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Trends in Desulfurization Capabilities, Processing Technologies, and The Availability of Crude Oils

MASTER

- U.S. Refineries
- Caribbean "Exporting" Refineries
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TRENDS IN DESULFURIZATION CAPABILITIES, PROCESSING TECHNOLOGIES, AND THE AVAILABILITY OF CRUDE OILS

- U.S. REFINERIES
- CARIBBEAN "EXPORTING" REFINERIES

Publications of the findings and recommendations herein should not be construed as representing either the approval or disapproval of the Department of Energy. The purpose of this report is to provide information and alternatives for further consideration by the Department of Energy and other Federal agencies.

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FOREWORD

This report was prepared as a result of concerns expressed by a number of persons within the Federal Government and industry over the great dependence of U.S. refiners on predominately sweet domestic crude oils. Since this production is declining, growing dependence must be placed on imported crude oils which are overwhelmingly sour in both production and reserves. The report addresses the subject of trends in conversion of domestic refineries to sour crude processing capability, technologies involved, the investments, operating costs and profitability of such capacity as well as problems confronting refiners installing capacity to handle sour crudes. The term "desulfurization" is used exclusively to refer to technologies relative to removing sulfur content in products.

TABLE OF CONTENTS

TABLES

Page

FIGURES

EXECUTIVE SUMMARY

Scope of Report

This report discusses trends in the capabilities of U.S. and of Caribbean "exporting" refineries to handle increasing quantities of sour crude oil feedstocks. The trends in the 1973-77 time period are examined and a projection to the 1980-81 period is made. Caribbean "exporting" refiners are those with refinery capacities beyond those needed to satisfy local needs.

The report also discusses the distribution and nature of sulfur compounds and metals in crude oil; the types of processes used in desulfurization; cost data for desulfurization processes; hydrogen manufacture; Federal, state, and local regulations on the sulfur level in fuel oils; prices of residual fuel oil; the production and disposal of sulfur in the U.S. refining industry; crude availability in relation to its sulfur content and other properties; and, an analysis of the PAD V (Petroleum Administration for Defense District V) 1/ situation regarding North Slope crude oil.

Conclusions

The following principal conclusions were established in this report:

1. While the capability of U.S. and Caribbean refinery capacity to handle sour crudes is slowly improving, the rate

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1/ Includes Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

of conversion is definitely inadequate in view of circumstances in the petroleum world. Our dependence on sweet crude oil imports from OPEC countries is growing rapidly and yet only 15 percent of their crude oil reserves are sweet. In the U.S., sweet crude reserves have dropped to 42 percent of the total. The exact amount of conversion required will depend greatly on the development of existing oil fields and new discoveries. Based on our present knowledge of domestic and foreign reserves, it would appear that the rate of conversion of U.S. refineries needs to be roughly on the order of three times as much as has been experienced in the past 4 or 5 years. Reasons for the slowness of conversion are given later in this summary. In some cases, solutions may be possible.

2. The need for future conversion to desulfurization is primarily due to the need for sour crude handling capability and not so much due to possible future changes in regulations in the several States limiting sulfur content of fuels in their respective areas. Most of these regulations were promulgated in the period of 1970 through 1974 and since then, consumption of fuel oils by sulfur levels have stabilized. However, stricter limits will probably be imposed by some States in the future and cause some shifts in the consumption of fuels by sulfur levels.

3. The cost of desulfurizing operations are very high. Deep desulfurization (reduction to 0.3 percent sulfur) of a residuum is in the range of $2 to $3 per barrel, especially

when return on capital is included. The cost of hydrogen consumed in these operations is in the order of $1 or more per Mscf (thousand standard cubic feet), making it one of the larger cost items.

4. There are a large number of desulfurization processes in operation, but most depend on "indirect" rather than "direct" processes. "Indirect" processes depend on the separation by distillation of gas oil from high metal containing residuum, the desulfurization of the gas oil, and its reblending with the residuum to achieve an overall lower sulfur level. Technologies are now emerging which may make it feasible to directly desulfurize residuum by removing from it heavy metals which deactivate and plug desulfurization catalysts.

5. Cargo prices of low pour No. 6 fuel oil differ by sulfur levels in a manner suggesting close relationship to desulfurizing costs.

6. The production and sale of by-product sulfur by refiners has not presented any serious problems to the industry, although rather severe price fluctuations have been experienced in recent years. New regulations on emissions from sulfur recovery plants (Claus process) may easily double investment costs in these plants.

7. The impact of Alaskan north slope crude on PAD V is discussed. Additional conversion of west coast capacity to sour crude capability is needed. Meanwhile excesses of this crude need to be moved eastward to existing refineries capable of absorbing it.

Background

The trends in the capabilities of U.S. refiners and of Caribbean "exporting" refiners to process sour crude oils is based on data published annually in the literature which depicts the downstream capacities of refinery processing units. A number of these units are capable of segregating and or chemically removing sulfur from petroleum streams. The changing capacities of these specific processing units form the basis for the desulfurization capacity trends portion of this report.

It is difficult, if not impossible, to quantify exactly the capabilities of U.S. and of Caribbean "exporting" refiners to handle sour crudes. The difficulty arises because of the large number of different crude oils used as feedstocks by refiners and because sulfur is but one of many important factors that affect the capability of a refiner to handle a particular crude oil in his processing units.

In light of the above, this report, rather than attempting to quantify the desulfurization capacity of U.S. and Caribbean "exporting" refiners, examines the trends of these refiners, each as a group, toward providing an increasing capability to process sour crudes. It does this by examination of additions to processing capacities of refiners, that are capable of removing sulfur from petroleum fractions, in relation to the capacity of new crude oil atmospheric distillation facilities.

A review of all U.S. refineries and their downstream equipment has lead us to the conclusion that slightly more than 40 percent of the existing capacity can handle some sour crude of one type or another. For various reasons, this cannot be an exactly defined number, nor does it coincide with the percent of hydroprocessing equipment in relation to crude capacity. A few refineries have hydrotreating facilities and yet only have sweet crude capability. A few refiners may only have capability to handle sour crudes in the lower sulfur ranges, say 0.5 to 1.0 percent, due to emissions problems or other limitations. These are limitations which can be overcome by investments. Still others would face problems in their product output pattern due to low gravity of some sour crudes.

Catalytic hydroprocessing (hydrocracking, hydrorefining, and hydrotreating) removes sulfur from refinery streams so that the total amount of sulfur in the products and residues is less than that in the crude oil feedstock. For this reason, changes in hydroprocessing capacity are used in this report as a measure of the changing capabilities of refiners to process sour crudes. On the other hand, thermal processes (vacuum distillation, visbreaking, and coking), segregate most of the sulfur contained in the refinery feedstocks into residual fractions, allowing the production of low sulfur containing products, but the total amount of sulfur in the products and in the residual fractions is essentially the same as that in the crude oil feedstocks. In this regard, thermal processes are limited in their ability to produce low-sulfur products.

Summaries of Sections of the Report

A. Trends in the Desulfurization Capabilities of U.S. and Caribbean "Exporting" Refineries

1. U.S. Refiners

There appears to be a trend in the United States toward an increasing capability of refiners to handle a larger portion of their refinery feedstocks as sour crudes. During the 1973-1977 period, hydroprocessing capacity (hydrocracking, hydrorefining, hydrotreating), expressed as a percentage of operating refinery crude oil capacity, increased from 41.6 to 47.6 percent. This percentage is expected to increase further to about 48.9 percent during the 1977-1981 period, based on announced projects. The following table summarizes the data in this regard.

TABLE 1 (Summary)

HYDROPROCESSING CAPACITY AS A PERCENTAGE OF CRUDE OIL ATMOSPHERIC DISTILLATION CAPACITY 1973-1981

Year 1/	Crude Oil Atmospheric Distillation Operating Capacity, B/SD 2/	Hydroprocessing Capacity, B/SD	Hydroprocessing Capacity As A % of Distillation Capacity
1973	14,195,000	5,903,500	41.6
1974	15,012,000	6,447,100	43.0
1975	15,512,000	6,643,300	42.8
1976	15,713,000	7,116,500	45.3
1977	16,759,000	7,975,900	47.6
1981	18,192,000	8,894,000	48.9

1/ As of January 1 of indicated year.
2/ Barrels per stream day.

There was a rapid growth in hydroprocessing capacity in relation to new crude oil atmospheric distillation capacity in the 1973-1977 time period. Expressed as a percent of crude oil atmospheric distillation capacity, this growth was about 81 percent of added crude oil distillation capacity. The percentage, based on announced projects, is projected to decrease to 53 percent in the 1977-1980 time interval.

There are a number of problems encountered in the processing of sour crudes which will tend to limit progress toward such processing.

- Most small refiners cannot handle sour crudes in their facilities. In most cases, to provide capability to handle sour crude would require a very costly reconstruction of their facilities.

- A number of sour crudes contain large amounts of heavy metals (vanadium, nickel, etc.). These metals tend to deactivate and to plug hydroprocessing catalysts. A suitable technology to handle such crudes is in early stages of development.

- Some refiners are limited in the quantity of sour crudes that they can handle because of refinery-related environmental problems.

- A number of high-sulfur crudes are also heavy crudes. Such crudes present some refiners with product-slate difficulties.

- Hydroprocessing facilities are very costly both as to capital requirements and operating costs.

2. Caribbean "Exporting" Refiners

The trend toward an increased capability of Caribbean "exporting" refiners to handle a larger portion of sour crudes in their refinery feedstocks is not as strong as that for their U.S. counterparts. In the 1973-1977 time interval, Caribbean "exporting" refiners hydroprocessing capacity growth was about 71 percent of added refinery atmospheric distillation crude oil capacity. There appears to be no hydroprocessing capacity growth planned in these refineries for the 1977-1980 period.

Caribbean refiners are mainly fuel oil producers, heavily dependent on product shipments to the U.S. east coast.

The lack of plans for hydroprocessing expansion in the 1977-1980 period is mainly due to competition from U.S. refiners who have significantly increased their share of residual production in meeting domestic demand.

B. Distribution and Nature of Sulfur Compounds and Metals in Crude Oils

This report arbitrarily defines a sweet crude as one containing 0.50 percent by weight or less of sulfur. Sour crudes are those containing in excess of 0.5 percent sulfur.

Very little of the sulfur in crude oil is there as elemental sulfur. Most of it is chemically bound in complex organic compounds. On the distillation of crude oil, the sulfur content in the crude tends to concentrate in the higher boiling fractions, leaving the lower boiling, or lighter fractions, with very little sulfur content.

For the above reasons, whole crudes are not desulfurized. Rather, refiners concentrate on the heavier fractions, thereby handling smaller volumes than those if the whole crude oil were desulfurized.

The metal content of crude oil varies with its origin. The metals, particularly, vanadium, nickel, and iron, if in concentrations above about 150 parts per million in the crude oil, plug and deactivate desulfurization catalysts. On distillation of the crude oil, these metals remain, essentially, in the residues, often making desulfurization of such residues very difficult, if not impossible. Technologies to deal with these metals are in the early stages of development. At the present time in the United States and the Caribbean, about 95 percent of low sulfur fuels are produced by the distillation of crude oil into fractions which are desulfurized and blended back into residual fuels rather than by the direct desulfurization of residues.

C. Types of Processes Used in Desulfurization

Catalytic hydrocracking, hydrorefining, and hydrotreating are the processes most used in desulfurization. The processes vary widely in terms of feedstocks and the intensity of treatment. As an example, during hydrocracking about 50 percent of the feedstock molecules are reduced in size, whereas hydrotreating has little or no affect on the molecular size of the feedstock. In other words, hydrocracking performs the function of cracking heavy fractions into lighter ones in addition to its desulfurizing function.

In typical hydroprocessing, the feed to be desulfurized is mixed with hydrogen and is heated in a furnace before passing into the reactor. Here the sulfur compounds in the feedstock are converted to hydrogen sulfide in the presence of a catalyst. On emerging from the reactor, the effluent is cooled and the hydrogen sulfide is removed. The hydrogen sulfide is sent to a sulfur recovery unit where the hydrogen sulfide is decomposed to elemental sulfur and water. Unused hydrogen is separated and recycled for reuse with the feed.

D. Cost of Desulfurization Processes

Refineries handling sour crudes have considerably higher investment costs and operating costs than those handling sweet crudes. Summarized below are representative investment costs, operating costs, and return-on-investment for three sizes of refineries handling sour and sweet crude oil feed-stocks.

Crude Throughput MB/SD 1/	Investment $MM	Investment $/B/CD 2/	$/Barrel Operating Cost (Ex-Fuel)	$/Barrel Return on Capital	$/Barrel Gross Margin Needed
Sour Crude (LT. Arabian)					
250.0	520.7	2,314	0.44	1.64	2.08
150.0	352.8	2,613	0.50	1.86	2.36
15.0	54.1	4,007	1.27	2.84	4.11
Sweet Crude (Ekofisk)					
245.0	307.4	1,394	0.20	1.00	1.20
147.0	200.8	1,518	0.25	1.09	1.34
14.7	29.2	2,207	0.43	1.59	2.02

1/ Thousand barrels per stream day.
2/ Dollars per barrel per calendar day.

For an equivalent profit or loss position for refiners handling sweet crude or sour crude, the laid-down cost of sour crude would need to be about $1.33 per barrel lower than that for sweet crude. It appears also from this data, that a small refiner, contemplating a new plant, would most likely process sweet rather than sour crude oil.

A representative operating cost for desulfurization of certain specific refinery fractions, as for example vacuum gas oil or residual fuel oil involves so many variables, among them the degree of desulfurization, the nature of the catalyst, quality of feedstock, etc., that a broad range of results could be obtained. In any case, the costs are high. For example, the cost of direct desulfurization of atmospheric residium to a level of 0.3 percent sulfur can be in the order of $2 to $3 per barrel of feedstock.

E. Hydrogen Manufacture

Hydrogen has become increasingly important to refineries as a material used in desulfurization. Hydrogen is produced in refineries from various sources, but one of the most important sources is catalytic reforming.

In simple type refineries, hydrogen produced from the catalytic reformer may suffice to meet desulfurization requirements. In more complex sour crude oil refineries, hydrogen sources must be supplemented with hydrogen generation using natural gas (methane), refinery gas, or naphtha.

Investments required for hydrogen manufacture are higher for naphtha than they are for methane as feedstock.

Size Unit, MMCF/D 1/	Million Dollars Cost	
	Naphtha Feed	Methane Feed
10	4.3	3.2
50	10.3	8.0
100	17.4	12.9

1/ Million cubic feet per day.

Hydrogen costs are high. Under present day costs, it is unlikely that hydrogen can be manufactured for much less than $1 per Mscf. Residual desulfurization processes consume 800 to 1,000 scf (standard cubic feet) per barrel of feedstock. Thus, the hydrogen alone contributes 80 cents to $1 to the cost of treating a barrel of residual fuel oil.

F. Federal, State and Local Regulations on the Sulfur Level in Fuel Oils

All States and the District of Columbia have regulations that control the sulfur levels in fuel oils in their areas. A review of the history of fuel oil consumption by sulfur levels, in terms of percent of the total, reveals that percentages in each sulfur level have remained essentially constant over the past 3 years. This is so because most of the impact occurred from regulations which were promulgated in the period between 1970 and 1974. One factor that may cause some added consumption of lower sulfur fuel oil would result from regulations in some areas which require new emission sources to adhere to more strict limitations than older established sources. In addition, some States may soon impose stricter standards on all sources causing some shift to a higher volume low sulfur consumption.

G. Prices of Residual Fuel Oils

Low-sulfur residual oils command a higher price than high sulfur residual fuel oils. For any single grade of fuel oil, the price relationship is inversely proportional to the sulfur content, with 0.3 percent sulfur (max.) being the highest priced and high sulfur (2.2 to 2.8 percent) being the lowest priced.

In recent months, low pour point, 0.3 percent sulfur content No. 6 fuel oil has been averaging a premium of slightly over $1 per barrel over 1.0 percent sulfur content fuel oil. The 1.0 percent sulfur fuel oil, in turn, has a $1.85 per barrel premium over high sulfur fuel oil with a sulfur content of 2.8 percent.

H. Production and Disposal of Sulfur in the U.S. Refining Industry

The second largest source of sulfur, next to its production by mining using the Frasch process, is through recovery from sour gas and refinery processes for the desulfurization of petroleum. This source has been growing rapidly in recent years, increasing from 15.2 percent of total U.S. sulfur production in 1972 to 25.8 percent in 1975. This increase is due largely to the greater emphasis on meeting environmental standards and the need to rely on increasing amounts of sour crudes.

In the desulfurization processes using hydrogen, the sulfur in the petroleum is converted to hydrogen sulfide. This is further processed to convert the hydrogen sulfide to elemental sulfur and water. The sulfur leaves the system as a liquid and is pumped to a storage area where it is allowed to solidify by cooling.

In the past 3 or 4 years, increasingly severe environmental restrictions have been placed on the sulfur recovery (Claus process) units themselves in terms of emissions controls.

I. Crude Availability in Relation to Sulfur Content and Other Properties

In 1975, OPEC sour crude reserves were 5.5 times greater than sweet crude reserves. In addition, the reserves to production ratio of sour crudes was 49 versus 33 for sweet crudes, indicating that the current tendency is to pull down sweet crude reserves relatively more rapidly than sour crude reserves. This trend accelerated significantly in 1976 and continues to accelerate in 1977.

More dramatic changes have occurred in the United States than in OPEC countries in regard to reserves of sweet and sour crudes. In 1964, 64 percent of all U.S. crude oil reserves were in the sweet crude category (0.5 percent sulfur or less). In the same year, 66 percent of the production was sweet crude. The discovery of the Prudhoe Bay field in Alaska has resulted in only 42 percent of 1975 crude oil reserves being in the sweet crude category.

By 1978, the sweet crude split in U.S. production will change significantly toward an increased percentage of sour crude. Another factor giving impetus to this shift will be such projects as enhanced recovery which in California is reflected in more production of heavy, high sulfur crude oils.

Barring any unforeseen large discoveries, the world's refiners will be forced to rely on sour crude supplies increasingly in the future.

Despite the proportionately greater reserves and the production of sour crudes, the United States continues to rely very heavily on sweet crude imports. In the period from 1969 to the present, the percentage of crude oil imports that are sweet has ranged from a high of 66.9 percent (1972) to a low of 54.7 percent (1977). In the same period crude oil imports rose from 2.2 million barrels per day to 6.6 million barrels per day. Although the percentage of sweet crude has dropped, the actual volume of sweet crude imports are increasing each year.

The rapidly growing sweet crude imports are originating more and more from OPEC sources. In 1969, the United States imported only 5 percent of OPEC's sweet crude production. In 1976, the United States imported 37.5 percent of OPEC's sweet crude production. In the first 4 months of 1977, this percentage grew to 42 percent. By contrast, in the same 4-month period, the United States imported only 12.4 percent of OPEC's sour crude production.

J. Analysis of PAD V Situation

A special situation exists on the west coast due to the introduction of Alaskan North Slope crude oil. Although ample refinery capacity exists in the area to meet local refined product needs, the volume of sour California crude plus sour North Slope crude exceeds the sour crude capacity in the area. Extensive conversion of Puget Sound refineries and some California refineries would be required to absorb most or all of the North Slope crude.

A Department of Energy (DOE) estimate of the breakdown of sour and sweet crude refining capacity in PAD V indicates that of the 2,426,8000 barrel/calendar day refinery capacity, 1,670,200 can handle sour crude and 756,600 must use sweet crudes.

DOE conducted a refinery by refinery survey in District V which indicated that from 601,000 to 969,000 barrels per day of North Slope crude could be absorbed in District V in 1978.

An average of forecasts, by several different sources, of PAD V surplus of North Slope crude indicated such surpluses at 447,000 barrels per day in 1978, and 709,000 and 1,002,000 barrels per day respectively in 1980 and 1985.

DISCUSSION

SECTIONS A - J

A. Present Status of Desulfurizaton in the United States and Caribbean Petroleum Refining Industries

1. Sulfur in Crude Oil and Petroleum Products

a. Trend to Higher Sulfur Containing Crude Oil

Barring any unforeseen large discoveries of crude oil, U.S. and world refiners will be forced to rely on sour crude oil supplies increasingly throughout the future. This means that desulfurization capacity in refineries will have to increase to meet the needs for low sulfur fuels. Based on our present knowledge of domestic and foreign reserves of sweet and sour crude oils, it would appear that the rate of conversion to sour crude capability should have been roughly three times as great as that experienced in the past 4 or 5 years.

OPEC sour crude reserves were 5.5 times greater than sweet (0.5 percent sulfur by weight or less) crude reserves in 1975. In addition, the current tendency is to pull down sweet crude reserves relatively more rapidly than sour crude reserves. This trend accelerated in 1976, and continues to accelerate in 1977.

Even greater changes than those in the OPEC countries have occurred in the United States. In 1969, a Bureau of Mines survey indicated that 64 percent of all crude oil reserves were in the sweet crude category. The same survey indicated that 66 percent of that year's production was sweet crude.

The discovery of the Prudhoe Bay field has resulted in only 42 percent of 1975 crude oil reserves being in the sweet crude category. In 1976, about 68 percent of the crude oil production in the United States was sweet. However, Alaskan North Slope crude oil had not yet begun production. By 1978, the sweet/sour split in the U.S. production will change significantly toward an increased percentage of sour crude. Another factor giving impetus to this shift will be the development of enhanced recovery. In California this will be reflected in more production of heavy, high sulfur crude oil. More details appear in Section I.

b. Sulfur and Other Contaminants in Crude Oil

Sulfur and sulfur compounds constitute the most significant contaminents in crude oil fractions. Oxygen compounds, nitrogen compounds and metal compounds of vanadium, nickel, iron, calcium, magnesium, aluminum, copper, sodium, potassium, arsenic, and zinc are other foreign materials which present treating problems. Of the metals, vanadium, nickel and iron are the most significant because they shorten the life of hydrodesulfurization catalysts.

The sulfur content of crude oils appears to be related to the density of the crude oil which in turn depends on the distribution of hydrocarbon types in the crude oil.

The sulfur content of crude oil is not uniformly distributed throughout the boiling range of the oil, but is progressively concentrated in the higher boiling fractions. The types of sulfur compounds present in crude oils vary. One hundred and eleven sulfur compounds have been identified in a research project involving only three crude oils. 2/ This subject is discussed in more detail in Section B.

2. Fuel Desulfurization

a. Introduction

Because the sulfur compounds found in crude oil tend to be concentrated in the higher boiling components of the crude oil, it is more economic to concentrate these sulfur-containing compounds in the higher boiling fractions, particularly residual fuel oil, of the crude oil by distillation and thereby reduce the volume of petroleum to be treated.

Should residual fuel oil not be a desired product, this fraction can be further processed until all liquid products are removed as distillate and only solid material or coke is left as the residue. While some of the resulting higher boiling distillate fractions will contain relatively large amounts of

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2/ H. T. Rall, C. J. Thompson, H. J. Coleman, R. L. Hopkins "Sulfur Compounds in Petroleum," API Research Project 48, 1962.

sulfur compounds, they can be desulfurized by hydrotreating techniques.

If residual fuel oil is a desired product, the liquid residue can be treated directly by hydrotreating techniques to reduce sulfur to the required level. This is referred to as a "direct" process.

It is generally accepted that desulfurization of the residual fraction of crude oil is not economical if it contains more than 150 parts per million (ppm) of heavy metal. These metals, found in varying amounts in crude oils from different locations, remain almost entirely in the residue on the distillation of the crude oil. The metals, when they exist in concentrations greater than 150 ppm in the petroleum fractions being treated, deactivate the hydrotreating catalyst very rapidly and block the passage of the liquid being treated through the catalyst. Recently, additives have been developed which deactivate these heavy metals, but this technology is in an early development state. 3/

An "indirect" route to reduce the amount of sulfur in the residual fraction of crude oil is to blend back into the fraction distillate which has been treated to remove sulfur.

3/ "Heavy Metals Deactivated by Cracking Additive," Oil and Gas Journal, March 28, 1977.

Desulfurization processes, for purposes of this report, are classified as thermal processes and as catalytic hydroprocessing processes. Thermal processes such as distillation, visbreaking or coking do not decrease the amount of sulfur originally in the crude oil, but merely segregate it into various fractions which can be treated to remove sulfur or wherein the sulfur can be disposed of, such as in coke.

Catalytic hydroprocessing chemically converts the sulfur in the sulfur-containing compounds in the crude oil to a form whereby it can be removed from the petroleum fraction, usually as a gas (hydrogen sulfide). The gas is then further processed to produce elemental sulfur.

b. Sulfur Segregating Processes

(1). Thermal Processes

(a). Distillation

Distillation is the first step in the refining of crude oil. Distillation can be under atmospheric or reduced pressure (vacuum distillation). Reduced pressure depresses the boiling point of petroleum compounds. Heavy crude oil fractions must be distilled at reduced pressure because, when such high boiling stocks are distilled, significant decomposition begins at about 800° F. The increased use of vacuum distillation has been encouraged by increased yields of gasoline and heating oil when compared to atmospheric distillation.

The trend has been toward larger capacity vacuum distillation towers and to design improvements which result in better fractionation and in minimized entrainment of crude oil contaminants in the distillate. Metal contamination in the distillates, particularly, can poison catalysts and reduce gasoline yields in downstream processing units.

Vacuum distillation alone, however, often is scarcely satisfactory because not enough material for desulfurization can be vaporized to meet product demands. For this reason, vacuum distillation is very often used in conjunction with viscosity breaking or coking. These processes reduce the boiling range of the residue and produce increased amounts of distillates.

(b). Visbreaking

Visbreaking is a mild thermal cracking process which is used to lower the viscosities and pour points of crude oil residues. The feed is heated quickly in a furnace coil to a temperature of 850° F to 900° F at a pressure of 200 to 500 psi (pounds per square inch). The effluent from the coil is quenched (cooled) with light gas oil to stop the cracking, the pressure is reduced, and gas oil and lighter fractions are flashed off and fractionated. The residue is further flashed in a vacuum tower to recover heavy gas oil.

The usual visbreaker feed in U.S. refineries is the residue from vacuum distillation. In order to avoid coking in the furnace coils, only mild cracking conditions are used in the visbreaker.

Compared to the coking process, the yields of gas oil and lighter products are lower. The octane number of visbreaker gasoline tends to be somewhat higher, and the quality of visbreaker gas oil as catalytic cracker feed is usually superior to that of coker gas oil.

(c). Coking

This is a well-established technique for decreasing the residual fuel yield. The process is dependent on thermal cracking to break down heavy fractions into lower boiling oils and decomposition is continued until a solid residue (coke) remains.

Coking was originally carried out as a batch process in which reduced crude or other heavy oil was heated and decomposed by direct fire in horizontal vessels equipped with condensing equipment. After all volatile products were driven off overhead, the hot coke was allowed to cool and was removed manually.

Delayed coking was commercialized in 1930 and is still the predominant process. The feed, in this process, is heated rapidly in a furnace to a temperature of 900°F or higher and is then discharged into large insulated vertical drums where it remains while cracking occurs from the contained heat. Temperatures are in the range of 775° F to 900° F and pressures up to 90 psi. Gas oil and lighter vapors pass into a fractionation system. Heavier fractions remain behind, gradually decomposing into lighter products and coke. The coke is removed from the drum with high pressure water jets.

Continuous fluid coking was commercially introduced in 1954. In this process, the heavy feedstock is cracked by contacting it with a fluidized bed of coke particles at a temperature of 900° F to 1,050° F at essentially atmospheric pressure. Coke formed by feed decomposition is deposited on the coke particles already in the bed. Vapors are moved overhead through a cyclone separation that returns coke particles to the bed. The heat required is supplied by circulating a stream of fluidized coke to a burner vessel where a portion is burned with air o maintain the vessel temperature. Net coke produced in the process is withdrawn from the system.

The fluid coking process can be combined with coke gasification to convert about 98 percent of normal crude residuum into liquid and gaseous products. This process handles high-sulfur, high-metal crude oils very well. The liquid products from the process are low in metals and can be more readily processed to produce high quality fuel oil or feedstocks. About 95 percent of the total sulfur in the coker feed can be recovered as elemental sulfur.

Coking will continue to be an important refining process. The combination process of fluid coking and coke gasification should be especially attractive for refineries designed to process heavy, high sulfur crude oils.

(2). Catalytic Processes Using Hydrogen

The nomenclature used in this study for the various hydrogen desulfurization processes used in the petroleum industry is that defined by the Oil and Gas Journal 4/ in their "Annual Refining Surveys." Under hydrocracking are those processes in which 50 percent or more of the feed is

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4/ The Petroleum Publishing Company, Tulsa, Oklahoma.

reduced in molecular size. Under hydrorefining are those processes in which the feed is reduced 10 percent or less in molecular size. For hydrotreating, essentially no molecular reduction occurs.

(a). Catalytic Hydrocracking

Catalytic hydrocracking is a combination of cracking, hydrogenation and isomerization (a process which alters the fundamental arrangement of atoms in the molecule without removing from or adding anything to the original material). It can also be regarded as a treating operation since hydrogen combines with and practically eliminates contaminents in the feed, such as sulfur, nitrogen, etc. Distillate, and to a much lesser degree, residual upgrading are the most important uses for catalytic hydrocracking.

The process consists basically of mixing hydrogen with hydrocarbon feed at elevated pressures, heating the mixture and contacting with a catalyst in a fixed or fluid bed. Hydrogen-rich gas and unconverted hydrocarbons are recycled. Operating conditions range from 500°F to 850°F and 500 to 4,500 pounds per square inch, gauge, (psig) pressure.

A variety of catalysts can be used. Hydrogen must be furnished from an external source. Normally, the hydrogen requirements vary from 1,000 scf per barrel for light feeds, to 2,500 scf per barrel for heavy feeds.

Metals are detrimental in catalytic hydrocracking, particulary in residual upgrading. The metals in the crude oil concentrate in these residues, and are deleterious to the catalyst. Metals are not troublesome in most U.S. or Middle East petroleums, but Venezuelean and some California oils contain large amounts of these contaminants.

