U.S. Petroleum Refining

Meeting Requirements for Cleaner Fuels and Refineries

Volume II—General Information Appendices

National Petroleum Council
August 1993

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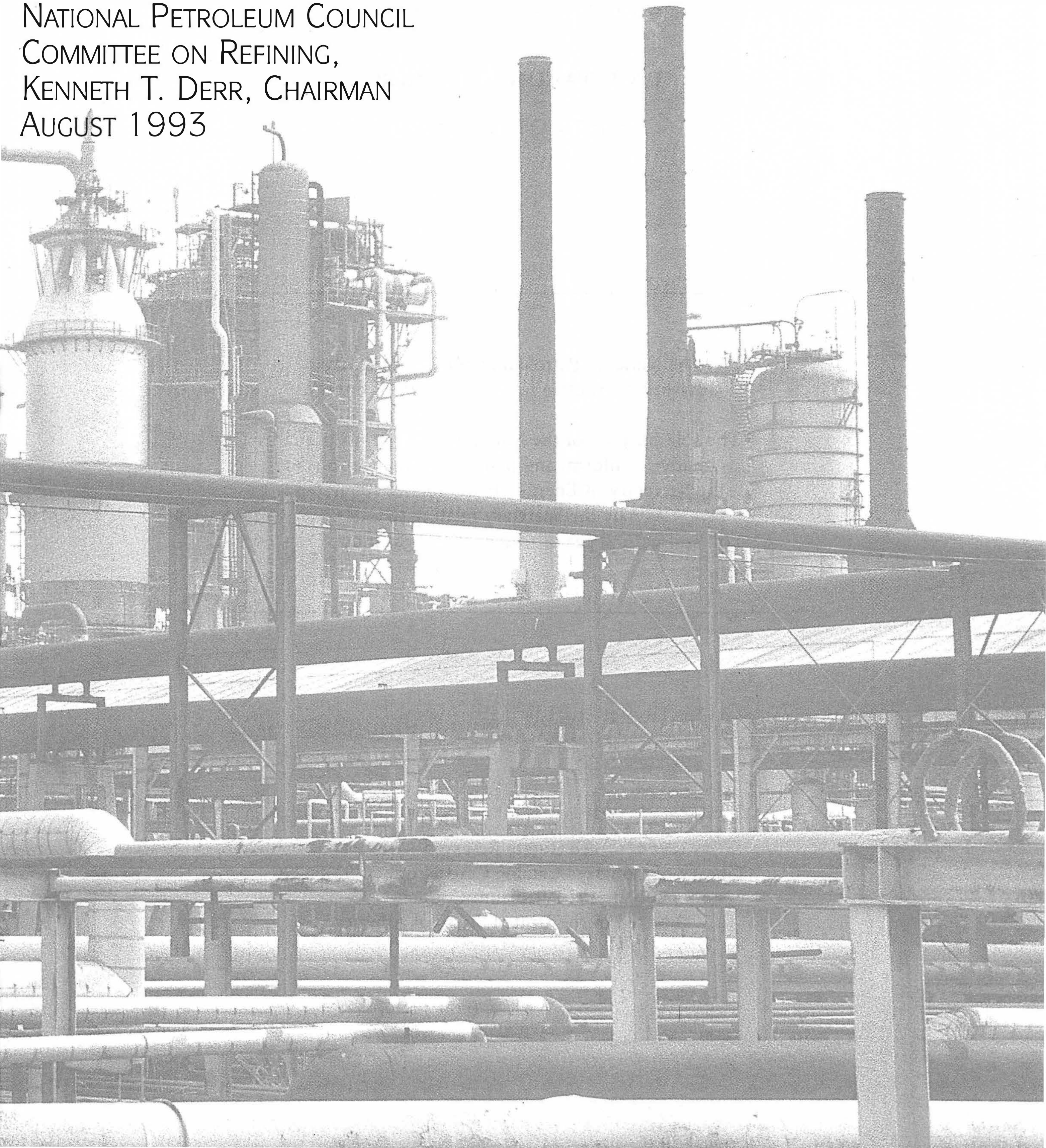
National Petroleum Council
Committee on Refining,
Kenneth T. Derr, Chairman
August 1993



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APPENDIX E

ALTERNATIVE TRANSPORTATION FUELS

SUMMARY

This report was developed by the National Petroleum Council Refining Study's Alternative Transportation Fuels Ad Hoc Group. The group was charged by the Coordinating Subcommittee with the development of a qualitative comparison of methanol, ethanol, compressed natural gas (CNG), liquefied natural gas (LNG), liquefied petroleum gas (LPG), and electric vehicles, and an assessment of their strengths and weaknesses in relation to reformulated gasoline (RFG). The comparison focuses on: the status of vehicle, supply/energy security, logistics, environmental impact, and consumer cost and issues.

For significant penetration of the gasoline market by any of these alternative fuels to occur, infrastructure for distribution and retailing of the new fuel must be put in place. For some of these fuels, a new system is required; others require major revision or extension of the current system. In either case, potential suppliers would have to be willing to invest very large capital sums on infrastructure well ahead and in anticipation of market demand developing. The introduction of the alternative fuel vehicles is subject to similar restraints. The cost comparisons presented in this report are meaningful and representative only for the situation existing after such startup hurdles have been surmounted.

The data presented in this report are from publicly available sources, which are used as a basis for the information provided in Table E-1. The comparison table covers the 1995-2010 time frame and the chart was constructed with the following bases: fuel costs were exclusive of excise taxes and subsidies, and generally based on self-service at the station; a mid-range of 7 cents per gallon (range of 4 to 9 cents) was added to the price of conventional unleaded gasoline to reflect the cost of reformulation; vehicles are based upon expected technology in the target time frame, high volume original equipment manufacture (OEM) light-duty vehicles, and not retrofit; and costs are expressed in 1990 dollars. The reformulated gasoline used for base case comparisons is that defined by the 1990 Clean Air Act Amendments as that required to be available in 1995. While more stringent reformulations are under consideration, they are not addressed in this report. Global warming is currently under study and, therefore, a comparison of greenhouse gas emissions is included.

The vehicle and fuel costs show a wide range for some fuels, reflecting the broad range of opinions in the literature and the uncertainties inherent in the estimates. Fuel supply and logistics costs for conventional gasoline, RFG, and ethanol that are included are consistent with those developed in the Refining Study. The ranges quoted for vehicle costs include estimates from multiple sources that are cross-referenced in the literature. Fuel cost estimates include all estimates found that give credible value to resources and capital. Attachment 1 includes detailed sources.

While the impetus for developing a comparison of alternative fuels to reformulated gasoline can be tied to the Clean Air Act Amendments of 1990, there are other legislative and regulatory events currently under consideration. For example, the National Energy Policy Act of 1992 includes provisions for utilizing alternative fuels and it appears that a number of states may adopt the more stringent California motor vehicle standards. These actions make understanding the alternative fuels issues important for the NPC's study of the future of U.S. refining.

A discussion of the comparative analysis follows.

TABLE E-1. ALTERNATIVE TRANSPORTATION FUELS COMPARISONS

	Methanol		Ethanol	
	M85	M100	E85	E100
Status of Vehicle:				
Technology Readiness	Available in a few engine types	Demonstrated with a few engine types	Demonstrated with a few engine types	Demonstrated with a few engine types
Incremental Cost (compared to reformulated gasoline vehicles)				
Initial Vehicle	$200 - $400+ *	$200 - $400+ *	$200 - $400+ *	$200 - $400+ *
Maintenance	Similar to possibly higher	Similar to possibly higher	Similar to possibly higher	Similar to possibly higher
Vehicle efficiency relative to reformulated gasoline	0 - 5% better (FFV)	10 - 15% better (fuel optimized vehicle)	0 - 5% better (FFV)	10 - 15% better (fuel optimized vehicle)
Quantity of fuel required to go the same distance as a conventional vehicle running on one gallon of reformulated gasoline	1.6 - 1.7 gallons	1.7 - 1.8 gallons	1.3 - 1.4 gallons	1.3 - 1.4 gallons
Consumer Issues:				
Reliability	Must prove	Must prove	Must prove	Must prove
Performance	Driveability (hesitation, stalling) are concerns but higher octane.	Starting vehicle in cold weather must be improved. Driveability (hesitation, stalling) are concerns.	Driveability (hesitation, stalling) are concerns.	Starting vehicle in cold weather must be improved. Driveability (hesitation, stalling) are concerns.
Convenience	Consumer visits station to refuel twice as much.	Consumer visits station to refuel twice as much.	More frequent refueling.	More frequent refueling.
General Safety and Toxicity	Higher hazard than RFG.	Higher hazard than RFG.	About equal to RFG.	About equal to RFG.
Supply:				
Domestic/Import	Import	Import	Domestic	Domestic
Import Diversity	Limited	Limited		
Supply Capability (with investment)	Sufficient	Sufficient	Subject to Agricultural Limits	Subject to Agricultural Limits
Costs: 1990 $				
U.S. Bulk Commodity Quantities				
Unit	gal	gal	gal	gal
$/Unit	0.49 - 0.79	0.46 - 0.75	0.99 - 1.49	1.05 - 1.58
$/gal RFG Equiv. (RFG = $0.70 - $1.07/gal)	0.85 - 1.38	0.93 - 1.51	1.38 - 2.09	1.58 - 2.38

Natural Gas			Electricity	
CNG	LNG	LPG	Battery	Hybrid
Available in a few engine types	Prototype fuel systems	Mature. Application of CNG engine research will help LPG meet future emissions regulations	Prototype	Concept
$600 - $1200	Extremely limited data	$150 - $675	$1200 - $4000 (lead-acid battery)	Limited information; likely higher than battery-only electric vehicle
Similar to possibly lower	Unknown though probably higher than CNG	Similar	$2000 - $4000 every 3+ years for battery replacement; other maintenance costs probably lower.	$2000 - $4000 every 3+ years for battery replacement
0 - 5% better	0 - 5% better	Similar to slightly worse	50 - 60% better (not including power plant generation and transmission losses).	Between battery-powered electric vehicle and RFG
110 - 120 SCF	1.4 gallons	1.3 gallons	14 - 16 kwh	Not available
High acceptance by current users	Testing underway.	High acceptance	Potential for uncharged batteries	Potential for uncharged batteries
Limited range.	Limited range.	Less range than RFG.	Poorer range. Quiet operation.	Range equal while engine/generator in use. Quiet operation.
More frequent refueling and more refueling time.	Testing underway.	More time refueling.	Quick recharge at station or long recharge time.	Recharge at home. Modified driving habits.
Better than RFG.	Testing underway.	Better than RFG.	High voltage (240+).	High voltage (240+).
Both	Imported	Imported	Domestic	Unknown
Limited	Limited	Severely Limited		
Sufficient	Sufficient	Subject to NGL Resource Limits	Sufficient	
k cu. ft.		gal	kwh	
3.08 - 6.35	Higher than CNG	0.24 - 0.40	.052 - .087	Unknown
0.38 - 0.78	Limited Data	0.34 - 0.57	1.74 - 2.90	

TABLE E-1. ALTERNATIVE TRANSPORTATION FUELS COMPARISONS (Continued)

	Methanol		Ethanol	
	M85	M100	E85	E100
Energy Security **Relative Ranking to RFG**	Gas from North American sources improves security. Other sources do not.	Gas from North American sources improves security. Other sources do not.	Security improved. Only domestic feedstocks used.	Security improved. Only domestic feedstocks used.
Logistics:				
Transportation System	New Liquid	New Liquid	New Liquid	New Liquid
Distribution and Marketing Costs $/gal of RFG Equivalent (RFG = $0.20/gal**)	0.37 - 0.45	0.39 - 0.47	0.30 - 0.36	0.30 - 0.36
Environmental Impact **(RFG = 100):**				
Vehicle Emissions Only				
Non-Methane Organic Gas (NMOG)	100	70 - 100	100	100
NOx	100	100	100	100
CO	100	100	100	100
Air Toxics				
Formaldehyde	800	1000	0-300	0-300
Benzene	25	?	25	?
1,3-Butadiene	10	?	10	?
			Acetaldehyde 500 - 700	Acetaldehyde 500 - 700
Greenhouse Gases	96 - 198	96 - 198	94 - 115	94 - 115
Spill potential from Manuf., Storage, and Transportation	Relative to crude, less risk. At retail outlet, more risk.	Relative to crude, less risk. At retail outlet, more risk.	No worse than RFG.	Less risk.
Consumer Cost: (Delta Relative to RFG)				
Cents per Mile (RFG = 34.6 - 35.9)	1.4 - 2.2	1.3 - 2.0	3.1 - 4.4	3.1 - 4.4
$/RFG Equivalent Gallon (RFG = 9.52 - 9.88)	0.39 - 0.61	0.36 - 0.56	0.85 - 1.20	0.87 - 1.21
$ Per Year (RFG = 4120 - 4280)	170 - 260	150 - 240	370 - 520	380 - 520
Total Cost – % of RFG	4 - 6	4 - 6	9 - 12	9 - 12
Fuel Only Cost – % of RFG	95 - (5)	90 - (5)	160 - 30	160 - 30

* Some references suggest these costs may be higher, but do not give a higher number.

** $0.12/gallon = distribution to retail station; $0.08/gallon = gross retail margin.

*** Currently reported levels. Development work is ongoing and could result in lower levels.

Natural Gas			Electricity	
CNG	LNG	LPG	Battery	Hybrid
Gas from North American sources improves security. Other sources do not.	Gas from North American sources improves security. Other sources do not.	Same	Security Improved	Security Improved
Extended Gas	New Cryogenic	Extended Liquid	Extended Electrical	Extended Electrical
0.24 - 0.36	Data Not Available	0.28 - 0.46	0.29 - 0.36	0.29 - 0.36
			(assumes generation from coal)	(assumes generation from coal)
40 - 60	40 - 60	100	0	Unknown
100	100	100	0	Unknown
15-40 ***	15-40 ***	15-40 ***	0	Unknown
100	100	100		
0	0	0	0	Unknown
0	0	0		
50 - 100	50 - 100	80	110	110
Considerably less risk.	Considerably less risk.	Considerably less risk.	Battery and electrolyte handling	Combination of RFG and battery risks
(0.3) - 0.8	Not Available	(0.8) - 0	7.6 - 16.4	Not Available
(0.07) - 0.23	Not Available	(0.23) - 0	2.08 - 4.52	Not Available
(30) - 100	Not Available	(100) - 0	900 - 1960	Not Available
(1) - 2	Not Available	(2) - 0	22 - 46	Not Available
(30) - (15)	Not Available	(30) - (20)	13 - 2	Not Available

Status of Vehicle

Automakers are currently offering a limited number of cars and light duty trucks able to run on M85. The use of undiluted methanol is further in the future. The experience with the ethanol vehicle in meeting U.S. emissions requirements is very limited; however, there has been significant use in the United States of low concentrations of ethanol blended with gasoline in cars without modifications. CNG vehicles are currently being manufactured in the United States, Europe, and Japan. There are currently over 30,000 vehicles in the United States (out of a total of 188 million vehicles) modified to operate on CNG, 750,000 worldwide. A CNG vehicle will cost more to purchase though it could cost less to maintain than an RFG vehicle due to the fuel's combustion characteristics. While there are LNG prototypes being tested, experience with this vehicle type is very limited. LPG technology is commercial, but engine design meeting stringent vehicle emissions and efficiency standards is not. Like CNG, the clean burning nature of LPG could give it an edge over RFG in engine maintenance. There are many electric vehicle prototypes currently being assessed. However, the battery technology needs more research and development for consumer acceptance of the vehicle.

The technology necessary to control NOx to mandated standards for LPG, M100, and E100 vehicles is not clearly defined in the literature. This comparison assumes that control must be in place for the vehicles to be utilized. However, the cost required is not available. Vehicle costs for these fuels may be understated as a result. The technology for controlling NOx in CNG vehicles has been developed (Reference 55).

Supply/Energy Security

Methanol and LPG offer little improvement in supply/energy security over RFG. These alternative fuels exhibit supply characteristics similar to RFG in that imports are likely required or would be required particularly as demand increased. Incremental use of LPG is also restricted because its resource base is smaller than oil, gas, or coal. To the extent that spare natural gas capacity in North America is used, energy security benefits could be improved as CNG, LNG, and methanol reduce oil demand. Both ethanol and electricity warrant further discussion. Current ethanol production is energy intensive and is subject to agricultural limitations. Electricity could provide the greatest improvement in energy security of all alternatives depending on the acceptability of coal and nuclear power. This study did not address the acceptability of expanding the use of those fuels.

Logistics

Major new distribution networks and extensive changes in the existing fuel infrastructure would be required to support significant methanol, ethanol, and LPG use. Increased volumes and product incompatibility with RFG would require large capital investments to support these alternative fuels. LNG would require cryogenic tank trucks, rail cars, and barges for transport and cryogenic storage at the distribution facility. On the other hand, the distribution networks for both CNG and electricity are highly developed in the United States. Natural gas pipelines currently supply gas to most major geographical regions of the contiguous United States. Dispensing equipment (compression, liquids removal, storage, meter) would need to be added to the point of sale (e.g., service stations) since only a few pioneering CNG stations exist in the United States. Significant numbers of electric vehicles could be supplied power from within the existing generation network, but recharging facilities will need to be installed.

Consumer Issues

Range is a key issue for consumers when comparing alternative fueled vehicles to conventional fueled vehicles and/or to each other. For the same volume of fuel an LPG fueled vehicle would travel about 75% as far as a conventional fueled vehicle; an ethanol vehicle about 70% as far; a methanol vehicle about 60% as far; and a CNG vehicle about 25% as far. The range of current electric vehicles is only half that of CNG vehicles.

Refueling frequency/time is also somewhat of a concern with each fuel. This problem is greatest with the battery electric vehicle and less of a problem with the other fuels.

Other characteristics are unique for each fuel. LPG has higher octane, good performance, and better hardware durability than conventional fuel. Methanol has higher octane, but cold start problems require attention. Ethanol has intermediate octane between methanol and RFG, also has cold start problems, but is less toxic than methanol or RFG.

Current users express satisfaction with CNG (Reference 43) except for the range limitation. Trunk space could be less, particularly in smaller vehicles, due to the large fuel tanks required. The inconvenience of connecting and disconnecting the electric charger daily for electric vehicles could require consumer adjustment.

From a safety standpoint, ethanol, CNG, and LPG are generally viewed by current users as no worse than gasoline. The toxicity, flame visibility, and potential fuel tank explosive mixtures associated with methanol give it a higher risk level than RFG. Testing is underway by fleet operators such as Houston Metropolitan Transit Authority to identify general safety issues for LNG.

Environmental Impact

In the simplest terms, the air quality effects of using alternative fuel vehicles depend on both the quantity and the composition of their emissions compared to the gasoline vehicles for which they would be substituted. This requires comparisons of vehicles of comparable technology development and assessments of the vehicle exhaust, evaporative emissions, and refueling emissions over their lifetime in the hands of the consumer.

The primary air quality thrust for the use of alternative fuels is a claimed effectiveness in reducing urban ozone. This claim rests on both the mass of vehicle emissions as well as the reactivity of the organic emissions, and their combination is sometimes used as a predictor of ozone. The vehicle contribution to ozone formation is, however, more complex and is also dependent upon the other vehicle emissions, particularly NOx, and the existing local atmospheric conditions. Air modeling of the atmospheric chemical reactions is the accepted way to predict the effect vehicle emission changes will have on atmospheric ozone.

It is these aspects and the uncertainty that lead to such a divergence of opinion in the technical community of the potential benefits of alternative fuels vis-a-vis gasoline, as exemplified by EPA's projections of up to 80 percent reduction in ozone-forming potential for methanol as contrasted to possible increases as projected by the Office of Technology Assessment and Sierra Research. However, a coordinated effort of the auto and oil industries is ongoing and additional information will be made available. Keeping this in mind, the following environmental comparison is offered.

CNG, LNG, and LPG offer some environmental advantages over RFG. The long term impact of fuel spills is minimal. It also appears that engine and catalyst converter technology will be available to allow vehicles using these fuels to be designed to meet the same emission standards set for RFG-fueled vehicles. Some automakers already have CNG-fueled prototypes that appear capable of meeting California ULEV standards, though they have not been tested long enough to know that they can meet the 1,000 mile durability requirement. Both methanol and ethanol exhibit similar emission characteristics in that their criteria pollutants are in RFG's range, but these alternative fuels have significantly higher aldehyde emissions. While the battery-powered electric car itself emits no pollutants, the source of incremental electricity must be considered. The ultimate level of emissions from power plants used to generate incremental electricity for vehicle consumption would be a function of the type of utility plant. NOx and SOx emissions will be limited by the more stringent controls required by the 1990 Clean Air Act. These controls will increase the cost of electricity above current rates. CO_2 emissions will be higher per mile driven than RFG vehicles if coal-fired power plants are considered. Conversely, natural gas and non-fossil fueled plants will lower CO_2 levels. Further, used battery materials from electric vehicles may cause a major disposal problem.

Consumer Cost

This comparison combines the fuel costs, annualized vehicle purchase costs (with interest), maintenance costs, and other costs (insurance, registration, and license) to show the total impact on the consumer. For this comparison, average driving data published by the American Automobile Association (AAA) are used to estimate annual mileage driven. A detailed analysis is provided in Attachment 1.

Fuel consumption per mile comparisons are based on current average new car efficiency (EPA test) of 27.5 miles per gallon. Alternative fuel vehicle fuel efficiencies are applied relative to this level of energy consumption. If a higher base efficiency is assumed, the vehicle costs weigh more heavily and the fuel costs are less important for a given fuel. Assuming a lower efficiency increases the impact of fuel costs and reduces the impact of vehicle costs.

Vehicle manufacturers are allowed a corporate average fuel economy (CAFE) credit for producing and selling alternative fuel vehicles. This credit is capped for flexible-fuel vehicles. How this CAFE credit might impact vehicle prices is not clear from the literature. Hence, this analysis makes no adjustment for this CAFE credit.

Table E-1 shows that both CNG and LPG have the potential to be no more costly to the consumer than RFG. This is mainly due to the lower fuel costs associated with these alternatives. Because of its significantly lower energy content and higher logistic costs, methanol would cost more than RFG. Ethanol would cost significantly more than RFG or methanol due to energy intensive fuel production costs. Electric vehicles incur high costs for purchasing and replacing the battery pack. However, the range of costs for some fuels is wide, reflecting the uncertainty of these costs, and an increase in fuel demand could significantly alter these cost comparisons.

The data on LNG vehicles and hybrid electric vehicles are too preliminary to make a valid cost comparison.

Closing Comments

The American consumer is accustomed to the reliability and convenience of the gasoline-powered automobile. A survey sponsored by the Motor Vehicle Manufacturers Association indicates that Americans will be reluctant to buy cars powered by alternative fuels until they have confidence in the technology (Reference 43).

METHANOL

Methanol has long been accepted as a racing fuel. Its superior octane and flame characteristics, and high heat of vaporization, allow engine design changes that result in more power for the same engine weight.

Race car drivers and crews have learned to cope with methanol's drawbacks. They have developed quick refueling techniques and strategies to deal with its reduced range. Cold starting is not a problem since racing is generally done during mild weather to draw crowds. The engines are also frequently preheated for other reasons. Its cost relative to the cost of the specialized race cars is insignificant. Since drivers and crews wear flame-resistant suits, concern over methanol's invisible flame is greatly mitigated.

Status of Vehicle

Methanol engine technology has developed to the point where automakers currently offer a limited number of cars and light duty trucks able to run on M85 or gasoline, or any mixture of the two. M85 is 85 percent methanol and 15 percent gasoline-boiling-range hydrocarbon material to improve cold start properties and flame visibility. Limited production runs of these vehicles have put over 1,000 vehicles in service. These are primarily in government agency fleets.

These vehicles have generally performed satisfactorily although the early versions have experienced some problems relating to engine wear and corrosion, cold starting, and higher-than-claimed emissions (References 28, 29, 39). It is not known if the current versions have completely eliminated these problems. Research is continuing at automakers and fuel suppliers to assure that these problems have been solved for the life of the vehicle before M85-capable vehicles will be aggressively sold to the general public.

Use of undiluted methanol (usually called M100) is further in the future. Cold starting problems and safety issues, like flame invisibility and the potential for explosive mixtures in the fuel tank under certain conditions, have not been fully resolved (Reference 30). The potential to sell M100-dedicated vehicles is also less since they would not run satisfactorily on reformulated gasoline or diesel fuel. Heavy duty engines require redesign to cope with methanol's poor compression-ignition characteristics. Alternatively, several percent of expensive ignition improvers could be added to the fuel (Reference 31).

Supply/Logistics

Manufacture, storage, transportation, and distribution of chemical methanol is mature technology. Widespread fuel use would require massive additions to existing methanol production and new or expanded distribution systems for methanol fuels because of much larger volumes and materials incompatibility.

The additional methanol would probably be made overseas in gas-rich countries where the overall cost of methanol manufacture would be less than in the United States (References 16, 17, 19, 32). It would likely be made by many of the same oil exporting countries (References 32, 33) who are members of OPEC. Adoption of methanol fuels is unlikely to measurably improve energy security from a supply standpoint because of this OPEC link.

There are also extensive gas reserves in parts of the former Soviet Union (Reference 33), notably the Russian Republic. Methanol could also be made from these reserves but costs are unknown at this time.

Modifications to and expansion of the fuel distribution system and service station network to accommodate methanol-containing fuels would add $0.17 to $0.27 per gasoline gallon equivalent over costs associated with gasoline (Reference 40).

Depending on vehicle design, flexible-fuel vehicles may have negative economic and air quality impacts even if run solely on RFG (Reference 39). This is because a flexible-fuel vehicle may use more RFG (Reference 11) to go the same distance as a gasoline-optimized vehicle using RFG (Reference 39).

Environmental Impact

Use of methanol-containing fuels will have both positive and negative impacts on health, safety, and the environment as compared to RFG.

Methanol can present a more serious health hazard than gasoline. Swallowing even small amounts of methanol can cause blindness or death. Methanol can be absorbed into the skin and methanol-hydrocarbon mixtures are even more readily absorbed. The chronic effects of methanol on human health are poorly known at this time (References 34, 35).

Use of methanol-containing fuel is likely to result in comparable NOx and CO emissions since automakers will design to meet the maximum permissible standards to improve engine efficiency. Methanol will result in lower benzene and 1,3-butadiene vehicle emissions, though recent testing shows it will generate 8 to 10 times more formaldehyde than RFG. Non-methane organic gas emissions are generally similar to RFG (References 1, 39).

Mixing of methanol-containing fuels and RFG (e.g., adding methanol-containing fuel to a vehicle tank partially full of RFG, or vice versa) will increase the vapor pressure of the mix. This will greatly increase the evaporative emissions. The severity of this problem and the design modifications of the FFV to solve/mitigate this problem are speculation at this time.

Since it dissolves in water, methanol spills have the potential to contaminate groundwater supplies, and conventional mitigation measures used for petroleum fuels, like skimming, would be ineffective. Methanol's environmental effects in surface water would likely be lower than crude oil because methanol will not coat shorelines and is more biodegradable. Light petroleum-derived products like gasoline also tend to have little or no long term effects since primary recovery methods, like skimming, generally remove most of the spill under favorable conditions and much of the rest evaporates.

Consumer Cost

Significant use of methanol-containing fuels will increase consumer fuel costs $120 to $200 per year for the typical driver. The vehicle is also likely to cost $200 to $400 or more per vehicle because of the need for fuel sensors (required by flexible-fuel vehicles), methanol-tolerant materials like stainless steel, and larger fuel tanks (dedicated methanol vehicles) (References 1, 17, 19, 24, 40).

ETHANOL

Although methanol is generally acknowledged as the least expensive of the alcohol fuels, ethanol has gained support because of its relationship to the U.S. agricultural economy. Proponents of ethanol argue that its expanded use will displace imported oil, aid the farm economy, and improve air quality by reducing emissions. However, the only way ethanol remains economic, given present conversion technology, is through U.S. government and state subsidies. Another major limitation is that it is subject to agricultural feedstock (such as crop yields) limits and availability. (Reference 1)

Ethanol can be used as a gasoline extender in blends with a maximum government waivered volume of 10 percent (gasohol or E10) which can be used in existing on-road vehicles. The two ethanol fuels being considered in addition are an 85 percent ethanol/15 percent gasoline-boiling-range hydrocarbon, referred to as E85, or in an undiluted form, E100. E100 would require denaturing. The literature is not specific on how this would be done.

Environmental Impact

Ethanol as gasohol (E10) has been used in the United States to reduce carbon monoxide emissions, as have other oxygenates. Use of E85 or E100 would likely result in comparable NOx and CO emissions since auto makers will design to meet prescribed emission levels in order to maximize engine efficiency. Vehicle mass exhaust organics will be similar to RFG (Reference 15). As stated in Table E-1, aldehyde (acetaldehyde and formaldehyde) emissions are toxic and are expected to be higher with ethanol fueled vehicles than other fuels with the exception of methanol (References 39, 48). Ethanol production is energy intensive and will generate additional emissions in crop production, harvesting, fermentation, and distillation, although these emissions are likely to be generated outside the urban pollution centers. If coal is used to supply the heat requirement for ethanol production, greenhouse gases will be greater with ethanol (Reference 38).

Distribution and use of ethanol as E100 may be slightly safer than gasoline. Like methanol E100 is highly soluble in water but may be less troublesome than RFG or methanol since it is somewhat less toxic. When compared to gasoline, a spill is less likely to ignite and will burn more slowly/less violently. In groundwater, E100's tendency to evaporate and biodegrade is expected to be very similar to M100.

E85 is expected to have spill and safety concerns that are no worse than RFG. (Reference 1)

Fuel Supply/Logistics/Energy Security

Ethanol's agricultural feedstock (normally corn) is a volatile production cost component although it has been the feedstock of choice in the United States since the byproduct sales contribute significantly to the net manufacturing cost of fuel ethanol. This is not the case for wood and plant waste conversion processes. Future technology improvements in conversion processes could change these conclusions. (Reference 1)

The fuel costs associated with ethanol range from $1.38 to $2.38 per gasoline equivalent gallon. This is double the costs associated with reformulated gasoline, $0.70 to $1.07 per gallon. All costs are exclusive of government subsidies and fuel taxes. (Attachment 1)

Similar to methanol, a distribution system for ethanol would require capital investments since it would become a new liquid fuel in volumes necessary to fuel a significant number of vehicles. Ethanol is currently being distributed in modest volumes via rail car and trucks to specific areas of the country for blending into gasoline at 10 percent by volume. This system was not set up to handle the large volumes of ethanol needed to supply E85 or E100 as fuels. In conventional pipeline systems, additional procedures and equipment upgrades would be necessary to keep the system dry so that phase separation does not occur.

Thus, totaling all of the logistics costs would add $0.10 to $0.16 per gallon over the costs associated with gasoline. These are lower than the costs needed for distribution of methanol. (Reference 6)

One of the major considerations favoring ethanol as a potential fuel is that it could reduce oil imports by using domestic gas and coal to provide most of the energy requirements to produce the ethanol. Diesel use in farming could also be replaced by ethanol, though this will reduce the overall yield of ethanol and increase costs.

Status of Vehicle

There is very limited experience with ethanol vehicles designed to meet stringent vehicle emissions standards in the United States, and therefore it is difficult to assess overall emissions benefits. The reliability of these vehicles must still be proven. Its volumetric energy content is similar to LPG and LNG; all three have greater range (for given fuel volume) than the other alternative fuels, although none match gasoline. It requires about 1.3 - 1.4 gallons of ethanol to equal the BTU equivalent of one gallon of gasoline, taking into account its energy efficiency benefit as a result of its higher octane. When E85 is used in a Flexible Fuel Vehicle it is expected to be 0 to 5 percent more efficient than reformulated gasoline, and E100 would be 10 to 15 percent more efficient if used in a fuel optimized vehicle. (Reference 19)

Consumer Cost

The incremental cost estimate of purchasing an ethanol flexible fuel vehicle is similar to the costs of a methanol flexible fuel vehicle (Reference 39). The consumer may perceive hesitation and cold weather startability as problems associated with E100, which must be resolved. There will also be more frequent trips to refuel due to lower BTU fuel content.

The overall consumer costs for operating ethanol vehicles are expected to be $370 to $520 per year more than costs associated with operating gasoline vehicles. This is mainly due to the cost of the fuel. (Attachment 1)

COMPRESSED NATURAL GAS

Compressed natural gas (CNG) is considered by many to be the front-runner in the alternative fuels competition in the United States. The fuel is cost competitive, has low emissions, can be supplied in part from domestic sources, and has a nationwide distribution system already in place which can be used to supply service stations and fleet filling sites.

Status of Vehicle

There are about 750,000 vehicles equipped to use CNG worldwide, including about 30,000 in the United States (as compared to 188 million total vehicles in the U.S.). Most are modified gasoline-burning vehicles and can use either fuel. CNG also has been tested in modified diesel engines and is being used in city buses in some U. S. locations on a test basis (References 6, 12).

CNG vehicles are currently being manufactured in the United States by General Motors, Chrysler, and Ford; in Europe by Mercedes-Benz and British Leyland; and in Japan by Toyota. GMC Truck Corporation began marketing CNG-powered, dedicated, 3/4 ton pickup trucks in 1992. Chrysler Corporation is producing a CNG powered Dodge full-size passenger or cargo van and Ford is equipping Crown Victorias to burn CNG. Once dedicated CNG vehicles are manufactured in large numbers, the cost is expected to range from $600 to $1,200 more than a gasoline-powered vehicle. A significant part of the cost is the high-pressure storage tanks used to store the compressed gas at up to 3,600 pounds per square inch (References 6, 12, 17).

Engine maintenance costs of CNG vehicles are expected to be similar to and possibly lower than gasoline vehicles (Reference 1). Periodic tank pressure testing and certification will be required for safety reasons.

CNG has a higher octane number than gasoline, and dedicated engines can be designed for higher compression ratios. The thermal efficiency of a CNG-powered vehicle is expected to be 0 to 5 percent better than a vehicle using reformulated gasoline, taking into account higher engine compression but also the additional weight of the high pressure tanks (Reference 12).

In dedicated CNG engines, about 120 cubic feet of natural gas at atmospheric pressure and 60 degrees Fahrenheit would be equivalent to one gallon of RFG. When compressed to 3,600 pounds per square inch, the thermal energy in about 3.7 gallons of CNG would be equivalent to the energy in one gallon of RFG.

Supply of Natural Gas

Currently there may be enough excess production capacity for natural gas in the United States to supply several million vehicles with CNG. This excess capacity is expected to decline as demand for gas increases, but more capacity can be added by drilling more wells and increasing exploration activities for gas (Reference 17). (See NPC report *The Potential for Natural Gas in the United States,* Reference 59).

As long as natural gas can be provided for vehicles from spare domestic or North American sources, energy security will be improved. If gas is imported as LNG from OPEC countries, energy security will not be benefited.

A nationwide system of pipelines connects gas producing regions with most major population centers, and distribution networks bring gas to individual customers (Reference 6). Based upon projected natural gas prices and an industrial user's rate (Attachment 1), prices to individual service stations and fleet filling sites typically might fall in the range of $3 to $6 per million BTUs. These costs would equate to 38 to 78 cents per RFG equivalent gallon. Users located near producing areas (the Texas-Louisiana Gulf Coast, the Rocky Mountains) would pay less than customers in the Midwest and East.

Logistics

Natural gas pipelines presently supply gas to most geographical regions of the lower 48 states (References 5, 6, 17), although the supply to New England is currently limited. Local distribution companies have distribution systems for supplying individual customers, including electric generating plants, industrial plants, and residential and commercial consumers. For a new customer, a line is connected from an existing distribution header to the customer location.

CNG will be supplied to vehicles by a combination of service stations and central fleet installations (Reference 6). Most filling sites will be equipped with large cylinders containing high pressure gas and a compressor that fills the cylinders. The cylinders provide an inventory of gas to permit rapid filling of vehicle tanks.

The Environmental Protection Agency has estimated distribution and marketing costs for CNG (Reference 12) based upon either electric motor drive or gas engine drive for the natural gas compressor. Facilities installed at the service station or fleet-filling site include the compressor, tanks, metering devices, and fill connections. Costs include capitalized service station conversion costs, operating costs, maintenance and other expenses and service station mark-up. Estimated costs range from $0.24 to $0.36 per RFG equivalent gallon for the electric motor drive and from $0.23 to $0.33 per gasoline equivalent gallon for the gas engine drive. Estimated total cost to the consumer, including vehicle costs as well as fuel, is about the same as RFG (Attachment 1).

Natural gas is sometimes mixed with propane and air by local distribution companies to expand the gas supply, but such gas may not be suitable for vehicular CNG use.

Environmental Impact

From the standpoint of vehicle emissions, CNG will be superior to reformulated gasoline with respect to carbon monoxide, benzene, and butadiene emissions. Its non-methane organic gas emissions are lower than those of reformulated gasoline, and its greenhouse gas emissions could be as low as one-half but could be higher depending on the amount of methane leakage (References 1, 5, 6, 8, 11, 12, 17).

Conventional three-way catalyst are capable of controlling NOx to RFG levels with hydrocarbon levels about 40% to 60% of RFG emissions and CO levels about 40% of RFG. Further reductions in hydrocarbons and/or CO result in increase NOx levels. However, new catalyst technologies are capable of controlling NOx while further reducing hydrocarbons and/or CO. Test results for the CNG-powered Dodge van, adjusted to 50,000 miles, show NOx emissions at less than 10% of the California Ultra Low Emission Vehicle standard (Reference 55). Additional development work is ongoing, and even better results could be forthcoming.

In terms of "spill" potential, CNG is very low risk. It is non-toxic and because it is lighter than air it disperses very quickly. Because CNG is stored in pressurized tanks, there is no possibility of an explosive mixture developing in the tank. Because the gas is stored at high pressure, there is potential for leakage at valves and fittings. Leakage from vehicles into tunnels is unlikely to be a significant risk because the leaking gas will disperse very rapidly, especially with ventilation, but enclosed parking areas, such as garages, could present a problem because explosive gas/air mixtures could form (References 1, 8, 13). There have been access restrictions to tunnels for CNG and LPG vehicles but these are currently being reviewed. For example, the Port Authority of New York has eliminated restrictions on the use of LNG and LPG vehicles in tunnels.

Consumer Issues

Acceptance of CNG by current customers, primarily commercial, is excellent (Reference 43). CNG vehicles start and run like gasoline vehicles, except that there is slower acceleration for dual-fuel retrofitted gasoline vehicles (References 6, 12). This should not be a problem in dedicated vehicles. There are no cold start or vapor lock problems with CNG vehicles.

The primary problem with CNG vehicles is their limited range (References 6, 12). Tanks must be filled every 100-200 miles, or vehicles will have to be redesigned for larger tanks. Fill times may be longer than with gasoline vehicles.

Local fire codes may require that customers receive special training to fill CNG vehicles.

LIQUEFIED NATURAL GAS

The concept of using liquefied natural gas (LNG) for automobiles and trucks is relatively new. LNG can be stored at more modest pressures than CNG, and a gallon of LNG contains more energy than a gallon of CNG. However, the fuel must be stored in well-insulated containers ("thermos bottles") to keep the fuel cold and liquefied. Its current and future market appears to be heavy trucks, buses, and rail applications (References 1, 6).

Technological Readiness

LNG is a commercial product. Liquefaction is used primarily as a means to store or transport natural gas over long distances. At LNG terminals, the liquid methane is regasified when needed and fed into pipelines for distribution.

Prototype LNG vehicles are being tested (Reference 6). No commercial distribution network exists. Cost estimates for LNG vehicles are sketchy, but costs are expected to be higher than for CNG vehicles. Little is known about maintenance costs, but they probably would be higher than for CNG vehicles because of the extremely low temperature of LNG and the need to maintain emergency venting systems and cryogenic storage tanks.

The performance of LNG engines would be similar to CNG engines, because the liquid methane would be vaporized before entering the engine.

In energy content, one gallon of gasoline is equivalent to 1.4 gallons of LNG. Estimates indicate that cryogenic storage tanks for LNG would be about 50 percent larger than gasoline tanks sized for the same range.

Supply

LNG can be produced by liquefying domestic gas or it can be imported. Imported LNG would have little, if any, energy security benefit. Possible sources are the Caribbean, North Africa, Northwest Europe (Norway), the Middle East, and the Far East. Worldwide resources of natural gas, discussed previously, are large. LNG currently is a high cost increment of natural gas supply and is primarily used during peak demand periods. Regasification at the terminals would not be required for fueling LNG vehicles.

If LNG were shipped to filling sites from LNG terminals, cryogenic tank trucks, rail cars, and possibly barges would be required. There is likely to be public resistance to building new LNG coastal terminals, if required. Distribution costs would be much higher than for gasoline. Cryogenic storage would be required at fill sites. Cost data are unavailable.

Consumer Issues

Because of the very limited testing of LNG, no information is available on consumer issues. LNG vehicles would have somewhat less range or larger fuel tanks than gasoline vehicles. With current designs, LNG in tanks would have to be vented after several days if not consumed and replenished, and this could be a consumer nuisance causing safety and environmental concerns as well as being wasteful.

Environmental Impact

Vehicle emissions would be similar to CNG, except that periodic venting, if required, would discharge methane, a greenhouse gas, into the atmosphere.

LIQUEFIED PETROLEUM GAS

Status of Vehicle

Liquefied petroleum gas (LPG) (liquefied propane and butane), has been used for over 60 years as a transportation fuel. As of 1990, there were approximately 300,000 LPG-fueled vehicles in the United States (Reference 12). The technology is considered mature, although current engine designs do not take full advantage of the fuel's combustion characteristics. Improved (optimized) LPG engine designs may provide additional economic benefits over reformulated gasoline (RFG). Auto makers will design to meet emission standards.

Compared to RFG vehicles, incremental costs for mass-produced light duty vehicles are in the range of $150 to $675 per vehicle (Reference 24). LPG tanks for fuel storage are less expensive than CNG or LNG due to the much lower pressure. Maintenance costs per mile are, from historical data, expected to equal those of conventional gasoline fueled vehicles (Reference 20). Basic component wear and tear for tires, belts, coolant, and related components experience similar service life in LPG-fueled vehicles as in RFG vehicles. Engine life should exceed that for gasoline-fueled vehicles because of cleaner combustion properties.

Thermal efficiency of LPG vehicles is similar to slightly poorer than a gasoline vehicle, but with lower energy density it requires 1.3 gallons of LPG to equal one gallon of gasoline (Reference 21). Thus an LPG-fueled vehicle can be expected to consume more fuel per mile traveled than an equivalent RFG-fueled vehicle.

Supply

Domestic production is currently estimated to be 13.2 billion gallons per year by 1995, of which less than a billion gallons will be used in vehicles compared to the 110 billion gallons of U.S. gasoline consumed in vehicles per year (Reference 20). Available imports (Western Hemisphere) for the same period could add 3.3 billion gallons to the U.S. total. Import diversity is considered limited. Even with investment, new supply is subject to natural gas liquids (NGL) resource limits worldwide.

Approximately 82 percent of NGL available for domestic use is produced by the United States (Reference 20). The remaining capacity is supplied primarily by Canadian and Mexican sources. Limited domestic expansion could come from gas plants, refineries, and switching of low value applications to other fuels. The production of LPG from synthesis gas is limited by economic considerations. However, additional vehicle use of LPG would likely be at the expense of other LPG consumers, with imported oil used as the likely backfill.

Logistics

The U.S. transportation system for LPG, consisting of pipelines, rail cars, and liquid bulk trucks into distributor terminals, would have to be extended. From the distributor, product is supplied to homes, refueling facilities for LPG fleet vehicles, and commercial/industrial customers (References 20, 24). Thus facilities (trucks, lines, load racks) are already in place for the commercial and residential consumer. Additional retail outlets for vehicles would have to be provided.

The bulk cost for LPG prior to entering the distribution system ranges from $0.34 to $0.57 per gallon per RFG equivalent. Operating costs from the distributor to the service station are estimated to be $0.28 to $0.46 per gallon (see Attachment 1).

Consumer Issues

Reliability from available information indicates that vehicle durability can be expected to compete favorably with RFG vehicles. Recent public surveys indicate that buyers would consider an LPG vehicle if a delivery system were in place (Reference 21).

Performance advantages over RFG include higher thermal efficiency, higher octane number, and hardware durability that includes extended three way catalyst life (Reference 21). Some of these benefits are not fully realized in a gasoline to LPG conversion.

Convenience remains a question mark but consumers will insist upon service equal to gasoline. Predictions are that refueling will initially be full service for liability concerns (References 20, 23). Safety in handling and use has been established over the many years this product has been used in vehicle and non-vehicle service. LPG does not have any detectable odor. An odorant is added prior to distribution for the purpose of detecting LPG leaks. Other safety precautions that must be considered include storage under pressure (300 psi) and leaks that can produce explosive mixtures over a wider air-to-fuel ratio than gasoline (References 12, 20). In garaging an LPG-fueled vehicle, on-board leak detector warning devices may be required.

Environmental Impact

Non-methane organic gas emissions for LPG will be the same as for RFG (Reference 20). Cold start CO will be reduced due to the advantage of injecting a gaseous mixture rather than a partially vaporized liquid and air mixture.

Vehicle emissions for LPG provide some benefit over RFG. It is assumed that oxides of nitrogen emissions will meet standards and ozone-forming gases, toxics, and carbon monoxide will be reduced. Greenhouse gases are expected to be 20 percent lower per mile driven and the impact of spills to have no long term effect on the environment.

Consumer Cost

There is a growing body of information comparing the operating cost for LPG- and gasoline-fueled vehicles. Available data suggest that, on a comparable basis, LPG vehicles have about the same consumer costs as RFG vehicles.

BATTERY-POWERED ELECTRIC VEHICLES

Electric vehicles were among the earliest automobiles developed, and competed with steam-powered vehicles and early vintage internal combustion engine vehicles. Although range and power advantages caused the internal combustion engine to dominate the vehicle business, interest in electric vehicles has been renewed for environmental and energy security reasons.

Status of Vehicle

There are numerous electric vehicles in use today in specialty applications and/or demonstration programs (References 1, 12, 46, 47). Many of the motor drives and electronic controls currently used in demonstration programs are adaptations of well-established uses in other commercial applications. However, the battery technology is not well developed. The most highly developed battery systems are the lead-acid system and the nickel-alkali system. Of these two, the lead-acid system is less expensive per battery pack, but has limited life, requiring replacement about every three years. Lead-acid batteries are very heavy, limiting the amount of energy that can usably be stored in a vehicle and, therefore, the driving range between recharges. Although lead-acid battery systems can be designed for quick discharge of power delivering good vehicle acceleration performance, this further reduces the vehicle range that can be delivered between recharges. Current technology is stretched to provide a vehicle with 125 mile range and "normal" vehicle acceleration capability.

Nickel-alkali batteries (nickel-iron and nickel-cadmium) are considerably more expensive per battery pack than lead-acid batteries (Reference 12). They provide about 60 percent more energy per pound, i.e., range, than lead-acid batteries, and could last up to the life of the vehicle. Their electrical recharging efficiency is lower than the lead-acid battery.

More advanced battery systems such as sodium-sulfur are being developed that have the potential to increase range and performance of electrical vehicles. However, these technologies are not commercial at this time. A joint government-industry $260 million program to develop an advanced and practical electric vehicle battery by 2000 was started in 1991.

Accessory systems tailored to electric vehicles also require development. Present passenger heating systems can draw up to 20 percent of the energy required to propel the vehicle. Air conditioning systems require even more energy. More efficient accessory systems are needed for electric vehicles to have acceptable range, performance, and comfort.

A major drawback to current electric vehicle technology is the time necessary to completely recharge the batteries. Current designs require six to eight hours for a complete recharge (References 1, 12, 46). Some specifically designed battery systems allow partial recharge (up to 40 percent) in 15 minutes using a 440 volt power source. None of the advanced batteries under study which recharge the battery in the vehicle solve this problem. Some proposed metal-air battery systems, however, are based on a change-out of electrodes and electrolyte, which may be accomplished in about the same time as a gasoline fill-up. A practical system for regenerating the electrodes and electrolytes must be developed in order to evaluate this concept.

Based on the currently developed lead-acid battery system, electric vehicles are estimated to cost $1,200 to $4,000 more than conventional vehicles. In addition, the batteries would have to be changed about every three years at $2,000 to $4,000 per change (Attachment 1).

Fuel Supply, Logistics, and Energy Security

The electrical generation and distribution facilities are universally available in the United States. The electrical load created by recharging electric vehicles is expected to occur mainly at night during off-peak electrical demand time, perhaps encouraged by time-of-day electricity prices. If this is the case, significant numbers of electrical vehicles (up to 30 percent of the vehicles in use in some areas) could be accommodated without the need for new power generation and distribution facilities (References 1, 12, 46). The fuel mix for this increment of electricity could have a larger oil component than base load.

Different battery systems under development could result in different recharging systems with unique designs and costs. Some of the advanced systems require recharging at a "filling station" whose usage level could allow electricity purchase at the commercial rate or possibly an industrial rate. Lead-acid and nickel-alkali systems likely allow recharging at home, which involves power use at a price up to the residential rate. Average U.S. power costs could range from industrial rates of 5.2 cents per kilowatt-hour (kwh) to residential rates of 8.7 cents per kwh, depending on which recharging configuration is employed (Attachment 1).

For a residential unit, recharging is estimated to require an additional 240-volt circuit for each vehicle rated at 30 to 50 amps (Reference 6). Cost estimates for adding this circuitry range from $400 to $700 per outlet. This adds 0.9 to 1.1 cents per kwh to the consumer cost of electricity. Use of time-of-day pricing could potentially reduce the consumer cost for electricity used in recharging electric vehicles.

A significant portion of the additional power generation is projected to be from power plants, fueled by domestic energy sources. This situation improves energy security.

Consumer Issues

Limited range and/or acceleration and long recharge times are significant problems for consumers. In addition, current estimates of high initial costs and battery replacement costs are major drawbacks. Additional consumer concerns that "dead" batteries could leave them stranded will need to be addressed (Reference 43). The key to all these problems lies in the battery technology development.

The need to plug in the recharge system (probably 240 volt) at home daily will require consumer adjustment (Reference 43).

Environmental Impact

Since a significant amount of the electricity that will be available to recharge electric vehicle batteries will come from coal-fired generating plants, there are some emissions considerations associated with these "clean cars." As controls become more stringent on these coal-fueled facilities, a closer look at gas-fired facilities, nuclear power, and even solar power may emerge.

Many of the existing utility plants are old and stack emissions of NOx are considerable. Newer facilities and those facilities that are in compliance areas have been fitted with scrubbers and reactors to hold NOx to acceptable levels. Additionally, a major disadvantage of the electric vehicle is the amount of SOx that would be emitted from coal-fired plants. The NOx and SOx emissions will be limited by the more stringent controls that will be placed upon utilities as a result of acid rain program implementation required by the 1990 Clean Air Act. The more stringent controls increase cost of electricity over current rates. Further, most utility plants have characteristically low hydrocarbon and CO stack emissions and can, in some cases, be remotely sited, all of which lower the local emissions level inside major metropolitan areas.

CO_2 is a greenhouse gas. Coal-fired plants emit a large amount of CO_2 as compared to the burning of other fossil fuels due to the higher carbon-to-hydrogen ratio of coal. Electric vehicles powered from coal-fired power plants emit more CO_2 per mile driven than RFG vehicles. However, electric vehicles powered from natural-gas-fueled power plants emit less CO_2 per mile driven than RFG vehicles. Non-fossil-fuel power plants (such as nuclear) would reduce CO_2 emissions even further.

Potential for major fuel spills into the environment is essentially eliminated. However, depending on the specific battery system under investigation, one could be handling and processing substantial quantities of various hazardous chemicals such as acid, caustic, bromine, hot liquid sodium, lithium, etc., and heavy metals such as lead, nickel, cadmium, mercury, and zinc. Recycling/disposition of used batteries is also a major challenge.

Overall Consumer Costs

Overall consumer costs for operating electric vehicles are estimated to be $900 to $1,960 per year (22 to 46 percent) more than the cost of operating reformulated gasoline-fueled vehicles. (See Attachment 1 for details.) These costs are based on lead-acid battery-powered electric vehicles. The additional costs are directly tied to the costs of the battery packs and their estimated service life.

HYBRID ELECTRIC VEHICLES

The hybrid electric vehicle currently being developed in the vehicle industry consists of an electric vehicle much like the one previously discussed, with a small (about 25-40 horsepower) internal combustion engine and generator onboard to constantly maintain the battery charge. The battery pack could be smaller, reducing weight and costs, since range would be set by the fuel tank for the internal combustion engine (References 1, 12, 46, 47).

The engine is sized to exceed the power required to move the vehicle at constant highway speed by a sufficient amount to rebuild battery charge consumed in acceleration. In operation, the engine runs at constant speed and load. The parameters are selected to optimize engine operation at very high efficiency and very low emissions.

The battery system is designed to provide the vehicle performance desired by the consumer. Since the batteries are rarely discharged completely, battery life is extended well beyond the deep discharge cycle life normally quoted.

These vehicles are just now in the concept stage and definitive performance and costs are not available.

Environmental performance is expected not to be as good as battery-powered electric vehicles, but substantially better than standard internal combustion engine vehicles. The hybrid electric vehicle does not currently qualify as a zero emissions vehicle (ZEV) under the California low emission vehicle program.

The overall cycle efficiency for hybrid electric vehicles is yet to be demonstrated. However, it is projected to be substantially higher than conventional internal combustion engines. This higher efficiency would reduce liquid fuel consumption and improve energy security.

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ATTACHMENT 1

BASIS FOR FUEL COST COMPARISON

Fuel Supply

Supply costs are estimates of average U.S. bulk commodity prices for all products. Logistics costs for delivery, wholesale and retail handling, and storage must be added to these to estimate consumer costs. All costs are stated in 1990 dollars.

Commodity costs for crude oil, natural gas, and electricity are taken from the Energy Information Administration (EIA) Annual Energy Outlook for 1991 published in March 1991 and the EIA Short-Term Energy Outlook published in August 1991.

Base commodity prices:

Crude Oil (reference)	\$19-34/Barrel (B)
Natural Gas:	
Gulf Coast Wellhead	\$1.76-5.04/thousand cubic feet (kcf)
Commercial User	\$4.95-8.29/kcf
Industrial User	\$3.08-6.35/kcf
Electricity	\$0.0522-0.0868/kilowatt-hour (kwh)
LPG	\$0.237-0.397/gallon
Motor Gasoline (conventional)	\$0.629-0.995/gallon

The 1989 actual data were taken for the low end of the range, and the year 2010 projections from the EIA's mid-range case were taken as the high end of the range. The electricity price range is based on industrial rates on the low end to residential rates on the high end. Average U.S. gasoline (conventional) bulk commodity price is estimated as follows. The reported U.S. average spot price for 1989 is taken for the low end of the range. The high range estimate is based on the high range crude oil cost and the 1989 spread between motor gasoline and crude oil.

The U.S. average spot price for LPG is used for the low end of the LPG range. The high range would likely be in competition with natural gas in the residential/commercial market. Use of LPG for a transportation fuel is projected to increase normal bulk value of LPG by 3 to 5 cents per gallon (Reference 5).

Based on results from the balance of the NPC Refining Study, reformulation of motor gasoline will cost 4 to 9 cents per gallon. A mid-range estimate of 7 cents per gallon is used for these comparisons. This is similar to the results of an earlier DRI Study (Reference 27).

Conventional gasoline and reformulated gasoline costs developed in the NPC refining study are in these ranges.

Alternative fuel prices:

Methanol (M100)	–	\$0.46-0.75/gallon
Ethanol (E100)	–	\$1.05-1.58/gallon
M85	–	\$0.49-0.79/gallon
E85	–	\$0.99-1.49/gallon

Methanol (M100) cost estimates have been prepared by many authors. The range used here covers estimates for methanol manufactured from natural gas in the U.S. Gulf Coast, Canada, the Caribbean Basin, and the Middle East. The low end of the range is a DOE estimate (Reference 36) for methanol supplied from Trinidad in a mega plant (10,000 metric tons per day). This plant is four times as large as current worldscale methanol plants (for chemical use). The high end of the range is an Office of Technology Assessment (OTA) study (Reference 1) that analyzes transition costs for methanol, assuming production from much smaller plants (2500 metric tons per day) are setting the methanol commodity cost. Costs developed by Bechtel (Reference 44) and Hahn (Reference 40) are in this range.

Ethanol (E100) cost estimates have also been produced by several authors. The range quoted is from DOE (Reference 12) but covers ranges published by the OTA (Reference 1) and the International Energy Agency (IEA) (Reference 5).

Costs for methanol and ethanol used in the NPC Refining Study are in the range.

M85 and E85 are calculated from the methanol, ethanol, and gasoline costs.

Natural gas for CNG is estimated to be purchased at the industrial user price.

Due to differences in energy content, these costs are difficult to compare. Typically, comparisons are made in terms of "motor gasoline equivalent (MGE) gallons" of energy. Table E-2 contains energy content estimates (Reference 12) used for this comparison and recommended by EPA.

