	......	15,000	3,000	5,750	....	......	13,100	4,500	......	4,250	6,750	2.9	.....
CALIFORNIA																
● Atlantic Richfield Co.—Carson	180,000	186,00	76,000	[1]10,000 [2]42,000 [4]32,500	[1]56,000	None	[2]38,000	[1]19,000	......	[n]35,000 [6]18,000 [5]5,500 [7]16,500	[1]7,200	[1]2,500	......	......	[1]50.0	1,800
Basin Petroleum Inc.—Long Beach	NR	15,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Beacon Oil Co.—Hanford	12,300	12,400	......	[1]500 [2]2,750	......	....	[1]1,650	....	......	......	......	......	......	......	......	.....
Champlin Petroleum Co.—Wilmington	31,200	32,500	20,000	[4]11,500	......	....	......	....	......	......	......	......	......	......	......	650

Source: "Oil and Gas Journal" March 26, 1979 (Legend follows Table)

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/day
Chevron U.S.A. Inc.—																
Bakersfield	26,000	NR	...	[5]9,800	...	...	[2]6,000			[3]6,000						
● El Segundo	405,000	NR	179,000	[4]54,000	[1]52,000	8,000	[2]60,000	[1]49,000	[1]24,000 [2]60,000 [5]14,000	[1]45,000 [2]11,000 [7]18,000	[1]5,900	[1]1,500	...	8,300	[2]107.0 [3]55.0	2,700
● Richmond	365,000	NR	226,000	...	[1]55,000	5,000	[2]84,000	[1]45,000 [4]30,000	[2]60,000 [5]65,000	[1]82,000 [6]3,200	[1]9,200	[1]2,000 [4]2,000	6,300	11,000	[1]135.0	...
DeMenno Resources—Compton	10,000	11,000	...	...	...	...	...	...	...	...	...	...	1,000	...	...	...
Douglas Oil Co.—Paramount	46,500	48.000	28,000	...	...	...	[2]11,500	...	...	[2]12,000 [4]7,000 [5]10,000	...	...	...	15,000	...	...
Santa Maria	9,500	10,000	7,800	...	...	...	...	...	...	...	...	...	...	6,800	...	...
Eco Petroleum Inc.—Signal Hill	5,600	6,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Edgington Oil Co. Inc—Long Beach	29,500	NR	12,600	...	...	...	...	...	...	...	...	...	...	8,000	...	...
● Exxon Co.—Benicia	99,000	105,000	54,000	[3]26,000	[1]49,000	11,000	[3]24,000	[1]23,000	[2]23,000	[2]50,000	[1]11,500	...	...	...	[1]104.0	1,000
Fletcher Oil & Refining Co.—Carson	25,000	26,000	...	...	...	...	[2]4,000	...	...	[1]4,000	...	...	...	...	...	...
Golden Bear Division, Witco Chemical Corp.—Oildale	10,500	11,000	9,500	...	...	...	...	...	...	...	...	...	4,000	3,200	...	...
Golden Eagle Refining Co.—Carson	16,500	17,200	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Gulf Oil Co.—Santa Fe Springs	51,500	53,800	25,000	[2]13.800 [5]6.500	[1]13,500	300	[2]19,000 [1]3,000	[1]11,000	...	[1]12,000 [1]3,000	[2]3,000	...	...	4,000	[5]12.0	...
Kern County Refinery Inc.—Bakersfield	15,900	NR	...	[5]6,500	[2]3,000	...	...	...	...	[1]3,000	...	...	...	...	...	...
Lunday-Thagard Oil Co.—South Gate	12,000	10,000	2,500	...	...	...	...	...	...	...	...	...	...	...	...	...
Macmillan Ring-Free Oil Co. Inc.—Signal Hill	NR	12,200	...	...	...	...	...	...	...	...	...	...	...	...	...	...
● Mobil Oil Corp.—Torrance	123,500	131,100	95,000	[2]16,100 [4]46,000	[1]60,000	None	[2]35,500	[1]21,700	...	[1]21,000 [3]13,000 [5]26,500	[2]13,008	...	...	...	[1]56.0	2,900
Mohawk Petroleum Corp. Inc.—Bakersfield	22,100	22,800	...	...	...	...	[2]2,500	...	[2]2,500	[1]2,500	...	...	...	...	...	...
Newhall Refining Co. Inc.—Newhall	17,600	NR	8,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Oxnard Refinery—Oxnard	2,500	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Pacific Refining Co.—Hercules	85,000	NR	...	...	...	...	[2]15,000	[1]3,000	...	[1]14,000	...	...	...	...	...	...
Powerine Oil Co.—Santa Fe Springs	44,120	46,000	15,000	...	[1]11,500	300 [2]6,000	[1]1,500	...	[4]8,000	[1]10,000	[2]2,700	...	...	1,000	...	...
Road Oil Sales—Bakersfield	1,500	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Sabre Refining Inc.—Bakersfield	NR	9,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
San Joaquin Refining Co.—Oildale	27,000	NR	25,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Shell Oil Co.—Martinez	104,000	107,000	55,300	...	[1]46,000	40,000	[3]25,000	[1]20,000	[4]50,000	[2]17,000 [3]10.000 [5]16,000 [6]6,300 [7]11,000	[1]8,000	...	4,500	10,500	[1]65.0	...
Wilmington	108,000	113,000	60,000	[4]41,500	[1]35,000	5,000	[2]24,000	...	...	[2]27,000 [3]12,000 [7]33,400	[1]8,600	[4]3,800	...	...	...	2,100
Sierra Anchor—McKittrick	10,000	10,750	2,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Sunland Refining Corp.—Bakersfield	15,000	15,000	...	...	...	...	[1]1,000	...	...	[1]1,500	...	...	...	...	...	...
● Texaco Inc.*—Wilmington	75,000	NR	...	[4]48,000	[1]28,000	NR	[1]35,000	[1]20,000	[4]13,000	[1]20,000	[1]4,400	...	...	...	[5]48.0	1,650
Tosco Corp.—Bakersfield	NR	40,000	23,500	[3]7,000	[2]12,000	0	[2]15,500	[1]14,000	...	[1]7,000 [7]1,400	[1]1,800	...	...	...	[1]20.0	250
● Martinez	137,000	NR	81,000	[3]37,000	[1]47,000	0	[1]8,700 [2]21,300	[1]20,000	...	[2]34,500	[1]10,500	[4]1.800	100	...	[1]60.0	1,200
● Union Oil Co. of California—Los Angeles	108,000	111,000	83,000	[2]20,000	[1]45,000	7,000	[2]49,000	[1]21,000	...	[1]52,000 [5]33,000	[1]8,000	...	...	...	[1]49.4	..

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
Rodeo	111,000	117,000	38,500	[4]42,500	...	...	[2]26,000	[1]30,000	...	[1]21,000 [5]9,000 [7]14,000	...	...	3,600	4,250	[1]70.0	1,850
USA Petrochem Corp.—Ventura	20,000	19,000	...	...	...	...	[2]6,000	...	...	[1]7,500	...	...	...	...	...	...
West Coast Oil Co.—Oildale	19,000	NR	...	...	...	...	...	...	...	...	...	...	600	...	...	...
Total	2,453,620	2,567,219	1,126,700	479,183	516,111	85,933	527,039	328,922	320,944	789,022	94,289	13,600	20,100	73,050	831.4	16,100

*All figures are capacity. Stream-day figures not reported.

COLORADO

Company and location	Crude capacity b/cd	Crude capacity b/sd	Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
Asamera Oil U.S. Inc.—Commerce City	NR	18,000	7,000	...	[1]7,000	200	[1]3,000	...	...	...	*1,800	...	...	...	...	...
Continental Oil Co.—Denver	10,000	11,000	2,500	...	...	...	[7]6,500	...	...	[1]7,000 [4]8,500	...	...	...	...	...	...
Gary Western Co.—Fruita	13,000	14,000	10,000	...	...	...	[7]2,000	...	...	[1]2,000	...	...	...	[1]0.6	...	...
Total	40,100	43,000	19,500	...	7,000	200	11,500	...	...	17,500	1,800	...	...	0.6	...	...

*Polymerization.