Metals in the crude oil, as a rule, have little effect on the "indirect" desulfurization methods of producing low sulfur fuel oils. These processes involve hydrodesulfurization of distillates, such as gas oil produced by vacuum flashing, or visbreaking followed by vacuum flashing, or by coking.

When crude oils are distilled to produce topped crude oils, substantially all of the sulfur and all of the metals remain in the residua. However, upon vacuum distillation, significant amounts of the sulfur are found in the vacuum gas oil while nearly all of the metals remain in the vacuum bottoms.

It is estimated that more than 95 percent of the low sulfur fuels produced in the United States are manufactured by "indirect" methods such as crude distillation, atmospheric or vacuum, and coking (delayed or fluid) followed by hydrodesulfurization of the distillates. When processing only high sulfur crudes, a significant amount of high-sulfur pitch results. The desulfurized oils are then blended with additional topped crude or with the residues.

Low-sulfur products from the distillation of low-sulfur crudes such as those produced in the United States, Algeria, Indonesia, Libya, Nigeria, etc., are useful for blending with the higher sulfur products produced from high-sulfur containing crudes.

(b). Catalytic Hydrorefining

Catalytic hydrorefining is a processing procedure to desulfurize and hydrogenate a wide range of charge stocks such as gas oil, catalytic cracker feedstock, cycle stock and middle distillates. The functions of the hydrogen treating are removal of sulfur compounds, nitrogen compounds, and other impurities; hydrogen saturation of olefins and/or aromatics; and mild hydrocracking (10 percent or less reduction in molecular size).

The most common catalyst is cobalt molybdate on an alumina carrier. Hydrogen consumption varies from 300 scf to 1,200 scf per barrel of charge. Operating conditions vary with the process from 500°F to 800°F and 400 to 1,200 psig.

Catalytic hydrorefining includes such processes as residual desulfurization, heavy gas-oil desulfurization, catalytic-cracker and cycle stock feed pretreatment, and middle distillate treating.

Regarding heavy fuel oil treating, two basic hydroprocessing routes have been developed for removing sulfur from heavy fuel oil: vacuum gas oil desulfurization ("indirect" route) and direct residuum desulfurization ("direct" route).

In the "indirect method," the residum is fractionated into a heavy gas oil and a high sulfur content vacuum tower bottoms. The heavy gas oil, after desulfurization, is then blended with the vacuum residuum. This method is a first step toward reducing fuel oil pool sulfur levels and avoids the problems associated with hydrorefining a material containing high concentrations of metal contaminants. There is a limit to the amount of sulfur that can be removed by vacuum gas oil desulfurization alone. For most atmospheric residua, only about 40 to 50 percent of the sulfur may be removed in this manner.

With "direct" residuum desulfurization, however, sulfur reductions of 80 to 90 percent are achievable. Certain problems arise, however, when desulfurizing the residuum directly. Deposition of vanadium and nickel on the catalyst reduces its activity and high pressure drops in the reactor are encountered due to catalyst bed plugging by nickel and vanadium deposition.

(c). Catalytic Hydrotreating

Catalytic hydrotreating is described as a hydrogen treating process for the removal of sulfur or nitrogen from feedstocks, during which essentially no molecular reduction occurs in the feed. The process is used to pretreat catalytic reformer feeds, to desulfurize naphtha, and straight run and other distillates.

The processing conditions vary with the process. A typical catalyst is cobalt-molybdenum supported by alumina. Operating conditions vary from temperatures of 300° to 800° F and pressures of 300 to 600 psig. Hydrogen requirements vary from 75 to 350 scf per barrel of charge, depending on the feed.

3. Trends in Desulfurization Processing in the United States and in the Caribbean Petroleum Refining Industries

a. Background

A recent literature article 5/ notes that nearly all processes for producing low-sulfur fuel oils rely on the vaporization of distillate or gas oil or cycle-stock materials.

5/ N. L. Nelson, "What Processes Make Desulfurized Fuel Oils," Oil and Gas Journal, August 15, 1977.

These vaporized fractions can then be hydrodesufurized for incorporation into residual fuel oils. The article states that probably 95 percent of the low-sulfur fuels produced in the United States are by such methods or combination of methods as the atmospheric and vacuum distillations of low-sulfur crude oil; the vacuum distillation of high sulfur crudes and the hydrodesulfurization of the distillates; vacuum distillation of topped crude; hydrotreating and catalytic cracking of the distillates; fluid and delayed coking followed by hydrodesulfurization of the distilled materials. The remainder of the low sulfur fuels are produced by the visbreaking of topped crude followed by vacuum distillation of the visbreaker overhead and by direct residual desulfurization whereby low metals (under 150 ppm vanadium and nickel) topped crude oil or vacuum bottoms can be directly, catalytically desulfurized in fixed or fluid-bed reactors.

b. The Trend in Desulfurization Processing

(1). Introduction

The data following is categorized as that for the United States (including the Hawaiian Trade Zone) and as that for Caribbean "exporting" 6/ refineries. The latter includes the Virgin Islands and Puerto Rico. In addition, Caribbean refineries are those located in Antigua, the Bahamas, the Netherland Antilles, Trinidad, Venezuela, and Panama.

6/ Refineries with capacities in excess of those needed to supply local or domestic needs.

The data for the years 1973 to 1977 is from the Oil and Gas Journal's 7/ "Annual Refining Issues" for the United States. The data differs from that in the Oil and Gas Journal in that it includes neither "Naphtha Olefin or Aromatics Saturation" and "Lube-Oil Polishing" under catalytic hydrotreating nor "Lube-Oil Manufacturing" under catalytic hydrocracking. Although some sulfur is removed during processing of feedstocks in those categories not included, the quantity so removed was considered to be insignificant for the purposes of this study. For the Caribbean "exporting" refiners, the data is from the "Worldwide" issues of the Oil and Gas Journal and from the Annual "World Refineries Survey" published in the Petroleum Times. 8/

The 1980 projections of desulfurization capacities are Department of Energy estimates based on information in the Oil and Gas Journal, "Worldwide Construction" issues of April 15, 1977, and October 3, 1977, and on data in the Department of Energy files.

(2). Thermal Processes

Thermal processes include vacuum distillation, visbreaking, fluid coking, delayed coking and "others".

7/ The Petroleum Publishing Company, Tulsa, Oklahoma.

8/ IPC Industrial Press, Dorset House, London, England.

Thermal processes evolved in the early stages of refinery development from a need to increase the yield of light products. While these processes increase the amount of light products, they are useful in segregating a major portion of the sulfur content of the feedstock crude oil into decreasing amounts of residua. Generally, thermal processes do not decrease the total amount of sulfur in the products from the original crude-oil feedstock, but rather concentrate it in a smaller portion of the products.

(a). Vacuum Distillation

U.S. Refiners - Vacuum distillation since 1945 has been widely used to augment the yield of catalytic cracking feedstocks. In 1972, total vacuum distillation capacity corresponded to about 35 percent of atmospheric distillation capacity. Vacuum distillation capacity as a percentage of atmospheric crude oil distillation capacity has not changed significantly since 1972, fluctuating between 35.3 to 37.1 percent. This percentage is not expected to change significantly through 1980.

Table A-1, following, shows the trend in U.S. vacuum distillation capacity as a percent of atmospheric distillation capacity. Appendix Tables 1, 2, and 3, show it in greater detail and by PAD districts.

Table A-1
U.S. Vacuum Distillation Capacity As A Percent of U.S. Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/SD 1/ Crude Oil Atmospheric Distillation Operating Capacity	Vacuum Distillation Capacity	Vacuum Capacity As % of Atmospheric Distillation Capacity
1973	14,195,000	5,150,000	36.3
1974	15,012,000	5,299,900	35.3
1975	15,512,000	5,497,200	35.4
1976	15,713,000	5,672,900	36.1
1977	16,759,000	6,216,700	37.1
1980 2/	17,608,000	6,367,400	36.2

1/ As of January 1 of indicated year.
2/ Estimated by DOE.

Caribbean "Exporting" Refiners - Vacuum distillation capacities of these refiners, as a percentage of atmospheric distillation crude oil capacity, historically has been lower than that of U.S. refiners, principally because of the orientation of the Caribbean refinery capacity to fuel oil rather than gasoline production. However, the percentage has been increasing since 1973 and the increase is projected to continue through 1980. The most likely reasons for this are the higher sulfur and lower gravity crudes which the Caribbean refineries are handling and their foreseeable need to produce lighter products as U.S. east coast resid demands decrease.

Table A-2, on the following page, indicates the trend in Caribbean vacuum distillation capacity as a percentage of atmospheric crude oil distillation capacity. Appendix Tables 4, 5, and 6, show it in greater detail and by refinery location.

Table A-2
Caribbean "Exporting" Refineries Vacuum Distillation Capacity As A Percent of Crude Oil Atmospheric Distillation Capacity

	Capacity, B/CD 1/		
Year	Crude Oil Atmospheric Distillation Operating Capacity	Vacuum Distillation Capacity	Vacuum Capacity As % of Atmospheric Distillation Capacity
1973	3,835,300	943,500	24.6
1974	4,372,300	989,500	22.6
1975	4,375,100	1,019,000	23.3
1976	4,277,800	1,138,400	26.6
1977	4,277,800	1,263,300	29.5
1980 2/	4,627,800	1,453,000	31.4

1/ As of January 1 of indicated year, barrels per calendar day.
2/ Estimated by DOE.

(b). Visbreaking Capacity

U.S. Refiners - U.S. visbreaking, both as total capacity and as a percentage of refinery crude oil distillation capacity, declined rapidly in the period 1955 to 1971 as shown in Table A-3 below.

Table A-3
U.S. Visbreaking Capacity As A Percent of
U.S. Crude Oil Distillation Capacity (1955-1971) 1/

Year	Barrels of Feed Per Stream Day 2/	% of Crude
1955	676,000	7.5
1960	636,000	6.1
1965	580,000	5.4
1971	265,000	1.9

1/ "Factors Affecting U.S. Petroleum Refining, Impact of New Technology," September 1973, National Petroleum Council, Table 7, pg. 39.

2/ As of year end.

Although total visbreaking capacity has more or less stabilized since 1974, expressed as a percentage of crude oil atmospheric distillation capacity, it has continued to decline, although at a somewhat slower rate. A projection through 1980 indicates that the slow decline will continue. Table A-4 on page 39 shows the trend for the period 1973-1980. Appendix Tables 1, 2, and 3, indicate it in greater detail and by PAD Districts.

Table A-4
U.S. Visbreaking Capacity As A Percent of U.S.
Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/SD 1/ Crude Oil Atmospheric Distillation Operating Capacity	Visbreaking Capacity	Visbreaking Capacity As % of Atmospheric Distillation Capacity
1973	14,195,000	240,000	1.7
1974	15,012,000	206,000	1.4
1975	15,512,000	205,300	1.3
1976	15,713,000	194,300	1.2
1977	16,759,000	202,300	1.2
1980 2/	17,608,000	202,300	1.1

1/ As of January 1 of indicated year.
2/ Estimated by DOE.

It is expected that visbreaking capacity, as a percent of crude oil distillation capacity, will continue to decline in the United States unless U.S. refinery capacity is encouraged to supply an increasing amount of the demand for low-sulfur heavy fuels. This is unlikely in light of existing Caribbean refinery capacity for such products, and the push to convert from heavy petroleum products to coal as fuels in the United States.

Caribbean "Exporting" Refiners - The visbreaking capacities of these refiners expressed as a percent of atmospheric crude oil distillation capacity is higher than that of U.S. refiners. This percent is not expected to change appreciably through 1980. The percentage is greater for these refiners because of the relatively greater production of low-sulfur heavy fuels in their product slates as compared to U.S. refiners. The visbreaking capacity was increased by about 160,000 B/SD in 1976. Table A-5, on the next page, summarizes the visbreaking capacity of Caribbean refiners for the years 1973-1977 and projects it into 1980 based on announced projects. Appendix Tables 4, 5, and 6 indicate this data in greater detail.

(c). Fluid and Delayed Coking

U.S. Refiners - Coking of petroleum residues is used to decrease residual fuel yields. During

Table A-5
Caribbean "Exporting" Refineries Visbreaking Capacity as a Percentage of Crude Oil Atmospheric Distillation Capacity

	Capacity, B/CD (1)		
Year	Crude Oil Atmospheric Distillation Capacity	Visbreaking Capacity	Visbreaking Capacity As % of Atmospheric Distillation Capacity
1973	3,835,300	230,400	6.0
1974	4,372,300	209,400	4.8
1975	4,375,100	209,400	4.8
1976	4,277,800	187,400	4.4
1977	4,277,800	348,400	8.1
1980 (2)	4,627,800	348,400	7.5

(1) As of January 1 of indicated year.
(2) Estimated by DOE.

the period 1950 through 1972, coking reached its peak capacity ative to crude runs. During the 17 years between 1955 and 1972, coking capacity more than doubled because domestic residual fuel oil could not compete with imported residual fuel oil. The trend is shown by the following table.

Table A-6 1/
U.S. Coking Capacity As A Percent of
Crude Oil Distillation Capacity (1955-1972)

	Capacity, B/SD 2/				Coking Capacity As % of Atmospheric Distillation Capacity			
Year	Batch	Delayed	Fluid	Total	Batch	Delayed	Fluid	Total
1955	28,200	298,800	13,800	340,800	0.3	3.3	0.2	3.8
1960	17,300	365,700	102,500	485,500	0.2	3.5	1.0	4.7
1965	7,000	530,000	108,200	645,200	---	4.9	1.0	5.9
1972	---	824,800	148,200	973,000	---	6.0	1.1	7.1

1/ "Factors Affecting U.S. Petroleum Refining, Impact of New Technology," September 1973, National Petroleum Council, Table 8, pg. 41.
2/ As of year end.

The batch coking process was not economical and was replaced by delayed and fluid coking. Coking capacity, as a percent of crude oil distillation capacity, has remained steady during the 1973-77 period, ranging between 6.1 to 6.8 percent of distillation capacity. The percentage is forecast to drop only slightly by 1980.

Table A-7 below summarizes the input capacities and coking capacity as a percent of crude oil distillation of the coking facilities of U.S. refiners for the period 1973 through 1977 and projects them into 1980. Appendix Tables 4, 5, and 6 indicate the capacities in greater detail and by PAD districts.

Table A-7
U.S. Delayed and Fluid Coking Capacity As A Percent of U.S. Crude Oil Atmospheric Distillation Capacity

	Capacity, B/SD 1/			Coking Capacity As % of Atmospheric Distillation Capacity		
Year	Delayed	Fluid	Total	Delayed	Fluid	Total
1973	793,200	118,200	911,400	5.6	0.8	6.4
1974	899,800	128,300	1,028,100	6.0	0.8	6.8
1975	913,100	134,800	1,047,900	5.9	0.9	6.8
1976	920,500	128,800	1,049,300	5.9	0.8	6.7
1977	849,300	177,200	1,026,500	5.1	1.0	6.1
1980 (2)	---	---	1,045,400	---	---	5.9

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

Coking will continue to be an important refining process. However, the extent of its use will be dependent on product slates. As residual fuel oil is replaced by coal as a fuel in the United States, the amount of coking, in the long term, can be expected to increase.

Caribbean "Exporting" Refiners - There is no coking capacity located in the Caribbean "exporting" refineries. These refineries are essentially fuel refineries designed to produce residual fuel oil for export to the U.S. east coast. There are no indications that coking capacity is being added in these refineries for operations between now and 1980. However, as U.S. east coast residual fuel oil demands drop, it is possible that coking capacity will be added in the ensuing years.

(3). Catalytic Desulfurization Processes Using Hydrogen

(a). Hydrocracking

U.S. Refiners - Catalytic hydrocracking is a versatile refinery process. It is an efficient, low temperature, catalytic method for converting retractory middle-boiling or residual stocks to gasoline, jet fuel, or fuel oil. In most cases, by adding a catalytic hydrocracker, a refiner can increase gasoline yield and at the same time reduce the crude oil input to the refinery.

Because of the need for hydrogen and the high pressures involved in the process, equipment investment and operating costs are high, tending to offset the advantages of catalytic hydrocracking.

Catalytic hydrocracking capacity grew rapidly between 1966 and 1971, increasing at a rate of about 27 percent per year. It increased only about 14 percent in 1971, and in 1972 dropped to about a 4 percent increase. 9/ Since 1972, it has just about kept even with refinery crude oil distillation capacity growth, remaining at about 5.6 percent of crude oil capacity from 1973 to 1976. In 1977, the percentage dropped to 5.3 percent and is expected to drop further to about 5.0 percent by 1981, based on known planned projects.

It appears that the most promising area for future development in the hydrocracking area is in the treatment of high-sulfur, high-metal containing residual feedstocks and their conversion to low-sulfur fuel oil products. Although progress has been made in removing metal contamination in residual fractions, metal contamination is still a serious problem in the hydrocracking of residual feedstocks.

Table A-8, on the following page, summarizes the catalytic hydrocracking input capacities of U.S. refiners for the period 1973 to 1981. Appendix Tables 7, 8, 9, and 10 indicate the data in more detail by PAD Districts.

9/ "Factors Affecting U.S. Petroleum Refining, Impact of New Technology," September 1973, National Petroleum Council, page 44.

Table A-8
U.S. Catalytic Hydrocracking Capacity As A Percent of U.S. Atmospheric Crude Oil Distillation Capacity

	Capacity, B/SD 1/		
Year	Crude Oil Atmospheric Distillation Operating Capacity	Hydrocracking Capacity	Hydrocracking Capacity As % of Atmospheric Distillation Capacity
1973	14,195,000	857,838	6.0
1974	15,012,000	845,638	5.6
1975	15,512,000	869,808	5.6
1976	15,713,000	883,108	5.6
1977	16,759,000	893,178	5.3
1981 2/	18,192,000	902,080	5.0

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

Caribbean "Exporting" Refiners - Caribbean "exporting" refiners do not have hydrocracking capacity. There are no indications that any such facilities are planned, at least in the near term.

(b). Hydrorefining

U.S. Refiners - Catalytic hydrorefining capacity as a percent of refinery crude oil atmospheric distillation capacity has just about doubled in the 1973 to 1977 period. The percentage is expected to increase further by 1980 (from 10.9 percent to 12.3 percent). Much of this growth can be traced to the expansion of new catalytic reforming technology requiring more stringent feedstock pretreatment and to the refining of larger quantities of sour crudes. Control of sulfur dioxide emissions from catalytic crackers has also been instrumental in spurring increases in such hydrogen treatment.

Table A-9, following, is a summary of U.S. hydrorefining input capacities for the period 1973 to 1977, including a projection to 1981. Appendix Tables 7, 8, 9, and 10 includes data in more detail by PAD Districts.

Caribbean "Exporting" Refiners - Catalytic hydrorefining capacity in the Caribbean "exporting" refineries increased appreciably in the 1973 to 1977 period growing from about 499,000 B/CD in 1973 to about 861,000 B/CD

Table A-9
U.S. Catalytic Hydrorefining Capacity as a Percent of U.S. Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/SD 1/ Crude Oil Atmospheric Distillation Operating Capacity	Hydrorefining Capacity	Hydrorefining Capacity As % of Atmospheric Distillation Capacity
1973	14,195,000	840,494	5.9
1974	15,012,000	1,019,828	6.8
1975	15,512,000	1,087,328	7.0
1976	15,713,000	1,276,788	8.1
1977	16,759,000	1,828,172	10.9
1981 2/	18,192,000	2,234,110	12.3

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

in 1977. Most of this hydrorefining capacity is dedicated to gas oil and middle distillate desulfurization to meet the growing requirements for low-sulfur fuels. There are no indications of any expansions of hydrorefining capacity in the "exporting" refineries through 1980. A new refinery with hydrorefining capacity, planned for the Virgin Islands, would start operations using sweet crude. Desulfurization facilities would not be expected to be on-stream until after 1980.

Table A-10, below, summarizes the Caribbean "exporting" refinery hydrorefining capacities for the years 1973 through 1977 with a projection to 1980. Appendix Tables 11, 12, and 13 show the data in greater detail.

Table A-10
Caribbean "Exporting" Refineries Catalytic Hydrorefining Capacity As A Percent of Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/CD 1/ Crude Oil Atmospheric Distillation Capacity	Capacity, B/CD 1/ Hydrorefining Capacity	Hydrorefining Capacity As % of Atmospheric Distillation Capacity
1973	3,835,300	498,700	13.0
1974	4,372,300	542,700	12.4
1975	4,375,100	695,500	15.9
1976	4,277,800	839,000	19.6
1977	4,277,800	861,100	20.1
1980 2/	4,627,800	861,100	18.6

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

(c). Hydrotreating

U.S. Refiners - Catalytic hydrotreating capacity of U.S. refiners increased by about one million barrels per day during the 1973 to 1977 period. This is an increase of less than 2 percent when expressed as a percent of U.S. refinery capacity.

U.S. catalytic hydrotreating capacity is expected to increase by about 503,000 B/SD by 1981, growing slightly from 31.4 percent to 31.7 percent of total U.S. crude oil distillation capacity. Growth in hydrotreating capacity can be attributed to a wider use of catalytic processes, where even low amounts of sulfur and nitrogen compounds cannot be tolerated, and to the increasing demand for higher-quality refined products.

Table A-11, on the following page, summarizes the U.S. hydrotreating capacities for the period 1973 to 1977 and projects the U.S. hydrotreating capacity to 1981. The data is shown in greater detail on Tables 7, 8, 9, and 10 of the Appendix.

Caribbean "Exporting" Refiners - Catalytic hydrotreating capacity in the Caribbean "exporting" refineries has not increased over the 1973 to 1977 period, but rather has shown a slight decline. In 1973, hydrotreating capacity as a percent of refinery atmospheric distillation

Table A-11
U.S. Catalytic Hydrotreating Capacity As A Percent of U.S. Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/SD 1/ Crude Oil Atmospheric Distillation Capacity	Hydrotreating Capacity	Hydrotreating Capacity As % of Atmospheric Distillation Capacity
1973	14,195,000	4,205,133	29.6
1974	15,012,000	4,581,589	30.5
1975	15,512,000	4,686,146	30.2
1976	15,713,000	4,956,609	31.5
1977	16,759,000	5,254,519	31.4
1981 2/	18,192,000	5,757,800	31.7

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

capacity was 11.2 percent; by 1977, the percentage had pped to 8.9 percent. There are no known plans for hydrotreating expansions in the area up to 1980.

Table A-12, below, summarizes the Caribbean "exporting" refineries hydrotreating capacities for the period 1973 to 1977, and projects the 1980 capacity growth. Tables 11, 12, and 13 of the Appendix show the data in greater detail.

Table A-12
Caribbean "Exporting" Refineries Catalytic Hydrotreating Capacity As A Percent of Crude Oil Atmospheric Distillation Capacity

Year	Capacity, B/CD 1/ Crude Oil Atmospheric Distillation Capacity	Capacity, B/CD 1/ Hydrotreating Capacity	Hydrotreating Capacity As % of Atmospheric Distillation Capacity
1973	3,835,300	430,900	11.2
1974	4,372,300	502,620	11.5
1975	4,375,100	399,000	9.1
1976	4,277,800	382,700	8.9
1977	4,277,800	381,600	8.9
1980 2/	4,627,800	381,600	8.2

1/ As of January 1 of indicated year.

2/ Estimated by DOE.

B. The Distribution and Nature of Sulfur Compounds and Metals in Crude Oils

There do not appear to be any official definitions which define the difference between sweet and sour crudes. Bland and Davidson 10/ define a sour crude as "Crude oil containing an abnormally large amount of sulfur compounds, which, upon refining, liberate corrosive sulfur compounds." For the purposes of this report, we have arbitrarily defined a sweet crude as a crude oil containing 0.5 percent or less of sulfur by weight. Sour crudes would contain in excess of 0.5 percent by weight.

When crude oil is distilled into fractions, the sulfur content of the fractions increases as the fractions become heavier. This is clearly illustrated in Figure B-1. This is also a probable reason why whole crude is not desulfurized. Since the naphtha and kerosene fractions contain relatively little sulfur, they require only relatively light treating and the refiner can concentrate on the heavier fractions at lesser volume than the whole crude.

Another reason why whole crude oil is not desulfurized is the presence of metals in crude oils principally as vanaduim, nickel and iron. These metals tend to foul catalysts used in desulfurization. In distillation, the metals stay in the

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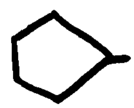
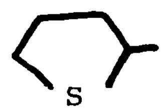
10/ Petroleum Processing Handbook, Bland and Davidson, Chapter 14, page 10, McGraw-Hill, Inc. (1967).

residual. In the past, the metals problem has been overcome largely by desulfurizing the vacuum gas oil and then blending it back with the vacuum pitch. However, new technologies have recently been developed for direct residual treating and these processes will become prominent in the future.

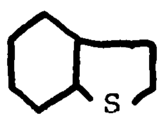
Some sulfur has been known to occur in crude oils in elemental form. The lightest sulfur compound found in crude oil is hydrogen sulfide. Other common sulfur compounds are mercaptans. Typical structures are:

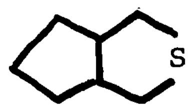
<u>Alkyl form</u> C_4-SH <u>Cyclic form</u>  SH

Sulfides would also include alkyl and cyclic compounds of which the following are typical:

<u>Alkyl form</u> C_2-S-C_3 <u>Cyclic form</u>  CH_3

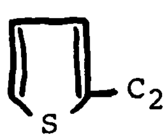
Di- and polycyclic sulfur compounds of the following typical formulas are also found in crude oils.



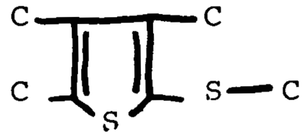


There are many classes of thiophenes in crude oils, typical structures of which are shown below.

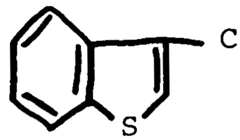
2-Ethylthiophene



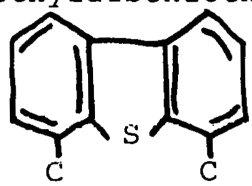
2(1-Thioethyl)-3,4,5 - Trimethylthiophene



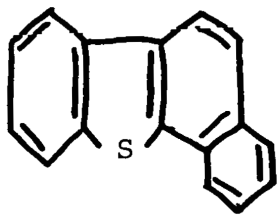
3-Methylbenzo (b) Thiophene



4,6-Dimethyldibenzothiophene



Benzo (b) Naphtho [2,1d] - Thiophene



The basic process involved in all hydrodesulfurization operations is for hydrogen to combine with the sulfur to form gaseous hydrogen sulfide. In this form, it is easily separable from the offgases by absorption, stripping and reduction to elemental sulfur. A typical hydrodesulfurization reaction is indicated below.

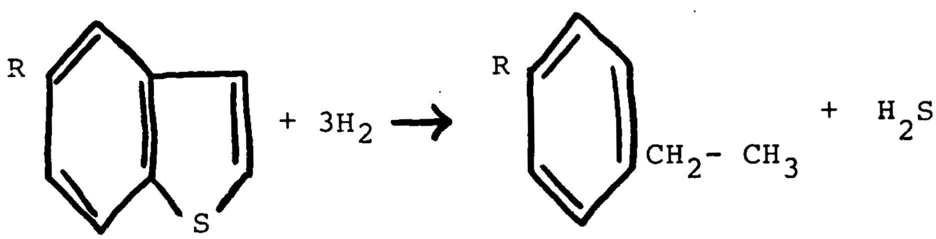
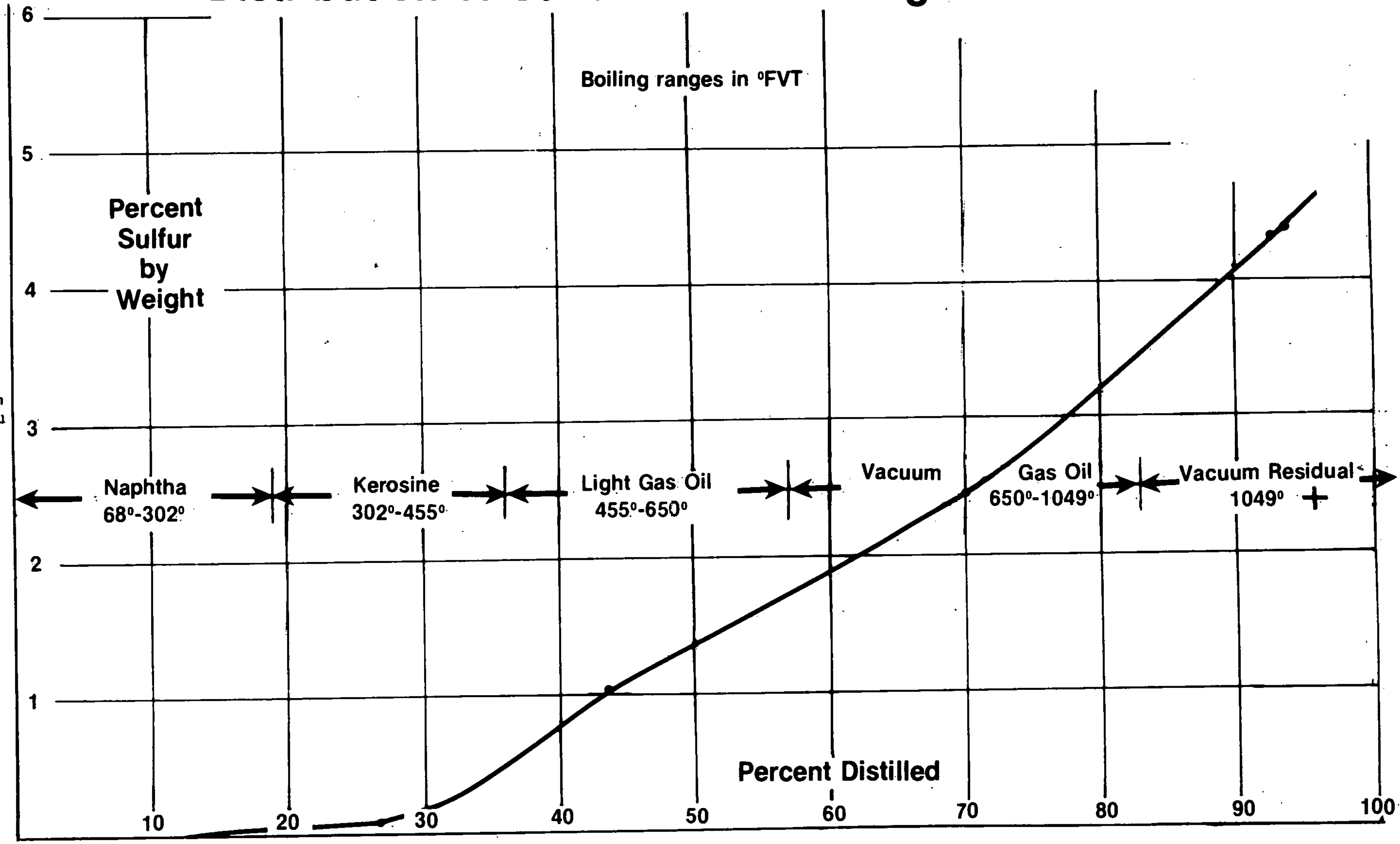


Figure B-1

Distribution of Sulfur in Arabian Light Crude Oil



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C. Types of Processes Used in Hydrodesulfurization

Tables C-1 and C-2 list some of the processes used in hydrotreating, hydrorefining, and hydrocracking, respectively. The processes vary widely in terms of type of feedstock and the intensity of reaction. Some of the milder processes are little more than a finishing operation and consume very little hydrogen. However, hydrocracking, a severe operation, can consume as much as 2,000 scf of hydrogen per barrel of feed. The data included in Tables C-1 and C-2 were derived from the Hydrocarbon Processing 1976 Refining Handbook Issue, 11/ and a number of technical papers presented by companies which license the processes.