The composition and energy content of reformulated gasoline is yet to be determined. Energy content for RFG is assumed to be the same as conventional gasoline for this comparison. When the composition and energy content is more clearly defined, this comparison can be revised properly. Using these energy equivalents, the costs per MGE gallon of energy are as shown in Table E-3.

Logistics Costs

The average U.S. costs to transport, store, and deliver the fuels to the consumer have also been widely studied. Table E-4 presents these costs for various fuels.

TABLE E-2

Fuel	Cost Unit	BTU/Unit (LHV)	Units per MGE Gallon
Motor Gasoline	gallon	114,132	1.0
Methanol:			
M100	gallon	56,560	2.02
M85	gallon	65,200	1.75
Ethanol:			
E100	gallon	75,670	1.51
E85	gallon	81,440	1.40
Natural Gas	cubic feet	930	123
LPG	gallon	89,300	1.28
Electricity	kwh	3,415	33.4

TABLE E-3

Fuel	Cost ($/MGE Gallon)
Motor Gasoline	0.63-1.00
Reformulated Motor Gasoline	0.70-1.07
M85	0.85-1.38
M100	0.93-1.5 1
E85	1.38-2.09
E100	1.58-2.38
Natural Gas (industrial)	0.38-0.78
LPG	0.34-0.57
Electricity	1.74-2.90

TABLE E-4

Fuel	Logistics Costs ($/MGE)	Reference
Motor Gasoline	0.20	41
Reformulated Motor Gasoline	0.20	41
M85	0.37-0.45	6, 40
M100	0.39-0.47	6, 40
E85/E 100	0.30-0.36	6
CNG	0.24-0.36	6
LPG	0.28-0.46	12
Electricity	0.29-0.36	6

Estimates for alcohol fuels are based on incremental costs over motor gasoline. Alcohol fuels require modifications to tanks and pumps in terminals and retail stations as well as modifications to tank trucks and loading racks. Larger volumes require increased capacity on some facilities. Logistics costs include the annualized costs of incremental capital, incremental operating costs, and additional retail margin attributed to longer, or more frequent fill times.

CNG requires pipeline tie-in to gas distribution system as well as compression and storage equipment at the retail station. Costs are based on capital and operating costs of these facilities.

LPG logistics costs are based on logistics costs for current LPG delivered through retail stores, but with a service station margin added.

Electricity logistics costs represent the annualized capital costs to add a 240-volt charging circuit rated at 30 to 50 amps to a residence.

Vehicle Costs

Vehicles that run on alternative fuels will likely cost the consumer more to buy than conventional vehicles. Maintenance costs may also be different for each type of fuel. Table E-5 presents these estimates for each fuel.

TABLE E-5

Fuel	Purchase Cost: Purchase Price ($)	Purchase Cost: Annual Cost With Interest ($/year)	Maintenance ($/year)	References
Motor Gasoline	16,000	2,450	440	26
Delta for Alternatives:				
Methanol	200-400	30-60	0	5, 6, 11, 12, 14, 16, 17, 18, 19, 40
Ethanol	200-400	30-60	0	11, 15, 18, 19
CNG	600-1200	90-180	0	1, 5, 6, 11, 12, 13, 16, 17, 18, 19
LPG	150-675	20-100	0	12, 18
Electricity	1200-4000	180-610	670-1330	1, 6, 11,12, 18, 19

TABLE E-6

	% Improvement	Comment	Reference
M85	0-5	Flexible Fuel Vehicle	1, 6, 11, 14
M100	10-15	Dedicated Vehicle	1, 6, 11, 14
E85	0-5	Flexible Fuel Vehicle	11, 15, 16
E100	10-15	Dedicated Vehicle	11, 15, 16
CNG	0-5	Dedicated Vehicle	1, 5, 6, 11, 13, 19
LPG	0	Dedicated Vehicle	12, 18
Electric	50-60	Battery Powered	6, 11

The different technologies used in these vehicles result in different energy efficiency. The efficiencies for alternative fuels are typically stated as percent differences from motor gasoline. Table E-6 presents efficiencies for various fuels (relative to motor gasoline).

Total Consumer Costs

Total consumer costs for different fuel/vehicle systems can be compared by adding the various cost components for each fuel and vehicle system. In order to combine fuel costs in dollars per gallon and vehicle costs in dollars per year, the rate of fuel usage must be established. For this analysis, an average fuel economy for conventional fuel vehicles of 27.5 miles per gallon was assumed. This is the current Corporate Average Fuel Economy (CAFE) requirement. The test data for new cars for several years has been about this level. In actual practice, specific vehicle designs would need to be compared with the appropriate fuel economies.

In addition to the costs compared here, the consumer has to pay insurance and registration fees to drive his or her vehicle and must pay for a license to drive. These costs are estimated by AAA to average $840 per year for each vehicle (Reference 26). This comparison assumes that these costs are the same for alternative fuel vehicles. In addition, AAA estimates

11,900 miles are driven per year on average for each vehicle (Reference 26). This level of driving is also assumed for alternative fuel vehicles.

Total consumer costs for each fuel system are shown in Table E-7:

TABLE E-7

FUEL COSTS
($/MGE Gallon)

	Supply Cost	Logistics Cost	Efficiency Credit	Net Fuel Cost	¢/mile	$/year	%Δ Over RFG
RFG	0.70-1.07	0.20	0	0.90-1.27	3.3-4.6	390-550	–
M85	0.85-1.38	0.37-0.45	0-0.09	1.22-1.74	4.4-6.3	530-750	93-(4)
M100	0.93-1.51	0.39-0.47	0.13-0.30	1.19-1.69	4.3-6.1	510-730	88-(6)
E85	1.38-2.09	0.30-0.36	0-0.12	1.68-2.33	6.1-8.5	730-1010	159-32
E100	1.58-2.39	0.30-0.36	0.19-0.41	1.70-2.33	6.2-8.5	730-1010	159-32
CNG	0.38-0.78	0.24-0.36	0-0.06	0.62-1.08	2.2-3.9	270-470	(31)-(15)
LPG	0.34-0.57	0.28-0.46	0	0.62-1.03	2.3-3.8	270-450	(31)-(19)
Electricity	1.74-2.90	0.29-0.36	1.02-1.96	1.02-1.30	3.7-4.7	440-560	13-2

NON-FUEL COSTS
($/Year)

	Purchase	Maintenance	Other	Total	¢/mile	$/MGE Gallon
RFG	2450	440	840	3730	31.3	8.62
Delta Over RFG:						
M85	30-60	0	0	30-60	0.3-0.5	0.07-0.14
M100	30-60	0	0	30-60	0.3-0.5	0.07-0.14
E85	30-60	0	0	30-60	0.3-0.5	0.07-0.14
E100	30-60	0	0	30-60	0.3-0.5	0.07-0.14
CNG	90-180	0	0	90-180	0.8-1.5	0.21-0.42
LPG	20-100	0	0	20-100	0.2-0.8	0.05-0.23
Electricity	180-610	670-1330	0	850-1940	7.1-16.3	1.96-4.48

TOTAL CONSUMER COSTS

	¢/Mile	$/Year	$/MGE Gallon	% Over RFG
RFG	34.6-35.9	4120-4280	9.52-9.88	–
Delta Over RFG:				
M85	1.4-2.2	170-260	0.39-0.61	4-6
M100	1.3-2.0	150-240	0.36-0.56	4-6
E85	3.1-4.4	370-520	0.85-1.20	9-12
E100	3.1-4.4	380-520	0.87-1.21	9-12
CNG	(0.3)-0.8	(30)-100	(0.07)-0.23	(1)-2
LPG	(0.8)-0	(100)-0	(0.23)-0	(2)-0
Electricity	7.6-16.4	900-1960	2.08-4.52	22-46

APPENDIX F

SUMMARY OF ENVIRONMENTAL LEGISLATION

THE PURPOSE OF THIS APPENDIX IS TO PROVIDE A BRIEF SUMMARY OF THE IMPORTANT ENVIRONMENTAL LAWS AND REGULATIONS AFFECTING THE REFINING INDUSTRY.

AIR

History

Federal clean air legislation derives primarily from four statutes: the Air Quality Act of 1967, the Clean Air Act Amendments of 1970 ("1970 Amendments"), the Clean Air Act Amendments of 1977 ("1977 Amendments"), and the Clean Air Act Amendments of 1990 ("Amendments"). Previous air pollution legislation (starting in 1955 and continuing into the 1960s) mainly authorized federal research and very limited controls.

The 1970 Amendments set up the first basic structure for serious federal control of air pollution, authorizing EPA to establish national standards for air quality and directing states to develop "state implementation plans" (SIPs). Mid-1975 was set as the goal for attainment of national standards in all states. The 1975 goal was not met in many states, so Congress enacted the 1977 Amendments, which added new compliance deadlines and enforcement mechanisms.

The recent Amendments are the most far-reaching of all the air legislation to date. They direct EPA to regulate further specific properties of certain fuels (e.g., gasoline and diesel fuel) and, in certain regions of the country, to improve emissions from the gasoline sold there. The Air Quality Act of 1967 and the Amendments of 1970, 1977 and 1990 are often collectively called the "Clean Air Act" (CAA).

Components of the Clean Air Act

Title I describes the framework for control of air pollution from stationary sources, national air quality standards, significant deterioration preventions, nonattainment provisions, and financial and technical assistance to states. Based on it, EPA in 1971 divided the United States into air quality control regions, and subsequently published criteria documents on the health effects of designated pollutants, which served as a basis for EPA's "national ambient air quality standards" (NAAQS). NAAQS have been set for six criteria pollutants: ozone, carbon monoxide, particulate matter of ten micrometers or less (PM-10), oxides of sulfur (SOx) and nitrogen (NOx), and lead.

Title I also authorized EPA to promulgate emission standards for new stationary sources, (called "new source performance standards," NSPS) to be based on the best technological system of continuous emission reduction which has been adequately demonstrated. Title I also required EPA to establish standards for certain pollutants not covered by NAAQS, and the 1990 Amendments provide a list of 189 toxic air pollutants to be included.

In regions where air quality is better than national standards (called "attainment areas"), the SIP must prevent significant deterioration of air quality. In "nonattainment areas," the state plan must limit new source construction unless decreased emissions ("emission offsets") are obtained from existing sources resulting in a net reduction in emissions in the nonattainment area. The 1990 Amendments superseded portions of the original Title I dealing with ozone depletion in the stratosphere by adding a new Title VI, which requires a complete phase-out by 2030 of the production of chemicals which destroy the stratospheric ozone layer.

Title II covers mobile sources (cars, trucks and aircraft). Title III covers administration, citizen suits and judicial review. Title IV deals with noise pollution. The Amendments added another Title IV to cover acid rain (but without removing the original Title IV). The Amendments also added Title V, dealing with permits, and Title VI, dealing with stratospheric ozone protection.

In general, states have discretion to determine the mix of emission controls they will impose through their SIPs. However, the Amendments establish a number of requirements the SIPs must satisfy. Mobile source controls under the Act have been national in scope and states cannot establish controls on these sources, with the exception of California. The Amendments recognized that California had, under "compelling and extraordinary circumstances," adopted its own motor vehicle emission standards prior to the time Congress had become active on the subject and the state is permitted to establish its own standards for motor vehicles and for certain off-road vehicles and engines. Other states may adopt vehicle standards identical to California's.

Major Components of the Clean Air Act Amendments of 1990

Attainment and Maintenance of the NAAQS

The attainment provisions in the Amendments are intended to reduce ozone, carbon monoxide and particulate matter pollution in areas exceeding the NAAQS and to maintain compliance elsewhere.

Ozone

About 100 areas in the United States did not meet the current health standard for this pollutant when the 1990 Amendments were adopted. (Ozone is formed when emissions of volatile organic compounds (VOCs), typically hydrocarbons, combine with NOx in the presence of sunlight. It is especially prevalent in the summer months.) With respect to ozone, the Amendments call for:

- Classification of ozone nonattainment areas into categories based on severity, with new attainment deadlines for each category
- Adoption of extensive control measures for stationary source and mobile source emissions of ozone precursors (VOCs, NOx), with specific additional control measures to be required of areas in each higher category of nonattainment severity
- Periodic demonstrations of reasonable further progress toward attainments (e.g., 15 percent reduction in the first 6 years, 3 percent per year thereafter), with waivers possible based on technological unfeasibility
- Certain measures to control emissions of VOCs from commercial products, the creation of ozone transport regions with controls on certain emission sources in these regions, and the issuance of new "control techniques guidelines" by EPA to help states regulate particular emission sources.

(The reformulated gasoline program stemming from ozone-reduction requirements is described below.)

Carbon Monoxide (CO)

In many areas, most of this pollutant comes from motor vehicles and tends to be worse in colder weather. Under the Amendments, nonattainment areas are classified as either moderate or serious and different attainment deadlines, sanctions and progress demonstration requirements apply to each.

The Amendments require an oxygenated fuel program in 39 serious CO nonattainment areas, starting no later than November 1, 1992. Oxygen-containing additives (such as ethers and alcohols) are to be blended with gasoline during the control period (i.e., the four high-CO winter months with timing adjusted to fit gasoline logistics) to maintain the average oxygen content of gasoline at a minimum of 2.7 percent (weight). (Several cities, including Denver, Albuquerque, Phoenix, and Salt Lake City, have already adopted mandatory oxygen content levels in gasoline for the winter months as part of their SIP to meet requirements of the Clean Air Act of 1977.) "Serious" areas must also provide for enhanced motor vehicle inspection and maintenance programs.

Particulate Matter

Particulate matter (PM-10) includes acid sulfates, toxic organics and metals, insoluble dusts from stack emissions, construction activities, roadways, mobile sources and small sources such as wood fires. It has been estimated that 58 areas exceed the health standard for PM-10, divided into moderate and serious categories; standards must be attained by 1994 and 2001 respectively. Moderate areas must install Reasonably Available Control Measures and serious areas must adopt Best Available Control Measures.

Prevention of Significant Deterioration (PSD)

Before the 1977 Amendments, there were no explicit provisions to prevent deterioration of air quality in attainment areas, although EPA did set up a regulatory program in 1974 for PSD in compliance with a stated purpose of the Act "to protect and enhance" air quality. In the 1977 Amendments, new provisions were enacted which are more comprehensive and stringent, cover more sources and require preconstruction review (permit) and "Best Available Control Technology" (BACT). The regulations specifically include petroleum refineries and petroleum storage and transfer units (exceeding 300,000 barrels capacity) on the list of "major emitting facilities," which emit, or have the potential to emit, 100 tons per year or more of any air pollutant.

Motor Vehicles and Motor Fuels

The Amendments establish two programs to promote the use of vehicles which use clean-burning fuels such as methanol, ethanol, reformulated gasoline (RFG), electricity or natural gas. One covers fleets of ten or more vehicles, and applies in serious, severe or extreme ozone nonattainment areas. The other, a California Pilot Program, provides that a certain number of vehicles meeting substantially more stringent standards be produced for sale in California.

The Amendments include requirements on the sulfur content and cetane index of diesel fuel for on-highway use to be effective October 1, 1993. Regulations require that sulfur cannot exceed 0.05 weight percent, the diesel fuel cetane index must be at least 40 (or a maximum aromatic level of 35 percent), and other diesel or distillate fuels must contain a blue dye for identification purposes. Trading of sulfur "credits" among refiners will be permitted.

The Amendments provide for creation of detailed standards for the sale of RFG in the 9 worst ozone-polluted areas by 1995, and require that the volatility of gasoline be limited to 9 psi Reid Vapor Pressure (RVP) during the high ozone summer season. The nine "worst ozone" areas are centered around Hartford, New York City, Philadelphia, Baltimore, Milwaukee, Chicago, Houston, Los Angeles and San Diego. About 90 other areas may opt-in to the RFG program if States are granted approval by EPA. The basic requirements for RFG are as follows:

- During the entire year, vehicle toxic emissions must be reduced by at least 15 percent in 1995-1999 and at least 20 to 25 percent in 2000 and beyond; benzene will be limited to no more than one percent by volume, oxygen to no less than two percent by weight, with no increase in NOx and no lead.
- During the high ozone season, vehicle VOC emissions must be reduced by at least 15 percent in 1995-1999, and at least 20 to 25 percent in 2000 and beyond.
- The baseline against which changes will be measured is 1990 average gasoline and 1990 model vehicles, including total emissions from exhaust, refueling, evaporation and running losses.
- Toxics are benzene, formaldehyde, acetaldehyde, 1, 3-butadiene and polycyclic organic matter (POM).
- EPA is working with the industry and other interested parties to define reformulated gasoline, with a goal of specifying "simple" and "complex" models. A simple model (which may be in effect from 1/1/95 to 2/28/97) will specifically regulate levels of benzene, oxygen and vapor pressure, (and indirectly aromatics) and would cap each refinery's annual sulfur, T90 and olefin levels at 125 percent of the 1990 average.
- The complex model was planned to be specified by late 1992 and adopted by 3/1/93. It is anticipated that the complex model will also incorporate sulfur, olefins and distillation terms to form new equations relating gasoline components to vehicle emissions in order to control VOCs, NOx and toxics.

Because gasoline evaporation accounts for as much as 40 to 50 percent of all VOC emissions, the Amendments require that EPA issue new regulations to control evaporative emissions. New vehicles were originally required to have onboard canisters adequate to capture refueling vapors, but EPA has removed the requirement for on-board canisters due to safety concerns. This decision is currently being litigated. Stage II hose and nozzle controls in the worst ozone areas will be required to control vapors at refueling station pumps.

One of the more controversial issues is the extent to which new standards might be applied to vehicle tailpipe emissions. While the Amendments will lead to new tailpipe limits during the 1990s, EPA may establish a tougher second-round of tailpipe standards to take effect in model year 2003 if needed.

Acid Rain

Acid rain occurs when sulfur dioxide and nitrous oxide emissions undergo a chemical change in the atmosphere and return to the earth in rain, fog, or snow. Most of the sulfur dioxide is emitted into the atmosphere during the burning of fossil fuels, generally high-sulfur coal by electric utilities; some comes from transportation sources.

In the Amendments, a new Title IV establishes a program to reduce overall emissions of sulfur oxide and nitrous oxide to less than 1980 levels, primarily by placing strict limitations on emissions from electric utilities. The refining industry will be affected mainly by likely increases in the cost of electricity.

Hazardous (Toxic) Air Pollutants

In the 1970 Amendments, Congress directed EPA to establish "national emissions standards for hazardous air pollutants" (NESHAPS), which would apply to both new and existing stationary sources of such pollutants. ("Hazardous" pollutants are those to which no ambient air quality standard is applicable because, while these pollutants may result in an increase in mortality and illness, they are not emitted by a large enough number of major sources to justify a NAAQS for each.) Prior to the Amendments, EPA was only required to list such pollutants and set a standard for each which provided a margin of safety to protect public health. Since 1970 EPA has listed only 8 hazardous air pollutants (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides and vinyl chloride); it has issued standards for all but coke oven emissions. EPA promulgated a final rule (referred to as "Benzene NESHAPS") in March 1990, which regulates air emissions of benzene from wastewaters and other streams containing benzene. Parts of this rule were reproposed in March, 1992, and finalized by EPA in December 1992.

The Amendments establish a list of 189 chemical and generic metal compounds that are to be regulated as air toxics. EPA is required to develop two rounds of emission standards, first a technology-based standard and then a health-based standard, if needed. The technological standard will require major sources to meet emissions limitations reflecting use of "maximum achievable control technology" (MACT). In the second round of regulation, EPA may establish health-based standards or, in some cases, impose work practice standards instead. "MACT" standards are to be set at a level that will require the "maximum degree of reduction in emissions of hazardous air pollutants," taking into consideration the cost of controls and any non-air quality health and environmental impacts and energy requirements. Control measures might include process changes, substitution of materials, enclosures, equipment to collect or treat emissions, or work practice or operational standards, including training and certification. These MACT standards are to be phased in over a ten-year period. In October, 1992, EPA proposed MACT for chemical plants; refinery MACT is scheduled to be proposed in 11/94 and 11/97.

Under a new accident prevention requirement, sources handling any of the listed accidental release substances in quantities greater than threshold amounts must develop and implement a risk management plan. The plan must include a hazard assessment, a prevention plan, and response program. The final list of at least 100 regulated substances and the accidental release regulations were to have been promulgated by November 15, 1993. Facilities must submit plans to EPA within three years of the time EPA publishes final accidental release regulations.

As with other major sources classified under the Clean Air Act, sources subject to this Title will have to obtain an operating permit. If EPA does not meet statutory deadlines for establishing standards, sources will still have to submit a permit application and meet "equivalent emissions limitations." By obtaining a 90 percent reduction (95 percent in the case of particulate matter) over 1987 (or later), prior to promulgation of the air toxic standard, sources may receive an extra six years to comply with the MACT standard.

EPA was expected to propose in early 1993 standards to control VOC emissions, and other pollutants that may endanger public health or welfare, from the loading and unloading of marine tank vessels. These controls will supplement those already in place due to some State regulations.

Impact on Refineries

The Clean Air Act Amendments of 1990 described above have direct impact on U.S. refineries by setting requirements on the emissions of the refinery as a stationary-source operating facility and by setting requirements on the specifications of the product output. Significant air-based requirements have been described above; this section discusses certain other air-based requirements on refineries.

Air Toxics (MACT)

The Amendments require EPA to promulgate MACT standards for hazardous air pollutants. MACT for existing sources will be as stringent as the best controlled 12 percent of similar sources, and MACT for new sources will be as stringent as the best controlled similar source. These standards are expected to cover emissions from vents, waste water transfer operations (storage and fugitives) and distillation operations; they will be promulgated over a period of several years, as discussed above.

Air Emission Permits and Fees

The Amendments require states to establish an operating permit program for all major sources of air emissions. Fees will be set to cover the cost of the permitting program, for a period of up to five years. States are given until November 1993, to develop their operating permit programs and to fully implement the program by November 1997. Of particular significant will be the extensive recordkeeping, monitoring and reporting requirements.

Industrial Toxics Program (Known as the "33/50" Program)

Air, water and waste emissions of listed toxic chemicals are required to be reported under the Superfund Amendments and Reauthorization Act (described below.) EPA is seeking voluntary reductions from industry through its Industrial Toxics Program. Emitters of the chemicals covered by Section 313 of SARA have been asked to reduce voluntarily their emissions of materials such as benzene, toluene and xylenes to all media. EPA has sought a 33 percent reduction by 1992 and a 50 percent reduction by 1995.

State and Local Programs

States and local jurisdictions all have their own environmental laws and regulations, some of which are in their SIPs, and others which are not. Those relating to marine vapor recovery and the southern California program are especially noteworthy.

Marine Vapor Recovery

State and local agencies are promulgating regulations, some effective already, to control emissions from dock loading and unloading of tankers and barges, as well as lightering activities. Federal guidelines have been proposed to standardize the various state and local regulations, and assign overall responsibility.

South Coast Air Quality Management Plan (SCAQMP)

The South Coast Air Quality Management District in California has adopted a three-tier plan for meeting ambient air quality standards as part of the State Implementation Plan. Tier I includes most, if not all, technically feasible air pollution control strategies. Tier II includes technologies which can reasonably be expected to be available within the next 5-10 years, including foreseeable extensions of known technologies. Tier III includes technologies which will require significant technical advancements, including major reductions in mobile sources.

Tier I includes very stringent requirements on various petroleum industry facilities, primarily refineries. Among the regulations affecting refineries are controls on:

- NOx, SOx, and PM-10 emissions from fluid catalytic cracking units
- PM-10 emissions from gas-fired boilers and process heaters
- Flare emissions
- NOx emissions from heaters and boilers
- Phase-out of fuel oil use in stationary heaters and boilers.

Other segments of the industry (production and marketing) will be affected by controls on:

- Emissions from outer continental shelf exploration and production operations
- Emissions from bulk terminals
- Emissions from loading operations
- Emissions from service stations beyond the current Phase I and Phase II control systems.

WATER

History

The federal government was first given responsibility for water pollution in the Rivers and Harbors Act of 1899 and later (in 1948) in the Federal Water Pollution Control Act, but neither produced substantial reductions in pollution. But with the enactment of the Federal Water Pollution Control Act Amendments of 1972 (FWPCA), the federal government was given substantially more authority to clean up the nation's waters. In 1977, Congress enacted the Clean Water Act Amendments of 1977, which amended the FWPCA. With its 1977 amendments, the FWPCA is now referred to as the "Clean Water Act," (CWA). The last major changes to the Act were made under the Water Quality Act of 1987. The CWA is the basis for a comprehensive regulatory scheme primarily to control the discharge of effluent from *point sources* into *navigable waters.* In practice, EPA has adopted a very broad definition of navigable waters, to include intrastate waters used for recreational purposes, those from which fish are taken and sold in interstate commerce, and those used by industries in interstate commerce.

Discharges to receiving waters are regulated primarily by the technology-based permits authorized by the CWA. When these limitations are insufficient to protect the water quality of the receiving water or its intended use, water quality-based limitations are incorporated into the discharge permit. These permit requirements are enforced under the National Pollutant Discharge Elimination System (NPDES).

Components of the Clean Water Act

Title I defines goals and provides for research and demonstration projects in water pollution control technology. Title II authorizes grants for sewage treatment plants, particularly public-owned treatment works (POTW). Title III authorizes effluent limitations to be met by municipal and industrial waste treatment systems (along with inspection and enforcement provisions.) Title IV covers permits and licenses and establishes the NPDES permit program. Title V describes citizen suits, judicial review and administration. Title VI authorizes state-run revolving loan funds to enable localities to finance treatment facilities and related programs.

Impact on Refineries

Water-Quality-Based Permits

Refineries and other industrial facilities must comply with new permit requirements limiting individual toxics and whole effluent toxicity, effective June, 1992. This water-quality-based approach to permitting will require facilities to conduct toxicity reduction evaluations which will lead to stringent limitations on individual toxic pollutants or on toxicity of the whole effluent.

Stormwater Regulation

EPA has promulgated regulations that apply to stormwater discharges from a variety of industrial facilities, including refineries. Most stormwater discharges from industrial facilities will have to be permitted under an NPDES permit. Facilities discharging stormwater that were not permitted previously were required to file applications by October, 1992, and the new requirements must also be met by stormwater discharges that had been previously permitted. Affected facilities must either apply for an individual permit, apply for a permit using a group application submitted by a number of similar facilities, or seek coverage under a general permit. These different classes of permit applications have varying deadlines from 1991-1993.

Selenium Discharges into San Francisco Bay

The California Regional Water Quality Control Board has passed a rule regarding selenium discharges into San Francisco Bay which sets stringent limits not thought to be attainable with current technology. Selenium is contained in San Joaquin Valley crude oil, and the rule will adversely affect the capability of the industry to process this crude oil.

WASTE

History

The principal legislation controlling disposal of waste materials is the Resource Conservation and Recovery Act (RCRA). It was enacted in 1976 and significantly amended in 1980 and 1984. RCRA has been said to close the loop in environmental legislation, supplementing the CWA and CAA. It authorizes EPA to regulate waste on and under the land, including generation, storage, treatment and disposal, particularly emphasizing the impacts of waste disposal on groundwater.

The three statutes overlap to some extent. While the CAA regulates discharges into ambient air, RCRA regulates some air emissions as well (incineration of hazardous waste, air emissions from land-based disposal units, tanks, containers and surface impoundments). While the CWA controls discharges and spills into surface water, RCRA also covers discharges of hazardous wastes into surface waters. When overlaps exist, EPA is directed by RCRA to integrate RCRA provisions with other statutory requirements to avoid duplication.

RCRA focuses on the ongoing activities of waste management facilities, not on closed or abandoned disposal sites. The latter are addressed primarily by CERCLA (Superfund) regulations. About ten percent of all solid wastes are "hazardous" wastes under RCRA. Solid waste is hazardous if it is specifically listed by EPA as hazardous waste or it exhibits any of the characteristics (ignitability, corrosivity, reactivity, or toxicity) of a hazardous waste. Generators of waste must determine if their waste is hazardous according to these criteria, and handle them accordingly.

RCRA Impacts on Refineries

Toxicity Characteristic Wastes

In recent years, a number of refining wastes have been identified as hazardous wastes because of their benzene content. As a result, increased treatment, special handling and disposal will be required. Many impoundments will have to either meet minimum technical requirements (MTR) or be replaced with tanks. Refineries storing or treating these newly-defined hazardous wastes must now comply with RCRA Hazardous Waste regulations.

Primary Sludge

Starting in May, 1991, all sludges resulting from oil/water/solids separation were regulated as listed hazardous wastes. Many wastewater treatment lagoons may come under RCRA jurisdiction.

Used Oil

EPA has ruled that used oil (destined for disposal) is not, per se, a hazardous waste, unless it exhibits hazardous characteristics.

Corrective Action

Refineries are currently being required to implement corrective action under RCRA Part B Permits or enforcement orders. The corrective action program requires remediation at all solid and hazardous waste management units (SWMUs) releasing contaminants into the air, surrounding soils or to groundwater. Under RCRA's corrective action requirements, some former waste disposal or treatment sites will need to be cleaned up or securely contained. Waste sites that continue to operate may be placed under further controls and monitoring. Potential control options include excavating contaminated soil for incineration or treatment on site, or further containment and monitoring.

Underground Storage Tanks (USTs)

The 1984 RCRA Amendments established a comprehensive regulatory program for underground storage tanks that contain "regulated substances," including petroleum and other hazardous chemicals, not just wastes. The program covers more than two million tanks and is administered by EPA or by states that adopt a program just as stringent as the federal one. EPA promulgated different technical standards for petroleum tanks than for hazardous substance tanks; for example, secondary containment is not required for petroleum tanks.

Other Waste-Related Requirements on Refineries

Land Ban Restrictions

Existing land ban restriction programs require extensive treatment of wastes prior to land disposal (e.g., landfarms, landfills). For many wastes, the specified treatment technology is incineration.

Groundwater/Hydrocarbon Cleanup

There are federal and state regulations protecting groundwater sources. These regulations specify cleanup standards for contaminated sites and aquifers. Superfund regulations, for example, require cleanup to the "maximum contaminant level goals," which in some cases approach zero. Controls may entail pumping, which may take years to complete, treating and other technologies. Various states (e.g., MN, WV, OH, KY) have promulgated groundwater protection regulations,

Remediation

Remediation of past product spills and leaks is currently being handled at many refineries through compliance orders from EPA and state regulatory agencies. Also, RCRA, CWA and CAA provisions require refiners to review the integrity of storage tank bottoms, vapor seals, and provisions for impounding storm and drawoff water.

OTHER LAWS

National Environmental Policy Act of 1969 (NEPA)

NEPA (enacted in 1969) was originally thought to be the most far-reaching environmental legislation because it created the Council on Environmental Quality and required federal agencies to address the environmental impact of their activities before making decisions (called "environmental impact statements," EIS). While NEPA itself has not had the impact of the air, water and waste statutes, it did set the stage for subsequent environmental law. Incidentally, EPA was not created by NEPA; the agency was created through an executive reorganization directed by President Nixon in 1970.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), (the "Superfund" Law)

Enacted in 1980, the Superfund law was intended to deal with uncontrolled releases of hazardous substances into the environment. It is a remedial statute which authorizes both federal and state governments, as well as private parties in certain cases, to respond to and clean up hazardous substances and other toxic pollutants in the water, air and on land. The statute requires that private parties responsible for the pollution either clean up their releases or reimburse the government for cleanup costs. Government response actions are financed through a "superfund" created by a tax imposed primarily on the chemical and petroleum industries. When CERCLA was enacted in 1980, Congress established the Hazardous Substances Response Trust Fund (which became known as the Superfund) funded for five years at $1.6 billion, principally through a tax on petroleum and 42 listed chemicals.

In the 1986 Amendments to CERCLA, Congress established the Hazardous Substances Superfund which was substantially larger than the original trust fund ($8.5 billion for the five years beginning January 1, 1987). The Superfund Amendments and Reauthorization Act (SARA) funded the Superfund by a new broad-based corporate environmental tax, in addition to expanded taxes on petroleum and chemicals. The Superfund was expanded again in 1990 when Congress extended taxing authority through 1995, increased the petroleum tax from 0.79 cents per barrel to 8.2 cents per barrel on petroleum products and crude oil produced in the United States, and 11.7 cents per barrel for imported petroleum products, and raised the total fund size to $11.97 billion. SARA also imposed an ambitious mandatory cleanup schedule on EPA.

CERCLA, designed to function without extensive regulations, imposes release reporting (to EPA) and cleanup requirements on the private sector. Cleanup activity is conducted according to the National Contingency Plan, which establishes a nationwide plan for dealing with environmental emergencies.

Toxic Substances Control Act (TSCA)

TSCA, enacted in 1977, is intended to protect people and the environment from exposure to injurious substances. TSCA seeks to develop data on what chemicals are produced, where, in what volume and with what risks. The responsibility for development of such data is placed on manufacturers, importers and processors; TSCA is aimed at 70,000 chemical substances now made in the United States and about 1,000 new substances coming into the market each year. TSCA provides for a regulatory structure to govern the testing, manufacture, processing and distribution of toxic chemicals, with clear distinctions made between chemicals that are already being made and used, and those which will be made in the future.

The main provisions of TSCA direct EPA to develop test procedures to see whether chemicals in current use are potentially harmful. If a chemical is found to pose "an unreasonable risk to human health or the environment," EPA may impose a limit or total ban on production, impose use restrictions, require labeling, special handling, disposal or quality control measures. While originally aimed at the chemical industry, a broader definition of "processor" now includes any person who prepares a chemical substance or mixture. Further, the term "manufacturer" is now broadly defined to include importer.

Safe Drinking Water Act (SDWA)

The SDWA was enacted in 1974 and amended in 1986. It contains two major sections: one relates to public water systems and the other relates to underground well injection affecting underground sources of drinking water. In 1980 and 1983, EPA promulgated regulations containing technical criteria and permitting requirements for all new wells, and existing wells within five years of approval of a state permit program. Among the classes of wells covered are oil and gas production and storage wells, and any special process wells related to mineral mining, energy recovery and gasification of oil shale. There is considerable connection between SDWA regulations, and those under the CWA, RCRA, and CERCLA, which has led to a consolidated permit program.

Occupational Safety and Health Act (OSHA)

The OSHA was passed in 1970 to reduce the number of occupational safety and health hazards at places of employment. Under its authority, the Secretary of Labor (acting through the Occupational Safety and Health Administration, also referred to as "OSHA") has set thousands of standards governing work practices for a large group of industries throughout the United States.

OSHA has promulgated a regulation, "Process Safety Management of Highly Hazardous Materials," which is required by the Clean Air Act Amendments of 1990. It outlines performance requirements in the following areas in which refineries must comply:

- Management of Change
- Incident Investigations
- Mechanical Integrity
- Personnel Training
- Process Safety Information
- Operating Procedures
- Process Hazards Analysis
- Contractors
- Pre-Startup Safety Inspections
- Auditing
- Hot Work Permits
- Emergency Response

Oil Pollution Act of 1990 (OPA)

The Oil Pollution Act of 1990 (OPA) requires certain refineries located on or near navigable waters (e.g., river, Gulf, or ocean water) to establish oil spill contingency plans for catastrophic spills. Extensive oil spill cleanup capabilities and guarantees are mandated. OPA directs the National Oceanic and Atmospheric Administration (NOAA) to revisit the area of damage assessment, including valuation methods and the categories of damage which should be assessed. While this relates primarily to spills upon the navigable waters of the United States, it may be broadened to cover land-based releases and spills.

OPA permits states to impose more stringent financial and operational requirements on terminal facilities. Several states, notably Alaska, California, Florida, Maryland, New Jersey, Oregon, and Washington, have enacted (or are expected to enact) such statutes.

REFERENCE

Information Sources

Detailed information on environmental regulations can be obtained from many sources, including the laws and regulations themselves. The citations for the laws and regulations are given below. Federal laws are documented in the United States Code (U.S.C.) and regulations are published in the Code of Federal Regulations (CFR). EPA's "Petroleum Refinery Cluster Rule Summary List" (January 15, 1992), a compilation of EPA regulations affecting petroleum refineries, provided some of the information in this appendix. Additional information on the history and highlights of certain laws and regulations was taken from "Practical Environmental Law," by Thomas H. Truitt, Ridgway M. Hall and Robert C. Davis, Jr. (published by Federal Publications, Inc. 1120 20th Street, NW, Washington, D.C., 20036), 1992.

Laws	References
Clean Air Act (CAA)	42 U.S.C. Para 7401 et seq. The Act is comprised of 186 sections, implemented in regulations comprising six volumes in the Code of Federal Regulations, 40 CFR, Parts 50-99.
Clean Water Act (CWA)	33 U.S.C. Para 1251 et seq. The Rivers and Harbors Act of 1899: 33 U.S.C. Para 401 et seq. Regulations are found primarily in 40 CFR, Parts 15, 30-35, 110-131, 220-231, 257-261, 402-417, 501 and 33 U.S.C. Parts 153, 323-324.
Oil Pollution Act of 1990 (OPA)	33 U.S.C. Para 2701 et seq.
Resource Conservation and Recovery Act (RCRA)	42 U.S.C. Para 6901 et seq. The regulations are in 40 CFR Parts 3001-3014.
Comprehensive Environmental Response, Compensation, and Reliability Act Of 1980 (CERCLA)	42 U.S.C. Para 9601 et seq. Regulations for CERCLA (Superfund) and Superfund Amendments and Reauthorization Act (SARA) are in 40 CFR Part 302.
Toxic Substances Control Act (TSCA)	15 U.S.C. Para 2601 et seq.
National Environmental Policy Act (NEPA)	42 U.S.C. Para 4321 et seq.

Glossary of Acronyms

AQCR	Air Quality Control Region
AQL	Acceptable Quality Level
BACM	Best Available Control Measures
BACT	Best Available Control Technology (Air)
BAT	Best Available Technology (Water)
BMP	Best Management Practice
BPT	Best Practicable Control Technology Currently Available
CAA	Clean Air Act
CEQ	Council On Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation And Liability Act
CFCs	Chlorofluorocarbons
CFR	Code Of Federal Regulations
CSMA	Consolidated Metropolitan Statistical Area
CWA	Clean Water Act
CWT	Central Wastewater Treatment
EA	Environmental Assessment
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
FWPCA	Federal Water Pollution Control Act
HSWA	Hazardous And Solid Waste Amendments
LAER	Lowest Achievable Emission Rate
MACT	Maximum Available Control Technologies
MCLs	Maximum Contaminant Levels
MSA	Metropolitan Statistical Area
NAAQS	National Ambient Air Quality Standards
NCP	National Contingency Plan
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards For Hazardous Air Pollutants
NOx	Nitrous Oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standard
OG	Oxygenated Gasoline

OPA	Oil Pollution Act
OSHA	Occupational Safety And Health Administration (Act)
POM	Polynuclear Organic Material
POTW	Publicly Owned Treatment Works
PSD	Prevention Of Significant Deterioration
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation And Recovery Act
RFG	Reformulated Gasoline
SARA	Superfund Amendments And Reauthorization Act
SDWA	Safe Drinking Water Act
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SOx	Sulfur Oxides
SRF	State Revolving Loan Fund
SWDA	Solid Waste Disposal Act
TOC	Toxic Organic Carbon
TSCA	Toxic Substances Control Act
TSDF	Treatment, Storage And Disposal Facility
USC	United States Code
UST	Underground Storage Tank
VOC	Volatile Organic Compounds
WQM	Water Quality Management

APPENDIX G

HISTORY PRIMER

U.S. PETROLEUM SUPPLY, DEMAND, AND LOGISTICS, 1970–1992

THIS APPENDIX OF THE REPORT PROVIDES BACKGROUND MATERIAL FOR THE GENERAL READER WHO IS INTERESTED IN GAINING A FAMILIARIZATION WITH THE HISTORY OF THE PETROLEUM INDUSTRY. IT WAS PREPARED FOR THIS NPC REFINING STUDY BY THE PETROLEUM SUPPLY DIVISION, OFFICE OF OIL AND GAS, ENERGY INFORMATION ADMINISTRATION, U.S. DEPARTMENT OF ENERGY. THE ENERGY INFORMATION ADMINISTRATION (EIA) IS PUBLISHING THIS MATERIAL SEPARATELY AS *THE U.S. PETROLEUM INDUSTRY: PAST AS PROLOGUE, 1970-1992.* THIS APPENDIX IS A REPRODUCTION OF THAT EIA REPORT.

Contents

Tables

Figures

1. Introduction

Present-day domestic petroleum operations and consumption patterns have been significantly influenced by the Nation's desire to improve air quality and reduce petroleum imports. The recurrent oil price and supply shocks of the past 2 decades at times disturbed the economic stability of the country. The shocks led to the enactment of U.S. laws designed to reduce petroleum imports through domestic price incentives, fuel efficiency improvements, or the use of alternative fuels.

The establishment of air quality standards under the Clean Air Act Amendments of 1970 set the stage for subsequent legislation enacted to curb emissions of toxic pollutants from petroleum and other fuels **(Table 1)**. The 1970 Amendments affected the petroleummarket throughout the 1970's, 1980's, and early 1990's. The enactment of the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 demonstrates that the reduction of petroleum imports and environmental quality will continue to be primary concerns well into the 21st century.

The U.S. petroleum industry and its customers responded to changes in Federal laws and sudden oil price shocks by altering petroleum supply and consumption patterns. Price-related declines in domestic crude oil exploration and production, and petroleum's growth in the transportation sector were particularly significant. The march of events over the years forced changes in the petroleum industry, and it evolved into a sophisticated supply mechanism stretching from the wellhead to the local retail dealer. During this evolution, new markets were developed for the myriad products manufactured from a barrel of crude oil.

The globalization of petroleum markets accelerated during the 1980's and early 1990's. The principal factors in this were the common national interests of petroleum consuming countries in allaying supply problems in the face of future petroleum supply disruptions, and the growth in foreign economies. The more global petroleum markets helped to mitigate the effects of the 1990 disruption in world oil supplies.

Foreign economic growth increased the demand for light petroleum products, particularly transportation fuels, and created the need for greater refinery downstream conversion capacity. These factors expanded the market for U.S. petroleum products, and created additional sources of supply for oxygenates and other U.S. petroleum needs. The newly industrialized countries' expanded petroleum use increased air quality concerns. As in the United States, by 1992, many foreign countries were moving toward the production and use of oxygenated motor gasoline and working toward improving oil spill controls.

Investments made during the past 23 years to modernize the industry's operations now provide a base for decisions to be made as the 1990's progress. This report focuses on the developments that shaped the domestic petroleum industry and U.S. demand patterns between 1970 and 1992. It also highlights foreign demand and refinery trends. These events are presented in statistical terms in Chapter 2, and are described in detail in Chapter 3. Some similarity in information noted in Chapters 2 and 3 allows each chapter to stand independently to facilitate the report's use. The report is intended to provide background information on the petroleum industry and its history, and to act as a reference for those more familiar with the industry.

- Chapter 2 describes the patterns of change for each component of supply and demand, and briefly touches on the events (fully described in Chapter 3) that induced significant change or fluctuation. Supplemental data are contained in the Appendix section.

- Chapter 3 presents a chronology of the major petroleum-related events and their consequences. The Chapter also describes the actions or reactions of the petroleum industry to the event, and the impact of the events and actions taken on domestic and/or foreign economies.

Notes: • Unless otherwise referenced, data in this report are from the EIA publications *Petroleum Supply Annual*, Volumes 1 and 2 and predecessor reports, *Annual Energy Review 1992*, *Monthly Energy Review*, June 1993, and *Historical Monthly Energy Review 1973 - 1988*. All data through 1992 are considered final and are not subject to further revision. • In this report, terminology for petroleum consumption also includes demand and product supplied.

Table 1. Significant Events Affecting the U.S. Petroleum Industry, 1970 - 1992

Laws and Regulations (As Amended), and Events		Date of Enactment or Occurrence	Primary Impact
	U.S. Crude Oil Production Peaks	October 1970	U.S. dependence on foreign sources of crude oil increased, primarily from the Organization of Petroleum Exporting Countries (OPEC).
PL 91-604	Clean Air Act of 1970 (CAA)	December 31, 1970	Fuel quality changes for air pollution reduction were mandated. Sophisticated downstream refinery processing techniques were developed to produce high-octane blending components. Leaded gasoline production and consumption were virtually phased out by 1992.
	1973 Arab Oil Embargo	October 17, 1973 - March 18, 1974	Petroleum supplies were disrupted and prices escalated. U.S. consumers made efforts to conserve energy and reduce petroleum consumption. Bulk petroleum heating fuels lost market share.
PL 93-159	Emergency Petroleum Allocation Act of 1973 (EPAA)	November 27, 1973	Government controls replaced market forces on domestic petroleum price and supply.
	Supplier-Purchaser Rule, Buy-Sell Program, and Crude Oil Entitlements Program	1974	Below-market petroleum prices and allocated supplies created the following situations: • Disincentives for crude oil exploration and production. • Proliferation of smaller, inefficient refineries. • Restrictions on exports. • Subsidies on petroleum imports made it more profitable to import petroleum. • The U.S. economy was shielded from price hikes, stimulating domestic demand.
	Introduction of Unleaded Motor Gasoline	1974	Pollution from lead emissions was greatly reduced. The transition to unleaded motor gasoline was aided by its compatibility with the catalytic converter that was developed in 1973 to eliminate vehicle tailpipe emissions.
PL 94-163	Energy Policy and Conservation Act of 1975 (EPCA)	December 22, 1975	Corporate Average Fuel Economy (CAFE) Standards were established to increase vehicle fuel efficiency. The Strategic Petroleum Reserve (SPR) was established. Modifications to EPAA's crude oil pricing regulations created incentives to import crude oil.
PL 95-91	Department of Energy Organization Act of 1977 (DOE)	August 4, 1977	Federal energy-related functions were consolidated under one Agency.
	U.S. Petroleum Demand Peaks	1978	Refinery utilization rates dropped. Subsequent decline in demand contributed to refinery shutdowns in the early 1980's. The ensuing decline contributed to lower crude oil imports.
PL 95-504	Airline Deregulation Act of 1978	October 24, 1978	Airline competition increased through removal of Federal restrictions on airline operations.
PL 95-620	Powerplant and Industrial Fuel Use Act (PIFUA)	November 9, 1978	Construction of electric powerplants with petroleum or natural gas as the primary fuel was restricted.
	1978 Iranian Revolution	November 1978- March 1979	Declines in Iran's crude oil production began a series of OPEC price escalations between 1979 and 1981. A worldwide recession and depressed oil consumption occurred after prices escalated.
Exec. Order 12287	Petroleum Price and Allocation Decontrol	January 28, 1981	Market forces on petroleum prices were reinstated. Refinery efficiency improved. Domestic crude oil production was revitalized. Higher-priced residual fuel oil lost its competive position.

Table 1. Significant Events Affecting the U.S. Petroleum Industry, 1970 - 1992 (Continued)

Laws and Regulations (As Amended), and Events		Date of Enactment or Occurrence	Primary Impact
	Net back Pricing	Fourth Quarter 1985- First Quarter 1986	Refiners were guaranteed specific margins. A crude oil glut on the world market was created.
	1986 Crude Oil Price Collapse	First Quarter 1986	Domestic crude oil production declined. Dependence on OPEC crude oil increased. Lower petroleum prices stimulated economic growth.
	Exxon Valdez Oil Spill	March 1989	Attention focused on oil spill prevention, tanker safety, and protection of U.S. coastal areas that culminated in the Oil Pollution Act of 1990.
CFR 40, App. E	Reid Vapor Pressure Regulations of 1989 and 1992 (RVP)	June 1, 1989; June 1, 1990	Emissions of smog-producing compounds in motor gasoline were reduced.
PL 101-549	Clean Air Act Amendments of 1990 (CAA Amendments; CAAA)	November 15, 1990	Mandated programs to reduce emissions of harmful substances in fuels include: • Reduction of carbon monoxide levels in motor gasoline. • Elimination of lead in gasoline. • Reduction in sulfur content of highway diesel fuel. • Addition of oxygen to winter motor gasoline.
	Persian Gulf Crisis of 1990 - 1991	August 1990 - March 1991	The impact from sudden price rises and supply cutoffs was reduced, compared with previous disruptions, through worldwide cooperation: • Strategic reserves built up by the International Energy Agency (IEA) since 1974 had a calming influence on oil markets. • OPEC, particularly Saudi Arabia, increased crude oil production to mitigate the loss of supplies. • Non-OPEC countries shifted supply patterns to offset lost supplies. • Efficiency improvements and fuel-switching capability improvements, made during the 1980's, reduced the impact of the supply cutoff.
PL 101-380	Oil Pollution Liability and Compensation Act of 1990	August 18, 1990	Some tanker owners stopped delivering oil to U.S. ports other than the Louisiana Offshore Oil Port (LOOP), but a very small portion of deliveries was affected. U.S. petroleum companies began increasing their foreign-flag double-hulled tanker fleets.
	Dissolution of the Soviet Union in 1991	December 31, 1991	Exploration and production opportunities have required caution and patience in the new Russia. Declines in petroleum supplies from the former Soviet Union have been offset by exports from the United States and other countries.
PL 102-486	Energy Policy Act	October 8, 1992	Petroleum will provide a smaller share of energy consumption in the future because of : • Influx of alternative transportation fuels. • Effects of energy efficiency standards that are to be developed. • Research and development projects that will result in new production technologies and highly efficient equipment.
	Oxygenated Fuels Program Implemented	November 1, 1992	Winter carbon monoxide (CO) emissions were reduced in specified U.S. nonattainment areas. Gasoline prices in nonattainment areas increased to offset higher production costs.

Source: Energy Information Administration, Office of Oil and Gas.

2. Patterns of Supply and Demand

Introduction

The United States derives more energy (measured in British thermal units) from petroleum than from any other energy source--nearly twice as much as either coal or natural gas and nearly four times as much as nuclear energy, hydroelectricity, and all other energy sources combined. It is also one of the largest petroleum producers in the world, but consumes far more than it produces.

A complex system has developed to accommodate the logistics of petroleum supply and demand (**Figure 1**). The 1992 volumes for each process in the supply and demand of petroleum illustrate the contribution each process makes. The flow of petroleum begins with the origins of the supply of crude oil, then proceeds through the refining process that transforms the crude oil into petroleum products. Some of these products are exported, and some are supplemented by imports for final disbursement to fill a variety of consumer needs.

The first part of this chapter, **Highs and Lows in Petroleum Data**, looks at the highest and lowest levels of petroleum consumed, produced, imported, exported and stored since 1970. These extremes demonstrate the ability of the petroleum supply and demand system to respond quickly to change.

The remainder of the chapter examines consumer demand for petroleum products, how the industry responds to that demand through refinery production and product imports, how these products are dispersed for consumption, and finally, the impact of the Nation's reliance on others for the crude oil supplies necessary to meet the country's needs:

- **Petroleum Demand** - Petroleum demand moved toward lighter fuels in the United States, as transportation use expanded during the past 2 decades. Cleaner-burning or less expensive fuels replaced petroleum as sources of heat and power in domestic and foreign markets.

- **Petroleum Refining** - Although the number of U.S. petroleum refineries declined after 1981, those remaining became more complex and efficient through technological advancements and additions to downstream units. At foreign refineries, downstream capacity increases served to offset declines in crude oil distillation capacity.

- **Petroleum Product Imports and Exports** - Imports of light petroleum products have surpassed those for heavier products in recent years, mainly in response to reduced demand for heavy products. Foreign markets for light U.S. products have expanded during the 1990's.

- **Petroleum Transportation and Storage** - Shifts in the transportation network and types of petroleum held in storage during the past 2 decades were in direct response to changing world and U.S. economic and political situations. Crude oil stocks, excluding the Strategic Petroleum Reserve, have claimed an increased share of total stocks, and petroleum inter-regional deliveries have shifted more toward pipelines.

- **Crude Oil Supplies** - The need to supplement domestic supplies of crude oil after 1970 led to greater reliance on the Organization of Petroleum Exporting Countries (OPEC) for imports. This reliance increased the United States' vulnerability to petroleum supply disruptions.

Highs and Lows in U.S. Petroleum Data Since 1970

The domestic petroleum industry has responded to changes in U.S. laws and world political and economic events through expansions or contractions of its various operations through the years. The unfolding of events during the 1970's, 1980's, and early 1990's brought shifts in consumer needs and abrupt changes in petroleum supply patterns that challenged the industry's flexibility. The highest and lowest annual levels recorded for the various components of U.S. petroleum supply and demand signified these shifts.

Energy Production

Domestic crude oil production reached its peak in October 1970 at 10.0 million barrels per day (**Table 2**). Although still a significant source of energy production at the end of 1992, crude oil declined from its high in 1970 to its low point of 7.0 million barrels per day in November 1992. In 1985, crude oil production, in British thermal units (Btu's), was a close second to coal. Since 1988, diminishing production has resulted in crude oil's drop from second to third in importance, behind natural gas and coal (**Figure 2**). Petroleum's share of energy production has dropped from 33 to 23 percent.

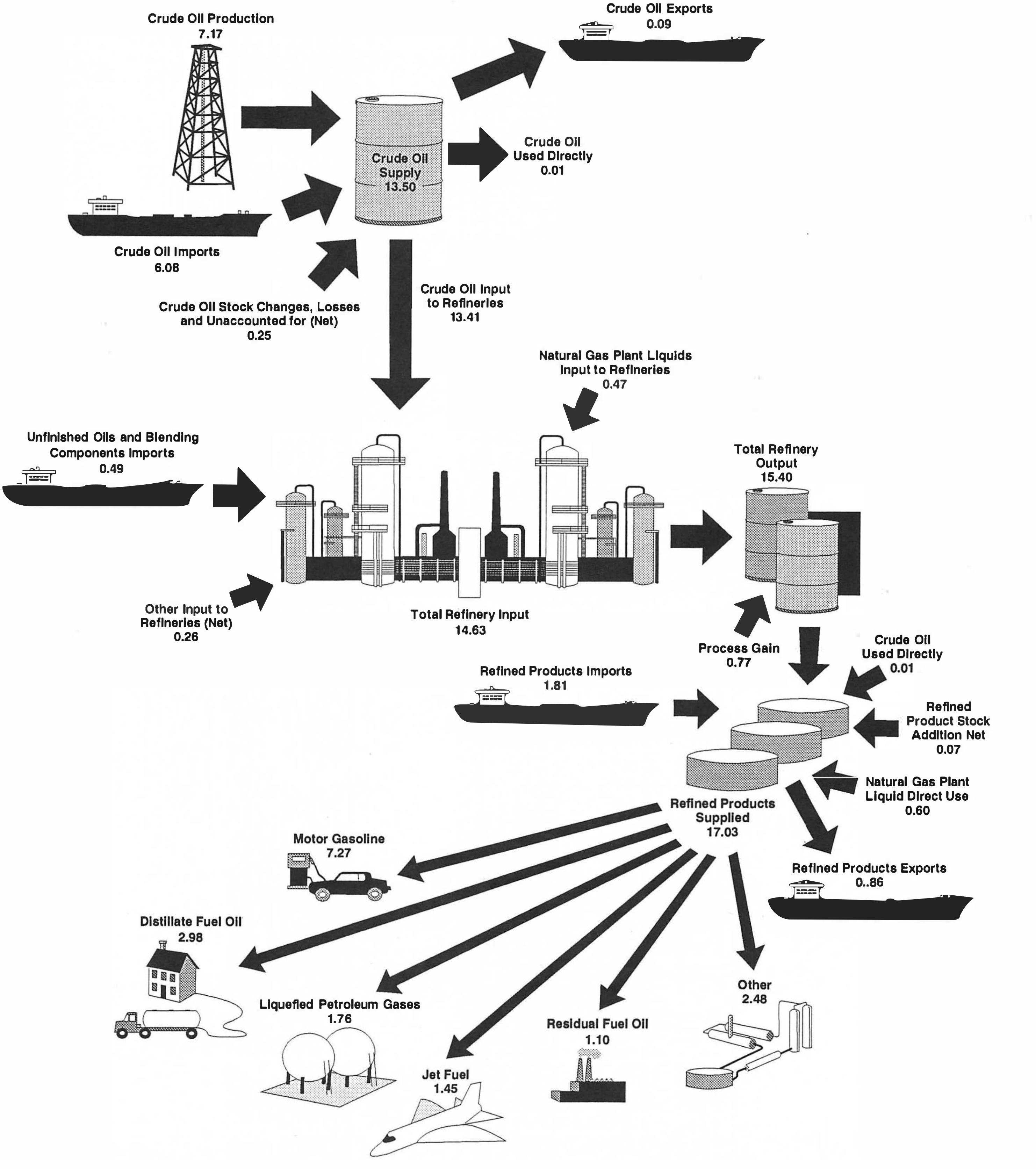
Energy Consumption

Petroleum has been the most important U.S. source of energy since 1970. Petroleum's share of total domestic energy consumption, in Btu's, peaked in 1977 at 49 percent. Since then, heightened use of coal and the increased availability of nuclear power have cut into petroleum's share of total energy use. Petroleum's share of total energy consumption was lowest in 1991, when it comprised 41 percent of the Nation's energy.