ILLINOIS

Company and location	Crude capacity b/cd	Crude capacity b/sd	Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
Amoco Oil Co.—Wood River	110,000	115,000	36,000	...	[1]38,000	4,000	[1]12,300	...	...	[1]15,600 [7]17,000 [7]3,000	[1]5,500	...	...	10.800	...	...
Clark Oil & Refining Corp.— Blue Island	66,500	70,000	27,000	...	[1]26,000	1,000	[2]30,500	[1]11,000	...	[1]20,500	[7]6,000	...	...	4,500	...	...
Hartford	57,000	60,000	18,000	[4]13,000	[1]28,000	1,000	[2]9,200	...	...	[1]10,000 [4]10,000	[7]8,000	...	...	...	...	...
Marathon Oil Co.—Robinson	195,000	205,000	62,000	[7]2,800 [4]19,000	[1]38,000	400	[1]12,400 [3]35,000	[1]22,000	[6]6,000	[1]22,000	[7]7,600	...	...	...	[1]25.0	...
Mobil Oil Corp.—Joliet	180,000	200,000	88,000	[4]34,000	[1]92,000	27,600	[2]47,000	...	[5]75,000	[1]74,000	[2]23,000	...	...	...	...	2,080
M. T. Richards Inc.—Crossville	700	737	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Shell Oil Co.—Wood River	283,000	295,000	95,500	...	[1]94,000	0	[2]22,000 [3]68,000	[1]33,500	[4]27,000	[2]64,000 [5]52,500 [6]7,000 [7]35,000	[1]22,000	[1]2,900	5,600	29,400	[1]57.0	...
Texaco Inc.*—Lawrenceville	84,000	NR	24,000	[1]9,000	[1]34,000	NR	[2]24,000	...	...	[1]24,000 [7]17,000	[1]6,600	...	...	2,700	...	...
Lockport	72,000	NR	14,000	[4]27,000	[1]30,000	NR	[2]19,000	...	...	[1]9,000 [4]10,000 [7]17,000	[1]8,000	...	...	...	...	300
Union Oil Co. of California— Lemont	151,000	NR	55,000	[4]21,000	[1]55,000	8,000	[2]31,000	...	...	[1]31,000 [2]13,000 [3]4,000 [5]36,000 [7]2,200	[1]15,500	[1]3,500	...	2,500	...	1,050
Wireback Oil Co. Inc.—Plymouth	1,800	NR	...	[1]1,800	...	...	...	...	...	...	...	...	...	...	...	...
Yetter Oil Co.—Colmar	1,000	1,053	1,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Total	1,202,000	1,271,841	424,722	131,600	442,111	83,332	315,178	66,500	108,400	500,456	103,822	6,400	5,600	50,200	82.0	3,430

*All figures are calendar day. Stream-day figures not reported.

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
INDIANA																
● Amoco Oil Co.—Whiting	380,000	405,000	180,000	[4]25,000	[1]140,000	4,000	[3]76,000	...	...	[1]83,000 [5]38,000 [6]5,160 [7]20,000	[1]19,000	[1]12,800 [4]2,900	6,200	40,000	...	1,200
Energy Cooperative Inc.—East Chicago	126,000	140,000	70,000	...	[1]48,000	2,000	[1]20,000	...	...	[1]20,000 [5]25,000	[1]6,000	...	...	10,400	...	...
Gladieux Refinery Inc.—Ft. Wayne	10,600	12,200	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Indiana Farm Bureau Cooperative Association Inc.—Mt. Vernon	21,500	NR	8,000	...	[1]7,200	690	[2]3,000	...	...	...	...	...	...	...	...	...
Industrial Fuel & Asphalt of Indiana Inc.—Hammond	9,800	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Laketon Asphalt Refining Inc.—Laketon	8,100	8,500	7,500	...	...	...	...	...	...	...	...	...	...	3,000	...	...
Princeton Refinery Inc.—Princeton	4,600	NR	...	...	...	...	[2]1,500	...	...	[1]1,500	...	...	...	...	...	...
Rock Island Refining Corp.—Indianapolis	43,600	44,500	17,000	...	[1]17,000	None	[2]8,700	...	...	[1]13,500	[2]4,200	...	...	5,000	...	...
Total	604,200	647,988	282,500	25,000	212,200	6,690	109,200	...	...	206,160	29,200	15,700	6,200	58,400	...	1,200
KANSAS																
CRA Inc.—Coffeyville	49,850	51,250	17,000	[4]13,000	[1]16,080	1,500	[2]8,600	...	[5]3,000	[1]19,800	[2]6,000	...	2,500	...	...	450
Phillipsburg	26,600	27,460	10,000	...	[1]8,500	800	[2]5,300	...	...	[1]7,500	[2]2,300	...	...	2,000	...	...
Derby Refining Co.—Wichita	25,600	27,650	9,800	[4]3,800	[2]10,800	1,700	[2]5,000	...	...	[1]5,008	[2]3,000	...	...	...	...	160
E-Z Serve Refining Inc.—Shallowater	4,608	4,800	...	...	...	...	...	...	...	...	...	...	...	...	...	...
● Getty Refining and Marketing Co.—El Dorado	80,577	82,000	27,000	[4]11,500	[1]31,000	17,000	[2]21,500	...	[4]40,000	[1]23,000 [3]4,300	[2]10,000	[1]1,400	...	...	...	610
Mid-America Refining Co. Inc.—Chanute	3,100	3,300	1,800	...	...	...	...	...	...							
● Mobil Oil Corp.—Augusta	50,000	52,000	18,300	[1]4,100	[2]21,500	2,000	[1]10,500 [4]11,500	...	...	[1]11,500	[2]3,800	...	...	8,000	...	...
National Cooperative Refinery Association—McPherson	54,150	57,000	18,000	[4]17,000	[1]20,000	1,000	[2]7,000	...	...	[1]8,000	[2]6,000	[4]2,000	...	...	...	425
Pester Refinery Co.—El Dorado	21,800	22,500	8,000	...	[1]11,000	500	[2]4,000	...	...	[1]4,000	[2]2,000	...	...	2,000	...	...
Phillips Petroleum Co.—Kansas City	78,000	85,000	23,500	...	[1]33,500	16,700	[2]21,000	...	...	[1]30,000 [4]27,000 [5]5,000	[2]9,500	...	2,900	6,200	...	...
Total Petroleum—Arkansas City	42,500	47,200	13,000	...	[1]9,600	1,200	[1]16,300	[1]3,000	...	[1]16,300	[2]2,600	...	...	3,000	...	...
Total	436,185	460,160	146,400	49,400	161,900	42,400	110,700	3,000	43,000	161,400	45,200	3,400	5,400	21,200	...	1,645
KENTUCKY																
● Ashland Petroleum Co.—Catlettsburg	135,800	140,000	72,700	[2]4,000	[1]55,000	...	[2]26,500	...	[4]40,000	[1]26,500 [7]6,500 [3]4,500 [4]40,000	[1]5,500	[1]4,000 [2]2,500 [5]12,000	5,000	20,000	[1]20.0	...
Louisville	25,200	26,000	13,000	...	[1]10,000	...	[2]3,000	...	...	[1]3,000	...	...	...	3,500	...	...
Kentucky Oil & Refining Co. Inc.—Betsy Layne	470	1,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Somerset Refinery Inc.—Somerset	5,000	NR	...	...	...	...	[2]1,000	...	...	...	...	...	...	...	...	...
Total	166,470	172,263	85,700	4,000	65,080	...	30,500	...	40,000	80,500	5,500	18,500	5,000	23,500	20.0	...