The composition and preparation of catalysts is essentially a proprietary matter. However, there are a wide variety of types. Some examples are colbalt-molybdate-alumina or silica alumina impregnated with nickel, tungsten oxide or platinum. Palladium is also used, particularly in the H-Oil process.

Hydrodesulfurization may be used either as a process to produce finished products or to treat unfinished refinery streams. In the latter case, improved results are obtained in downstream processing units. For example, catalytic reformers need pretreated feed. By hydrotreating reformer

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11/ Gulf Publishing Company, Houston, Texas.

feed, sulfur is reduced to very low levels, thus insuring long catalyst life. When cat cracker feed is treated, higher yields are obtained.

A simplified flow diagram for a typical hydrorefining operation is presented in Figure C-1.

In a typical vacuum gas oil or residual hydrodesulfurization process, the feed is mixed with hydrogen and heated in a furnace before passing to a fixed bed reactor. After emerging from the reactor, the stream is cooled and passes through a scrubber for the removal of H_2S and NH_3. Unused hydrogen is separated and recycled for reuse with the feed. H_2S is separated and sent to a sulfur recovery unit. The desulfurized product, as a final step, passes through a stripper where a small amount of naphtha is removed. The naphtha originates from a slight amount of cracking which occurs during the process.

Operating conditions range through very broad ranges as can be seen from Table C-3. The reason for these variations are listed below.

1. The amount of desulfurization desired.
2. The nature of the catalyst.
3. The type of feedstock being processed.

Table C-1

HYDROTREATING AND HYDROREFINING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment: $ per bpsd	Investment: Size Plant MB/D
RCD Unibon	U.O.P.	Atmospheric residual desulfurization	Four	800	$421-1.0%S 1973 dollars - Entire onsite unit	50
Arosat	CE-Lummus	Saturate aromatics or distillate fractions from C_6 to 600°F	One (Finland)	3,960	Special Process	
Autofining	BP Trading, Ltd.	Desulfurize straight run distillates up to 465°F TBP also SNG feed	Four: 2 - UK 1 - Aden 1 - France		$75 (excl. catalyst) March 1976 dollars England	45
Distillate Hydro-desulfurization	Institut Francais du Petrole	Desulfurize distillates ranging from light distillate to VGO1/.	87: 42 - Naphthas 29 - Mid. Dist. 8 - VGO 8 - Other		$250 1975 dollars onsite	30
Go-fining	Exxon Research and Engineering Co. with Union Oil	Desulfurize VGO thermal and cycle oils	17	410 - 975	$150 - $300 4Q 2/ - 1975 dollars onsite	
Residfining	Exxon Research and Engineering Co. with Union Oil	Desulfurize atmospheric residuum	Three building	625 - 915	$500 - $1,200 4Q 2/ - 1975 dollars onsite	

Table C-1

HYDROTREATING AND HYDROREFINING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment $ per bpsd	Investment Size Plant MB/D
Gulfining	Gulf Research and Development Co. with Houdry	Desulfurize atmospheric residuum	Six	350	$325 1976 dollars	35
Hydrodesulfurization, residual oil	Shell Internationale Research Maatschappij B.V.	Desulfurize residual oils	One (47,000 bpsd) (Japan)	920		
Hydrodesulfurization, trickle flow	Shell Internationale Research Maatschappij B.V.	Desulfurize kerosene through VGO	90 - Total 1,400,000 bpsd	315		
Hydrodesulfurization, vapor phase	Shell Internationale Research Maatschappij B.V.	Desulfurize naphtha or up to 480°F	68 - Total 1,400,000 bpsd	400-800		
RDS and VRDS	Chevron Research	Desulfurize atmospheric residual (RDS) or vacuum residual (VRDS)	Eight VRDS bldg. One RDS bldg.	RDS 620-880 VRDS 960	$418 (excl. distillation RDS) 1972 dollars	107 (fuel oil product)
Resid Hydroprocessing	Standard Oil of Indiana	Desulfurize atmospheric residuum or improve cat feed		400-780	$900-$1,000 January 1976 dollars	20-40

Table C-1

HYDROTREATING AND HYDROREFINING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment: $ per bpsd	Investment: Size Plant MB/D
VGO and DAO Hydro-treating	Chevron Research	Desulfurize heavy gas oil (VGO) and de-asphalted resi-duum (DAO)	16 (VGO); One (DAO)	VGO - 410 DAO - 630		
Residue Desulfu-rization	BP Trading, Ltd.	Desulfurize atmos-pheric residual		625 at 1.0% S product 1,050 at 0.3% S product	$430 to 1% S $450 to 0.3% S March 1976 dollars UK location	50
Fuel Hydrodesul-furization	Badische Anilin-und Soda-Fabrik AG and Institut Francais du Petrole	Desulfurize atmos-pheric residue, crude oil, VGO and DAO		225 - VGO 505 - DAO 673 - TC	$250-VGO $530-DAO $820-TC 1976 dollars in France (onsite)	30 15 50
Unicracking HDS	Union Oil Co. of California	Hydrotreat atmos-pheric resids and some vacuum resids	One	340 - 730	$500 - $1,000 1976 dollars	
Hydrofining	BP Trading Co.	Desulfurize naphtha to VGO	49 operating or constructing		$100-Naphtha $115-Kerosine $135-Gas Oil $150-VGO March 1976 dollars UK location (excl. catalyst cost)	30

Table C-1

HYDROTREATING AND HYDROREFINING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment: $ per bpsd	Investment: Size Plant MB/D
Hydrofining	Exxon Research and Engineering Co.	Desulfurize naphtha to heavy gas oil	225		$80 - $300 4Q 1975 dollars Gulf location	
Ultrafining	Standard Oil Co. of Indiana	Desulfurize and saturate olefins and some aromatics			$150 - $230 January 1976 dollars Gulf Coast	10-30
Unionfining	Union Oil Co. of California	Desulfurize naphtha through VGO	75	75 - 350	$175 - $425 1976 dollars	
Resid HDS	Gulf Research and Development Co.	Desulfurize atmospheric and vacuum residua	Five	Atm. 500 - 800 Vac 1,250	$704 - $1,166 1976 dollars	50

1/In this table, the term VGO means "Vacuum Gas Oil."

2/4Q = Fourth Quarter

Table C-2

HYDROCRACKING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment $ per bpsd	Investment Size Plant MB/D
H-G Hydrocracking	Gulf Research and Development Co. with Houdry	Hydrocrack light and heavy gas oils	Four		$900-$1,050 1976 dollars	10
Hycracking	Exxon Research and Engineering Co.	Hydrocrack various types of light and heavy oils	22 operating or in construction		$400-$1,200 40 2/ 1975 dollars onsite	
Hydrocracking	Badische Anilin-und Soda-Fabrik AG and Institut Francois du Petrole	Hydrocrack sour heavy feedstocks	One	989-1368	$1,240 1976 dollars France (onsite)	21
Hydrocracking	BP Trading, Ltd.	Hydrocrack VGO 1/ to middle distillate primarily	One	1,510	$705 March 1976 dollars UK location	15
Isocracking	Chevron Research Co.	Hydrocrack all ranges of distillate	21 plus 2 under construction			
Ultracracking	Standard Oil Co. (Indiana)	Hydrocrack wide range distillates	One	1,880	$1,000-$1,400 January 1976 dollars Gulf Coast	

Table C-2

HYDROCRACKING PROCESSES

Process	Licensor	Function	Number of Commercial Plants	Hydrogen Consumption Scf/Bbl	Investment: $ per bpsd	Investment: Size Plant MB/D
Unicracking	Union Oil Co. of California	Hydrocrack wide range of gas oils	21 and 2 more building	1,700-2,500	$500-$1,000 1976 dollars	
H-Oil[3/]	Hydrocarbon Research, Inc.	To hydrocrack residuum or to desulfurize	Three	1,150 hydro-crack	$1,000 hydrocrack 1976 dollars	20
				725 desul-furize	$966 desul-furize	
HDC Unibon	U.O.P.	To hydrocrack V.G.O.		1,443-2,280		
LC - Fining[3/]	C-E Lummus and Cities Service Research and Development Co.	To hydrocrack gas oils or residues or to desulfurize	Two	529-1,410	$1,800 (atm.) 1976 dollars	27
					$2,900 (vac.)	17

1/In this table, the term VGO means "Vacuum Gas Oil."

2/4Q = Fourth Quarter

3/Variations in these two processes can result in ordinary desulfurization as opposed to hydrocracking.

Table C-3

OPERATING CONDITIONS FOR DESULFURIZATION PROCESSES
(EXTREME RANGES)

	Reactor Temperature, °F	Reactor Pressure, psig	Hydrogen Consumption scf/Bbl Feed
Hydrotreating			
Lube Finishing	480 - 550	About 400	30 - 200
Middle Distillates	500 - 800	300 - 600	75 - 350
Hydrorefining			
Vacuum Gas Oil	500 - 800	400 - 1,200	300 - 750
Atm. Residuum	500 - 800	400 - 1,200	420 - 800
Vac. Residuum	500 - 800	400 - 1,200	500 - 1,200
Hydrocracking	500 - 850	500 - 4,500	1,000 - 2,500

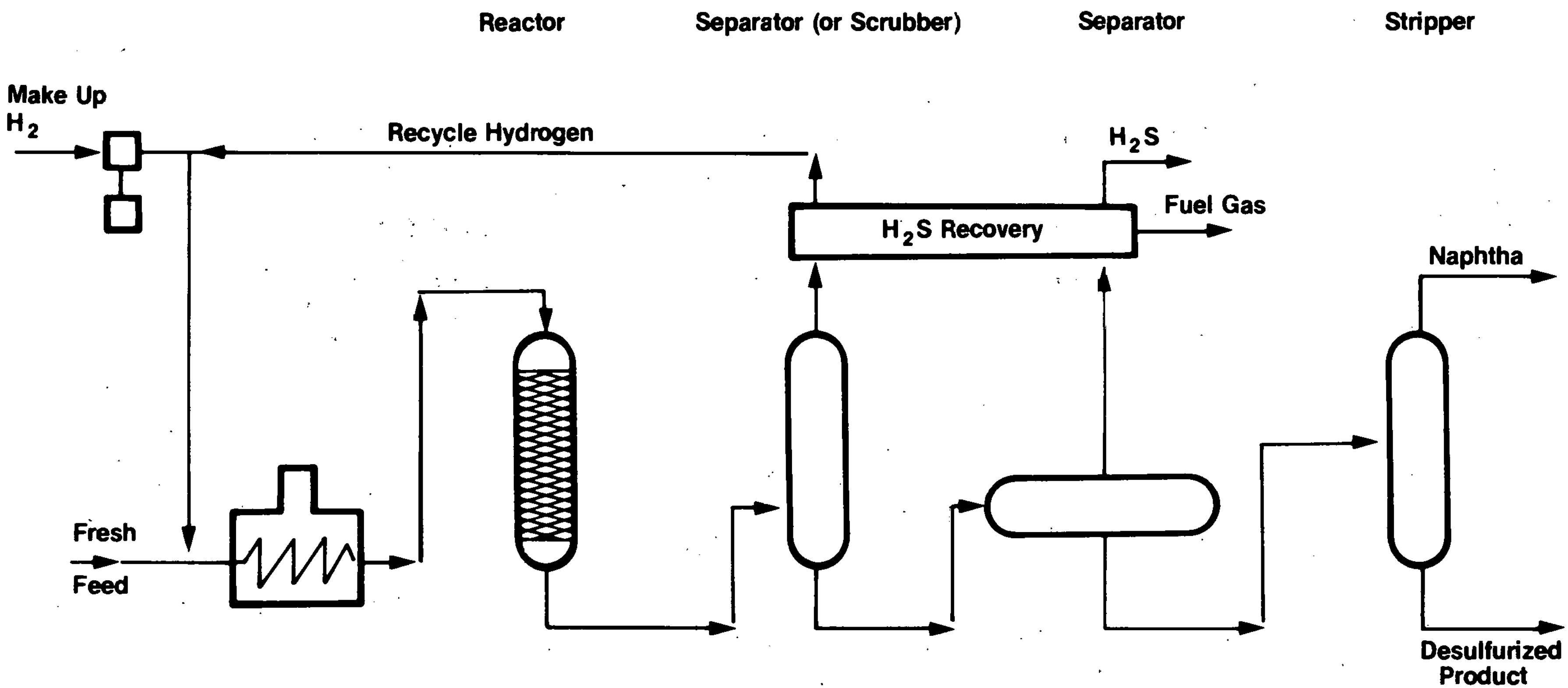


Figure C-1
Gas Oil Hydrorefining Simplified Flow Diagram

D. Cost Data for Desulfurization Processes

It is the purpose of this section to discuss the relative costs of processing sour versus sweet crudes in terms of capital and operating costs. Refinery margins required to cover operating costs and an adequate return on capital are also determined.

Cost data are presented for hydroskimming type refineries of various sizes. In each case, the refinery design called for the following yield pattern.

	%
Unleaded Gasoline	12.6
Regular Gasoline	7.8
Premium Gasoline	1.3
Jet A	4.0
No. 2 Fuel Oil	23.5
No. 6 Fuel Oil	46.2
Butane	0.9
Propane	1.5
Process Gas (FOE)	1.2
Sulfur 1.96 Tons/MB Crude	
Total (Ex-sulfur)	99.0

The above yields include refinery fuel. Small deviations, such as butane, propane, and process gas yields occur when running sweet crude.

The following summary indicates investment costs, operating costs and return on capital required for three distinct sizes of refineries, namely 250 MB/SD, 150 MB/SD and 15 MB/SD.

Crude Throughput MB/SD	Investment MM$	Investment $/B/CD	$/Barrel Operating Cost (Ex-Fuel)	$/Barrel Return on Capital	$/Barrel Gross Margin Needed
Sour Crude (Lt. Arabian)					
250.0	520.7	2,314	0.44	1.64	2.08
150.0	352.8	2,613	0.50	1.86	2.36
15.0	54.1	4,007	1.27	2.84	4.11
Sweet Crude (Ekofisk)					
245.0	307.4	1,394	0.20	1.00	1.20
147.0	200.8	1,518	0.25	1.09	1.34
14.7	29.2	2,207	0.43	1.59	2.02

The sweet crude volumes shown above are slightly smaller than the sour crude volumes due to the need for some purchased butane input. Product volumes are essentially the same in the sweet crude and sour crude cases for equal refinery size. All costs reflect January 1977 construction and operating costs.

The very high unit investment of $4,007 per barrel per day of capacity and the high gross margin required for a new refinery of 15,000 barrels per day equipped to process sour crude, would render such a unit uneconomical. A small refiner contemplating a new plant of this size would more likely plan it for sweet crude processing. To effect even further economies in investment and operating cost, such a refiner would design the plant to produce naphtha rather than gasoline, provided he has an assured outlet for the naphtha.

Detailed investment data for the sour crude processing in the three refinery sizes are presented in Table D-1. Investment data for the same three size units for processing sweet crude are presented in Table D-2.

Projected earnings and economics for the three sizes of refineries when designed for and running sour crude is detailed in Table D-3. The equivalent data for sweet crude are presented in Table D-4. It is interesting to note that while all cases resulted in a positive net margin after deducting all operating expenses, none of the margins were sufficient to cover a return on capital equivalent to a 15 percent after tax DCF return. Undoubtedly, this situation has arisen in part from skyrocketing refinery construction costs that have been experienced in the past 2 or 3 years. Another factor is that present DOE regulations under controlled prices do not permit the pass through of return on investment items. Presumably, if price controls are lifted, adjustments will occur in prices which may justify new construction. On the other hand, incentives could be provided to promote conversion to sour crudes. A possible solution could include such items as investment tax credits, accelerated depreciation, or partial rebates of crude oil equalization taxes which may be enacted into law.

Crude prices used in Tables D-3 and D-4 were derived as follows:

	34° Arabian Light ($/B)	35° North Sea Ekofisk ($/B)
F.O.B. Price:		
Ras Tanura	12.09	-----
Teeside	-----	14.10
Transportation	1.38	0.64
Insurance	0.06	0.06
Import Fee	0.09	0.09
Entitlements Credit*	(2.76)	(2.76)
Delivered Cost, CIF Gulf Coast	10.86	12.13

*Does not include the small refiner bias portion of the entitlements program.

For an equivalent profit or loss position, the laid-down cost of the sour crude for the 250 and 150 MB/SD refineries, respectively, would need to be about $1.32 to $1.49 per barrel lower (derived from Tables D-3 and D-4) than the corresponding cost of sweet crude rather than the $1.27 per barrel ($12.13 to $10.86) noted above.

Operating costs for each case in terms of dollars per barrel are indicated in Table D-5.

Operating Costs of Specific Desulfurizing Steps

The foregoing portion of this section has dealt with the overall operation of a refinery in which sour crude and desulfurizing operations occur as opposed to an identically sized refinery processing sweet crudes to essentially the same yields. In effect, this has illustrated the overall penalty in operating costs for running sour crudes versus sweet crudes with the differential reflecting the added cost of operating a series of desulfurizing steps on certain fractions of the crude.

To present a representative operating cost for desulfurizing certain specific fractions, such as vacuum gas oil or residual, involves so many variables that a broad range of results could be obtained. Some of these variables are:

1. Degree of Desulfurization - The greater the the percentage removal of sulfur, all other factors being constant, the greater the unit cost of the operation. A major part of the contribution to the cost is hydrogen consumption. The greater consumption associated with a greater degree of sulfur removal is illustrated in Figure D-1. Figure D-1 applies only to residuals, but similar relationships apply in the case of gas oils or middle distillates.

2. Nature of Catalyst - Since some catalysts are superior in activity or duration of activity, costs will vary accordingly.

3. Quality of Feedstock - Costs will vary with the level of initial sulfur content as well as certain other factors such as metals content of residuals, etc. High metals content will deactivate catalyst more rapidly.

Tables D-6, D-7, and D-8 illustrate the costs of desulfurizing typical crude residua. The data are based on older studies updated by cost indices to the year 1977. It should be noted that direct comparisons cannot be made between these tables. This is because there are variations in feedstocks, plant size, and the treatment of return on capital. For example, Table D-6 includes an 8 percent interest on capital, but Table D-7 contains a built in 10 percent DCF (discounted cash flow) return which would cause the costs in D-7 to be higher, all other factors being equal.

In summary, it can only be concluded that under today's conditions, the cost of direct desulfurization of atmospheric residuum to the level of 0.3 percent sulfur is in the order $2 to $3 per barrel of feedstock, particularly, when an acceptable DCF return is included in the costs. This cost is in line with differences in high and low sulfur residual fuel prices which are covered in Section G.

Table D-1

INVESTMENTS FOR LIGHT ARABIAN CRUDE HYDROSKIMMING REFINERIES

Item	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$
Atmospheric Crude Unit	250.0	33.5	150.0	23.4	15.0	3.5
Vacuum Crude Unit	115.5	16.8	69.3	11.7	6.9	1.8
Naphtha Hydrodesulfurization	61.0	15.8	36.6	11.7	3.7	2.2
Distillate Hydrodesulfurization	30.5	5.5	18.3	4.3	1.8	0.8
Gas Oil Hydrodesulfurization	82.5	27.9	49.5	19.6	5.0	2.9
Vacuum Resid Hydrodesulfurization	28.8	32.0	17.2	22.2	1.7	3.0
Catalytic Reforming - Low Press.	46.0	27.1	27.6	19.4	2.8	3.4
Penex Unit	10.5	7.0	6.3	5.3	0.6	1.1
Merox Jet Treater	38.5	4.9	23.1	3.4	2.3	0.5
H_2 Plant - Purification (MMSCF/SD)	(24.0)	5.1	(14.4)	2.6	(1.4)	0.6
H_2 Compressors (MMSCF/SD)	(48.0)	8.7	(29.0)	6.8	(2.9)	1.4
Gas Recovery Unit	11.5	7.2	6.9	5.3	0.7	1.0
Amine - H_2S recovery unit (LT/SD)	(490.0)	9.4	(294.0)	6.8	(29.4)	1.2
Sulfur Plant (LT/SD)	(490.0)	11.4	(294.0)	8.3	(29.4)	1.5
Subtotal Process		212.3		150.8		24.9
Tankage		41.2		24.6		2.7
Pressure Storage		2.9		1.8		0.5
Piping		24.9		17.7		2.9
Wharf Piping		7.0		5.5		1.7
Steam Generation		22.2		14.1		1.0
Cooling Water System		4.9		3.6		0.6
Electrical Distribution		5.3		3.6		0.5
Firewater System		2.8		2.3		1.0
Flare		2.1		1.5		0.3
Air Systems		0.9		0.6		0.2
Wharf & Dredging		5.1		3.9		1.3
Site Preparation		6.2		4.2		0.6
Buildings		7.4		5.1		0.8
Contingency - 15%		60.9		42.2		6.9
Total Plant		406.1		281.5		45.9

Table D-1

INVESTMENTS FOR LIGHT ARABIAN CRUDE HYDROSKIMMING REFINERIES

Item	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$
Land		6.2		4.2		0.6
Interest During Construction		12.2		8.5		1.4
Startup Expense		8.1		5.6		0.9
Total Capital		432.6		299.8		48.8
Working Capital						
Crude - 20 days		48.9		29.3		2.9
Entitlements - 60 days		37.3		22.4		2.2
Spare Parts - supplies		1.9		1.3		0.2
Total Working Capital		88.1		53.0		5.3
Total Capital		520.7		352.8		54.1

Table D-2

INVESTMENTS FOR EKOFISK CRUDE HYDROSKIMMING REFINERIES

Item	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$	MB/SD Size	Cost MM$
Atmospheric Crude Unit	245.0	33.1	147.0	23.2	14.7	3.4
Naphtha Hydrodesulfurization	39.8	12.3	23.9	8.1	2.7	1.9
Catalytic Reforming - Low Pressure	39.8	24.7	23.9	17.7	2.7	3.2
Merox Gasoline Treater	10.1	0.4	6.1	0.3	0.84	0.05
Gas Recovery Unit	6.2	5.0	3.7	3.0	0.37	0.4
Subtotal Process		75.5		52.3		8.9
Tankage		41.2		24.6		2.9
Pressure Storage		1.8		1.1		0.2
Piping		9.1		6.5		1.1
Wharf Piping		7.0		5.5		1.7
Steam Generation		14.7		9.3		0.5
Cooling Water System		3.8		2.8		0.4
Electrical Distribution		2.0		1.4		0.2
Firewater System		2.8		2.3		0.6
Flare		2.1		1.5		0.3
Air Systems		0.9		0.6		0.1
Wharf and Dredging		5.1		3.9		1.3
Site Preparation		3.7		2.5		0.3
Buildings		3.1		2.1		0.3
Contingency - 15 percent		30.5		20.5		3.3
Total Plant Investment		203.3		136.9		22.1
Land		3.9		2.6		0.5
Interest During Construction		6.1		4.1		0.7
Startup Expense		4.1		2.8		0.4
Total Capital Investment		217.4		146.4		23.7
Working Capital						
Crude for Refinery - 20 days		53.0		31.8		3.2
Entitlements - 60 days		36.1		2.0		2.2
Spare Parts and Supplies		0.9		0.6		0.1
Total Working Capital		90.0		54.4		5.5
Total Capital		307.4		200.8		29.2

Table D-3

PROJECTED EARNINGS AND ECONOMICS - LIGHT ARABIAN CRUDE OIL

Revenue Products	¢/Gal.	$/B	250 MB/SD		150 MB/SD		15 MB/SD	
			MB/CD	MM$/YR	MB/CD	MM$/YR	MB/CD	MM$/YR
Unleaded Gasoline	39.02	16.39	28.24	168.9	16.95	101.3	1.70	10.1
Regular Gasoline	37.52	15.76	17.55	101.0	10.53	60.6	1.05	6.1
Premium Gasoline	39.29	16.50	2.93	17.6	1.76	10.6	0.18	1.1
Jet A	32.93	13.83	9.00	45.4	5.40	27.3	0.54	2.7
No. 2 Fuel Oil	31.83	13.37	52.88	258.1	31.73	154.8	3.17	15.5
No. 6 Fuel Oil	27.48	11.54	103.94	437.8	62.37	262.7	6.24	26.3
Butanes	23.90	10.04	2.07	7.6	1.24	4.5	0.12	0.4
Propane	21.64	9.09	3.47	11.5	2.08	6.9	0.21	0.7
Process Gas (FOE)	27.48	11.54	2.81	11.9	1.69	7.1	0.17	0.7
Sulfur		$40/LT	441LT/D	6.4	265LT/D	3.9	26.5LT/D	0.4
Total Revenue	31.20	13.10	222.90	1,066.2	133.75	639.7	12.38	64.0
Raw Material Cost								
Crude	25.86	10.86	225.00	891.9	135.00	535.1	13.50	53.5
Gross Margin		2.12*		174.3		104.6		10.5
Operating Costs								
Fuel				63.6		38.2		3.8
Power				7.7		4.6		0.5
Lead				1.2		0.7		0.1
Catalyst, Chemicals				9.0		5.4		0.5
Subtotal Variable				81.5		48.9		4.9
Operating Manpower				1.6		1.6		1.6
Salaried Manpower				0.8		0.8		0.8
Maintenance				7.7		5.4		0.9
Operating Supplies				1.1		1.1		1.1
Taxes and Insurance				4.1		2.8		0.5
General and Administrative				3.2		2.2		0.4
Subtotal Fixed				18.5		13.9		5.3
Total				100.0		62.8		10.2
Net Margin				74.3		41.8		0.3
Capital Charge - 15% DCF				135.2		91.6		14.0
Net Profit (Loss)				(60.9)		(49.8)		(13.7)

*$/B of Crude

Table D-4

PROJECTED EARNINGS AND ECONOMICS - NORTH SEA EKOFISK CRUDE OIL

Revenue Products	¢/Gal.	$/B	250 MB/SD MB/CD	250 MB/SD MM$/YR	150 MB/SD MB/CD	150 MB/SD MM$/YR	15 MB/SD MB/CD	15 MB/SD MM$/YR
Unleaded Gasoline	39.02	16.19	28.28	169.2	16.97	101.5	1.70	10.1
Regular Gasoline	37.52	15.76	17.55	101.0	10.53	60.6	1.05	6.0
Premium Gasoline	39.29	16.50	2.93	17.6	1.76	10.6	0.18	1.1
Jet A	32.93	13.83	9.00	45.4	5.40	27.3	0.54	2.7
No. 2 Fuel Oil	31.83	13.37	52.88	258.1	31.73	154.8	3.17	15.5
No. 6 Fuel Oil	27.48	11.54	103.95	437.8	62.37	262.7	6.24	26.3
Propane	21.64	9.09	1.69	5.6	1.01	3.4	0.10	0.3
Process Gas (FOE)	27.48	11.54	3.01	12.7	1.81	7.6	0.18	0.8
Total Revenue	31.16	13.09	219.29	1,047.4	131.58	628.5	13.16	62.8
Raw Material Cost								
Crude	28.88	12.13	218.25	966.3	130.95	579.8	13.09	57.9
Butane	24.19	10.16	1.35	5.0	0.81	3.0	0.08	0.3
Gross Margin		0.96*		76.1		45.7		4.6
Operating Costs								
Fuel				35.0		21.0		2.1
Power				2.3		1.4		0.1
Lead				1.2		0.7		0.1
Catalyst, Chemicals				4.5		2.7		0.3
Subtotal variable				43.0		25.8		2.6
Operating Manpower				0.4		0.4		0.4
Salaried Manpower				0.2		0.2		0.2
Maintenance				3.4		2.1		0.4
Operating Supplies				0.3		0.2		0.2
Taxes and Insurance				2.0		1.4		0.2
General and Administration				1.6		1.1		0.2
Subtotal fixed				7.9		5.4		1.6
Total				50.9		31.2		4.2
Net Margin				25.2		14.5		0.4
Capital Charge - 15% DCF				79.8		52.1		7.6
Net Profit (Loss)				(54.6)		(37.6)		(7.2)

*$/B Crude Oil

Table D-5

OPERATING COSTS IN DOLLARS PER BARREL OF CRUDE OIL
FOR SOUR AND SWEET CRUDE CASES

	Sour Crude - MB/CD			Sweet Crude - MB/CD		
	225.0	135.0	13.5	218.25	130.95	13.09
Fuel	$0.77	$0.77	$0.77	$0.44	$0.44	$0.44
Power	0.09	0.09	0.09	0.03	0.03	0.03
Lead	0.01	0.01	0.01	0.02	0.02	0.02
Catalyst, Chemicals	0.11	0.11	0.11	0.06	0.06	0.06
Operating Wages	0.02	0.03	0.32	0.01	0.01	0.08
Salaries	0.01	0.02	0.16	----	----	0.04
Maintenance	0.09	0.11	0.18	0.04	0.04	0.08
Operating Supplies	0.01	0.02	0.22	----	----	0.04
Taxes and Insurance	0.05	0.06	0.10	0.02	0.03	0.04
General Administration	0.04	0.04	0.08	0.02	0.02	0.04
Total	$1.20	$1.26	$2.04	$0.64	$0.65	$0.87

Table D-6

OPERATING COSTS - DESULFURIZING KUWAIT ATMOSPHERIC REDUCED CRUDE 1/
50,000 BPSD 2/

	1% Sulfur in Product		0.3% Sulfur in Product	
	1973	1977 3/	1973	1977 3/
Investment, 10^6\$	21.0	29.6	31.0	43.7
Direct Operating Costs	¢/Bbl	¢/Bbl	¢/Bbl	¢/Bbl
Labor	1.2	1.7	1.5	2.2
Utilities	10.3	22.8	10.9	24.2
Catalyst & Royalties	6.3	9.8	9.0	13.9
Maintenance, Taxes, & Insurance @ 6% Plant Cost	7.6	10.7	11.3	15.9
Sub-Total	25.4	45.0	32.7	56.2
Indirect Operating Costs				
Administrative	1.2	1.7	1.5	2.2
Interest and Depreciation (8% and 10 years)	20.1	28.4	29.7	41.9
Sub-Total	21.3	30.1	31.2	44.1
Total Operating Costs (ex H_2)	46.7	75.1	63.9	90.3
Hydrogen 4/	42.0	70.5	54.0	90.6
Grand Total	86.7	145.6	117.9	180.9

1/ From "Desulfurization of Kuwait Reduced Crude to 0.3% Sulfur Content," C. H. Watkins, R. J. Parker, and J. M. Pharis (U.O.P.), API Meeting, May 16, 1973.