Petroleum Demand

The variation in U.S. petroleum demand (measured as product supplied) has been linked to changes in the prices of petroleum products relative to one another, and relative to other energy sources. Dramatic petroleum price increases and eventual steep

Figure 1. U.S. Petroleum Flow, 1992
(Million Barrels per Day)



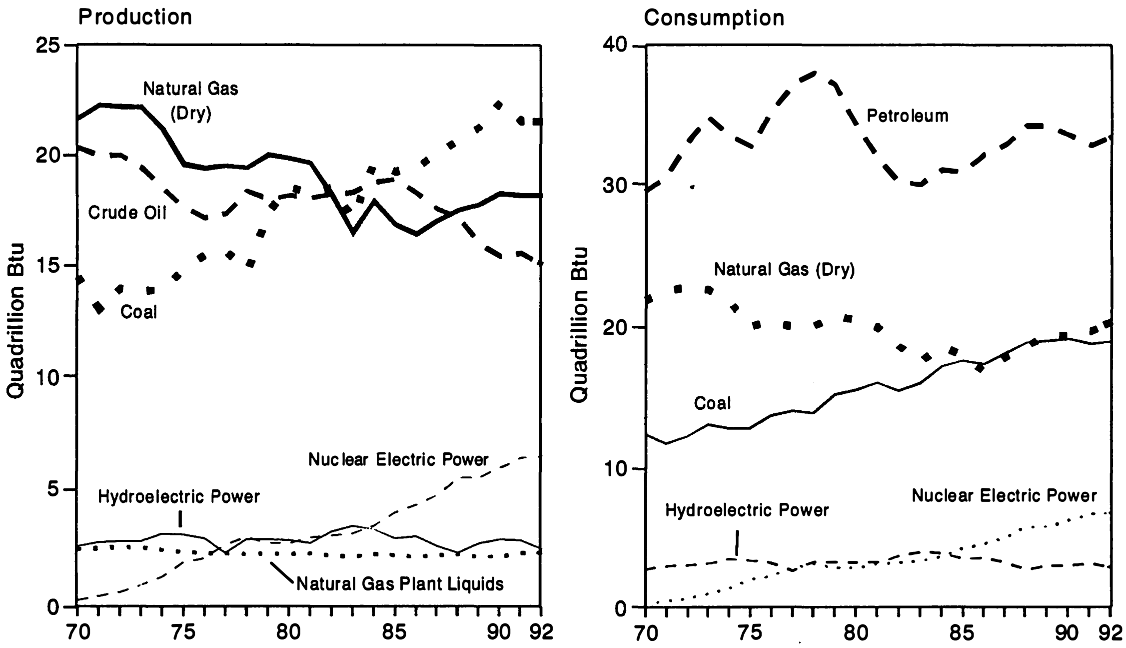
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, and *Petroleum: An Energy Profile*, 1991.

Table 2. Highest and Lowest Levels for Major U.S. Petroleum Supply and Demand Elements, 1970 - 1992
(Thousand Barrels per Day Unless Otherwise Noted)

Item	Production		Imports		Exports		Demand		Refinery Inputs		Stocks (Million Barrels)	
	Volume	Date	Volume	Date	Volume	Date	Volume	Date	Volume	Date	Volume	Date
Crude Oil, excluding SPR												
Lowest..........	7,024	Nov 1992	1,122	Jan 1971	0	1970-1976*	--	--	10,633	Feb 1983	233	Jan 1974
Highest..........	10,013	Oct 1970	7,068	Jul 1977	370	Mar 1979	--	--	15,421	Dec 1978	397	Apr 1981
Alaskan Crude Oil												
Lowest..........	188	Feb 1972	--	--	--	--	--	--	--	--	--	--
Highest..........	2,086	Mar 1988	--	--	--	--	--	--	--	--	--	--
Crude Oil Imports by Source:												
Arab OPEC												
Lowest.......	--	--	30	Jan 1974	--	--	--	--	--	--	--	--
Highest......	--	--	3,377	Jan 1979	--	--	--	--	--	--	--	--
Other OPEC												
Lowest.......	--	--	246	Jan 1971	--	--	--	--	--	--	--	--
Highest......	--	--	2,978	Jul 1977	--	--	--	--	--	--	--	--
Total OPEC												
Lowest.......	--	--	429	Aug 1970	--	--	--	--	--	--	--	--
Highest......	--	--	6,184	Jul 1977	--	--	--	--	--	--	--	--
Non-OPEC												
Lowest.......	--	--	629	Feb 1976	--	--	--	--	--	--	--	--
Highest......	--	--	3,024	Jul 1992	--	--	--	--	--	--	--	--
Motor Gasoline												
Lowest..........	5,561	Feb 1970	36	Oct 1971	(s)	1970-1981*	5,341	Feb 1970	--	--	190	Oct 1970
Highest..........	7,833	Dec 1978	585	May 1990	184	Dec 1992	7,913	Jun 1978	--	--	285	Mar 1981
Distillate Fuel Oil												
Lowest..........	1,993	Mar 1983	42	Mar 1983	(s)	1970-1981*	1,622	Jul 1970	--	--	90	Mar 1988
Highest..........	3,696	Feb 1977	731	Feb 1973	393	Feb 1991	5,103	Jan 1977	--	--	271	Nov 1977
Residual Fuel Oil												
Lowest..........	567	Jun 1970	280	Jul 1992	1	Jan 1971	887	Sep 1992	--	--	36	Apr 1987
Highest..........	1,955	Feb 1977	2,196	Mar 1973	330	Nov 1989	3,974	Feb 1978	--	--	97	Jan 1980
Jet Fuel												
Lowest..........	765	May 1970	3	Jun 1982	0	1979-1981*	905	Apr 1970	--	--	25	1972-1973
Highest..........	1,630	Oct 1990	286	Oct 1972	159	Feb 1991	1,745	Dec 1989	--	--	52	Dec 1990
Liquefied Petroleum Gases												
Lowest..........	1,466	Feb 1982	26	Jun 1970	9	Sep 1979	933	May 1970	162	May 1971	37	Feb 1970
Highest..........	2,106	May 1992	327	Feb 1981	149	Aug 1981	2,184	Dec 1992	461	Dec 1988	157	Sep 1978
All Products												
Lowest..........	--	--	1,330	Apr 1981	156	Jan 1976	13,175	May 1970	--	--	--	--
Highest..........	--	--	3,635	Feb 1973	1,288	Feb 1991	21,288	Feb 1979	--	--	--	--

-- = Not Applicable.
(s) = Less than 500 barrels per day.
*Indicates that the level occurred more than once during the period.
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1991-1992, Tables S1 - S8, and predecessor reports, and *Historical Monthly Energy Review 1973-1988*, Tables 3.1A-3.9.

Figure 2. U.S. Energy Production and Consumption by Source, 1970 - 1992



Note: Because vertical scales differ, graphs should not be compared.
Sources: Energy Information Administration, *Annual Energy Review 1992* and *Monthly Energy Review*, June 1993.

drops were in response to wars, political upheaval in producing areas, and supply disruptions during the past 2 decades. During this period, the more stable and lower prices of alternative fuels led consumers to switch from petroleum as their fuel of economic choice. Except during periods of economic recession, U.S. petroleum demand grew during the 1970's. From a low of 14.7 million barrels per day in 1970, demand reached its peak at 18.8 million barrels per day in 1978.

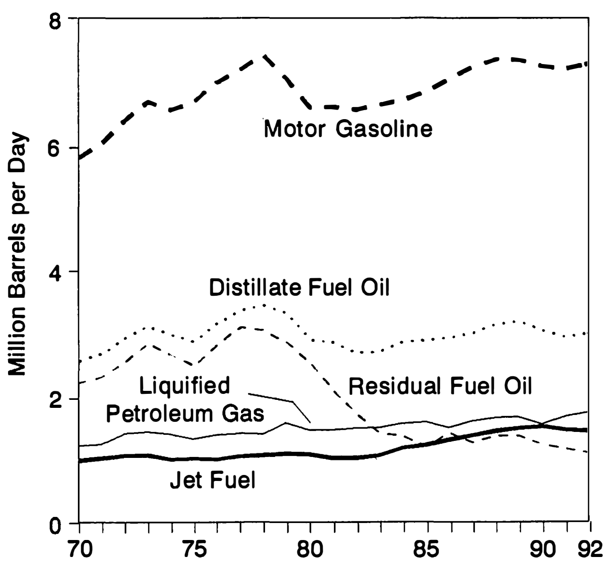
Motor gasoline demand increased from a 1970 low of 5.8 million barrels per day to a high of 7.4 million barrels per day in 1978. The increase reflected a 31-percent growth in the number of automobiles in use[1] and a 25-percent growth in miles traveled. From 1985 to 1992, motor gasoline accounted for about 42 percent of all petroleum products consumed and remained the most important fuel in the United States, averaging over 7 million barrels per day (**Figure 3**).

Changes in demand for distillate fuel oil were similar to motor gasoline in that consumption reached its lowest and highest levels in 1970 and 1978 respectively. Demand increased from 2.5 to 3.4 million barrels per day during the period. Between 1985 and 1992, consumption was relatively stable at about 3 million barrels per day and accounted for about 18 percent of total U.S. petroleum consumption.

Residual fuel oil demand, in response to lower-priced natural gas and other factors, fell 64 percent, from a high of 3.1 million barrels per day in 1977 to 1.1 million barrels per day in 1992.

In contrast, expanding air travel spurred a 57-percent growth in jet fuel demand between 1970 and 1990. Demand increased from a

Figure 3. U.S. Demand for Petroleum Products, 1970 - 1992



Sources: Energy Information Administration, *Annual Energy Review 1992* and *Petroleum Supply Annual*, Vol. 1, 1992.

[1]U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book: Edition 13*, March 1993, Table 3.4.

1970 low of 1.0 million barrels per day to 1.5 million barrel per day in 1990.

Refinery Capacity and Utilization

With rising demand for petroleum products throughout the 1970's, the number of refineries and the capacity to distill crude oil rose rapidly. Between 1970 and the beginning of 1981, there was a 16-percent increase in the number of U.S. refineries; their number grew from 279 to 324. Crude oil refinery capacity also increased, from a low of 12.0 million barrels per day at the beginning of 1970 to its high of 18.6 million barrels per day at the beginning of 1981 **(Figure 4)**.

In 1978, the Iranian Revolution and the subsequent disruption of crude oil supplies triggered a rush to conservation and efficiency improvements. The dramatic drop in U.S. petroleum consumption between 1978 and 1983 resulted in a large decline in refinery utilization rates. Between the beginning of 1978 and the beginning of 1983, utilization dropped from 87.4 to 71.7 percent, and the U.S. refining industry entered a period of significant rationalization. By the beginning of 1986, 108 refineries had closed, representing a loss of more than 3 million barrels per day of crude oil distillation capacity. This restructuring has continued, with the number of refineries falling to a low of 187 at the beginning of 1993.

Petroleum Imports and Exports

Total petroleum imports, including imports for the Strategic Petroleum Reserve (SPR), increased from a low of 3.4 million barrels per day in 1970 to peak at 8.8 million barrels per day in 1977. The 158-percent increase was the result of declining domestic crude oil production and escalating demand prior to the Iranian Revolution. Crude oil imports peaked at 6.6 million barrels per day in 1977.

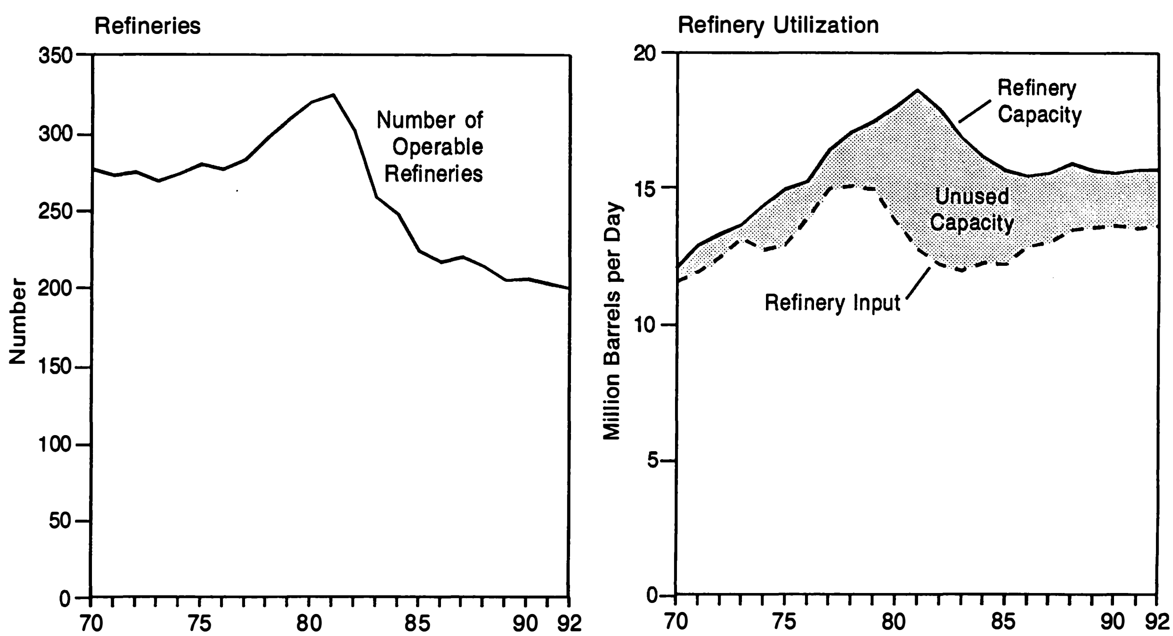
Product imports were highest at 3.0 million barrels per day in 1973. As refining capacity grew under U.S. price and allocation controls, product imports declined, reaching a low of 1.6 million barrels per day in 1981. Residual fuel oil imports had the greatest impact on the decline during that period **(Figure 5)**.

Crude oil exports were very low until the phaseout of price controls began in 1976. Exports peaked in 1980, then declined through 1992. The decline was primarily in response to decreasing U.S. production **(Figure 6)**.

Petroleum product exports also picked up after price controls on petroleum were lifted in 1981. Exports of most major petroleum products reached their highest levels in 1991 or 1992. During that period, U.S. demand was relatively stable, and world supply lines were realigned. These higher exports, particularly distillate fuel oil, served to offset shortages from Kuwait resulting from the Persian Gulf crisis and lower exports from the former Soviet Union after restructuring. The United States also provided petroleum products to newly industrialized countries in recent years. Notably, the United States was a net exporter of distillate fuel oil in both 1991 and 1992.

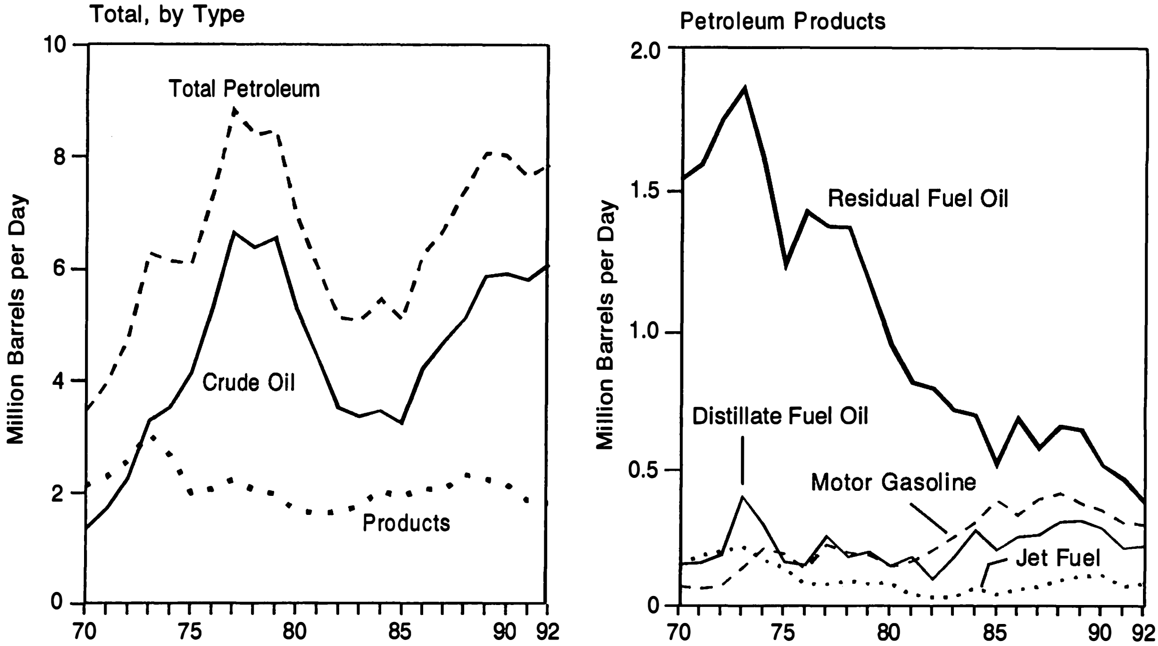
The net imports (gross imports minus exports) of crude oil rose quickly from the low of 1.3 million barrels per day in 1970 to 6.6

Figure 4. Number of Operable U.S. Refineries and Refinery Utilization, 1970 - 1992



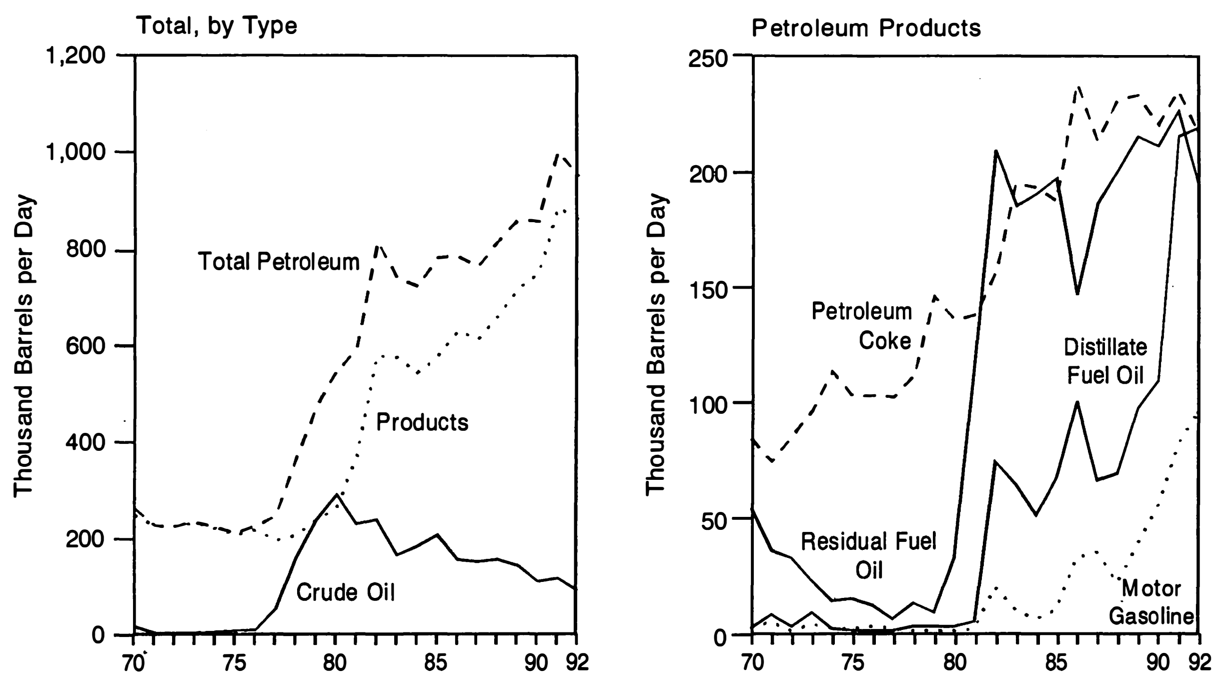
Note: Because vertical scales differ, graphs should not be compared.
Sources: Energy Information Administration, *Annual Energy Review 1992* and *Petroleum Supply Annual*, Vol. 1, 1992.

Figure 5. U.S. Petroleum Imports, 1970 - 1992



Note: Because vertical scales differ, graphs should not be compared.
Sources: Energy Information Administration, *Annual Energy Review 1992* and *Petroleum Supply Annual*, Vol. 1, 1992.

Figure 6. U.S. Petroleum Exports, 1970 - 1992



Note: Because vertical scales differ, graphs should not be compared.
Source: Energy Information Administration, *Annual Energy Review 1992* and *Petroleum Supply Annual*, Vol. 1, 1992.

million barrels per day in 1977. Then, higher prices following the Iranian Revolution triggered a decline to 3.0 million barrels per day by 1985 (**Figure 7**). Petroleum product net imports, on the other hand, peaked at 2.8 million barrels per day in 1973, and have since witnessed a general decline, falling to a low of 944,000 barrels per day in 1992.

Domestic and Foreign Demand

Domestic Uses of Petroleum Products

Petroleum supplies energy in varying degrees to the four basic sectors of the economy. Each sector--Household and Commercial, Industrial, Transportation, and Electric utilities--uses different types of products in the respective energy mixes.

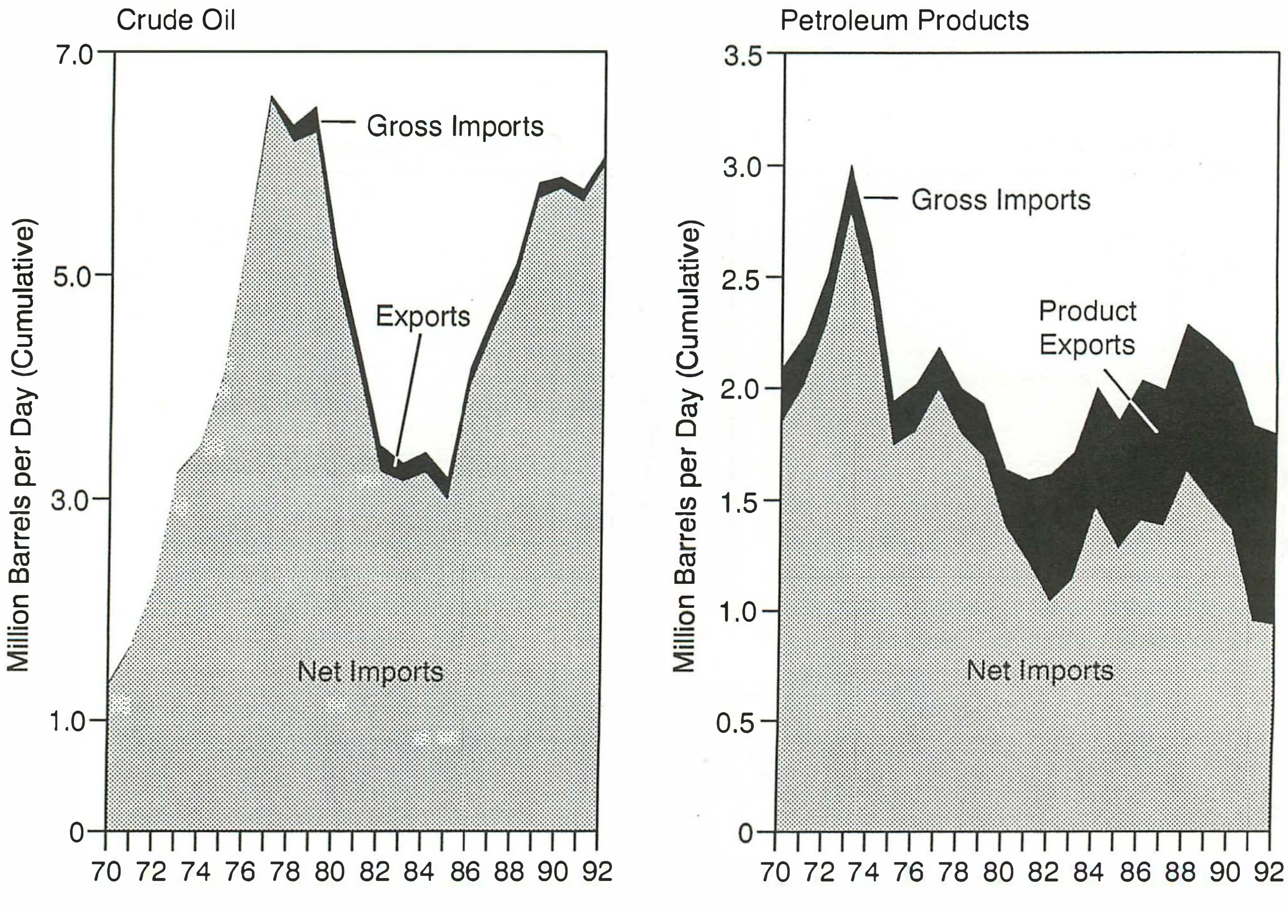
Nowhere is petroleum's use more widespread than in the transportation sector (**Table 3**). Light transportation fuels dominate this area. Together with heavy marine bunkering fuel, they power the millions of automobiles, trucks, airplanes, ships, trains, barges, and military vehicles which provide goods and services to the Nation.

Use in the industrial sector includes a wide range of petroleum products. Bulk fuels such as residual and distillate heating oils are used for boiler and power fuel, and diesel fuel is used to operate construction and farm equipment. Non-fuel products are used for specialized operations, as petrochemical feedstocks and in manufacturing processes. Other non-fuels used in industrial operations are asphalt and road oil for highway and building construction, lubricants and greases, petroleum coke, and wax. Petroleum fuels in the industrial sector compete with natural gas, coal, and electricity.

Petroleum energy in the household and commercial sector is furnished primarily by the bulk light heating oils, distillate and propane. Its principal competitors in this sector are natural gas and electricity.

In the electric utility sector, petroleum supplies energy in the form of bulk heavy residual fuel oil and smaller amounts of bulk light distillate fuel oil. Some kerosene-type jet fuel is used for peak

Figure 7. Gross Petroleum Imports, Exports, and Net Imports, 1970 - 1992



Note: Because vertical scales differ, graphs should not be compared.
Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, and predecessor reports. See Table A4 for corresponding data.

Table 3. U.S. Transportation and Other Demand for Selected Petroleum Products, 1970 - 1992
(Thousand Barrels per Day)

Year	Motor Gasoline			Distillate Fuel Oil			Jet Fuel			Liquefied Petroleum Gases		
	Transportation	Other	Total	Transportation	Other	Total	Transportation	Other	Total	Transportation	Other	Total
1970	5,589	195	5,784	737	1,803	2,540	967	0	967	33	1,192	1,225
1971	5,827	187	6,014	800	1,861	2,661	1,010	0	1,010	36	1,216	1,252
1972	6,199	177	6,376	910	2,003	2,913	1,022	23	1,045	38	1,382	1,420
1973	6,496	178	6,674	1,044	2,048	3,092	1,041	18	1,059	36	1,413	1,449
1974	6,373	164	6,537	1,036	1,912	2,948	978	15	993	33	1,373	1,406
1975	6,512	163	6,675	997	1,854	2,851	992	9	1,001	30	1,303	1,333
1976	6,817	161	6,978	1,074	2,059	3,133	978	9	987	33	1,371	1,404
1977	7,021	156	7,177	1,170	2,182	3,352	1,022	17	1,039	36	1,386	1,422
1978	7,264	148	7,412	1,260	2,172	3,432	1,044	13	1,057	38	1,375	1,413
1979	6,894	140	7,034	1,367	1,944	3,311	1,068	8	1,076	16	1,576	1,592
1980	6,440	139	6,579	1,311	1,555	2,866	1,063	5	1,068	14	1,455	1,469
1981	6,460	128	6,588	1,364	1,465	2,829	1,003	4	1,007	25	1,441	1,466
1982	6,422	117	6,539	1,312	1,359	2,671	1,011	2	1,013	25	1,474	1,499
1983	6,510	112	6,622	1,367	1,323	2,690	1,044	2	1,046	30	1,479	1,509
1984	6,555	138	6,693	1,475	1,370	2,845	1,175	0	1,175	30	1,542	1,572
1985	6,668	163	6,831	1,507	1,361	2,868	1,218	0	1,218	22	1,577	1,599
1986	6,872	162	7,034	1,553	1,361	2,914	1,307	0	1,307	19	1,493	1,512
1987	7,042	164	7,206	1,594	1,382	2,976	1,385	0	1,385	16	1,596	1,612
1988	7,178	158	7,336	1,730	1,392	3,122	1,449	0	1,449	16	1,640	1,656
1989	7,170	158	7,328	1,806	1,351	3,157	1,489	0	1,489	16	1,652	1,668
1990	7,082	153	7,235	1,803	1,218	3,021	1,522	0	1,522	16	1,540	1,556
1991	7,031	157	7,188	1,730	1,191	2,921	1,471	0	1,471	16	1,673	1,689
1992[1]	7,109	159	7,268	1,764	1,215	2,979	1,454	0	1,454	17	1,738	1,755

Year	Residual Fuel Oil			All Other			All Products		Total Demand
	Transportation	Other	Total	Transportation[2]	Other	Total	Transportation	Other	
1970	332	1,870	2,202	121	1,858	1,979	7,779	6,918	14,697
1971	304	1,992	2,296	116	1,864	1,980	8,093	7,120	15,213
1972	281	2,248	2,529	117	1,967	2,084	8,567	7,800	16,367
1973	318	2,504	2,822	120	2,092	2,212	9,055	8,253	17,308
1974	304	2,335	2,639	114	2,016	2,130	8,838	7,815	16,653
1975	310	2,152	2,462	110	1,890	2,000	8,951	7,371	16,322
1976	358	2,443	2,801	112	2,046	2,158	9,372	8,089	17,461
1977	397	2,674	3,071	116	2,254	2,370	9,762	8,669	18,431
1978	430	2,593	3,023	120	2,390	2,510	10,156	8,691	18,847
1979	534	2,292	2,826	126	2,548	2,674	10,005	8,508	18,513
1980	607	1,901	2,508	111	2,455	2,566	9,546	7,510	17,056
1981	532	1,556	2,088	104	1,976	2,080	9,488	6,570	16,058
1982	444	1,272	1,716	93	1,765	1,858	9,307	5,989	15,296
1983	359	1,062	1,421	95	1,848	1,943	9,405	5,826	15,231
1984	350	1,019	1,369	100	1,972	2,072	9,685	6,041	15,726
1985	342	860	1,202	97	1,911	2,008	9,854	5,872	15,726
1986	378	1,040	1,418	101	1,995	2,096	10,230	6,051	16,281
1987	392	872	1,264	103	2,119	2,222	10,532	6,133	16,665
1988	397	981	1,378	102	2,240	2,342	10,872	6,411	17,283
1989	425	945	1,370	102	2,211	2,313	11,008	6,317	17,325
1990	446	783	1,229	101	2,324	2,425	10,970	6,018	16,988
1991	448	710	1,158	95	2,192	2,287	10,791	5,923	16,714
1992[1]	423	671	1,094	103	2,380	2,483	10,870	6,163	17,033

[1] Transportation and other demand were calculated based on previous year's share of total demand for each product.
[2] Lubricants and aviation gasoline.
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, Tables S1 and S4-S8, and predecessor reports, and *State Energy Data Report 1960-1991*, Tables 12 and 16.

shaving purposes. Petroleum inputs at electric utilities were modest compared to coal throughout the past 23 years. After 1978, natural gas, nuclear power, and hydroelectricity inputs also overtook petroleum. Electricity generated by utilities becomes a secondary energy source which competes with petroleum in other sectors of the economy.

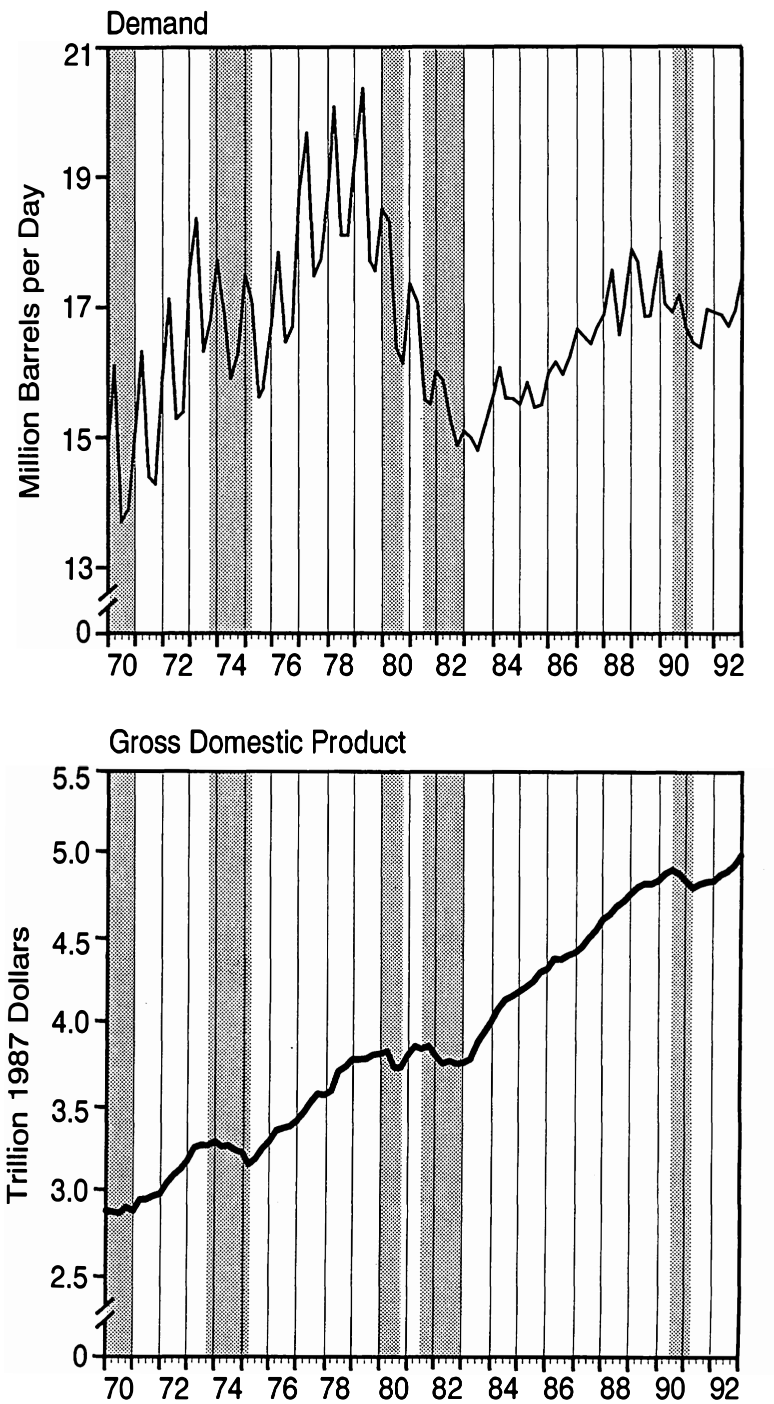
Impact of Events on Domestic Demand

The decade of the 1970's proved to be very different for the domestic petroleum industry and its customers than the 2 decades that preceded it. From the end of the Second World War, petroleum demand had risen steadily with supplies adequate to meet demand.

However, late in 1973, a combination of domestic and foreign circumstances crystallized into the first peacetime petroleum supply disruption in the history of the Nation. The disruption marked the end of the era of cheap, secure oil supplies. The economic recession that followed is widely considered to have been caused by the disruption (**Figure 8**), though some recent economic studies indicate that U.S. monetary policy may have contributed.[2] Crude oil prices worldwide tripled in one year, but price controls in effect in the United States partially shielded the economy from the full impact of the price hikes. Nevertheless, the retail prices of gasoline and home heating oil rose 35 and 58 percent, respectively--indicative of the additional cost increases to the U.S. economy.

Following several years of economic readjustment and stable oil markets, petroleum demand began a resurgence that lasted until 1978. Then, early in 1979, a revolution in the Middle East precipitated a second global peacetime petroleum supply disruption. Again, petroleum prices advanced rapidly and by 1981, U.S. refiners were paying 183 percent more for crude oil than in 1978, and 749 percent more than in 1973.

Figure 8. U.S. Petroleum Demand, Gross Domestic Product, and Economic Recessions, 1970 - 1992



Note Periods of economic recessions are shaded.

Sources: • Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992 and predecessor reports; • U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, December 1992 and March 1993.

Since the energy market does not operate in a vacuum, the rapid rise in petroleum prices caused similar types of price increases for other energy sources.[3] Faced with vastly higher energy costs, economic activity retreated. By 1983, U.S. demand had fallen to 15.2 million barrels per day, 19 percent below its 1978 peak and the lowest level since 1971.

An additional constraint to demand growth was the 1978 implementation of the Corporate Average Fuel Economy (CAFE) legislation that mandated increased fuel efficiency in highway vehicles. In 1977, passenger cars averaged 13.8 miles per gallon. Yearly increases in gas mileage since the CAFE standards went into effect brought the average miles per gallon in 1991 to 21.7.

[2] Douglas R. Bohi, *Energy Price Shocks and Macroeconomic Performance*, Resources for the Future 1989, pp. 1, 3, and 83 - 87.
[3] Energy Information Administration, *State Energy Price and Expenditure Report 1970-1981*, p. 3.

Economic growth began to recover in 1983 and continued for almost eight years, until the Persian Gulf crisis of 1990. As crude oil prices gradually moderated and the availability of supplies increased, petroleum demand also began to revive.

In 1986, a third global oil price shock occurred. Unlike the previous two, this one was a sharp decline, as foreign producers, competing for market share, dumped their excess crude oil into the market. The world price of crude oil responded during the first quarter of 1986 by dropping more than 50 percent from the price at the end of 1985. Crude oil prices reverted to levels not seen since 1977 and 1978. Between 1985 and 1986, the retail price of regular motor gasoline declined 23 percent while the retail price of No. 2 home heating oil fell 24 percent. By 1989, demand had returned to the 1973 level.

The Changing Mix of Bulk, Transportation, and Nonfuels

In response to the first oil price shock of 1973, U.S. consumers and industry sought ways to reduce petroleum use or switch to alternative energy sources. Residential consumers moderated their heating and cooling temperatures, installed more insulation,[4] and drove less.[5] Industry increased use of alternative energy sources wherever possible and streamlined operations to reduce petroleum use and overall energy use, in general.

Initially, bulk heating oils (distillate and propane of the light oils and residual among heavy oils) lost energy market share in the economy. However, the reductions were somewhat offset by other factors at work.

Legislation enacted in the 1970's mandated crude oil price and allocation controls, froze buyer-seller relationships, and limited the fuel choices of electric utilities. Collectively, the legislation reduced the flexibility of the petroleum industry and the economy to fully respond to the impact of the supply disruption, and tended to subsidize demand.

As a result, after the economy began to recover in 1975, low-cost bulk heating oils recaptured much of the energy markets they had lost in the industrial and electric utility sectors.[6] By switching to low-sulphur residual fuel oil from the high-sulphur product, electric utilities and industrial plants were able to economically satisfy both their energy needs and their environmental obligations.[7]

[4] Energy Information Administration, *Energy Consumption Indicators, 1984 Annual Report*, Figures 14, 24, 40, and 43.
[5] U.S. Department of Transportation, Federal Highway Administration, *Traffic Volume Trends*, April 1993, Figure 1.
[6] Energy Information Administration, *Sales of Fuel Oil and Kerosene in 1977*, Figures 1 and 2.
[7] Energy Information Administration, *Availability of Heavy Fuel Oils by Sulfur Levels*, December 1977, and predecessor reports, 1975 and 1976, Tables 3 and 5.

Petroleum Products, By Type

Bulk Fuels:

Bulk petroleum fuels are used in all sectors of the U.S. economy. They are used as industrial boiler and power fuel, household and commercial heating fuel, and specialty fuels. They are also used in electric power generation, construction and farm operations. These fuels compete with alternative energy sources, and lost market share after 1978.

Light Bulk Fuels:

- Kerosene
- Distillate fuel oil
- Liquefied petroleum gases
- Still gas
- Miscellaneous products

Heavy Bulk Fuels:

- Petroleum coke
- Residual fuel oil

Transportation Fuels

Transportation fuels are primarily engine fuels for vehicles used in highway, marine, and aviation modes. For the foreseeable future, petroleum will remain the principal engine fuel, as it is not yet largely replaceable by alternative fuels.

Light Transportation Fuels:

- Aviation gasoline
- Diesel fuel
- Jet fuel
- Liquefied petroleum gases
- Motor gasoline

Heavy Transportation Fuels:

- Lubricants
- Residual fuel oil

Nonfuels

Specialized industrial operations are the predominant uses for petroleum non-fuels. These operations include the production of petrochemicals, manufacturing processes, highway and building construction. Consumption of light non-fuels doubled between 1970 and 1992.

Light Nonfuels:

- Liquefied petroleum gases
- Petrochemical feedstocks
- Miscellaneous products
- Still gas
- Special naphthas

Heavy Nonfuels:

- Asphalt and road oil
- Lubricants
- Petroleum coke
- Waxes

Table 4. U.S. Demand for Light and Heavy Petroleum Products, 1970 - 1992
(Thousand Barrels per Day)

Year	Light				Heavy				Total			
	Transportation[1]	Bulk[2]	Nonfuel[3]	Total Light	Transportation[1]	Bulk[2]	Nonfuel[3]	Total Heavy	Transportation[1]	Bulk[2]	Nonfuel[3]	Total Demand
1970....	7,382	3,346	960	11,688	397	1,870	742	3,009	7,779	5,216	1,702	14,697
1971....	7,723	3,368	1,001	12,092	370	1,991	760	3,121	8,093	5,359	1,761	15,213
1972....	8,215	3,613	1,142	12,969	352	2,248	797	3,397	8,567	5,861	1,939	16,367
1973....	8,663	3,641	1,218	13,522	392	2,505	889	3,786	9,055	6,146	2,107	17,308
1974....	8,463	3,427	1,229	13,119	375	2,335	824	3,534	8,838	5,762	2,053	16,653
1975....	8,570	3,355	1,117	13,042	381	2,151	748	3,280	8,951	5,506	1,865	16,322
1976....	8,937	3,636	1,259	13,832	435	2,443	751	3,629	9,372	6,079	2,010	17,461
1977....	9,288	3,794	1,399	14,481	474	2,674	802	3,950	9,762	6,468	2,201	18,431
1978....	9,644	3,766	1,490	14,900	512	2,593	842	3,947	10,156	6,359	2,332	18,847
1979....	9,383	3,886	1,499	14,768	622	2,292	831	3,745	10,005	6,178	2,330	18,513
1980....	8,862	3,343	1,534	13,739	684	1,901	732	3,317	9,546	5,244	2,266	17,056
1981....	8,882	3,209	1,114	13,205	606	1,556	691	2,853	9,488	4,765	1,805	16,058
1982....	8,795	2,984	1,056	12,835	512	1,272	677	2,461	9,307	4,256	1,733	15,296
1983....	8,975	2,831	1,175	12,981	430	1,061	759	2,250	9,405	3,892	1,934	15,231
1984....	9,259	2,884	1,322	13,465	426	1,019	814	2,259	9,685	3,903	2,136	15,726
1985....	9,441	2,886	1,287	13,614	413	860	839	2,112	9,854	3,746	2,126	15,726
1986....	9,784	2,886	1,271	13,941	446	1,040	854	2,340	10,230	3,926	2,125	16,281
1987....	10,061	2,905	1,458	14,424	471	871	899	2,241	10,532	3,776	2,357	16,665
1988....	10,402	2,880	1,631	14,913	470	981	919	2,370	10,872	3,861	2,550	17,283
1989....	10,506	2,929	1,556	14,991	502	945	887	2,334	11,008	3,874	2,443	17,325
1990....	10,445	2,599	1,689	14,733	525	782	948	2,255	10,970	3,381	2,637	16,988
1991....	10,271	2,540	1,792	14,603	520	710	881	2,111	10,791	3,250	2,673	16,714
1992[4]...	10,366	2,587	1,970	14,923	504	716	890	2,110	10,870	3,303	2,860	17,033

[1] Light transportation fuels include motor gasoline, aviation gasoline, distillate(diesel fuel), jet fuel, and liquefied petroleum gases. Heavy transportation fuels include residual fuel oil and lubricants.

[2] Light bulk fuels include motor gasoline, distillate fuel oil, jet fuel, liquefied petroleum gases, kerosene, still gas, and miscellaneous products. Heavy bulk fuels include residual fuel oil.

[3] Light nonfuels include liquefied petroleum gases, naphtha and other oils for petrochemical feedstock use, special naphthas, pentanes plus, still gas, miscellaneous products, and other liquids. Heavy nonfuels include crude oil, lubricants, wax, asphalt and road oil, and petroleum coke.

[4] Transportation, Bulk, and Nonfuel data were calculated based on previous year's share of total for each type.

Sources: • Energy Information Administration, **Bulk and Nonfuel, except liquefied petroleum gases:** *Petroleum Supply Annual*, Vol. 1, 1981-1992, Table 2, and predecessor reports. **Transportation:** *State Energy Data Report 1960-1991*, Table 12. **Bulk and Nonfuel liquefied petroleum gases:** *Sales of Liquefied Petroleum Gases and Ethane*, 1977-1982, Table 1, and predecessor reports. • American Petroleum Institute, *Sales of Natural Gas Liquids and Liquefied Refinery Gases*, 1984-1991, Table 1.

Since technology to reduce pollutants from coal burning was in its developmental stages, competition from coal was minimal at that time. Natural gas use generally was restricted to the residential market, since it was in short supply. Consequently, demand for bulk oils grew, reaching a peak of 6.5 million barrels per day in 1977 (**Table 4**).

Price and allocation decontrol in 1981 followed on the heels of the 1979 petroleum supply shock. This time, the U.S. economy was fully exposed to the effects of the large increases in energy prices in general and petroleum prices in particular. In order to reduce their energy bills, consumers intensified their efforts to conserve energy. They further moderated heating and cooling habits, increased insulation,[8] and traveled even less. Residential consumers switched to electricity and natural gas as alternatives to petroleum.[9] Many consumers bought smaller, more fuel efficient automobiles, or turned to mass transit to reduce transportation costs.[10]

Industry turned to electricity and natural gas as alternatives to petroleum. In addition, industry researched and developed new technologies to reduce overall energy use and installed fuel switching capabilities to minimize costs.

Electric utilities turned more to other energy sources, and away from petroleum after prices were decontrolled in 1981. Coal was plentiful and more economical. Hydroelectric and nuclear power were also competitive and more secure. Gradually, natural gas supplies became price competitive and also began to displace petroleum in the electric utility sector. Within a few years after

[8] Energy Information Administration, *Energy Consumption Indicators, 1984 Annual Report*, Figures 14, 19, 24, and 40.
[9] Energy Information Administration, *Residential Energy Consumption and Expenditures by End Use for 1978, 1980, and 1981*, Figure 1.
[10] U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book, Edition 13*, March 1993, Tables 3.18 and 3.30.

the repeal of the Powerplant and Industrial Fuel Use Act in 1987, electricity generation from natural gas was stable while generation from petroleum was declining substantially.

Although overall energy demand declined 10 percent from 1978 to 1983, petroleum demand decreased by 19 percent, losing 3.6 million barrels per day. Sixty-eight percent of the lost volume was made up of bulk oils, light and heavy. Collectively, their use was diminished by 2.5 million barrels per day. Residual fuel oil, the predominant heavy bulk oil, lost 1.5 million barrels per day, accounting for 42 percent of the total decline in demand. Demand for bulk oils after 1983 remained relatively stable until 1990, when they continued to lose market share. By 1992, demand of 3.3 million barrels per day was 15 percent below the 1983 volume and only about half of the volume consumed in 1978 (**Figure 9**).

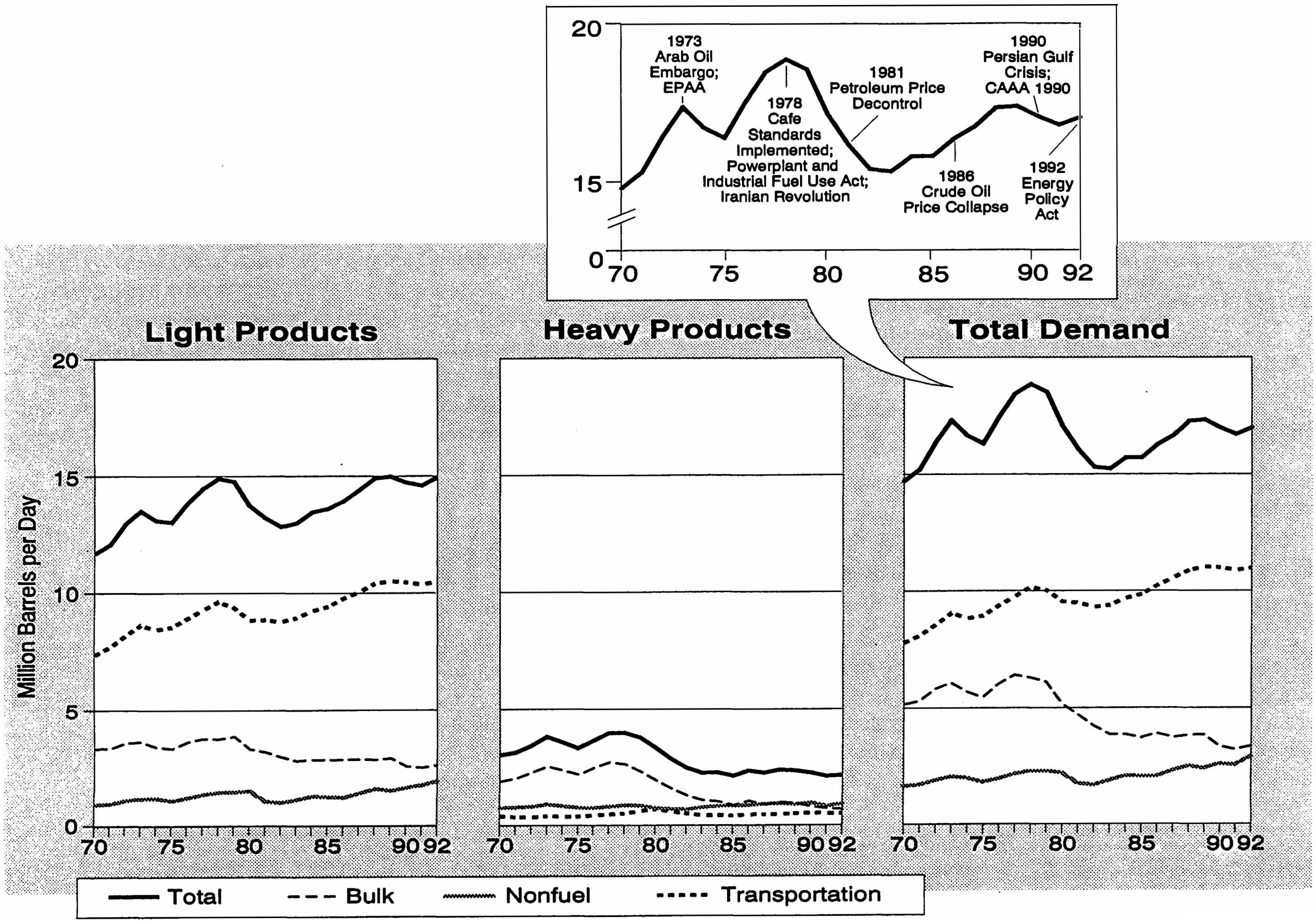
In contrast to bulk fuels, nonfuel products maintained or increased their respective market positions. Nonfuel products made up approximately 13 percent of total demand in 1983. By 1992, they comprised almost 17 percent. Much of this growth is attributable to the increase in demand for plastics and other basic chemicals. This growth is mainly reflected in the increase of light nonfuel products, which expanded 68 percent from 1983 to 1992.

The transportation sector, unlike other sectors, did not see a decrease in petroleum's influence. Over the entire 2-decade period, petroleum transportation fuels supplied more than 95 percent of the energy used in the transportation sector. In turn, light transportation fuels, mainly motor gasoline, jet fuel and diesel, dominated that petroleum market, providing 95 percent of the volume.

During the 1990's, the influx of alternative transportation fuels will continue, but petroleum will retain its dominance in the transportation market. The Energy Policy Act of 1992 mandates the phase-in of alternative fuels such as methanol, ethanol, natural gas, and electricity in automobile and truck fleets.

The greatest demand for light transportation fuels is for highway travel. Almost all motor gasoline is used for this purpose. Some 59 percent of total distillate oil demand also was dedicated to transportation in 1992, with on-highway use representing about

Figure 9. U.S. Demand for Light and Heavy Petroleum Products for Transportation, Bulk, and Nonfuel Uses, and Related Events, 1970-1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table 4 for corresponding data and defintions.

46 percent. Diesel's contribution to the growth of light transportation fuels cannot be underestimated. While motor gasoline grew by 27 percent from 1970 to 1992, diesel fuel use more than doubled.

Excluding small amounts used for electric utility peak shaving, all jet fuel is consumed for transportation. Though some kerosene-type jet fuel is blended with diesel fuel for vehicle engine ignition in cold weather, the major portion goes to the commercial aviation market. Demand for jet fuel grew 150 percent from 1970 to 1992.

Heavy transportation fuels, principally marine bunkering fuel, grew in the United States throughout the 1970's. Sheltered by price controls, domestic bunker fuels were a bargain. After price decontrol in 1981, domestic bunkering prices escalated to world levels and demand receded. Since the mid-1980's, heavy transportation fuel use has remained fairly static.

Over the years, the growth in light transportation fuels altered the composition of total domestic petroleum demand. In 1970, light transportation fuels made up 50 percent of total demand. When petroleum demand peaked in 1978, their share was 51 percent. After price decontrol in 1981, they commanded an even larger share of the market. In 1992, they comprised 61 percent of all petroleum use.

Since the 1973 supply disruption, U.S. consumers have learned to use energy more efficiently. While the gross domestic product expanded 51 percent from 1973 to 1992, the amount of energy expended to produce each dollar declined 26 percent. As a result, the overall energy market grew only 11 percent.

While petroleum's share of the energy market declined from 49 percent in 1977, it still commanded 41 percent of the larger 1992 market. Petroleum continued to be the predominate energy source in the U.S. economy, though consumption of coal and nuclear power grew.

Foreign Demand

Foreign demand for petroleum grew from 32.1 to 49.8 million barrels per day between 1970 and 1991, an increase of 55 percent. Growth in demand for light products expanded during this period, while demand for heavy products was about the same in 1991 as in 1970.

Replacement of heavy bulk fuels in Western Europe and Far Eastern countries served to offset increases in developing areas. In Japan and France, for example, replacing residual fuel oil with nuclear power for electric generation has been a way to counter the lack of indigenous energy resources.[11] Japan is also expanding its use of lower-priced natural gas as a way to diversify its energy sources.

As in the United States, light products (excluding LPG's for lack of data prior to 1986), increased and claimed a greater share of foreign petroleum demand after 1970. In the Far East and Oceania, total petroleum demand doubled between 1970 and 1990, and continued to rise in 1991 **(Table 5)**. Demand for light products almost tripled to 7.1 million barrels per day by 1990, and its share of total demand grew from 40 to 52 percent **(Figure 10)**.

Western Europe's total petroleum demand grew from 12.6 to 13.0 million barrels per day between 1970 and 1990. The share attributed to light products increased from 47 to 62 percent over the period. Among heavy products, residual fuel oil remains a primary fuel for power generation in Italy and other Western European countries, but is gradually being replaced by nuclear power in France and Scandinavia. Residual fuel oil's share of Western European petroleum demand fell from 36 percent in 1970 to 18 percent in 1990.

Among the other products, foreign demand for LPG's grew after the mid-1980's. In 1986, LPG's comprised 26 percent of the demand for other products. By 1990, foreign LPG demand of 3.7 million barrels per day represented 37 percent of foreign demand for other products.[12]

The switch from heavy products was less dramatic in some of the developing areas of the world. In North America, Mexico's recent booming economy continued to rely on residual fuel oil for power generation and industrial power.[13] Among the other products, however, LPG demand in Mexico grew.[14] LPG is the leading residential fuel, dominant petrochemical feedstock, and competes with motor gasoline as a transportation fuel.[15] In Africa, where total petroleum demand almost tripled between 1970 and 1990, residual fuel oil use more than doubled, but its share declined from 32 to 25 percent. Demand for both light and heavy products increased in Eastern Europe and the Former Soviet Union, but the shares of each remained about the same through the years. Selected light fuels comprised about 50 percent of the total in Eastern Europe and the Former Soviet Union, and selected heavy fuels accounted for about 32 percent.

Light transportation fuels predominate in developed areas of the world, but the mix of fuels (excluding air travel) differs from that in the United States. Of the non-air light transportation fuel U.S. consumers used in 1990, 79 percent was motor gasoline and 20 percent diesel fuel. In contrast, Italy's diesel fuel share was 57 percent. The mix in Japan and France was 56 percent motor gasoline to 44 percent diesel fuel **(Figure 11)**. The cost of diesel fuel to motorists is about one-half the cost of motor gasoline in many European and Far Eastern countries. In addition, diesel fuel is a primary fuel in foreign mass transit.