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
LOUISIANA																
Atlas Processing Co., Division of Pennzoil—Shreveport	45,000	47,400	9,100	...	...	...	[2]10,000	...	...	[1]10,000 [3]1,800 [6]3,300 [7]4,800	...	[1]1,000	2,200	600	...	...
Bayou State Oil Corp.—Hosston	5,000	NR	2,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Calumet Refining Co.—Princeton	2,400	NR	4,800	...	...	...	...	...	...	...	...	...	2,000	500	...	...
Calcasieu Refining Ltd.—Lake Charles	NR	6,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Canal Refining Co.—Church Point	6,400	6,500	...	...	...	...	[2]2,100	...	...	...	...	...	...	...	...	...
Cities Service Co.—Lake Charles	291,000	NR	83,000	[4]28,000	[1]125,000	20,000	[2]46,000	...	[1]6,000 [5]30,000	46,000 [4]14,000	[1]33,000	[1]2,300	7,000	...	...	1,000
Claiborne Gasoline Co.—Lisbon	6,500	6,700	...	...	...	...	...	[1]2,200	...	...	...	...	...	...	...	...
Continental Oil Co.—Lake Charles	87,000	90,000	11,500	[1]7,000 [4]8,500	[2]25,500	5,000	[2]18,500	...	...	[1]19,000	[1]4,500	[4]630	...	...	...	...
Cotton Valley Solvents (Kerr-McGee Refining Corp.)—Cotton Valley	11,000	11,225	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Evangeline Refining Co. Inc.—Jennings	NR	5,000	...	...	...	...	[2]600	...	...	...	...	...	...	...	...	...
Exxon Co.—Baton Rouge	500,000	540,000	215,000	[4]50,000	[1]154,000	NR	[2]83,000	[1]25,000	...	[2]2,600 [3]70,000 [6]20,000 [7]3,000	[1]29,800	...	16,000	28,900	...	2,400
Good Hope Refineries Inc.—Good Hope	86,000	95,000	60,000	...	[1]65,000	500	[4]4,500	...	...	[1]4,500		[1]2,000				
Gulf Oil Corp.—Belle Chasse	195,900	202,000	73,000	[4]16,000	[1]78,000	2,300	[2]37,500	...	[4]15,000 [5]22,000	[1]42,000	[2]28,400	[1]11,100 [2]5,400	...	...	...	840
Venice	28,700	29,100	...	...	...	...	[2]18,000	[1]1,500	...	[1]14,400	...	...	...	...	...	...
Hill Petroleum Co.—Krotz Springs	10,100	10,700	...	...	...	...	...	...	...	...	...	...	...	...	...	...
LaJet Inc.—St. James	20,000	NR	20,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Marathon Oil Co.—Garyville	200,000	205,000	100,000	...	...	...	[5]37,500	...	[2]53,500 [5]37,000	[1]37,500	...	...	...	20,000	...	...
Mt. Airy Refinery Co.—Mt. Airy	13,600	14,200	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Murphy Oil Corp.—Meraux	92,500	95,400	40,000	...	[1]10,500	500	[6]23,000	...	...	[1]29,000 [4]15,000	[2]3,000	...	...	...	...	...
Placid Refining Co.—Port Allen	34,200	36,000	20,000				[2]5,500			[1]6,000						
Shell Oil Co.—Norco	230,000	240,000	90,000	[4]18,000 [5]29,000 [5]17,900	[1]10,000	2,000	[2]18,000 [3]28,000	[1]24,000	[4]25,000	[2]29,000	[1]13,500	...	...	10,000	[1]51.0	860
Shepherd Oil Inc.—Mermentau	10,000	10,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
T & S Refining Inc.—Jennings	10,200	10,984	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Tenneco Oil Co.—Chalmette	NR	120,000	23,000	[4]9,000	[1]22,000	NR	[2]35,000	[1]18,000	[5]13,000	[1]24,000	[2]5,000	[1]7,000	...	...	[1]22.0	350
Texaco Inc.†—Convent	140,000	NR	35,000	[2]12,000	[1]70,000	NR	[2]30,000	...	...	[4]55,000	[1]12,500	...	...	...	...	...
Total	2,149,950	2,263,733	788,242	196,733	567,777	106,433	402,733	78,500	203,500	457,011	131,088	29,430	27,200	60,000	73.0	5,450

*Cat poly. †All figures calendar day. Stream-day figures not reported.

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/day
MICHIGAN																
Crystal Refining Co.—Carson City	6,200	4,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Dow Chemical U.S.A.—Bay City	14,000	22,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Lakeside Refining Co.—Kalamazoo	5,600	NR	......	......	......	....	[1]2,000	....	......	......	......	......	......	......	......	.....
Marathon Oil Co.—Detroit	65,000	67,000	25,000	......	[1]25,500	1,300	[1]16,000	....	[4]12,500	[1]16,500	[1]3,500	......	......	8,650	......	.....
Osceola Refining Co.—West Branch	12,500	10,000	......	......	......	....	[1]1,600	....	[1]1,600	......	......	......	......	......	......	.....
Total Petroleum Inc.—Alma	40,000	42,000	......	......	[1]16,000	550	[2]10,000	....	[4]1,150 [2]3,500 [5]1,500	[1]10,000	[2]3,000	*1,000	......	......	......	.....
Total	143,300	150,895	25,000	......	41,500	1,850	29,600	....	20,250	26,500	6,500	1,000	......	8,650	......	.....
MINNESOTA																
Continental Oil Co.—Wrenshall	23,500	24,000	9,000	......	[1]9,500	500	[2]3,600	....	......	[2]3,600	......	*1,200	......	......	......	.....
Koch Refining Co.—Rosemont	127,300	131,905	80,000	[4]23,000	[1]50,000	1,000	[2]15,000	....	[4]45,000	[1]17,000 [4]28,000 [5]7,000	[1]8,500	......	......	35,000	[2]14.0	1,300
Northwestern Refining Co., Division of Ashland Petroleum Co.—St. Paul Park	67,000	69,000	32,000	......	[1]23,000	NR	[2]12,000	....	[4]20,000	[1]13,000 [4]7,200	[2]3,300	......	......	14,000	......	.....
Total	217,800	224,905	121,000	23,000	82,500	8,400	30,600	....	65,000	75,800	11,800	1,200	......	49,000	14.0	1,300
MISSISSIPPI																
Amerada-Hess Corp.—Purvis	30,000	NR	......	[4]7,000	[2]16,200	NR	5,400	....	......	[1]5,450	5,200	......	......	......	......	320
Chevron USA Inc.—Pascagoula	280,000	NR	148,000	......	[1]56,000	2,000	[2]90,000	[1]68,000	[4]26,000 [5]30,000	[1]48,000	[1]9,200	[1]6,000	......	......	[1]109.0	.....
Ergon Refining Inc.—Vicksburg	10,000	10,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Southland Oil Co.—Lumberton	5,725	6,600	......	......	......	....	......	....	......	......	......	......	......	2,772	......	.....
Sandersville	10,958	12,500	6,875	......	......	....	......	....	......	......	......	......	......	5,000	......	.....
Yazoo City	3,765	4,500	2,475	......	......	....	......	....	......	......	......	......	......	1,890	......	.....
Total	340,448	359,914	157,350	7,000	72,200	6,860	95,400	68,000	56,000	53,450	14,400	6,000	......	9,682	109.0	320
MISSOURI																
Amoco Oil Co.—Sugar Creek	109,000	111,000	40,000	[4]13,500	[1]42,000	12,000	[3]16,000	....	......	[1]21,000 [7]2,500 [4]38,000	[1]5,000	......	......	65,000	......	800
Total	109,000	111,000	40,000	13,500	42,000	12,000	16,000	....	......	61,500	5,000	......	......	65,000	......	800
MONTANA																
Cenex—Laurel	40,400	42,500	14,000	......	[1]12,000	3,000	[2]12,000	....	[5]14,000	[1]15,000	[2]3,000	[4]2,000	......	6,000	......	.....
Continental Oil Co.—Billings	52,500	56,000	17,000	......	[1]15,000	NR	[2]15,800	....	......	[1]16,000 [4]9,500	[2]3,800	[4]2,600	......	4,500	......	.....
Exxon Co.—Billings	45,000	46,000	18,000	[3]7,000	[1]19,200	14,500	[1]14,500	[1]4,900	......	[5]12,500 [2]15,500 [4]10,000 [5]10,000	[2]3,400	......	......	3,000	[5]16.7	310
Kenco Refining Inc.—Wolf Point	4,500	4,700	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Phillips Petroleum Co.—Great Falls	6,000	6,300	2,100	......	[1]2,100	1,250	[2]650	....	......	[1]750 [4]1,250	......	......	......	850	......	.....
Westco Refining Co.—Cut Bank	5,300	6,000	......	[1]2,200	......	....	[2]2,300	....	......	[1]2,300 [7]1,000	......	*100	......	......	......	.....
Total	153,700	161,500	51,100	9,200	46,300	23,750	45,250	4,900	14,000	93,800	10,200	4,700		14,350	16.7	310

*C_3 (Michigan)

*Cat polymerization. (Minnesota)

*Cat polymerization. (Montana)