2/ 330 operating days per year.

3/ Escalated to 1977 using various W. L. Nelson indicies.

4/ 1977 H_2 cost at \$1/Mcf.

Table D-7

COST OF DESULFURIZING 650 °F + ATM. BOTTOMS
TO MAKE 0.3 WT. % SULFUR PRODUCT 1/ 70 MB/SD

	1974	1977 2/
Heavy Iranian		
Investment, $10^6$$	42.3	55.7
Operating Costs	$/Bbl	$/Bbl
Hydrogen 4/	0.55	0.63
Utilities	0.15	0.25
Catalyst	0.45	0.54
Other Investments	0.35	0.46
Maint., Labor, etc. 3/	0.09	0.12
Total	$ 1.59	$ 2.00
Heavy Arabian		
Investment, $10^6$$	50.9	67.0
Operating Costs	$/Bbl	$/Bbl
Hydrogen 4/	0.80	0.92
Utilities	0.15	0.25
Catalyst	0.65	0.86
Other Investments	0.35	0.42
Maint., Labor, etc. 3/	0.10	0.14
Total	$ 2.05	$ 2.59

1/ From "Recent Advances in Residua Processing," J. A. Rionda, S. Bodnick, T. K. Kett (E. R. & E. Company), NPRA Annual Meeting, March 31, 1974.

2/ Escalated to 1977 using various W. L. Nelson indicies.

3/ Added by DOE.

4/ 1977 H_2 Cost at $1/Mcf.

Table D-8

COST OF DESULFURIZING KUWAIT ATMOSPHERIC RESIDUUM 1/
100,000 B/D

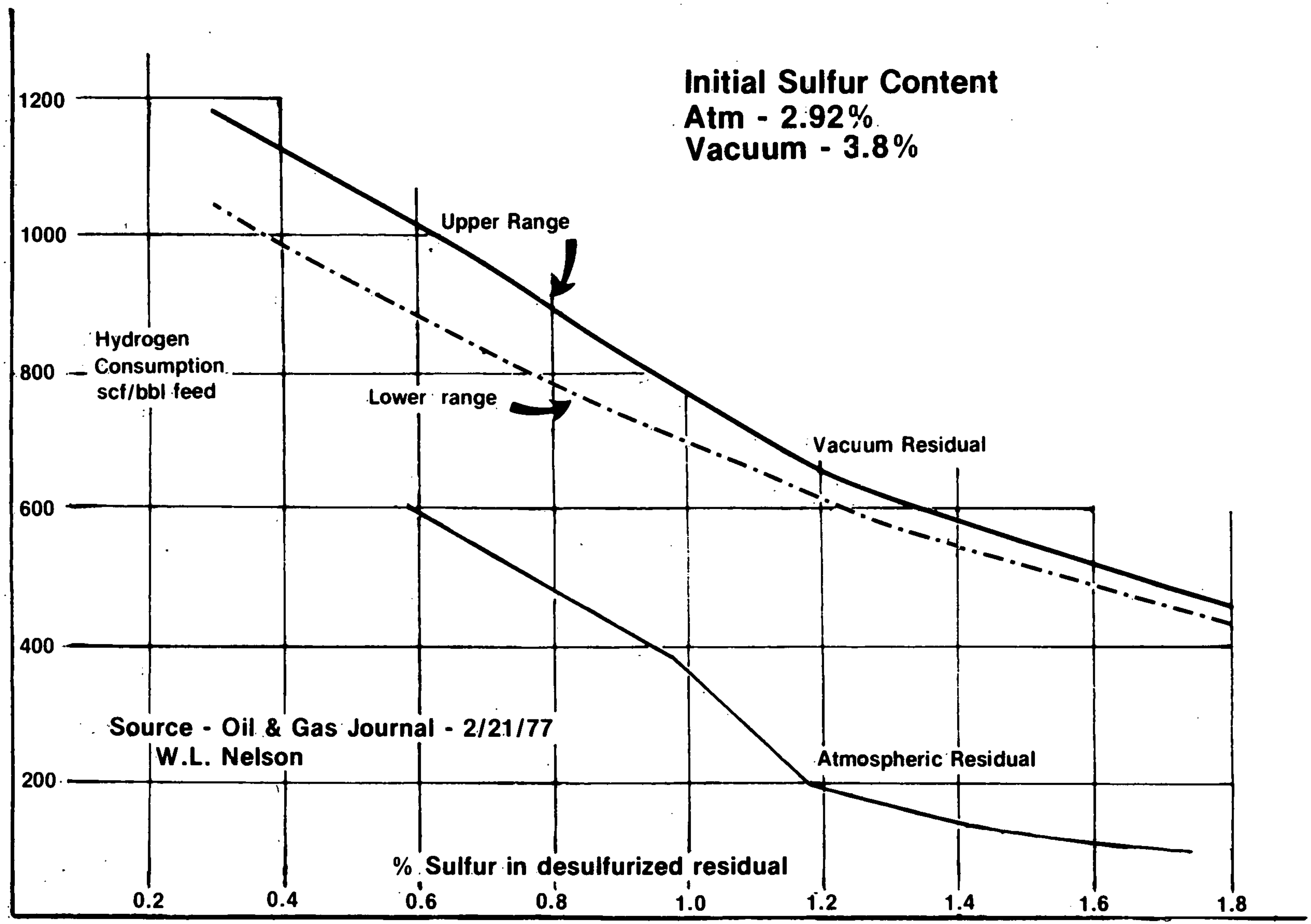
	1% Sulfur in Product		0.7% Sulfur in Product	
	1972	1977 2/	1972	1977 2/
Cost ¢/B F. O.	95 - 110	160 - 185	125 - 140	210 - 240

1/ "Hydrodesulfurization Technology Takes on the Sulfur Challenge," Leo Aalund, Oil and Gas Journal, September 11, 1972.

2/ Adjusted to 1977 costs using weighted combination of various indicies by W. L. Nelson.

Figure D-1

Hydrogen Consumption
Light Arabian Residual Desulfurization



E. Hydrogen Manufacture

Hydrogen has become increasingly important to refineries as a material used in desulfurization. One of the most important sources is from catalytic reforming. The hydrogen yield from all U.S. reformers has a potential output of about 4,400 MMscf/d when operating near capacity. The production of hydrogen may vary from 2 to 3 percent by weight of reformer feed. Unfortunately, much of this production is mingled with other refinery gas and burned as plant fuel. This is largely because reformers are also needed in sweet crude refineries where desulfurization is usually not needed.

In many hydroskimming or simpler type refineries, the hydrogen produced from the reformer may suffice to meet the desulfurizing requirements. In more complex sour crude refineries, hydrogen sources must be supplemented with hydrogen generators. The three broad classes of generators include methane reforming, naphtha reforming and partial oxidation. Feedstocks for reformers include:

Natural Gas
Refinery Gas
Naphtha

The partial oxidation process can accept a wide range of hydrocarbon feedstocks.

The total U.S. refinery capacity for hydrogen manufacture totals 1,562.6 MMscf/D. 12/

12/ Oil and Gas Journal, March 28, 1977, page 98.

The types of units which comprise this capacity are listed below:

U.S. Refinery Hydrogen Generating Units

Process	Capacity MMCF/D	% of Total
Methane Reforming	1,062.9	68.0
Naphtha Reforming	365.5	23.4
Partial Oxidation	105.5	6.8
Other	28.7	1.8
Total	1,562.6	100.0

Methane reforming includes units which use either natural gas or refinery gas as feedstock. Some methane reformers have been modified to be capable of accepting feeds as heavy as butane. However, we have no data on how much capacity has been so modified.

The process consists of heating the hydrocarbon feed and passing it through a furnace in which the tubes are filled with catalyst. The feed is mixed with steam and the reaction takes place at a temperature of about 1,100 °F. New designs contemplate a pressure of 600 psig and temperatures from 1,400°F to 1,850°F. Carbon monoxide and carbon dioxide produced as co-products with the hydrogen are removed in the purification process. A simplified flow diagram is indicated in Figure E-1.

Investments required for hydrogen manufacture adjusted to February 1977 costs are shown below: 13/

MMCF/D Size Unit	Million Dollars Cost: Naphtha Feed	Million Dollars Cost: Methane Feed
10	4.3	3.2
50	10.3	8.0
100	17.4	12.9

Operating costs for hydrogen manufacture can vary over a wide range depending on the cost of the feed gas and fuel used as well as plant size and whether or not credits are taken for excess steam generation. In Table E-1, an update of operating costs adjusted for feed gas values and other costs to present day values from an older paper by W. L. Nelson, is presented. 14/ Some costs have also been presented recently in a paper by Wesley Wolf. 15/ In the latter, a 50 MMscf/d hydrogen plant is quoted at \$1.04/MMscf/d H_2 operating cost for a traditional unit while a PSA (pressure swing absorption) unit cost is quoted at \$0.96/MMscf/d H_2. The latter unit purifies the hydrogen stream by adsorption of carbon monoxide and carbon dioxide by molecular sieves.

13/ Guide to Refinery Operating Costs, 3rd Edition, W. L. Nelson, p. 252.
14/ Ibid.
15/ "PSA System Can Reduce Hydrogen Costs," Oil and Gas Journal, February 23, 1976.

It appears that under present day feed gas costs, it is unlikely that hydrogen can be manufactured for much less than about $1.00 per Mscf. This identifies hydrogen as perhaps the most expensive single item in hydrodesulfurization processes. Residual desulfurization processes consuming 800 to 1,000 scf per barrel of feedstock could, therefore, attribute $0.80 to $1.00 per barrel of costs to hydrogen alone.

Table E-1

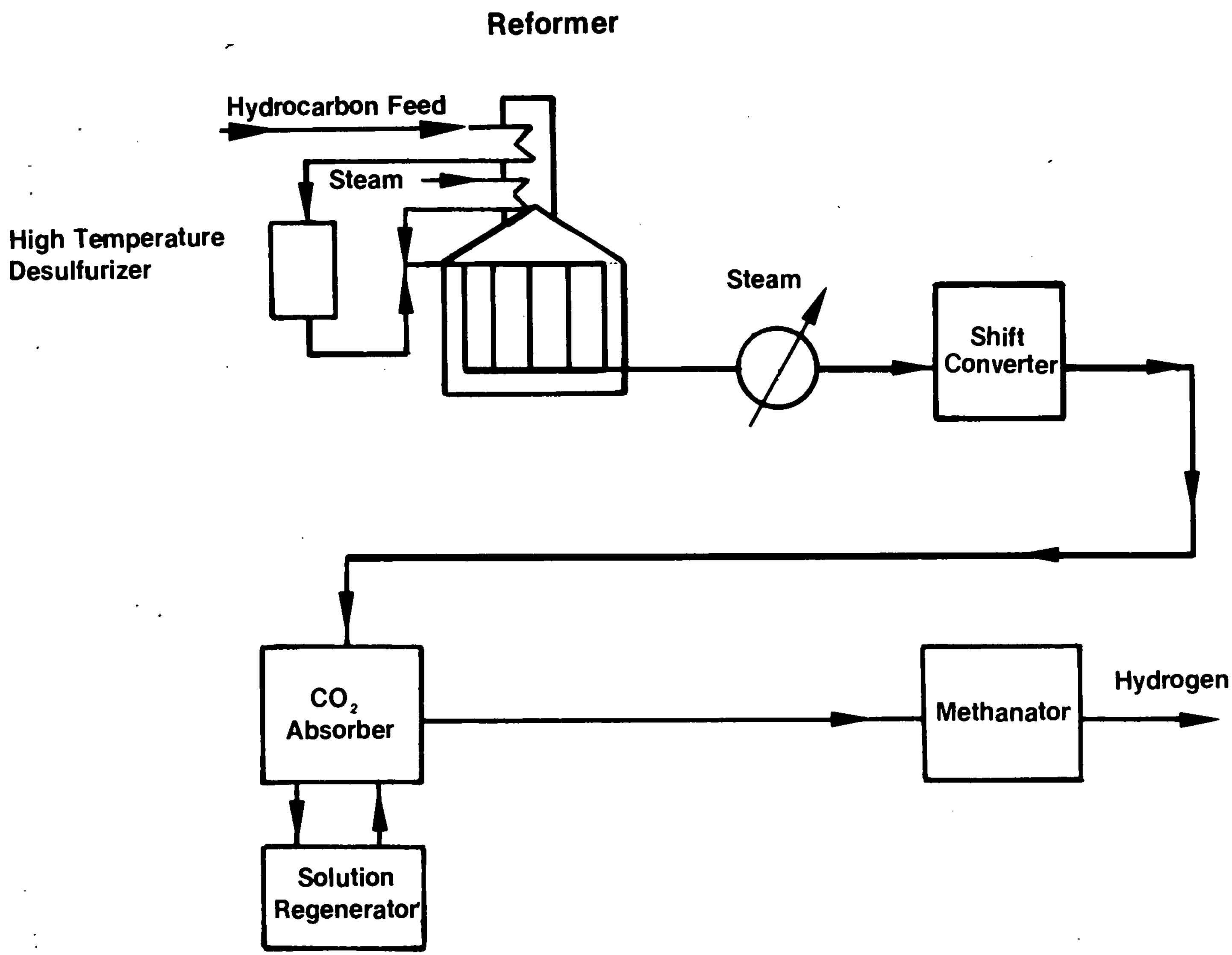
HYDROGEN PLANT OPERATING COSTS 1/
Approximate Ranges (1977)

	$0.50/Mcf Feed Gas Cents/Mscf	$1.50/Mcf Feed Gas Cents/Mscf
Labor: supervision	1.4 - 3.4	1.4 - 3.4
operating	6.6 - 18.0	6.6 - 18.0
Electricity	0.8 - 2.0	0.8 - 2.0
Maintenance	3.4 - 5.7	3.4 - 5.7
Steam	0 - 30.0	0 - 30.0
Fuel	10.6 - 15.4	33.0 - 48.0
Cooling Water	0.7 - 2.5	0.7 - 2.5
Boilerfeed Water	2.3 - 0	2.3 - 0
Catalyst/Chemicals	1.8 - 4.5	1.8 - 4.5
Direct Operating Cost	30 - 75	55 - 150
Feed Gas 190-260 scf/Mscf	9.5 - 13.0	28.5 - 39.0
Hydrogen Cost (Probable Extremes)	40 - 88	84 - 189
Obsolescence, Ins., Taxes - 10% of Replacement Cost	7.7 - 9.6	7.7 - 9.6
Laboratory	2.7	2.7
Hydrogen Cost, Incl. Investment Cost (Extremes)	50 - 98	94 - 201

1/Based on a 10,000,000 scfd size plant.

Figure E-1

Hydrogen Manufacture-Steam Reforming Simplified Flow Diagram



F. Federal, State and Local Regulations on the Sulfur Level in Fuel Oils

All states have regulations which control the sulfur level in fuel oils burned in their areas. Some states further subdivide their territory into areas with differing limitations. In still other cases, the regulations may be on a strictly local basis. Examples would include New York City and Philadelphia.

The Department of Environmental Affairs of the American Petroleum Institute has undertaken the task of compiling these regulations and publishing them. They appear in Table F-1. Since many of the regulations are expressed in such terms as maximum allowable parts per million of SO_2 in flue gases, these values have been converted into a sulfur content of the fuel by calculations which assume certain amounts of excess air in the flue gas.

Figure F-1 shows the history of fuel oil consumption by sulfur levels in terms of percent of the total. It will be noted that the percentages in each sulfur level have remained essentially constant over the past three years. This is because practically all of the regulations were promulgated in the period between 1970 and 1974. One factor which may cause some added consumption of lower sulfur fuel oil would result from regulations in some areas which require new emission sources to adhere to more strict limitations than older established sources. However, states may be expected to impose more severe limitations on all sources in the future and this could cause some increase in fuel oil volumes consumed at low sulfur content levels.

The sharp climb in the percentage consumption of lower sulfur fuel oil in the years 1971 through 1973 as shown in Figure F-1 reflects the application of the new regulations. It is suspected that the drop in 1974 may be due to exceptions granted at the time of the Arab embargo. The same data is presented on a total barrels basis in Figure F-2. This chart illustrates the decrease in demand which occurred in 1974 and 1975. Figure F-2 is based on data summarized in Table F-2.

While figures F-1 and F-2 are labeled "consumptions," they are actually derived by adding production from U.S. refineries in each year to the imports of that year. The result will, therefore, differ from the exact consumption due to stock changes and any exports. However, the net result should be relatively accurate in indicating trends.

TABLE F-1

FEDERAL, STATE, AND LOCAL FUEL SULFUR RESTRICTIONS 1/

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Alabama	Category I Counties and Jefferson County	Oil	All	1.70 (1)	3-25-76
				1.66 (2)	
		Coal		1.08 (3)	3-25-75
	Category II Counties	Oil	All	3.9 (1)	3-25-75
				3.7 (2)	
		Coal		2.4 (3)	3-25-75
Alaska	All	Oil	All	1.00 (4)	5-8-74
		Coal	All	0.85 (5)	5-8-74
Arizona	All	Oil	Existing	0.98 (1)	10-1-75
				0.93 (2)	
		Oil (high sulfur)*	Existing	2.15 (1)	10-1-75
				2.04 (2)	
		Coal	Existing	0.60 (3)	10-1-75
		Oil	New	0.78 (1)	10-1-75
				0.74 (2)	
		Coal	New	0.48 (3)	10-1-75

*High sulfur fuel oil=fuel oil containing .90% or more by weight of sulfur.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Arkansas	All	The only regulations adopted by the State require that SO_2 concentrations do not exceed 0.20 ppm in the ambient air at any places beyond the premises on which the source of the emissions is located.			7-30-73
California	Air Basins				
	North Coast (Less Mendocina and Sonoma Counties)	All	All	1.9	12-31-75
	San Francisco Bay	Oil	Existing	0.60 (4)	5-19-76
		Coal	Existing	0.51 (5)	
			New		
		Oil	>250 $\overline{M}$BTU/hr.	.78 (1)	5-19-76
				.74 (2)	
		Coal	>250 $\overline{M}$BTU/hr.	.72 (3)	5-19-76
	North Central Coast	All	All	0.5	12-74
	South Central Coast	All	All	0.5	8-2-76
	South Coast	All	All	0.5	2-15-77
		All	All	0.25	7-1-78*
	Northeast Plateau (Lassen and Modoc Counties)	All	All	0.5	11-5-71
	Sacramento Valley (Sacramento and Tehama Counties)	All	All	0.5	4-6-77
	Southeast Desert	All	All	0.5	12-31-75
	San Diego	All	All	0.5	9-2-76

*Effective July 1, 1978, all power plants must use fuels with a .25 %wt. S content; before July 1, 1978, such fuels must be used if available.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Colorado	All	Oil	<250 $\overline{M}$BTU/hr	.78 (1)	**
				.74 (2)	
			>250 $\overline{M}$BTU/hr.	.29 (1)	
				.28 (2)	
		Coal	<250 $\overline{M}$BTU/hr.*	.72 (3)	**
			>250 $\overline{M}$BTU/hr.	.24 (3)	

*Applies also to facilities converting from other fuels to coal.

**Approved August 11, 1977; to be finalized by end of October 1977.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Connecticut	All	All	All	0.5	3-1-76
Delaware	All	Distillate	All	0.30	3-28-74
	New Castle County	All	All	1.00	3-28-74
District of Columbia	All	All	All	1.00	5-19-77
	All	All		.50	10-1-78*

*Effective date.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Florida	Duval County (north)	Oil	>250 $\overline{M}$BTU/hr.*	2.54 (1)	5-10-77
			Existing**	2.41 (2)	
	Duval County (south)	Oil	Existing	1.63 (1)	5-10-77
				1.54 (2)	
	Hillsborough County	Oil	Existing	1.17 (1)	5-10-77
				1.11 (2)	
	Rest of state	Oil	Existing	2.69 (1)	5-10-77
				2.55 (2)	
		Oil	New	.78 (1)	5-10-77
				.74 (2)	
	Hillsborough County	Coal	Existing	1.44 (3)	5-10-77
	Rest of state	Coal	Existing	3.70	5-10-77
		Coal	New	.72 (3)	5-10-77

*Units with a heat input of less than 250 $\overline{M}$BTU/hr. must use "latest reasonably available technology."

**Emission limits for existing sources will be reevaluated prior to October 1, 1978.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Georgia	All	All	<100 $\overline{M}$BTU/hr.	2.50	11-30-75
			>100 $\overline{M}$BTU/hr.	3.00	11-30-75
			>250 $\overline{M}$BTU/hr.		
		Oil	New	0.74 (2)	11-30-75
		Coal	New	0.72 (3)	11-30-75

Notes: (1) Sulfur content greater than the above may be allowed provided that the source utilizes SO_2 removal and the SO_2 emission does not exceed that allowed by the above sulfur content limitations, utilizing no SO_2 removal.

(2) Large fuel burning sources are limited by a maximum allowable SO_2 emission level expressed in pounds per hour. The allowable level varies with size and location of the facility and with stack height.

Footnote at end of table.

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Hawaii	All	All	All	2.0	2-13-76
		All	>250 MBTU/hr.	0.5	2-13-76
Idaho	All	No. 1	All	0.30	5-7-76
		No. 2	All	0.50	5-7-76
		Residual	All	1.75	5-7-76
		Coal	All	1.00	5-7-76
Illinois	All	Distillate	All	.29 (1)	9-4-75
		Residual	New		9-4-75
			<250 MBTU/hr.	.93 (2)	
			>250 MBTU/hr.	.74 (2)	
			Existing	.93 (2)	9-4-75
	Chicago, St. Louis, and Peoria metropolitan areas	Coal	Existing	.72 (3)*	9-4-75
	Other metropolitan areas	Coal	Existing	1.08 (3)**	9-4-75
	Rest of state	Coal	Existing	3.60 (3)	9-4-75
	All	Coal	New		9-4-75
			>250 MBTU/hr.	.72 (3)*	
			<250 MBTU/hr.	1.08 (3)	

*Suspended January 20, 1976, pending further review (Commonwealth Edison v. Pollution Control Board, No. 47352).

**If the annual arithmetic average SO_2 level is greater than .015 ppm for any one year ending on or after 5-30-76.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Indiana*	All	Oil	New		
			>250 MBTU/hr.	.78 (1)	9-16-74
				.74 (2)	
		Coal	>250 MBTU/hr.	.72 (3)	9-16-74
	All	All	Existing and New, <250 MBTU/hr.		9-16-74

*Indiana has stack emission limits for each site on the basis of unit size, stack height, number of stacks, etc. According to state implementation plan information, allowable limits for coal range from .57 to .98 wt.%S, and for oil, from 1.03 to 1.9 wt.%S.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Iowa	All	Oil	New	.78 (1)	6-15-77
			>250 MBTU/hr.	.74 (2)	
		Oil	Existing, and <250 MBTU/hr.	2.4 (1)	6-15-77
				2.3 (2)	
	All	Coal	New		
			>250 MBTU/hr.	.72 (3)	6-15-77
			<250 MBTU/hr.	3.60 (3)	6-15-77
	Black Hawk, Clinton, Des Moines, Dubuque, Jackson, Lee, Linn, Louisa,	Coal	Existing	3.60 (3)	6-15-77

4

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
	Muscatine, and Scott Counties				
	All	Coal	Existing >500 MBTU/hr.	4.80 (3)	6-15-77
Kansas	All		>250 MBTU		
		Oil	New	2.78 (2)	1-1-74
		Coal	New	1.80 (3)	1-1-74

Kentucky — Note: Sulfur dioxide emission limitations are expressed on a sliding scale based on the size of the facility. Values for typical units are given below:

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Kentucky	All	Oil	New		6-5-75
			<10 MBTU/hr.	2.31 (2)	
			100 MBTU/hr.	1.02 (2)	
			>250 MBTU/hr.	.74 (2)	
		Coal	<10 MBTU/hr.	2.40 (3)	6-5-75
			100 MBTU/hr.	1.02 (3)	
			>250 MBTU/hr.	.72 (3)	
	Class I Counties		Existing		6-5-75
		Oil	<10 MBTU/hr.	Same as New	
			100 MBTU/hr.		
			>250 MBTU/hr.		
		Coal	Existing		6-5-75
			<10 MBTU/hr.	Same as New	
			100 MBTU/hr.		
			>250 MBTU/hr.		
	Class II Counties	Oil	Existing		6-5-75
			<10 MBTU/hr.	3.70 (2)	
			100 MBTU/hr.	1.67 (2)	
			>250 MBTU/hr.	1.11 (2)	
		Coal	Existing		6-5-75
			<10 MBTU/hr.	3.60 (3)	
			100 MBTU/hr.	1.56 (3)	
			>250 MBTU/hr.	1.08 (3)	
	Class III Counties	Oil	Existing		6-5-75
			<10 MBTU/hr.	4.26 (2)	
			100 MBTU/hr.	2.41 (2)	
			>250 MBTU/hr.	2.04(2)	
		Coal	Existing		6-5-75
			<10 MBTU/hr.	4.20 (3)	
			100 MBTU/hr.	2.40 (3)	
			>250 MBTU/hr.	1.92 (3)	
	Class IV Counties	Oil	Existing		6-5-75
			<10 MBTU/hr.	5.00 (2)	
			100 MBTU/hr.	3.70 (2)	
			>250 MBTU/hr.	3.24 (2)	
		Coal	Existing		6-5-75
			<10 MBTU/hr.	4.80 (3)	
			100 MBTU/hr.	3.54 (3)	
			>250 MBTU/hr.	3.12 (3)	
	Class V Counties	Oil	Existing		6-5-75
			<10 MBTU/hr.	5.55 (2)	
			100 MBTU/hr.	4.16 (2)	
			>250 MBTU/hr.	3.70 (2)	
		Coal	Existing		6-5-75
			<10 MBTU/hr.	5.40 (3)	
			100 MBTU/hr.	4.02 (3)	
			>250 MBTU/hr.	3.60 (3)	

5

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Louisiana	All	Oil	All	4.00 (4)	2-11-76
		Coal	All	3.40 (5)	2-11-76
Maine	Portland Peninsular AQCR	All	All	1.50	7-76
		All	All	1.00	11-1-85**
	Rest of State	All	All	2.50*	7-76

*Limit does not apply to any emission source which through use of SO_2 collecting devices or other equipment reduces the emission of SO_2 to the equivalent of burning such fuel with a sulfur content of 1.50%.

**Effective date

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Maryland	Areas I, II, V, and VI	Residual*	All	2.00	6-28-77
		Distillate	All	.30	6-28-77
		Coal	All	2.10 (3)	6-28-77
	Areas III and IV (Baltimore and Washington metropolitan areas)	Residual	All	1.00	6-28-77
		Residual	All	.50	7-1-80*
		Distillate	All	.30	6-28-77
		Coal		1.00	6-28-77

*Effective date.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Massachusetts	All (except metropolitan Boston)	Residual	All*	1.02 (2)	6-17-77
		Distillate	All	.33 (1)	
		Coal	All	.66 (3)	
	Metropolitan Boston	Residual	All*	.52 (2)	6-17-77
		Distillate	All	.33 (1)	
		Coal	All	.34 (3)	
	Central Mass. AQCR (from 7-1-76 to 11-1-77, and from 4-1-78 to 7-1-78)	All	>100 M̄BTU/hr.	2.34 (1) 2.24 (2) 1.45 (3)	7-1-76
	Merrimack Valley AQCR (from 5-1-76 to 5-1-78)	All	>100 M̄BTU/hr.	2.34 (1) 2.24 (2) 1.45 (3)	5-1-76
	Pioneer Valley AQCR (from 6-1-76 to 6-1-78)	All	>100 M̄BTU/hr.	2.34 (1) 2.24 (2) 1.45 (3)	6-1-76
	Southeastern Mass. AQCR (from 5-1-76 to 5-1-78)	All	>100 M̄BTU/hr.	2.34 (1) 2.24 (2) 1.45 (3)	5-1-76
	Berkshire County AQCR (from April 1 to Sept. 30 each year)	Residual	All	2.00	6-17-77

*No residual to be used in units less than 3 M̄BTU/hr. heat imput.