[11] Energy Information Administration, *International Energy Outlook 1990*, p. 17.
[12] Energy Information Administration, *International Energy Annual*, 1987, Table 11, 1991, Table 18.
[13] "Mexican Energy Law Developments," *Petroleum Economist*, July 1992, Energy Law special supplement.
[14] Energy Information Administration, *International Energy Annual*, 1987, Table 11, and 1988 - 1991, Table 18.
[15] "High Mexican Prices Take Bite Out Of Local Demand," *Petroleum Intelligence Weekly*, December 7, 1992, p. 5.

Table 5. Primary Components of World Demand, Selected Years
(Thousand Barrels per Day)

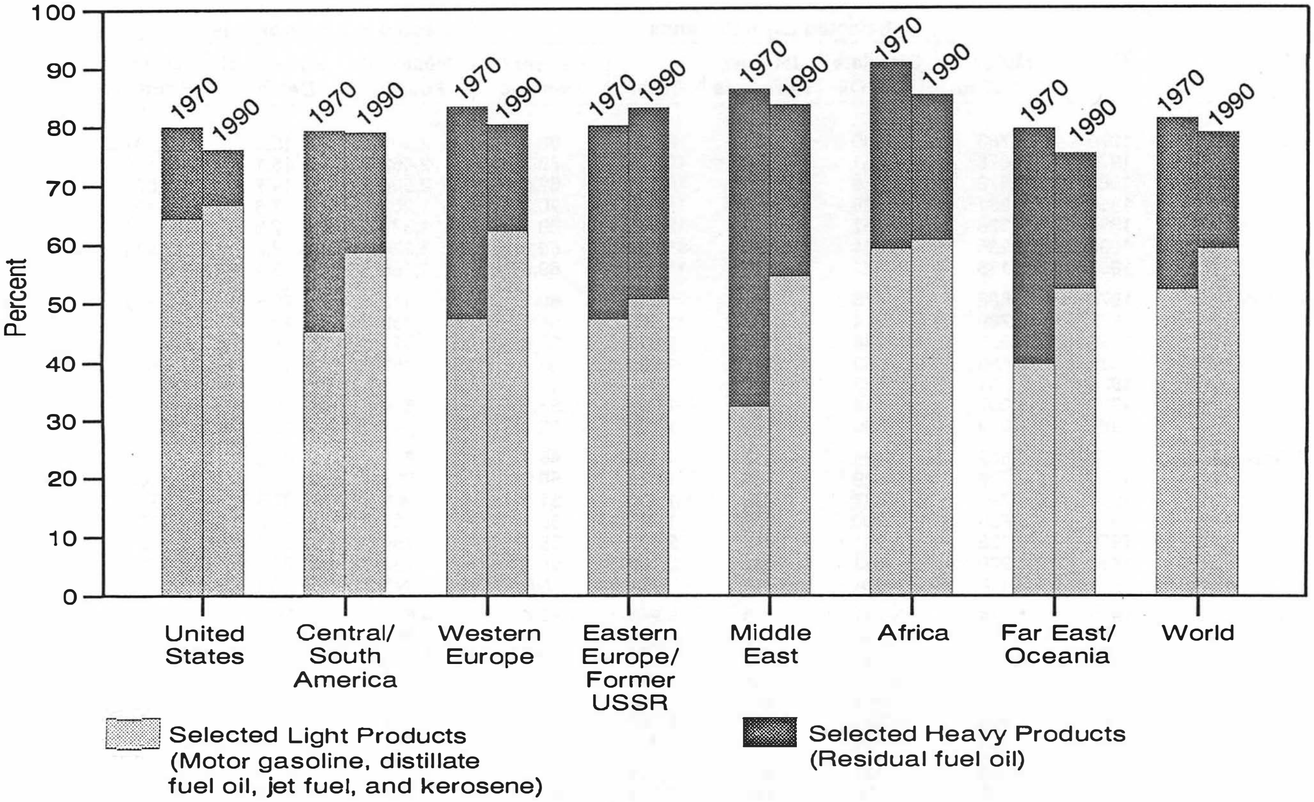
Area	Year	Selected Light Products					Selected Heavy Products		All Other Products	Total Demand
		Motor Gasoline	Distillate Fuel Oil	Jet Fuel/ Kerosene	Total	Percent of Demand	Residual Fuel Oil	Percent of Demand		
United States	1970	5,783	2,540	1,230	9,553	65.0	2,203	15.0	2,941	14,697
	1975	6,675	2,851	1,159	10,685	65.5	2,462	15.1	3,175	16,322
	1980	6,579	2,866	1,226	10,671	62.6	2,508	14.7	3,877	17,056
	1985	6,831	2,868	1,333	11,032	70.2	1,202	7.6	3,492	15,726
	1989	7,328	3,157	1,573	12,058	69.6	1,370	7.9	3,897	17,325
	1990	7,235	3,021	1,565	11,821	69.6	1,229	7.2	3,938	16,988
	1991	7,188	2,921	1,517	11,626	69.6	1,158	6.9	3,930	16,714
Other North America	1970	602	475	141	1,218	60.1	412	20.3	395	2,025
	1975	789	614	159	1,562	61.6	488	19.2	487	2,537
	1980	995	744	174	1,913	60.8	571	18.1	664	3,148
	1985	883	653	149	1,685	56.7	450	15.1	839	2,974
	1989	991	629	197	1,817	53.4	677	19.9	907	3,401
	1990	1,007	616	185	1,808	53.2	670	19.6	942	3,422
	1991	1,019	590	171	1,780	52.2	547	16.0	1,084	3,412
Central and S. America	1970	532	425	162	1,119	45.3	840	34.0	511	2,470
	1975	709	629	188	1,526	50.0	939	30.8	584	3,049
	1980	791	827	235	1,853	51.9	986	27.6	734	3,573
	1985	738	800	229	1,767	55.5	637	20.0	781	3,185
	1989	925	951	215	2,091	58.5	754	21.1	732	3,577
	1990	930	953	223	2,106	58.6	734	20.4	755	3,595
	1991	NA	NA	NA	NA	NA	NA	NA	NA	3,653
Western Europe	1970	1,714	3,761	473	5,948	47.4	4,518	36.0	2,093	12,559
	1975	2,128	4,136	545	6,809	50.6	4,483	33.3	2,173	13,465
	1980	2,475	4,351	555	7,381	52.9	3,728	26.7	2,838	13,947
	1985	2,487	4,172	527	7,186	59.8	2,467	20.5	2,370	12,023
	1989	2,851	4,306	686	7,843	61.0	2,357	18.3	2,659	12,859
	1990	2,962	4,393	714	8,069	62.2	2,344	18.1	2,551	12,964
	1991	NA	NA	NA	NA	NA	NA	NA	NA	13,568
E. Europe and Former USSR	1970	1,249	1,341	463	3,053	47.3	2,110	32.7	1,293	6,456
	1975	1,687	1,710	616	4,013	43.7	3,255	35.4	1,921	9,189
	1980	1,857	2,510	753	5,120	46.2	3,208	28.9	2,754	11,082
	1985	1,913	2,318	751	4,982	46.0	3,050	28.2	2,792	10,824
	1989	1,895	2,253	733	4,881	46.5	3,211	30.6	2,398	10,490
	1990	2,070	2,312	678	5,060	50.6	3,243	32.4	1,704	10,007
	1991	NA	NA	NA	NA	NA	NA	NA	NA	9,281
Middle East	1970	83	161	94	338	32.3	564	53.9	144	1,046
	1975	160	298	187	645	46.7	545	39.5	190	1,380
	1980	290	436	275	1,001	48.6	646	31.4	411	2,058
	1985	479	791	301	1,571	55.0	815	28.6	468	2,854
	1989	503	917	322	1,742	51.9	1,036	30.9	577	3,355
	1990	542	965	377	1,884	54.4	1,010	29.1	571	3,465
	1991	NA	NA	NA	NA	NA	NA	NA	NA	3,520
Africa	1970	159	208	88	455	59.1	243	31.6	72	770
	1975	237	314	127	678	61.7	268	24.4	152	1,098
	1980	314	406	179	899	61.0	332	22.5	243	1,474
	1985	402	496	214	1,112	60.9	424	23.2	290	1,826
	1989	439	559	232	1,230	61.8	468	23.5	293	1,991
	1990	460	574	239	1,273	60.6	516	24.6	311	2,100
	1991	NA	NA	NA	NA	NA	NA	NA	NA	2,169
Far East and Oceania	1970	961	1,030	693	2,684	39.6	2,691	39.7	1,411	6,786
	1975	1,220	1,635	1,096	3,951	43.1	3,176	34.7	2,031	9,158
	1980	1,432	2,210	1,109	4,751	44.3	3,749	34.9	2,229	10,729
	1985	1,617	2,445	1,119	5,181	48.5	2,493	23.3	3,012	10,686
	1989	2,055	3,273	1,346	6,674	51.2	2,972	22.8	3,386	13,032
	1990	2,184	3,497	1,428	7,109	52.2	3,124	22.9	3,381	13,614
	1991	NA	NA	NA	NA	NA	NA	NA	NA	14,244
Total Foreign	1970	5,300	7,400	2,114	14,814	46.1	11,378	35.4	5,919	32,111
	1975	6,928	9,335	2,916	19,179	48.1	13,155	33.0	7,542	39,876
	1980	8,154	11,484	3,279	22,917	49.8	13,219	28.7	9,875	46,011
	1985	8,519	11,675	3,286	23,480	52.9	10,335	23.3	10,557	44,372
	1989	9,659	12,888	3,732	26,279	54.0	11,475	23.6	10,951	48,705
	1990	10,155	13,311	3,843	27,309	55.5	11,642	23.7	10,216	49,167
	1991	NA	NA	NA	NA	NA	NA	NA	NA	49,847
Total World	1970	11,083	9,940	3,344	24,367	52.1	13,581	29.0	8,860	46,808
	1975	13,603	12,186	4,075	29,864	53.1	15,617	27.8	10,717	56,198
	1980	14,733	14,350	4,505	33,588	53.3	15,727	24.9	13,752	63,067
	1985	15,350	14,543	4,619	34,512	57.4	11,537	19.2	14,049	60,098
	1989	16,987	16,045	5,305	38,337	58.1	12,845	19.5	14,848	66,030
	1990	17,390	16,332	5,408	39,130	59.1	12,871	19.5	14,154	66,155
	1991	NA	NA	NA	NA	NA	NA	NA	NA	66,560

NA = Not Available.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, Office of Energy Markets and End Use, *Annual Energy Review 1992*, Table 11.10, *International Energy Annual 1991*, Table 18, and International Statistics Branch.

Figure 10. Distribution of Selected Light and Heavy Products in World Petroleum Demand by Area,1970 and 1990



Note: The remainder above each bar represents all other products, both light and heavy, for which individual data are not available.
Source: Energy Information Administration, Office of Energy Markets and End Use, *Annual Energy Review 1992.* See Table 6 for corresponding data.

Petroleum's share of the total foreign energy market remained at about 39 percent since at least 1988. In areas where petroleum's share declined, generally the switch was to natural gas.[16]

Domestic and Foreign Petroleum Refining

Crude oil quality changes, shifting petroleum demand patterns, and evolving regulations (described in Chapter 3) during the past 23 years provoked changes that resulted in a more complex, more flexible domestic refining industry. Refining capacity and utilization, configuration and processing flexibility, slates and product yields were reshaped. Ownership of U.S. refineries changed through consolidation and foreign investments. As the U.S. industry evolved and became more sophisticated during the 1980's and early 1990's, the foreign refining industry was also modernizing to accommodate shifts in world product markets.

U.S. Refineries and Utilization Rates

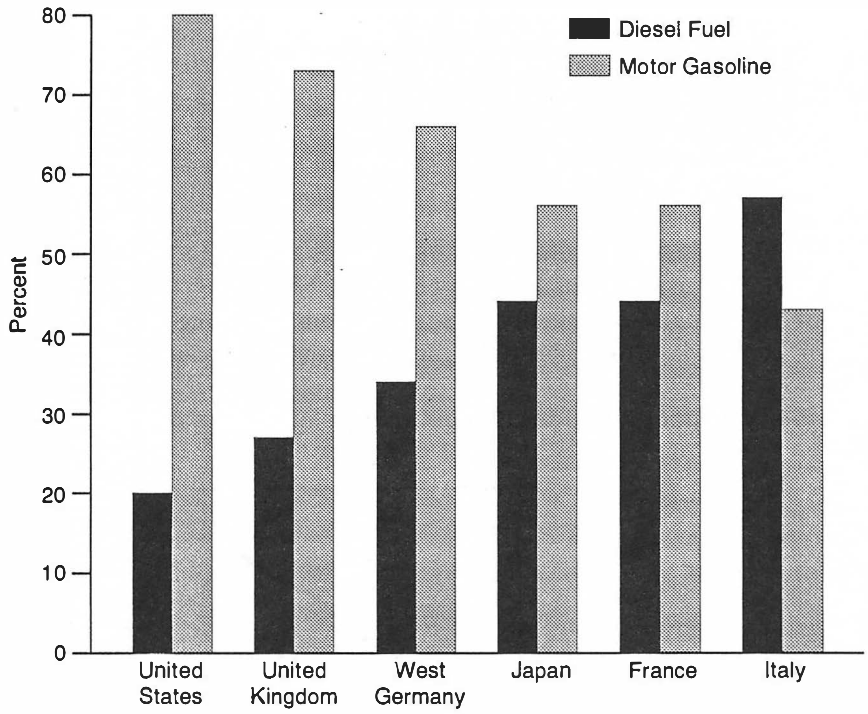
A record number of U.S. refineries were operating at the beginning of 1981 when crude oil distillation capacity peaked at 18.6 million barrels per day. The number of refineries and refining capacity had both grown steadily under the price and allocation programs set up in 1973 and 1974. These programs benefitted small refineries, with the result that the number of refineries proliferated before price controls and allocations were removed in early 1981.

At the beginning of 1973, 281 U.S. refineries, with an average crude oil distillation capacity of 49,000 barrels per day, were in operation. Between 1973 and the beginning of 1981, while 32 refineries shut down, 75 newly constructed refineries were activated, and only two of these had distillation capacities exceeding 50,000 barrels per day.[17] The average capacity of the additional plants was 14,700 barrels per day. Crude oil distillation capacity continued to increase even after the 1978 Iranian Revolution caused demand to drop through 1981 **(Table 6)**.

The operable refinery utilization rate[18] began falling after the Iranian Revolution, and reached a low of 68.5 percent by January 1, 1982.[19] The restoration of market forces in 1981 and the decline in petroleum demand in the early 1980's caused many small refineries and older, inefficient plants to shut down. From the beginning of 1981 to the beginning of 1983, refinery closings resulted in the net loss of 66 U.S. refineries, or 20 percent of those in operation at the beginning of 1981. The shutdowns accounted

[16] Energy Information Administration, *International Energy Annual*, 1988-1989, Table HL2, and 1990-1991, Table ES2.
[17] American Petroleum Institute, *Entry and Exit in U.S. Petroleum Refining, 1948-1992*, January 1993, Tables 7 and 8.
[18] The operable utilization rate represents the utilization of the atmospheric crude oil distillation units of refineries. The rate is calculated by dividing the gross refinery inputs (crude and other oils) by the operable refining capacity of the units.
[19] Energy Information Administration, *Petroleum Refining in the 1980's*, October 1990, Table C4.

Figure 11. Distribution of Motor Gasoline and Diesel Fuel for Non-Air Transportation Use, Selected Countries, 1990



Sources: • Energy Information Administration, *State Energy Data Report 1960-1991*, Table 16. • *Bloomberg Oil Buyers Guide*, February 17, 1992.

Table 6. Number and Operable Capacity of U.S. Petroleum Refineries as of January 1, 1971 - 1993
(Thousand Barrels per Stream Day, Except Where Noted)

Year	Number	Crude Oil Distillation (thousand barrels per calendar day)	Vacuum Distillation	Thermal Cracking	Catalytic Cracking (Fresh & Recycled)	Catalytic Reforming	Catalytic Hydrocracking	Catalytic Hydrotreating
1971	279	12,860	--	--	--	--	--	--
1972	282	13,292	--	--	--	--	--	--
1973	281	13,642	--	--	--	--	--	--
1974	284	14,362	--	--	--	--	--	--
1975	290	14,961	--	--	--	--	--	--
1976	287	15,237	--	--	--	--	--	--
1977	291	16,398	--	--	--	--	--	--
1978	302	17,048	--	--	--	--	--	--
1979	311	17,441	--	--	--	--	--	--
1980	319	17,988	6,381	1,564	5,773	3,970	864	4,616
1981	324	18,621	7,033	1,587	6,136	4,098	909	8,487
1982	301	17,890	7,197	1,782	6,036	3,966	892	8,539
1983	258	16,859	7,180	1,715	5,890	3,918	883	8,354
1984	247	16,137	7,165	1,852	5,802	3,907	952	9,009
1985	223	15,659	6,998	1,858	5,738	3,750	1,053	8,897
1986	216	15,459	6,892	1,880	5,677	3,744	1,125	8,791
1987	219	15,566	6,935	1,928	5,716	3,805	1,189	9,083
1988	213	15,915	7,198	2,080	5,806	3,891	1,202	9,170
1989	204	15,655	7,225	2,073	5,650	3,911	1,238	9,440
1990	205	15,572	7,245	2,108	5,755	3,896	1,282	9,537
1991	202	15,676	7,276	2,158	5,862	3,926	1,308	9,676
1992	199	15,696	7,172	2,100	5,888	3,907	1,363	9,644
1993	187	15,121	6,892	2,082	5,784	3,728	1,397	9,677

-- = Data not available 1971-1979.

Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol.1, 1991 and 1992, Table 36, *The U.S. Petroleum Refining Industry in the 1980's*, October 1990, Table 1, and *Petroleum Refineries in the United States and U.S. Territories*, 1977-1979, Table 1, and predecessor reports.

for a 9-percent reduction in crude oil distillation capacity. The refinery shutdowns resulted in improved operating efficiency. This enabled the refinery utilization rate to increase, despite lower crude oil inputs than during the era of price controls in the 1970's **(Figure 12)**. Refinery closings continued at a slower pace after 1983, reflecting changing economics and technological advancements.

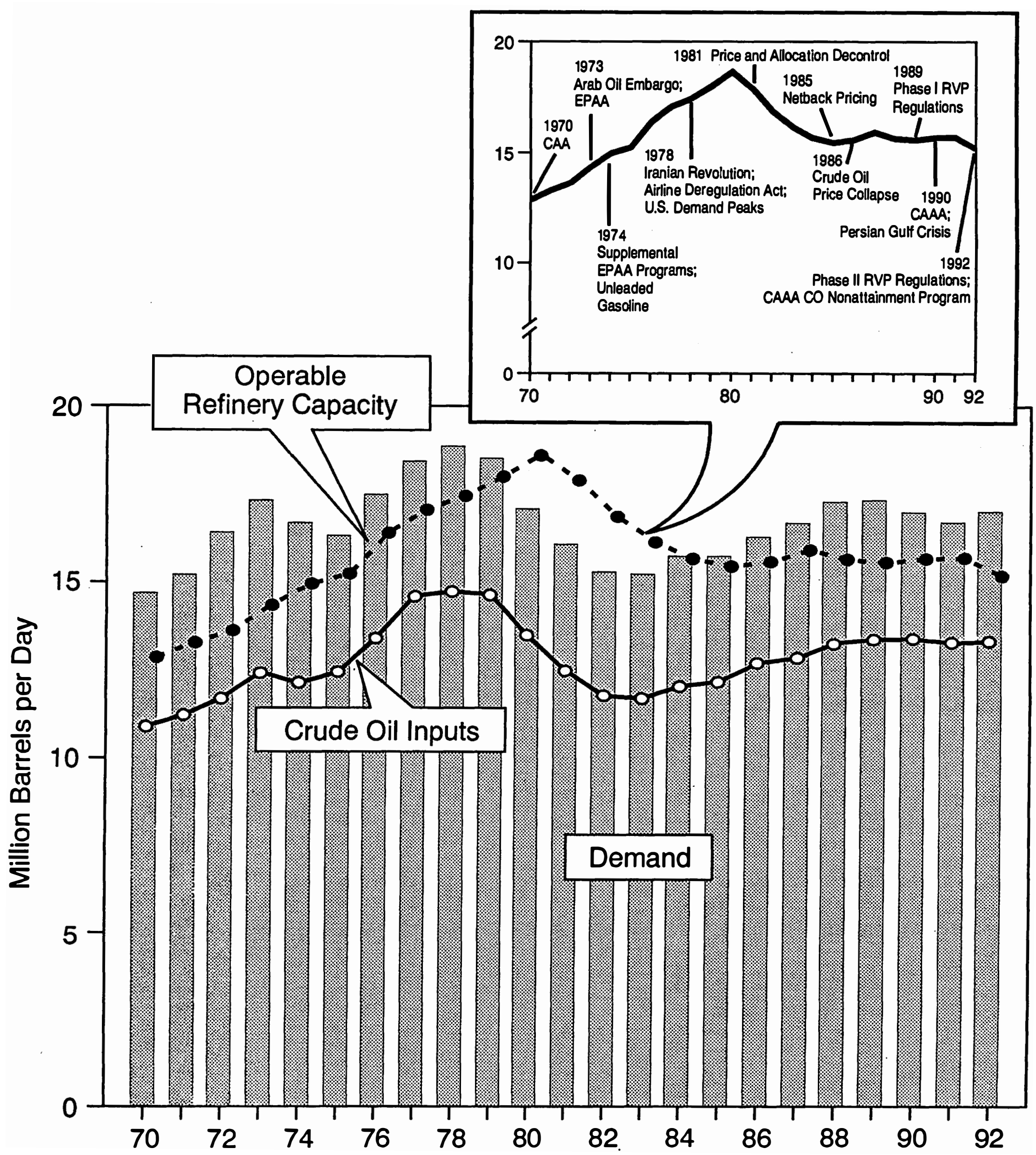
Downstream Processing

Price and allocation decontrol in 1981 changed refining economics. It was no longer profitable or feasible to produce heavy bulk oils. Production of light fuels, principally transportation types, claimed more of the production from a barrel of crude oil, and became essential to the economic viability of refiners.

Most of the 187 U.S. refineries in operation at the beginning of 1993 increased their flexibility and complexity through expansions in downstream processing capacities after 1981. A significant change was the addition of downstream capacity to desulfurize and process poorer quality crude oils into lighter products than could be obtained through distillation. These heavier, more sour crude oils have been used increasingly since the 1980's **(Table 7)**.

Downstream processing units have also been essential as a means for U.S. refineries to conform to new and emerging environmental

Figure 12. U.S. Operable Refinery Capacity, Crude Oil Inputs, Petroleum Demand, and Related Events, 1970 - 1992



Note: Operable refining capacity data are per calendar day as of January 1 of the following year.
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992, and predecessor reports. See Table A1 for corresponding data.

Table 7. U.S. Utilization of Heavier, Higher Sulfur Crude Oil, 1981 - 1992

Year	Sulfur Percent by Weight	API Gravity (degrees)
1981	0.89	33.74
1982	0.91	33.11
1983	0.90	33.19
1984	0.94	32.96
1985	0.91	32.46
1986	0.96	32.33
1987	0.99	32.22
1988	1.04	31.93
1989	1.06	32.14
1990	1.10	31.86
1991	1.13	31.64
1992	1.16	31.32

Sources: Energy Information Administration, *Petroleum Supply Annual,* Vol. 1, 1991, Tables FE9 and 16, and 1993, Table 16.

regulations. For example, downstream units have been used in the production of unleaded gasoline since lead phaseout regulations took effect in the mid-1970's. Since 1989, when Reid Vapor Pressure regulations were first implemented, downstream units have been important for the production of gasoline blending components that are needed in the summer gasoline pool to replace butane. Additions to downstream processing will continue to be made, to produce low-sulfur highway diesel fuel and reformulated gasolines as required by the 1990 Clean Air Act (CAA) Amendments.

Refinery Yields

Downstream units also enabled refiners to increase or maintain yields of light products, despite the decline in crude oil distillation capacity. Yields of motor gasoline comprise the greatest portion of all refinery yields (about 45 percent). With the 1974 introduction of unleaded motor gasoline, as required by the Clean Air Act of 1970, unleaded gasoline yields began to grow steadily, and over the years, leaded gasoline was virtually phased out. Distillate fuel oil yields have been relatively stable (about 20 percent) through the years. Yields of kerosene-type jet fuel increased more than any other product since 1980. Yields of residual fuel oil increased during the period of price controls in the 1970's, when small, inefficient refineries were operating. Declines since then brought 1992 yields to the same rate as in 1970 **(Figures 13 and 14)**.

Among the remaining product yields, those for still gas, liquefied refinery gases (LRG's), and petroleum coke showed the greatest changes between 1970 and 1992. The more severe processing of the growing downstream operations increased yields of LRG's and still gas by about 1 percent each. In 1992, the typical barrel of crude oil yielded 4.3 percent LRG's and 4.7 percent still gas. Yields of petroleum coke rose more dramatically because of the increased use of heavy crude oils requiring thermal cracking. Petroleum coke yields increased from 2.7 percent in 1970 to 4.2 percent in 1992.

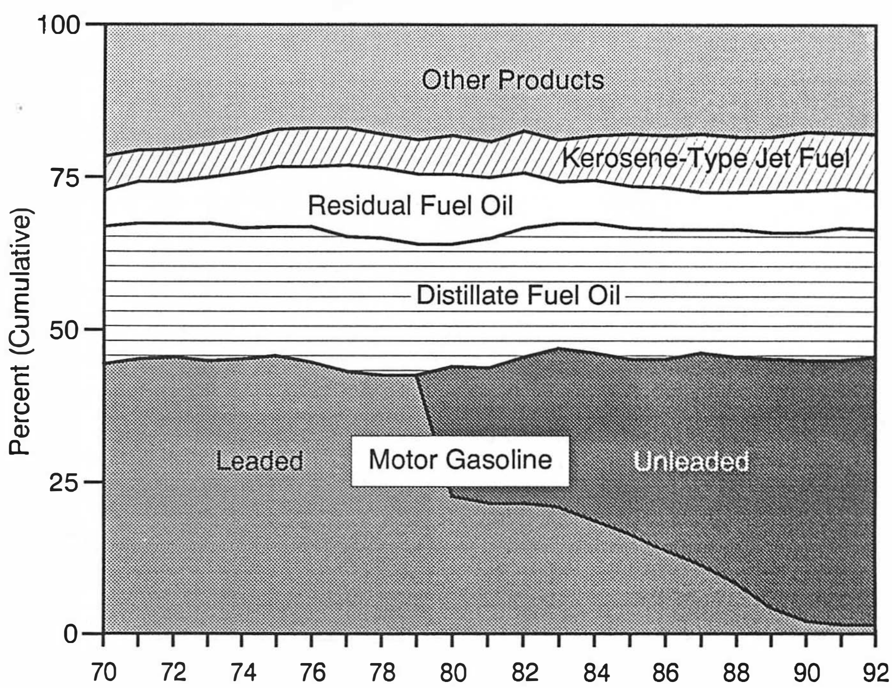
Partially offsetting the increased yields of these products, yields of asphalt and road oil declined by about 1 percent, and comprised 3 percent of all refinery yields in 1992. The greater severity of refining operations as more downstream capacity came on stream also increased the volumes of refined products, resulting in greater processing gains since 1980. During the 1970's, the annual processing gain was between 3 and 4 percent. As downstream processing grew during the 1980's, processing gains were greater, and in 1992, the processing gain was almost 6 percent.

Refinery Production

Refinery production increased 32 percent between 1970 and 1978, when it peaked at 16.0 million barrels per day. After the Iranian Revolution in 1978, refinery production declined by 18 percent over the next 5 years to a low of 13.1 million barrels per day in 1983. A significant increase in domestic demand in 1984 served to stimulate domestic refinery production. Refiners have increased production almost every year since 1984. In 1992, 15.4 million barrels of petroleum products were produced at U.S. refineries **(Table 8)**.

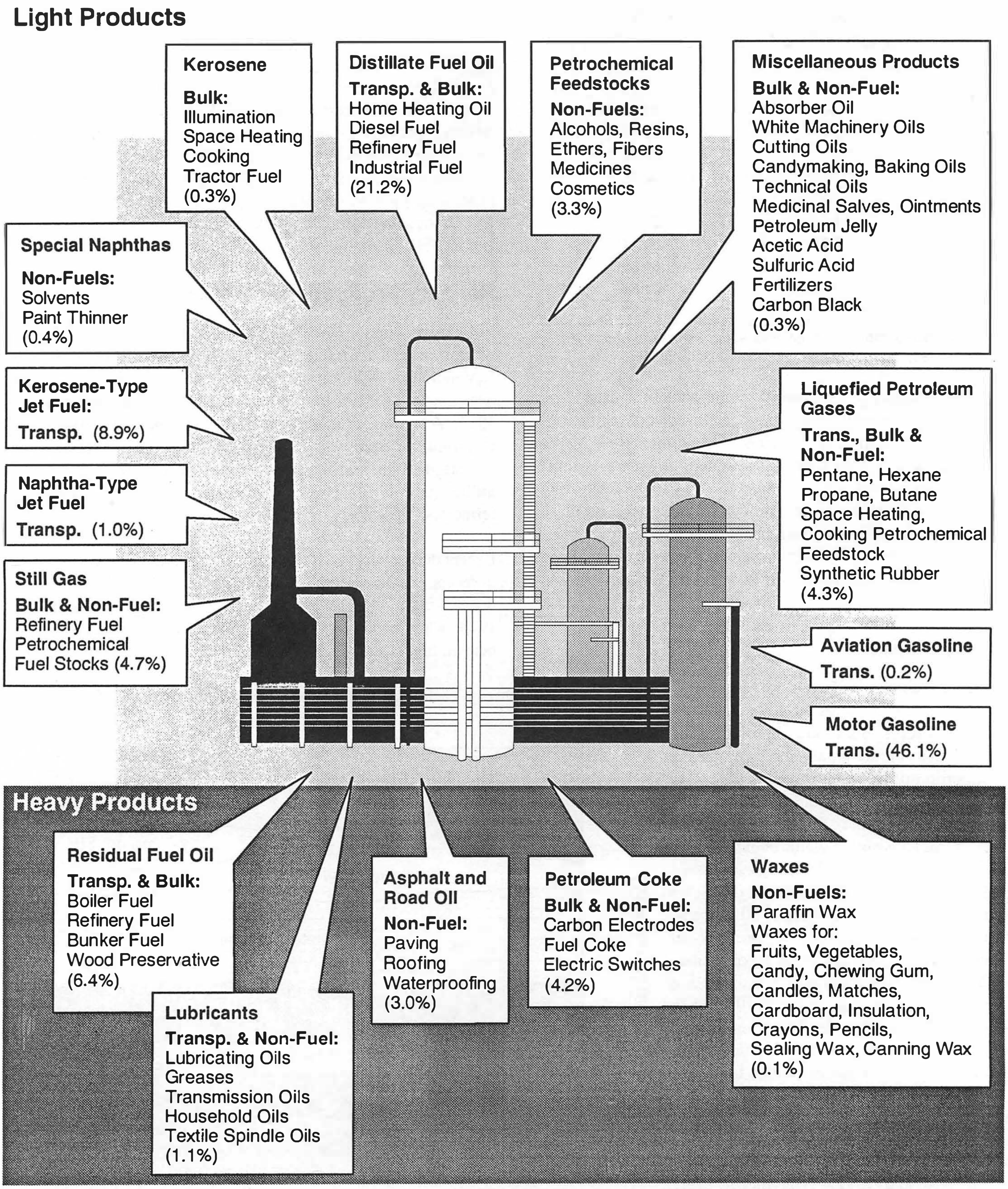
Except during periods of economic recession, refinery production of motor gasoline generally rose each year. In 1970, production was 5.7 million barrels per day, then increased generally through 1978, when production of 7.2 million barrels per day was 26 percent higher than in 1970. Output declined between 1979 and

Figure 13. Refinery Yields of Major Petroleum Products, 1970-1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table A2 for corresponding data.

Figure 14. U.S. Refinery Yields and Petroleum Product Uses, 1992



Source: Energy Information Administration, *The U.S. Petroleum Refining Industry in the 1980's*, October 1990, and *Petroleum Supply Annual*, Vol. 1, 1992.

Table 8. U.S. Refinery Production of Selected Products, 1970 - 1992
(Thousand Barrels per Day)

Year	Motor Gasoline	Distillate Fuel Oil	Kerosene-Type Jet Fuel	Residual Fuel Oil	Other Products	Total Products
1970	5,699	2,454	827	706	2,427	12,113
1971	5,970	2,495	835	753	2,445	12,498
1972	6,281	2,630	847	799	2,523	13,080
1973	6,527	2,820	859	971	2,677	13,854
1974	6,358	2,668	836	1,070	2,566	13,498
1975	6,518	2,653	871	1,235	2,408	13,685
1976	6,838	2,924	918	1,377	2,620	14,677
1977	7,031	3,277	973	1,754	2,839	15,874
1978	7,167	3,167	970	1,667	2,995	15,966
1979	6,837	3,152	1,012	1,687	3,075	15,763
1980	6,492	2,661	999	1,580	2,890	14,622
1981	6,400	2,613	968	1,321	2,688	13,990
1982	6,336	2,606	978	1,070	2,401	13,391
1983	6,338	2,456	1,022	852	2,470	13,138
1984	6,453	2,680	1,132	891	2,523	13,679
1985	6,419	2,686	1,189	882	2,574	13,750
1986	6,752	2,796	1,293	889	2,792	14,522
1987	6,841	2,729	1,343	885	2,828	14,626
1988	6,956	2,857	1,370	926	2,913	15,022
1989	6,963	2,899	1,403	954	2,956	15,175
1990	6,959	2,925	1,488	950	2,950	15,272
1991	6,975	2,962	1,438	934	2,947	15,256
1992	7,058	2,974	1,254	892	3,220	15,398

Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992, Table 3, and predecessor reports.

1982 to 6.3 million barrels per day, then slowly increased through 1988. Between 1988 and 1992, production was steady at about 7.0 million barrels per day.

From 2.5 million barrels per day in 1970, refinery output for distillates increased generally through 1977, when output peaked at 3.3 million barrels per day. Over the next 6 years, refinery production fell back to 2.5 million barrels per day, its 1970 level. Then, output increased slightly almost every year, reaching 3.0 million barrels per day in 1992.

Unlike motor gasoline and distillates, kerosene-type jet fuel refinery output grew throughout the 1970's and 1980's, with only a few dips interrupting growth. Output was 0.8 million barrels per day in 1970, and almost doubled by 1990 before declining to 1.3 million barrels per day in 1992.

Residual fuel oil refinery production grew rapidly, from 0.7 million barrels per day in 1970 to a peak of 1.8 million barrels per day in 1977. After 1977, output generally declined, and was 0.9 million barrels per day in 1992.

Refinery Ownership

Consolidation and foreign investments in U.S. refining expanded during the late 1980's. Foreign-affiliated companies have long been active in the U.S. refining and marketing sector and have played major roles in shaping the industry. At the beginning of 1983, foreign-affiliated companies owned interests in 14 percent of total U.S. operating capacity. By the beginning of 1991, foreign affiliation had risen to 28 percent of the U.S. total.[20] Foreign affiliation declined slightly during 1991.

Venezuela and Saudi Arabia were major investors in U.S. refining operations in the late 1980's. At that time, producing countries wanted access to refineries near consuming regions, where stable product markets would assure outlets for their crude oil. At the same time, foreign acquisitions increased the financial stability of the U.S. refining industry.

Foreign Refining

As in the United States, the foreign refining industry has turned toward expansions in downstream capacity since 1981 (the earliest data available), while crude oil distillation capacity has declined. Total foreign expansions to reforming, catalytic, and thermal cracking capacity increased 43 percent to 14.7 million barrels per day between the beginning of 1981 and the beginning of 1992 (**Table 9**). Downstream additions were greatest in Western Europe and the Far East and Oceania. These are areas where total demand for petroleum is almost as high as in the United States.

During the early 1970's, total foreign crude oil inputs exceeded foreign demand. At the time, U.S. operable refining capacity was not sufficient to meet growing U.S. petroleum demand, and excess refined products from foreign refineries were supplied to the United States. By 1980, however, U.S. crude oil distillation capacity was at its peak, and downstream operations were becoming an important means of producing domestic products. As a result, foreign crude oil inputs became about equal to foreign demand (**Figure 15**).

Increases to foreign operable refinery capacity (measured as crude oil distillation capacity) during the 1970's were primarily in Western Europe and the Far East and Oceania. Operable refinery capacity in Western Europe grew from 13.9 million barrels per day at the beginning of 1970 to 20.2 million barrels per day at the beginning of 1980. A slump in European and U.S. demand during the 1980's caused Western European operable refining capacity to recede. Capacity dropped to about the same level as in 1970 by the beginning of 1989.[21]

Operable refining capacity increased in the Far East and Oceania from 5.6 to 10.3 million barrels per day during the 1970's, then stabilized until the early 1990's, when capacity increased to 13.2 million barrels per day.

[20] Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy, 1986*, Table 10, *1990*, Table 9, and *1991*, Table 10.
[21] American Petroleum Institute, *Basic Petroleum Data Book*, Vol. XII, Number 3, September 1992, Section VIII, Table 1.

Table 9. World Refinery Capacity and Number of Refineries, As of January 1, Selected Years
(Thousand Barrels per Calendar Day)

Area	Year	Number of Refineries	Crude Oil Distillation Capacity	Downstream Capacity			
				Catalytic Cracking	Thermal Cracking	Reforming	Total
United States	1981	324	18,620	4,775	338	3,690	8,803
	1986	216	15,459	5,393	1,786	3,557	10,736
	1989	204	15,655	5,368	1,969	3,715	11,052
	1990	205	15,572	5,467	2,003	3,701	11,171
	1991	202	15,676	5,569	2,050	3,730	11,349
	1992	199	15,696	5,594	1,995	3,712	11,301
Other North America	1981	42	3,560	755	109	469	1,333
	1986	37	3,125	674	156	517	1,347
	1989	36	3,210	655	170	528	1,353
	1990	37	3,366	654	170	530	1,354
	1991	37	3,561	655	171	525	1,351
	1992	36	3,479	646	151	559	1,356
Central and S. America	1981	74	7,157	654	501	334	1,489
	1986	68	5,491	851	474	309	1,634
	1989	68	5,629	922	574	327	1,823
	1990	70	5,641	906	574	340	1,820
	1991	74	5,875	880	604	321	1,805
	1992	76	5,981	966	691	341	1,998
Western Europe	1981	166	20,545	1,114	1,049	2,607	4,770
	1986	124	14,516	1,556	1,553	2,094	5,203
	1989	113	13,843	1,796	1,689	1,943	5,428
	1990	116	14,216	1,932	1,749	2,031	5,712
	1991	127	14,814	2,025	1,876	2,261	6,162
	1992	124	14,811	2,055	1,936	2,282	6,273
E. Europe and Former USSR	1981	70	14,227	NA	NA	NA	NA
	1986	83	15,350	NA	NA	NA	NA
	1989	84	15,598	NA	NA	NA	NA
	1990	99	15,598	157	90	171	418
	1991	77	14,317	69	13	95	177
	1992	74	14,305	173	127	189	489
Middle East	1981	33	3,390	97	184	250	531
	1986	36	3,831	68	233	384	685
	1989	38	4,353	188	293	477	958
	1990	38	4,465	198	292	472	962
	1991	40	5,039	202	336	531	1,069
	1992	40	5,011	204	349	532	1,085
Africa	1981	41	1,698	117	71	195	383
	1986	43	2,521	130	83	290	503
	1989	44	2,789	174	94	333	601
	1990	44	2,824	173	94	330	597
	1991	44	2,872	173	103	335	611
	1992	44	2,866	173	103	330	606
Far East and Oceania	1981	129	12,365	611	207	979	1,797
	1986	128	12,262	811	473	1,067	2,351
	1989	142	12,263	988	509	1,096	2,593
	1990	142	12,181	1,023	549	1,087	2,659
	1991	143	12,603	1,061	566	1,169	2,796
	1992	143	13,195	1,095	518	1,273	2,886
Total Foreign	1981	555	62,942	3,348	2,121	4,834	10,303
	1986	519	57,096	4,090	2,972	4,661	11,723
	1989	525	57,685	4,723	3,329	4,704	12,756
	1990	546	58,291	5,043	3,518	4,961	13,522
	1991	542	59,081	5,065	3,669	5,236	13,970
	1992	537	59,648	5,310	3,875	5,505	14,690
Total World	1981	879	81,562	8,123	2,459	8,524	19,106
	1986	735	72,555	9,483	4,758	8,218	22,459
	1989	729	73,340	10,091	5,298	8,419	23,808
	1990	751	73,863	10,510	5,521	8,662	24,693
	1991	744	74,757	10,634	5,719	8,966	25,319
	1992	736	75,344	10,904	5,870	9,217	25,991

NA = Not Available.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *International Energy Annual*, 1980, Table 21, 1985, Table 14, and 1991, Table 21.

Large export refineries were constructed to provide products to other markets. Oil-producing countries in the Middle East have the largest concentration of export refineries[22] and provide refined products to the Far East and other areas.[23]

As in the United States, countries in Western Europe and the Far East began moving toward oxygenated motor gasoline to combat pollution in recent years. Oxygenate facilities were added at refineries or built independently.[24] The European Fuel Oxygenate Association was formed in November 1984 to address issues concerning oxygenates in the European gasoline pool.[25] Finland began using oxygenated gasoline in June 1991, and by the end of 1992, this product accounted for approximately 70 percent of Finnish motor gasoline consumption. Norway has been planning for the future use of oxygenated fuels. Italy, with serious pollution problems and higher gasoline demand than Norway and Finland, replaced some of the lead in gasoline with aromatics,[26] as the United States had done in earlier years.[27] Aromatics increase tailpipe emissions of ozone precursors and toxic air pollutants such as benzene. In the Far East, Korea has moved toward a mandatory program to begin in 1993, and some Japanese companies were producing oxygenated gasoline in 1992.

Product Imports and Exports

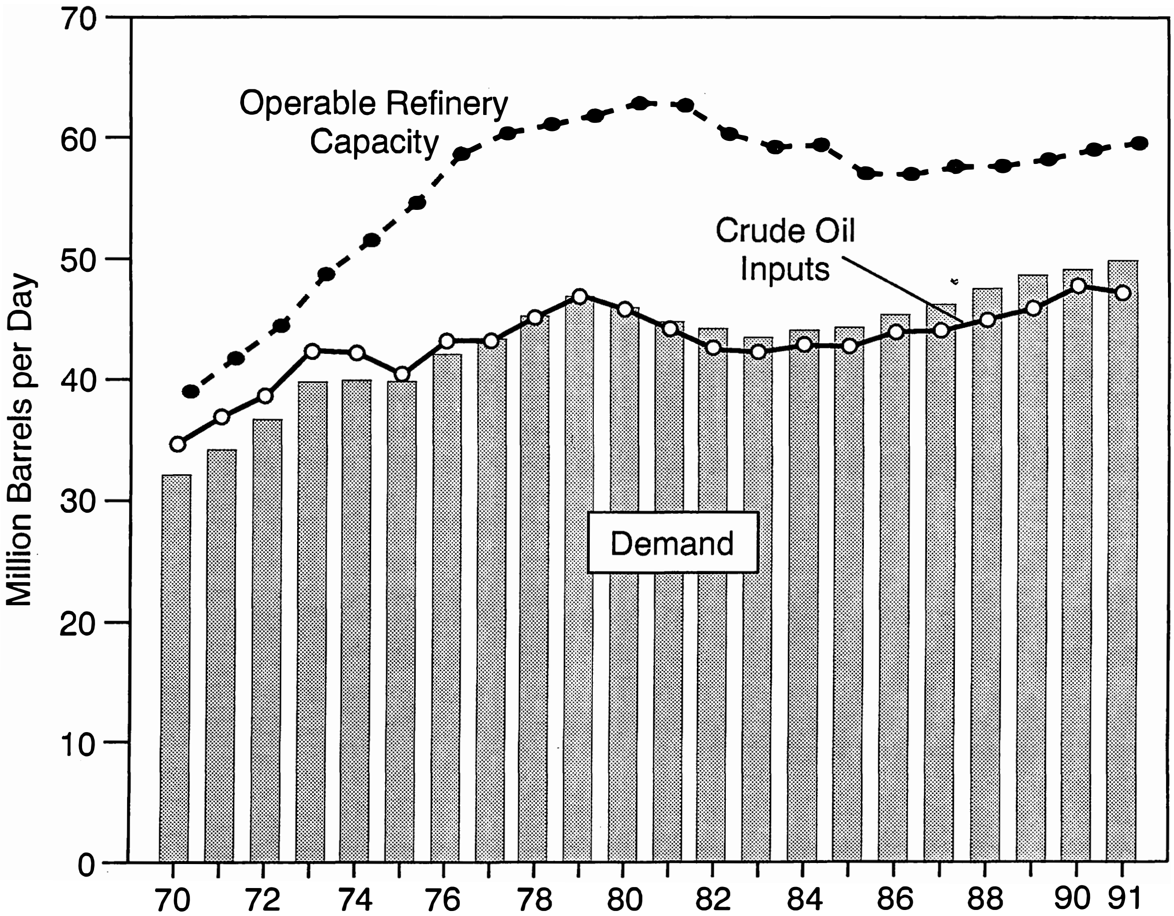
The market for crude oil and petroleum products has been an international one for over 75 years. The shared effects of oil supply disruptions and price changes since the 1970's have modified the patterns of U.S. petroleum imports and exports. In contrast to crude oil imports, which are a primary component of crude oil supplies, imports of petroleum products are used to augment refinery production.

Net Imports

U.S. total net imports of petroleum products increased 50 percent between 1970 and 1973, when they peaked (**Table 10**). At the time, residual fuel oil accounted for 66 percent of the 2.8 million

[22]"Worldwide refining," *Oil and Gas Journal*, December 21, 1992, pp. 57-72.
[23]*BP Statistical Review of World Energy*, June 1993, pp. 16 and 17.
[24]"Worldwide refiners making big move into modernization," *Oil and Gas Journal*, December 21, 1992, p. 48.
[25]*MTBE/Oxygenates/New Fuels*, October 22, 1992, p. 1.
[26]*MTBE/Oxygenates/New Fuels*, November 5, 1992, p. 1.
[27]Congressional Research Service, *Alternative Transportation Fuels: Are They Reducing Oil Imports?*, January 15, 1993, p. CRS-4.

Figure 15. Foreign Operable Refinery Capacity, Crude Oil Inputs, and Petroleum Demand, 1970 - 1991



Source: Energy Information Administration, *Annual Energy Review 1991* and *1992*, and *International Energy Annual*, 1991. See Table A1 for corresponding data.

Table 10. U.S. Imports, Exports, and Net Imports of Selected Petroleum Products, 1970 - 1992
(Thousand Barrels per Day)

Year	Motor Gasoline			Distillate Fuel Oil			Jet Fuel		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
1970	66	1	65	147	2	145	144	6	138
1971	59	1	58	153	8	145	180	4	176
1972	68	1	67	182	3	179	194	3	191
1973	134	4	130	392	9	383	212	4	208
1974	204	2	202	289	2	287	163	3	160
1975	184	2	182	155	1	154	133	2	131
1976	131	3	128	146	1	145	76	2	74
1977	217	2	215	250	1	249	75	2	73
1978	190	1	189	173	3	170	86	1	85
1979	181	(s)	181	193	3	190	78	1	77
1980	140	1	139	142	3	139	80	1	79
1981	157	2	155	173	5	168	38	2	36
1982	197	20	177	93	74	19	29	6	23
1983	247	10	237	174	64	110	29	6	23
1984	299	6	293	272	51	221	62	9	53
1985	381	10	371	200	67	133	39	13	26
1986	326	33	293	247	100	147	57	18	39
1987	384	35	349	255	66	189	67	24	43
1988	405	22	383	302	69	233	90	28	62
1989	369	39	330	306	97	209	106	27	79
1990	342	55	287	278	109	169	108	43	65
1991	297	82	215	205	215	(10)	67	43	24
1992	294	96	198	216	219	(3)	82	43	39

Year	Residual Fuel Oil			All Other			Total		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
1970	1528	54	1,474	210	182	28	2,095	245	1,850
1971	1583	36	1,547	270	174	96	2,245	222	2,023
1972	1,742	33	1,709	339	182	157	2,525	222	2,303
1973	1,853	23	1,830	421	189	232	3,012	229	2,783
1974	1,587	14	1,573	392	197	195	2,635	218	2,417
1975	1,223	15	1,208	256	184	72	1,951	204	1,747
1976	1,413	12	1,401	260	197	63	2,026	215	1,811
1977	1,359	6	1,353	292	181	111	2,193	193	2,000
1978	1,355	13	1,342	204	186	18	2,008	204	1,804
1979	1,151	9	1,142	334	224	110	1,937	237	1,700
1980	939	33	906	345	220	125	1,646	258	1,388
1981	800	118	682	431	240	191	1,599	367	1,232
1982	776	209	567	530	270	260	1,625	579	1,046
1983	699	185	514	573	310	263	1,722	575	1,147
1984	681	190	491	697	285	412	2,011	541	1,470
1985	510	197	313	736	290	446	1,866	577	1,289
1986	669	147	522	746	333	413	2,045	631	1,414
1987	565	186	379	733	302	431	2,004	613	1,391
1988	644	200	444	854	342	512	2,295	661	1,634
1989	629	215	414	807	339	468	2,217	717	1,500
1990	504	211	293	891	330	561	2,123	748	1,375
1991	453	226	227	822	319	503	1,844	885	959
1992	375	193	182	838	310	528	1,805	861	944

(s) = Less than 500 barrels per day.
Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, *Petroleum Supply Annual,* Vol. 1, 1981 - 1992, Tables S1 and S4 - S7, and predecessor reports.

barrels per day of net imports. U.S. net imports gradually declined until, in 1982, they were 62 percent below the 1973 level, with most of the decline in residual fuel oil. Net imports of residual fuel oil declined further until, by 1985, 313,000 barrels per day represented only 25 percent of the total net imports of petroleum products. During the 1980's, net imports of motor gasoline and distillate fuel oil were rising to fill the growing demand for these products. Net imports of these products declined during the early 1990's, however, as overseas markets opened up to U.S. product exports and gross imports declined. Net imports of residual fuel oil dropped to only 182,000 barrels per day in 1992 and were 90 percent below the 1973 level.

Gross Imports

U.S. gross imports of petroleum products constitute only about 11 percent of U.S. total product use, yet are important supplements to domestic supplies from refinery production. Gross imports of petroleum products peaked in 1973 at 3.0 million barrels per day. By 1981, U.S. product imports had fallen 47 percent. Refinery output was providing increasing quantities of refined products during the intervening years, helping to allay concern about price spikes and short supplies in the aftermath of the 1973 oil supply disruptions.

Because few products were being exported in significant quantities prior to 1981, gross product imports followed a similar pattern to net imports, with residual fuel oil claiming the dominant share. Residual fuel oil imports accounted for an average 65 percent of all product imports and 42 percent of heavy product demand during the 1970's. Imports of motor gasoline, jet fuel, and distillate fuel oil together accounted for about 21 percent of the volumes entering the country between 1970 and 1975. These imports averaged 4 percent of light product demand during that time. While imports of distillate fuel oil remained relatively stable after 1975, jet fuel imports declined as domestic refinery production increased. Imports of motor gasoline tripled between 1972 and 1974 before moderating through 1982.

When the U.S. economic recession ended in 1982 and demand for light petroleum products began to escalate, their imports also began to grow. By 1983, motor gasoline, distillate fuel oil, and jet fuel imports totaled 450,000 barrels per day, still well below residual at 699,000 barrels per day. Over the next decade, the mix of product imports turned more toward light products. As fuel oil was replaced by natural gas, light-product imports overtook heavy products. By 1992, imports of motor gasoline, distillate, and jet fuel together comprised 33 percent of all product imports and still represented 4 percent of light product demand. Residual fuel oil imports were 21 percent of total gross product imports in 1992, and accounted for only 18 percent of the demand for heavy products.

During the early 1990's, there were fewer imports of both light and heavy products because of slack demand during the recent recession and changes in world supply patterns. Declines from Central and South America accounted for about 46 percent of the drop in total product imports between 1989 and 1992 (**Table 11**).

Exports

Between 1973 and 1981, U.S. petroleum prices were controlled and were much lower than overseas prices. Petroleum product exports were restricted during this period. U.S. product exports during the 1970's were generally a little above 200,000 barrels per day, and were primarily specialty products such as petroleum coke and lubricants.

The lifting of the export restrictions in 1981 opened the way for exports of major products to escalate (**Figure 16**). Residual fuel oil exports picked up after 1980, and were almost 600 percent higher in 1991 than in 1980.

In recent years, new markets for U.S. light products emerged (**Table 12**). During the early 1990's, economic expansion in Mexico, Central and South America, and the Far East increased their petroleum needs and attracted U.S. exports of light products to these areas. The disruption of petroleum supplies from Kuwait and lower exports from the former Soviet Union also created new markets for U.S. light products. U.S. product exports grew because they were lower-cost than alternative sources of supply. They reached an all-time high in 1990 at 885,000 barrels per day.

U.S. Regional Import and Export Patterns

PAD District I (East Coast)

Refined product exports from the East Coast are modest, but large volumes of product imports are needed to meet demand. In addition to unfinished oils, substantial imports of the major products are needed. Residual fuel oil imports were particularly important in the past, when the East Coast relied more heavily on fuel oils for electric power generation and for industrial uses. When imports into PAD[28] District I peaked in 1973 at 2.5 million barrels per day, 71 percent was residual fuel oil. In 1992, residual fuel oil comprised 28 percent of the 1.1 million barrels per day imported.

The East Coast is the natural market for products from Central and South America, but some imports arrive from the Middle East and Canada.

PAD District II (Midwest)

Propane has been the only product imported into PAD District II in significant quantities (about 50,000 barrels per day). Used widely in the Midwest for heating and for agriculture, propane imports arrive in the Midwest via pipeline from Canada.

Refined products exported from the Midwest accounted for a very small portion of U.S. product exports during the past 23 years.

[28]Petroleum Administration for Defense.

Table 11. U.S. Petroleum Imports by Major Source, Selected Products and Years
(Thousand Barrels per Day)

Source	Year	Crude Oil	Petroleum Products							Total Imports
			Motor Gasoline	Distillate Fuel Oil	Jet Fuel	Liquefied Petroleum Gases	Residual Fuel Oil	All Other	Total	
North America	1970	672	2	14	(s)	49	39	32	137	809
	1975	671	11	5	6	83	66	77	247	918
	1980	706	14	1	1	199	50	17	281	988
	1985	1,183	51	51	6	165	48	94	415	1,598
	1989	1,346	45	69	22	138	40	38	352	1,698
	1990	1,331	54	57	19	143	40	46	359	1,690
	1991	1,502	68	59	8	116	39	49	339	1,841
	1992	1,584	61	55	4	111	30	54	315	1,899
Central and S. America	1970	291	65	124	132	3	1,321	115	1,759	2,050
	1975	572	143	124	96	14	1,011	59	1,447	2,019
	1980	331	110	134	62	9	782	95	1,192	1,523
	1985	477	116	131	25	2	334	197	805	1,282
	1989	796	170	187	60	8	379	197	1,001	1,797
	1990	934	149	185	67	3	310	194	908	1,842
	1991	927	114	145	56	5	295	250	865	1,792
	1992	1,092	114	155	74	4	235	230	812	1,904
Western Europe	1970	0	(s)	6	7	(s)	152	1	166	166
	1975	17	13	9	3	(s)	51	4	77	94
	1980	318	2	2	7	2	13	1	28	343
	1985	310	148	5	2	6	26	48	235	545
	1989	290	110	23	10	4	81	80	308	598
	1990	252	97	13	8	2	49	129	298	550
	1991	183	77	1	0	3	33	103	217	400
	1992	319	82	4	(s)	1	23	125	235	554
E. Europe and Former USSR	1970	0	0	4	0	0	7	0	11	11
	1975	0	4	4	0	0	25	0	33	33
	1980	0	(s)	0	0	0	2	(s)	2	2
	1985	(s)	10	3	0	0	1	42	56	56
	1989	0	5	10	0	0	7	53	75	75
	1990	1	3	7	1	0	8	40	59	60
	1991	1	0	0	0	0	1	28	29	30
	1992	5	4	1	(s)	(s)	1	12	18	23
Middle East	1970	170	0	0	5	(s)	4	5	14	184
	1975	1,122	7	12	9	11	2	4	45	1,167
	1980	1,533	(s)	1	(s)	3	1	7	12	1,545
	1985	245	33	1	0	3	3	48	88	333
	1989	1,791	37	3	9	7	7	72	135	1,926
	1990	1,858	37	4	13	8	13	102	177	2,035
	1991	1,770	34	(s)	4	6	4	64	112	1,882
	1992	1,640	29	0	3	8	11	116	167	1,807
Africa	1970	122	0	(s)	0	0	4	(s)	5	127
	1975	1,229	2	(s)	(s)	3	49	1	53	1,282
	1980	1,998	0	0	0	(s)	63	(s)	64	2,062
	1985	612	1	6	(s)	6	82	39	134	746
	1989	1,287	0	12	(s)	21	81	136	250	1,537
	1990	1,236	1	12	(s)	26	60	157	256	1,492
	1991	1,159	1	0	0	14	63	164	242	1,401
	1992	1,256	0	0	0	5	66	136	207	1,463
Far East and Oceania	1970	70	0	(s)	(s)	0	(s)	2	3	73
	1975	384	6	1	18	3	20	1	49	433
	1980	376	14	4	9	2	27	9	65	441
	1985	374	21	5	4	4	17	83	134	508
	1989	334	2	1	5	3	35	51	97	431
	1990	282	1	0	(s)	5	23	38	67	349
	1991	239	3	(s)	0	4	18	15	40	279
	1992	186	5	1	(s)	1	10	34	51	237
Total Imports	1970	1,324	67	147	144	52	1,528	157	2,095	3,419
	1975	3,995	186	155	132	114	1,224	146	1,951	6,056
	1980	5,262	140	142	80	215	938	129	1,646	6,909
	1985	3,201	380	202	37	186	511	551	1,866	5,067
	1989	5,844	369	305	106	181	630	627	2,217	8,061
	1990	5,894	342	278	108	187	503	706	2,123	8,018
	1991	5,781	297	205	68	148	453	673	1,844	7,627
	1992	6,083	294	216	82	131	375	707	1,805	7,888

(s) = Less than 500 barrels per day.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1985, Table 15, 1989 - 1992, Table 21, and predecessor reports.