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking Fresh feed	Cat cracking Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/day
NEBRASKA																
CRA Inc.—Scottsbluff	5,600	6,160	2,400	...	[1]2,400	500	[1]750	...	...	...	...	...	...	...	...	...
NEVADA																
Nevada Refining Co.—Tonopah	4,000	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Total	4,000	4,200	...	...	...	...	...	...	...	...	...	...	...	...	...	...
NEW MEXICO																
Caribou Four Corners Inc.—Kirtland	2,375	2,500	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Giant Industries Inc.—Farmington	8,800	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Navajo Refining Co.—North Artesia	NR	6,250	...	[1]1,500	...	...	[1]1,700 [2]6,000	...	...	[1]10,000 [4]3,200 [5]1,200	...	...	...	...	...	...
South Artesia	NR	23,750	4,000	...	[2]5,600	400	...	...	...	...	[2]1,500	...	...	2,400	...	...
Plateau Inc.—Bloomfield	12,900	14,000	...	...	[1]5,000	NR	[1]2,250	...	...	[1]2,250	...	...	...	...	...	...
Shell Oil Co.—Ciniza	18,000	19,000	7,900	...	[1]7,200	3,600	[2]6,800	...	...	[2]6,800	[2]1,440	...	...	700	...	...
Southern Union Refining Co.																
Lovington	36,000	37,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Monument	5,000	5,200	...	...	...	...	[5]650	...	...	...	...	...	...	...	...	...
Thriftway Co.—Bloomfield	3,500	5,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Total	115,074	121,963	11,900	1,500	17,800	5,500	17,400	...	...	23,450	2,940	...	...	3,100	...	...
OHIO																
Ashland Petroleum Co.—Canton	64,000	66,000	33,000	...	[1]25,000	NR	[2]11,000	...	[4]22,500 [5]12,000	[1]12,000	[2]7,000	...	...	12,000	...	...
Findlay	*NR	21,000	8,000	...	...	...	...	...	...	...	...	...	...	6,500	...	...
Gulf Oil Co.—Cleves	42,700	44,000	13,000	...	[1]18,000	2,000	[2]10,000	...	[5]5,000	[1]11,000	[2]4,500	...	...	2,900	...	...
Toledo	50,300	51,000	12,500	...	[1]19,800	2,000	[2]11,000	...	[5]5,500	[1]11,000	[2]5,500	...	...	2,000	...	...
Standard Oil Co. of Ohio—Lima	168,000	177,000	51,000	[4]16,200	[1]37,700	7,800	[2]47,000	[4]20,000	...	[1-2]59,000	...	...	2,100	...	...	620
Toledo	120,000	126,000	68,000	[4]11,200	[1]55,000	16,500	[2]40,700	[4]35,000	...	[1-2]37,000	[1]11,300	...	...	7,000	[1]24.0	630
Sun Co. Inc.—Toledo	125,000	130,000	22,000	...	[1]50,000	7,500	[1]25,000 [2]16,000	[1]26,000	...	[1]27,500	[1]7,000	[1]8,900 [2]2,400	...	3,600	[1]48.0	...
Total	589,950	615,000	207,500	27,400	205,500	43,300	160,700	81,000	45,000	157,500	35,300	11,300	2,100	34,000	72.0	1,250
OKLAHOMA																
Allied Materials Corp.—Stroud	7,000	7,250	7,250	...	...	...	...	...	...	...	...	...	1,000	1,800	...	...
Champlin Petroleum Co.—Enid	53,800	56,000	18,000	[4]5,000	[1]19,000	300	[2]15,000	...	...	[1]20,400	[2]4,500	[6]6,000	1,100	1,800	...	200
Continental Oil Co.—Ponca City	132,000	136,000	32,000	[4]17,000	[1]45,000	NR	[2]31,000	...	...	[1]31,000 7,000	[2]9,700	[4]3,000 [6]1,700	1,950	3,000	...	600
Hudson Refining Co. Inc.—Cushing	19,000	19,814	7,000	[4]4,000	[1]7,500	3,000	[2]4,500	...	...	[1]4,500 [2]2,000 [3]1,000 [7]1,000	[2]2,000	...	...	...	...	100
Kerr-McGee Refining Corp.—Wynnewood	50,000	51,000	10,000	...	[1]11,500	2,000	[2]7,500	[1]4,500	...	[1]7,500 [7]4,000	[2]3,500	...	...	3,500	[1]9.0	...
OKC Refining Inc.—Okmulgee	25,000	24,000	3,200	...	[2]8,000	2,000	...	...	...	...	[2]1,500	...	...	1,800	...	...
Oklahoma Refining Co.—Cyril	14,000	14,700	5,000	...	[1]6,700	1,675	[2]1,125	...	...	[1]1,125	[2]1,700	...	...	1,600	...	...
Sun Co. Inc.—Duncan	48,500	50,000	17,000	[4]12,000	[1]25,000	10,500	[2]8,000	...	...	[1]8,000	[2]5,800	...	...	...	...	400
Tulsa	88,500	90,000	31,500	[4]8,200	[1]30,000	1,400	[2]23,000	...	...	[1]24,000 [6]11,000	[1]2,600 [2]6,000	[1]2,000 [2]950 [3]1,500 [4]2,300	9,000	4,800	...	300
Texaco Inc.†—Tulsa	50,000	NR	14,500	[1]6,000	[1]18,000	NR	[2]20,000	...	...	[1]8,000 [7]17,000	[1]3,000	[4]500	...	...	...	...
Tonkawa Refining Co.—Arnett	6,000	6,500	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Vickers Petroleum Corp.—Ardmore	NR	64,500	30,000	...	[1]21,500	1,000	[1]12,000	...	[2]20,000	[1]12,000	[2]5,000	...	...	15,000	...	...
Total	555,075	572,395	177,061	52,866	194,200	42,875	124,347	4,500	20,000	162,301	45,633	18,005	13,050	33,300	9.0	1,600

*Seasonal operations: 7 months of the year.

[4]Cat poly. †All figures are calendar day. Stream day figures not reported.

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking Fresh feed	Cat cracking Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/day
OREGON																
Chevron U.S.A. Inc.—Portland	14,000	NR	15,000	......	......	....	......	....	......	......	......	......	......	8,600	......	.....
Total	14,000	14,737	15,000	......	......	....	......	....	......	......	......	......	......	8,600	......	.....
TENNESSEE																
Delta Refining Co.—Memphis	42,500	43,820	12,000	......	[2]12,500	None	[2]9,300	....	......	[1]9,300 [2]4,200	[2]3,600	......	......	3,015	......	.....
Total	42,500	43,820	12,000	......	12,500	....	9,300	....	......	13,500	3,600	......	......	3,015	......	.....
TEXAS																
Adobe Refining Co.—La Blanca	5,000	5,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
American Petrofina Inc.—Big Spring	60,000	65,000	25,000	[1]10,000	[1]24,000	1,000	[2]20,000	....	[5]8,000	[1]25,000	[2]6,000	[1]4,500 [2]2,500 [3]800	......	8,000	......	.....
Port Arthur	90,000	110,000	28,000	[1]10,000	[1]34,000	2,000	[1]22,000	....	[5]30,000	[1]22,000	[1]2,500	[1]3,000 [2]1,600	......	......	......	.....
Amoco Oil Co.—Texas City	415,000	432,000	191,000	[4]33,500	[1]184,000	33,000	[4]134,000	[1]42,000	......	[1]139,000 [4]50,000	[1]31,000	[1]45,000	......	5,300	......	1,500
Atlantic Richfield Co.—Houston	363,000	381,000	149,000	[4]30,000	[1]76,000	5,000	[1]95,000	....	[2]44,000 [5]88,000 [6]37,000	[1]95,000 [3]8,000 [6]6,600	[1]9,000	[1]11,200	6,400	......	......	1,800
Carbonit Refinery Inc.—Hearne	10,000	11,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Champlin Petroleum Co.—Corpus Christi	155,000	159,000	52,000	......	[1]65,000	NR	[2]6,300 [5]25,000	....	[4]50,000	[1]27,000 [2]6,300	[2]17,600	[1]2,500 [3]1,600	......	......	......	.....
Charter International Oil Co.—Houston	65,000	70,000	22,000	[2]10,000	[1]40,000	NR	[1]13,500	....	......	[1]15,000 [2]6,000 [3]1,800 [4]16,000 [7]7,500	[1]4,500	[1]2,850	......	5,000	......	.....
Chevron U.S.A. Inc.—El Paso	76,000	NR	26,000	......	[1]22,000	NR	[2]25,000	....	[4]14,000 [5]4,000	[1]25,000	[1]5,000	[4]2,000	.....	5,000	......	.....
Coastal States Petrochemical Co.—Corpus Christi	185,000	NR	45,000	[4]12,000	[1]19,000	600	[1]15,000 [6]20,000	....	[2]25,000	[1]30,000 [4]10,000 [5]10,000	[2]2,500	[1]11,500 [2]6,000	......	500	......	500
Crown Central Petroleum Corp.—Houston	100,000	103,000	38,000	[4]9,500	[1]50,000	0	[1]8,000 [2]14,000	....	......	[1]22,000	[2]10,000	[1]2,000 [2]2,000	......	......	......	300
Diamond Shamrock Corp.—Sunray	51,500	53,500	16,500	[1]2,500	[2]11,500 [3]11,500	2,000 2,000	[2]14,000	....	......	[1]14,000	[1]8,700	[4]1,400	.....	2,500	......	......
Dorchester Refining Co.—Mt. Pleasant	26,000	28,500	13,000	......	[2]10,000	500	[2]4,000	....	......	[1]4,000 [4-5]6,000	[2]2,400	......	......	8,000	......	.....
White Deer	NR	1,000	......	......	......	....	[2]1,000	....	......	......	......	......	......	......	......	.....
Eddy Refining Co.—Houston	NR	3,500	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Erickson Refining Co.—Port Neches	30,000	32,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Exxon Co. U.S.A.—Baytown	640,000	668,000	180,000	......	[1]145,000	15,000	[3]88,000 [4]60,000	[1]21,000	[1]75,000 [4]78,000 [5]45,000	[1]175,000 [5]192,000 [6]41,000 [7]8,500	[1]26,000	......	33,800	12,000	[1]75.0	.....
Flint Chemical Co.—San Antonio	1,200	1,400	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Gulf Oil Co.—Port Arthur	334,500	342,000	157,500	[4]30,000	[1]120,000	6,000	[2]65,000	[1]15,000	[5]65,000	[1]65,000	[1]5,500 [2]14,500	[1]2,700 [2]2,500 [5]7,200	13,200	......	[1]28.8	1,390