6

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Michigan	Wayne (Detroit area)	Distillate	All	.30	6-16-77
		Residual	All	1.00	6-16-77
				.70	7-31-78*
		Coal, pulverized	All	1.50	6-16-77
				1.00	7-31-78*
		Coal, other	All	.75	6-16-77
	All	All	<500 M lbs. steam/hr.	2.00	1-12-76
				1.50	7-1-78*
			> 500 M lbs. steam/hr.	1.50	1-12-76
				1.00	7-1-78*

*Effective date.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Minnesota	Minneapolis-St. Paul AQCR	Oil	Existing >250 M̄BTU/hr.	1.56 (1) 1.48 (2)	11-24-76
			<250 M̄BTU/hr.	1.95 (1) 1.86 (2)	
		Coal	>250 M̄BTU/hr.	1.80 (3)	11-24-76
			<250 MBTU/hr.	2.40 (3)	
	Rest of state	Oil	>250 M̄BTU/hr.	1.95 (1) 1.85 (2)	11-24-76
		Coal	All	2.40 (3)	11-24-76
	All		New		11-24-76
		Oil	>250 M̄BTU/hr.	.78 (1) .74 (2)	11-24-76
		Coal	>250 M̄BTU/hr.	.72 (3)	11-24-76
Mississippi	All	Oil	>250 M̄BTU/hr.	4.68 (1) 4.44 (2)	5-27-75
		Oil	<250 M̄BTU/hr.	2.34 (1) 2.22 (2)	5-27-75
		Coal	>250 M̄BTU/hr.	2.88 (3)	5-27-75
			<250 M̄BTU/hr.	1.44 (3)	
Missouri	All except cities of St. Louis and St. Charles, and St. Louis, Jefferson, Franklin, Clay, Cass, Buchanan, Ray, Jackson, Platte and Green Counties	Oil	Existing	4.00 (4)	2-9-72
		Coal	Existing	3.40 (5)	2-9-72
		Oil	New	1.00 (4)	2-9-72
		Coal	New	0.85 (5)	2-9-72
	St. Louis AQCR	All	<2000 M̄BTU/hr.	2.0	12-19-75
		Oil	>2000 M̄BTU/hr.	2.13 (2)	12-19-75
		Coal	>2000 M̄BTU/hr.	1.38 (3)	12-19-75

Notes: (1) The sulfur limits for facilities <2,000 M̄BTU/hr. are effective only for the period October through April.

(2) Missouri is currently developing regulations limiting sulfur content of fuels for the entire state.

7

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Montana	All	Oil	All	1.00	9-5-72
		Coal	All	1.00	9-5-72
Nebraska	All	Oil	All	2.4 (1)	9-22-76
				2.3 (2)	
		Coal	All	1.5 (3)	9-22-76
Nevada	Las Vegas	All	All	1.0	7-28-77
	Washoe County: Cities of Reno and Sparks.	All	<250 MBTU/hr.	1.0	8-19-75
		All	>250 MBTU/hr.	*	

*Allowable emissions calculated by use of the Formula, y = 0.105x, where x = minimum heat input, number of millions of BTUs per hour, and y = allowable rate of sulfur dioxide emission in pounds per hour.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
Nevada	Rest of State	All	All		7-28-77

*Maximum allowable rate of SO_2 calculated by use of the formula Z = 0.15x, where Z = allowable rate of SO_2 emission in pounds per hour and X = maximum heat input in MBTU/hr.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
New Hampshire	All	No. 2	All	0.40	2-20-75
		No. 4	All	1.00	2-20-75
		No. 5 & 6*	All	2.00	2-20-75
		Coal	Existing	1.68 (3)	2-20-75
			New	0.90 (3)	2-20-75

*New Hampshire portion of the Androscoggin Valley AQCR is permitted to use No. 5 & 6 oil with a 2.20 wt% sulfur.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
New Jersey	Atlantic, Cape May, Cumberland,	Oil	All	1.00	10-1-71
	Hunterdon, Ocean, Sussex, and Warren Counties	Coal	All	1.00	10-1-71
	Rest of state	No. 2	All	0.2	10-1-71
		Residual	All	0.3	10-1-71
		Coal	All	0.2	10-1-71

8

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
New Mexico	All	Oil	>1,000,000 MBTU/hr.	0.31 (2)	12-31-74
		Coal	>250 MBTU/hr.		12-31-74
			New	0.20 (3)	12-31-74
			Existing	*	12-31-74
		Coal	>3000 MBTU/hr.		
			Existing	0.60 (3)	12-31-74

*SO_2 emissions to the atmosphere may not be in excess of 35% by weight of the SO_2 which would be produced upon combustion of the coal prior to any pretreatment.

Note: Changes in SO_2 emissions limits for coal-fired operations are expected in 1978.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt. %)	Most Recent Amendment Date
New York	New York City	Distillate	All	0.20	8-31-76
		Residual	All	0.30	8-31-76
		Coal	All	0.20	8-31-76
	Nassau, Rockland	Oil	All	0.37	8-31-76
	and Westchester Counties	Coal	All	0.20	8-31-76
	Suffolk County—	Oil	All	1.0	8-31-76
	towns of Babylon, Brookhaven, Huntington, Islip & Smithtown	Coal	All	0.6	8-31-76
	Erie & Niagara	Oil	All	1.1	8-31-76
	Counties	Coal	All	1.7	8-31-76
	Rest of State	Oil	All	2.0	8-31-76
		Coal	All	2.5	8-31-76
	All except New York		>250 MBTU/hr.		
	City, Nassau,	Oil	New	0.75	8-31-76
	Rockland and Westchester Counties)	Coal	New	0.72 (3)	8-31-76
North Carolina	All	Oil	New	.78 (1)	6-18-76
				.74 (2)	6-18-76
		Coal		.72 (3)	6-18-76
	All	Oil	Existing	2.24 (1)	4-1-77
				2.13 (2)	
		Coal		1.38 (3)	4-1-77
North Dakota	All	Oil	Existing	2.90 (1)	2-9-76
			Existing	2.78 (2)	
		Coal	Existing	1.80 (3)	
	All		>250 MBTU/hr.		2-9-76
		Oil	New	.78 (1)	
				.74 (2)	
		Coal	New	.72 (3)	

9

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Ohio	Note: Ohio state regulations for control of sulfur dioxide were found inadequate by the federal EPA and are not presently being enforced. The federal SO_2 emission limits for Ohio (41 FR 36323, Aug. 27, 1976) vary from county to county depending on the air pollution problem, the existing emission rate of contributing sources, and the overall reduction needed. Listed below are the ranges for sulfur content of fuels allowable in the various air quality control regions corresponding to the SO_2 emissions limitations.				
	Metropolitan Cincinnati	Oil	All	1.23 - 1.85	8-27-76
		Coal		.90 - 1.10	
	Huntington-Ashton-Portsmouth-Ironton	Oil	All	.74 - 8.79	8-27-76
		Coal		.61 - 4.86	
	Metropolitan Toledo	Oil	All	.44 - 1.00	8-27-76
		Coal		.68 - 1.71	
	Dayton	Oil	All	.56 - 4.27	8-27-76
		Coal		.69 - 2.72	
	Greater Metropolitan Cleveland	Oil	All	.74 - 4.81	8-27-76
		Coal		.67 - 3.33	
	Mansfield-Marion	Oil	All	.70 - 7.94	8-27-76
		Coal		.16 - 5.53	
	Metropolitan Columbus	Oil	All	1.32 - 5.59	8-27-76
		Coal		.66 - 3.32	
	Youngstown-Northwest Pa.	Oil	All	2.28 - 8.53	8-27-76
		Coal		1.30 - 4.95	
	Marietta-Parkersburg	Oil	All	.74 - 5.99	8-27-76
		Coal		.64 - 3.32	
	Sandusky	Oil	All	7.00	8-27-76
		Coal		4.63	
	Steubenville-Weirton-Wheeling	Oil	All	7.49	8-27-76
		Coal		.66 - 4.34	
	Zanesville-Cambridge	Oil	All	.74 - 5.24	8-27-76
		Coal		.58 - 2.92	
Oklahoma	All	Oil	New	0.74 (2)	2-8-74
		Coal	New	0.72 (3)*	2-8-74
Oregon	All	No. 1	All	0.3	7-29-77
		No. 2	All	0.5	
		Residual	All	1.75	
		Coal	All	1.0	7-29-77
			>150 >250 MBTU/hr.		
		Oil	New	1.37 (1)	7-29-77
				1.30 (2)	
		Coal	New	.96 (3)	
			>250 MBTU		
		Oil	New	.78 (1)	7-29-77
				.74 (2)	
		Coal	New	.72 (3)	7-29-77

*The regulation prohibits any emission of SO_2 from existing equipment which results in an ambient air concentration of SO_2 at any given point in excess of 0.52 ppm in a five minute period of any hour . . .

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Pennsylvania	Pittsburgh area (Allegheny County, Beaver Valley, & Monongahela Valley Air Basins) and Southeast Pennsylvania Air Basin (Bucks, Chester, Delaware, Montgomery, & Philadelphia Counties)	Oil & Coal	<2.5 MBTU/hr.	3.70 (2)	7-15-76
				2.40 (3)	
			2.5-50 MBTU/hr.	0.92 (2)	
				0.60 (3)	
			50-2,000 MBTU/hr.	Use Formula:	
			$A=1.7E^{-0.14}$ where A = allowable emission in pounds SO_2 per million BTU heat input. E = heat input in MBTU's per hour.		
			>2,000 MBTU/hr.	0.55 (2)	
				0.36 (3)	
	All other	Oil & Coal	<2.5 MBTU/hr.	3.70 (2)	7-15-76
				2.40 (3)	
			2.5-50 MBTU/hr.	2.78 (2)	
				1.80 (3)	
			50-2,000 MBTU/hr.	Use formula:	
			$A=5.1E^{-0.14}$ where A = allowable emission in pounds SO_2 per million BTU heat input. E = heat input in MBTU's per hour.		
			>2,000 MBTU/hr.	1.67 (2)	
				1.08 (3)	
	Philadelphia	No. 1&2	All	0.2	10-1-77
		No. 4	All	0.3	10-1-77
		No. 5&6	All	0.3	10-1-77
		Coal	All	0.3	7-15-76
Puerto Rico	All	All	<8 MBTU/hr.	2.5	1-1-75
			≥8 MBTU/hr.	*	1-1-75
Rhode Island	All	Distillate	All	1.07 (1)	2-22-77
		Residual	All	1.02 (2)	2-22-77
		Coal	All	.66 (3)	2-22-77

*Actual percentage value, not to exceed 3.1% is assigned through the permit system.

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
South Carolina	Class I (Charleston County)	Oil	<10 MMBTU/hr.	3.41 (1)	2-14-76
				3.24 (2)	
		Coal	<10 MMBTU/hr.	2.10 (3)	2-14-76
		Oil	>10 MMBTU/hr.	2.24 (1)	2-14-76
				2.13 (2)	
		Coal	>10 MMBTU/hr.	1.38 (3)	2-14-76
	Class II (Aiken and Anderson Counties)	Oil	<1000 MMBTU/hr.	3.41 (1)	2-14-76
				3.24 (2)	
		Coal	<1000 MMBTU/hr.	2.10 (3)	2-14-76
		Oil	>1000 MMBTU/hr.	2.24 (1)	2-14-76
				2.13 (2)	
		Coal	>1000 MMBTU/hr.	1.38 (3)	2-14-76
	Class III (All remaining Counties)	Oil	All	3.41 (1)	2-14-76
				3.24 (2)	
		Coal	All	2.10 (3)	2-14-76

Note: Variances granted on a case by case basis.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
South Dakota	All	Oil	Existing	2.90 (1)	11-6-75
			Existing	2.78 (2)	
		Coal	Existing	1.80 (3)	11-6-75
	All		>250 MMBTU/hr.		11-6-75
		Oil	New	.78 (1)	
			New	.74 (2)	
		Coal	New	.72 (3)	11-6-75
Tennessee	Class I (Polk County)	Distillate	>1,000 MMBTU/hr.	1.17 (1)	3-20-76
			<1,000 MMBTU/hr.	1.56 (1)	
		Residual	>1,000 MMBTU/hr.	1.11 (2)	
			<1,000 MMBTU/hr.	1.48 (2)	
		Coal	>1,000 MMBTU/hr.	.72 (3)	3-20-76
			<1,000 MMBTU/hr.	.96 (3)	
	Class II (Humphreys, Maury, Roane Counties)	Distillate	>1,000 MMBTU/hr.	1.17 (1)	3-20-76
			<1,000 MMBTU/hr.	4.88 (1)	
		Residual	>1,000 MMBTU/hr.	1.11 (2)	
			<1,000 MMBTU/hr.	4.63 (2)	
		Coal	>1,000 MMBTU/hr.	.72 (3)	3-20-76
			<1,000 MMBTU/hr.	3.00 (3)	
	Class III (Sullivan County)	Distillate	All	2.34 (1)	3-20 76
		Residual	All	2.22 (2)	
		Coal	All	1.44 (3)	3-20-76
	Class IV (Shelby County)	Distillate	All	.49 (1)	3-20-76
		Residual	All	2.50 (2)	
		Coal	All	2.40 (3)	3-20-76
	Class V (Anderson Davidson, Hamilton, Hawkins, Knox, Rhea)	Distillate	All	3.90 (1)	3-20-76
		Residual	All	3.70 (2)	
		Coal	All	2.40 (3)	8-20-76

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
	Class VI (All other Counties)	Distillate	All	4.88 (1)	3-20-76
		Residual	All	4.63 (2)	
		Coal	All	3.00 (3)	3-20-76
	Class IV (Shelby County)		New		
		Distillate	<250 MMBTU/hr.	3.90 (1)	3-20-76
		Residual	<250 MMBTU/hr.	3.70 (2)	
		Coal	<250 MMBTU/hr.	2.40 (3)	3-20-76
	All		New		
		Distillate	>250 MMBTU/hr.	.78 (1)	3-20-76
		Residual	>250 MMBTU/hr.	.74 (2)	
		Coal	>250 MMBTU/hr.	.72 (3)	3-20-76
Texas	All	Oil	Existing	.88 (4)	3-5-75
		Coal	Existing	1.80 (3)	
	All		>250 MMBTU/hr.		
		Oil	New	.78 (1)	3-5-75
			New	.74 (2)	
		Coal	New	.72 (3)	3-5-75
Utah	All	Oil	All	1.50	5-22-77
		Coal	All	1.00	5-22-77
Vermont	All	All	All	2.00	7-7-76
	All		>250 MMBTU/hr.		
		Oil	New	.78 (1)	7-7-76
			New	.74 (2)	
		Coal	New	.72 (3)	7-7-76
Virginia	AQCR 7	Oil	All	1.03 (1)	4-8-77
				0.98 (2)	
		Coal	All	0.63 (3)	4-8-77
	Rest of State	Oil	All	2.57 (1)	4-8-77
				2.44 (2)	
		Coal	All	1.58 (3)	4-8-77

TABLE F-1

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Washington	Puget Sound Area:	No. 1	All	0.30	11-18-76
	King, Kitsap,	No. 2	All	0.50	11-18-76
	Pierce & Snohomish	Oil-Other	All	2.00 (4)	11-18-76
	Counties	Coal	All	1.00	11-18-76
	Rest of State	Oil	New	2.00 (4)	12-21-76
			Existing	2.00 (4)	12-21-76
		Coal	All	1.70 (5)	12-21-76
West Virginia	All		>250 MBTU/hr.		
		Oil	New	.78 (1)	12-10-76
			New	.74 (2)	
		Coal	New	.72 (3)	12-10-76

West Virginia's regulations set SO_2 weight emission standards for existing fuel burning units by priority regions. In addition, the state Air Pollution Control Commission "strongly recommends that the following fuel sulfur contents be met by fuel suppliers:

All	Oil	All	1.50	12-10-76
		All	.50	6-30-78*
	Coal	All	2.00	12-10-76
		All	1.00	6-30-78*

*Effective date.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Wisconsin	Southeast Wisconsin Intrastate AQCR	Standby Fuel:*			
		Distillate	All	0.70	11-1-76
		Residual	All	1.00	11-1-76
		Coal	All	1.50	11-1-76
	Racine County	Oil	Existing	2.31 (2)	11-1-76
		Coal	Existing	1.50 (3)	11-1-76
	All	New or modified Facilities:			
		Distillate	>250 MBTU/hr.	0.78 (1)	11-1-76
		Residual	>250 MBTU/hr.	0.74 (2)	11-1-76
		Coal	>250 MBTU/hr.	0.72 (3)	11-1-76

*Standby fuel is defined as a fuel normally used less than 15 days per year.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Most Recent Amendment Date
Wyoming	All		>250 MBTU/hr.		
		Oil	New	.78 (1)	11-6-76
			New	.74 (2)	
		Coal	New	.72 (3)	11-6-76

NOTES

(1) No. 1 & 2 Oil — Regulation expressed as lbs. S or SO_2/M BTU. Equivalent weight percent sulfur calculated using 19,500 BTU/lb.

(2) No. 4, 5, & 6 Oil — Regulation expressed as lbs. S or SO_2/M BTU. Equivalent weight percent sulfur calculated using 18,500 BTU/lb.

(3) Coal — Regulation expressed as lbs. S or SO_2/M BTU. Equivalent weight percent sulfur calculated using 12,000 BTU/lb.

(4) Oil — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 25% excess air.

(5) Coal — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 25% excess air.

(6) Oil — Regulation expressed in parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 10% excess air.

(7) Coal — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 10% excess air.

1/ Fuel Sulfur Regulations, Federal, State, and Local, September 1977, Department of Environmental Affairs, American Petroleum Institute.

TABLE F-2

RESIDUAL FUEL OIL PRODUCED DOMESTICALLY AND IMPORTED - BY SULFUR LEVEL
Millions of Barrels

	Percent Sulfur 0 - 0.5	0.51 - 1.00	1.01 - 2.00	Over 2.00	Total
1971					
Produced	50	58	98	69	257
Imported	109	167	77	183	536
Total	159	225	175	252	810
1972					
Produced	65	71	93	64	293
Imported	203	164	79	145	592
Total	268	235	172	210	884
1973					
Produced	97	83	103	73	355
Imported	246	138	79	164	626
Total	342	220	182	237	981
1974					
Produced	98	103	105	84	390
Imported	196	107	76	156	535
Total	294	210	181	240	925
1975					
Produced	109	112	123	107	451
Imported	170	66	67	112	414
Total	278	177	190	219	865
1976					
Produced	128	119	128	129	504
Imported	173	107	70	146	496
Total	301	226	198	275	1,000
1977 1/					
Produced	56	53	50	58	217
Imported	64	39	25	53	180
Total	120	92	75	111	397

1/ 4 months only

Source: U.S. Bureau of Mines, Mineral Industry Surveys, "Availability of Heavy Fuel Oil by Sulfur Levels."

Totals may not check due to rounding.

Figure F-1

U.S. Residual Fuel Oil Consumption by Sulfur Content

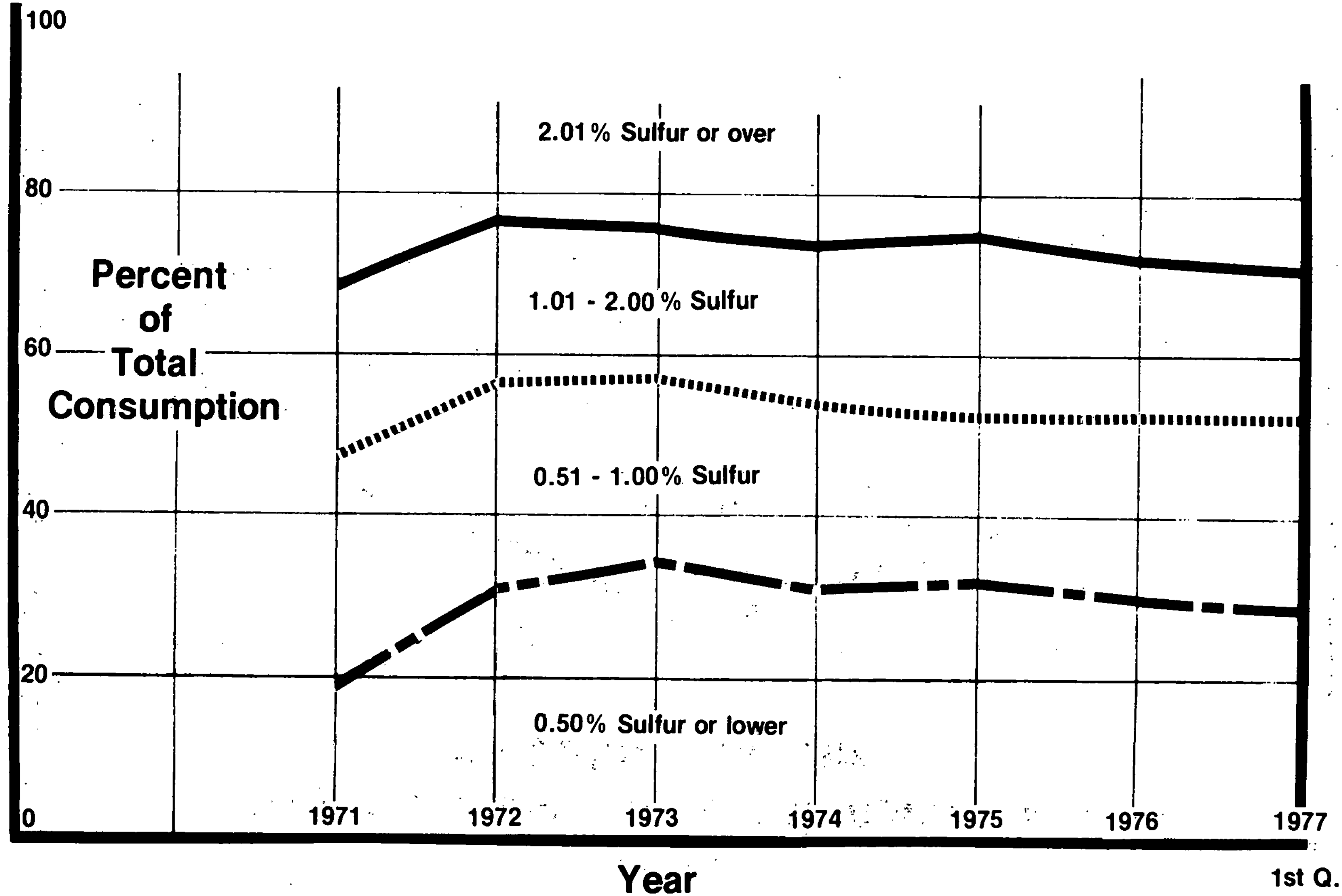


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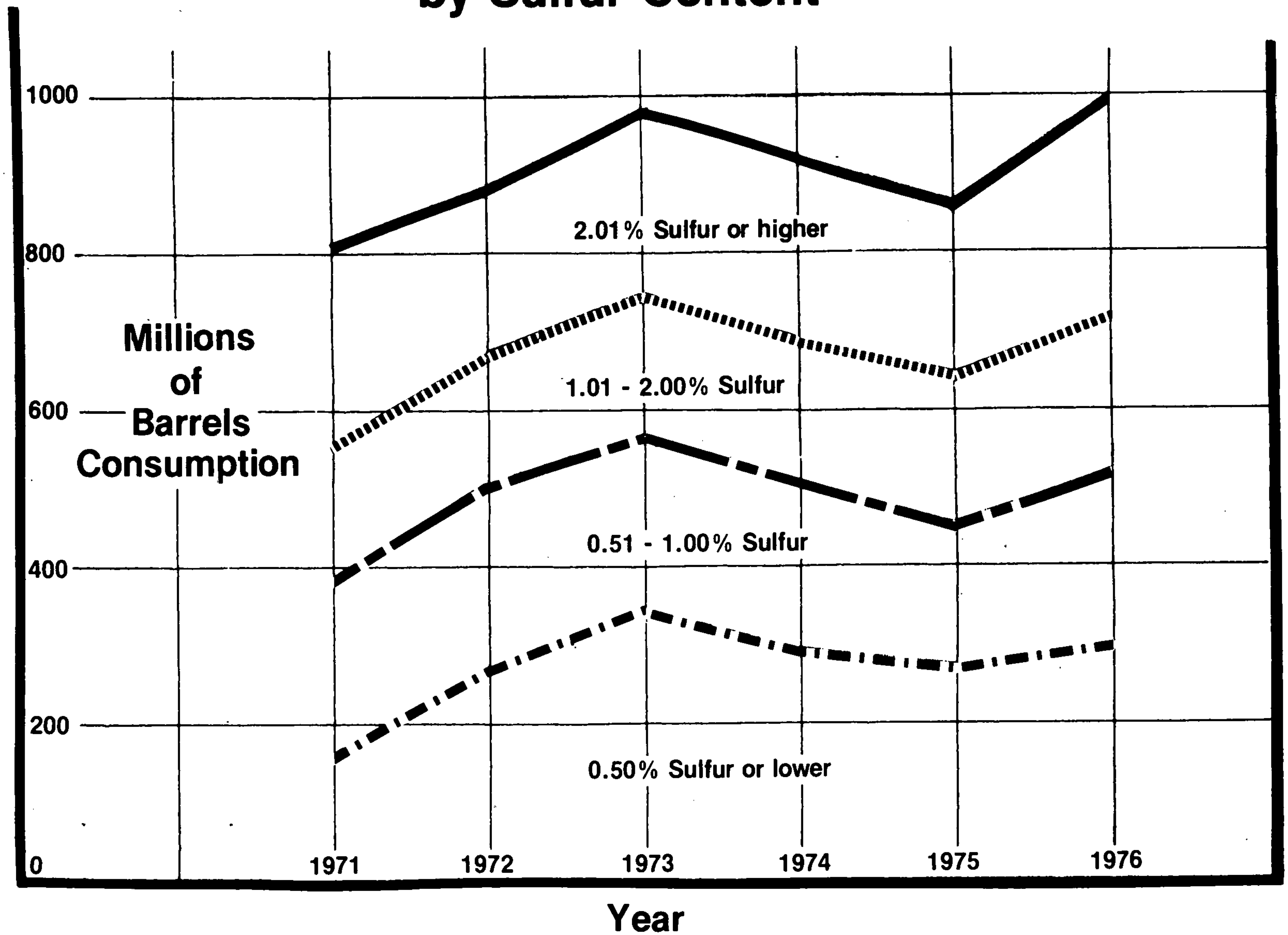
Figure F-2

U.S. Residual Fuel Oil Consumption by Sulfur Content



G. Prices of Residual Fuel Oils

Low-sulfur residual fuel oils command a higher price than high-sulfur residual fuel oils. For any single grade of fuel oil, the price relationship can be described as inversely proportional to the sulfur content with 0.3 percent sulfur (max.) being the highest priced and high sulfur (2.2 percent or 2.8 percent) being the lowest priced. See Figure G-1.

For any given grade of fuel oil, the prices will differ depending on whether it is high pour or low pour, all other factors being equal. Low pour residual fuel oil will be priced higher than high pour residual. For the purposes of this report, any prices discussed relate to low pour residual fuel oil only.

The selling price for low sulfur fuel oil is higher because the low-sulfur crude it came from is more expensive than high sulfur crude, or it is higher because more effort is required to convert high sulfur (lower cost) crude into low sulfur fuel oil.

Table G-1 reflects New York Harbor cargo lot prices. Both contract and spot price histories are given. However, the spot prices represent only a small percentage of the total sales and are more subject to fluctuations. For this reason, the contract prices are more indicative of the true market value of the residuals. In recent months, 0.3 percent sulfur content No. 6 Fuel Oil has been averaging a premium of slightly over $1 per barrel over 1.0 percent sulfur content fuel oil. The 1.0 percent sulfur fuel oil, in turn, has a $1.85 per barrel premium over high sulfur residual fuel oil.

Table G-2 presents the history of New York Harbor cargo prices for No. 4 fuel oil. Due to the lightness of No. 4 fuel oil relative to No. 6 fuel oil, attainment of a low-sulfur level is easier and less costly. This is reflected in the lower premium for 0.3 percent sulfur No. 4 fuel oil over the 1.0 percent sulfur grade.