Table 12. U.S. Petroleum Exports by Major Area of Destination, Selected Products and Years
(Thousand Barrels per Day)

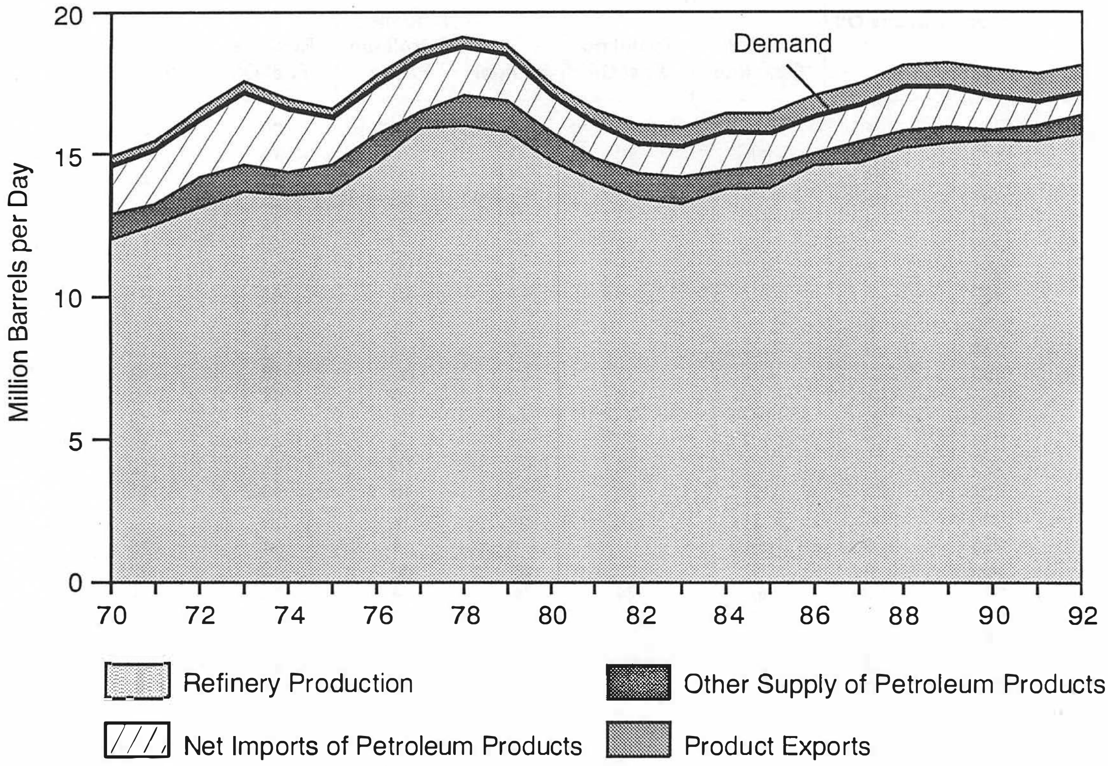
Area of Destination	Year	Crude Oil	Petroleum Products							Total Exports
			Motor Gasoline	Distillate Fuel Oil	Jet Fuel	Liquefied Petroleum Gases	Residual Fuel Oil	All Other	Total	
North America	1970	1	1	2	(s)	24	20	21	69	70
	1975	(s)	(s)	(s)	1	25	14	25	65	65
	1980	84	1	3	1	19	3	25	52	136
	1985	53	3	8	9	48	21	27	116	169
	1989	8	15	16	6	28	71	38	174	182
	1990	11	26	8	12	32	62	30	170	181
	1991	5	52	5	8	20	49	30	164	170
	1992	3	71	6	8	28	43	31	187	189
Central and S. America	1970	12	1	1	6	1	1	16	26	38
	1975	6	2	(s)	0	(s)	1	15	18	24
	1980	203	(s)	1	(s)	(s)	18	18	37	240
	1985	151	5	16	1	9	41	9	82	233
	1989	132	16	42	4	4	40	12	117	249
	1990	97	12	37	4	4	47	13	116	213
	1991	111	20	62	3	9	46	12	151	262
	1992	85	16	68	5	15	40	11	155	240
Western Europe	1970	(s)	1	2	(s)	1	8	57	69	69
	1975	0	(s)	(s)	0	(s)	(s)	75	75	75
	1980	0	(s)	(s)	(s)	(s)	0	99	99	99
	1985	0	(s)	24	(s)	4	33	111	173	173
	1989	0	(s)	5	1	2	7	152	167	167
	1990	0	11	35	2	3	7	151	246	246
	1991	0	4	67	7	10	25	134	247	247
	1992	0	1	34	1	5	24	125	190	190
E. Europe and Former USSR	1970	0	0	0	0	0	0	0	0	0
	1975	0	0	0	0	0	0	0	0	0
	1980	0	0	0	0	0	0	2	2	2
	1985	0	0	(s)	0	0	2	4	6	6
	1989	0	0	1	0	0	(s)	2	3	3
	1990	0	0	1	0	0	(s)	2	4	4
	1991	0	0	(s)	0	0	(s)	2	2	2
	1992	0	0	1	0	(s)	2	1	4	4
Middle East	1970	0	0	(s)	0	0	0	0	0	0
	1975	0	0	(s)	(s)	(s)	(s)	3	3	3
	1980	0	0	(s)	0	(s)	(s)	3	3	3
	1985	0	0	(s)	0	(s)	0	3	3	3
	1989	0	0	(s)	3	(s)	1	5	8	8
	1990	0	1	2	2	(s)	1	8	13	13
	1991	0	(s)	4	6	(s)	(s)	8	19	19
	1992	0	(s)	1	(s)	(s)	1	7	9	9
Africa	1970	(s)	(s)	(s)	0	(s)	(s)	4	4	4
	1975	0	0	0	0	(s)	0	6	6	6
	1980	0	0	(s)	0	(s)	(s)	6	6	6
	1985	0	0	1	0	(s)	5	4	9	9
	1989	0	(s)	(s)	0	(s)	1	3	4	4
	1990	0	0	1	0	(s)	(s)	3	4	4
	1991	0	(s)	(s)	0	(s)	2	4	5	5
	1992	0	(s)	2	(s)	0	2	4	8	8
Far East and Oceania	1970	1	(s)	1	0	1	25	56	83	84
	1975	0	1	(s)	1	(s)	(s)	35	37	37
	1980	0	1	(s)	(s)	1	12	43	57	57
	1985	0	1	18	3	(s)	96	69	187	187
	1989	2	8	33	14	1	95	93	245	245
	1990	1	6	27	23	1	94	82	233	233
	1991	(s)	6	76	20	3	104	88	297	297
	1992	1	7	107	29	1	82	86	311	312
Total Exports	1970	14	4	6	6	27	54	153	250	264
	1975	6	2	1	1	26	15	158	204	209
	1980	287	1	3	1	21	33	197	258	544
	1985	204	10	67	13	62	197	227	577	781
	1989	142	39	97	27	35	215	303	719	859
	1990	109	55	109	43	40	211	289	749	857
	1991	116	82	215	44	41	226	277	885	1,001
	1992	89	96	219	43	49	194	263	862	950

(s) = Less than 500 barrels per day.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1985, Table 17, 1989 - 1992, Table 28, and predecessor reports.

Figure 16. Components of U.S. Domestic Demand, and Petroleum Product Exports, 1970 - 1992



Notes: Other supply include field production, crude used directly as fuel, and stock change less refinery inputs. Domestic Demand is the sum of refinery production, other supplies, and net imports.

Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, and predecessor reports. See Tables 3, 8, and 10 for corresponding data.

PAD District III (Gulf Coast)

Unfinished oils and petrochemical feedstocks have been the leading products imported into the Gulf Coast, reflecting the concentration of the refining and petrochemical industries in the region. Venezuela and Saudi Arabia were the primary suppliers of unfinished oils, while Algeria supplied nearly all of the petrochemical feedstock imports between 1970 and 1992. Unfinished oils and petrochemical feedstocks together accounted for 34 percent of PAD District III product imports in 1980. Since then, increased imports of these products have been needed to replace declines in their output from U.S. refineries. In 1992, unfinished oils and petrochemical feedstocks together represented 76 percent of the 541,000 barrels per day of petroleum products imported into the Gulf Coast.

The Gulf Coast has also been a significant exporter of petroleum products. Prior to 1982, unfinished oils, LPG's, and residual fuel oil were the primary products exported from PAD District III. Exports of unfinished oils were phased out after 1982. During the 1990's, exports of distillate fuel oil increased, and in 1992 comprised 27 percent of the 435,000 barrels per day of petroleum products exported from the Gulf Coast. The main market for Gulf Coast distillate fuel oil and petroleum coke exports was Europe in 1992. The primary destination for residual fuel oil and motor gasoline was Mexico.

PAD District IV (Rocky Mountain)

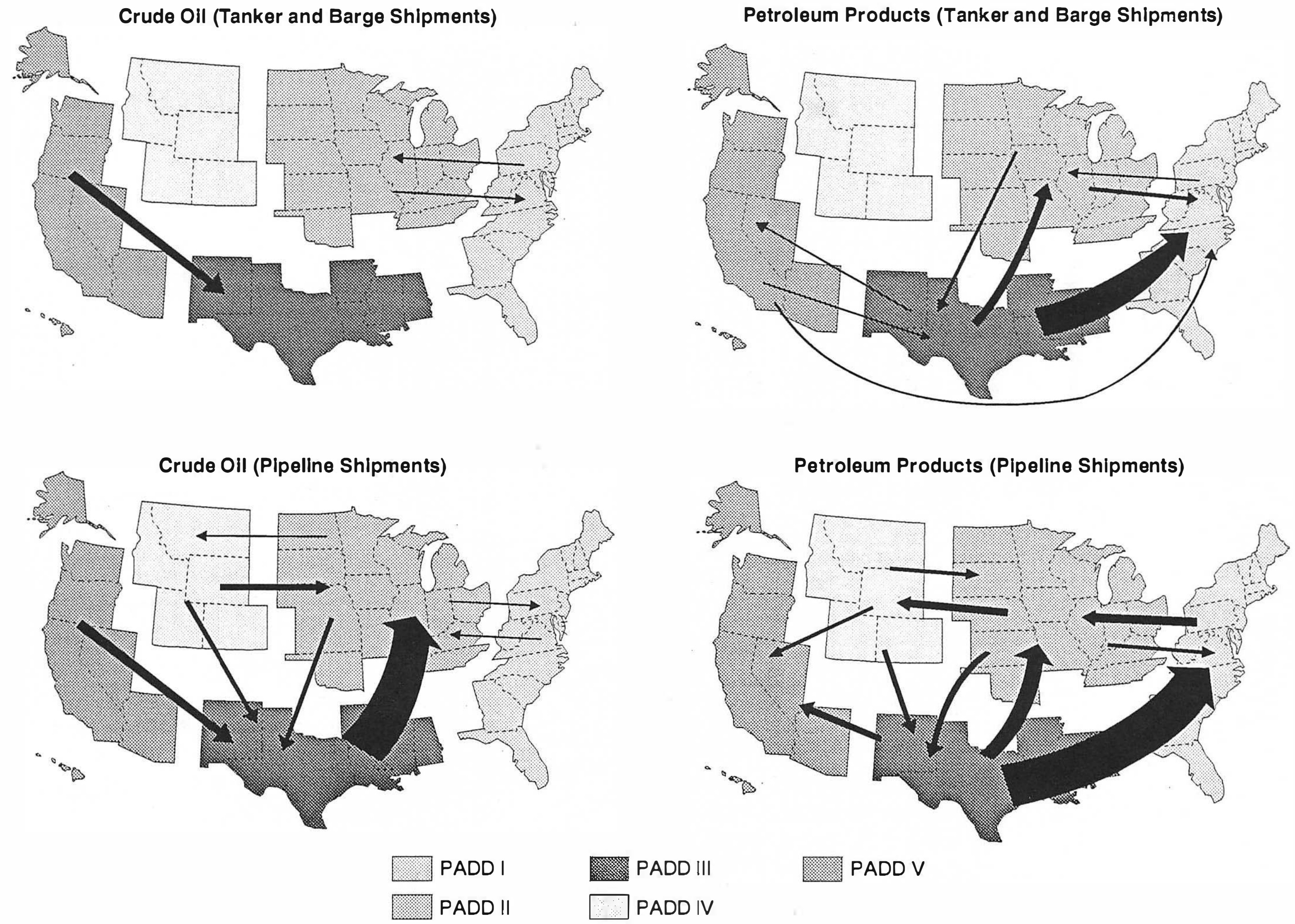
The modest product imports into PAD District IV primarily consisted of LPG's from Canada between 1970 and 1992, but exports from PAD District IV were very small. The region's lack of port facilities and the availability of only a few pipeline links with other regions limit movements of product into and out of the region. Refineries in the region, while relatively small, are designed to meet most product needs.

PAD District V (West Coast)

During the 1970's, a wide array of products were imported into PAD District V. After refineries were built to accommodate Alaskan crude oil, imports declined. In 1992, imports were primarily motor gasoline, residual fuel oil, and blending components.

The West Coast exported small amounts of residual fuel oil and petroleum coke prior to 1981. Then, exports of these products expanded, accounting for 56 percent in 1992. Exports of distillate fuel oil increased in the early 1990's, and comprised 26 percent of the 367,000 barrels per day of petroleum products exported from PAD District V in 1992. The natural markets for these products were the Far East, Canada, and Mexico.

Figure 17. U.S. Inter-Regional Movement of Crude Oil and Petroleum Products by Water and Pipeline, 1992



Note: Arrows vary in size to show the relative difference in inter-regional shipments.
Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table A3 for corresponding data.

Transportation and Storage

The U.S. petroleum distribution system links the importing and refining centers with consumption areas through a complex system of transportation and storage facilities. Each region (PAD District) of the United States is unique in its petroleum transportation and storage configurations. Distribution of crude oil and petroleum products between regions is primarily by pipeline or water **(Figure 17)**.

Primary crude oil and petroleum product stocks are held at tank farms, refineries, natural gas liquids plants, bulk terminals, and pipelines throughout the distribution system. Since 1977, crude oil purchased by the Federal Government for use in emergencies has been stored in the U.S. Strategic Petroleum Reserve (SPR) in PAD District III. The SPR contained 575 million barrels at the end of 1992 **(Figure 18)**.

End-of-year stocks of crude oil (excluding the SPR) peaked in 1981 at 363 million barrels, then declined to 321 million barrels by the end of 1985. After that, crude oil stocks fluctuated moderately **(Figure 19)**. Crude oil stocks stood at 318 million barrels at the end of 1992.

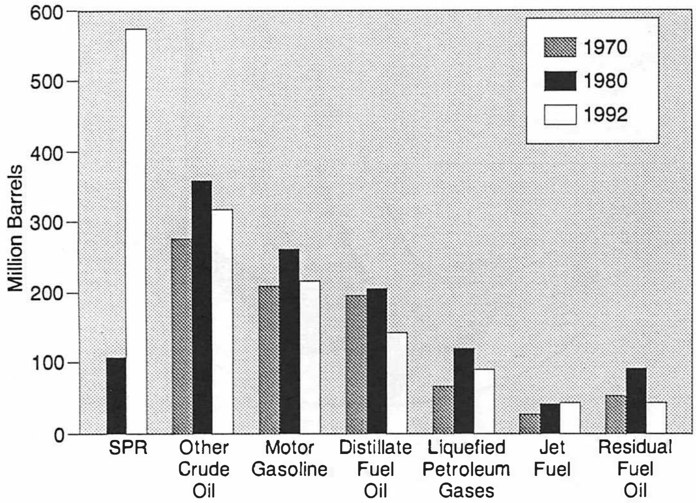
End-of-year total product stocks peaked at 964 million barrels in 1977, then generally declined through 1992. Crude oil accounted for 26 percent of total petroleum stocks (excluding the SPR) at the end of 1977. As total product stocks declined, crude oil stocks accounted for a higher share of total petroleum stocks, excluding the SPR. At the end of 1989, when total product stocks were low at 660 million barrels, crude oil accounted for 34 percent of total petroleum stocks, excluding the SPR **(Table 13)**.

Distillate fuel oil stocks declined more than stocks of any other product after 1978 **(Figure 20)**. In all probability, the decline reflects decreasing use of distillate fuel oil for heat and power.

U.S. Regional Transportation Patterns

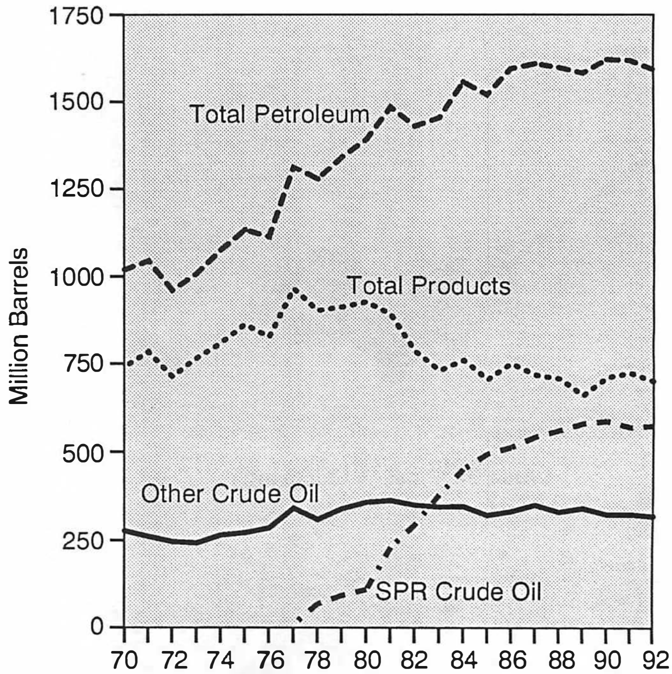
Total inter-regional movements of crude oil have hovered around 2.4 million barrels per day since 1985, the earliest complete data available (See Appendix Tables A3 and A4 for regional data).

Figure 18. End-of-Year U.S. Primary Stocks of Petroleum, Selected Years



Note: SPR is the Strategic Petroleum Reserve.
Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table 13 for corresponding data.

Figure 19. Total U.S. Primary Petroleum Stocks at End of Year, 1970 - 1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table 13 for corresponding data.

Inter-regional movements of petroleum products have held steady at around 4.3 million barrels per day since 1980.

The opening of the All-American crude oil pipeline in 1987 led to the replacement of an average 110,000 barrels per day of crude oil movements that had been shipped by tanker and barge from the West Coast to the Gulf Coast. Additional changes in pipeline movements were a decline in crude oil deliveries from the Rocky Mountain area to the Midwest during the mid-1980's because of production declines. Pipeline reversals and expansions opened the way for increased volumes of crude oil to be shipped from the Gulf Coast to the Midwest in the mid-to-late 1980's.

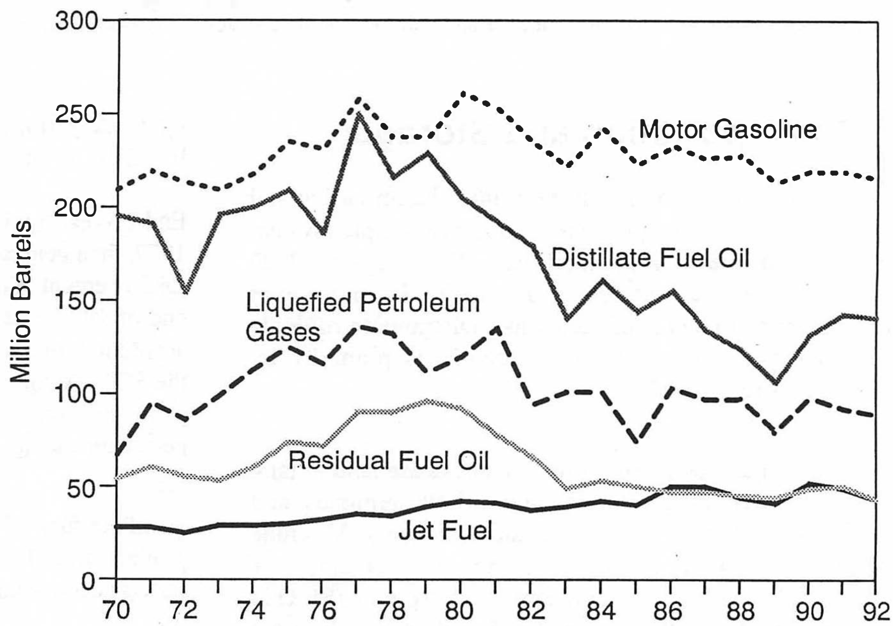
Pipeline deliveries of products from the Gulf Coast to the East Coast displaced some movements by tanker and barge by 1980, as the Colonial Pipeline opened and expansions were completed on the Plantation Pipeline System.

PAD District I (East Coast)

Of the five U.S. regions, PAD District I was the largest consumer of oil between 1970 and 1992. However, its share declined from 40 percent in 1970 to 29 percent in 1992. East Coast demand peaked in 1973 at 6.7 million barrels per day; in 1992 it was 5.0 million barrels per day.

Because refinery output is well below the level needed to meet product demand, the East Coast is dependent on imports and shipments from Gulf

Figure 20. End-of-Year U.S. Primary Stocks of Selected Petroleum Products, 1970 - 1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table 13 for corresponding data.

Table 13. U.S. Primary Stocks of Petroleum at End of Year, 1970 - 1992
(Million Barrels)

Year	Crude Oil			Petroleum Products							
	SPR[1]	Other	Total	Motor Gasoline[2]	Distillate Fuel Oil	Liquefied Petroleum Gases	Jet Fuel	Residual Fuel Oil	Other Products[3]	Total	Total Petroleum
1970......	--	276	276	209	195	67	28	54	188	741	1,018
1971......	--	260	260	219	191	95	28	60	193	784	1,044
1972......	--	246	246	213	154	86	25	55	179	713	959
1973......	--	242	242	209	196	99	29	53	179	766	1,008
1974......	--	265	265	218	200	113	29	60	188	809	1,074
1975......	--	271	271	235	209	125	30	74	188	862	1,133
1976......	--	285	285	231	186	116	32	72	188	826	1,112
1977......	7	340	348	258	250	136	35	90	195	964	1,312
1978......	67	309	376	238	216	132	34	90	191	901	1,278
1979......	91	339	430	237	229	111	39	96	200	911	1,341
1980......	108	358	466	261	205	120	42	92	206	926	1,392
1981......	230	363	594	253	192	135	41	78	191	890	1,484
1982......	294	350	644	235	179	94	37	66	175	786	1,430
1983......	379	344	723	222	140	101	39	49	180	731	1,454
1984......	451	345	796	243	161	101	42	53	160	760	1,556
1985......	493	321	814	223	144	74	40	50	174	705	1,519
1986......	512	331	843	233	155	103	50	47	162	750	1,593
1987......	541	349	890	226	134	97	50	47	163	718	1,607
1988......	560	330	890	228	124	97	44	45	170	707	1,597
1989......	580	341	921	213	106	80	41	44	176	660	1,581
1990......	586	323	908	220	132	98	52	49	162	712	1,621
1991......	569	325	893	219	144	92	49	50	170	724	1,617
1992......	575	318	893	216	141	89	43	43	168	699	1,592

[1]SPR = Strategic Petroleum Reserve.
[2]Includes motor gasoline blending components.
[3]Includes pentanes plus, other hydrocarbons and alcohol, unfinished oils, and all finished petroleum products except motor gasoline, distillate fuel oil, residual fuel oil, jet fuel, and liquefied petroleum gases.
-- = Not Applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol 1, 1992, Tables S1, S2, and S4 - S8, and predecessor reports.

Coast and Midwest refineries. In 1992, 79 percent of the 2.8 million barrels per day of petroleum products delivered to the East Coast were by pipeline.

PAD District II (Midwest)

Midwest petroleum demand has been approximately one-fourth of the U.S. total since 1970. Demand fluctuated between 4.0 and 5.2 million barrels per day. Refinery output provided about 80 percent of the total demand.

Indigenous crude oil production, which represented 16 percent of Midwest product demand in 1992, is supplemented by direct imports from Canada. Pipeline shipments from the Gulf Coast and Rocky Mountain area provide most of the additional crude oil needed in PAD District II.

Crude oil and products move into PAD District II from surrounding areas, but the region also supplies some crude oil and products to the Gulf Coast, Rocky Mountain, and East Coast. In 1992, 94 percent of the petroleum movements into or from PAD District II were by pipeline, and the rest by water. Pipeline reversals and expansions since 1988 have displaced some tanker and barge movements from the Gulf Coast.[29]

Despite declines in inter-regional petroleum movements by water in PAD District II, the Mississippi River and the Tennessee-Tombigbee river system are important routes for petroleum deliveries within the Midwest and other PAD Districts.

The Tennessee-Tombigbee Waterway. Opened in 1985 as a parallel route to the Mississippi River for transporting goods between Illinois and the Gulf of Mexico, the Tennessee-Tombigbee system proved essential in keeping petroleum and other goods moving during the 1988 drought that disrupted Mississippi River traffic. Though much smaller than the Mississippi River, the Tennessee-Tombigbee system maintained its normal 9-foot depth throughout the drought because of its system of 10 locks and dams that are used to regulate its flow at a constant level.

Petroleum shipments on the Tennessee-Tombigbee waterway jumped from an average 118,000 barrels per month during the first 5 months of 1988 to over 600,000 barrels in June. The waterway moved 1.8 million barrels of petroleum in July before the 1988 drought eased and Mississippi River traffic returned to normal.[30] The river system returned to a slower pace after the drought, resuming its previous growth rate for transporting petroleum and other goods.

PAD District III (Gulf Coast)

PAD District III has the largest concentration of U.S. refining capacity and storage, both for crude oil and for petroleum products. The Gulf Coast accounts for about half of the Nation's primary stocks of crude oil, all of the SPR stocks, and about one-third of the petroleum product stocks.

The Gulf Coast has been the predominant supplier of petroleum to other regions since 1970. The Gulf Coast furnishes crude oil and/or refined products to the East Coast, the Midwest, and the West Coast. The region also receives smaller amounts of crude oil and products from the Midwest, the Rocky Mountain area, and the West Coast. By 1980, some product movements that had been by water to the East Coast were displaced by pipeline shipments after large product pipelines were built or expanded. Between 1975 and 1980, pipelines' share of petroleum product movements from PAD District III to I increased from 52 percent to 67 percent. By 1987, pipelines were claiming 80 percent of the petroleum products transported from PAD District III to I. In 1992, pipelines carried 86 percent of the petroleum entering or leaving PAD District III.

Petroleum demand in the Gulf Coast increased from 2.5 to 4.5 million barrels per day from 1970 to 1992. Its share of U.S. demand also grew, from 17 percent in 1970 to 26 percent in 1992.

Although PAD District III produces more crude oil than any other region (**Figure 21**), it replaced PAD District I as the largest importer of crude oil in 1976, and in 1992 accounted for 65 percent of U.S. crude oil imports. Although some of the crude oil imports are used in the region, large amounts also pass through the Gulf Coast by pipeline to refineries in PAD District II.

The Louisiana Offshore Oil Port. Until 1981, most crude oil imports into PAD District III were offloaded at ports along the Texas and Louisiana coasts. However, because many ports cannot handle large crude carriers, crude oil had to be transferred from very large and ultra-large tankers to smaller ships. The opening of the Louisiana Offshore Oil Port (LOOP) in 1981 reduced the need for lightering of crude oil tankers. Located 18 miles south of Louisiana, the LOOP is the Nation's only deepwater port that can accommodate ultra-large tankers.[31] The LOOP has the capacity for unloading 1.4 million barrels of oil per day. Pipelines link the LOOP to major refineries in Louisiana, Texas, and the Midwest.[32]

PAD District IV (Rocky Mountain)

PAD District IV is geographically isolated, with no access to water and only a few pipelines. All the movements in and out of the area are by pipeline. The Rocky Mountain area supplies petroleum products and/or crude oil to the Midwest, the Gulf Coast, and the West Coast. The area also receives crude oil and products from the Midwest. Declining crude oil production in the late 1980's caused shipments from PAD District IV to drop. By decreasing shipments out of the region, the balance between crude oil supply and product demand in PAD District IV was preserved.

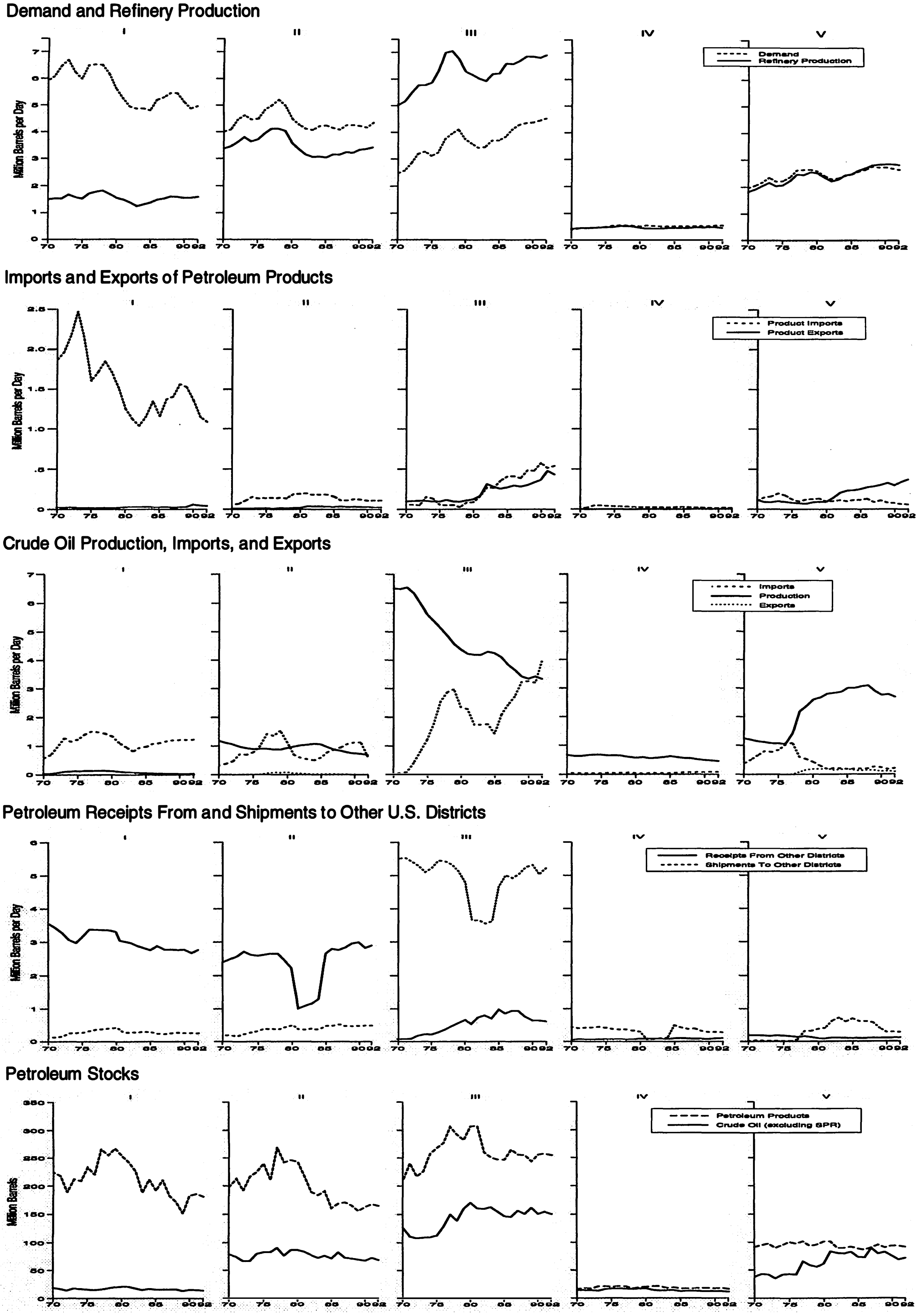
Despite the isolation of PAD District IV, the economics driving supply and demand in the region are not appreciably different from those in the rest of the country. PAD District IV accounts for only about 3 percent of total U.S. demand, but its crude oil supplies are about in balance with product demand. Although the Rocky Mountain area refineries tend to be small, they are relatively sophisticated and produce a wide range of products specially suited to the region.

PAD District V (West Coast)

PAD District V, which accounted for about 15 percent of U.S. demand in 1992, has been essentially self-sufficient both in crude oil production and in refined product production. Since the mid-1980's, refinery production in PAD District V has exceeded demand, and product imports have accounted for only a small portion of supply. Small amounts of petroleum products have also

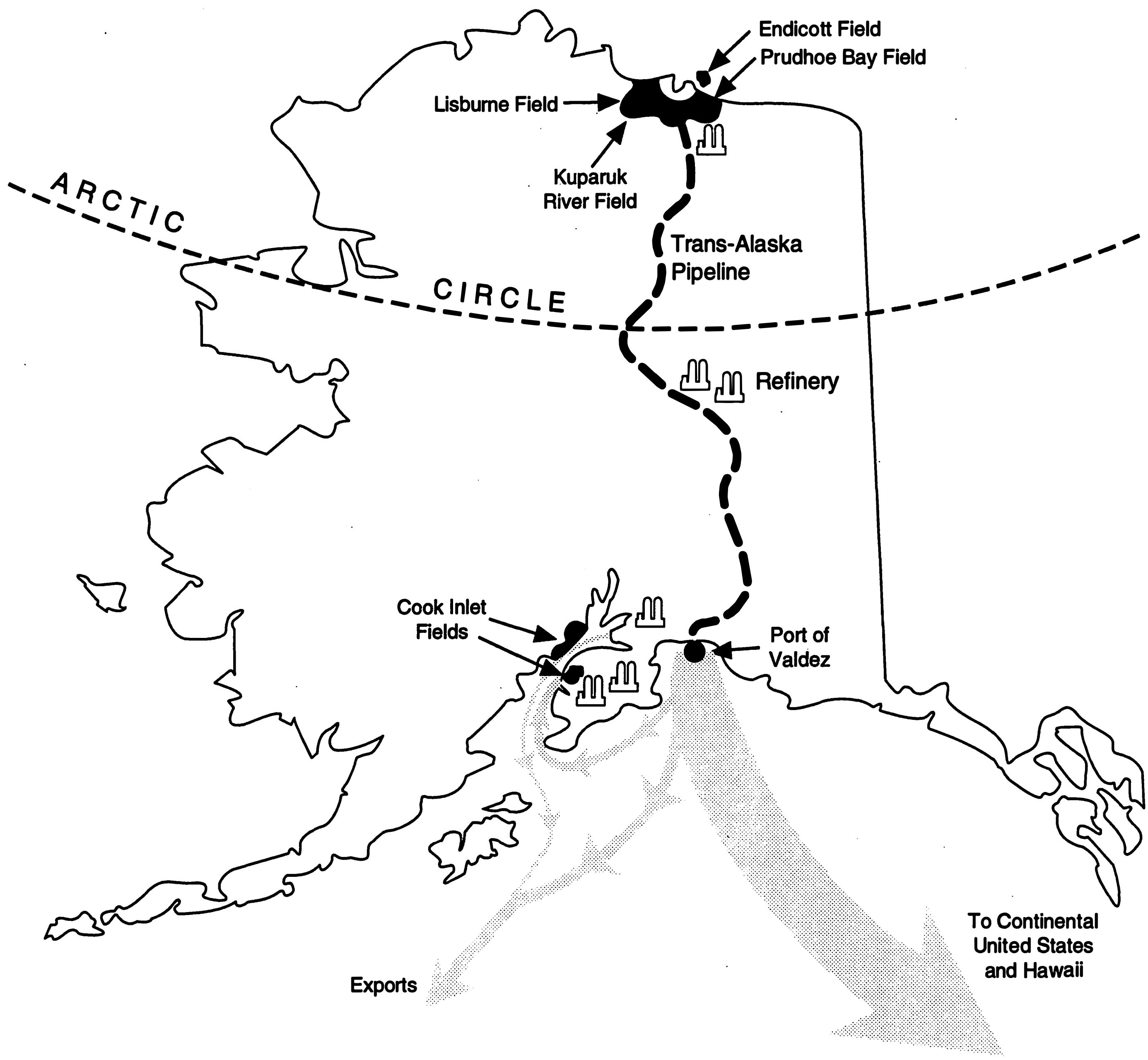
[29]Energy Information Administration, "Proposed Projects Underscore Need for Imports and Pipeline Capacity in PAD District II," *Petroleum Supply Monthly*, April 1991, pp. xvi and xvii.
[30]U.S. Army Corps of Engineers, *Tenn-Tom Waterway Traffic by Commodity*, Historical Summary, August 1988.
[31]"LOOP expects profit for 3rd time in history," *The Advocate*, August 20, 1992, p. 1D.
[32]"LOOP Sees October Drop in Crude Imports," *Bloomberg Oil Buyers Guide*, September 28, 1992, p. 3.

Figure 21. Selected Components of U.S. Regional Petroleum Supply and Demand, 1970-1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table A4 for corresponding data.

Figure 22. Alaska: Major Producing Areas and Crude Oil Flow



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, and Form EIA-810, "Refinery Report;" Pennwell Publishing Company, *International Petroleum Encyclopedia*, 1991.

arrived from PAD Districts III and IV. In 1992, 59 percent of the petroleum movements into or out of the West Coast were by pipeline.

Transporting Alaskan North Slope Crude Oil. Completion of the 818-mile Trans-Alaska Pipeline (TAPS) in 1977 made up to 2 million barrels per day of Alaskan North Slope (ANS) crude oil accessible to other areas (**Figure 22**). Because of export restrictions on U.S. crude oil, most of the ANS crude oil goes to the U.S. West Coast, where it is refined or shipped to other areas. Transporting ANS crude oil involves a complex shipping network. Except for the oil being shipped to the U.S. Virgin Islands, all of the oil is transported in U.S. flag vessels to comply with the Jones Act of 1920.

Since the opening of the All American Pipeline in 1988, ANS crude oil for use beyond PAD District V can be transported by pipeline from California, or can go by the traditional route to Panama. At Panama, ANS oil is transferred to the Trans-Panama Pipeline (opened in 1983) or is lightered to smaller ships and sent through the Panama Canal. On the Caribbean side of the Isthmus, the oil is transferred to other U.S. flag vessels to travel on to Puerto Rico or ports on the mainland.

The crude oil being shipped to the Virgin Islands is not under Jones Act restrictions. At competitive costs, foreign flag tankers transport ANS crude oil from Valdez, Alaska, around the tip of South America (over twice the distance via Panama).

Tanker shipments of crude oil from PAD District V to other districts rose from virtually zero in 1970 to 707,000 barrels per day in 1983. As ANS crude oil production has declined in recent years, so have shipments from PAD District V to other districts.

After peaking in 1988 at 2.0 million barrels per day, ANS production declined by 15 percent over the following 4 years. Despite the decline, ANS production accounted for about 23 percent of the total 1992 U.S. crude oil production and 63 percent of PAD District V production (**Table 14**).

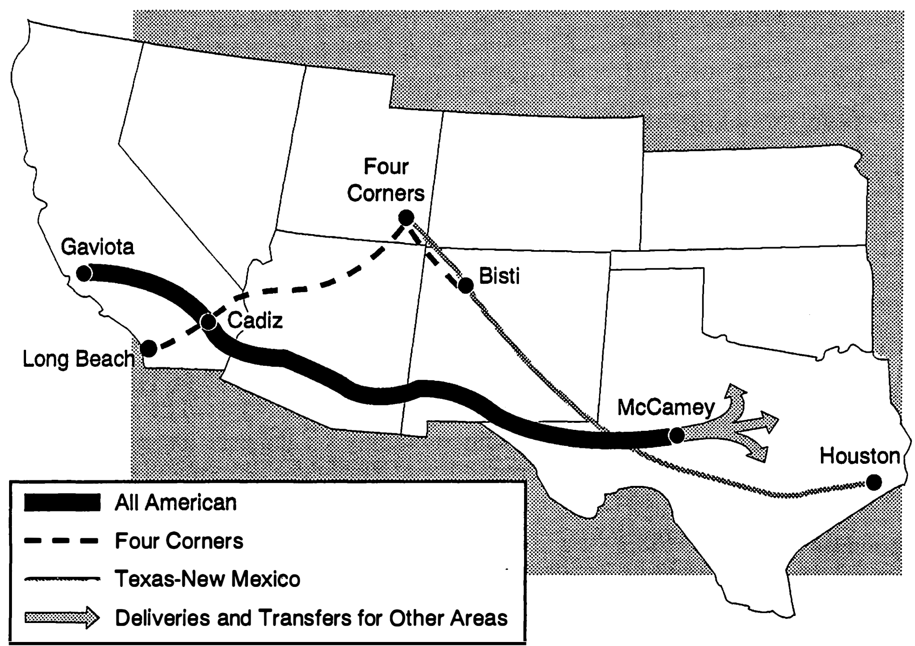
Table 14. Alaskan North Slope Crude Oil Production and Refinery Receipts, 1981 - 1992
(Thousand Barrels per Day)

Year	Crude Oil Production	Refinery Receipts			
		PAD Districts		Puerto Rico and Virgin Islands	Total
		I-IV	V[1]		
1981	1,524	326	843	161	1,330
1982	1,621	534	823	184	1,541
1983	1,646	629	863	101	1,593
1984	1,662	542	969	122	1,633
1985	1,779	531	950	10	1,491
1986	1,818	401	1,131	106	1,638
1987	1,917	466	1,228	127	1,821
1988	1,974	404	1,362	127	1,893
1989	1,832	236	1,428	132	1,796
1990	1,743	186	1,434	96	1,716
1991	1,756	153	1,438	110	1,700
1992	1,672	138	1,405	85	1,629

[1]Includes Hawaiian Foreign Trade Zone receipts for 1981-1986.
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1988, Table 9, 1989-1992, Table 14, and Form EIA-810, "Refinery Report," 1981-1992.

Pipelines From the West Coast. Although more than half of the petroleum deliveries from PAD District V to other districts are by tanker, shipments by pipeline have grown. In the 1970's, the Four Corners Pipeline and the Texas-New Mexico Pipeline were used to transport small amounts of crude oil (55,000 barrels per day to 70,000 barrels per day) from California to Texas. In late 1987, the All American Pipeline was completed, with the capacity to carry 300,000 barrels per day of crude oil to Texas (**Figure 23**).[33] Since 1988, shipments of crude oil by pipeline from PAD District V have averaged about 113,000 barrels per day, comprised of crude oil from Alaska and the San Joaquin Valley of California. The All American Pipeline has no facility on the California coast for receiving waterborne shipments of ANS crude oil. The limited capacity of the Four Corners Pipeline that connects the All American Pipeline with ports at Long Beach, California, has contributed to the relatively low volumes transported. An additional constraint is that San Joaquin Valley crude oils are too heavy to be shipped on the unheated All American line unless blended with lighter crude oils.

Figure 23 Crude Oil Pipelines: California to Texas



Source: Pennwell Publishing Company, *Crude Oil Pipelines of the United States and Canada*, 1992.

Crude Oil Supplies

Domestic supplies of petroleum, including crude oil and smaller amounts of natural gas liquids (NGL's) and other hydrocarbons, are augmented by imports to meet demand. The United States always has been one of the world's largest producers of crude oil, and for many years was the largest.[34] Nevertheless,

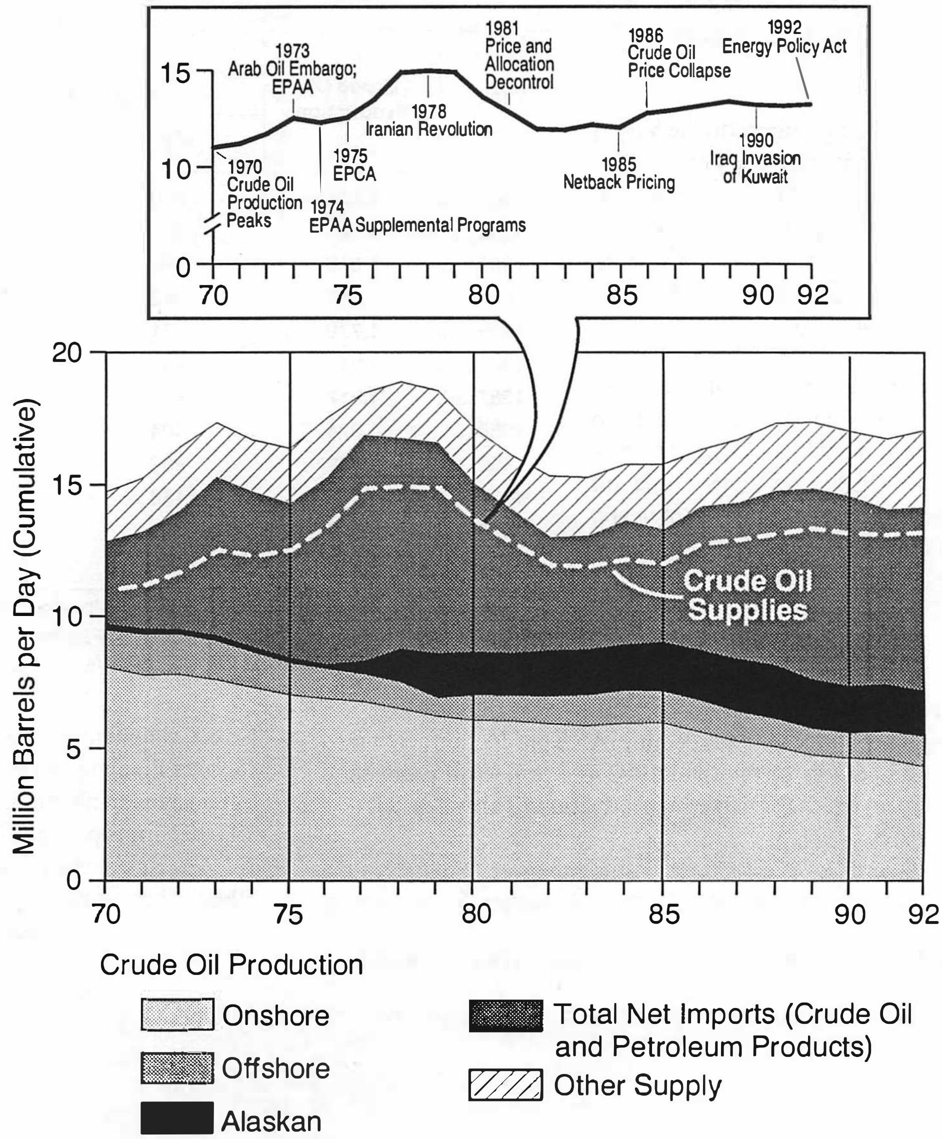
[33]Energy Information Administration, "Crude Oil Pipelines: California to Texas," *Petroleum Supply Monthly*, December 1987, p. xiv.
[34]American Petroleum Institute, *Basic Petroleum Data Book*, Vol. XII, Number 3, September 1993, Section IV, Table 1.

since at least 1949, the United States has been a net importer of crude oil.

U.S. dependence on foreign petroleum has increased since 1970, when domestic crude oil production was at its peak **(Figure 24)** and accounted for 66 percent of U.S. oil demand. By 1992, domestic crude oil's share had fallen to 42 percent. Crude oil imports have compensated for the decline in domestic production. From a 9-percent share of demand in 1970, crude oil net imports (excluding the SPR) grew and accounted for 36 percent in 1977 before falling off in the late 1970's and early 1980's. Since 1985, however, net crude oil imports have accounted for a growing portion of demand and in 1992 again approached the 1977 share, reaching 35 percent.

One aim of the Energy Policy Act of 1992 is to reduce consumption of imported oil through the use of alternative transportation fuels and the development of new technologies to increase energy efficiency. Success of these programs will likely reduce petroleum consumption over time.[35] At the same time, domestic crude oil production will continue to fall, barring any large discoveries of the magnitude of Alaska's giant Prudhoe Bay field. It remains to be seen whether these programs will result in a major reduction in crude oil imports.

Figure 24. U.S. Petroleum Supply and Related Events, 1970 - 1992



Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Table15 for corresponding data.

State Allowables

In the early 1970's, production capacity was peaking and rapid growth in demand was beginning to outpace domestic production **(Table 15)**. One indication of the tightening supply situation in 1970 was the virtual elimination of the State allowables. Originally enacted by State governments in the 1930's to conserve resources and keep prices stable, the allowables dictated the amount of crude oil that could be produced from a producing property under a prorationing order.[36] Prorationing tended to restrict full production, but with production peaking, the need for prorationing became obsolete. U.S. supplies tightened further after the 1973 Arab Oil Embargo, when the cost of foreign crude oil tripled.

The Importance of Price

The two-tiered pricing system implemented under the 1973 Emergency Petroleum Allocation Act (EPAA) discouraged new domestic oil exploration and production by controlling the price of domestic crude oil. From 1973 to 1974, while the refiner acquisition cost of imported crude oil jumped from about \$4 to more than \$12 per barrel, the comparable cost of domestic crude oil rose from around \$4 to just \$7 per barrel **(Table 16)**. The Energy Policy and Conservation Act of 1975 extended price controls over even larger portions of domestic production.

Between 1970 and 1982, U.S. production in the Lower 48 States, both onshore and offshore, fell by about 25 percent. Price controls

[35] Congressional Research Service, *Alternate Transportation Fuels: Are They Reducing Oil Imports?*, January 15, 1993, Summary and p. CRS-4.
[36] U.S. Department of Energy, Office of the Secretary for Conservation and Solar Operations, *An Analysis of Federal Incentives Used to Stimulate Energy Production*, June 1978, p. 207.

Table 15. U.S. Petroleum Production, Net Imports, and Demand, 1970 - 1992
(Thousand Barrels per Day)

Year	Production						
	Crude Oil						
	Lower 48						
	Offshore	Onshore	Alaskan	Total	Percent of Demand	Other[1]	Total Production
1970	1,385	8,023	229	9,637	65.6	1,677	11,314
1971	1,503	7,742	218	9,463	62.2	1,709	11,172
1972	1,486	7,756	199	9,441	57.7	1,771	11,212
1973	1,446	7,564	198	9,208	53.2	1,767	10,975
1974	1,324	7,257	193	8,774	52.7	1,724	10,498
1975	1,197	6,987	191	8,375	51.3	1,670	10,045
1976	1,115	6,844	173	8,132	46.6	1,642	9,774
1977	1,040	6,741	464	8,245	44.7	1,668	9,913
1978	1,011	6,467	1,229	8,707	46.2	1,621	10,328
1979	962	6,189	1,401	8,552	46.2	1,627	10,179
1980	946	6,034	1,617	8,597	50.4	1,617	10,214
1981	956	6,007	1,609	8,572	53.4	1,658	10,230
1982	1,044	5,909	1,696	8,649	56.5	1,603	10,252
1983	1,135	5,839	1,714	8,688	57.0	1,611	10,299
1984	1,228	5,929	1,722	8,879	56.5	1,675	10,554
1985	1,210	5,936	1,825	8,971	57.0	1,665	10,636
1986	1,212	5,601	1,867	8,680	53.3	1,609	10,289
1987	1,134	5,253	1,962	8,349	50.1	1,659	10,008
1988	1,052	5,071	2,017	8,140	47.1	1,678	9,818
1989	992	4,747	1,874	7,613	43.9	1,606	9,219
1990	954	4,628	1,773	7,355	43.3	1,639	8,994
1991	1,023	4,596	1,798	7,417	44.4	1,751	9,168
1992	1,068	4,389	1,714	7,171	42.1	1,825	8,995

Year	Net Imports						Total Production and Net Imports	Total Demand
	Crude Oil							
	SPR[2]	Other	Total	Petroleum Products	Total Net Imports	Percent of Demand		
1970	--	1,310	1,310	1,850	3,160	21.5	14,474	14,697
1971	--	1,680	1,680	2,023	3,703	24.3	14,875	15,213
1972	--	2,215	2,215	2,303	4,518	27.6	15,730	16,367
1973	--	3,242	3,242	2,783	6,025	34.8	17,000	17,308
1974	--	3,474	3,474	2,417	5,891	35.4	16,389	16,653
1975	--	4,099	4,099	1,747	5,846	35.8	15,891	16,322
1976	--	5,279	5,279	1,811	7,090	40.6	16,864	17,461
1977	21	6,544	6,565	2,000	8,565	46.5	18,478	18,431
1978	162	6,036	6,198	1,804	8,002	42.5	18,330	18,847
1979	67	6,217	6,284	1,700	7,984	43.1	18,163	18,513
1980	44	4,932	4,976	1,388	6,364	37.3	16,578	17,056
1981	256	3,912	4,168	1,232	5,400	33.6	15,630	16,058
1982	165	3,087	3,252	1,046	4,298	28.1	14,550	15,296
1983	234	2,931	3,165	1,147	4,312	28.3	14,611	15,231
1984	197	3,048	3,245	1,470	4,715	30.0	15,269	15,726
1985	118	2,879	2,997	1,289	4,286	27.3	14,922	15,726
1986	48	3,976	4,024	1,414	5,438	33.4	15,727	16,281
1987	73	4,450	4,523	1,391	5,914	35.5	15,922	16,665
1988	51	4,901	4,952	1,634	6,586	38.1	16,404	17,283
1989	56	5,645	5,701	1,500	7,201	41.6	16,420	17,325
1990	27	5,758	5,785	1,375	7,160	42.1	16,154	16,988
1991	0	5,666	5,666	959	6,625	39.6	15,793	16,714
1992	10	5,984	5,994	944	6,938	40.7	15,933	17,033

[1] Includes natural gas liquids, other hydrocarbons, and alcohol.
[2] SPR = Strategic Petroleum Reserve.
-- = Not Applicable.
Source: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1982, Tables 9 and 10, 1983-1988, Table 9, 1989-1992, Tables S1, S2, and 14, and predecessor reports.

Table 16. U.S. Refiner Acquisition Cost of Crude Oil, 1970 - 1992
(Dollars per Barrel)

Year	Domestic	Imported	Composite
1970..........	3.46	2.96	3.40
1971..........	3.68	3.17	3.60
1972..........	3.67	3.22	3.58
1973..........	4.17	4.08	4.15
1974..........	7.18	12.52	9.07
1975..........	8.39	13.93	10.38
1976..........	8.84	13.48	10.89
1977..........	9.55	14.53	11.96
1978..........	10.61	14.57	12.46
1979..........	14.27	21.67	17.72
1980..........	24.23	33.89	28.07
1981..........	34.33	37.05	35.24
1982..........	31.22	33.55	31.87
1983..........	28.87	29.30	28.99
1984..........	28.53	28.88	28.63
1985..........	26.66	26.99	26.75
1986..........	14.82	14.00	14.55
1987..........	17.76	18.13	17.90
1988..........	14.74	14.56	14.67
1989..........	17.87	18.08	17.97
1990..........	22.59	21.76	22.22
1991..........	19.33	18.70	19.06
1992..........	18.63	18.20	18.43

Source: Energy Information Administration, *Annual Energy Review 1992*, Table 5.20.

in effect during much of the period contributed to the decline. Imports filled the widening gap between domestic production and demand. From 1.3 million barrels per day in 1970, gross crude oil imports (including SPR) climbed steadily before reaching a historic high of 6.6 million barrels per day in 1977. OPEC[37] also achieved its strongest market penetration in the 1970's, increasing its share of U.S. crude oil imports from 46 percent in 1970 to 86 percent in 1976.