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydrocracking	Cat hydrorefining	Cat hydrotreating	Production capacity, b/sd: Alkylation	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
Gulf States Oil & Refining Co.—Corpus Christi	12,500	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Howell Corp.—Corpus Christi	15,000	15,790	4,000	...	...	...	[2]9,500	[1]5,000	...	[2-3]10,000	...	[1]2,750 [2]4,000	...	...	...	...
San Antonio	3,000	4,000	...	...	...	...	[1]1,300	...	...	...	...	[1]750	...	...	...	...
Independent Refining Corp.—Winnie	16,000	15,360	...	...	...	...	[1]5,000 [2]2,700	[1]3,000	...	[1]8,000 [2]300	...	[1]400	...	...	...	...
LaGloria Oil & Gas Co.—Tyler	29,300	29,700	...	[1]3,000 [4]12,000	[1]10,000	5,000	[2]9,500	...	...	[1]7,000	[1]3,000	...	...	...	...	80
Longview Refining Co., Division of Crystal Oil Co.—Longview	8,827	9,000	...	...	...	...	[2]5,500	...	[6]3,000	[1]4,000	...	...	...	...	...	...
Marathon Oil Co.—Texas City	66,000	68,000	28,000	...	[1]38,000	1,000	[1]8,000	...	...	...	[7]11,000	[1]2,500	...	...	...	...
● Mobil Oil Corp.—Beaumont	325,000	335,000	103,000	[4]27,000	[1]90,000 [2]24,000	NR NR	[7]102,000	[1]29,000	...	[1]85,000 [6]5,000 [7]116,000	[1]12,000	[3]20,000	8,800	...	[1]60.0	1,200
● Phillips Petroleum Co.—Borger	97,000	100,000	...	...	[1]52,000	10,400	[1]7,500 [2]21,000	...	...	[1]26,500 [4]27,400 [5]12,600	[2]16,800	[3]3,060 [4]8,100 [5]12,100 [6]12,500	...	...	...	...
● Sweeny	97,000	100,000	18,000	[2]8,000	[1]35,500	5,200	[2]36,000	...	...	[1]54,500	[2]10,500	[1]2,725 [3]7,630 [5]9,100 [6]7,800	...	...	...	...
Pioneer Refining Ltd.—Nixon	4,900	,5000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Pride Refining Inc.—Abilene	20,500	36,500	12,000	...	...	...	...	...	...	...	...	...	...	...	...	...
Quintana Refinery Co.—Corpus Christi	15,000	15,790	4,000	...	...	...	[2]9,500	[1]5,000	...	[2-3]10,000	...	[1]2,750 [2]4,000	...	...	[1]25.0 [4]72.0	...
Quitman Refining Co.—Quitman	6,000	5,700	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Rancho Refining Co. of Texas—Donna	1,200	1,164	1,164	...	...	...	...	...	...	...	...	...	...	...	...	...
Saber Refining Co.—Corpus Christi	20,000	21,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Sector Refining Co.—Tucker	9,700	10,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Sentry Refining Inc.—Corpus Christi	10,000	10,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Shell Oil Co.—Deer Park	285,000	310,000	125,500	[1]65,000 [5]20,000	[1]70,000	NR	[2]28,000 [3]40,000	...	[4]50,000	[2]71,000 [3]35,000 [6]7,000 [7]85,000	[1]7,850	[1]15,600	7,900	4,200	[1]68.0	...
Odessa	32,000	35,000	10,000	...	[1]10,500	5,500	[1]11,000	...	...	[2]11,000	[2]3,000	[1]1,000	...	...	...	...
Sigmor Refining Co.—Three Rivers	22,800	24,000	1,600	...	...	...	[2]8,500	...	...	[1]8,500 [6]2,000	...	...	1,200	...	...	...
South Hampton Refining Co.—Silsbee	20,500	22,500	...	...	...	...	[2]4,000	...	...	...	...	...	...	...	...	...
● Southwestern Refining Co. Inc.—Corpus Christi	120,000	122,450	36,000	...	[1]12,000	700	[2]30,000	...	[2]18,000	[1-2]35,000	[2]4,000	[1]6,000				
● Sun Co. Inc.—Corpus Christi	57,000	60,000	10,000	[4]7,700	[1]25,000	6,500	[1]13,000 [3]11,000	...	[1]12,500	[2]3,200	[1]6,000 [2]1,300	...	...	...	...	235
Tesoro Petroleum Corp.—Carrizo Springs	26,100	27,500	...	...	...	...	[2]3,000	...	...	[1]3,000	...	...	...	...	...	...
Texaco*—Amarillo	20,000	NR	...	[4]4,000	[1]8,000	NR	[2]5,000	...	...	[1]5,000	[1]1,500	...	...	...	...	100
El Paso	17,000	NR	...	[4]4,000	[1]7,000	NR	[2]3,500	...	...	[1]3,500	[1]1,500	[4]500	...	...	...	100
Port Arthur	406,000	NR	142,000	[1]18,000	[1]135,000	NR	[2]60,000	[1]15,000	...	[1]60,000 [4]62,000 [6]18,000	[1]15,000	...	20,000	...	...	...
Port Neches	47,000	NR	26,000	...	...	...	...	...	...	...	...	...	...	9,000	...	...
Texas Asphalt & Refining Co.—Euless	5,000	6,000	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Texas City Refining Inc.—Texas City	119,600	130,000	49,000	[2]9,000	[1]35,000	0	[2]11,000	...	...	[1]11,000	...	...	...	...	...	...
Thriftway Inc.—Graham	1,800	2,500	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Tipperary Corp.—Ingleside	6,590	6,500	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Uni Refining Inc.—Ingleside	NR	12,500	...	...	...	...	...	...	...	...	...	...	...	...	...	...
● Union Oil Co. of California—Beaumont	120,000	NR	43,000	...	[1]38,000	4,000	[3]36,000	...	...	[1]36,000 [3]6,000 [7]7,000	[1]4,200	[1]2,100 [3]1,800	3,400	3,600	...	...
Winston Refining Co.—Fort Worth	20,000	20,500	3,500	...	[1]3,400	2,600	[1]1,700	...	...	...	...	...	...	...	...	...
Total	4,708,571	4,957,352	1,578,431	328,088	1,422,066	249,133	1,120,612	136,66[illegible]	646,500	1,906,103	244,351	240,071	96,922	64,100	328.8	7,205

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking: Fresh feed	Cat cracking: Recycle	Cat reforming	Cat hydro-cracking	Cat hydro-refining	Cat hydro-treating	Production capacity, b/sd: Alkyla-tion	Aromatics/ Isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
UTAH																
Amoco Oil Co.—Salt Lake City	39,000	41,500	...	...	[1]18,000	4,000	[3]6,000	...	...	[1]6,000	[1]3,750	[4]3,000	...	9,000	...	...
Caribou Four Corners Inc.—Woods Cross	7,050	7,400	1,000	...	[2]2,000	NR	...	[1]1,100	...	[2]3,500	...	...	...	...	...	...
Chevron U.S.A.—Salt Lake City	45,000	NR	35,000	[4]8,500	[1]11,000 [3]7,000	None 1,000	[2]5,500	...	[5]5,500	[1]5,500	[2]4,300	[4]750	...	...	...	350
Husky Oil Co.—North Salt Lake City	25,000	26,000	3,800	...	[2]4,400	2,500	[2]5,000	...	...	[1]6,000	[2]1,000	...	...	...	...	...
Morrison Petroleum Co.—Woods Cross	2,500	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Phillips Petroleum Co.—Woods Cross	24,000	25,000	3,200	...	[2]8,400	2,600	[2]4,700	...	...	[1]11,000 [3]1,600	[2]2,100	...	...	1,700	...	...
Plateau Inc.—Roosevelt	8,000	8,500	...	...	[1]5,200	None	...	...	...	...	...	...	...	...	...	...
Wesreco Inc.—Woods Cross	NR	12,500	1,000	...	...	...	[4]2,300	...	...	...	...	...	...	...	...	...
Total	162,425	170,899	44,000	8,500	56,000	10,700	23,500	1,100	5,500	33,600	11,150	3,750	...	10,700	...	350
WASHINGTON																
Atlantic Richfield Co.—Cherry Point, Ferndale	106,000	110,000	65,000	[4]30,000	...	...	[4]39,000	[1]39,000	[5]12,000	[1]27,000	...	...	...	...	[1]62.0	1,600
Chevron U.S.A. Inc.—Seattle	4,500	NR	5,000	...	...	...	...	...	...	...	...	...	...	4,000	...	...
Mobil Oil Corp.—Ferndale	71,500	75,000	13,000	[2]7,000	[2]25,500	2,000	[2]11,000 [4]12,000	...	...	[1]13,000 [3]21,000	[2]5,900	...	...	...	...	...
Shell Oil Co.—Anacortes	91,000	94,000	33,000	...	[1]36,000	17,000	[2]20,000	...	[4]8,500	[2]20,000 [3]7,000 [7]21,000	[1]12,100	[4]2,900	...	...	...	...
Sound Refining Inc.—Tacoma	8,000	10,000	3,500	...	...	...	...	...	...	...	...	...	...	...	...	...
Texaco Inc.*Anacortes	78,000	NR	25,000	...	[1]30,000	NR	[2]20,000	...	...	[4]25,000 [7]17,000	[1]6,600	...	...	...	...	...
United Independent Oil Co.—Tacoma	1,000	NR	...	...	...	...	...	...	...	...	...	...	...	...	...	...
U.S. Oil & Refining Co.—Tacoma	21,400	NR	4,800	...	...	...	[2]3,000	...	...	[1]3,000	...	...	...	...	...	...
Total	381,400	399,420	152,078	37,000	94,833	38,000	107,222	39,000	20,500	158,667	25,333	2,900	...	4,000	62.0	1,600
WISCONSIN																
Murphy Oil Corp.—Superior	40,000	46,800	20,500	...	[1]9,700	1,000	[2]10,000	...	[5]5,800	[1]10,000	[2]1,700	...	...	13,500	...	...