Table G-1

NEW YORK HARBOR CARGO PRICES NO. 6 LOW-POUR FUEL OIL

First 7 Months Average Prices - 1977 - Contract

Maximum % S Content	Price - $/B	Differential Over High S - $/B
0.3	15.66	2.86
0.5	15.22	2.42
1.0	14.65	1.85
2.8	12.80	--

Annual Averages - $/B - Contract

Year	0.3% Max.	1.0% Max.	Differential 0.3 Over 1.0
1972	4.3556	3.7053	0.61
1973	5.7065	4.8548	0.85
1974	13.1067	12.0079	1.10
1975	13.1608	12.2626	0.90
1976	13.2615	12.0150	1.25
1977 (7 Mos.)	15.66	14.65	1.01

Annual Averages - $/B - Spot

Year	0.3% Max.	1.0% Max.	Differential 0.3 Over 1.0
1972	3.8497	3.3220	0.53
1973	6.8228	5.9989	0.82
1974	14.6922	12.0155	2.67
1975	12.2474	11.2317	1.02
1976	12.6393	11.5640	1.08

Sources: Oilgram Price Service
Platt's Oil Price Handbook

Table G-2

NEW YORK HARBOR CARGO PRICES NO. 4 FUEL OIL

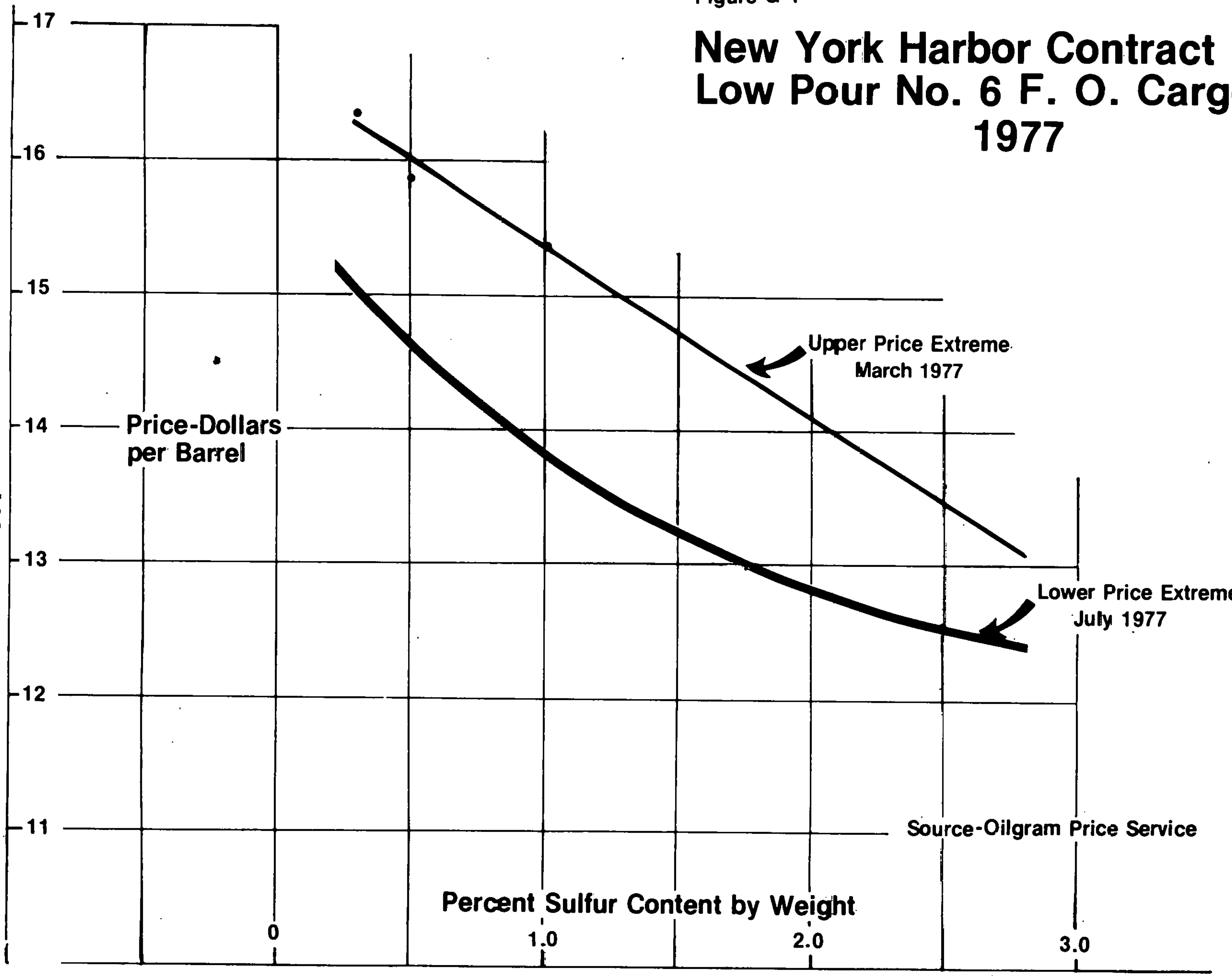
Annual Averages - $/B - Contract

Year	0.3% Max.	1.0% Max.	Differential 0.3 Over 1.0
1971	4.7050	4.3263	0.38
1972	4.4535	4.0282	0.43
1973	5.9341	5.1209	0.81
1974	13.3862	12.3167	1.07
1975	13.4608	12.7752	0.69
1976	13.5650	12.7686	0.80
1977 (7 Mos.)	16.00	15.43	0.57

Sources: Oilgram Price Service
Platt's Oil Price Handbook

Figure G-1

New York Harbor Contract Prices Low Pour No. 6 F. O. Cargoes 1977



H. Production and Disposal of Sulfur in the U.S. Refining Industry

Between 80 and 90 percent of all sulfur consumed in the United States is used for the manufacture of sulfuric acid. The second largest use is in pulp and paper manufacture. Because sulfuric acid is used in a number of established industries, its consumption is reasonably stable and demand has grown steadily over the years. However, the supply of sulfur has not been as steady, and as a result, the price of sulfur has gone through some wide fluctuations. Imports from Canada and Mexico have been instrumental in provoking price fluctuations.

The sources of produced sulfur in the United States, over a period of years, are listed in Table H-1. The greatest source of sulfur is from mining by the Frasch process. The sulfur is recovered in elemental form and one of the great producing areas is in the Gulf of Mexico. The second largest source of sulfur is through recovery from sour gas and refinery processes for desulfurization of petroleum. Table H-1 shows how rapidly this source is growing in recent years, largely due to the great emphasis on meeting environmental standards and the need to rely on increasing amounts of sour crudes.

Price data in terms of dollars per long ton are presented in Table H-2. Extreme fluctuations may be noted with especially depressed periods in 1963 and in 1971 to 1973.

Anti-dumping actions have been taken against certain sulfur imports in the past. Sulfur produced in refineries from desulfurization processes is a by-product and refiners will make sure it moves in the marketplace even if there are wide fluctuations in price. Between the impact of low-priced imports and recovered sulfurs, the Frasch mining process has absorbed the fluctuations. Since 1966, it has not demonstrated any meaningful trend and has remained in the range of 7,000 to 7,900 thousands of long tons per day.

1. Recovery of Sulfur from Desulfurizing Operations

In the desulfurization process, sulfur is primarily converted into H_2S which is separated from the desulfurized oil. The H_2S is then usually absorbed from the gas stream in diethanolamine from which it is then stripped and converted to elemental sulfur by the widely used Claus process. In the first step, one-third of the H_2S is oxidized to SO_2 followed by catalytic reaction of the product with the remaining H_2S to form sulfur and water.

$$2H_2S + 3O_2 \rightleftharpoons 2SO_2 + 2H_2O$$
$$4H_2S + 2SO_2 \rightleftharpoons 6S + 4H_2O$$
$$\overline{H_2S + 1/2O_2 \rightleftharpoons S + H_2O}$$

Recovery is very high, but never 100 percent because of the equilibrium between reactants and products. A typical flow diagram is presented in Figure H-1. The feed gas is burned with air in a steam boiler. The sulfur dioxide formed is mixed with two parts of H_2S and passed through a converter that contains an activated bauxite catalyst. Gases enter the first converter at 600° F. The outlet temperature is 750° F. Through heat exchange, the effluent is cooled to 500° F before introduction into the sulfur condenser. Liquid sulfur leaves the condenser at 300° F and is pumped to a vat for further cooling.

Because of the steam generated in the process, it is possible, in the case of a large plant, to obtain a negative net operating cost. This is illustrated in Table H-3.

The cost data presented in Table H-3 were obtained by applying appropriate operating expense indicies to 1973 operating costs. The costs are those for a single reactor plant and do not include offsites. In the past 3 or 4 years, increasingly severe environmental restrictions have been placed on sulfur recovery plants in terms of emissions control. Decreased emissions are obtained by adding more reactors and special tail gas treating facilities. Changes such as these could double capital investment and investment-related operating costs. 16/

16/ Tougher Air Quality Standards Face Sulfur Recovery Plants, Oil and Gas Journal, May 9, 1977, page 53.

Table H-1

PRODUCTION OF SULFUR IN THE UNITED STATES IN THOUSANDS OF LONG TONS 1/

Year	Recovered	Frasch	Pyrites	Other	Total
1960	767	4,943	416	644	6,770
1961	858	5,385	399	647	7,239
1962	900	4,985	379	616	6,880
1963	947	4,882	344	604	6,777
1964	1,021	5,228	354	623	7,226
1965	1,215	6,116	354	678	8,363
1966	1,240	7,002	356	729	9,327
1967	1,268	7,014	355	499	9,136
1968	1,359	7,460	362	554	9,735
1969	1,422	7,146	334	643	9,545
1970	1,457	7,082	339	679	9,577
1971	1,595	7,025	316	644	9,580
1972	1,950	7,290	283	605	10,218
1973	2,416	7,605	212	688	10,921
1974	2,632	7,901	162	724	11,419
1975p	2,890	7,280	235	815	11,220

p = preliminary

1/ Source: "Chemical Economics Handbook," SRI International, Menlo Park, California

Table H-2

U.S. PRICE HISTORY OF SULFUR, FOB MINE OR PLANT
DOLLARS PER LONG TON 1/

Year	Frasch	Recovered	Total	Imports	Exports
1960	$23.10	$23.40	$23.14	---	---
1961	23.20	22.70	23.13	---	---
1962	21.80	21.60	21.77	---	---
1963	19.80	20.85	19.97	---	---
1964	20.00	21.30	20.18	---	---
1965	22.70	21.00	22.46	$18.25	$24.50
1966	26.05	23.95	25.75	22.14	33.86
1967	32.75	31.90	32.63	32.30	39.89
1968	40.35	38.89	40.12	39.82	42.38
1969	26.60	29.15	27.05	34.16	37.09
1970	23.65	20.89	23.14	22.22	23.16
1971	17.50	17.37	17.47	19.57	18.17
1972	17.39	15.60	17.03	14.31	17.55
1973	18.63	15.45	17.84	12.06	19.38
1974	30.52	23.79	28.88	23.78	37.02
1975	49.64	39.72	46.50	37.16	54.18

1/ Source: "Chemical Economics Handbook,"
SRI International, Menlo Park, California.

Table H-3

APPROXIMATE 1977 OPERATING COSTS FOR SULFUR RECOVERY PLANTS - $/Long Ton

			Dollars/Long Ton	
Cost Element	Unit	1977 Unit Cost	100 Tons/Day Plant (1)	1,000 Tons/Day Plant (1)
Labor, Super & Lab	1.1 - 1.9 men/shift	$9.00 - $13.80/hr.	2.93	0.49
Maintenance	3.8 percent invest./yr.		1.04	0.54
Boiler Feed Water	650 gals./ton	80¢/1,000 gal.	0.53	0.53
Cooling Water	5,000 gals./ ton	3.2¢/1,000 gal.	0.16	0.16
Power	20 KW/ton	2.5¢/KWH	0.51	0.51
Supplies (est.)			0.16	0.16
Direct Operating Cost			$ 5.33	$ 2.39
Interest, taxes, Ins., etc.	16.5% invest./yr.		5.03	2.57
Operating Cost Total			$10.36	$ 4.96
Steam Credit	5,400 lb/ton		7.74	7.74
Net Operating Cost			$ 2.62	$(2.78)

(1) Investments: $1,114,000 for 100 ton plant; $5,640,000 for 1,000 ton plant, derived by updating "Sulfur Recovery Provides Steam," by W. L. Nelson, <u>Guide to Refining Operating Costs</u>, pg. 141.

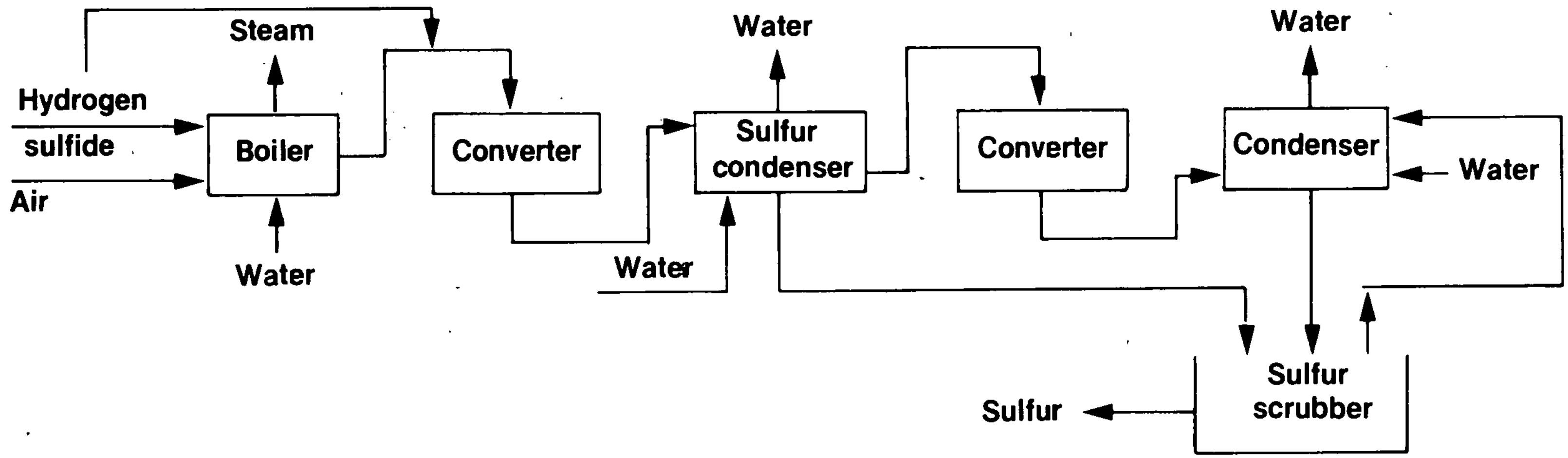


Figure H-1
Claus Process for Sulfur Recovery Flow Diagram

I. Crude Availability in Relation to Sulfur Content and Other Properties

Table I-1 details information on OPEC crude oil in terms of production and reserves by country, as well as by sweet and sour classifications. Other properties are listed where available. These include gravity, metals content and pour point. For the purposes of this table, sweet crudes are assumed to contain 0.5 percent sulfur by weight or less.

It is significant to note that sour crude reserves were 5.5 times greater than sweet crude reserves in 1975. In addition, the reserves to production ratio of sour crudes is 49 versus 33 for sweet crudes, indicating that the current tendency is to pull down sweet crude reserves relatively more rapidly than sour crude reserves. This trend has accelerated significantly in 1976 and especially in recent months. For example, in a recent 3-month period, OPEC production of sweet crudes averaged 25 percent above the 1975 levels of production. In the same 3-month period, OPEC source crude production rose only 14 percent over 1975 production levels.

Changes that have occurred in the United States are more dramatic than those in the OPEC countries. In 1969, the Bureau of Mines analyzed the sulfur content of U.S. crude oil reserves and production. This revealed that 64 percent of all U.S. crude oil reserves were in the sweet crude category (0.5 percent sulfur or less). The same survey indicated that 66 percent of that year's production was sweet crude.

The discovery of the Prudhoe Bay field has resulted in only 42 percent of 1975 crude oil reserves being in the sweet crude category. In 1975, 68 percent of the crude oil production in the United States was sweet. However, Alaskan north slope crude oil had not yet begun production. By 1978, the sweet/ sour split in U.S. production will change significantly toward an increased percentage of sour crude. Another factor giving impetus to this shift will be such projects as enhanced recovery which in California is reflected in more production of heavy, high sulfur crude. The method of arriving at the 1975 U.S. crude oil split in reserves is detailed in Table I-2 where the reserves are split State-by-State in accordance with latest available Bureau of Mines data on sulfur content of specific crude fields.

In Table I-3, OPEC reserves and production are combined with those of the United States. As such, the total represents about 79 percent of the free world reserves and 78 percent of the total free world production. The combined figures illustrate more dramatically the lower reserves and lower reserve/production ratio for sweet crudes.

Barring any unforeseen large discoveries, the world's refiners will be forced to rely on sour crude supplies increasingly throughout the future.

Despite the disproportionately greater reserves and production of sour crudes, the United States continues to rely very heavily on sweet crude imports. Figure I-1 illustrates this growing dependence. In the period from 1969 to the present, the percentage of crude oil imports that are sweet has ranged from a high of 66.9 percent (1972) to a low of 54.7 percent (1977).

The rapidly growing sweet crude imports are originating more and more from OPEC sources. In 1969, the United States imported only 5 percent of OPEC's sweet crude production. In 1976, the United States imported 37.5 percent of OPEC's total sweet crude production. In the first 4 months of 1977, this percentage grew to 42 percent. By contrast, in the same 4-month period, the United States imported only 12.4 percent of OPEC's sour crude production.

GRAVITY - Data on gravity of OPEC countries' reserves and production are presented in Table I-4. An attempt was made to determine over a 6-year period if there was a significant trend in gravity of reserves or production. Unfortunately, firm data existed on only about 70 percent of the reserves for the two periods which were compared (1969 and 1975). In the case of these countries, reserves appear to have become very slightly higher in gravity. A more distinct difference appeared in gravity of production which rose from 31.7 to 33.4.

Firm data exists for additional countries in 1975 only. If these are combined with the other countries, it shows that about 94 percent of the reserves of OPEC countries average 33.9° API and 92 percent of the production averages 34.0° API. It would appear that OPEC crude oil gravity is relatively stable and shows no significant trend.

The data presented do not include the enormous deposits of heavy oil in the Orinoco basin. Should Venezuela be successful in producing a significant amount of this oil, it could impact on the OPEC averages.

A more significant change will be taking place in the United States. When North Slope crude oil reaches full anticipated production, U.S. average crude gravity of production could drop by about 2° API. Projects in California which are producing heavy crudes will further tend to depress the national average.

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
Arab OPEC									
Saudi Arabia	Abqaiq	762	7,252		38.0	1.30	56	-15	
	Abu Hadriyah	49	700		35.0	1.20			
	Abu Sa'fah	60	6,297		30.0	2.70	44		
	Berri	334	5,121		33-38.0	2.40	27	-30	
	Damman	19	4,774		34.0	1.54		-10	
	Fadhili	11	848		40.0	1.30			
	Ghawar	4,205	63,240		35.0	1.80	19	-30	Arabian Light
	Khursaniyah	55	2,029		31.0	2.38	21	+5	Arabian Medium
	Manifah	36	870		28.0	3.00	13		
	Qatif	66	8,585		31.0	2.57		+10	
	Safaniyah	827	11,927		27.0	2.90	62-94	-30	Arabian Heavy
	Zuluf	82	1,000		32.0	2.51		-40	
	Total	6,827	148,600	10,000					
Iran	Agha Jari	800	3,843		33.8	1.36	50	-20	Iranian Light
	Ahwaz-Asmari	967	7,391		31.9	1.66	23		
	Bahregansar	16	194		27.0				
	Bibi Hakimeh	310	6,925		29.7				
	Darius	88	976		34.0	2.45		0	
	Gach Saran	808	7,512		31.1	1.66	118	-5	Iranian Heavy
	Haft Kel	27	944		38.4	1.12	25		
	Karanji	195	744		34.2				
	Marun	1,151	8,084		32.9	1.40	50	-20	Iranian Light
	Masjid-e-Suleimon	11	1,514		40.3				
	Naft Safid	36	734		36.5				
	Nowrouz	27	878		20.9				
	Paris	129	2,377		34.2				
	Pazanan	25	3,367		33.6				
	Rag-e-Safid	241	2,187		28.5				
	Rostam	22	934		33.7	1.55		-8	

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
	Sassan	178	1,093		34.0	1.91	19	-5	
	Binak	47	100		29.7				
	Kharq[2]	41	100		32.4				
	Total	5,350	64,500	6,500					
Kuwait	Ahmadi				31.7	2.21	50		
	Bahrah								
	Burgan				31.0	2.54			
	Magwa								
	Minagish	1,890	54,552		33.2	2.12			
	Raudhatain				32.8	2.13			
	Sabriyah				32.1	1.82			
	Umm Gudair								
	Total	1,807	68,000	3,800					
Iraq	Ain Zalah	5	54		31.0		110		
	Bai Hassan	33	966		35.0		19		
	Kirkuk	959	9,005		36.0	1.97	35-41		
	Naft Kaneh	11	36		42.5				
	Rumaila	800	11,405		35.0	2.10			
	Rumaila N.	151			34.0	1.98		-2	
	Zubair	200	3,566		34.2		17-24		
	Total	2,240	34,300	2,600					
Abu Dhabi (UAE)	Asab	247	500		40.0				
	Bu Hasa	427	1,289		40.0	0.77	2	-15	Murban
	Mulbarras	19	150		37.8	0.62		-30	
	Umm Shaif	162	706		40.0	1.38	1.5-2	+5	
	Zakum	225	1,314		40.0	0.98	1.7	+5	
	Total	1,403	29,500	1,920					

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
Dubai (UAE)	Fateh	148	1,303		31.6				
	Fateh, S.Y.	101	1,000		32.5	1.68	44	-5	
	Total	254	1,350	317					
Sharjah (UAE)	Mubarek	38	250		37.4	0.62		+10	
	Total	38	1,350	45					
Qatar	Bul Hanine	145	352		35.0				
	Dukhan	173	1,269		41.1	1.27	1.1-7		
	Idd El Shargi	16	1,962		35.0	1.99	25		
	Mayden-Mahzan	123	9,797		38.0	1.48	12		
	Total	441	5,850	650					
Libya	Bu Atlifel	82	500		41.0	0.10	Trace	+102	
	Amal	52	3,725		36.0	0.14			
	Bahi	16	154		43.4				
	Dahra	3	344		41.0	0.29	3		
	Defa	115	191		35.6	0.28			
	Gialo	118	2,945		35.7	0.52			
	Intisar A	68	1,107		45.0				
	Intisar D	137	703		39.5				
	Jebel	22	50		37.0				
	Nafoora	49	740		36.0	0.09-0.94			
	Nasser	90	2,445		38.0	0.23			
	Raguba	44	611		43.0	0.18			
	Sarir	175	7,445		37.2	0.15	5	+79	
	Waha	71	365		3610	0.24			
	Samah	36	100		38.4	0.25			
	Total	1,488	26,100	3,000					

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
Neutral Zone	Hout	41	485		34.0	1.40	14.1	0	
	Khafji	274	14,043		28.4	2.84	75	-30	
	S. Umm Gudair	49	400		24.0	3.91	53-59		Wafra
	Total	496	6,400	300					
Bahrain	Awali	63	185		33.0	1.42			
	Total	61	312	100					
Oman	Fahud-Naith	104	698		32.7				
	Natih-Natih	52	425		31.0				
	Yibal-Shuiaba	93	500		39.7				
	Total	342	5,900	400					
Algeria	Edjeleh	19	128		35.0	0.09			
	El Gassi el Agreb	41	125		47.0				
	Hassi Messaoud N.	222	4,685		49.0	0.15			
	Hassi Messaoud S.	77	4,532		49.0	0.15			
	Rhourde El Baçuel	11	209		40.0				
	Zarzaitaine	90	552		42.0	0.06	2	+16	
	Tin Foye	8	40		41.0	0.14			
	Total	946	7,370	1,100					
Arab OPEC Totals									
Sweet Crudes		2,434	33.470	4,100					
Sour Crudes		19,259	366,062	26,632					
All Crudes		21,693	399,532	30,732					

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
Non-Arab OPEC									
Venezuela	Chimire	8	278		34.0	1.07	69		
	Dacion	14	42		31.0	1.29	162		
	Guara	27	378		28.0	2.06			
	Leona	14	60		22.0	1.38		−35	
	Mata	27	653		33.9	0.60	26		
	Merey	19	66		12.0	2.52	354		
	Nipa	19	274		29.0				
	Oficina	38	498		33.4	0.59	62		
	Oscurote	5	30		20.0				
	Santa Rosa				37.8	0.09			
	Soto	5	38		37.3				
	Zapatos	4	57		36.0	0.48	4		
	Morichal	22	82		10.3				
	Oritupano	19	175		19.2				
	Quiriquire	14	763		16.3	1.27			
	Santa Barbara	3	19		28.3				
	Temblador	5	15		19.7	0.99			
	Las Mercedes	2	12		28.7				
	Silvestre	8	71		25.0	1.17	268		
	Sinco	18	158		24.4	1.38			
	Bachaquero	419	1,684		21.1	2.68	452	−10	
	Boscan	52	523		10.4	5.54	1,350	−60	
	Cabimas	77	300		27.3	1.71			
	Centro	110	316		36.8				
	Guces Manueles	5	21		31.7				
	Ceuta	58	134		28.5				
	La Concepcion	5	7		34.7				
	Lago	52	172		31.1	1.16	146	−15	
	Lagunillas	551	2,003		24.4	2.12	259		
	Lama	191	2,241		32.5				
	Lamar	121	664		34.2				

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
	La Paz	19	845		31.7	1.48			
	Mara	11	380		25.7	2.10			
	Mene Grande	14	583		4.0				
	Tia Juana	244	1,497		19.4	2.15		+10	
	San Joaquin	14			42.1	0.14		+80	
	Total	2,345	17,700	3,300					
Nigeria	Delta	33	175		27.9	0.18	4		
	Delta S.	44	334		38.1				
	Forc-Jones Creek	79	384		25.0				
	Forc-Forc/Yokri	88	350		25.0				
	Meren	74	309		32.3	0.09			
	Okan	38	354		34.9				
	Phl-Bomu	30	366		33.2	0.14	2		
	Phl-Imo River	60	355		32.0				
	Phl-Amuechen	14	95		37.6				
	Phs-Cawth, Cannel	38	98		39.0				
	Ugh-Kokori	49	155		44.0				
	Ugh-Olomoro	27	175		22.3				
	Total	1,787	20,200	2,500					
Indonesia	Ardjuna	68	150		36.8	0.12		+80	
	Attaka	99	262		41.1	0.07		-30	
	Bangko	77	165		34.1				
	Bekasap	58	280		33.4	0.17	8		
	Benakat	3	10		35.0				
	Cinta	27	120		34.0	0.08	20.2	+110	
	Duri	27	1,756		21.3	0.21	33	+57	
	Kitty	2	146		18.2				
	Limau	8	47		27.8				
	Melahin	3	50		23.8	0.27		+10	

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity	%S	Metals PPM	Pour Point °F	Comment
	Minas	356	5,270		35.4	0.09	7	+90	
	Nora	3	75		22.7				
	Pematang	41	135		31.7	0.10	11		
	Petani	55	84		32.7				
	Rantau	22	87		48.0				
	Sago	5	38		34.0				
	Sanga-Sanga	3	12		29.3				
	Talang Akar	1	357		35.0				
	Talang Jimar	3	180		27.8				
	Tarakan	3	9		21.6	0.15		-50	
	Total	1,313	14,000	1,600					
Gabon	Gamba	22	102		32.4	0.11	30.6	+73	
	Total	200	2,200	210					
Ecuador	Ancon	2	8		35.6				
	Lago Agrio	22	197		28.6				
	Sacha	38	357		29.7	0.87	89	+20	Composite
	Shushufindi	60	328		31.7				
	Total	160	2,450	255					

	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	Reserves/ Production Ratio
Non-Arab OPEC Totals				
Sweet Crudes	3,320	36,400	4,328	30
Sour Crudes	2,485	20,150	3,537	22
All Crudes	5,805	56,550	7,865	27

Table I-1

AVAILABILITY AND CHARACTERISTICS OF OPEC CRUDE OILS

Country	Crude Oil	1975 Production MB/D	Reserves 1/1/76 MMB	Usable Capacity MB/D	°API Gravity Reserves/ Production Ratio	%S	Metals PPM	Pour Point °F	Comment
Arab OPEC Totals									
Sweet Crudes		2,434	33,470	4,100	38				
Sour Crudes		19,259	366,062	26,632	52				
All Crudes		21,693	399,532	30,732	50				
All OPEC Totals									
Sweet Crudes		5,754	69,870	8,428	33				
Sour Crudes		21,744	386,212	30,169	49				
All Crudes		27,498	456,082	38,597	45				

Notes: Oil fields listed for an individual country will not necessarily add up to "Total" for that country. When "Total" is larger it is because it contains other unlisted oil fields. When "Total" is smaller, it is because one or more of the oil fields listed is shared by another country so production and reserves are split.

Sources: International Petroleum Encyclopedia
Petroleum Intelligence Weekly
U.S. Bureau of Mines
Miscellaneous crude assays in DOE files

Table I-2

U.S. CRUDE OIL RESERVES

State	12/31/75 Reserves 1/ (MBbls)	% Sweet 2/	Sweet Reserves (MBbls)
Alabama	61,032	86.9	53,037
Alaska	10,037,262		
North Slope	9,597,809	0.0	---
South	439,453	100.0	439,453
Arkansas	95,662	7.5	7,175
California	3,647,537		
Coastal	637,615	2.1	13,390
L.A. Basin	1,137,708	0.7	7,964
S.J. Basin	1,872,214	23.6	441,843
Colorado	276,066	36.0	99,384
Florida	262,539	0.0	---
Illinois	160.985	99.9	160,825
Indiana	22,029	99.6	21,941
Kansas	364,394	69.6	253,618
Kentucky	39,306	100.0	39,306
Louisiana	3,827,197		
North	253,911	87.0	220,903
South	3,573,276	95.8	3,423,198
Michigan	93,312	85.3	79,595
Mississippi	231,158	23.2	53,629
Montana	163,968	55.4	90.838
Nebraska	28,376	43.9	12,455
New Mexico	588,110		
Northwest	24,815	100.0	24,815
Southeast	563,295	52.8	297,420
New York	10,024	100.0	10,024
North Dakota	158,245	60.7	96,055
Ohio & Pennsylvania	169,291	100.0	169,291
Oklahoma	1,239,687	71.9	891,335
Texas	10,080,035		
District 1	126,457	25.5	32,247
2	563,204	99.4	559,825
3	1,244,579	99.3	1,235,867
4	193,370	100.0	193,370
5	91,267	9.2	8,397
6	1,773,893	84.6	1,500,713
7B	227,772	100.0	227,772
7C	185,234	88.0	163,006

Footnotes at end of table.

Table I-2

U.S. CRUDE OIL RESERVES

State	12/31/75 Reserves 1/ (MBbls)	% Sweet 2/	Sweet Reserves (MBbls)
8	2,922,387	28.4	829,958
8A	2,292,651	56.8	1,302,226
9	304,510	66.2	201,586
10	154,711	100.0	154.711
Utah	208,318	95.5	198.944
West Virginia	31,418	100.0	31,418
Wyoming	877,385	35.5	311,472
Miscellaneous	8,804	77.6	6,832
Total U.S.	32,682,127		13,691,805

1/ "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada As of December 31, 1975," American Petroleum Institute.