The world oil price escalation of 1978 to 1980 caused domestic, price-controlled crude oils to be undervalued against foreign crude oils on the world market. Domestic producers in the Lower 48 States, both onshore and offshore, lost the incentive to produce crude oil under these conditions, and production declined more rapidly.

However, with the completion of the Trans-Alaska Pipeline System (TAPS) in 1977, much of the decline in production in the Lower 48 States was offset by new Alaskan North Slope (ANS) production. Within a year of the opening of the TAPS, Alaskan production exceeded 1.2 million barrels per day, and by 1988, Alaskan output topped 2.0 million barrels per day.

The decontrol of oil prices in 1981 restored economic incentives and spurred production in the Lower 48 States. When combined with the growing ANS production, the increase temporarily reversed the decline in domestic crude oil supplies. By 1985, domestic crude oil production recovered to 9.0 million barrels per day, 9 percent above the 1977 level.

These trends and declining demand resulted in a steep drop in crude oil imports. From 1977 to 1985, gross imports of crude oil fell to 3.2 million barrels per day, a decrease of 52 percent. The U.S. dependence on OPEC oil also declined (**Table 17**). In the early 1980's, large-scale development projects in the North Sea, Mexico, and other non-OPEC countries began adding significantly to world supplies, forcing OPEC to cut output to defend its official price. Consequently, OPEC's share of U.S. crude oil imports slipped from a high of 86 percent in 1976 to 41 percent in 1985. At the same time, non-OPEC countries such as Canada, Mexico, Norway, and the United Kingdom accounted for a growing portion of U.S. crude oil supply.

The 1986 price collapse that resulted from OPEC production increases and netback pricing damaged the U.S. exploration and production sector. From 1985 to 1992, crude oil production in the Lower 48 States fell 24 percent. In addition, production from Alaska also declined after 1988. In 1992, domestic crude oil production dropped to 7.2 million barrels per day, its lowest level since 1960.

These events led to a rapid rise in crude oil imports. Gross crude oil imports of 6.1 million barrels per day in 1992 were 90 percent higher than in 1985. Countries with excess production capacity, primarily Saudi Arabia but also including other Persian Gulf states, were the primary beneficiaries of the 1986 price collapse. This is evident in the rise in OPEC's share of U.S. gross crude oil imports, which rebounded from 41 percent in 1985 to 60 percent in 1990.

The U.S. crude oil production decline was interrupted during the Persian Gulf crisis in 1990 and 1991, when efforts were being made in major world producing areas to increase output to offset the embargoed crude oil production from Iraq and Kuwait. Crude oil prices rose sharply after the U.N. embargo was enforced. Between August 1 and October 11, 1990, the spot market price for West Texas Intermediate (WTI), the U.S. benchmark crude oil, rose from $21.59 per barrel to $41.07 per barrel.[38]

Prices remained relatively high until January 16, 1991. The initial success of the allied air attack on Iraq, combined with reports of uninterrupted loadings at Saudi Arabian ports and the announced release of SPR oil, calmed world markets.[39] The spot price for WTI crude oil experienced a record one-day drop, from $32.25 per barrel on January 16 to $21.48 per barrel on January 17.[40]

[37] Organization of Petroleum Exporting Countries, composed of 13 member nations until December 31, 1992, when Ecuador withdrew. Between 1970 and 1992, Arab members of OPEC included Algeria, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and the United Arab Emirates. Other OPEC members included Ecuador, Gabon, Indonesia, Iran, Nigeria, and Venezuela.
[38] *Reuter's News Service*, daily issues for the period.
[39] Energy Information Administration, "Initial Allied Attack Calms Oil Markets," *Petroleum Supply Monthly*, January 1991, pp. xvii and xviii.
[40] *Reuter's News Service*, daily issues for the period.

Table 17. U.S. Crude Oil Imports, 1970 - 1992
(Thousand Barrels per Day)

Year	OPEC				Non-OPEC		Total Imports
	Arab	Other	Total	Percent of Total	Total	Percent of Total	
1970	189	420	609	46.0	715	54.0	1,324
1971	301	614	915	54.4	766	45.6	1,681
1972	487	811	1,298	58.6	919	41.5	2,216
1973	838	1,257	2,095	64.6	1,149	35.4	3,244
1974	713	1,827	2,540	73.1	937	26.9	3,477
1975	1,330	1,882	3,211	78.2	893	21.8	4,105
1976	2,378	2,167	4,545	86.0	742	14.0	5,287
1977	3,136	2,507	5,643	85.3	971	14.7	6,615
1978	2,930	2,254	5,184	81.6	1,172	18.4	6,356
1979	3,002	2,110	5,112	78.4	1,407	21.6	6,519
1980	2,503	1,361	3,864	73.4	1,399	26.6	5,263
1981	1,774	1,149	2,922	66.5	1,474	33.5	4,396
1982	736	998	1,734	49.7	1,754	50.3	3,488
1983	533	944	1,477	44.4	1,853	55.7	3,329
1984	634	878	1,512	44.1	1,914	55.9	3,426
1985	300	1,012	1,312	41.0	1,888	59.0	3,201
1986	854	1,259	2,113	50.6	2,065	49.4	4,178
1987	965	1,435	2,400	51.3	2,274	48.7	4,674
1988	1,415	1,281	2,696	52.8	2,411	47.2	5,107
1989	1,794	1,582	3,376	57.8	2,467	42.2	5,843
1990	1,864	1,650	3,514	59.6	2,381	40.4	5,894
1991	1,754	1,622	3,377	58.4	2,405	41.6	5,782
1992	1,660	1,746	3,406	56.0	2,676	44.0	6,083

Note: Totals may not equal sum or components due to independent rounding
Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1992, Table S3, and predecessor reports.

Table 18. U.S. Merchandise Trade Value, 1974 - 1992
(Million Dollars)

Year	Exports			Imports			Trade Balance	
	Petroleum	Total Merchandise	Petroleum as percent of Total	Petroleum	Total Merchandise	Petroleum as percent of Total	Petroleum	Total Merchandise
1974	792	99,437	0.8	24,668	103,321	23.9	(23,876)	(3,884)
1975	907	108,856	0.8	25,197	99,305	25.4	(24,289)	9,551
1976	998	116,794	0.9	32,226	124,614	25.9	(31,228)	(7,820)
1977	1,276	123,182	1.0	42,368	151,534	28.0	(41,093)	(28,353)
1978	1,561	145,847	1.1	39,526	176,052	22.5	(37,965)	(30,205)
1979	1,914	186,363	1.0	56,715	210,285	27.0	(54,801)	(23,922)
1980	2,833	225,566	1.3	78,637	245,262	32.1	(75,803)	(19,696)
1981	3,696	238,715	1.5	76,659	260,982	29.4	(72,963)	(22,267)
1982	5,947	216,442	2.7	60,458	243,952	24.8	(54,511)	(27,510)
1983	4,557	205,639	2.2	53,217	258,048	20.6	(48,659)	(52,409)
1984	4,470	223,976	2.0	56,924	330,678	17.2	(52,454)	(106,703)
1985	4,707	218,815	2.2	50,475	336,526	15.0	(45,768)	(117,712)
1986	3,640	227,159	1.6	35,142	365,438	9.6	(31,503)	(138,279)
1987	3,922	254,122	1.5	42,285	406,241	10.4	(38,363)	(152,119)
1988	3,693	322,426	1.1	38,787	440,952	8.8	(35,094)	(118,526)
1989	5,021	363,812	1.4	49,704	473,211	10.5	(44,683)	(109,399)
1990	6,901	393,592	1.8	61,583	496,088	12.4	(54,682)	(102,496)
1991	6,954	421,730	1.6	51,350	488,453	10.5	(44,396)	(66,723)
1992	6,412	448,164	1.4	51,217	532,665	9.6	(44,805)	(84,501)

Notes: • The U.S. import statistics reflect both government and nongovernment imports of merchandise from foreign countries into the U.S. customs territory, which comprises the 50 States, the District of Columbia, Puerto Rico, and the Virgin Islands. • Totals may not add to sum of components due to independent rounding.
Source: Energy Information Administration, *Monthly Energy Review*, June 1993, Table 1.6.

Exploration in Former USSR

The breakup of the Soviet Union at the end of 1991 opened new areas of exploration to U.S. and other crude oil producers. Despite myriad uncertainties about the direction that policies will take in the former Soviet Union with regard to these opportunities, some U.S. producing firms have entered into joint ventures to explore, develop, and export petroleum from this oil-rich area.[41]

Imports, Exports, and the Balance of Oil Trade

The United States has run trade deficits in petroleum for many years, but data have only been available since 1974 (**Table 18**). The value of crude oil imports is the principal component of the total petroleum trade balance, but both crude oil and petroleum products contribute to it.

Net Oil Imports

The size of the U.S. petroleum trade deficit is essentially a function of two variables: net volume and price. These variables often move in opposite directions, and their effects on the petroleum trade deficit often counterbalance one another. For instance, although the average cost of net petroleum imports fell by nearly one-half in 1986, the petroleum trade deficit fell by only about one-third. An increase in net import volumes, of 1.2 million barrels per day, offset much of the decrease in price.

The petroleum trade deficit rose steadily from 1974 to 1980. Much of the increase reflects the steep rise in prices that resulted from the two oil shocks of the 1970's. In 1980, the average cost per barrel of net petroleum imports was nearly three times higher than in 1974, and the value of petroleum imports peaked at $75.8 billion. This was more than triple the value of net petroleum imports in 1974.

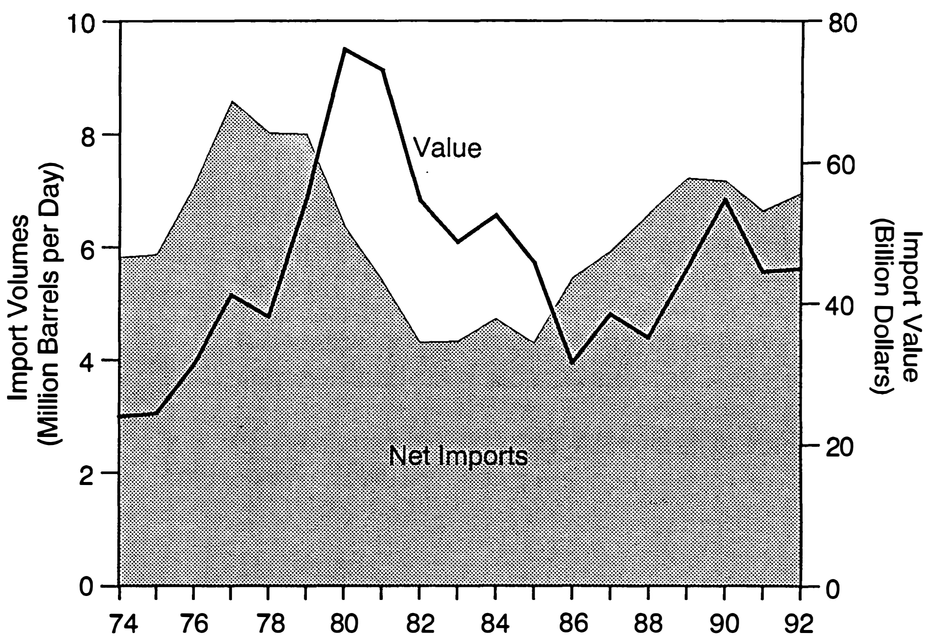
In contrast to the preceding 8 years, 1982 to 1985 were years of comparative price stability between foreign and domestic crude oils. However, the high cost of petroleum during these years led to increased fuel-switching and conservation. As a result, net petroleum imports fell by one-third from 1980. Largely as a result of the decline in import volumes, the oil deficit in 1985 declined to $45.8 billion, a decrease from 1980 of 40 percent.

From 1986 to 1992, price change again had a pronounced influence on the petroleum trade deficit. In 1986, tumbling world oil prices[42] brought the value of net petroleum imports to $31.5 billion, the lowest level since 1976 (**Figure 25**). After 1986, fluctuations in the value of petroleum imports generally tracked movements in price.

Oil Exports

Although oil exports have not figured prominently in the trade balance over the years, their dollar value has grown substantially since the mid-1970's. Most of the value of oil exports is captured from refined products because exports of crude oil are restricted by Federal law.[43] A large increase in product exports, which received a boost during the Persian Gulf crisis in 1990 and 1991, was primarily responsible for the rebound in oil export value in the late 1980's and early 1990's. In 1991, the value of all petroleum exports reached a high of $7.0 billion.

Figure 25. U.S. Net Petroleum Imports and Merchandise Trade Value, 1974 - 1992



Source: Energy Information Administration, *Monthly Energy Review*, June 1993, and *Petroleum Supply Annual*, Vol. 1, 1981-1992 and predecessor reports. See Tables 15 and 18 for corresponding data.

[41]Energy Information Administration, "Russia's Oil Industry Undergoes Restructuring," *Petroleum Supply Monthly*, February 1992, pp. xxx-xxxiii.
[42]Energy Information Administration, *Weekly Petroleum Status Report*, August 6, 1986, pp. 18 and 19.
[43]Energy Information Administration, "Petroleum Exports," *Petroleum Supply Monthly*, August 1987, pp. xix and xx.

3. Chronology of Events

National security and environmental quality concerns were important forces affecting the U.S. petroleum industry during the past 23 years. Much of the Federal legislation on petroleum was directly or indirectly associated with limiting petroleum imports or reducing petroleum-related pollution (**Figure 26**). Several political and economic events that occurred between 1970 and 1992 were critical because of the Nation's dependence on petroleum imports.

These events created broad changes in the way petroleum is produced, imported, stored, transported, and consumed in the United States. The petroleum industry's course as it responded to the events, and the impact on the U.S. economy, are described in this chapter.

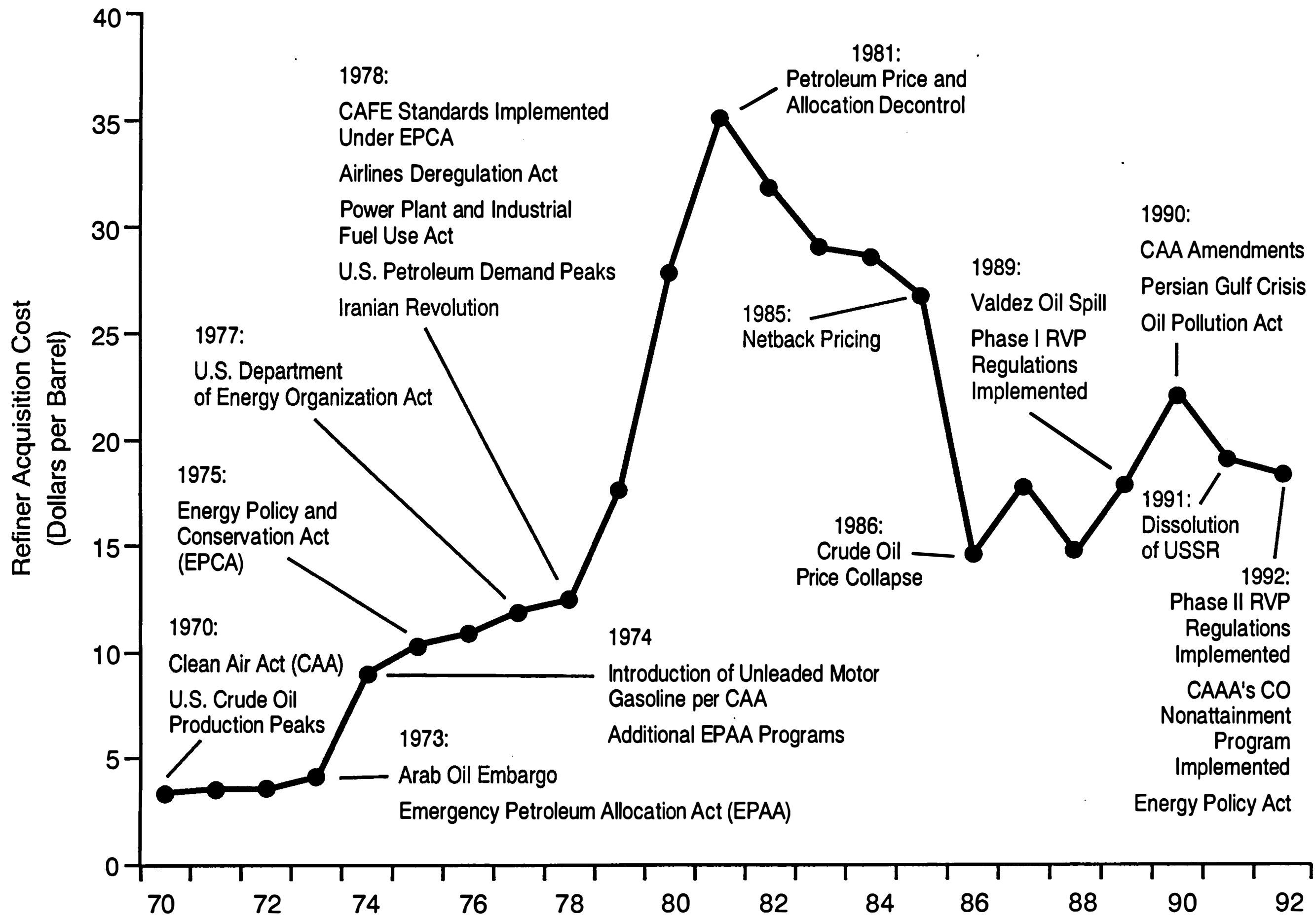
The information for each event in the chronology is organized, with bullets emphasizing the major points, in the following manner:

Description of the Event illustrates what happened.

Industry Action/Reaction describes how the U.S. petroleum industry dealt with the effects of the event.

Results describe the impacts of the event and petroleum industry action/reaction on domestic and/or foreign petroleum prices, consumption patterns, and other related economic activity.

Figure 26. Critical Petroleum-Related Events and U.S. Refiner Acquisition Cost of Crude Oil, 1970 - 1992



Source: Energy Information Administration, *Annual Energy Review 1992* and Office of Oil and Gas. See Table 16 for corresponding data.

Clean Air Act Amendments of 1970

Description:

- The 1970 Clean Air Act (CAA) Amendments significantly expanded the role of the Federal Government in controlling air pollution. It established National Ambient Air Quality Standards (NAAQS). The Environmental Protection Agency (EPA) developed the NAAQS and in 1971 established standards for sulfur dioxide, nitrous oxides, carbon monoxide, oxidants (ozone), non-methane hydrocarbons, and total suspended particulates. A lead standard was adopted in 1978.
  - Sulfur dioxide emissions from electric utilities and industrial plants were restricted by the requirement that distillate and residual fuel oil used at these facilities be low-sulfur.

- The 1970 CAA also permitted the regulation of fuel additives. It established a schedule for reducing lead additives and required automobile manufacturers to design and construct vehicles that could run on low-lead and unleaded fuel. The legislation required that all gasoline stations of specific sizes offer at least one grade of unleaded gasoline (minimum 87 octane) by July 1, 1974.
  - The allowable lead in gasoline was reduced to 1.1 grams per gallon in 1982, and a system of waivers was established that allowed refiners to build up lead credits. Further reductions in July 1985 and on January 1, 1986, brought the allowable lead to a maximum of 0.1 grams per gallon. The lead credit program was ended on December 31, 1987, when a maximum lead content of 0.1 grams per gallon was strictly enforced. All grades of gasoline must be completely lead-free as of January 1, 1996.

Industry Action/Reaction:

- Lead has been used since the 1920's to boost gasoline octane. During the early 1970's, when the maximum allowable lead in gasoline was 4.0 grams per gallon, 2.5 grams per gallon were typically blended into gasoline.[44] Producing high-octane gasoline without lead required greater use of complex refining techniques to increase the octane of gasoline blending components, which increased production costs. Downstream units, such as catalytic reformers, were operated under severe conditions.[45]

- Refiners increased the use of and constructed more downstream conversion units to produce high-octane (anti-knock) blending components to replace the lost lead. In addition, new catalysts were developed to enhance the ability of refiners to generate larger volumes of high-octane gasoline components. High-octane lead substitutes, such as MTBE, also have been developed to maintain octane quality. Other motor gasoline additives also began to be developed and used to maintain the lubricating qualities previously obtained from lead.[46]

- Desulfurization processing units were constructed at refineries in the 1970's to meet the increased demand for low-sulfur fuels. Refiners also increased the use of catalysts to remove sulfur from fuel oil.

- The most significant change in refinery output as a result of the 1970 CAA was the increase in unleaded gasoline. During the 6 years following its introduction in 1974, unleaded gasoline production grew, comprising 27 percent of the motor gasoline produced in the United States by 1980.[47] Production increased each year and, in 1992, 98 percent of the gasoline produced in the United States was unleaded.

Results:

- The catalytic converter, introduced in 1973 to reduce tailpipe emissions, is deactivated by leaded gasoline but is compatible with the unleaded product.[48] Within 10 years of the introduction of the catalytic converter, unleaded gasoline comprised 55 percent of the motor gasoline consumed in the United States.

- The air pollution abatement projects installed during the 1970's resulted in much lower emissions of air pollutants at refineries, per barrel of crude oil run. By 1979, carbon monoxide (CO) emissions were 68 percent lower, emissions of total suspended particulates were 50 percent lower, sulfur dioxide was 19 percent lower, and nitrogen oxide emissions were 18 percent lower than in 1970.[49] Emissions of various atmospheric pollutants were reduced further during the 1980's.[50]

[44] Energy Information Administration, *The Motor Gasoline Industry: Past, Present, and Future*, January 1991, p. 12.
[45] Energy Information Administration, "What is Motor Gasoline?," *Petroleum Supply Monthly*, February 1984, p. xii.
[46] Energy Information Administration, *The U.S. Petroleum Refining Industry In the 1980's*, October 11, 1990, p. 12.
[47] Energy Information Administration, Form EIA-810, "Refinery Report."
[48] Energy Information Administration, "Recent Motor Gasoline Trends," *Petroleum Supply Monthly*, February 1984, p. xi.
[49] National Petroleum Council, *Environmental Conservation*, 1982, Table 33.
[50] "EPA Report Highlights Progress & Problems In Achieving Air Quality," *Oxy-Fuel News*, April 9, 1990, p. 10.

The Clean Air Amendments of 1970 led to refinery additions to downstream conversion capacity as a means to replace lead in motor gasoline, and to produce lower-sulfur fuels.

Arab Oil Embargo of 1973

Description:

- In 1973, several Arab nations, angered at U.S. support of Israel in the 1973 Arab-Israeli War, instituted an oil embargo against the United States and Holland. The Arab oil embargo came at a time of declining domestic crude oil production, rising demand, and increasing imports. The embargo was accompanied by decreased OPEC production, and with minimal global excess production capacity available outside OPEC, created short-term shortages and price increases.[51] When Arab production was restored and the embargo lifted 6 months later, world crude oil prices had tripled from the 1973 average to about $12 per barrel and OPEC was firmly in control of the world oil market.

Industry Action/Reaction:

- U.S. refiners made short-term changes in oil purchasing and began importing crude oil from any available source. About 30 percent less of the more costly crude oil was imported during the embargo. Iran at the time appeared to be a stable, long-term source. Iran moved to expand sales to the United States, and these imports served to offset losses from Kuwait and Libya until Libyan crude oil imports resumed in early 1975.

- Imports from other Arab OPEC countries resumed shortly after the embargo ended in March 1974, and continued to climb through 1977. Despite production buildups from the North Sea and Alaska, Arab OPEC's share of U.S. crude oil imports increased from 26 percent in 1973 to 47 percent in 1977, when imports were at historic high levels.

[51]R. Stobaugh and D. Yergin, *Energy Future*, Random House 1979, pp. 26 and 27.

- The refining industry moved to develop technology and processing methods to reduce fuel consumption and to increase operating efficiency.[52]

Results:

- The embargo caused sudden price hikes and short-term shortages of refined products after decades of ample supplies and growing consumption. Tight supplies caused lines to form at gasoline stations. All petroleum products were much more costly. From 1972 to 1975, when OPEC restored output to pre-embargo levels, consumers were paying approximately 57 percent more for leaded regular gasoline and 91 percent more for home heating oil.[53] These increases reflect the increase in world oil prices over the period. The large jump in energy prices is widely considered to be a cause of the economic recession that occurred in 1974 and 1975, though some recent economic studies indicate that other factors may have contributed.[54]

- Various efforts were undertaken to conse ve energy and to switch from petroleum to less expensive alternative fuels. Petroleum consumption declined both in 1974 and 1975 as a result of conservation efforts.[55] Large volumes of distillate fuel oil and residual fuel oil were replaced by alternative fuels in some industrial and electric utility facilities.

- To plan for future supply dis uptions and to establish secure stable supplies, the United States joined with 20 other nations in 1974 to form the International Energy Agency (IEA). Member nations, including the United States, developed plans to establish strategic reserves for use in any future supply disruptions.[56]

- Legislation was put in place over the next several years that had a significant impact on all aspects of the petroleum industry.

Emergency Petroleum Allocation Act of 1973

Description:

- The principle aims of the Emergency Petroleum Allocation Act (EPAA) were to ensure equitable distribution of available products, to establish equitable prices, and to preserve the independent segments of the oil industry. EPAA established a two-tiered pricing system for domestic crude oil. "Old" oil, designated as crude oil from properties producing at or below their 1972 production levels, was subject to a price ceiling while "new" oil, stripper oil, and "released oil" (added as an incentive for increased production from old fields) was allowed to be sold at market prices. The price of imported oil remained unregulated.

  The increase in the world price of crude oil resulting from the Arab oil embargo created a significant disparity between the cost of old and new oil. Before long, major problems with the two-tiered system developed, and additional regulatory programs were instituted. These included the Supplier-Purchaser Rule, the Buy-Sell Program, and the Entitlements Program.

  - The Supplier-Purchaser Rule froze buyer-seller relationships as of 1972 among domestic petroleum producers, refiners, resellers, and retailers. Its purpose was to stop refiners from engaging in transactions to gain access to additional quantities of price-controlled "old" oil.

  - The Buy-Sell Program required refiners with access to proportionately above-average amounts of less expensive crude oil to sell (at controlled prices) crude oil to other refiners. Originally applicable to all refiners, after several months the program was limited to only the 15 largest integrated refiners, who were required to sell, and to small refiners who were allowed to buy.

  - The Crude Oil Entitlements Program was established to equalize crude oil costs across domestic refiners including imported oil. In essence, those with above-average access to lower priced old oil were required to buy rights to their supplies from those with below-average access. A special provision of this program was the "small refinery bias." The bias provision was established to compensate small refineries for the relatively higher operating and capital costs by providing them with guaranteed access to low-priced crude oil.

Industry Action/Reaction:

- In response to changing regulations, growth in domestic exploration slowed and production was curtailed as the price of U.S. crude oil was kept well below world prices by Federal controls.

- The small refinery bias provision made it progressively more profitable to operate a small, inefficient refinery. Consequently, reactivation and construction of small

[52]U.S. Department of the Interior, Bureau of Mines, *Crude Petroleum, Petroleum Products, and Natural Gas Liquids*, Final Summary, 1973, Table 22, and 1975, Table 23.
[53]Energy Information Administration, *Annual Energy Review* 1991, Table 73.
[54]Douglas R. Bohi, *Energy Price Shocks and Macroeconomic Performance*, Resources for the Future 1989, pp. 1, 3, and 83 - 87.
[55]Energy Information Administration, *Energy Consumption Indicators, 1984 Annual Report*, Figures 14, 24, 40, and 43.
[56]"The IEA Charters A Global Course," *Petroleum Intelligence Weekly*, October 5, 1992, p. 8.

refineries increased sharply during the 1970's. The bulk of these were hydroskimming plants with less than 30,000 barrels per day of distillation capacity and little or no downstream conversion capacity.[57] Between 1973 and 1981, the number of operable refineries in the United States rose from 281 to a record high of 324.

- Crude oil distillation capacity grew dramatically through the entire decade as many small, unsophisticated refineries were built. The regulatory protection afforded by Federal controls enabled capacity to continue increasing even after U.S. oil demand peaked in 1978. Crude oil distillation capacity grew from 13.7 million barrels per day at the beginning of 1973 to 18.6 million barrels per day at the beginning of 1981.

- Many refiners operated at low utilization rates since their market positions were protected by the regulations in place. Moreover, since the entitlements program subsidized imports of crude oil, distillate fuel oil, and residual fuel oil, some refiners increased imports of these products. As a result, inefficiencies developed in the production and marketing of petroleum.

- Crude oil imports more than doubled from 1973 to 1977, reaching a record level of 6.6 million barrels per day in 1977.

- Under price and allocation controls, exports were restricted, further distorting the domestic market. Only petroleum coke and lubricating oils were exported during this period in significant quantities.

Results:

- As price controls held down domestic petroleum prices, demand increased to record levels in 1978. Demand for distillate and residual fuel oils increased as artificially low prices generated by Federal controls enhanced their competitive positions *vis-a-vis* natural gas and coal.[58] In the vessel bunkering market, U.S.-produced residual fuel oil enjoyed a marked price advantage over foreign competition, resulting in increasing domestic sales of vessel bunkering fuel.[59]

- Residual fuel oil imports declined sharply during the 1970's. After 1973, residual fuel oil imports were increasingly replaced by production from new entitlements refineries. By 1980, gross imports accounted for 37 percent of residual fuel oil, down from 66 percent in 1973. The volume of imports also fell significantly during this period.

Energy Policy and Conservation Act of 1975

Description:

- The Energy Policy and Conservation Act (EPCA) of 1975 was enacted to achieve a number of goals. These included, but were not limited to: increasing oil production through price incentives, establishing a Strategic Petroleum Reserve (SPR), and increasing automobile fuel efficiency. Specifically, the EPCA:

  - Sought to roll back the price of domestic crude oil. Old oil was to be priced at the May 15, 1973, price plus $1.35 per barrel. New oil and stripper oil prices were set at the September 30, 1975, new oil price less $1.32 per barrel. In addition, the released oil program was dropped.

  - Authorized the creation of the Strategic Petroleum Reserve for the storage of up to 1 billion barrels of oil.

  - Established the Corporate Average Fuel Economy (CAFE) standards that mandated increases in average automobile fuel-economy. The standards set a corporate sales-fleet average of 18 miles per gallon beginning with the 1978 model year, and established a schedule for attaining a fleet goal of 27.5 miles per gallon by 1985. The CAFE standards apply separately to domestic and imported sales fleets.

Industry Action/Reaction:

- The two-tiered price system established under EPAA and later modified under EPCA was intended to encourage domestic production and exploration. However, the roll-back of new oil prices and the inclusion of new oil in the entitlements program actually served as a mild incentive to oil companies to increase purchases of imported crude oil.[60] EPCA did little to slow the decline in production in the Lower 48 States, which fell from 8.2 million barrels per day in 1975 to 7.0 million barrels per day in 1980.

- Automobile manufacturers built and sold more subcompact and compact cars to meet the CAFE standards. From 1977 to 1991, the combined market share of new minicompact, subcompact, compact, and midsized cars (both domestic and foreign) rose from 73 percent to 85 percent. In contrast,

[57] American Petroleum Institute, *Entry & Exit in U.S. Petroleum Refining 1948-1992*, January 1993, Table 7.
[58] Energy Information Administration, *State Energy Price and Expenditure Report 1970-1981*, p. 3.
[59] Energy Information Administration, "Trends In Petroleum Product Consumption," *Petroleum Supply Monthly*, January 1984, p. xvi.
[60] U.S. Department of Energy, Office of the Secretary for Conservation and Solar Operations, *An Analysis of Federal Incentives Used to Stimulate Energy Production*, June 1978, pp. 211 and 212.

over the same period the combined market share of new large cars fell from 25 percent to 14 percent.[61]

Results:

- The Federal Government began filling SPR in 1977. Over the years, its fill rate has varied considerably, reaching a high of 336,000 thousand barrels per day in 1981. Imports make up most of the crude oil stored in SPR. At the end of 1992, SPR contained 575 million barrels of crude oil.

- The early impact of CAFE was largely overshadowed by a pronounced decrease in gasoline use caused by price and availability factors related to the Iranian Revolution in 1978-1979 and the Iran-Iraq War which began in 1980. An additional constraint on the effects of CAFE on gasoline consumption has come from the influx of gasoline-powered light trucks and recreational vehicles since 1977. CAFE standards for light trucks are lower than for automobiles (19.5 miles per gallon for 1985 model trucks compared with 27.5 miles per gallon for 1985 model cars).[62] Nevertheless, the impact of CAFE has grown as older cars have been gradually replaced by fuel-efficient new cars. From 1977 to 1991, average automobile fuel economy increased 57 percent, from 13.8 miles per gallon to 21.7 miles per gallon. This was more than enough to offset a 26-percent increase in the number of automobiles registered and a 9-percent increase in the average number of miles driven per automobile. As a result, motor gasoline demand in 1991 was about the same as in 1977.

- In response to automobile manufacturers' difficulty in meeting the 27.5 mile-per-gallon CAFE standard, the standard was lowered in 1986 to 26.5 miles per gallon. In 1989, the standard was restored to 27.5 miles per gallon. The light truck sales fleet in 1992 was required to meet a standard of 20.2 miles per gallon.[63]

Department of Energy Organization Act of 1977

Description:

- The creation of the U.S. Department of Energy (DOE) in 1977 consolidated many energy-related functions of the Federal Government into a single, Cabinet-level organization. Primarily, the Department of Energy merged the energy-related functions of several Federal agencies.
  - Until the 1970's, fuel-specific programs were handled by several Federal departments: the Department of the Interior managed most Federal programs affecting the coal and oil industries, the Federal Power Commission regulated natural gas prices, and the Atomic Energy Commission (AEC) oversaw the development of nuclear power.
  - The energy crises of the 1970's accelerated the reorganization of the energy-related programs of the Federal government. In addition to the replacement of the AEC with two new agencies, the Federal Energy Administration (FEA) was created in 1974 to administer programs that included crude oil price and allocation, the SPR, replacement of natural gas and oil with coal, and energy conservation.

Results:

- The petroleum-related functions of DOE were originally to formulate comprehensive energy policy. Energy management became the primary role of the agency in the early 1980's. Energy shocks and public sensitivity have molded DOE's role over the past 16 years. Evolving issues include energy conservation, development of alternative fuels, reduced oil consumption, national security, and energy prices.[64]

Airline Deregulation Act of 1978

Description:

- In 1978, passage of the Airline Deregulation Act (ADA) altered the rules by which airlines compete in the marketplace. In particular, ADA removed restrictions on market entry, service routes, and prices, and allowed increased competition among commercial air carriers.

Industry Action/Reaction:

- To meet demand increases related to airline deregulation, refinery operations were modified to increase yields of kerosene-type jet fuel. Yields had remained around 5.4 percent during the 1970's until 1979, when they began to rise. Yields of kerosene-type jet fuel reached 9.4 percent in

[61] U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 13, March 1993, Table 3.18, and Edition 10, September 1989, Table 3.9.
[62] U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 13, March 1993, Table 3.36.
[63] U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 13, March 1993, Table 3.36.
[64] Donald R. Whitnah, editor-in-chief, "Government Agencies," *The Greenwood Encyclopedia of American Institutions*,, 1983, pp. 110-114.

1990 before declining slightly in recent years. During the Persian Gulf War, yields of kerosene-type jet fuel routinely exceeded 10 percent.

Results:

- Airline deregulation at first prompted the formation of many new airlines. Increased competition made airfares more affordable, and air travel increased. However, with fuel accounting for as much as 30 percent of an airline's operating costs,[65] airlines were vulnerable to rapid price rises. With little capacity to store fuel as a hedge against price increases or supply disruptions, many airline consolidations and bankruptcies occurred during the 1980's.

- Continued competition among airlines often resulted in low airfares throughout the 1980's and early 1990's. As a result, demand for kerosene-type jet fuel escalated.

Powerplant and Industrial Fuel Use Act of 1978

Description:

- The Powerplant and Industrial Fuel Use Act (PIFUA), passed in 1978, restricted the construction of powerplants that use petroleum or natural gas as their primary fuels. The main purpose of the law was to promote national energy security by encouraging the use of coal and alternative fuels in new electric powerplants.

Industry Action/Reaction:

- Although PIFUA's primary impact was expected to be on future residual fuel oil demand growth, it was only slightly effective in reducing residual fuel oil demand. After the 1973 oil price shock, electric utilities saw a need to reduce reliance on petroleum.[66] Most of the new utility plants announced after 1975 were coal and nuclear facilities.[67] As a result, a large portion of the oil-fired capacity in the late 1970's and early 1980's was reserved for peak load periods or for emergencies and turnarounds.

Results:

- In small part due to PIFUA, but primarily due to new plant construction and higher oil prices in the late 1970's and early 1980's, the use of residual fuel oil at electric utilities declined substantially. From a peak of 1.7 million barrels per day in 1978,[68] oil consumption at electric utilities fell to 475,000 barrels per day in 1985.

- PIFUA was repealed in 1987.

Iranian Revolution of 1978-1979

Description:

- The Iranian Revolution, which began in late 1978, resulted in a drop of 3.9 million barrels per day of crude oil production from Iran from 1978 to 1981. World supplies appeared to be tight, although much of this lost production was offset initially by increases in output from other OPEC members, particularly from Iran's Persian Gulf neighbors.[69] In 1980, the Iran-Iraq War began and many Persian Gulf countries reduced output as well. OPEC crude oil prices increased to unprecedented levels between 1979 and 1981. By 1981, OPEC production declined to 22.8 million barrels per day, 7.0 million barrels per day below its level for 1978.

Industry Action/Reaction:

- At the same time OPEC was trimming output, companies and governments began to stockpile oil and build reserve supplies. Those actions, combined with the cuts in production, put upward pressure on oil prices. The world price of crude oil[70] jumped from around $14 per barrel at the beginning of 1979 to more than $35 per barrel in January 1981 before stabilizing. Prices did not drop appreciably until 1983, when the world price stabilized between $28 and $29 per barrel.[71]

- The high cost of crude oil stimulated exploration and production operations in non-OPEC countries, prolonged the productive life of marginal wells, and made secondary and tertiary production techniques profitable. In addition to these trends, development projects in the North Sea, Mexico, and the North Slope of Alaska began to contribute significantly to world crude oil supplies. By 1985, non-OPEC production comprised 69 percent of total world

[65] Energy Information Administration, "Persian Gulf Situation and Petroleum Markets," *Petroleum Supply Monthly*, July 1990, p. xxxiv.
[66] Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970-1991*, March 1993, pp. 11, 21, and Table C6.
[67] Energy Information Administration, *Fuel Choice in Steam Electric Generation: Historical Overview*, August 1985, Table 3.
[68] Energy Information Administration, *Electric Power Annual*, 1981, Table 41, and 1986, Table 10.
[69] Energy Information Administration, *International Energy Annual 1982*, Table 8.
[70] The weighted average international price of internationally traded crude oil only. The average price (FOB) is weighted by the estimated export volume.
[71] Energy Information Administration, *Weekly Petroleum Status Report*, January 2 and December 12, 1981, p. 20, and December 20 and 27, 1985, p. 19.

production, up from 50 percent in 1978. These trends allowed U.S. refiners to tap new sources of non-OPEC supply.

- The rapid increase in non-OPEC production caused OPEC, led by Saudi Arabia, to defend its official price of $34.00 per barrel[72] by cutting output further. Between 1978 and 1985, OPEC production fell from 29.9 million barrels per day to 16.6 million barrels per day. Over the same period, as U.S. refiners imported proportionately more crude oil from Canada, Mexico, the United Kingdom, and other non-OPEC countries, OPEC's share of U.S. crude oil imports fell from 82 percent to 41 percent.

Results:

- The higher oil prices depressed U.S. petroleum consumption and encouraged fuel-switching and energy conservation. Other fuels replaced petroleum in many applications, and industrial processes, appliances, equipment, and motors were made more efficient. These developments had a large impact on U.S. petroleum demand, which from 1978 to 1983 fell from 18.8 to 15.2 million barrels per day, the lowest level since 1971.

- World demand for petroleum also fell steeply in response to the rising crude oil prices. From 63.1 million barrels per day in 1980, world petroleum demand slid to 60.1 million barrels per day in 1985, a drop of 5 percent.

- Western Europe, with petroleum demand almost as high as U.S. levels, reacted with equally strong reductions. Distillate and residual fuel oils, the primary components of Western European demand when it reached its peak in 1979, showed the greatest declines.[73]

In countries in the Far East and Oceania, declines in petroleum use as a result of conservation and fuel-switching were largely offset by other factors. China, Japan, and other countries with low-cost materials, labor, and in some cases more efficient production methods, were successfully competing with the United States in energy-intensive industries. As a result, in the Far East, there was a growing demand for petroleum for use in steel production, petrochemicals, metals mining, and other energy-intensive industries.[74]

Petroleum Price and Allocation Decontrol in 1981

Description:

- In early 1981, the U.S. Government responded to the oil crisis of 1978-1980 by removing price and allocation controls on the oil industry. For the first time since the early 1970's, market forces replaced regulatory programs and domestic crude oil prices were allowed to rise to a market-clearing level. Decontrol also set the stage for the relaxation of export restrictions on petroleum products.

Industry Action/Reaction:

- Soon after deregulation, many small refineries and older, inefficient plants could no longer compete and were forced to shut down. Between the beginning of 1981 and 1985, the number of refineries operating in the United States declined by 101 to 223, and operable crude oil distillation capacity fell 3.0 million barrels per day to 15.7 million barrels per day.

- The loss of so many small, low-conversion refineries, which were a large source of unfinished oils, sent many sophisticated refiners overseas for intermediate oil supplies. From 1980, the last full year of price and allocation controls, to 1981, imports of unfinished oils more than doubled, jumping form 55,000 barrels per day to 112,000 barrels per day. Unfinished oils continued to rise and in 1992 were 440,000 barrels per day.

- With fewer refineries in operation, refinery utilization increased between 1981 and 1985 despite the lower overall level of refinery inputs over this period. Since 1985, distillation capacity has remained fairly stable and changes in refinery inputs, not distillation capacity, have been the primary cause of changing utilization rates.

- Decontrol of crude oil prices allowed producers to raise prices to the market-clearing level for the first time since the early 1970's, and domestic crude oil prices became more closely aligned with foreign crude oil prices.[75] The production sector responded by increasing crude oil exploration and production in the Lower 48 States during the first half of the 1980's. However, sharply falling oil prices in 1986 reversed this upward trend in domestic exploration and production.

- Increases in Alaskan North Slope (ANS) production during this period aided the domestic crude oil situation. This helped to stem the flow of imported crude oil, greatly reducing U.S. reliance on OPEC crude oil. Imports remained low until crude oil prices collapsed in 1986.

[72]Energy Information Administration, *Weekly Petroleum Status Report*, December 18, 1981, pp. 21 and 22.
[73]Energy Information Administration, Office of Energy Markets and End Use, International Statistics Branch, 1992 revisions to world consumption data.
[74]U.S. Department of Commerce, Bureau of the Census, *U.S. Imports for Consumption and General Imports*, 1981-1985, Table 1.
[75]Energy Information Administration, *Weekly Petroleum Status Report*, December 24, 1982, p. 19.

Results:

- After decontrol, residual fuel oil prices were allowed to rise to market clearing levels,[76] and this accelerated fuel-switching and conservation at generating[77] and industrial facilities.[78] By 1985, demand for residual fuel oil of 1.2 million barrels per day was the lowest since the Second World War.[79,80]

- Larger volumes of unfinished oils, motor gasoline, and distillate fuel oil began arriving from overseas and, by the mid-1980's, accounted for a larger share of imports than residual fuel oil. Imports of residual fuel continued to decline in the 1990's, and in 1992 fell to 375,000 barrels per day, their lowest level since 1954.

- With the removal of export restrictions in late 1981, product exports began to expand, and the composition of these exports changed. Exports of all major light products increased markedly by the mid-1980's. Moreover, these products, along with petroleum coke and lubricants, were being shipped to a greater variety of nations. Countries in Central and South America and the Far East, which received little or no U.S. exports in 1973, were now purchasing U.S. products on a regular basis.

Crude Oil Price Collapse of 1986

Description:

- Faced with declining world oil demand and increasing non-OPEC production, OPEC cut output significantly in the first half of the 1980's to defend its official price. Saudi Arabia, which played the role of swing-producer in the cartel, bore most of the production cuts. In late 1985, Saudi Arabia abandoned its swing producer role, increased production, and aggressively moved to increase market share. Saudi Arabia tried a netback pricing concept, which tied crude oil prices to the value of refined petroleum products.[81] This reversed traditional economic relationships by guaranteeing specific margins to refiners, thereby transferring risk from the crude oil purchaser to the producer.

- In response, other OPEC members also increased production and offered netback pricing arrangements to maintain market share and to offset declining revenues. These actions resulted in a glut of crude oil in world markets, and crude oil prices fell sharply in early 1986.[82]

Industry Action/Reaction:

- By July 1986, the average per-barrel F.O.B. price for OPEC crude oil had dropped from $23.29 in December 1985 to $9.85, and prices for crude oil from non-OPEC countries were following a similar path.

- The collapse of crude oil prices in 1986 reversed the upward trend in U.S. production of the first half of the decade. Many high-cost wells, which became productive after the oil crisis of 1978-1980, became unprofitable in 1986 and were shut in. Domestic crude oil production began dropping in early 1986. After the world price fell more than 50 percent between January and March 1986, drilling plummeted. Since then, excluding a few months in 1990 during the Persian Gulf Crisis, domestic drilling and production have declined dramatically.

- The net effect of the decline in domestic production beginning in 1986 was an increase in crude oil imports, which climbed from 3.2 million barrels per day in 1985 to 6.1 million barrels per day in 1992. Most of this increase was met by OPEC, whose share of total U.S. crude oil imports rose from 41 percent in 1985 to 60 percent in 1990, before dropping to 56 percent in 1992.

- Oil company investments began shifting to foreign oil exploration and production after the 1986 price drop.[83] Foreign fields are generally much larger than in the United States and average production costs are lower. Changes in policy in the former Soviet Union since 1991 have increased U.S. production investments there,[84] and recent moves toward foreign investments in Mexico have attracted American exploration and production companies.[85]

Results:

- The sharp drop in crude oil prices pushed U.S. petroleum demand steadily higher in the second half of the decade. From 1985 to 1990, demand climbed from 15.7 million barrels per day to 17.0 million barrels per day.

[76] Energy Information Administration, *Weekly Petroleum Status Report*, January 2, 1981 and January 8, 1982 issues, p. 23.
[77] Energy Information Administration, *Fuel Choice in Steam Electric Generation: Historical View*, August 1985, Table 1.
[78] Energy Information Administration, *Impacts of Lower World Oil Prices on Conservation*, June 1986, Table 7.
[79] American Petroleum Institute, *Basic Petroleum Data Book*, Volume XII, Number 3, September 1992, Section VII, Table 6.
[80] U.S. Department of the Interior, Bureau of Mines, *A Quarter Century of Fuel Oil Sales*, 1926-1950, Table 2.
[81] Energy Information Administration, "Year in Review," *Petroleum Marketing Annual 1986*, p. 7.
[82] Energy Information Administration, *Weekly Petroleum Status Report*, February 25, 1986, p. 19.
[83] "Salomon Reports Shift to Overseas Operations," *Bloomberg Oil Buyers Guide*, August 3, 1992, p. 3.
[84] Energy Information Administration, "Russia's Oil Industry Undergoes Restructuring," *Petroleum Supply Monthly*, February 1992, pp. xxxii and xxxiii.
[85] "Mexican Energy Law Developments," *Petroleum Economist*, July 1992, Energy Law Special Supplement.

Gasoline pump nozzles such as this 1981 style were replaced at many gasoline service stations after most Northeastern States mandated the use of anti-vapor gasoline pump nozzles in the late 1980's. Hydrocarbon emissions during refueling had increased as more butane and benzene were added to motor gasoline to replace lead.

- Until 1986, the value of U.S. petroleum imports comprised between 15 percent and 32 percent of all imported goods. The steep decline in petroleum prices in 1986 reduced petroleum's portion of the U.S. trade deficit.

- The economy expanded at a faster pace in 1987 and 1988. Low petroleum prices stimulated growth in industrial production, employment increased,[86] and travel picked up. Temporary conservation measures that had been instituted during earlier oil price escalations were discontinued. The overall energy intensity of the economy (measured by the ratio of total energy consumption to the constant dollar level of the Gross Domestic Product), a reflection of energy conservation,[87] did not increase between 1986 and 1988.

Reid Vapor Pressure Regulations of 1989 and 1992

Description:

- To combat emissions of volatile organic compounds (VOC's) and other ozone precursors, the EPA implemented a two-phased program limiting summertime motor gasoline volatility in some U.S. urban areas in the spring of 1989. VOC's react photochemically in the atmosphere and are a major component of smog. Concentrations are reduced by lowering the vapor pressure of motor gasoline. At warm temperatures and high altitudes, gasoline evaporates more readily, increasing the amount of VOC's released to the atmosphere. Alaska and Hawaii are exempt from the volatility restrictions.

  – Phase I summer volatility standards went into effect in 1989. This phase mandated that the average summer

[86] Council of Economic Advisors, *Economic Indicators*, June 1993, pp. 4, 11, and 17.
[87] Energy Information Administration, *Impacts of Lower World Oil Prices on Energy Conservation*, June 1986, p. 13.

RVP in motor gasoline be reduced from 11.5 psi to a maximum of 10.5 psi RVP, and as low as 9.0 psi RVP in certain areas of the country.

- Phase II summer volatility standards were implemented in 1992 and will stay in effect through the summer of 1994. In 1995, RVP requirements will change again with the implementation of the reformulated gasoline program. Phase II set a nationwide maximum summer RVP standard of 9.0 psi. Gasoline sold in southern cities that do not meet Federal ozone standards must meet an even stricter standard of 7.8 psi RVP (**Figure 27**).

Industry Action/Reaction:

- Refiners met the Phase I standards by reducing the amount of normal butane blended into motor gasoline. Butane is a lower-cost gasoline blending component that has a relatively high RVP and high octane. To compensate for the loss in volume and octane in motor gasoline when butane was removed, refiners increased crude oil inputs and the use of catalytic cracking and alkylation units.[88]

- The more stringent Phase II standards increased requirements for downstream processing. Some refiners made large capital investments to produce high-octane, lower RVP blending components, to meet these standards.

- To assure that the distribution system was in full compliance by the May 1, 1992 deadline for meeting the more stringent 1992 RVP restrictions, pipeline operators adjusted shipping schedules.

  - In some cases, lower RVP gasoline was shipped well in advance of the deadline.

  - In areas where both attainment and non-attainment areas share markets, some pipelines shipped six or more grades of gasoline, using breakout tankage to divert products so that a compatible product could go through.[89]

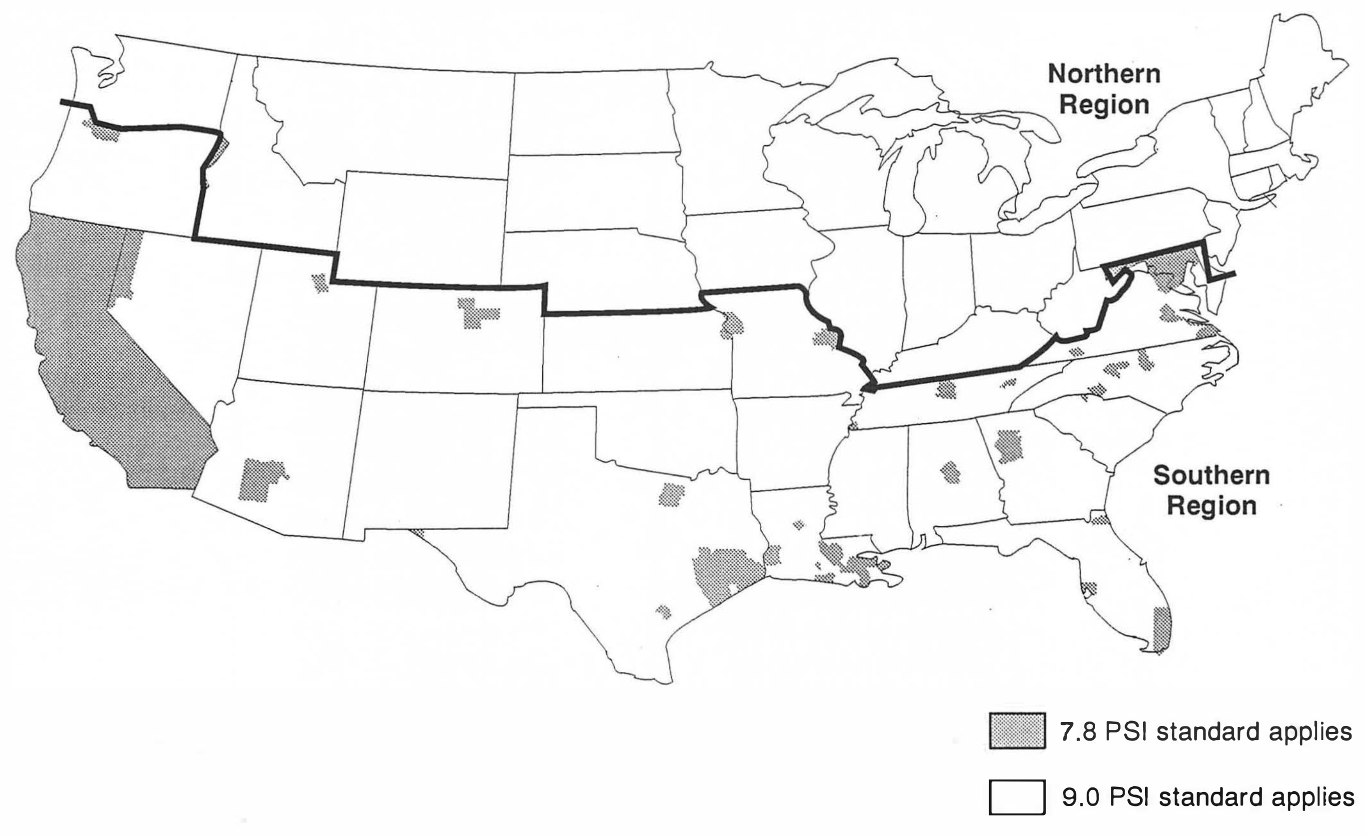
  - Other adjustments, such as blending additives at destination terminals and exchanging products between suppliers, reduced the number of grades of gasoline being shipped.

Results:

- Some reduction in ambient smog levels was observed after this program went into effect.[90]

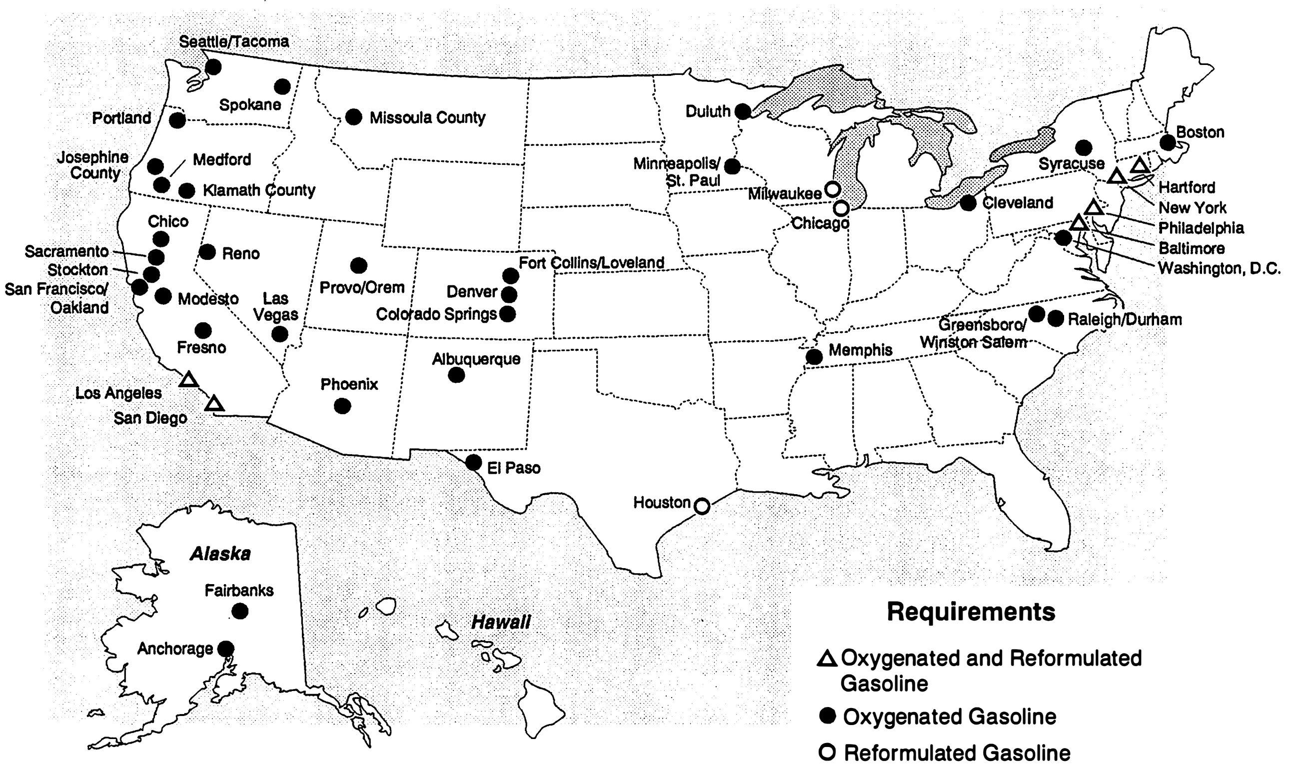
[88]Energy Information Administration, "Changing Requirements for Motor Gasoline Volatility: Production and Market Responses," *Petroleum Supply Monthly*, July 1992, xviii and xix.
[89]Energy Information Administration, "Pipelines Prepare to Ship Low RVP Gasoline," *Petroleum Supply Monthly*, March 1992, pp. xxiv and xxv.
[90]U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 13, March 1993, Table 3.45.