*All figures are calendar day. Stream-day figures not reported.

Table F-1 (continued)

Company and location	Crude capacity b/cd	Crude capacity b/sd	Charge capacity, b/sd: Vacuum distillation	Thermal operations	Cat cracking Fresh feed	Cat cracking Recycle	Cat reforming	Cat hydro-cracking	Cat hydro-refining	Cat hydro-treating	Production capacity, b/sd: Alkyla-tion	Aromatics/ isomerization	Lubes	Asphalt	Hydrogen, MMcfd	Coke, tons/ day
WYOMING																
Amoco Oil Co.—Casper	47,000	48,000	15,500	......	[1]13,000	1,500	[2]5,800	....	......	[1]7,100	[1]1,300	......	1,830	1,550	......	.....
C & H Refinery Inc.—Lusk	190	200	200	......	......	....	......	....	......	......	......	......	......	......	......	.....
Glacier Park Co.—Osage	3,900	4,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Glenrock Refinery Inc.—Glenrock	NR	1,000	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Husky Oil Co.—Cheyenne	24,200	25,200	14,000	......	[1]10,000	2,500	[1]1,000 [2]5,200	....	......	[1]6,200 [4]4,900	[2]2,750	[4]1,500	......	3,000	......	.....
Cody	10,800	11,300	6,500	......	[1]3,300	1,000	[2]1,500	....	......	[1]1,500 [4]1,800	[2]800	......	......	4,000	......	.....
Little America Refining Co.— Casper	24,500	NR	8,600	......	[2]6,500	4,000	[1]3,750	....	......	[1]5,000 [2]3,750	......	......	......	2,000	......	.....
Mountaineer Refining Co. Inc.—LaBarge	500	700	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Sage Creek Refining Co. Inc.—Cowley	1,000	1,200	......	......	......	....	[1]500	....	......	......	......	......	......	......	......	.....
Sinclair Oil Corp.—Sinclair	49,000	50,000	16,100	......	[1]17,700	1,200	[1]9,700	....	[4]12,200	[1]13,000 [4]12,000	[1]2,200	......	......	2,600	......	.....
Southwestern Refining Co.—LaBarge	1,000	NR	......	......	......	....	......	....	......	......	......	......	......	......	......	.....
Texaco Inc.*—Casper	21,000	NR	10,000	[5]4,000	[1]7,000	NR	[2]4,000	....	[4]4,000	[1]4,000	......	......	......	1,500	......	125
Wyoming Refining Co.—Newcastle	10,500	11,000	......	......	[2]4,000	3,000	......	....	......	......	[2]900	......	......	......	......	.....
Total	194,540	201,548	72,011	4,444	62,278	15,533	31,894	....	16,644	59,694	7,850	1,500	1,830	14,817	......	125

*All figures are calendar day. Stream-day figures not reported.

• Refineries with capability to denitrify 10 thousand barrels per day of raw shale oil.

LEGEND

Numbers identify processes in table.

CAT HYDROREFINING
1. Residual desulfurizing
2. Heavy gas-oil desulfurizing
3. Residual visbreaking
4. Cat-cracker and cycle-stock feed pretreatment
5. Middle distillate
6. Other

CAT HYDROTREATING
1. Pretreating cat-reformer feeds
2. Naphtha desulfurizing
3. Naphtha olefin or aromatics saturation
4. Straight-run distillate
5. Other distillate
6. Lube-oil "polishing"
7. Other

AROMATICS/ISOMERIZATION
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. C_4 feed
5. C_5 feed
6. C_5 and C_6 feed

CAT HYDROCRACKING
1. Distillate upgrading
2. Residual upgrading
3. Lube-oil manufacturing
4. Other

CAT REFORMING

Semiregenerative:
1. Conventional catalyst
2. Bimetallic catalyst

Cyclic:

3. Conventional catalyst
4. Bimetallic catalyst

Other:

5. Conventional catalyst
6. Bimetallic catalyst

THERMAL PROCESSES
1. Gas-oil cracking
2. Visbreaking
3. Fluid coking
4. Delayed coking
5. Other

ALKYLATION
1. Sulfuric acid
2. Hydrofluoric acid

CAT CRACKING
1. Fluid
2. Thermofor
3. Houdriflow

HYDROGEN
1. Steam methane reforming
2. Steam naphtha reforming
3. Partial oxidation
4. Cryogenic
5. Other

NR—not reported

TABLE F-2

REFINERIES WITH SURPLUS HYDROGEN ALLOWING REFINING OF RAW SHALE OIL VOLUMES OF 10,000 BARRELS PER DAY OR MORE

Refinery/Location	Surplus[1] Hydrogen (MMSCFD)	Potential[2] Shale Oil Capacity (BPD)
PADD 2A		
Marathon Oil/Robinson, Illinois	40	20,000
Mobil Oil/Joliet, Illinois	26	13,000
Shell Oil/Wood River, Illinois	50	25,000
Texaco/Lawrenceville, Illinois	22	11,000
Amoco Oil/Whiting, Indiana	50	25,000
Ashland Petroleum/Catlettsburg, Kentucky	33	16,500
Sun Oil/Toledo, Ohio	53	26,500
Total	274	137,000
PADD 2B		
Getty Oil/Eldorado, Kansas	22	11,000
Mobil Oil/Augusta, Kansas	25	12,500
Continental Oil/Ponca City, Oklahoma	30	15,000
Texaco/Tulsa, Oklahoma	20	10,000
Total	97	48,500
PADD 3		
Amoco Oil/Texas City, Texas	56	23,000
Arco/Houston, Texas	39	19,500
Chevron/El Paso, Texas	20	10,000
Crown Central Petroleum/Houston, Texas	23	11,500
Exxon/Baytown, Texas	31	15,500
Gulf Oil/Port Arthur, Texas	46	23,000
Mobil Oil/Beaumont, Texas	75	37,500
Phillips Petroleum/Borger, Texas	20	10,000
Phillips Petroleum/Sweeny, Texas	33	16,500
Southwestern Refining/Corpus Christi, Texas	25	12,500
Sun Oil/Corpus Christi, Texas	27	31,500
Union Oil of California/Beaumont, Texas	34	17,000
Cities Service/Lake Charles, Louisiana	33	16,500
Exxon/Baton Rouge, Louisiana	36	18,000
Gulf Oil/Belle Chasse, Louisiana	28	14,000
Texaco/Convent, Louisiana	25	12,500
Chevron USA/Pascagoula, Mississippi	44	22,000
Total	595	297,500

.......Continued

TABLE F-2 - Continued

Refinery/Location	Surplus[1] Hydrogen (MMSCFD)	Potential[2] Shale Oil Capacity (BPD)
PADD 4		
None		
PADD 5		
Arco/Carson, California	49	24,500
Chevron/El Segundo, California	95	47,500
Chevron/Richmond, California	25	12,500
Exxon/Benicia, California	81	40,500
Mobil Oil/Torrance, California	51	25,500
Texaco/Wilmington, Caliofrnia	49	24,500
Tosco Corporation/Martinez, California	61	30,500
Union Oil/Los Angeles, California	56	28,000
Union Oil/Rodeo, California	44	22,000
Arco/Cherry Point, Washington	42	21,000
Total	553	276,500

Notes: Refineries only include those with catalytic reforming and catalytic hydrotreating/catalytic hydrorefining units.

[1] Approximate hydrogen surplus based on plant hydrogen balance.

[2] Capacity of refining raw shale oil which is estimated to require 2,000 standard cubic feet of hydrogen per barrel of crude oil to remove excess nitrogen and sulfur.