2/ Derived from "Oil Availability by Sulfur Levels," prepared by the Bureau of Mines for the Environmental Protection Agency, Office of Air Programs, August 1971, Table 2.

TABLE I-3

U.S. AND OPEC CRUDE OIL RESERVES AND PRODUCTION

	1969		1975	
OPEC		R/P		R/P
M Bbls Reserves				
Sweet	61,525,000	31	69,870,000	33
Sour	347,116,550	59	386,212,000	49
Total	408,641,550	52	456,082,000	45
Production B/D				
Sweet	5,465,990		5,754,000	
Sour	16,096,926		21,744,000	
Total	21,562,916		27,498,000	
UNITED STATES				
M Bbls Reserves				
Sweet	18,905,128	7.3	13,691,805	6.6
Sour	10,726,734	7.9	18,990,322	20.4
Total	29,631,862	7.5	32,682,127	10.7
Production B/D				
Sweet	7,096,000		5,686,625	
Sour	3,721,000		2,688,375	
Total	10,817,000		8,375,000	
UNITED STATES & OPEC				
M Bbls Reserves				
Sweet	80,430,128	17.5	83,562,000	20.0
Sour	357,843,284	49.5	406,202,000	45.6
Total	438,273,412	37.1	489,764,000	37.4
Production B/D				
Sweet	12,561,990		11,441,000	
Sour	19,817,926		24,432,000	
Total	32,379,916		35,873,000	

Table I-4

AVERAGE CRUDE GRAVITY IN OPEC COUNTRIES

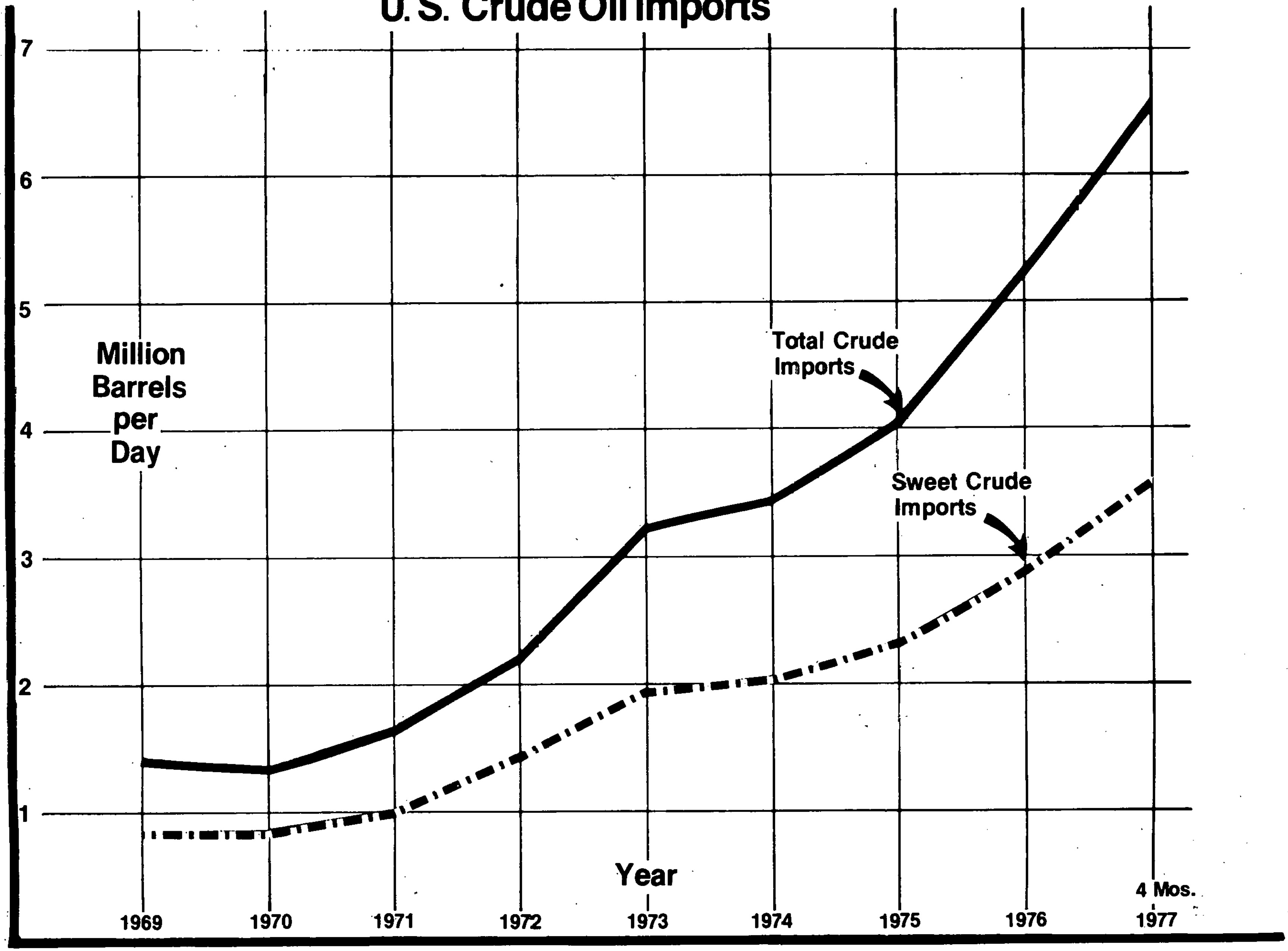
OPEC Country	1975 Production MB/D	1975 Production Wt. Aver. °API	12/31/75 Reserves MMB	12/31/75 Reserves Wt. Aver. °API	1969 Production MB/D	1969 Production Wt. Aver. °API	12/31/69 Reserves MMB	12/31/69 Reserves Wt. Aver. °API
Firm Data								
Saudi Arabia	6,827	34.2	148,600	33.6	3,216	33.5	137,069	32.3
Iran	5,350	32.3	64,500	32.2	3,375	29.2	55,000	32.5
Iraq	2,240	35.3	34,300	35.2	1,512	35.7	28,505	35.4
Abu Dhabi	1,403	40.0	29,500	40.0	590	39.2	15,000	38.7
Dubai	254	32.0	1,350	32.0	10	31.0	1,000	31.0
Libya	1,488	38.2	26,100	37.6	3,109	38.8	30,000	37.7
Venezuela	2,345	25.3	17,700	25.1	3,594	23.4	16,005	24.1
Total	19,907	33.4	322,050	33.9	15,406	31.7	282,579	33.1
Partial Data								
Kuwait	1,807	33.0	68,000	33.0	2,575	(1)	71,210	(1)
Qatar	441	38.1	5,850	37.1	355	(1)	3,900	(1)
Neutral Zone	496	28.4	6,400	28.4	428	(1)	13,000	(1)
Bahrain	61	33.0	312	33.0	76	(1)	428	(1)
Oman	342	35.0	5,900	34.4	360	(1)	3,000	(1)
Algeria	946	46.6	7,370	48.2	974	(1)	8,025	(1)
Indonesia	1,313	35.0	14,000	32.2	742	(1)	18,000	(1)
Total	5,406	36.0	107,832	34.0	5,510		117,563	
Subtotal	25,313	34.0	429,882	33.9				
Inadequate Gravity Data								
Sharjah	38	37.4	1,350	37.4	—	—	—	—
Ecuador	160	30.6	2,450	(1)	4	(1)	3,000	(1)
Nigeria	1,787	(1)	20,200	(1)	542	(1)	5,000	(1)
Gabon	200	(1)	2,200	(1)	99	(1)	500	
Total	2,185		26,200		645		8,500	
Grandtotal	27,498		456,082		21,561		408,642	

(1) Insufficient gravity data available to be representative of full production or reserves.

Sources: International Petroleum Encyclopedia; U.S. Bureau of Mines; and, miscellaneous crude assays in DOE files.

Figure I-1

U.S. Crude Oil Imports



J. Analysis of PAD V Situation

A special situation exists on the west coast due to the introduction of Alaskan North Slope crude oil. Although ample refinery capacity exists in the area to meet local refined product needs, the volume of sour California crude plus sour North Slope crude exceeds the sour crude capacity in the area. Extensive conversion of Puget Sound refineries and some California refineries would be required to absorb most or all of the North Slope crude.

A paper on this problem is presented in the Appendix of this report. The paper was prepared early in 1977 in response to a request by Congressman Harold Runnels as a result of a hearing by the Committee on Interior and Insular Affairs, which was held on April 29, 1977.

This paper compares forecasts prepared by several entities and gives a general idea of the expected surplus on the west coast during the next few years.

APPENDIX A

Analysis of PAD V Situation

Demand for Crude Oil

As long as refined product imports remain small in PAD V, crude oil demand will be a function of the district's petroleum product requirements. Required crude oil volumes will be equal to total refined product demand, less product imports, less processing gain, plus provision for any inventory changes over the specific period in question. Another small adjustment will be necessary to the extent natural gas liquids contribute to satisfying product demand.

Several crude demand forecasts have been made by various oil companies, consultants and DOE. The DOE forecast is compared with the average of all forecasters below in thousands of barrels per day.

Crude Oil Demand - MB/D

	DOE	Average For All Forecasters
1975 (actual)	1,937	1,937
1976	2,185	2,206
1977	2,340	2,338
1978	2,650	2,637
1979	2,750	2,857

DOE data for the years 1977 and 1978 were derived from product demand data based on the latest short-range forecast of the Office of Oil and Gas Analysis, Data and Analysis. The years 1980 and 1985 were derived from the latest available data of the National Energy Outlook (NEO) of 1977 (now changed).

Although the DOE crude demand figures agree closely with the average for all forecasters, there is significant divergence in some individual cases.

Current Sources of Crude Oil

Crude oil imports are shown in Table 1 for the year of 1975. This breaks down crude oil imports by country of origin, sulfur content, quantities, and refining area of PAD V. Domestic production in PAD V in the past has been limited to southern Alaska, which is sweet crude, and to California which produces predominantly sour crude.

PAD V Refinery Capability to Process Sour Crude and North Slope Crude

It is difficult to forecast the distribution of Alaskan crude, foreign crude, and domestic crudes among the PAD V refining centers. Much will depend on the laid-down price of North Slope oil in comparison with other foreign crudes. It is known that a certain amount of sweet crude will have to continue to be imported, particularly for most Puget Sound refineries. There is no indication yet that any efforts are being made to convert these refineries into sour crude capability.

PAD V refineries have the capability of meeting all requirements for their district from the standpoint of overall crude capacity. The district's percent of utilization of capacity as been consistently lower than the national averabe. For a 6-year average, this has been 85 percent for PAD V versus 87 percent for a national average. Planned expansions insure that this capacity will suffice to meet all area requirements. Most of the completed expansions, and those in progress, are designed to handle sour crude. While there is not a problem in meeting area requirements, the main problem is in ability to process the anticipated volume of North Slope Alaskan crude after meeting all needs for processing other domestically produced crude oils from PAD V.

Sweet and sour crude capacity in PAD V can be generally grouped as follows:

	PAD V MB/CD Refining Capacity - 1/1/76		
Area	Sour	Sweet	Total
Hawaii	----	99.5	99.5
Alaska	----	60.0	60.0
Washington	96.0	270.9	366.9
California	1,574.2	309.2	1,883.4
Oregon & Arizona	----	17.0	17.0
Total	1,670.2	756.6	2,426.8

The above breakdown is purely a DOE estimate based on equipment capabilities. In addition, many significant additions to sour crude capacity have been made or are in the process of being made since January 1, 1976. There are many other factors to be taken into account before any judgement can be made on the capability to run any specific sour crude in PAD V equipment to displace other imported crudes. Some of these items are:

- o Limitations due to product mix and effects of displacing some crudes with crudes of differing gravity.
- o Effect on specifications of product output.
- o Delivered price of the new crude in relation to other crudes.
- o Transportation and geographical problems.
- o Committments to run currently produced California crudes.
- o Potential for sweet crude refineries to handle a limited amount of sour crude blended with normal sweet crude feedstocks.

An example of the sensitivity of certain refining areas to such factors as sulfur content and gravity of crude oils is demonstrable in the Chicago area. This area has slightly less than one million barrels per day of refining capacity. Conversations with representatives of companies operating these refineries revealed that probably not more than 130 to 200 MB/D of North Slope crude could be absorbed in that area.

The problem is more complex than mere equipment capable of handling sour crude and desulfurization of product streams. Residual fuel oil outlet in the area is limited and inflexible. Introduction of small amounts of heavier crudes, such as North Slope, will displace lighter crudes, causing significant reductions in throughput. Large investments will be required to maintain the product slate, if heavier crude is introduced. This situation directionally indicates a northern tier pipeline to be less favorable than some other alternatives.

Other refining centers are less sensitive to crude changes. For example, on the gulf coast there is a very substantial amount of refinery capacity capable of processing sour crude. The injection of a heavier sour crude at this location is not as great a concern since any increases in production of residual fuel merely back out an equivalent quantity of residual imports.

Estimates of PAD V's ability to absorb North Slope crude and hence, the amount which will become surplus, have been made by a number of oil companies, consultants and the DOE. These are listed below:

1. SOHIO
2. Exxon
3. A. D. Little
4. DOE
5. Proprietary
6. Arco
7. Socal
8. Rand

Some of these surveys dealt with differing periods of time and distinctly differing means of approach to the problem. The summary of all indicated surpluses appears in Table 2.

An average of all forecasts for the anticipated PAD V surplus is as follows;

	MB/D - Surplus N.S. Crude	
Year	Average	Extreme Variations
1978	447	230 - 600
1980	709	500 - 1,100
1985	1,002	600 - 1,713

DOE conducted a refinery-by-refinery survey from which was derived an estimate of the capability of absorbing North Slope crude in 1978. This appears in Table 3. Many of the responses from individual refiners expressed uncertainties over many factors including price, Government controls and questions over North Slope crude assays. The result indicated that from 601 to 969 MB/D could be absorbed.

DOE also conducted a Refining and Petrochemical Modeling System (RPMS) survey of the disposition of Alaskan North Slope crude in west coast refineries. This survey was not designed to pinpoint specific consumptions and excesses of North Slope crude in specific forecast years. Rather, it was designed to evaluate the competitive price levels required for this crude versus currently imported crudes as gradually increasing increments of North Slope crude are injected into west coast refinery crude slates. In a 1978 analysis, a "probable market range" at the $12 level, indicated potential for absorption of 500 to 800 MB/D leaving from 400 to 700 MB/D as excess.

Forecasts of Crude Imports

Forecasts of crude oil imports are essential for the purposes of this study because they point up a very large potential supply surplus for future years. The size of the west coast supply surplus in each of the available forecasts is largely influenced by the volume of foreign imports which is assumed. Forecasts of crude oil imports are shown in Table 4. The table indicates that most forecasters believe that crude oil imports will continue at approximately 500,000 barrels per day through 1980. Imports provide sweet and light crudes with which refiners balance feedstocks. Also, refiners lack the incentive to run exclusively or predominantly on heavy crudes without some guarantee that:

(1) they will be priced much lower than foreign alternatives, and;

(2) the conversion costs can be passed on to consumers in product prices.

The import forecasts are less similar for 1985 than for 1980. Exxon forecasts no foreign imports in that year.

Standard of California forecasts a maximum foreign import of 260 MB/D although it is unclear to what extent this implies crude oil or refined product imports. A. D. Little forecasts 339 MB/D (Best Estimate) when 650 plus volume fraction and crude sulfur content are held constant. Rand Corporation assumed no imports of foreign crude after North Slope became available. This appears to be one of the major shortcomings in the Rand forecast, as it is clear that at least the Puget Sound and Hawaiian refineries will continue to run on light sweet crudes of limited availability. Indonesia will probably continue to be the most important source of this kind of oil.

Conversion Costs

The forecasted imports which might remain once Alaskan North Slope crude oil is available are largely made up of sweet and light crudes needed to balance feedstocks. Refinery conversions to run on predominantly heavy crude are possible with a 2 to 3 year lead time depending upon the magnitude of the conversion and assuming availability of capital.

Estimates of the costs of converting refiners which were specifically designed and constructed to utilize low sulfur, light crudes to utilize heavy, high-sulfur North Slope crude vary from refinery to refinery. Estimates of the capital investment cost range between $1,200 to $3,000 per barrel per day, depending on the size of the refinery.

In another separate study for the DOE of Crude Supply Alternatives for the Northern Tier States, Bonner and Moore Associates, Inc., estimated how much investment would have to be made in desulfurization in those refineries that would process Alaskan North Slope crude as a substitute for Canadian crude. Average cost of capital investment per barrel per day would equal approximately $570. Operating costs for this add-on desulfurizaing package would be approximately $.73 per barrel, or $53.59 million per year for a 200 MB/D refinery. These calculations are presented in Table 5.

TABLE 1

PAD V IMPORTS OF FOREIGN CRUDE OIL BY REFINING AREA
(MB/D 1975)

	Sulfur Content (Wt %)	PADD V Total	Puget Sound	SF Bay Area	LA Basin	Hawaii
OAPEC						
Saudi Arabia	1.70	95.6	5.1	66.5	24.0	--
United Arab Emirates	0.74	49.9	16.8	10.9	22.2	--
Algeria	0.13	1.1	--	--	1.1	--
Libya	0.20	7.3	--	--	7.3	--
Qatar	1.29	10.9	--	8.8	2.1	--
Total		164.8	21.9	86.2	56.7	--
Other OPEC						
Iran	1.36	105.2	49.2	18.8	37.2	--
Venezuela	1.51	44.1	6.9	26.0	11.2	--
Nigeria	0.21	13.8	3.0	2.6	8.2	--
Indonesia	0.07	295.4	37.1	34.6	188.2	1/35.5
Ecuador	0.93	52.7	2.9	1.6	48.2	--
Total		511.2	99.1	83.6	293.0	35.5
Non OPEC						
Malaysia	0.07	5.3	1.2	--	4.1	--
Bolivia	0.03	5.3	0.7	--	4.6	--
Canada	0.21	163.5	163.5	--	--	--
Oman	1.25	1.3	--	--	1.3	--
Total		175.4	165.4	--	10.0	--
Grand Total		851.3	286.4	169.8	359.7	35.5
Sweet		491.7	205.5	37.2	213.5	35.5
Sour		359.7	80.9	132.6	146.2	--

1/ Does not include HIRI refinery in Hawaii (48.3 MB/D sweet).

Source: Bureau of Mines data and miscellaneous assay information.

Table 2

FORECASTS OF WEST COAST (PADD V)
CRUDE OIL SURPLUSES
(MB/D)

	1978	1980	1982	1985
Sohio	320-600	--	660-960	--
Exxon	600	700	600	1000
Rand (Med Use. Med Prod)	320	--	--	751
A.D. Little (Best)	--	689	--	805-1395
Cal Standard	--	600	--	600
Proprietary	392	737	--	--
Arco	300-400	500-600	--	850
FEA	560	980	--	1713

The above data are presented to show the wide divergence between individual forecasts of volumes to be considered excess. Although most of the forecasters assumed initial Trans-Alaskan Pipeline capacity of 1.2 million barrels per day with expansion later to 2 million barrels per day, we are not aware of the exact capacity assumed in the case of each specific forecast number shown above.

Table 3

FEA Survey
1978 Potential Distribution of North Slope
and Foreign Imports in PAD V
(MB/D)

Refinery *	Capacity	Alaska North Slope	Foreign Imports
LOS ANGELES			
Union of Calif.	108	0-50	10-20
Arco	182	70-100	30-50
Stand.of Calif.	405	130-190	50-90
Shell	96	20-35	5-10
Mobil	124	25-30	8-10
Gulf	52	10-25	10-15
Douglas of Calif.	47	5-25	5-10
Texaco	75	15-20	15-20
Powerine	44	0-5	10-15
Total	1,133	275-480	143-240
SAN FRANCISCO			
Exxon	93	88-93	0-5
Stand. of Calif.	365	120-176	30-42
Shell	100	30-40	0-5
Tosco	110	0-30	15-20
Union of Calif.	111	0-19	0-15
Total	779	238-358	45-87
PUGET SOUND			
Arco	96	96-96	
Mobil	71	10-35	35-60
Shell	91	0-15	75-90
Texaco	78	0-2	76-78
Total	336	106-150	186-228
West Coast Total	2,248	619-988	374-555

* Includes only those refineries likely to utilize North Slope crude oil.

Table 4

FORECAST
PAD DISTRICT V CRUDE OIL IMPORTS
(MB/D)

FORECAST		1976	1977	1978	1980	1985
FEA		832	642	500	400	200
EXXON		942	945	509	520	
A.D. LITTLE	(40%) 1/				508	400
	(60%)				339	339
	(75%)				212	200
SOHIO	(HI)			550		
	(LOW)			450		
STANDARD OF CALIFORNIA					520	260
PROPRIETARY		893	732	200	200	

1/ Percentage of North Slope crude oil refined in PAD V. 1/1/77
Prior to Administration Energy Message

TABLE 5

DESULFURIZING PACKAGE "ADD-ON" FOR EXISTING REFINERY INVESTMENT SUMMARY

Capacity = 200,000 B/CD Alaska North Slope Crude
($MM per year)

	ON-SITE	OFF-SITE
PROCESS UNITS:		
Gas Oil Desulfurization	16.56	3.31
Residuum Desulfurization	48.39	13.56
Hydrogen Production by Partial Oxidation	2.75	--
Sulfur Recovery	5.93	1.18
UTILITIES:		
Steam Generation	4.64	2.33
Electric Power Generation	10.79	--
Electric Power Distribution	1.51	--
Cooling Water	3.22	--
Total Investment	$93.79	$20.38
Grand Total	$114.17	
OPERATING COST:		
Operating Labor	0.88	
Maintenance, Insurance, Taxes, Overhead	6.76	
Fuel and H_2 Feedstock (@ $12/Bbl)	17.41	
Capital Recovery	28.54	
Total Operating Cost	$53.59	
Per Barrel	$ 0.73	

Source: Crude Supply Alternative for the Northern Tier States, Volume II Technical Report, prepared by Bonner and Moore Associates, Inc. for the FEA, July 25, 1976.

APPENDIX B

Tables Supporting Section A Data of Report

TABLE 1

U.S. REFINERS THERMAL REFINING PROCESSES WHICH SEGREGATE SULFUR, PAD DISTRICTS I-V
(Including Hawaiian Trade Zone) Barrels Per Stream Day (As of January 1 of Indicated Year)

Year	Vacuum Distillation 1/		Visbreaking 1/		Coking 1/				Grand Total	Crude Oil 2/ Dist. Oper. Cap. As of January 1	Sulfur Segreg. Cap. As % of Total Crude Oil Capacity
	Bbl/SD	% of Crude Oil Oper. Cap.	Bbl/SD	% of Crude Oil Oper. Cap.	Fluid Bbl/SD	Delayed Bbl/SD	Total Bbl/SD	% of Crude Oil Oper. Cap.			
						DISTRICT I					
1973	765,700	45.4	39,400	2.3	42,000	23,700	65,700	3.9	870,800	1,686,000	51.6
1974	752,700	42.7	28,600	1.6	44,000	37,700	81,700	4.6	863,000	1,762,000	49.0
1975	802,600	47.1	26,400	1.6	44,000	37,700	81,700	4.8	910,700	1,703,000	53.5
1976	802,600	45.5	14,400	0.8	44,000	37,700	81,700	4.6	898,700	1,765,000	50.9
1977	845,600	45.1	21,400	1.1	44,000	38,700	82,700	4.4	949,700	1,877,000	50.6
						DISTRICT II					
1973	1,231,400	32.1	29,500	0.8	---	212,900	212,900	5.6	1,473,800	3,857,000	38.4
1974	1,287,400	31.4	29,500	0.7	---	260,300	260,300	6.4	1,577,200	4,094,000	38.5
1975	1,396,200	33.1	25,000	0.6	12,000	260,700	272,700	6.5	1,693,900	4,221,000	40.1
1976	1,487,400	34.2	28,000	0.6	---	261,600	261,600	6.0	1,777,000	4,355,000	40.8
1977	1,496,000	34.3	28,000	0.6	---	262,300	262,300	6.0	1,786,300	4,363,000	40.9
						DISTRICT III					
1973	1,899,100	32.6	62,500	1.1	---	261,000	261,000	4.5	2,222,600	5,823,000	38.2
1974	1,976,100	31.6	38,300	0.6	---	306,300	306,300	4.9	2,320,700	6,245,000	37.2
1975	2,036,700	31.2	42,300	0.6	---	297,300	297,300	4.5	2,376,300	6,538,000	36.3
1976	2,099,600	32.1	42,300	0.6	---	300,400	300,400	4.6	2,439,200	6,523,000	37.4
1977	2,394,700	33.3	50,300	0.7	---	309,800	309,800	4.3	2,754,800	7,198,000	38.3
						DISTRICT IV					
1973	159,700	33.5	6,000	1.3	5,200	8,000	13,200	2.8	178,900	477,000	37.5
1974	158,800	29.8	6,000	1.1	13,700	---	13,700	2.6	178,500	533,000	33.5
1975	162,300	28.1	8,000	1.4	5,200	22,000	27,200	4.7	197,500	577,000	34.2
1976	170,500	29.4	6,000	1.0	11,500	18,500	30,000	5.2	206,500	581,000	35.5
1977	173,600	30.2	6,000	1.0	6,300	18,500	24,800	4.3	204,400	575,000	35.5

*Footnotes at end of table.

TABLE 1

U.S. REFINERS THERMAL REFINING PROCESSES WHICH SEGREGATE SULFUR, PAD DISTRICTS I-V
(Including Hawaiian Trade Zone) Barrels Per Stream Day (As of January 1 of Indicated Year)

Year	Vacuum Distillation 1/		Visbreaking 1/		Coking 1/				Grand Total	Crude Oil 2/ Dist. Oper. Cap. As of January 1	Sulfur Segreg. Cap. As % of Total Crude Oil Capacity
	Bbl/SD	% of Crude Oil Oper. Cap.	Bbl/SD	% of Crude Oil Oper. Cap.	Fluid Bbl/SD	Delayed Bbl/SD	Total Bbl/SD	% of Crude Oil Oper. Cap.			
						DISTRICT V					
1973	1,094,900	46.6	102,600	4.4	71,000	287,600	358,600	15.2	1,556,100	2,352,000	66.2
1974	1,124,900	47.3	103,600	4.4	70,600	295,500	366,100	15.4	1,594,600	2,378,000	67.1
1975	1,099,400	44.5	103,600	4.2	73,600	295,400	369,000	14.9	1,572,000	2,473,000	63.6
1976	1,112,800	44.7	103,600	4.2	73,300	302,300	375,600	15.1	1,592,000	2,488,000	64.0
1977	1,306,800	47.6	96,600	3.5	126,900	220,000	346,900	12.6	1,750,300	2,746,000	63.7
						TOTAL - DISTRICTS I - V					
1973	5,150,800	36.3	240,000	1.7	118,200	793,200	911,400	6.4	6,302,200	14,195,000	44.4
1974	5,299,900	35.3	206,000	1.4	128,300	899,800	1,028,100	6.8	6,534,000	15,012,000	43.5
1975	5,497,200	35.4	205,300	1.3	134,800	913,000	1,047,900	6.8	6,750,400	15,512,000	43.5
1976	5,672,900	36.1	194,300	1.2	128,800	920,500	1,049,300	6.7	6,916,500	15,713,000	44.0
1977	6,216,700	37.1	202,300	1.2	177,200	849,300	1,026,500	6.1	7,445,500	16,759,000	44.4

1/ Oil and Gas Journal, April 2, 1973; April 1, 1974; April 17, 1975; March 29, 1976; March 28, 1977; "Annual Refining Issues."

2/ Basis: "Trends in Refinery Capacity and Utilization," June 1977, Department of Energy, Bbl/CD ÷ 0.95, Operating Capacity.

Note: Percentages may not add up because of rounding.

TABLE 2

U.S. REFINERS PROJECTED THERMAL REFINING PROCESSING CAPACITY WHICH SEGREGATES SULFUR -- PAD DISTRICTS I-V (INCLUDING HAWAIIAN TRADE ZONE)
Barrels Per Calendar Day and Estimated On-Stream Times
Basis: Oil and Gas Journal, 4/25/77 and 10/3/77

	Vacuum Distillation		Visbreaking		Coking 3/	
	Bbl/CD	On-Stream	Bbl/CD	On-Stream	Bbl/CD	On-Stream
District I						
	----	----	----	----	----	----
District II						
	17,700	1977	----	----	7,000	1977
	7,500	1979	----	----	1,000 2/	----
Total	25,200				8,000	
District III						
	34,900	1977	----	----	----	----
	54,500	1978	----	----	----	----
Total	89,400					
District IV						
	5,000	1978	----	----	9,000	1978
District V						
	16,000	1978	----	----	----	----
Grand Total Bbl/CD	135,600		----		17,000	
Grand Total Bbl/SD 1/	150,700		----		18,900	

1/ Bbl/CD/.90 = Bbl/SD

2/ Bureau of Mines, "Petroleum Refiners in the United States and Puerto Rico," Jan. 1, 1977.

3/ Type of coking not indicated.

TABLE 3

U.S. REFINERS 1980 ESTIMATED TOTAL THERMAL REFINING PROCESSING CAPACITY WHICH SEGREGATES SULFUR
PAD DISTRICTS I - V (Including Hawaiian Trade Zone)
Barrels Per Stream Day

Vacuum Distillation		Visbreaking		Coking				
Bbl/SD 3/	% of Crude Oil Oper. Cap.	Bbl/SD 3/	% of Crude Oil Oper. Cap.	Bbl/SD 3/	% of Crude Oil Oper. Cap.	Grand Total	Crude Oil Operating Capacity 1/ 2/	Sulfur Segregating Capacity As % of Total Crude Oil Capacity
6,367,400	36.2	202,300	1.1	1,045,400	5.9	7,615,100	17,608,000	43.3

1/ Bbl/CD ÷ 0.90 = Bbl/SD.

2/ June 1977, "Trends in Refinery Capacity and Utilization,"
1980 Operable Capacity x 0.95 ÷ 0.95.