Figure 27. U.S. Regional Retail RVP Requirements for Motor Gasoline, June 1 - September 15, 1992



Source: Federal Register Vol. 55, No. 112, Page 23659, June 11, 1990, Federal Register Vol. 56, No. 239, Page 64704, December 12, 1991.

Figure 28. U.S. Areas Subject to Clean Air Requirements



Source: Environmental Protection Agency, Office of Air Quality Planning and Standards, *Ozone and Carbon Monoxide Areas Violating the National Ambient Air Quality Standards and Status of 1988 & 1989 Calls for State Implementation Plan Revisions* (September 12, 1990)

Clean Air Act Amendments of 1990

Description:

- Strict new controls to reduce mobile sources of air pollution were mandated under the CAA Amendments of 1990. The Amendments contain six provisions to be implemented by the EPA in stages between November 1, 1992, and January 1, 2000. Four major programs to reduce harmful emissions from highway fuel go into effect between November 1, 1992, and January 1, 1996. These programs include:

  – **Oxygenated Fuels Program.** As of November 1, 1992, all motor gasoline sold in most of the 39 areas of the country designated as carbon monoxide (CO) nonattainment areas **(Figure 28)** must contain a minimum of 2.7 percent oxygen by weight during at least 4 winter months. Adding oxygenates to motor gasoline lowers the level of carbon monoxide produced during gasoline combustion. Concern over poisonous nitrogen oxide emissions from the higher winter oxygen content resulted in a winter maximum of 2.0 percent oxygen by weight in California's CO nonattainment areas.[91]

  – **Highway Diesel Fuel Program.** As of October 1, 1993, the sulfur content of highway diesel fuel must be reduced from the current maximum of 0.25 percent to 0.05 percent by weight. In addition, the cetane index, which measures the self-ignition quality of diesel fuel, must be maintained at a minimum of 40. Small refineries (those with *bona fide* crude oil throughput of less than 18,250 thousand barrels per year) will get relief from the sulfur limit in the form of tradeable credits until December 31, 1999.

  – **Reformulated Gasoline Program.** As of January 1, 1995, reformulated gasoline will be required in the nine metropolitan areas with the worst ozone problems. Other areas may "opt in" to the program by applying to the EPA. The "opt-in" provision may be delayed for up to 3 years if EPA determines that not enough reformulated gasoline is available.

  Reformulated gasoline must meet specific composition and emission performance criteria. The core composition requirements limit benzene to a maximum of 1.0 volume percent, mandate an oxygen content of at least 2.0 weight percent, prohibit lead and manganese, and require deposit control additives. The core emission

[91] Congressional Research Service, *Alternative Transportation Fuels: Are They Reducing Oil Imports?*, January 15, 1993, p. CRS-5.

Table 19. Number and U.S. Production Capacity of Operable Oxygenate Plants by PAD District, January 1, 1993
(Thousand Barrels Per Calendar Day)

PAD District	Number of Operable Plants	Oxygenate Capacity						
		Fuel Ethanol	ETBE	Methanol	MTBE	TAME	TBA	Other[1]
I	7	1	1	10	5	0	0	0
II	35	84	0	4	11	0	0	0
III	44	4	10	105	143	5	32	6
IV	7	1	0	3	4	0	0	0
V	7	1	0	0	7	0	0	0
U.S.Total	100	90	10	123	170	5	32	6

[1] Includes other aliphatic alcohols and ethers intended for motor gasoline blending (e.g., isopropyl ether (IPE) or n-propanol).
Note: Operable production capacity is the sum of operating and idle capacity. Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration' *Petroleum Supply Annual,* Vol. 1, 1992, Table 48.

Table 20. U.S. Supplies of Selected Oxygenates for Motor Gasoline Blending, by Quarter, 1992
(Thousand Barrels per Day, Except Where Noted)

Item	Quarter				1992 Average
	1	2	3	4	
Fuel Ethanol					
Production	70	67	68	74	70
Blended*	66	62	57	89	63
Ending Stocks (Thousand Barrels)	1,462	1,941	2,973	1,791	--
MTBE					
Production	94	86	99	124	101
Imports	W	W	W	W	W
Blended	47	45	67	213	70
Ending Stocks (Thousand Barrels)	13,966	18,887	22,853	13,818	--

W = Withheld to avoid disclosure of individual company data.
* Quantities of fuel ethanol blended into motor gasoline are calculated by the Energy Information Administration. This quantity is equal to production plus imports, minus stock change.
Sources: Energy Information Administration, *Weekly Petroleum Status Report,* 1992 editions, Table B1, and *Petroleum Supply Monthly,* May 1993, Tables D2 and D3.

requirements for 1995 to 1999 prohibit any increase in nitrous oxides emissions and mandate a year-round reduction of toxic air pollutants (TAP's) and a summertime reduction of VOC's of 15 percent below 1990 "baseline" gasoline. By 2000, TAP and VOC emissions are to be reduced by a minimum of 20 percent. If technically feasible, a 25-percent cut will be mandated.

- **Leaded Gasoline Removal**. Sales of leaded motor gasoline are prohibited after 1995.

Industry Action/Reaction:

- Construction of oxygenate production facilities escalated in recent years in preparation for the implementation of the program. At least 33 refineries had facilities for producing oxygenates from refinery streams in 1992.[92] This was in addition to oxygenate capacity from nonrefinery standalone units that produce ethanol from grain and MTBE from field butane streams and from methanol that was produced from natural gas. At the beginning of 1991, total U.S. production capacity for oxygenates from all these sources was 338,000 barrels per day. By the beginning of 1993, production capacity for oxygenates was 59 percent higher at 536,000 barrels per day (**Table 19**). Production of fuel ethanol is concentrated in the Midwest cornbelt area, whereas MTBE production facilities are primarily along the Gulf Coast.

Capacity increases continued in 1992 in the United States. Canada and countries in Western and Eastern Europe, South America, and the Far East were also increasing production capacity.[93]

[92] "Worldwide refiners making big move into modernization," *Oil and Gas Journal*, December 21, 1992, p. 48.
[93] *MTBE/Oxygenates/New Fuels,* October 22, 1992, p. 1, and November 5, 1992, pp. 1 and 2.

- Primary U.S. stocks of oxygenates, mainly fuel ethanol and MTBE, were built up during the summer of 1992 (**Table 20**). Blending to accommodate winter oxygenated gasoline requirements began in August 1992.

- Shipment of oxygenated gasoline for the Oxygenated Fuels Program also began in August 1992, to assure that product would be in place by November 1. Motor gasoline containing MTBE is transported to the consuming areas through the normal distribution network, primarily by pipeline.

- Motor gasoline containing fuel ethanol is susceptible to water solubility problems during pipeline transportation.[94] Therefore, ethanol is often shipped across country and then blended with motor gasoline at terminals for local distribution.

- Spillover of oxygenated gasoline into attainment areas was kept to a minimum.[95]

- Construction of desulfurization downstream units, in particular catalytic hydrocracking and hydrotreating units, accelerated after 1980 as heavier, higher-sulfur crude oils became available to U.S. refiners. More projects are underway to increase desulfurization capacity to remove sulfur from products and to comply with the 1990 CAA Amendment's on-highway diesel fuel regulations.[96]

  Small refineries lacking the desulfurization equipment for removing sulfur may choose to produce only distillate fuel oil for non-highway use, or they may modify current refinery processes.[97]

- Highway diesel fuel and home heating oil are currently compatible products. However, by October 1, 1993, transportation and storage systems will need to have separate facilities for heating oil and on-highway diesel fuel. Distillate fuel oil and diesel fuel that are not for highway use will be marked with a dye to prevent the illegal sale of the higher sulfur distillate fuel oil for highway use.

- To comply with requirements of the reformulated gasoline program, components of gasoline will need to be upgraded to reduce the aromatic and VOC emissions from light-duty vehicles.[98] The use and/or severity of catalytic reforming, a process used to convert naphthas into primarily aromatic compounds, could be reduced by the requirement to significantly limit total aromatics and, in particular, benzene. Benzene was found to be a toxic carcinogen. Hydrotreating units will become even more essential to meet the lower sulfur specifications. The reduction in reforming, a hydrogen producer, and the increase in hydrotreating, which uses hydrogen, adversely affects the refinery hydrogen balance.

Results:

- About 31 percent of total gasoline sales were affected during the 1992-1993 winter oxygenated gasoline season. The national average price spread between gasoline for nonattainment areas and that for attainment areas grew to approximately 5 cents per gallon between early October 1992 and early January 1993.[99]

- Prior to the startup of the oxygenated gasoline program, updated information on CO pollution indicated that 13 of the 39 designated CO nonattainment areas had reduced emissions to acceptable levels in 1990 and 1991.[100] Before these areas can leave the program, each must develop a maintenance plan covering a 10-year period. The plan would include computer modeling of air pollution patterns, taking into account factors such as urban growth.

- Highway diesel fuel has comprised a growing portion of distillate fuel oil demand since 1970, when it accounted for 16 percent; in 1991, its portion was 46 percent.[101] The EPA estimates that the low-sulfur highway diesel fuel will reduce the amount of cancer-causing exhaust particulates by about 90 percent.

- The 9 U.S. metropolitan areas that will be directly affected by the implementation of the reformulated gasoline program represent about 22 percent of the U.S. gasoline market.[102]

[94] National Petroleum Council, *Petroleum Refining In the 1990's, Meeting the Challenges of the Clean Air Act*, June 1991, p. 30.
[95] Energy Information Administration, "Update on Oxygenated Gasoline Markets," *Short Term Energy Outlook*, First Quarter 1993, p. 11.
[96] Energy Information Administration, "Refineries Upgrade in Response to Clean Air Act," *Petroleum Supply Monthly*, May 1992, pp. xix and xx.
[97] Energy Information Administration, "Effects of the Clean Air Act's Highway Diesel Fuel Oil Provisions," *Petroleum Supply Monthly*, June 1991, p. xiii.
[98] National Petroleum Council, *Petroleum Refining in the 1990s, Meeting the Challenges of the Clean Air Act*, June 1991, pp. 12 and 13.
[99] Energy Information Administration, *Short Term Energy Outlook*, Second Quarter 1992, p. 12, and First Quarter 1993, p. 11.
[100] "No Quick Exit Seen From Oxygenated Fuels Program, Officials Say," *The Oil Daily*, November 13, 1992, p. 2.
[101] Energy Information Administration, *Fuel Oil and Kerosene Sales 1991*, Table 13, and predecessor reports.
[102] American Petroleum Institute, *Meeting the Oxygenate Requirements of the 1990 Clean Air Act Amendments*, June 1991, p. 35.

Persian Gulf Crisis of 1990-1991

Description:

- Iraq invaded Kuwait on August 2, 1990, causing crude oil and product prices to rise suddenly and sharply for the third time in 17 years. After the United Nations approved an embargo on all crude oil and products originating from either country, fears of shortfalls similar to the magnitude of those in 1979 caused the rapid price escalation. Between the end of July and August 24, 1990, the world price of crude oil climbed from about $16 per barrel to more than $28 per barrel. The price escalated further in September, reaching about $36 per barrel.[103]

- When the United Nations approved the use of force against Iraq in October 1990, prices began falling. This was after only 2 months of price escalation, even though the crisis led to a 2-month war that lasted from January to March 1991. The cutoff of about 4.3 million barrels per day of Iraqi and Kuwaiti petroleum tested modern petroleum markets. Since 1979, these markets had become more global and had controls in place that were intended to keep the logistics of world supply and demand more balanced.[104]

Industry Action/Reaction:

- Non-OPEC countries in Central America, Western Europe, the Far East, and even the United States, supplemented OPEC production increases to offset the 7-percent shortfall in world supplies.[105]

- Refinery upgrades had been made during the 1980's to convert heavy, sour crude oils into light petroleum products in non-OPEC countries in Central and South America, Western Europe, Africa, and the Far East. These areas were well-positioned to shift petroleum supply patterns to accommodate those countries that had relied on Iraq and Kuwait for crude oil[106] or refined products. Excess operable refining capacity in many of these areas was sufficient to supply additional petroleum products.

- Permanent energy efficiency improvements had been made to U.S. automobiles, housing, and industrial machinery since the Iranian Revolution. The development of multifuel boilers had enhanced industrial and electric utility plants' ability to switch from petroleum when its price relative to natural gas became too high.

- The strong need felt during the 1970's to build up stocks in anticipation of market tightness or uncertainty had been reduced. This resulted from the realization that SPR oil could be available if supply shortages occurred, and from the utilization of the futures market to hedge against large swings in price. Participants in the futures market in the 90 days following the invasion were mostly refiners, airlines, and chemical companies who used oil and wanted to guarantee prices for their customers. There was no apparent increase in speculative activity, and the futures market did not contribute to the run-up in prices or to price volatility.[107] The rise in crude oil and petroleum product prices occurred because of uncertainties regarding the spread of the invasion and replacement of supplies. After peaking in mid-October, domestic and worldwide prices dropped substantially by the end of 1990.[108]

- European supplies were tight after Kuwait's petroleum product exports to Europe and the Far East ceased. The United States began exporting motor gasoline to countries in Western Europe that had previously been sources of imports. Exports of distillate fuel oil and kerosene-type jet fuel to Canada and the Far East escalated, also. Product exports from Kuwait had not returned to pre-crisis levels by the end of 1992.[109]

Results:

- The International Energy Agency planned the release of 2 million barrels per day from government-held stocks for 30 days. As part of this plan, the United States offered to release 1.1 million barrels per day, Japan pledged 350,000 barrels per day, and European countries 250,000.[110]

- The success of the Allied air strike on January 16, 1991, caused a record 1-day drop in oil prices[111] as fears of a cutoff in Middle East crude oil production were allayed. As a result, only about one-third of the pledged strategic stocks were sold, and the sales were spread over 2 months. The United States sold 17.3 million of the 33.8 million barrels originally offered.[112]

- Saudi Arabia and Iran also released stocks as a means of gaining revenue during the war. The releases served to calm oil markets.

[103] Energy Information Administration, *Weekly Petroleum Status Report*, March 1, 1991, Figure 9.
[104] Energy Information Administration, "Iraq Invasion of Kuwait Felt in U.S. Petroleum Market," *Petroleum Supply Monthly*, June 1990, p. xxi.
[105] Energy Information Administration, *International Energy Annual 1991*, Table 1.
[106] Energy Information Administration, *Monthly Energy Review*, December 1992, Table 10.1b.
[107] Energy Information Administration, *Petroleum Prices and Profits In the 90 Days Following the Invasion of Kuwait*, November 1990, pp. vii and 3-11.
[108] *Reuter's News Service*, daily issues for the period.
[109] Energy Information Administration, *International Petroleum Statistics Report*, June 1993, Table 4.16.
[110] "Release Of Strategic Stocks Comes From All Sides," *Global Stocks and Balances*, February 1991, p. 12.
[111] *Reuter's News Service*, daily issues for January, 1991.
[112] Energy Information Administration, "Energy Department Accepts Bids for SPR Crude Oil," *Petroleum Supply Monthly*, February 1991, p. xxxii.

Oil Pollution Liability and Compensation Act of 1990

Description:

- The *Exxon Valdez* grounding in Prince William Sound in March 1989, followed by several smaller oil spills from tankers near U.S. shores, focused attention on oil spill prevention, tanker safety, and protection of U.S. coastal areas. Prior legislation on oil pollution liability was enacted in 1972, when petroleum imports were restricted and U.S. waters were less crowded. The Oil Pollution Liability and Compensation Act of 1990 increased liability from $150 to $1,200 per gross ton, with a minimum liability of $10 million for vessels larger than 3,000 gross tons, and a minimum liability of $2 million for smaller vessels.[113] Before passage of the 1990 Act, liability was capped at $14 million.

  The Act allows unlimited liability against tanker owners where gross negligence or willful misconduct is involved, and does not preclude states from imposing their own unlimited liability requirements. Most of the 24 coastal states have no limit on damage liability. Offshore and onshore facilities and ports are also liable for huge damages.

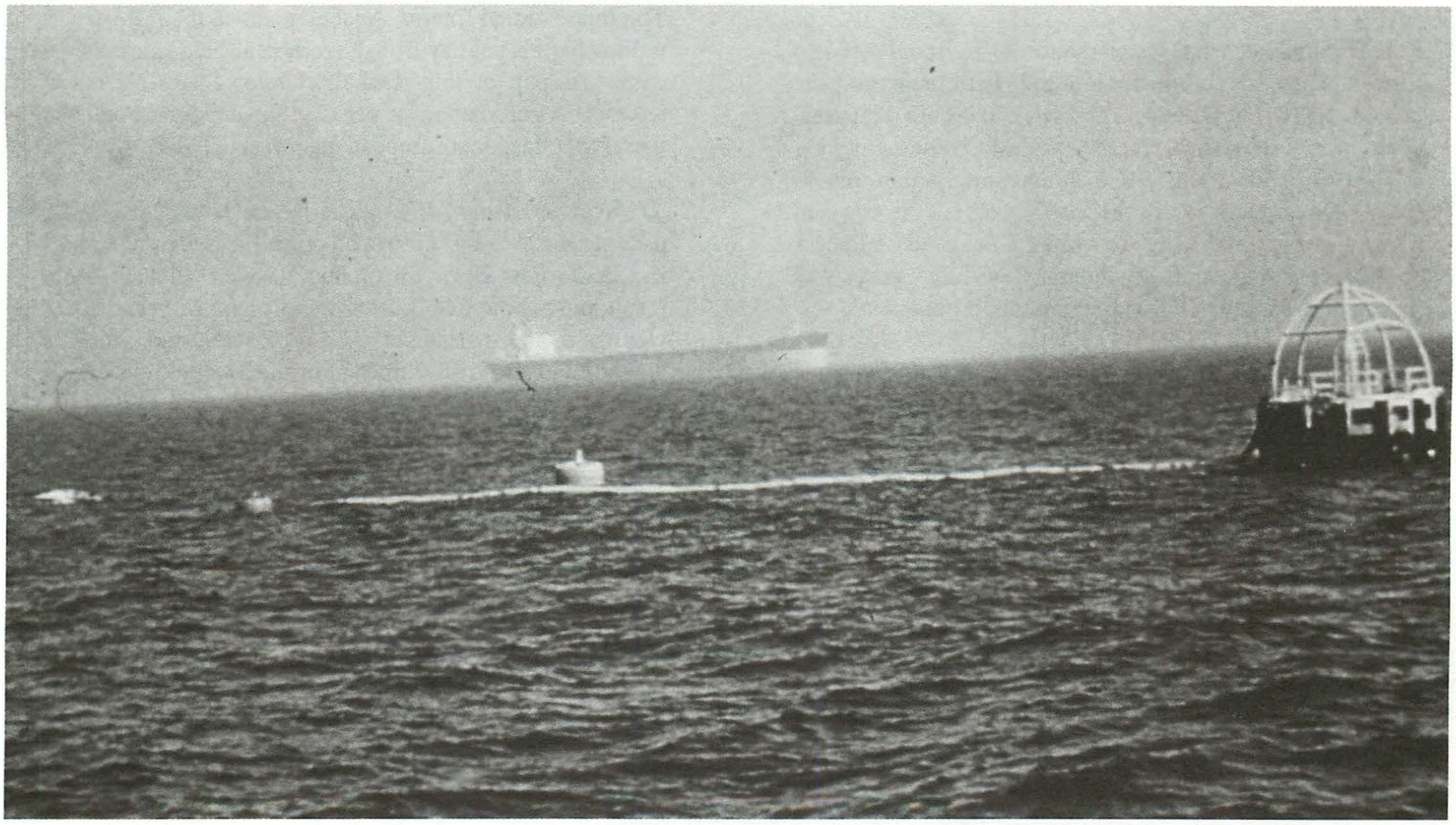
  In addition to the liability provisions, the Act requires that, over a 15-year phase-in period, double hulls be used for all new tankers and for vessels trading with the United States.

Industry Action/Reaction:

- Several oil companies and independent tanker owners stopped delivering oil to U.S. ports other than the Louisiana Offshore Oil Port (LOOP). Prior to enactment of the law, ships owned by these companies delivered less than 10 percent of U.S. petroleum imports, and at least 33 percent of these imports were delivered to the LOOP.[114]

- Many U.S. oil companies are increasing their double-hulled foreign-flag tanker fleets. Double-hulled barges for inland marine use have replaced some single-hulled barges since 1990, also.[115] Most of these are unmanned, unpowered barges requiring no documentation as to foreign or domestic registry. Worldwide, about 5 percent of the operating tankers have double hulls.[116]

[113] U.S. Department of Energy, Office of Domestic and International Energy Policy, *Transporting U.S. Oil Imports: The Impact of Oil Spill Legislation on the Tanker Market*, June 1992, pp. 25-27.
[114] Energy Information Administration, "President Bush Signs Oil Spill Bill," *Petroleum Supply Monthly*, July 1990, p. xxxiv.
[115] Energy Information Administration, "Tanker Industry Responds to Oil Pollution Act of 1990," *Petroleum Supply Monthly*, May 1992, p. xix.
[116] "The Trouble With Tankers," *Los Angeles Times*, January 12, 1993, p. A1.



Since 1981, bouys, hoses, and pipeline have been used to transport crude oil from the ultra large tankers at the Louisiana Offshore Oil Port in the Gulf of Mexico. This system has reduced the need to transfer crude oil to smaller ships.

- Financial risks of providing insurance coverage were increased by the expanded scope of potential claimants for pollution clean-up costs provided by the Act. International protection and indemnity clubs were particularly vulnerable, as about 75 percent of the petroleum imported into the United States is transported in tankers they insure.[117]

Results:

- Fears of unlimited U.S. liabilities caused some major international oil companies to charter high-quality ships and to do their own tanker safety inspections.
- In 1992, the proliferation of large oil spills overseas, many from substandard ships, prompted the European Community to speed up work to tighten maritime safety controls, including increased use of escorts through narrow passages.[118]
- The International Maritime Organization, charged with creating common international regulations, will require double hulls on all new ships built after June 1993.[119]

Dissolution of the Soviet Union in 1991

Description:

- As 1991 ended, the Soviet Union, one of the three largest crude oil producers in the world, collapsed and dissolved into several nations, including among others, Russia, the Ukraine, Azerbaijan, and Kazakhstan. Concern focused on the availability of supplies of crude oil and refined products previously provided to the international market by the former Soviet Union. Exports from the former Communist entity included large amounts of crude oil and refined products to countries in Latin America and Western Europe, and crude oil to the Far East.[120]

Industry Action/Reaction:

- The legal and economic complexities of moving from the controlled economy of a single sovereign socialist state to free market economies of multiple democratic nations has caused Western and Japanese oil companies to proceed with caution in establishing joint ventures with the governments of these new nations. Although the economic incentives appear to be great and business ventures abound, progress in forging actual agreements and initiating operations has been slow. Recently, however, several joint production development projects involving American companies have been agreed upon. One includes Chevron Corporation and the Tengiz oil field in Kazakhstan,[121] and another involves the Amoco Corporation and the Azeri oil field in the Caspian Sea.[122]

Results:

- In the world market, the decline in petroleum supplies from the former Soviet Union has been offset by exports from other countries, including the United States.[123]
- The Russian Government is struggling to develop its legal framework for foreign investment and encourage greater independence for oil producers.[124]
- The U.S. Export-Import Bank and the World Bank have agreed to make large investments for the rehabilitation of Russian oil fields.

Energy Policy Act of 1992

Description:

- The provisions of the Energy Policy Act of 1992 are aimed at restructuring energy markets in the United States. Energy efficiency programs, the use of alternative fuels and renewable energy, research and development programs, and various tax credits and exemptions are mandated in the Act.[125] Programs that will have the greatest impact on petroleum include the following:
  - **Alternative Minimum Tax Exemption.** As of January 1993, independent oil and gas producers can take greater

[117] Energy Information Administration, "Tanker Industry Responds to Oil Pollution Act of 1990," *Petroleum Supply Monthly*, May 1992, p. xviii.
[118] "The Trouble With Tankers," *Los Angeles Times*, January 12, 1993, p.
[119] "Oil Spill in the Shetlands," *Financial Times*, January 7, 1993, p. 11.
[120] "Russia's Oil Industry Undergoes Restructuring," *Petroleum Supply Monthly*, February 1992, pp. xxx-xxxiii.
[121] "Russia Grappling With Economic And Political Challenges," *Oil and Gas Journal*, August 2, 1993, pp. 58-62.
[122] "Conoco Among U.S. Leader in Advancing Russian Oil Projects, *The Oil Daily*, January 23, 1992, p.2.
[123] Energy Information Administration, *International Petroleum Statistics Report*, June 1993, Table 2.1.
[124] "Russia Grappling With Economic And Political Changes," *Oil and Gas Journal*, August 2, 1993, p. 61.
[125] A comprehensive discussion of the Energy Policy Act's impact on future energy markets is included in the EIA report, *Annual Energy Outlook 1993*.

Petroleum product deliveries by tanker, such as this arrival at Boston Harbor, will continue to be an important means of satisfying domestic demand, at least for the remainder of the century.

deductions against the alternative minimum tax for percentage depletion and intangible drilling costs. This encourages domestic exploration, and could increase U.S. oil production slightly.

- **Alternative Transportation Fuels**. The mandate to phase in alternative fuels in government and private automobile and truck fleets will eventually cut into petroleum use for transportation. The Act sets a national goal of 30 percent penetration of non-petroleum fuels in the light-duty vehicle market by 2010.[126] Natural gas, electricity, methanol, ethanol, and coal-derived liquid fuels are among those set to replace petroleum in vehicle fleets. The fleets of four or more automobiles alone in 1991 comprised 9 percent of the automobiles in operation.[127] Additional displacement by truck fleets will further impact petroleum use.
- **Energy Efficiency Standards.** The Act requires the Secretary of Energy to set efficiency standards for all new Federal buildings and new buildings with federally backed mortgages. Efficiency standards for commercial and industrial equipment are required also. The primary effect of these standards on petroleum will be a reduction in consumption of petroleum heating fuels.
- **Research and Development.** Programs to reduce consumption of imported oil include the development of oil shale and advanced oil-recovery techniques as methods of increasing domestic oil production. Research into high-efficiency heat engines and high temperature superconducting electric power systems are intended to lower dependence on oil imports by reducing petroleum product consumption. Research into the development of renewable energy technologies for the production of electricity could also reduce petroleum consumption.

Industry Action/Reaction:

- While the number of exploratory oil wells drilled for November 1992 through February 1993 was up 7 percent from the same period a year earlier, it is too soon to know whether domestic oil exploration will increase substantially as a result of the Energy Policy Act.

Results:

- All sectors of the economy will, in time, see shifts in the typc of energy used and the amount needed. The provisions of the Act that will have the most impact on petroleum will take many years to develop. Petroleum imports will continue to be an important part of the Nation's supply for the remainder of the century, as domestic crude oil production will likely decline more rapidly than substitutes for petroleum products can be developed and used.

[126] Congressional Research Service, *Alternative Transportation Fuels: Are They Reducing Oil Imports?*, January 15, 1993, p. CRS-4.
[127] U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 13, September 1992, Tables 3.11 and 3.34.

Appendix
Supplemental Data

Table A1. U.S. and Foreign Operable Crude Oil Distillation Capacity, Refinery Crude Oil Inputs, and Petroleum Demand, 1970 - 1992
(Million Barrels per Day)

Year	Operable Capacity[1]			Crude Oil Inputs			Demand		
	United States	Foreign	Total World	United States	Foreign	Total World	United States	Foreign	Total World
1970	12.86	39.05	51.91	10.87	34.65	45.52	14.70	32.11	46.81
1971	13.29	41.84	55.13	11.20	36.89	48.09	15.21	34.21	49.42
1972	13.64	44.56	58.20	11.70	38.77	50.47	16.37	36.72	53.09
1973	14.36	48.79	63.15	12.43	42.50	54.93	17.31	39.93	57.24
1974	14.96	51.56	66.52	12.13	42.29	54.42	16.65	40.03	56.68
1975	15.24	54.69	69.93	12.44	40.46	52.90	16.32	39.88	56.20
1976	16.40	58.72	75.12	13.42	43.27	56.69	17.46	42.21	59.67
1977	17.05	60.41	77.46	14.60	43.23	57.83	18.43	43.40	61.83
1978	17.44	61.14	78.58	14.74	45.24	59.98	18.85	45.31	64.16
1979	17.99	61.86	79.85	14.65	46.96	61.61	18.51	46.75	65.26
1980	18.62	62.94	81.56	13.48	45.83	59.31	17.06	46.01	63.07
1981	17.89	62.74	80.63	12.48	44.20	56.68	16.06	44.81	60.87
1982	16.86	60.35	77.21	11.77	42.52	54.29	15.30	44.17	59.47
1983	16.14	59.28	75.42	11.69	42.31	54.00	15.23	43.46	58.69
1984	15.66	59.46	75.12	12.04	42.91	54.95	15.73	44.05	59.78
1985	15.46	57.10	72.56	12.17	42.78	54.95	15.73	44.37	60.10
1986	15.57	57.00	72.57	12.72	44.02	56.74	16.28	45.23	61.51
1987	15.92	57.65	73.57	12.85	44.12	56.97	16.67	46.10	62.77
1988	15.65	57.69	73.34	13.28	45.04	58.32	17.28	47.22	64.50
1989	15.57	58.29	73.86	13.40	45.94	59.34	17.33	47.70	65.03
1990	15.68	59.08	74.76	13.41	47.79	61.20	16.99	49.17	66.16
1991	15.70	59.65	75.34	13.30	47.23	60.53	16.71	49.89	66.60
1992	15.12	NA	NA	13.41	NA	NA	17.03	49.53	66.56

NA = Not Available.

Note: Operable refining capacity data are per calendar day as of January 1 of the following year.

[1] Totals may not equal sum of components due to independent rounding.

Sources: • Energy Information Administration, *Annual Energy Review 1991* and *1992*, Tables 11.9 and 11.10, *Petroleum Supply Annual*, Vol. 1, 1992, Tables S2 and 36, and *International Energy Annual 1992*, Table 21. • American Petroleum Institute, *Basic Petroleum Data Book*, September 1992, Section VIII, Table 2 revised.

Table A2. U.S. Refinery Yields of Major Petroleum Products, 1970 - 1992
(Percent)

Year	Motor Gasoline			Distillate Fuel Oil	Kerosene-Type Jet Fuel	Residual Fuel Oil	Other
	Leaded	Unleaded	Total				
1970	44.9	0	44.9	22.4	5.4	6.4	20.9
1971	45.8	0	45.8	22.0	5.3	6.6	20.3
1972	45.9	0	45.9	22.2	5.4	6.8	19.7
1973	45.3	0	45.3	22.5	5.4	7.7	19.1
1974	--	--	45.6	21.8	5.2	8.7	18.7
1975	--	--	46.2	21.3	5.6	9.9	17.0
1976	--	--	45.3	21.8	5.4	10.3	17.2
1977	--	--	43.2	22.4	5.4	12.0	17.0
1978	--	--	43.9	21.4	5.4	11.3	18.0
1979	--	--	42.8	21.5	5.7	11.5	18.5
1980	23.5	21.0	44.5	19.7	6.0	11.7	18.1
1981	22.3	22.2	44.5	20.5	6.1	10.4	18.5
1982	21.8	24.3	46.1	21.5	6.4	8.8	17.2
1983	21.2	26.2	47.4	20.5	6.8	7.1	18.2
1984	18.5	28.0	46.5	21.5	7.4	7.1	17.5
1985	16.2	29.4	45.6	21.6	7.9	7.1	17.8
1986	14.2	31.5	45.7	21.2	8.3	6.7	18.1
1987	11.3	35.1	46.4	20.5	8.5	6.6	18.0
1988	8.6	37.4	46.0	20.8	8.5	6.7	18.0
1989	5.0	40.7	45.7	20.8	8.6	6.9	18.0
1990	2.4	43.2	45.6	20.9	9.4	6.8	17.3
1991	1.6	44.1	45.7	21.3	9.1	6.7	17.2
1992	1.4	44.6	46.0	21.2	8.9	6.4	17.5

-- = Not available.
Note: Yields are based on crude oil input and net reruns of unfinished oils.
Sources: Energy Information Administration, *The U.S. Petroleum Refining Industry in the 1980's*, Table C5, and *Petroleum Supply Annual*, Vol. 1, 1990-1992, Tables 17 and 19, and predecessor reports.

Table A3. U.S. Inter-Regional Movements of Crude Oil and Petroleum Products, 1970 - 1992
(Thousand Barrels per Day)

PAD Districts	Year	Pipeline			Tanker and Barge			Total Inter-Regional Movements		
		Crude Oil	Products	Total	Crude Oil	Products	Total	Crude Oil	Products	Total
I to II	1970	NA	120	NA	0	NA	NA	NA	NA	NA
	1975	NA	176	NA	0	NA	NA	NA	NA	NA
	1980	NA	196	NA	3	73	76	NA	269	NA
	1981	NA	196	NA	1	65	66	NA	261	NA
	1982	NA	191	NA	0	70	70	NA	261	NA
	1983	NA	184	NA	1	73	74	NA	258	NA
	1984	NA	199	NA	0	89	89	NA	288	NA
	1985	0	200	200	0	84	84	0	284	284
	1986	0	218	218	0	2	2	0	220	221
	1987	0	222	222	1	3	5	1	225	227
	1988	0	231	231	0	4	4	0	235	235
	1989	0	235	235	0	5	5	0	240	240
	1990	1	233	234	0	4	4	1	237	238
	1991	3	233	236	1	3	4	4	236	240
	1992	2	243	245	(s)	4	4	2	247	249
I to III	1970	NA	0	NA	0	NA	NA	NA	NA	NA
	1975	NA	0	NA	0	NA	NA	NA	NA	NA
	1980	NA	0	NA	8	24	32	NA	24	NA
	1981	NA	0	NA	1	22	24	NA	22	NA
	1982	NA	0	NA	0	19	19	NA	19	NA
	1983	NA	0	NA	0	10	10	NA	10	NA
	1984	NA	0	NA	2	8	10	NA	8	NA
	1985	0	0	0	0	4	4	0	4	4
	1986	0	0	0	0	6	6	0	6	6
	1987	0	0	0	0	5	5	0	5	5
	1988	0	0	0	0	8	8	0	8	8
	1989	0	0	0	0	8	8	0	8	8
	1990	0	0	0	0	8	8	0	8	8
	1991	0	0	0	0	4	4	0	4	4
	1992	0	0	0	0	3	3	0	3	3
II to I	1970	NA	56	NA	0	31	31	NA	87	NA
	1975	NA	86	NA	0	51	51	NA	137	NA
	1980	NA	67	NA	3	14	17	NA	81	NA
	1981	NA	70	NA	2	15	18	NA	85	NA
	1982	NA	74	NA	1	18	19	NA	92	NA
	1983	NA	82	NA	3	20	22	NA	102	NA
	1984	NA	82	NA	1	19	20	NA	101	NA
	1985	2	89	91	3	15	18	5	104	109
	1986	2	81	83	3	63	66	5	144	149
	1987	1	81	82	3	61	64	4	142	146
	1988	0	73	73	4	57	61	4	130	135
	1989	1	67	68	4	49	53	5	116	121
	1990	(s)	70	70	3	60	63	3	130	133
	1991	(s)	71	71	3	53	56	3	124	127
	1992	(s)	74	74	4	51	55	4	125	129
II to III	1970	NA	72	NA	0	NA	NA	NA	NA	NA
	1975	NA	79	NA	0	NA	NA	NA	NA	NA
	1980	NA	135	NA	0	45	45	NA	180	NA
	1981	NA	150	NA	0	39	39	NA	189	NA
	1982	NA	151	NA	0	30	30	NA	181	NA
	1983	NA	180	NA	1	11	12	NA	191	NA
	1984	NA	181	NA	0	7	7	NA	188	NA
	1985	70	151	221	0	23	23	70	174	244
	1986	68	147	215	0	9	9	68	156	224
	1987	75	185	260	0	11	11	75	196	271
	1988	81	163	243	0	12	12	81	175	256
	1989	82	164	245	0	15	15	82	179	260
	1990	67	164	231	(s)	19	19	67	183	250
	1991	59	165	224	0	24	24	59	189	248
	1992	57	161	218	0	21	21	57	183	240

See footnotes at end of table.

Table A3. U.S. Inter-Regional Movements of Crude Oil and Petroleum Products, 1970 - 1992 (Continued)
(Thousand Barrels per Day)

PAD Districts	Year	Pipeline			Tanker and Barge			Total Inter-Regional Movements		
		Crude Oil	Products	Total	Crude Oil	Products	Total	Crude Oil	Products	Total
II to IV	1970	NA	0	NA	0	0	0	NA	0	NA
	1975	NA	13	NA	0	0	0	NA	13	NA
	1980	NA	78	NA	0	0	0	NA	78	NA
	1981	NA	82	NA	0	0	0	NA	82	NA
	1982	NA	78	NA	0	0	0	NA	78	NA
	1983	NA	72	NA	0	0	0	NA	72	NA
	1984	NA	74	NA	0	0	0	NA	74	NA
	1985	23	73	96	0	0	0	23	73	96
	1986	22	79	102	0	0	0	22	79	102
	1987	20	70	90	0	0	0	20	70	90
	1988	23	59	82	0	0	0	23	59	82
	1989	18	64	82	0	0	0	18	64	82
	1990	18	57	75	0	0	0	18	57	75
	1991	16	80	96	0	0	0	16	80	96
	1992	8	94	102	0	0	0	8	94	102
III to I	1970	NA	1,442	NA	646	1,328	1,974	NA	2,770	NA
	1975	NA	1,637	NA	65	1,266	1,331	NA	2,903	NA
	1980	NA	2,027	NA	20	987	1,007	NA	3,014	NA
	1981	NA	2,013	NA	15	846	861	NA	2,859	NA
	1982	NA	1,989	NA	13	786	799	NA	2,774	NA
	1983	NA	1,908	NA	12	733	745	NA	2,641	NA
	1984	NA	1,942	NA	10	667	677	NA	2,609	NA
	1985	0	1,941	1,941	10	611	621	10	2,552	2,562
	1986	0	2,074	2,074	10	580	590	10	2,654	2,664
	1987	0	2,070	2,070	10	509	519	10	2,579	2,589
	1988	0	2,083	2,083	15	514	530	15	2,597	2,612
	1989	0	2,093	2,093	13	537	550	13	2,631	2,644
	1990	0	2,102	2,102	15	532	547	15	2,634	2,649
	1991	0	2,075	2,075	1	474	475	1	2,549	2,550
	1992	0	2,127	2,127	0	517	517	0	2,645	2,645
III to II	1970	NA	322	NA	49	213	262	NA	535	NA
	1975	NA	461	NA	36	167	203	NA	628	NA
	1980	NA	500	NA	36	115	151	NA	615	NA
	1981	NA	572	NA	34	97	131	NA	670	NA
	1982	NA	654	NA	42	87	130	NA	742	NA
	1983	NA	697	NA	47	91	139	NA	788	NA
	1984	NA	812	NA	37	84	121	NA	896	NA
	1985	1,220	756	1,976	0	86	86	1,220	842	2,062
	1986	1,338	835	2,173	0	117	117	1,338	953	2,291
	1987	1,418	734	2,152	0	137	137	1,418	871	2,290
	1988	1,495	735	2,230	0	136	136	1,495	872	2,367
	1989	1,659	751	2,410	0	137	137	1,659	888	2,547
	1990	1,782	693	2,475	(s)	126	126	1,782	819	2,601
	1991	1,722	594	2,316	0	108	108	1,722	702	2,424
	1992	1,736	650	2,386	0	107	107	1,736	758	2,494
III to IV	1970	NA	27	NA	0	0	0	NA	27	NA
	1975	NA	27	NA	0	0	0	NA	27	NA
	1980	NA	0	NA	0	0	0	NA	0	NA
	1981	NA	0	NA	0	0	0	NA	0	NA
	1982	NA	0	NA	0	0	0	NA	0	NA
	1983	NA	0	NA	0	0	0	NA	0	NA
	1984	NA	0	NA	0	0	0	NA	0	NA
	1985	0	0	0	0	0	0	0	0	0
	1986	0	0	0	0	0	0	0	0	0
	1987	0	0	0	0	0	0	0	0	0
	1988	0	0	0	0	0	0	0	0	0
	1989	0	0	0	0	0	0	0	0	0
	1990	0	(s)	0	0	0	0	0	0	0
	1991	0	(s)	0	0	0	0	0	0	0
	1992	0	0	0	0	0	0	0	0	0

See footnotes at end of table.

Table A3. U.S. Inter-Regional Movements of Crude Oil and Petroleum Products, 1970 - 1992 (Continued)
(Thousand Barrels per Day)

PAD Districts	Year	Pipeline			Tanker and Barge			Total Inter-Regional Movements		
		Crude Oil	Products	Total	Crude Oil	Products	Total	Crude Oil	Products	Total
III to V	1970	NA	51	NA	0	9	9	NA	60	NA
	1975	NA	50	NA	0	22	22	NA	72	NA
	1980	NA	46	NA	0	16	16	NA	62	NA
	1981	NA	39	NA	0	26	26	NA	65	NA
	1982	NA	51	NA	0	29	29	NA	80	NA
	1983	NA	54	NA	0	12	12	NA	65	NA
	1984	NA	55	NA	0	10	10	NA	66	NA
	1985	0	51	51	0	4	4	0	55	55
	1986	0	52	52	0	7	7	0	58	58
	1987	0	56	56	0	4	4	0	60	60
	1988	0	58	58	0	6	6	0	63	63
	1989	0	54	54	0	9	9	0	63	63
	1990	0	53	53	0	6	6	0	59	59
	1991	0	58	58	0	3	3	0	61	61
	1992	0	70	70	0	6	6	0	76	76
IV to II	1970	NA	21	NA	0	0	0	NA	21	NA
	1975	NA	25	NA	0	0	0	NA	25	NA
	1980	NA	39	NA	0	0	0	NA	39	NA
	1981	NA	37	NA	0	0	0	NA	37	NA
	1982	NA	36	NA	0	0	0	NA	36	NA
	1983	NA	50	NA	0	0	0	NA	50	NA
	1984	NA	56	NA	0	0	0	NA	56	NA
	1985	263	54	317	0	0	0	263	54	317
	1986	232	49	281	0	0	0	232	49	281
	1987	198	47	245	0	0	0	198	47	245
	1988	175	43	218	0	0	0	175	43	218
	1989	129	48	177	0	0	0	129	48	177
	1990	106	47	153	0	0	0	106	47	153
	1991	98	53	151	0	0	0	98	53	151
	1992	99	51	150	0	0	0	99	51	150
IV to III	1970	NA	0	NA	0	0	0	NA	0	NA
	1975	NA	9	NA	0	0	0	NA	9	NA
	1980	NA	0	NA	0	0	0	NA	0	NA
	1981	NA	0	NA	0	0	0	NA	0	NA
	1982	NA	1	NA	0	0	0	NA	1	NA
	1983	NA	15	NA	0	0	0	NA	15	NA
	1984	NA	26	NA	0	0	0	NA	26	NA
	1985	108	31	139	0	0	0	108	31	139
	1986	73	30	102	0	0	0	73	30	102
	1987	59	33	92	0	0	0	59	33	92
	1988	79	47	126	0	0	0	79	47	126
	1989	54	42	96	0	0	0	54	42	96
	1990	49	42	91	0	0	0	49	42	91
	1991	46	46	92	0	0	0	46	46	92
	1992	43	48	91	0	0	0	43	48	91
IV to V.............	1970	NA	50	NA	0	0	0	NA	50	NA
	1975	NA	44	NA	0	0	0	NA	44	NA
	1980	NA	30	NA	0	0	0	NA	30	NA
	1981	NA	29	NA	0	0	0	NA	29	NA
	1982	NA	36	NA	0	0	0	NA	36	NA
	1983	NA	36	NA	0	0	0	NA	36	NA
	1984	NA	37	NA	0	0	0	NA	37	NA
	1985	0	38	38	0	0	0	0	38	38
	1986	0	40	40	0	0	0	0	40	40
	1987	0	41	41	0	0	0	0	41	41
	1988	0	47	47	0	0	0	0	47	47
	1989	0	43	43	0	0	0	0	43	43
	1990	0	45	45	0	0	0	0	45	45
	1991	0	48	48	0	0	0	0	48	48
	1992	0	41	41	0	0	0	0	41	41

See footnotes at end of table.

Table A3. U.S. Inter-Regional Movements of Crude Oil and Petroleum Products, 1970 - 1992 (Continued)
(Thousand Barrels per Day)

PAD Districts	Year	Pipeline			Tanker and Barge			Total Inter-Regional Movements		
		Crude Oil	Products	Total	Crude Oil	Products	Total	Crude Oil	Products	Total
V to I	1970	NA	0	NA	1	5	6	NA	5	NA
	1975	NA	0	NA	0	1	1	NA	1	NA
	1980	NA	0	NA	64	6	70	NA	6	NA
	1981	NA	0	NA	78	13	91	NA	13	NA
	1982	NA	0	NA	83	5	88	NA	5	NA
	1983	NA	0	NA	133	2	135	NA	2	NA
	1984	NA	0	NA	100	1	102	NA	1	NA
	1985	0	0	0	96	1	97	96	1	97
	1986	0	0	0	79	0	79	79	0	79
	1987	0	0	0	46	0	46	46	0	46
	1988	0	0	0	41	0	41	41	0	41
	1989	0	0	0	10	0	10	10	0	10
	1990	0	0	0	2	0	2	2	0	2
	1991	0	0	0	0	0	0	0	0	0
	1992	0	0	0	0	3	3	0	3	3
V to III	1970	NA	0	NA	0	0	0	NA	0	NA
	1975	NA	0	NA	0	3	3	NA	3	NA
	1980	NA	0	NA	209	8	217	NA	8	NA
	1981	NA	0	NA	312	6	318	NA	6	NA
	1982	NA	0	NA	527	8	534	NA	8	NA
	1983	NA	0	NA	574	3	577	NA	3	NA
	1984	NA	0	NA	474	2	477	NA	2	NA
	1985	50	0	50	538	1	539	588	1	589
	1986	20	0	20	508	2	510	528	2	530
	1987	20	0	20	539	1	540	558	1	560
	1988	103	0	103	430	1	431	532	1	534
	1989	109	0	109	281	1	282	390	1	391
	1990	113	0	113	166	2	168	279	2	281
	1991	112	0	112	172	2	174	284	2	286
	1992	125	0	125	152	1	153	277	1	278
Total	1970	NA	2,161	NA	696	NA	NA	NA	2,161	NA
	1975	NA	2,607	NA	101	NA	NA	NA	2,607	NA
	1980	NA	3,118	NA	343	1,288	1,631	NA	4,406	NA
	1981	NA	3,189	NA	443	1,130	1,573	NA	4,319	NA
	1982	NA	3,261	NA	667	1,051	1,718	NA	4,312	NA
	1983	NA	3,278	NA	771	955	1,726	NA	4,233	NA
	1984	NA	3,464	NA	625	888	1,513	NA	4,353	NA
	1985	1,736	3,384	5,120	647	829	1,476	2,383	4,213	6,596
	1986	1,755	3,605	5,360	600	786	1,386	2,355	4,391	6,746
	1987	1,791	3,540	5,331	600	733	1,332	2,391	4,272	6,663
	1988	1,955	3,538	5,493	490	740	1,230	2,445	4,278	6,723
	1989	2,051	3,562	5,613	309	760	1,069	2,360	4,322	6,682
	1990	2,136	3,506	5,642	186	757	943	2,322	4,263	6,585
	1991	2,056	3,423	5,479	177	671	848	2,233	4,094	6,327
	1992	2,070	3,559	5,629	156	712	868	2,226	4,274	6,500

NA=Not Available.

Notes: • Totals may not add to sum of components due to independent rounding. • Pipeline movements of crude oil were not collected by the Energy Information Administration prior to 1985, and tanker and barge shipments from PAD District I and from PAD Districts II to III were not collected prior to 1980.

Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1982, Tables 23-25, 1983, Tables 19-21, 1984-1988, Tables 20-22, and 1989-1992, Tables 32-34, and predecessor reports.

Table A4. Selected Components of U.S. Regional Supply and Demand, 1970 - 1992
(Thousand Barrels Per Day Unless Otherwise Noted)

Year and PAD District	Crude Oil Production	Refinery Output	Receipts from Other Districts	Shipments to Other Districts	Imports		Exports		Demand	Stocks (Million Barrels)		
										Crude Oil		
					Crude Oil	Products	Crude Oil	Products		SPR[1]	Other	Products
PAD District I												
1970	31	1,503	3,546	120	579	1,867	0	21	5,884	0	19	224
1971	36	1,536	3,440	120	691	1,962	0	19	6,078	0	17	218
1972	66	1,526	3,280	150	969	2,164	0	21	6,459	0	14	189
1973	108	1,674	3,073	228	1,277	2,469	0	17	6,688	0	18	212
1974	119	1,576	2,988	246	1,174	2,114	0	17	6,232	0	17	209
1975	133	1,535	3,171	277	1,237	1,603	0	15	5,983	0	16	233
1976	139	1,710	3,389	312	1,415	1,718	1	14	6,488	0	15	220
1977	144	1,775	3,380	367	1,518	1,850	0	15	6,522	0	16	266
1978	147	1,820	3,371	373	1,487	1,708	0	13	6,506	0	18	255
1979	146	1,691	3,361	408	1,432	1,517	4	19	6,169	0	20	267
1980	133	1,556	3,309	419	1,342	1,250	5	24	5,619	0	21	254
1981	117	1,484	3,053	286	1,116	1,124	0	24	5,250	0	21	242
1982	93	1,379	2,968	280	958	1,036	0	24	4,942	0	18	226
1983	77	1,241	2,892	269	817	1,157	0	28	4,864	0	15	188
1984	63	1,307	2,822	299	944	1,345	0	23	4,871	0	17	211
1985	57	1,369	2,767	289	977	1,159	0	23	4,796	0	16	192
1986	47	1,483	2,892	227	1,081	1,373	0	25	5,183	0	16	211
1987	41	1,521	2,782	232	1,111	1,404	0	18	5,295	0	16	183
1988	38	1,594	2,788	244	1,175	1,560	0	22	5,447	0	16	172
1989	35	1,576	2,775	248	1,201	1,527	0	26	5,447	0	13	151
1990	30	1,546	2,784	246	1,209	1,359	0	56	5,113	0	15	183
1991	26	1,549	2,678	243	1,209	1,147	1	46	4,867	0	15	186
1992	27	1,588	2,776	252	1,222	1,087	0	38	4,979	0	14	181
PAD District II												
1970	1,169	3,384	2,405	183	317	54	1	11	4,009	0	79	199
1971	1,098	3,464	2,487	190	376	63	0	11	4,099	0	75	213
1972	1,050	3,612	2,571	163	468	109	0	10	4,462	0	67	192
1973	969	3,808	2,708	218	714	150	0	10	4,626	0	67	217
1974	916	3,652	2,617	252	687	140	0	10	4,479	0	80	225
1975	883	3,724	2,594	286	774	136	0	12	4,510	0	83	240
1976	896	3,949	2,617	376	1,000	132	6	9	4,831	0	83	211
1977	892	4,124	2,643	374	1,416	144	43	15	4,996	0	91	269
1978	874	4,125	2,639	353	1,354	128	75	14	5,207	0	77	242
1979	871	4,043	2,445	417	1,526	189	69	15	4,986	0	87	246
1980	926	3,596	2,234	483	1,119	188	83	16	4,485	0	87	243
1981	974	3,363	1,005	359	681	192	45	35	4,268	0	84	217
1982	1,020	3,157	1,081	352	580	187	36	36	4,115	0	78	189
1983	1,038	3,073	1,147	379	530	181	19	37	4,084	0	73	184
1984	1,076	3,088	1,295	363	499	177	16	30	4,227	0	77	191
1985	1,052	3,046	2,663	448	590	156	21	28	4,245	0	72	161
1986	956	3,174	2,793	475	784	108	16	35	4,150	0	83	169
1987	865	3,164	2,762	508	870	107	16	26	4,092	0	73	171
1988	825	3,247	2,821	472	948	125	10	33	4,259	0	72	166
1989	765	3,226	2,964	464	1,067	118	7	29	4,266	0	70	156
1990	742	3,346	2,992	459	1,123	102	11	29	4,233	0	68	163
1991	721	3,376	2,814	473	1,119	106	1	20	4,174	0	73	168
1992	679	3,425	2,893	469	623	107	3	21	4,352	0	69	155

See footnotes at end of table.

Table A4. Selected Components of U.S. Regional Supply and Demand, 1970 - 1992 (Continued)
(Thousand Barrels Per Day Unless Otherwise Noted)

Year and PAD District	Crude Oil Production	Refinery Output	Receipts from Other Districts	Shipments to Other Districts	Imports		Exports		Demand	Stocks (Million Barrels)		
					Crude Oil	Products	Crude Oil	Products		Crude Oil: SPR[1]	Crude Oil: Other	Products
PAD District III												
1970	6,508	5,001	82	5,507	0	61	12	98	2,478	0	126	211
1971	6,485	5,156	88	5,534	56	54	1	103	2,578	0	111	240
1972	6,540	5,472	94	5,428	77	49	0	104	2,851	0	108	217
1973	6,336	5,750	178	5,295	399	154	1	103	3,200	0	109	226
1974	5,969	5,762	212	5,109	795	170	3	99	3,281	0	110	258
1975	5,600	5,867	213	5,231	1,198	55	6	97	3,129	0	113	268
1976	5,374	6,308	276	5,453	1,780	48	1	118	3,253	0	129	277
1977	5,122	6,980	346	5,430	2,541	51	0	97	3,755	7	150	306
1978	4,856	7,053	463	5,328	2,865	24	0	93	3,955	67	139	292
1979	4,556	6,944	547	5,117	2,969	79	0	110	4,183	91	160	282
1980	4,367	6,482	643	4,789	2,334	87	4	126	3,870	108	171	307
1981	4,217	6,354	530	3,642	2,269	161	0	167	3,586	230	161	308
1982	4,183	6,208	736	3,651	1,722	271	0	315	3,429	294	160	260
1983	4,182	6,118	794	3,554	1,734	266	0	281	3,458	379	163	251
1984	4,291	6,393	702	3,617	1,747	354	0	255	3,706	451	155	247
1985	4,238	6,405	975	4,679	1,419	409	0	275	3,701	493	147	247
1986	4,094	6,792	862	5,012	2,073	414	0	298	3,854	512	146	265
1987	3,827	6,777	928	4,939	2,431	388	0	284	4,130	541	157	256
1988	3,642	6,892	923	5,042	2,718	484	0	303	4,296	560	151	255
1989	3,418	7,053	755	5,253	3,236	479	0	336	4,357	580	162	244
1990	3,340	7,045	632	5,309	3,255	576	0	367	4,380	586	151	256
1991	3,419	6,998	632	5,035	3,196	515	0	480	4,445	569	155	258
1992	3,331	7,099	612	5,214	3,951	541	0	435	4,513	575	151	255
PAD District IV												
1970	675	412	45	436	48	9	0	0	373	0	14	16
1971	640	438	64	390	46	20	0	0	421	0	14	18
1972	635	444	53	410	39	46	0	0	436	0	14	17
1973	673	464	57	414	44	45	0	0	457	0	13	21
1974	689	474	61	433	45	39	0	0	469	0	16	21
1975	683	482	67	407	44	34	0	0	484	0	17	20
1976	657	492	58	375	54	32	0	0	531	0	17	21
1977	662	518	63	363	44	30	2	0	544	0	17	21
1978	647	522	58	352	50	24	4	0	548	0	16	17
1979	608	510	63	333	65	23	2	0	535	0	17	19
1980	576	474	85	298	39	23	1	(s)	507	0	17	20
1981	596	434	82	67	29	22	0	0	544	0	14	21
1982	554	431	78	74	40	20	0	0	523	0	13	21
1983	565	431	72	101	38	21	0	0	507	0	14	18
1984	594	455	74	119	33	24	0	0	513	0	14	19
1985	628	458	96	494	39	25	0	0	519	0	12	17
1986	594	456	102	424	54	21	0	0	517	0	13	17
1987	561	460	90	379	65	19	0	1	513	0	13	17
1988	554	480	82	391	64	19	0	1	525	0	12	18
1989	514	485	82	316	72	13	0	0	531	0	12	18
1990	498	491	75	290	76	13	0	1	531	0	12	17
1991	480	491	96	292	86	17	1	1	550	0	12	18
1992	458	466	102	282	78	13	0	(s)	549	0	11	17

See footnotes at end of table.