TABLE F-3

COMPARISON OF PRODUCTION, EXISTING REFINING CAPACITY, AND DEMAND (Thousand Barrels Per Day)

	PAD District				
	2A	2B	3	4	5
Production					
Actual					
1977	228	668	5,121	594	1,424
Projected					
1985	190	570	4,295	520	3,340
1990	160	510	3,570	515	3,375
2000	125	410	2,050	580	4,230
Existing Refinery Capacity	2,860	1,250	6,880	504	2,860
Refined Product Demand					
Actual					
1976	2,975	1,263	2,667	464	2,252
Projected					
1985	4,433	1,328	3,006	586	2,751
1990	2,486	1,427	3,443	610	2,806
2000	4,343	1,575	4,179	731	3,601

G

GRASS ROOTS REFINERY CONSIDERATIONS

G

GRASS ROOTS REFINERY CONSIDERATIONS

CAPITAL INVESTMENT REQUIREMENTS

A configuration of a grass roots shale oil refinery would depend on the desired product slate and volume of available shale oil in the area. The investment estimate of $85 million for the onsite processing facilities required to distill 50 thousand barrels per day of shale oil and hydrotreat the naphtha, distillate, and gas oil fractions is representative of the required investment for a standard hydroskimming type refinery. For a grass roots refinery of this nature, the offsites investment would be roughly $55 million, bringing the total investment to $140 million. Further processing equipment, such as catalytic reforming, hydrocracking, or catalytic cracking could be added if a complex refinery were the operator's desire. Investment requirements for those units in a shale oil refinery should not vary from those of a conventional crude oil refinery.

PLANT SITING CONSIDERATIONS

Factors which must be considered in siting a grass roots refinery or undertaking a major expansion of an existing facility include:

- Regional demand for products which can be produced from shale oil.
- Availability of a reliable supply of shale oil--a constant production rate and access to a shale oil transportation system are required.
- Need for additional refining capacity to meet the product demand.
- Ability to meet environmental restrictions as well as other federal, state, and local regulations.
- Availability of infrastructure to accommodate construction/operation of refinery.
- Availability of other resources, such as water, which will be required by the new facility.

The siting of a grass roots refinery is problematical and would require a major effort to define potential sites. However, the following observations which apply particularly to oil shale are in order.

At first glance it appears logical to site a grass roots oil shale refinery near the resource--namely the Piceance Creek Basin of Colorado or the Uintah Basin of Utah. The current political realities are that such a refinery would receive a cool reception by the State of Colorado, and probable support from the State of Utah. Water availability to support both a shale oil industry and refining industry would be likely to provide a focal point for opposition.

While sufficient water will probably be available for both industries, conflicts with competing users would intensify as the shale oil industry grows. If the public gradually comes to accept the fact that liquid hydrocarbons will be in tighter and tighter supply, support for a local source of fuel supply might gain public acceptance as a means to avoid shortages.

H

REFINING INDUSTRY ATTITUDES

H

REFINING INDUSTRY ATTITUDES

Concern has been expressed that shale oil may be difficult to market to refiners because of its severe refining requirements. If this were the case, it is conceivable that shale oil's role in supplementing conventional energy supplies would be limited because of refiners' resistance to process shale oil. Closer examination of this critical issue indicates that the concern may be unfounded.

Refiners' acceptance of shale oil must be viewed from a perspective of the shale oil industry. Most of the shale oil projects which are proposed are being conducted by oil companies planning to process any shale oil produced in their own refineries. Hence, shale oil production and refining are tied together in these projects. If the shale oil could not be refined, it would not be produced. We have contacted the sponsors of those shale oil projects which have been proposed and are currently active to determine the disposition of any produced shale oil, and their outlook on refining problems which might be encountered. A summary of these findings is presented in the following.

COLONY DEVELOPMENT OPERATION

The Colony Project is jointly sponsored by Tosco and Arco, who propose to produce 47 thousand barrels per day of upgraded shale oil to be pipelined to Arco's Houston refinery. Arco chose to upgrade on site to produce syncrude for the following reasons:

- Raw shale oil would cause operational problems in their Houston, Texas refinery given its present configuration.
- Raw shale oil would produce contamination problems with other crude oils which are flowing through the Texas/New Mexico line to Houston.
- Fuel gas is available on site for the production of hydrogen by steam reforming.
- Upgraded shale oil will be used by Arco to back out imported oil, and it might also be traded to other refiners in exchange for other crude supplies. Raw shale oil would present problems in such trades.

It can thus be concluded that shale oil refining will not be a problem for production from the Colony Project.

PARAHO

Paraho has proposed a modular shale development at Anvil Points on the Naval Oil Shale Reserves. Because the shale oil produced by Paraho at Anvil Points would be the property of the government, Paraho has not attempted to market the shale oil, although authorization to do so has been requested. Paraho's opinion is that the diversity of the refining industry and broad range of conditions which apply to crude availability will make shale oil an attractive feedstock to enough refiners to dispose of any available shale oil.

Thus, the disposition of shale oil produced by Paraho is uncertain--it might be sold to independent refiners or used as boiler fuel.

OCCIDENTAL PETROLEUM (TRACT C-B)

Oxy has proposed a project to produce 57 thousand barrels per day of raw shale oil for sale to refiners or for use as boiler fuel. Oxy has assessed the marketability of their shale oil, including an extensive marketing survey done for them by Purvin & Gertz, Inc. This survey was submitted to the Department of Energy as Appendix K in "Summary Report for the Period November 1, 1976 to October 31, 1977, Volume II." The survey included talks with the following refiners:

- Amoco
- Ashland
- Centex
- Clark
- Conoco
- Energy Cooperative
- Exxon
- Farmland Industries
- Koch Refining
- Marathon
- Mobil
- Murphy
- Phillips
- Shell
- Skelly
- Texaco
- Union

We conclude that refiners with a lack of long-term crude oil supplies were interested in acquiring shale oil as a feedstock. Refiners whose plant capacities were limited by high bottoms production were also interested in shale oil due to its lack of a large bottoms fraction. Those refiners who were not interested in shale oil generally either had an assured crude oil supply or lacked hydrotreating capacity.

RIO BLANCO OIL SHALE COMPANY

The Rio Blanco Oil Shale Project is jointly sponsored by Gulf and Standard of Indiana (Amoco), and proposes to build a 76 thousand barrels per day commercial oil shale plant in Colorado.

Rio Blanco would only provide enough onsite treatment to make the raw shale oil pipelineable. This would be done with pour point depressants and thermal treatment. An Amoco pipeline would be used to transport the shale oil to the Midwest where it would be processed in Amoco or Gulf refineries. The small relative volumes of shale oil would not present a problem to either Gulf or Amoco from a refining standpoint.

SUPERIOR OIL

Superior has proposed a 13 thousand barrels per day oil shale retorting modular program which would also recover nahcolite and dawsonite.

Superior Oil is strictly an exploration/production company, and has no refining facilities. Therefore, Superior Oil is planning to sell its shale oil production to other refiners or utilities. Superior has talked to several refiners regarding their capability and interest in refining raw shale oil. Because Superior is in the business of selling crude oil to refiners, they had no particular problems in identifying refiners who are in need of additional crude oil supplies.

Refiners who have excess capacity are not concerned about the contaminants in shale oil. Superior expects that raw shale oil will be marketed at a discount of about $1.00 per barrel compared with medium quality crude oil. If the discount for shale oil were to reach $3.00 to $4.00 per barrel, Superior would probably look at onsite upgrading.

Based on the above, Superior feels that shale oil will be readily accepted by refiners who are crude oil limited. If raw shale oil is assessed a large quality penalty, onsite upgrading to syncrude will be considered.

UNION OIL

Union Oil is proposing a 9,000 barrels per day module to produce raw shale oil in its Long Ridge Project.

Raw shale oil produced from the first module would be sold as boiler fuel. When three modules are operational, Union would most likely go with onsite upgrading to produce syncrude for their Los Angeles, California; Rodeo, California; Beaumont, Texas; or Chicago, Illinois refineries.

Union does not anticipate any problems in either using the raw shale oil as boiler fuel, or in processing the upgraded shale oil in their refineries.

In summary, shale oil refining will be an integral part of many shale oil projects because the project sponsors plan to process the shale oil in their own refineries. In these cases, refining is not viewed as a major problem. Those projects which will sell raw shale oil have found refiners without assured crude oil supplies to be very interested in processing shale oil. Lack of hydrotreating capacity and equipment capable of operating under severe conditions will be the limiting factors preventing individual refiners from accepting raw shale oil.

In our discussions with project sponsors, a simple tradeoff was expressed: if problems develop in marketing raw shale oil to refiners, onsite upgrading will be employed. This makes the shale oil transportable in any pipeline, and capable of being processed in any refinery.

APPENDIX

ABSTRACTS FROM THE CURRENT SHALE OIL PROCESSING LITERATURE

INTRODUCTION

Included in this Appendix are abstracts of papers and reports which identify and document present shale oil processing R&D technology, refining options being considered, and prospective market outlets for refined products. Because of the number of documents on these subjects and because of the great degree of repetition of subject matter, it was necessary to screen the documents for inclusion in this Appendix. Therefore, these abstracts represent current and thorough treatment of the issues at hand.