3/ Total Bbl/SD capacities on Table 1 and Table 2.

TABLE 4

CARIBBEAN "EXPORT" REFINERIES THERMAL REFINING PROCESSES
WHICH SEGREGATE SULFUR, 1973-1977
Barrels Per Calendar Day
(As of January 1 of Indicated Year)

Country	Vacuum 4/ Distillation	% of Crude Oil Capacities	Visbreaking 1/	% of Crude Oil Capacities	Fluid and Delayed Coking 4/	Total Thermal Processes	Crude Oil Capacity 5/	Sulfur Segregating Capacity as a % of Crude Oil Capacity
1977								
Antigua	S	H	U	T	D	O	W	N
Bahamas	94,000		---		---		500,000	
Netherland Antilles	230,000		240,000		---		810,000	
Panama	14,000		---		---		100,000	
Puerto Rico	114,200		---		---		283,800	
Trinidad	194,000		---		---		461,000	
Venezuela	477,100		94,000		---		1,423,000	
			14,400 2/					
Virgin Islands	140,000		---		---		700,000	
Total, B/CD	1,263,300	29.5	348,400	8.1	---	1,611,700	4,277,800	37.6
B/SD 6/	1,403,700		387,100			1,790,800		
1976								
Antigua	S	H	U	T	D	O	W	N
Bahamas	94,000		---		---		500,000	
Netherland Antilles	230,000		79,000		---		810,000	
Panama	14,000		--- 3/		---		100,000	
Puerto Rico	114,200		---		---		283,800	
Trinidad	194,000		---		---		461,000	
Venezuela	352,200		94,000		---		1,423,000	
			14,400 2/					
Virgin Islands	140,000		---				700,000	
Total, B/CD	1,138,400	26.6	187,400	4.4	---	1,325,800	4,277,800	31.0
B/SD	1,264,900		208,200			1,473,100		

Footnotes at end of table.

TABLE 4

CARIBBEAN "EXPORT" REFINERIES THERMAL REFINING PROCESSES
WHICH SEGREGATE SULFUR, 1973-1977
Barrels Per Calendar Day
(As of January 1 of Indicated Year)

Country	Vacuum 4/ Distillation	% of Crude Oil Capacities	Visbreaking 1/	% of Crude Oil Capacities	Fluid and Delayed Coking 4/	Total Thermal Processes	Crude Oil Capacity 5/	Sulfur Segregating Capacity As a % of Crude Oil Capacity
1975								
Antigua	1,500		---		---		17,300	
Bahamas	---		---		---		500,000	
Netherland Antilles	230,000		79,000		---		900,000	
Panama	14,000		22,000		---		100,000	
Puerto Rico	114,200		---		---		283,800	
Trinidad	194,000		---		---		461,000	
Venezuela	360,300		94,000 14,400 2/		---		1,523,000	
Virgin Islands	105,000		---		---		590,000	
Total, B/CD	1,019,000	23.3	209,400	4.8	---	1,228,400	4,375,100	28.1
B/SD	1,132,200		232,700					
1974								
Antigua	2,000		---		---		17,300	
Bahamas	70,000		---		---		500,000	
Netherland Antilles	130,000		79,000		---		945,000	
Panama	14,000		22,000		---		75,000	
Puerto Rico	114,200		---		---		305,000	
Trinidad	187,000		---		---		436,000	
Venezuela	367,300		94,000 14,400 2/		---		1,504,000	
Virgin Islands	105,000		---		---		590,000	
Total, B/CD	989,500	22.6	209,400	4.8	---	1,198,900	4,372,300	27.4
B/SD	1,099,400		232,700			1,332,100		

Footnotes at end of table.

TABLE 4

CARIBBEAN "EXPORT" REFINERIES THERMAL REFINING PROCESSES WHICH SEGREGATE SULFUR, 1973-1977
Barrels Per Calendar Day
(As of January 1 of Indicated Year)
(Continued)

Country	Vacuum 4/ Distillation	% of Crude Oil Capacities	Visbreaking 1/	% of Crude Oil Capacities	Fluid and Delayed Coking 4/	Total Thermal Processes	Crude Oil Capacity 5/	Sulfur Segregating Capacity as a % of Crude Oil Capacity
1973								
Antigua	---		---		---		17,300	
Bahamas	70,000		---		---		250,000	
Netherland Antilles	130,000		100,000		---		880,000	
Panama	14,000		22,000		---		75,000	
Puerto Rico	115,000		---		---		260,000	
Trinidad	187,000		---		---		436,000	
Venezuela	382,500		94,000 14,400 2/		---		1,499,000	
Virgin Islands	45,000		---		---		418,000	
Total, B/CD	943,500	24.6	230,400	6.0	---	1,173,900	3,835,300	30.6
B/SD	1,048,300		256,000			1,304,300		

1/ Petroleum Times: Jan 26, 1973; Mar. 8, 1974; Jan. 24, 1975; Jan. 23, 1976; Mar. 18, 1977.

2/ Converted to Barrels/Calendar Day by 0.9 factor.

3/ Visbreaking capacity converted to pipestill.

4/ Oil and Gas Journal: Dec. 27, 1976; Dec. 29, 1975; Dec. 30, 1974; Dec 31, 1973; Dec. 25, 1972.

5/ "Trends in Refinery Capacity and Utilization," June 1977, June 1976, June 1975, June 1974, Department of Energy Publications.

6/ Barrels/CD/.90.

TABLE 5

CARIBBEAN "EXPORT" REFINERIES 1980 PROJECTED
THERMAL PROCESSES WHICH SEGREGATE SULFUR
Barrels Per Calendar Day
(Basis: Oil and Gas Journal, April 25, 1977)

Country or Territory	Vacuum Distillation	On-Stream	Visbreaking	On-Stream	Fluid and Delayed Coking	On-Stream
Venezuela	84,200	1978	---	---	---	---
Virgin Islands	105,000	1980	---	---	---	---
Total, B/CD	189,200		---	---	---	---
B/SD	210,200		---	---	---	---

TABLE 6

CARIBBEAN "EXPORT" REFINERIES 1980 ESTIMATED TOTAL THERMAL REFINING
PROCESSING CAPACITY WHICH SEGREGATES SULFUR
Barrels Per Calendar Day

Vacuum Distillation		Visbreaking		Coking				
Bbl/CD	% of Crude Oil Oper. Cap.	Bbl/CD	% of Crude Oil Oper. Cap.	Bbl/CD	% of Crude Oil Oper. Cap.	Total Thermal Processes	Crude Oil Capacity	Total Sulfur Segregating Capacity As % of Crude Oil Capacity
1,452,500 1/	31.4	348,400 1/	7.5	---	---	1,800,900	4,627,800	38.9
(1,613,900 B/SD)		(387,100 B/SD)				(2,001,000 B/SD)		

1/ Basis: Tables 4 and 5

TABLE 7

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICTS I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day
(As of January 1 of Indicated Year)

Year	Catalytic Hydrocracking 3/ Bbl/SD	Catalytic Hydrocracking 3/ % of Total Oper. Ref. Cap.	Catalytic Hydrorefining Bbl/SD	Catalytic Hydrorefining % of Total Oper. Ref. Cap.	Catalytic Hydrotreating 4/ Bbl/SD	Catalytic Hydrotreating 4/ % of Total Oper. Ref. Cap.	Grand Total	Operating 2/ Refinery Capacity	Hydroprocessing As % of Total Ref. Cap.
				DISTRICT I					
1977	70,500	3.8	306,440	16.3	801,703	42.7	1,178,643	1,877,000	62.8
1976	68,000	3.9	295,440	16.7	766,203	43.4	1,129,643	1,765,000	64.0
1975	67,000	3.9	247,440	14.5	681,203	40.0	995,643	1,703,000	58.5
1974	47,000	2.7	208,640	11.8	618,303	35.1	873,943	1,762,000	49.6
1973	47,000	2.8	164,000	9.7	667,915	39.6	878,915	1,686,000	52.1
				DISTRICT II					
1977	155,190	3.6	249,300	5.7	1,372,554	31.5	1,777,044	4,363,000	40.7
1976	157,100	3.6	224,460	5.2	1,308,444	30.0	1,690,004	4,355,000	38.8
1975	156,000	3.7	229,000	5.4	1,210,241	28.7	1,595,241	4,221,000	37.8
1974	155,950	3.8	236,500	5.8	1,171,965	28.6	1,564,415	4,094,000	38.2
1973	156,650	4.1	125,800	3.3	1,053,815	27.5	1,336,265	3,857,000	34.8
				DISTRICT III					
1977	298,666	4.1	852,900	11.8	2,030,331	28.2	3,181,897	7,198,000	44.2
1976	297,166	4.6	551,000	8.4	1,897,081	29.1	2,745,247	6,523,000	42.1
1975	286,166	4.4	429,000	6.6	1,829,821	28.0	2,544,987	6,538,000	39.9
1974	284,166	4.6	393,500	6.3	1,832,478	29.3	2,510,144	6,245,000	40.2
1973	298,066	4.1	379,000	6.5	1,622,999	27.9	2,300,065	5,823,000	39.4
				DISTRICT IV					
1977	5,900	1.2	40,588	7.1	197,394	34.3	243,882	575,000	42.4
1976	6,020	1.1	36,144	6.2	177,094	30.5	219,258	581,000	37.7
1975	6,020	1.0	22,144	3.8	194,094	33.6	222,258	577,000	38.5
1974	5,900	1.0	22,444	4.2	187,544	35.2	215,888	533,000	40.5
1973	5,400	0.9	45,694	9.6	130,494	28.2	181,588	477,000	38.1

Footnotes at end of table.

TABLE 7

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICTS I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day
(As of January 1 of Indicated Year)

	Catalytic Hydrocracking 3/		Catalytic Hydrorefining		Catalytic Hydrotreating 4/				
Year	Bbl/SD	% of Total Oper. Ref. Cap.	Bbl/SD	% of Total Oper. Ref. Cap.	Bbl/SD	% of Total Oper. Ref. Cap.	Grand Total	Operating 2/ Refinery Capacity	Hydroprocessing As % of Total Ref. Cap.
					DISTRICT V				
1977	362,922	13.2	378,944	13.8	852,537	31.0	1,594,403	2,746,000	58.1
1976	354,822	14.3	169,744	6.8	807,787	32.5	1,332,353	2,488,000	53.6
1975	354,622	14.3	159,744	6.5	770,787	32.5	1,285,153	2,473,000	52.0
1974	352,622	14.8	158,744	6.7	771,299	32.4	1,282,665	2,378,000	53.9
1973	350,722	14.9	126,000	5.4	729,910	31.0	1,206,632	2,352,000	51.3
					TOTAL DISTRICTS I - V				
1977	893,178	5.3	1,828,172	10.9	5,254,519	31.4	7,975,869	16,759,000	47.6
1976	883,108	5.6	1,276,788	8.1	4,956,609	31.5	7,116,505	15,713,000	45.3
1975	869,808	5.6	1,087,328	7.0	4,686,146	30.2	6,643,282	15,512,000	42.8
1974	845,638	5.6	1,019,828	6.8	4,581,589	30.5	6,447,055	15,012,000	43.0
1973	857,838	6.0	840,494	5.9	4,205,133	29.6	5,903,465	14,195,000	41.6

1/ Basis: Oil and Gas Journal - March 28, 1977; March 29, 1976; April 17, 1975; April 1, 1974; April 2, 1973.

2/ "Trends in Refinery Capacity and Utilization," Table 1, June 1977. Converted to stream days by 0.95 factor.

3/ Does not include lube oil manufacture.

4/ Does not include naphtha olefin or aromatics saturation or lube oil polishing.

TABLE 8

U.S. REFINERS PROJECTED CATALYTIC SULFUR REMOVING HYDROPROCESSING
PAD DISTRICTS I-V (Including Hawaiian Trade Zone)
Barrels Per Calendar Day
Basis: Oil and Gas Journal, April 25, 1977

PAD Districts		Catalytic Hydrocracking		Catalytic Hydrorefining		Catalytic Hydrotreating	
		Bbl/CD	On-Stream	Bbl/CD	On-Stream	Bbl/CD	On-Stream
I		----	----	135,350	1980	800	1979
						40,250	1980
	Sub-Total					41,050	----
II		----	----	40,000	1977	13,000	1977
		----	----	----	----	12,900	1979
		----	----	----	----	6,100	1980
	Sub-Total	----	----	40,000	----	32,000	----
III		5,000	1978	115,000	1977	169,500	1977
		----	----	----	----	50,800	1978
		----	----	----	----	30,000	1979
		----	----	75,000	----	103,300	1980
	Sub-Total	5,000		190,000		353,600	
IV		----	----	----	----	13,000	1977
		----	----	----	----	1,200	1978
	Sub-Total					14,200	
V		3,000	1978	----	----	1,800	1978
		----	----	----	----	10,300	1979
	Sub-Total	3,000				12,100	
	Grand Total, B/CD	8,000	----	365,350	----	452,950	----
	Grand Total, B/SD 1/	8,900	----	405,940	----	503,280	----

1/ B/CD ÷ 0.90 = B/SD

TABLE 9

1981 ESTIMATED TOTAL CATALYTIC SULFUR REMOVING HYDROPROCESSING
PAD DISTRICTS I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day

Catalytic Hydrocracking		Catalytic Hydrorefining		Catalytic Hydrotreating				
Bbl/SD 2/	% of Crude Oil Oper. Cap.	Bbl/SD 2/	% of Crude Oil Oper. Cap.	Bbl/SD 2/	% of Crude Oil Oper. Cap.	Grand Total	Total Crude Oil 1/ Operating Capacity	Hydroprocessing Capacity As % of Total Oper. Cap.
902,080	5.0	2,234,110	12.3	5,757,800	31.7	8,894,000	18,192,000	48.9

1/ June 1977, "Trends in Refinery Capacity and Utilization,"
1980 Operable Capacity x 0.95 ÷ 0.95.

2/ 1977 Capacity from Table 7 plus estimated expansions from Table 8.

TABLE 10

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICT I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day (As of January 1 of Indicated Year)

		Catalytic Hydrocracking 2/			
PAD District	Year	Distillate Upgrading	Residual Upgrading	Other	Sub-Total
I	1973	47,000	---	---	47,000
	1974	47,000	---	---	47,000
	1975	47,000	---	20,000	67,000
	1976	47,000	---	21,000	68,000
	1977	47,000	---	23,500	70,500
II	1973	156,650	---	---	156,650
	1974	155,950	---	---	155,950
	1975	100,000	---	56,000	156,000
	1976	100,000	---	57,000	157,100
	1977	100,190	---	55,000	155,190
III	1973	286,066	12,000	---	298,066
	1974	281,166	3,000	---	284,166
	1975	286,166	---	---	286,166
	1976	297,166	---	---	297,166
	1977	298,666	---	---	298,666
IV	1973	5,400	---	---	5,400
	1974	5,900	---	---	5,900
	1975	5,900	---	120	6,020
	1976	5,900	---	120	6,020
	1977	4,900	1,000	---	5,900
V	1973	350,722	---	---	350,722
	1974	326,622	---	26,000	352,622
	1975	328,622	---	26,000	354,622
	1976	328,822	---	26,000	354,822
	1977	332,922	---	30,000	362,922
Total: I-V	1973	845,838	12,000	---	857,838
	1974	816,638	3,000	26,000	845,638
	1975	767,688	---	102,120	869,808
	1976	778,988	---	104,120	883,108
	1977	783,678	1,000	108,500	893,178

Footnotes at end of table.

TABLE 10

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICT I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day (As of January 1 of Indicated Year)
(Continued)

		Catalytic Hydrorefining					
PAD District	Year	Residual Desulfur.	Heavy Gas Oil Desulfur.	Cat. Cracker and Cycle Stock	Middle Distillates	Other	Sub-Total
I	1973	---	50,000	20,000	94,000	---	164,000
	1974	---	82,000	20,000	102,200	4,440	208,640
	1975	---	82,000	60,000	101,000	4,440	247,440
	1976	---	130,000	60,000	101,000	4,440	295,440
	1977	---	133,000	64,000	105,000	4,440	306,440
II	1973	---	---	68,300	52,500	5,000	125,800
	1974	4,500	---	88,300	133,200	10,500	236,500
	1975	---	---	85,800	132,700	10,500	229,000
	1976	---	---	82,000	131,300	11,160	224,460
	1977	---	20,000	122,500	100,800	6,000	249,300
III	1973	12,500	103,500	114,000	129,000	20,000	379,000
	1974	6,000	48,000	135,000	204,500	---	393,500
	1975	6,000	73,000	105,000	245,000	---	429,000
	1976	6,000	112,000	134,000	299,000	---	551,000
	1977	6,000	127,500	259,200	411,300	48,900	852,900
IV	1973	7,000	---	15,444	15,750	7,500	45,694
	1974	---	---	15,444	5,500	1,500	22,444
	1975	---	---	16,644	5,500	---	22,144
	1976	---	---	16,644	19,500	---	36,144
	1977	---	---	16,644	19,500	4,444	40,588
V	1973	---	30,500	58,500	37,000	---	126,000
	1974	---	30,000	80,944	47,800	---	158,744
	1975	---	31,000	80,944	47,800	---	159,744
	1976	---	41,000	80,944	47,800	---	169,744
	1977	24,000	164,000	72,944	111,000	7,000	378,944
Total: I-V	1973	19,500	184,000	276,244	328,250	32,500	840,494
	1974	10,500	160,000	339,688	493,200	16,440	1,019,828
	1975	6,000	186,000	348,388	532,000	14,940	1,087,328
	1976	6,000	283,000	373,588	598,600	15,600	1,276,788
	1977	30,000	444,500	535,288	747,600	70,784	1,828,172

Footnotes at end of table.

TABLE 10

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICT I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day (As of January 1 of Indicated Year)
(Continued)

PAD District	Year	Catalytic Hydrotreating 3/ Pretreat Cat. Reformer Feeds	Naphtha Desulfur.	Straight-Run Distillate	Other Distillates	Other	Sub-Total
I	1973	368,804	67,500	103,000	111,111	17,500	667,915
	1974	379,748	24,500	60,500	153,555	---	618,303
	1975	390,648	51,500	81,500	144,555	13,000	681,203
	1976	400,648	66,500	92,055	179,000	28,000	766,203
	1977	372,148	126,500	66,500	223,555	13,000	801,703
II	1973	617,115	122,300	44,700	136,000	133,700	1,053,815
	1974	777,865	126,400	83,500	159,500	24,700	1,171,965
	1975	790,565	88,700	79,500	182,976	68,500	1,210,241
	1976	870,690	82,700	60,788	201,966	92,300	1,308,444
	1977	857,990	84,700	80,400	278,164	71,300	1,372,554
III	1973	977,059	233,811	30,600	271,000	110,529	1,622,999
	1974	1,107,206	207,811	77,200	322,300	117,961	1,832,478
	1975	1,044,209	233,100	150,911	332,000	69,601	1,829,821
	1976	1,150,809	175,100	167,522	249,700	153,950	1,897,081
	1977	1,189,009	150,500	225,022	444,800	21,000	2,030,331
IV	1973	38,000	22,750	7,044	7,700	55,000	130,494
	1974	55,094	30,850	37,200	25,400	39,000	187,544
	1975	70,644	19,250	25,800	37,900	40,500	194,094
	1976	87,644	19,250	27,200	3,500	39,500	177,094
	1977	85,444	22,750	27,200	22,500	39,500	197,394
V	1973	348,910	125,500	12,000	173,500	70,000	729,910
	1974	313,122	198,177	12,000	183,000	65,000	771,299
	1975	319,322	173,100	39,777	195,588	43,000	770,787
	1976	350,722	178,700	58,665	155,700	64,000	807,787
	1977	393,622	187,700	27,777	199,188	44,250	852,537
Total: I-V	1973	2,349,888	571,861	197,344	699,311	386,729	4,205,133
	1974	2,633,035	587,738	270,400	843,755	246,661	4,581,589
	1975	2,615,388	565,650	377,488	893,019	234,601	4,686,146
	1976	2,860,513	522,250	406,230	789,866	377,750	4,956,609
	1977	2,898,213	572,150	426,899	1,168,207	189,050	5,254,519

Footnotes at end of table.

TABLE 10

U.S. REFINERS CATALYTIC SULFUR REMOVING HYDROPROCESSING 1/
PAD DISTRICT I-V (Including Hawaiian Trade Zone)
Barrels Per Stream Day (As of January 1 of Indicated Year)
(Continued)

Summary Catalytic Hydrocracking, Hydrorefining & Hydrotreating

PAD District	Year	Grand Total Hydro-Processing	Operating 4/ Refinery Capacity January 1 (BBL/CD)	Operating 5/ Refinery Capacity January 1 (BBL/SD)	Hydro-Processing Capacity As % of Total Refinery Capacity
I	1973	878,915	1,602,000	1,686,000	52.1
	1974	873,943	1,674,000	1,762,000	49.6
	1975	995,643	1,618,000	1,703,000	58.5
	1976	1,129,643	1,677,000	1,765,000	64.0
	1977	1,178,643	1,783,000	1,877,000	62.8
II	1973	1,336,265	3,664,000	3,836,000	34.8
	1974	1,564,415	3,889,000	4,094,000	38.2
	1975	1,595,241	4,010,000	4,221,000	37.8
	1976	1,690,014	4,137,000	4,355,000	38.8
	1977	1,777,044	4,145,000	4,363,000	40.7
III	1973	2,300,065	5,532,000	5,823,000	39.4
	1974	2,510,144	5,933,000	6,245,000	40.2
	1975	2,544,987	6,211,000	6,538,000	38.9
	1976	2,745,247	6,197,000	6,523,000	42.1
	1977	3,181,897	6,838,000	7,198,000	44.2
IV	1973	181,588	453,000	477,000	38.1
	1974	215,888	506,000	533,000	40.5
	1975	222,258	548,000	577,000	38.5
	1976	219,258	552,000	581,000	37.7
	1977	243,882	546,000	575,000	42.4
V	1973	1,206,632	2,234,000	2,352,000	51.3
	1974	1,282,665	2,259,000	2,378,000	53.9
	1975	1,285,153	2,349,000	2,473,000	52.0
	1976	1,332,353	2,364,000	2,488,000	53.6
	1977	1,594,403	2,609,000	2,746,000	58.1
Total: I-V	1973	5,903,465	13,485,000	14,195,000	41.6
	1974	6,447,055	14,261,000	15,012,000	43.0
	1975	6,643,282	14,736,000	15,512,000	42.8
	1976	7,116,505	14,927,000	15,713,000	45.3
	1977	7,975,869	15,921,000	16,759,000	47.6

1/ Basis: Oil and Gas Journal, Annual Refining Issues, March 28, 1977, March 29, 1976, April 17, 1975, April 1, 1974, April 2, 1973.

2/ Does not include lube oil manufacture.

3/ Does not include naphtha olefin, aromatics saturation, or lube oil polishing.

4/ "Trends in Refinery Capacity and Utilization," Table 1, June 1977, Department of Energy publication.

5/ Converted to stream days by 0.95 factor.

TABLE 11

CARIBBEAN "EXPORT" REFINERIES CATALYTIC SULFUR REMOVING HYDROPROCESSING, 1973-1977
Barrels Per Calendar Day
(As of January 1 of Indicated Year)

Year	Country or Other	Catalytic Hydrocracking 1/ Distillate	Residual	% of Crude Oil Capacity	Catalytic Hydrorefining 1/ Capacity	% of Crude Oil Capacity	Catalytic Hydrotreating 1/ Capacity	% of Crude Oil Capacity	Total	Crude Oil Capacities 2/	Catalytic Hydroprocessing As % of Crude Oil Capacity
1977	Antigua	---	---	---	---	SHUTDOWN	---	---	---	---	
	Bahamas	---	---	---	60,000	---	---	---	---	500,000	
	Netherland Antilles	---	---	---	185,600	---	217,700	---	---	810,000	
	Panama	---	---	---	---	---	30,000	---	---	100,000	
	Puerto Rico	---	---	---	107,700		21,000			283,800	
	Trinidad	---	---	---	80,000	---	67,000	---	---	461,000	
	Venezuela	---	---	---	277,800	---	45,900	---	---	1,423,000	
	Virgin Islands	---	---	---	150,000	---	---	---	---	700,000	
	Total, B/CD	---	---	---	861,100	20.1	381,600	8.9	1,242,700	4,277,800	29.0
	Total, B/SD 3/	---	---	---	956,800		424,000		1,380,800		
1976	Antigua	---	---	---	---	SHUTDOWN	---	---	---	---	
	Bahamas	---	---	---	60,000	---	---	---	---	500,000	
	Netherland Antilles	---	---	---	185,600	---	217,700	---	---	810,000	
	Panama	---	---	---	---	---	30,000	---	---	100,000	
	Puerto Rico	---	---	---	106,400	---	18,000	---	---	283,800	
	Trinidad	---	---	---	80,000	---	67,000	---	---	461,000	
	Venezuela	---	---	---	257,000	---	50,000	---	---	1,423,000	
	Virgin Islands	---	---	---	150,000	---	---	---	---	700,000	
	Total, B/CD	---	---	---	839,000	19.6	382,700	8.9	1,221,700	4,277,800	28.6
	Total, B/SD	---	---	---	932,200		425,200		1,357,400		
1975	Antigua	---	---	---	7,500	---	---	---	---	17,300	
	Bahamas	---	---	---	---	---	---	---	---	500,000	
	Netherland Antilles	---	---	---	140,000	---	223,000	---	---	900,000	
	Panama	---	---	---		---	30,000	---	---	100,000	
	Puerto Rico	---	---	---	112,400	---	12,000	---	---	283,800	
	Trinidad	---	---	---	80,000	---	67,000	---	---	461,000	
	Venezuela	---	---	---	262,000	---	67,000	---	---	1,523,000	
	Virgin Islands	---	---	---	93,600	---	---	---	---	590,000	
	Total, B/CD	---	---	---	695,500	15.9	399,000	9.1	1,094,500	4,375,100	25.0
	Total, B/SD	---	---	---	772,800		443,300		1,216,100		

Footnotes at end of table.

TABLE 11

CARIBBEAN "EXPORT" REFINERIES CATALYTIC SULFUR REMOVING HYDROPROCESSING, 1973-1977
Barrels Per Calendar Day
(As of January 1 of Indicated Year)

Year	Country or Other	Catalytic Hydrocracking 1/			Catalytic Hydrorefining 1/		Catalytic Hydrotreating 1/		Total	Crude Oil Capacities 2/	Catalytic Hydroprocessing As % of Crude Oil Capacity
		Distillate	Residual	% of Crude Oil Capacity	Capacity	% of Crude Oil Capacity	Capacity	% of Crude Oil Capacity			
1974	Antigua	---	---	---	4,800	---	2,020	---	---	17,300	
	Bahamas	---	---	---	---	---	---	---	---	500,000	
	Netherlands Antilles	---	---	---	95,000	---	237,500	---	---	945,000	
	Panama	---	---	---	---	---	30,000	---	---	75,000	
	Puerto Rico	---	---	---	8,300	---	116,100	---	---	305,000	
	Trinidad	---	---	---	80,000	---	67,000	---	---	436,000	
	Venezuela	---	---	---	261,000	---	50,000	---	---	1,504,000	
	Virgin Islands	---	---	---	93,600	---	---	---	---	590,000	
	Total, B/CD	---	---	---	542,700	12.4	502,620	11.5	1,045,320	4,372,300	23.9
	Total, B/SD	---	---	---	603,000		558,500		1,161,500		
1973	Antigua	---	---	---	4,800	---	2,000	---	---	17,300	
	Bahamas	---	---	---	---	---	---	---	---	250,000	
	Netherlands Antilles	---	---	---	95,000	---	129,000	---	---	880,000	
	Panama	---	---	---	---	---	30,000	---	---	75,000	
	Puerto Rico	11,200	---	---	19,300	---	108,600	---	---	260,000	
	Trinidad	---	---	---	80,000	---	64,000	---	---	436,000	
	Venezuela	---	---	---	251,000	---	68,500	---	---	1,499,000	
	Virgin Islands	---	---	---	48,600	---	28,800	---	---	418,000	
	Total, B/CD	11,200	---	---	498,700	13.0	430,900	11.2	940,800	3,835,300	24.5
	Total, B/SD	12,400	---	---	554,100		478,800		1,032,900		

1/ "Oil and Gas Journal," December 27, 1976; December 29, 1975; December 30, 1974; December 31, 1973; December 25, 1972, "Worldwide Reports."

2/ Trends in Refinery Capacity and Utilization, June 1977, June 1976, June 1975, June 1974, Department of Energy publications.

3/ Barrels/CD/.90

TABLE 12

CARIBBEAN "EXPORT" REFINERIES PROJECTED CATALYTIC SULFUR REMOVING HYDROPROCESSING
Barrels Per Calendar Day and Estimated On-Stream Date
(As of January 1 of Indicated Year)
Basis: Oil and Gas Journal, April 25, 1977

Country or Territory	Catalytic Hydrocracking		Catalytic Hydrorefining		Catalytic Hydrotreating	
	Bbl/CD	On-Stream	Bbl/CD	On-Stream	Bbl/CD	On-Stream
Virgin Islands	----	----	100,000	After 1980	45,000	After 1980

TABLE 13

CARIBBEAN "EXPORT" REFINERIES 1980 ESTIMATED TOTAL CATALYTIC SULFUR REMOVING HYDROPROCESSING

Barrels Per Calendar Day

Catalytic Hydrocracking		Catalytic Hydrorefining		Catalytic Hydrotreating				
Bbl/CD	% of Crude Oil Capacity	Bbl/CD	% of Crude Oil Capacity	Bbl/CD	% of Crude Oil Capacity	Total	Crude Oil Operating Capacity 2/	Catalytic Hydroprocessing As % of Crude Oil Oper. Cap.
----	----	861,100 1/ (956,800 B/SD)	18.6	381,600 1/ (424,000 B/SD)	8.2	1,242,700 (1,380,800 B/SD)	4,627,800	26.8

1/ Basis: Table 11.

2/ "Trends in Refinery Capacity and Utilization," June 1977, Department of Energy publication.

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