ABSTRACT

REFINING OF PARAHO SHALE OIL INTO MILITARY SPECIFICATION FUELS: RESULTS OF PHASE I; PILOT PLANT STUDIES

E.T. Robinson, SOHIO

February 1979

This paper presents the final results of the first phase of a three-phase program to refine up to 100,000 barrels of Paraho shale oil into military specification fuels. The program is a joint effort by DOE and DOD and is managed by the U.S. Navy.

The refining process includes in a pre-treating phase batch settling and guard bed treatment to reduce iron and arsenic as well as ash and solids. Following pre-treatment the whole oil is catalytically hydrotreated at elevated temperatures and hydrogen partial pressure. The hydrotreated oil is subsequently fractionated and acid/clay treatment was necessary to meet military specification gum and stability requirements.

Preliminary results from the actual refining run lead to the conclusion that military specification fuels can be produced from shale oil. However, given the process scheme used in the test run, the guard bed is necessary to protect the hydrotreating catalyst from nitrogen poisoning and hydrotreating is required to remove heteroatoms, increase the hydrogen/carbon ratio, and improve the yield of 650° minus product. Acid/clay treatment is required to meet thermal and storage stability requirements of jet and diesel fuel.

ABSTRACT

SHALE OIL: AN ACCEPTABLE REFINERY SYNCRUDE

Stauffer, H.C. and Yanik, S.J.
Gulf Science and Technology Company

September 1978

This paper is concerned with the upgrading of shale oil which in raw state is not suitable for conventional refining processes. The upgrading studies have two objectives: (1) produce a syncrude that can be pipelined and then refined in an existing facility; or (2) upgrade and refine to a full slate of products at the retort site. In either case, the overall upgrading requirements are substantial and quite similar. This paper presents the results of the most recent exploratory studies made to determine (1) the effectiveness of the commercially-available hydrotreating technology for upgrading shale oil to a petroleum substitute and (2) the response obtained in conventional downstream refining processes. This report is presented under the following headings:

- Upgrading Routes
- Shale Oil Quality
- Delayed Coking of Residuum
- Catalytic Cracking
- PPC Product Quality
- Middle Distillate Hydrotreating
- NAPTHA Pretreating and Reforming
- Alternate Upgrading Route.

It is concluded that shale oil fractions, when suitably upgraded, are quite amenable to refining in conventional processes.

Product yields and quality are comparable to those obtained with a good quality petroleum crude. Upgrading the total shale oil via the modified gulf HDS process results in an improved yield structure and a less complex facility. New catalyst formulations are expected to substantially reduce process severity.

ABSTRACT

REFINING AND UPGRADING OF SYNFUELS FROM COAL AND OIL SHALE BY ADVANCED CATALYTIC PROCESSES: FIRST INTERIM REPORT; PROCESSING OF PARAHO SHALE OIL

Chevron Research Company

July 1978

Surface retorted Paraho oil from the Piceance Creek Basin in Colorado was refined in pilot plant facilities. The objective of the project was to utilize petroleum processing technology to convert crude shale oil into transportation fuels. Four refining routes were demonstrated:

- Hydrotreating followed by hydrocracking
- Hydrotreating followed by catalytic cracking
- Coking followed by hydrotreating
- Hydrotreating to produce a synthetic crude which is suitable for processing in an existing petroleum refinery.

The shale oil used in this study contained over 2 wt percent nitrogen, roughly an order of magnitude greater than typical petroleum crudes. The pilot plant tests showed that nitrogen can be reduced to 1 ppm with severe hydrotreating although this low nitrogen level is neither economical, nor necessary.

Refining costs were estimated for each of the first three process routes based on producing (1) 50,000 BPCD of transportation fuels from a "grass roots" refinery in a remote Rocky Mountain location, and (2) 100,000 BPCD of transportation fuels from a "grass roots" refinery located near a Rocky Mountain or Mid-Continent urban center. The costs for hydroprocessing to produce a synthetic crude also were estimated both for a "grass roots" site near the shale oil retorting facilities and for location at a typical existing Mid-Continent refinery. All refineries were designed with facilities to meet present environmental requirements and anticipated near-term environmental and energy conservation regulations.

Including a 15 percent DCF rate of return, the study found the cost of processing shale oil into finished products ranged from $8-10 per barrel for a 100,000 BPCD refinery, while the cost of upgrading raw shale oil into synthetic crude was about $6.50 per barrel. All cost figures are based on Rocky Mountain and Mid-Continent "grass roots" refineries.

Technical areas were identified which indicate further studies, but no overriding problems with the technology were found.

ABSTRACT

MARKETS FOR CRUDE SHALE OIL IN CENTRAL U.S.

Occidental Oil Shale, Inc.

May 1977

This study focused on the transportation modes and costs of crude shale oil; market analysis for the refined products, pricing and regulatory issues; and petrochemical markets.

The study indicated that almost 200,000 BPD of spare capacity exists in the Amoco Pipeline Company and Platte Pipeline Company systems. These pipelines originate in Casper, Wyoming, and transport crude oil to various mid-west terminals. This may be the best prospect for inexpensive transport of shale oil to refining centers. To utilize these pipelines, a new pipeline would have to be built to connect the Piceance Creek Basin to the Casper area. The construction of such a pipeline has been under construction by the Marathon Pipeline Company for several years.

The study concluded that a reasonable tariff for the Piceance-Casper pipeline is about $0.30 per barrel. Total 1980 transportation costs by pipeline from Colorado to Chicago were estimated at about $0.90 per barrel while the Colorado to Minneapolis tariff would be about $1.30 per barrel. Transportation costs of Alaskan or imported oil to these refining centers was substantially greater than for shale oil because of the proximity of shale oil to

the midwest. Other shale oil transportation systems studied had shortcomings either in economics or ability to handle movement of large amounts (200,000 BPD) of shale oil.

The most favorable market for raw shale oil is as a refinery feed. The study divided the central U.S. into four refining areas to reflect differences in refining capacities, crude supply, and product demand. For each case, processing margins for crude oil and raw shale oil were developed, taking into account the modifications necessary to refine shale oil. These modifications required capital investment in the facilities and resulted in higher operating costs for processing raw shale oil than for petroleum crude. This, coupled with a different refined product mix, indicates that crude shale oil value will be less than conventional crude by about $2.10 per barrel (Great Lakes area) to $3.00 per barrel (Colorado and Wyoming).

ABSTRACT

MOTOR GASOLINE FROM SHALE OIL

Phillip L. Cottingham, Laramie Energy Research Center

March 1976

Shale oil produced from oil shale of the Rocky Mountain region by many of the usual retorting processes consists mainly of high backing compounds of nitrogen, sulfur, and oxygen; less than half the oil consists of hydrocarbons. Thermal cracking of the oil followed by acid and caustic treating of the gasoline fraction has produced stable gasolines with low to moderate octane numbers. Hydrogenating the raw crude oil has produced higher yields of stable gasolines, also with low to moderate octane numbers. The yields and octane numbers of the gasolines are dependent on the hydrogenation temperatures used. Low-octane hydrogenated gasoline has been catalytically reformed over platinum containing catalyst to produce high-octane motor fuel.

ABSTRACT

FINAL REPORT: THE PRODUCTION AND REFINING OF CRUDE SHALE OIL INTO MILITARY FUELS

Applied Systems Corporation

August 1975

The technical objectives of the program were to demonstrate that a wide spectrum of military operational fuels derived from shale oil crude could be obtained in a commercial industrial facility with minimum or minor modification, and to produce incentives for industry in oil shale development and technology.

Shale oil crude was processed into gasoline, heavy fuel oil, and JP-4 in small laboratory quantities in the United States by the Bureau of Mines (ERDA) and private industry, however, no large-scale commercial refining of the shale oil crude into a wide variety of products has been attempted up until this program.

The production of 5,765 bbl of various military operational fuels (JP-4, JP-5/Jet A, DFM/DF-2, gasoline, Heavy Fuel Oil) from 10,000 bbl of crude shale oil was accomplished in a commercial refinery having a capacity of about 9,000 BPSD.

The 10,000 bbl of crude shale oil was produced by the Paraho process using the shale mined from the Naval Oil Shale Reserve located in Anvil Points, Colorado.

The various fuels produced met a majority of the military, Federal, and commercial specifications requirements. However, these fuels tended to exhibit storage and thermal instabilities. In addition, the fuels contained a high wax content, high particulate matter, and high gum content. It is believed that a higher pressure in the hydrogenation stage (about 1500 to 3000 psi), along with clay treatment of the final products, would reduce or eliminate some or most of these problem areas.

It is concluded that it is feasible to obtain military and civilian operational fuels from shale oil crude using a commercial refinery. However, additional effort has to be expended to overcome some refinery and operational problems to obtain maximum yields and improved properties.

*U.S. GOVERNMENT PRINTING OFFICE: 1979 0-310-012/122