Table A4. Selected Components of U.S. Regional Supply and Demand, 1970 - 1992 (Continued)
(Thousand Barrels Per Day Unless Otherwise Noted)

Year and PAD District	Crude Oil Production	Refinery Output	Receipts from Other Districts	Shipments to Other Districts	Imports		Exports		Demand	Stocks (Million Barrels)		
										Crude Oil		
					Crude Oil	Products	Crude Oil	Products		SPR[1]	Other	Products
Pad District V												
1970	1,254	1,813	192	24	380	104	1	115	1,953	0	38	92
1971	1,204	1,904	192	37	512	146	0	89	2,037	0	43	95
1972	1,150	2,026	182	29	663	157	1	87	2,159	0	42	98
1973	1,122	2,159	167	28	810	194	1	99	2,337	0	35	90
1974	1,081	2,035	185	23	776	172	0	92	2,192	0	42	95
1975	1,076	2,078	180	24	852	124	0	80	2,216	0	43	101
1976	1,066	2,218	161	20	1,038	96	0	74	2,359	0	42	98
1977	1,424	2,476	135	68	1,096	118	5	66	2,614	0	66	102
1978	2,185	2,447	159	316	600	125	79	84	2,631	0	59	94
1979	2,371	2,575	131	321	528	129	159	91	2,638	0	56	96
1980	2,595	2,513	95	376	429	97	194	92	2,575	0	62	102
1981	2,667	2,353	94	411	302	101	183	140	2,410	0	84	102
1982	2,798	2,215	117	622	188	111	201	203	2,287	0	81	90
1983	2,825	2,275	111	714	210	97	146	229	2,317	0	80	90
1984	2,854	2,435	103	596	203	111	165	233	2,409	0	83	92
1985	2,995	2,472	94	685	177	116	184	251	2,465	0	74	89
1986	2,989	2,618	99	608	187	129	138	273	2,576	0	73	87
1987	3,055	2,704	101	606	197	86	134	284	2,635	0	90	91
1988	3,081	2,810	110	574	201	108	145	301	2,756	0	80	96
1989	2,881	2,835	106	401	267	80	134	326	2,724	0	83	91
1990	2,746	2,845	104	283	232	73	98	294	2,731	0	76	94
1991	2,770	2,842	109	287	171	61	113	338	2,679	0	69	94
1992	2,675	2,821	117	281	209	57	86	367	2,639	0	73	92
U.S. Total												
1970	9,637	12,113	0	0	1,324	2,095	14	245	14,697	0	276	741
1971	9,463	12,498	0	0	1,681	2,245	1	222	15,213	0	260	784
1972	9,441	13,080	0	0	2,216	2,525	1	222	16,367	0	246	713
1973	9,208	13,854	0	0	3,244	3,012	2	229	17,308	0	242	766
1974	8,774	13,498	0	0	3,477	2,635	3	218	16,653	0	265	809
1975	8,375	13,685	0	0	4,105	1,951	6	204	16,322	0	271	862
1976	8,132	14,677	0	0	5,287	2,026	8	215	17,461	0	285	826
1977	8,245	15,874	0	0	6,615	2,193	50	193	18,431	7	340	964
1978	8,707	15,966	0	0	6,356	2,008	158	204	18,847	67	309	901
1979	8,552	15,763	0	0	6,519	1,937	235	236	18,513	91	339	911
1980	8,597	14,622	0	0	5,263	1,646	287	258	17,056	108	358	926
1981	8,572	13,990	0	0	4,396	1,599	228	367	16,058	230	363	890
1982	8,649	13,391	0	0	3,488	1,625	236	579	15,296	294	350	786
1983	8,688	13,138	0	0	3,329	1,722	164	575	15,231	379	344	731
1984	8,879	13,679	0	0	3,426	2,011	181	541	15,726	451	345	760
1985	8,971	13,750	0	0	3,201	1,866	204	577	15,726	493	321	705
1986	8,680	14,522	0	0	4,178	2,045	154	631	16,281	512	331	750
1987	8,349	14,626	0	0	4,674	2,004	151	613	16,665	541	349	718
1988	8,140	15,022	0	0	5,107	2,295	155	661	17,283	560	330	707
1989	7,613	15,175	0	0	5,843	2,217	142	717	17,325	580	341	660
1990	7,355	15,272	0	0	5,894	2,123	109	748	16,988	586	323	712
1991	7,417	15,256	0	0	5,782	1,844	116	885	16,714	569	325	724
1992	7,171	15,398	0	0	6,083	1,805	89	861	17,033	575	318	699

[1] Strategic Petroleum Reserve.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Petroleum Supply Annual*, Vol. 1, 1981-1982, Tables 2-9, 14, 18, 20, and 26, 1983-1988, Tables 2-9, 14, 16, and 23, 1989-1992, Tables 2-12, 14, 20, 27, and 35, and predecessor reports, and *Supply, Demand, and Stocks of All Oils by Petroleum Administration for Defense District and Imports Into the United States by Country*, 1976-1980, Table 1, and predecessor reports.

APPENDIX H

HISTORY AND FUNDAMENTALS OF REFINING OPERATIONS

THIS APPENDIX IS A REVISED EDITION OF APPENDIX C, *HISTORY AND FUNDAMENTALS OF REFINING OPERATIONS*, WHICH WAS PROVIDED IN THE NATIONAL PETROLEUM COUNCIL REPORT *U.S. PETROLEUM REFINING*, OCTOBER 1986.

HISTORY

Petroleum refining industry operations have had tremendous changes in growth and complexity since their inception in the 1800's. Equipment design and size of process units have advanced greatly over the years, product demands and specifications have shifted and petroleum feedstock form and quality have changed with differing sources of supply.

The history of the refining industry has been one of many advancements in petroleum technology. Most of the technological and equipment changes in petroleum refineries have been in the downstream processing units that are used after the primary distillation, or crude oil separation, process. Although equipment design has advanced greatly over the years, the principle of crude oil distillation remains today what it was in the early years–the separation of the different components (fractions) of crude oil based on their different boiling points. These downstream changes were caused by the inability of the distillation process itself to produce enough modern fuels such as high octane motor gasoline and kerosene jet fuel to meet market demands. The evolution of the industry was necessary to meet the demands of the marketplace, and the developments of each period were based largely on scientific advances of the previous period.

The evolving market demand brought changes in petroleum product characteristics such as gasoline octane number and sulfur content of distillates and fuel oils. These changes were made by developing downstream processes (those that occur after the initial separation process of the crude oil) to produce lighter products, such as gasoline: by converting heavy crude oil fractions; by combining high volatile hydrocarbons to produce heavier products; by rearranging the molecular structure of molecules to improve their physical characteristics; and by treating crude oil fractions to remove contaminants such as sulfur, nitrogen, and arsenic.

As presented in the main body of this report, this evolution in market demand changes continues today with a very strong emphasis on creating products that will result in a cleaner environment. The processes are much the same as current but additional downstream capacity and revamping is required for fractionation of product component streams and for purification steps such as removal of aromatics and olefins from gasoline and deeper removal of sulfur from on-highway diesel fuel.

In the early 1800s, the distillation of coal provided some currently produced from crude oil, condensate, and natural gasoline. Between 1830 and 1858, use of illuminating and lubricating oils increased at a rate that exceeded their supply. Illuminating oil was the main item and was called "coal-oil." During this period a Pittsburgh druggist, Samuel Kier, inspired by the popularity of this product and by the coal-oil industry's distillation facilities, produced a substitute oil from "rock-oil" (crude oil). This product was also called coal-oil, but now is known as kerosene. The demand for this new product increased rapidly.

From the 1860s until 1920, refining operations were generally limited to crude oil distillation for the production of kerosene. The petroleum refining industry increased in processing capacity from 11,680 barrels per day in 1865 to 142,465 barrels per day in 1900. By 1960, capacity stood at 9.9 million barrels per day (MMB/D). Capacity nearly doubled over the next 20 years and peaked at 18.6 MMB/CD in 1981. Industry capacity was then reduced in the 1980's, reflecting primary the removal of government price controls and improved processing efficiency for making light products. By 1993, crude oil distillation capacity had decreased by 3.5 MMB/CD to 15.1 MMB/CD.

Though the number of refineries increased rapidly, the average capacity was low. For example, in 1918 there were 267 refineries with a total operating capacity of 1,186 MB/D or less than 4.5 MB/D per refinery. In 1940, the number of operating refineries peaked at 461 refineries with a total capacity of 4,197 MB/D, an average of 9.1 MB/D. As of January 1, 1993, the Department of Energy (DOE) reported in the Petroleum Supply Annual that 187 refineries were operable with a capacity of 15,121 MB/D, or an average of 80.9 MB/D. Downstream processing played an increasing role throughout the history of refining. In 1925, the ratio of the sum of cracking and reforming operating capacity to crude distillation operating capacity was 27.5%; in 1993 this ratio was 85.9%.

GROWTH AND CHANGES IN REFINERY CONFIGURATION

The initial refining process separates crude oil into discrete boiling range fractions having differing characteristics. These fractions, or cuts, may be sold directly or may be further "refined" in other process units. Those components that "boil" and are recovered as an overhead stream, or as side-cuts, are called "naphthas, kerosene, and distillates" and are further categorized by other physical properties. The bottom product from the crude oil atmospheric distillation column contains materials that are too heavy to boil under the atmospheric pressure conditions of the crude oil unit. This bottom product has many names "atmospheric resid," "residual oil," "topped crude," and "No. 6 fuel oil" among them.

These various distillation fractions can also be processed by cracking the large hydrocarbon molecules into smaller ones. The structure of some of these molecules is rearranged and others are joined in different combinations to provide the desired components for blending into finished products. This takes place in many refinery process units, each with a specific purpose, integrated into a processing sequence. The type and number of refinery process units in a given plant depend upon the type of crude oil to be processed, product requirements, and economic factors such as crude oil costs, product values, and availability and cost of utilities and equipment. The type and size of processing units thus vary greatly. Theoretically, any petroleum or petrochemical product can be manufactured from any type of crude oil. However, a refinery is designed based on the available crude oil and the market demand for its products and each has its unique "product slate."

Initially, kerosene and light distillates were considered the prime products. Gasoline had only nuisance value until the early 20th century, when the arrival of the automobile and its internal combustion engine resulted in increased demand for gasoline. Still, the quantities required were in approximate balance with the amount contained in the quantity of crude oil processed to meet demand for the heavier distillates. Simultaneously, a growing market was developing for lubricating oils of better quality.

During World War I, military requirements necessitated rapid advancement in application and refinement of existing internal combustion engine technology. In the immediate post-war years, "spin-offs" from wartime technology led to design and production improvements in automotive manufacture that made automobile ownership generally more common. During this period, the typical U.S. refinery was small and simple in operation (see Figure H-1).

Within a short time, petroleum refiners were faced with the problem of shifting their product slate toward production of more, higher quality gasoline from a given barrel of crude oil than had previously been recovered by simple distillation processes. The conversion of heavier fractions to gasoline boiling range stocks became necessary.

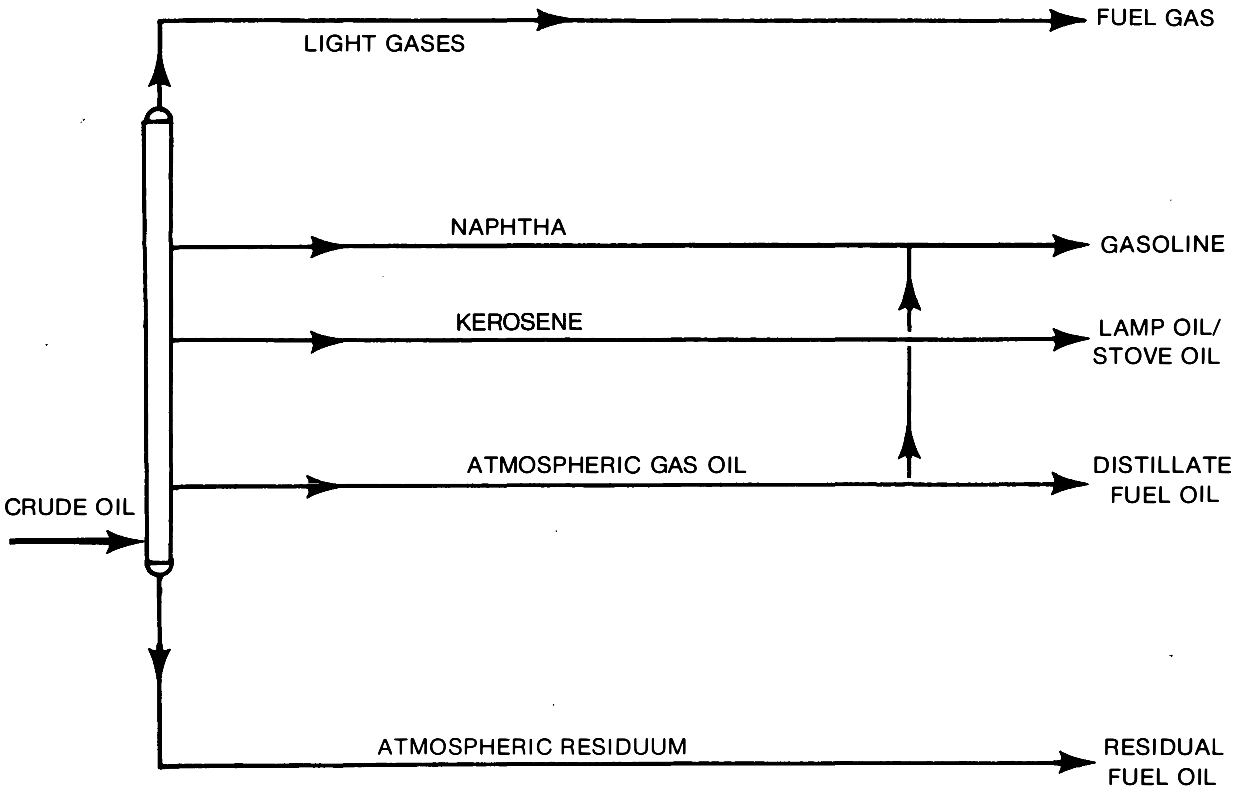


Figure H-1. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1915).

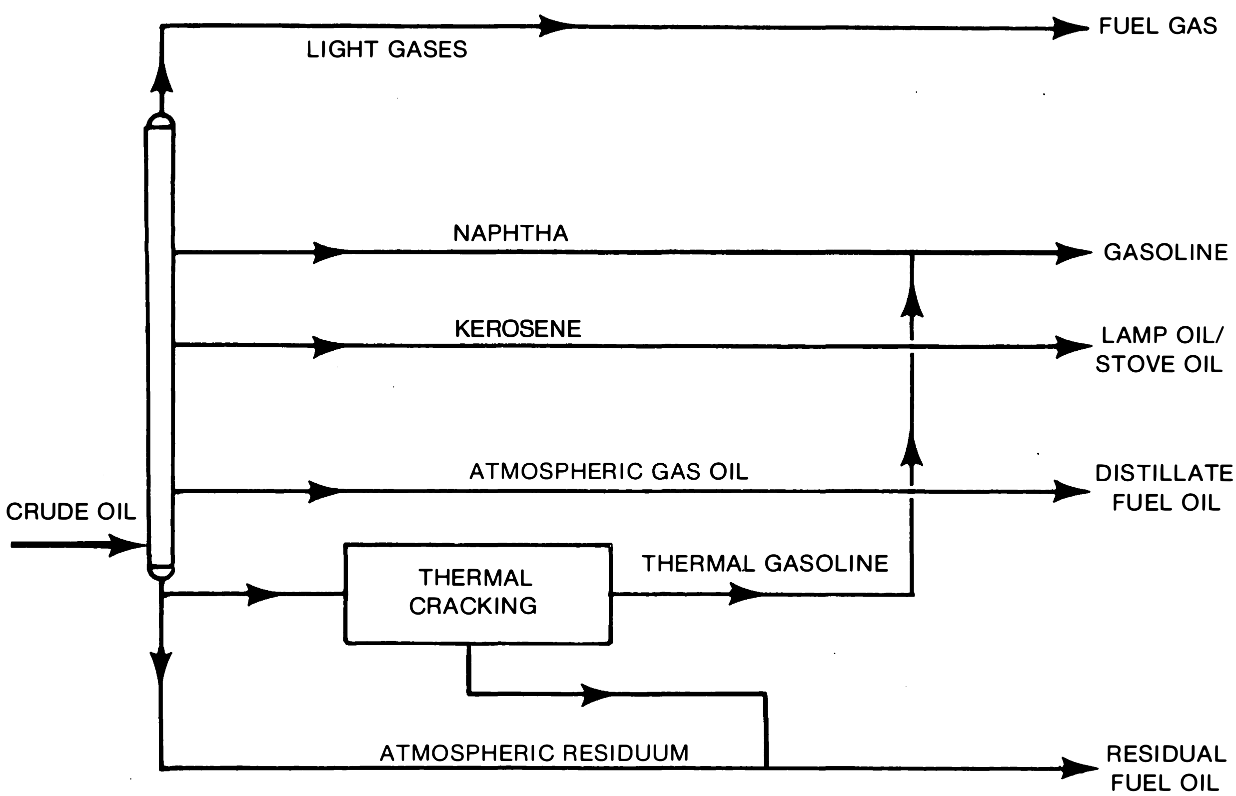


Figure H-2. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1920s).

In the early 1920s, with the commercialization of the thermal cracking process, refiners found a satisfactory economic solution that was complemented by a substantial increase in domestic crude oil production (see Figure H-2). Thermal cracking is a severe form of thermal processing. It reduces the amount of heavy fuel oil produced by cracking, or fracturing, the molecules of the heaviest components present in crude oil to produce lighter, generally more valuable materials, such as gasoline components and light fuel oils.

Acceptance of the new processing technique was immediate. From the standpoint of the automotive industry, the successful commercialization of the cracking process came none too soon. Apart from the problem of gasoline availability, gasoline quality had become troublesome. Engine knock had been identified as a severe fuel problem; straight run gasoline from crude oil distillation units burned too fast and unevenly, affecting engine performance. Cracked gasoline was of superior quality, as measured by the "octane rating" and demand soared for what was then considered to be a "premium" fuel from thermal crackers. The thermal cracking process became a mainstay of the early refinery.

During the late 1920s and early 1930s, consumer demand required that the refining industry continue to shift from production of heavy distillates and fuel oils toward that of higher quality gasoline (see Figure H-3).

A by-product of the previously commercialized thermal cracking process was a gaseous material, rich in a type of hydrocarbon known as "olefins." Olefins are typically produced in operations where a deficiency in hydrogen exists. They are reactive materials and can be made to form heavier, liquid materials. In the early days of thermal cracking, this olefin-rich gaseous co-product was used as a fuel gas or sometimes, burned as a waste product.

To make economic use of these light thermal olefins, the catalytic condensation or polymerization process was developed. This processing technique uses a catalyst to provide the proper processing conditions under which light olefins will react selectively to yield a high octane gasoline. The overall efficiency of the operation was improved by separating the light olefins in a gas recovery plant for processing in the polymerization unit. This process was later applied to produce gasoline from suitable olefins recovered from other types of operations.

The yield of residual oil was reduced through application of improvements in vacuum distillation techniques and equipment design. As mentioned previously, the bottom product from the crude oil distillation column contains materials that will not distill at atmospheric pressure. When the atmospheric residuum was fractionated using a vacuum distillation unit, a distillate, called vacuum gas oil, was recovered, which could be directed to thermal cracking to produce additional gasoline.

The refiner could cut deeply into the crude oil and further reduce heavy fuel oil yields by applying the visbreaking and coking processes to the vacuum residuum, or pitch. Visbreaking is a mild form of thermal cracking that was, and still is, used primarily to reduce the viscosity of the vacuum residuum used in fuel oil.

Coking is a more severe type of thermal processing. In the coking unit, atmospheric or vacuum residuum is subjected to time and temperature conditions that, through a series of complex reactions, result in production of gas, gasoline, distillates, and petroleum coke.

During the early years of World War II, the U.S. government brought together the refining technologies to hasten the contribution of the petroleum industry to the war effort, particularly in the manufacture of badly needed high octane aviation fuel. Working in close collaboration, petroleum industry scientists and engineers immediately directed their broad

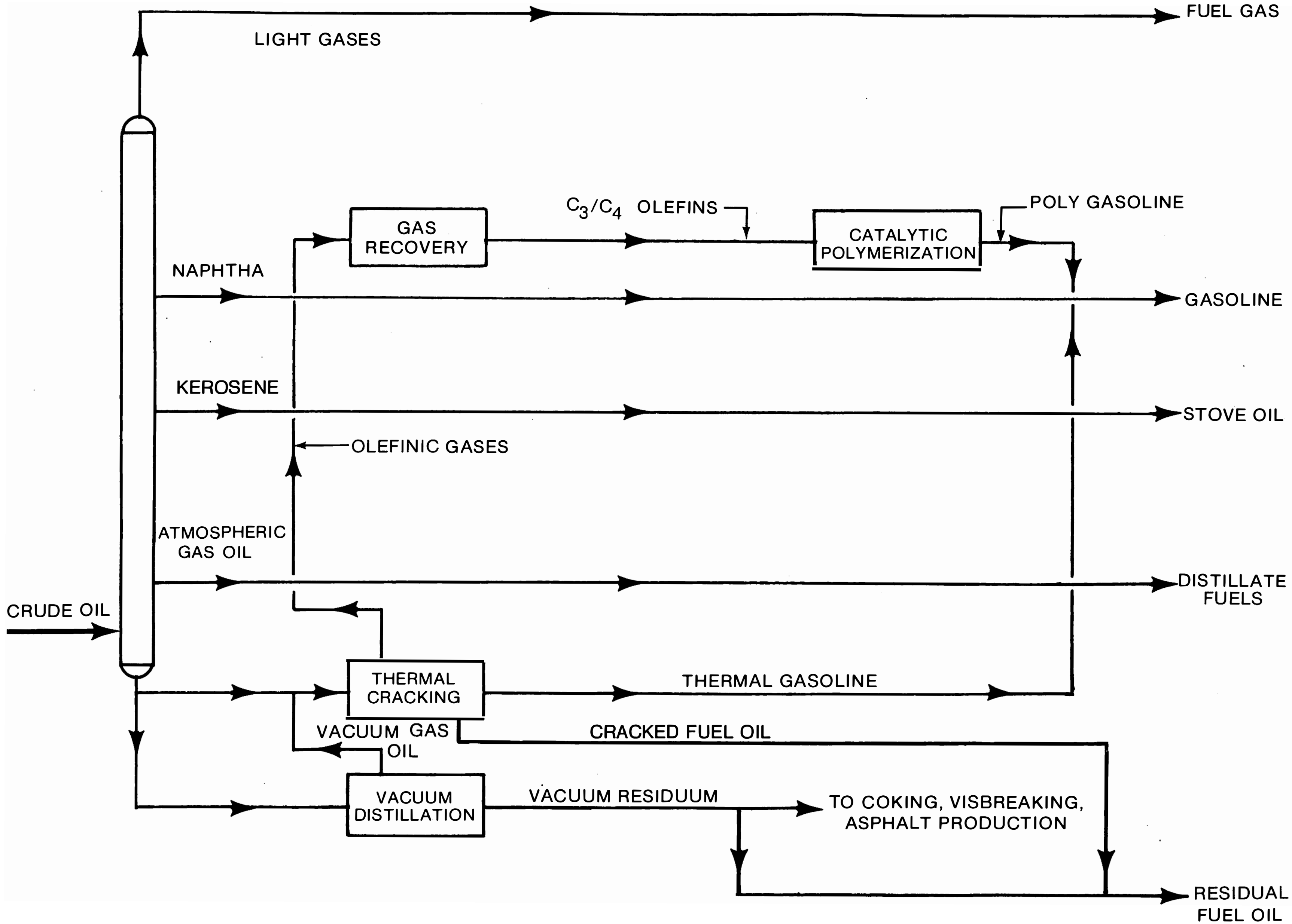


Figure H-3. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1930s).

knowledge and talents to the war effort. From the industry's laboratories and engineering departments came technology for the processes of alkylation, isomerization, toluene manufacture and several forms of catalytic cracking, fixed bed, thermofor, and the most important of the heavy distillate conversion processes, fluid bed catalytic cracking (FCC) (see Figure H-4).

Fluid catalytic cracking converts virgin atmospheric and vacuum gas oils and heavy stocks derived from other refinery operations into high octane "cat" gasoline and light fuel oils called "cycle stocks." Olefin-rich light gases, which can be directed to polymerization or alkylation operations to produce gasoline, are co-products. With proper design and selection of operating conditions and catalysts, yields and qualities of specific FCC products may be varied. Typically, yields of liquid products will exceed 75 to 80 volume percent of the FCC feed. The cracking reaction is done in the presence of a catalyst at controlled conditions of temperature, pressure, and time. The term "fluid catalytic cracking" derives from the use of a catalyst consisting of small particles that, when aerated with a vapor, behave as a fluid. This fluidized catalyst will flow and is circulated within the system.

The alkylation process for motor fuel production catalytically combines light olefins, primarily mixtures of propylene and butylenes, with isobutane (a paraffinic hydrocarbon) to produce a fuel that is one of the highest quality components of a gasoline pool. The alkylate product has excellent antiknock properties and lead response. It is clean burning, has high unleaded and leaded Research and Motor octane ratings, and has an excellent aviation gasoline "performance" rating, as well. The alkylation takes place in the presence of a catalyst, hydrofluoric acid or sulfuric acid, under conditions selected to maximize alkylate yield and quality.

When considered together, the FCC and alkylation processes are of major importance in the manufacture of quality gasoline. The total gasoline yield of the two processes, the "cat" gasoline plus the alkylate produced from the FCC olefins, will typically exceed 90 volume percent of the FCC feed. Allowing for the blending of butane into the gasoline to meet volatility requirements, the total yield approaches 100 volume percent. In other words, for each barrel of feedstock processed in the FCC unit, approximately one barrel of gasoline can be recovered from the combined FCC-alkylation operation. In addition, there is an additional yield of fuel oil from the FCC unit.

Isobutane is consumed in the alkylation process. The butane isomerization process was developed and added to the refinery components to produce isobutane from normal butane and, thus, supplement the isobutane recovered from the crude oil itself and from other processes.

After World War II, the availability of catalytically cracked gasolines and alkylate for motor fuel blending made refinery naphtha, with its low octane number, increasingly unattractive as a gasoline component. In the late 1940s, a radically different process was developed that utilized a catalyst containing platinum in petroleum refining for the first time. This process, known as catalytic reforming, revolutionized the art of converting low grade naphthas into high octane gasoline components called reformates.

Within the mandated introduction of unleaded gasoline in 1974, catalytic reforming became even more important to the gasoline oriented refinery. Reformates became the principal octane balancing component with the elimination of tetra ethyl lead in gasoline. The gasoline-range materials recovered from other operations, such as FCC, alkylation, hydrocracking, and polymerization, are of relatively fixed octane quality. The catalytic reforming process can efficiently yield gasoline products ranging in octane number from the low 80s to

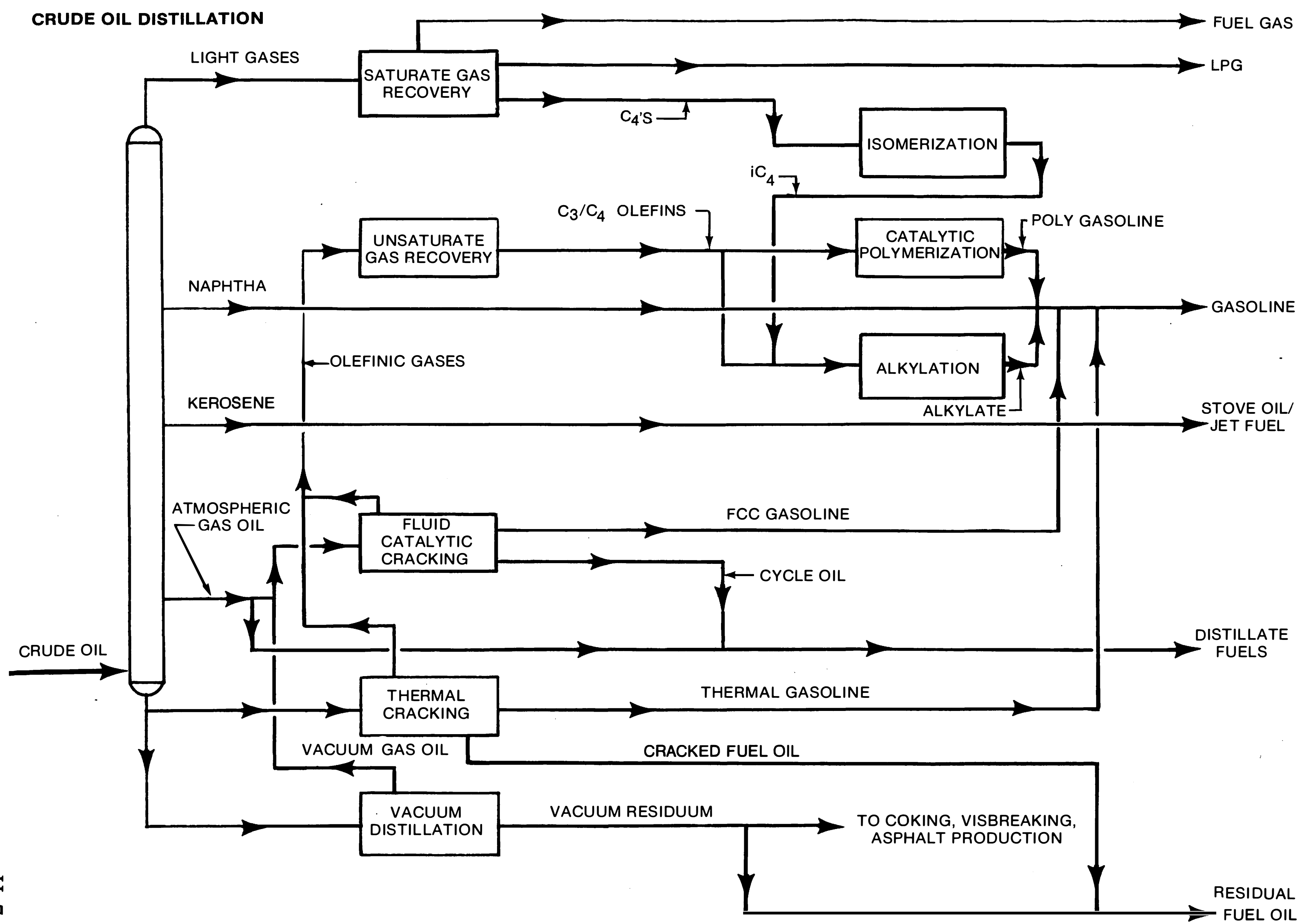


Figure H-4. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1940s).

over 100 Research clear (unleaded). Unfortunately, as operating severity is increased to raise the octane number, gasoline yield decreases. Based on gasoline produced per unit of feedstock, typical yields can range from over 90 volume percent to 70 volume percent, respectively, for low to high octane operations. This process is also the major source of the hydrogen required for many of the operations employed in today's modern refineries.

Since processing over a platinum catalyst produces aromatics, such as benzene, toluene, and xylene, catalytic reforming quickly established itself as a processing base for development of an aromatic-based petrochemical industry.

With continuing emphasis on producing greater quantities of higher octane gasolines, it became necessary to upgrade other materials that were formerly used directly as gasoline components, such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as refinery naphthas having more than modest amounts of sulfur and nitrogen. The contaminants present in these materials, however, were detrimental (poisonous) to the platinum-based catalyst used in the reforming process. Treatment of such stocks before catalytic reforming became a necessity.

With the development of the hydrotreating process in the mid-1950s, an efficient answer to this problem was provided. The process used hydrogen produced in the catalytic reformer itself to remove sulfur, nitrogen, and other reformer catalyst poisons. The yield of treated product from a hydrotreater generally approaches 100 volume percent. As catalytic reforming severity increased over the years, more active catalysts were developed and greater care was exercised to provide clean feedstocks for these operations. Thus, it became routine practice to hydrotreat reformer feeds for elimination of contaminants (see Figure H-5). The hydrotreating process was also used to desulfurize high-sulfur distillate fuels produced from high–sulfur crude oils.

In the latter part of the 1950s, improvements in the design and reliability of sulfuric and hydrofluoric alkylation process units resulted in the initial phasing out of the catalytic polymerization process as a route to gasoline production. Polymerization technology, however, retained its importance as a refining tool in the production of a variety of compounds used in the petrochemical industry.

The use of chemical treating processes for odor improvement of gasoline and distillate, or for reduction of the sulfur content of light hydrocarbon streams, became widespread.

With the development of catalytic processing during the war years and early 1950s, thermal based operations became relegated to a position of lesser importance. Most thermal processing now is being used in the area of visbreaking and coking. The refining industry has passed from the thermal to the catalytic era.

In the late 1950s and early 1960s, rapid acceptance by the airlines of the turbine engine resulted in a startling increase in kerosene jet fuel consumption. The petroleum industry was hard pressed to meet the demand from straight run stocks. With the coming of hydrocracking process in 1960, the refiner was provided with a tool for production of high quality jet fuel from otherwise unsuitable materials. Hydrocracking is a highly versatile process that can charge any fraction of crude oil to yield virtually any product lighter (lower boiling) and cleaner than the charge stock. The process can produce directly almost any material the refiner markets, such as liquefied petroleum gas (LPG), light gasoline, naphtha for reformer feed, turbine fuels, lubricating oils, and diesel and distillate fuels. It also can upgrade stocks for subsequent processing in other operations. With hydrocracking reactions, undesirable sulfur, nitrogen, and oxygen compounds are almost completely removed (see Figure H-6).

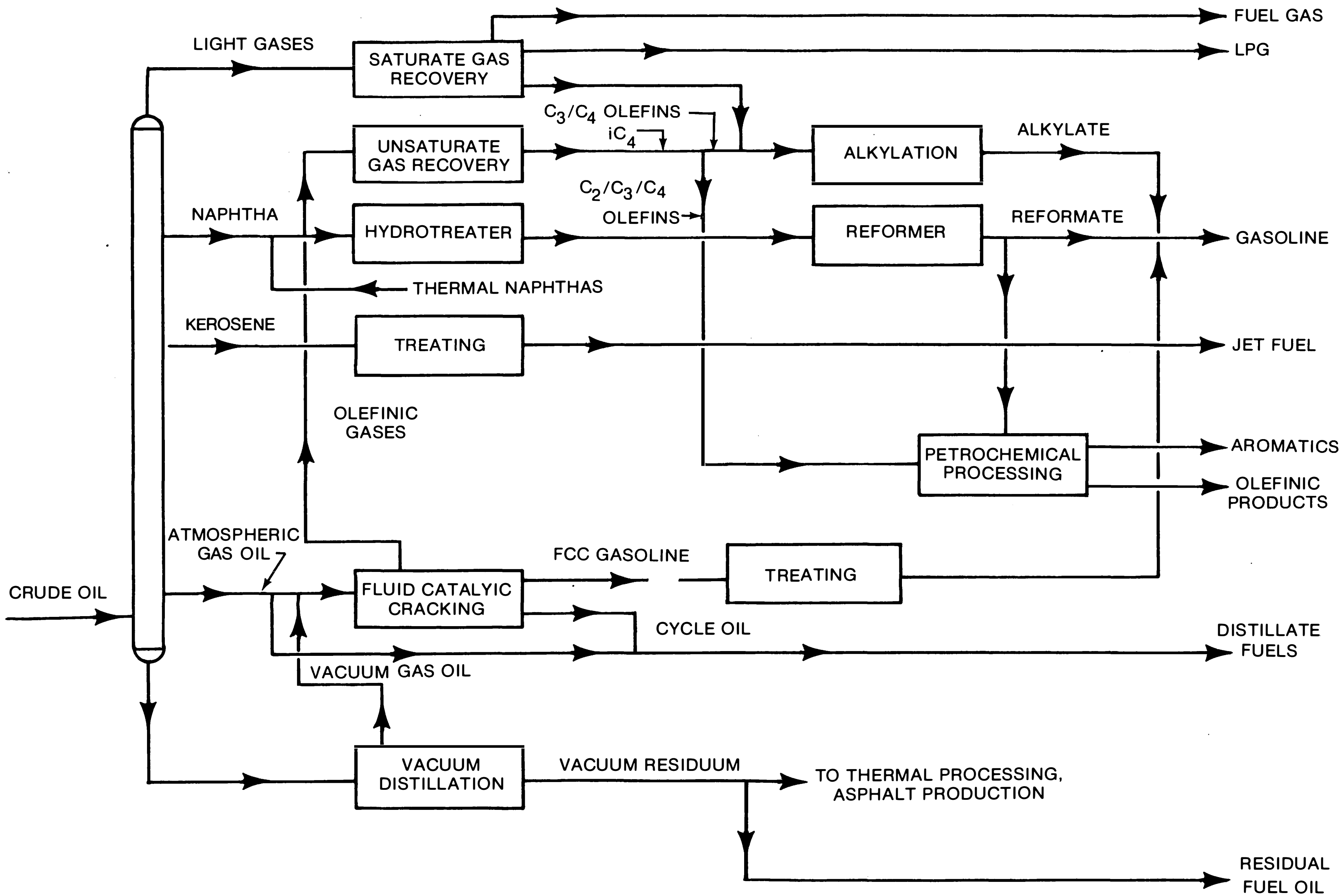


Figure H-5. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1950s).

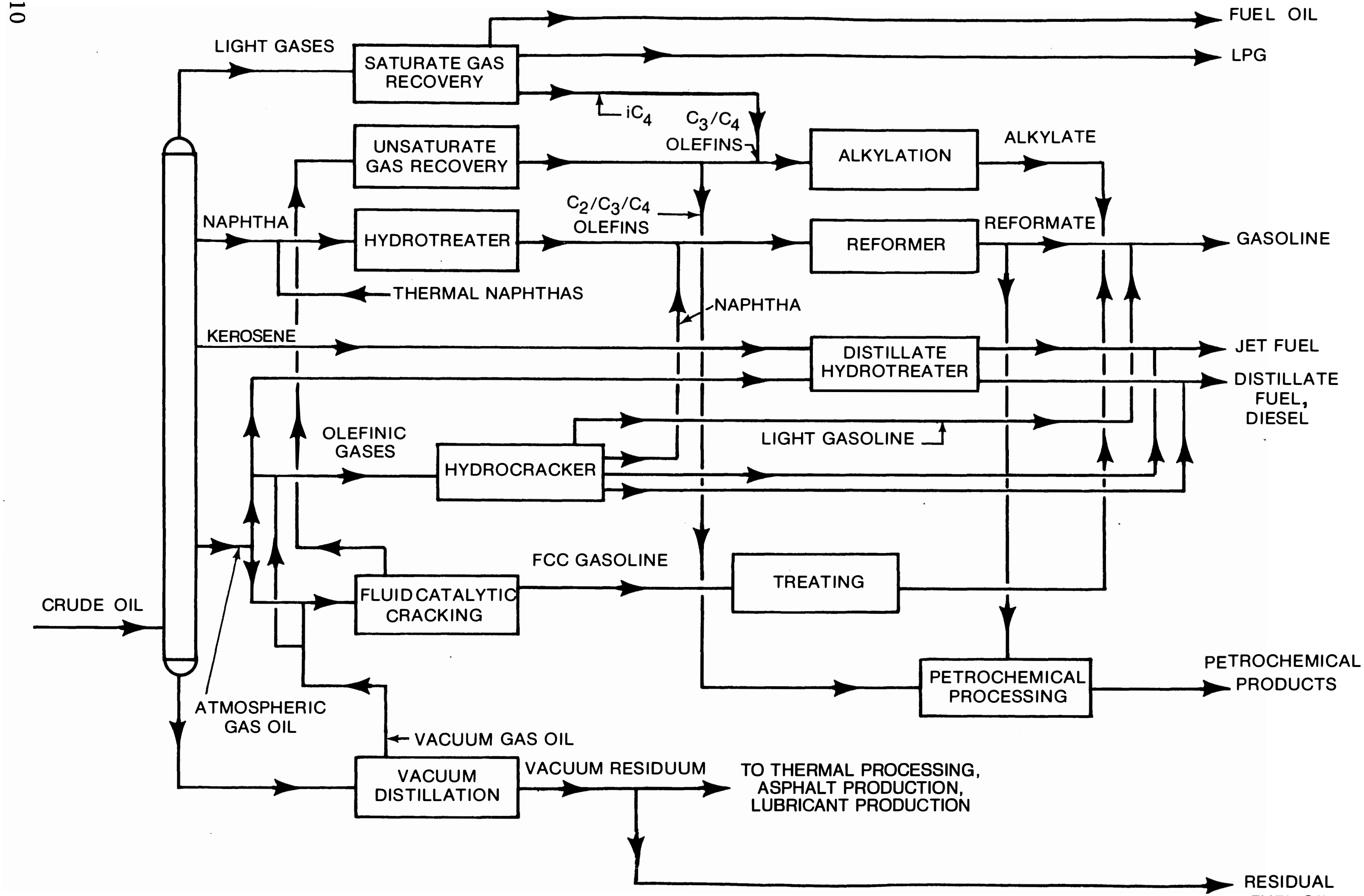


Figure H-6. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1960s).

Hydrocracking flexibility permits ready adjustment of refinery production to whatever proportions are necessary for variations in seasonal, geographic, or marketing requirements.

Hydrocracking is a catalytic process and, as is hydrotreating, a hydrogen consumer. Total yield of liquid products, that is, gasoline and heavier materials, will exceed 100 volume percent of feed. The yield of specific products will depend on the application.

Hydrogen for hydrocracking and hydrotreating is most often supplied by catalytic reforming operations. Process selection and flow scheme often have been dictated by "hydrogen balance" considerations. Where this has not been possible, supplementary hydrogen generation facilities have been installed.

The decade of the 1960s saw rapid growth in the production of petrochemicals, particularly in the area of light olefins. For example, U.S. domestic demand for ethylene tripled during the 1960-1970 period. A representative configuration of a refinery operating in the 1970s is presented in Figure H-7. Refinery operation in the 1980s and the 1990s is much the same as in the 1970s but has been impacted by the changes created by environmental legislation. The principal addition to the refinery flow scheme has been the incorporation of oxygenates into gasolines. Ethers are manufactured from purchased methanol and FCC butylenes and amylenes - methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME). Ethanol has been added to gasoline (gasohol) also has been considered for etherification with refinery olefins - primarily iso-butylene to produce ethyl tertiary butyl ether (ETBE). Although oxygen addition is now mandated for several environmental purposes, both MTBE and ethanol have been used on an economic basis as well.

As noted in the body of this report, environmental considerations are expected to change the emphasis on the use of downstream process units. Reformulated gasoline is likely to be blended to control emissions by controlling Reid Vapor Pressure (RVP) and content of hydrocarbon types. For instance, control of aromatics will tend to affect the use of catalytic reforming, control of olefins will affect the use of cat cracking, etc.

Lubricating oil manufacture is a highly specialized operation not included in most fuel refineries. The lubricating oil process generally starts with a heavy paraffinic gas oil (also known as a wax distillate) produced from the crude oil vacuum distillation unit, as shown in Figure H-8. The wax distillate is solvent extracted with furfural or n-methyl pyrolidone to remove the aromatic compounds. This processing step reduces the viscosity changes with increasing temperatures (viscosity index).

The refined oil is then dewaxed by using solvents such as methyl ethyl ketone and propane. The most recent process is to catalytically dewax the lube oil. The lube oil is generally finished today by hydrotreating, but in some instances the older clay treating process is used. The waxes produced by solvent dewaxing can be de-oiled to produce marketable paraffin wax.

During the latter part of the 1960s and continuing to the present, increasing emphasis has been placed on environmental considerations. Such concerns have affected the design of every process unit in the refinery. Proper handling of waste materials, such as contaminant-containing water, gas streams, and spent chemicals, has required creation of new and improved antipollution techniques. For further discussion see Appendix I.

The choice of refinery processes is based on the specific circumstances of each operation and is dependent on crude oil type, product slate, product quality requirements, and

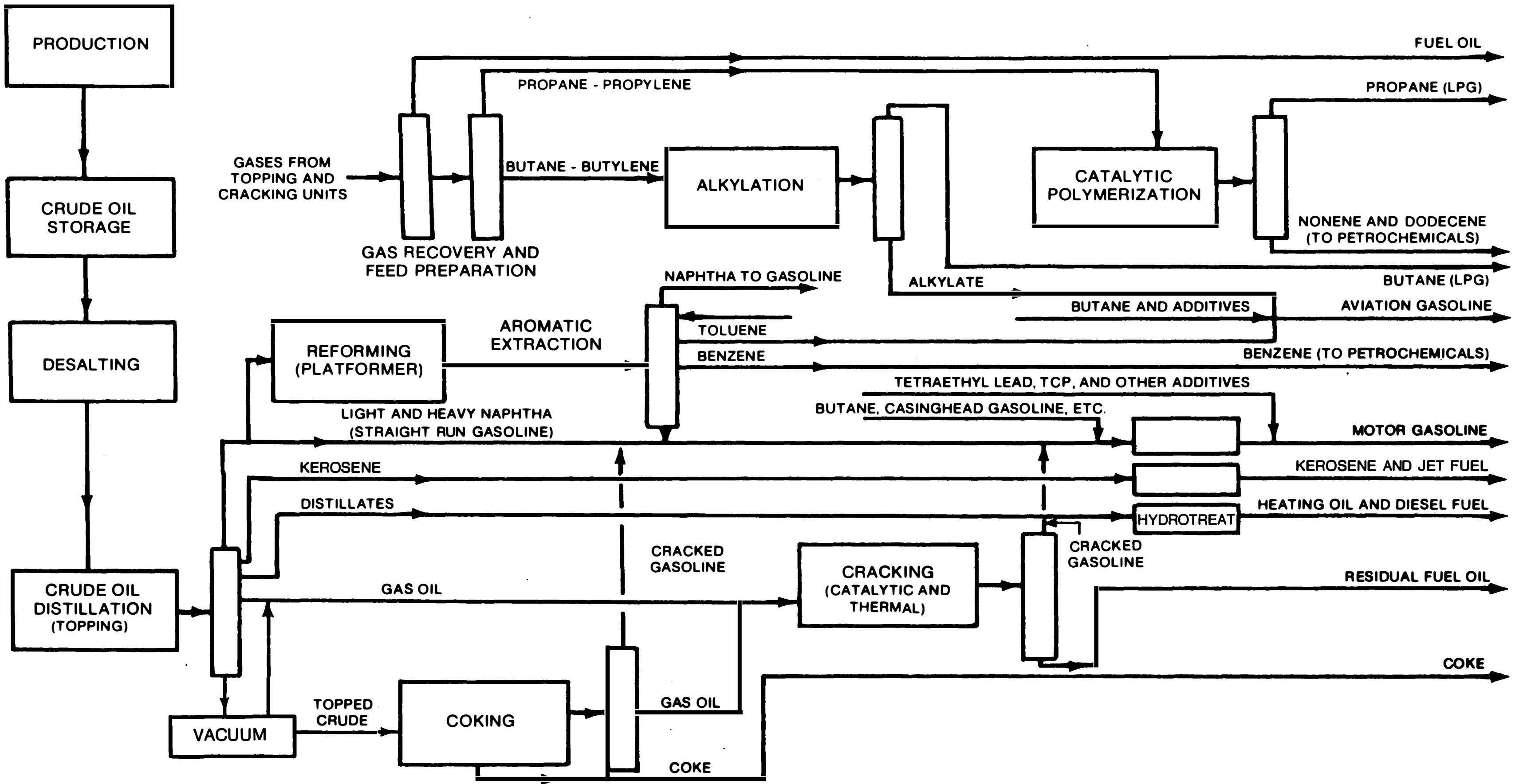


Figure H-7. Simplified Flow Chart of a Refinery (circa 1970s).

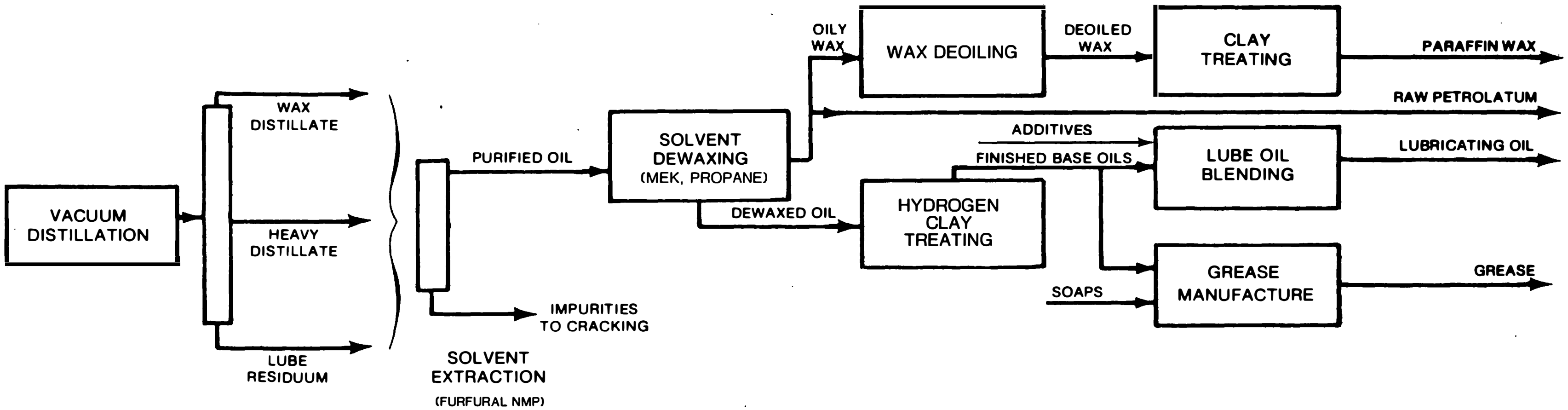


Figure H-8. Simplified Flow Chart of a Lubricating Oils Refinery.

economic factors such as crude oil costs, product values, availability and cost of utilities, and availability of equipment and capital.

The characteristics of the crude oil feedstock are critical to process selection. There are hundreds of crude oils available on the world market today that vary widely in physical properties. Many crude oils from the Middle East tend to be high in sulfur content and of moderate metals content, both important factors to be considered if low sulfur-heavy fuel oils are the desired products. Some of the more readily available Middle East crude oils, such as those from Kuwait, have a poor naphtha component, which makes them less desirable for gasoline operations. Many Venezuelan crude oils, while moderate in sulfur, contain a high level of metals, which poisons catalysts. Some North African crude oils are low in sulfur and other contaminants but are waxy and, therefore, less suitable for production of lubricating oils.

As for product slate, in a gasoline oriented refinery, the yields of heavy oils will be minimized through the application of conversion processes. Fluid catalytic cracking would be used to crack the distillate products from resid conversion processes as well as virgin distillate materials, to yield gasoline and olefins for motor fuel alkylate production.

In situations where quality distillates, such as turbine fuel, diesel and lube oils, and low-sulfur fuel oils are required, hydrogen refining concepts will apply, with hydrocracking and hydrodesulfurizing processes predominating.

The variability of marketing requirements and the potential uncertainty in crude oil supply require that processing flexibility be a major consideration in the design of today's modern petroleum refinery. The general result is an overall operation combining cracking and hydrogen refining capabilities.

REFINERY OPERATING UNITS

As of January 1, 1992, the operable capacity of U.S. refineries ranged from 1,000 barrels per calendar day to 433,000 barrels per calendar day. The simplest refineries "top" the crude oil and are usually limited to atmospheric distillation and, in some cases, vacuum distillation (Figure H-9). These refineries produce only a few products, such as naphthas, distillates, residual fuels, and asphalts. More complex refineries have process units such as cracking, alkylation, reforming, isomerization, hydrotreating, and lubricant processing (Figure H-10), producing a wide range of products, including gasolines, low-sulfur fuel oils, lubricants, petrochemicals, and petrochemical feedstocks.

To understand better the operation of a refinery, the processing and facilities can be divided into seven steps:

- *Separation of Crude Oil.* The most widely used methods for separating crude oil fractions by boiling point are atmospheric and vacuum distillation.
- *Restructuring Hydrocarbon Molecules.* Conversion processes, which change the size or structure of the hydrocarbon molecule, convert some of the heavier crude oil fractions into higher value products. The most common conversion processes are catalytic cracking, hydrocracking, coking, viscosity breaking, and thermal cracking. Other restructuring processes that combine/condense molecules (alkylation, etherification, and polymerization), or rearrange molecules (catalytic reforming and isomerization) provide product components with more desirable properties.

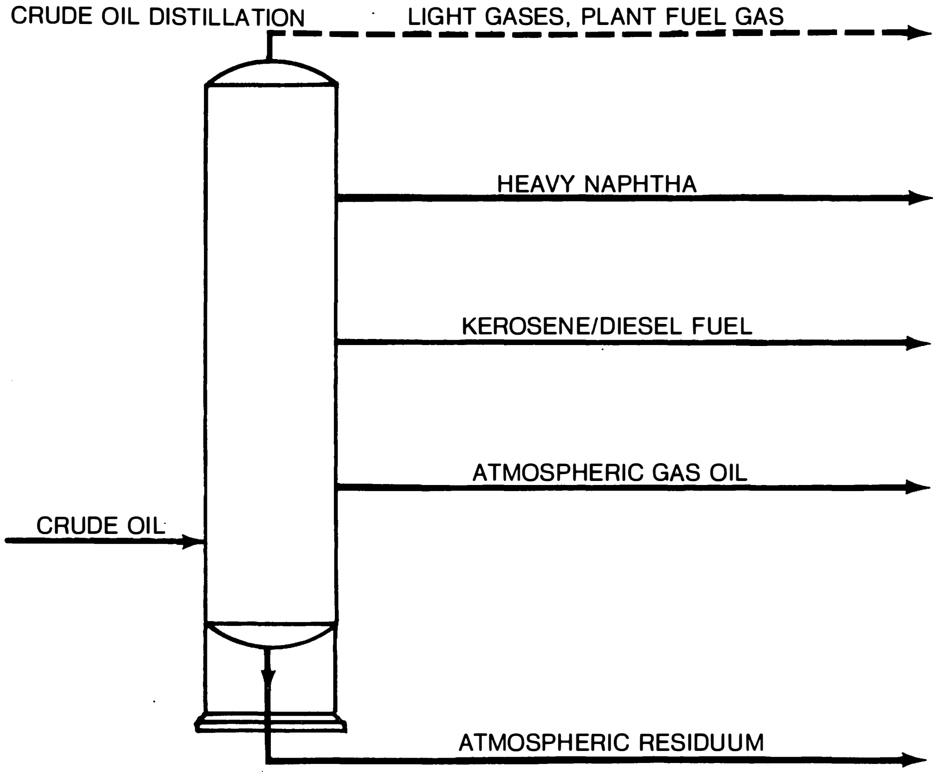


Figure H-9. Crude Oil Skimming or Topping Plant.

NOTE: The following legend applies to Figures H-9 through H-28.
——————— HYDROCARBON — — — — — — GASES

- *Treating Intermediate Streams.* Undesirable compounds, primarily those containing sulfur, are removed by treating processes such as hydrodesulfurizing and chemical treating. Some of the original sulfur compounds are converted to hydrogen sulfide (H2S), which can be separated and converted to elemental sulfur.

- *Blending Hydrocarbon Products.* Most petroleum products are a blend of hydrocarbon fractions or components produced by various refinery processes. Motor gasoline is a blend of various gasoline blending stocks, including butanes, reformate, alkylate, straight-run naphtha, thermally and catalytically cracked gasoline, oxygenates such as MTBE and ethanol and necessary additives. The fuel oils, lubricants, and asphalt products are blends of refinery base stocks.

- *Auxiliary Operating Facilities.* A number of refinery units are used to maintain normal operating conditions. These units support processes such as hydrogen processing, improve operating efficiency by allowing reuse of water and the use of sour gas as fuel, and help the refinery meet environmental standards. Included among the functions of auxiliary operating facilities are hydrogen production, light ends recovery, acid gas treating, sour water stripping, sulfur recovery, tail gas treating, and wastewater treatment.

- *Refinery Offsite Facilities.* Refinery offsite facilities are equipment and systems used to support refinery operations. These facilities include storage tanks, steam gen-

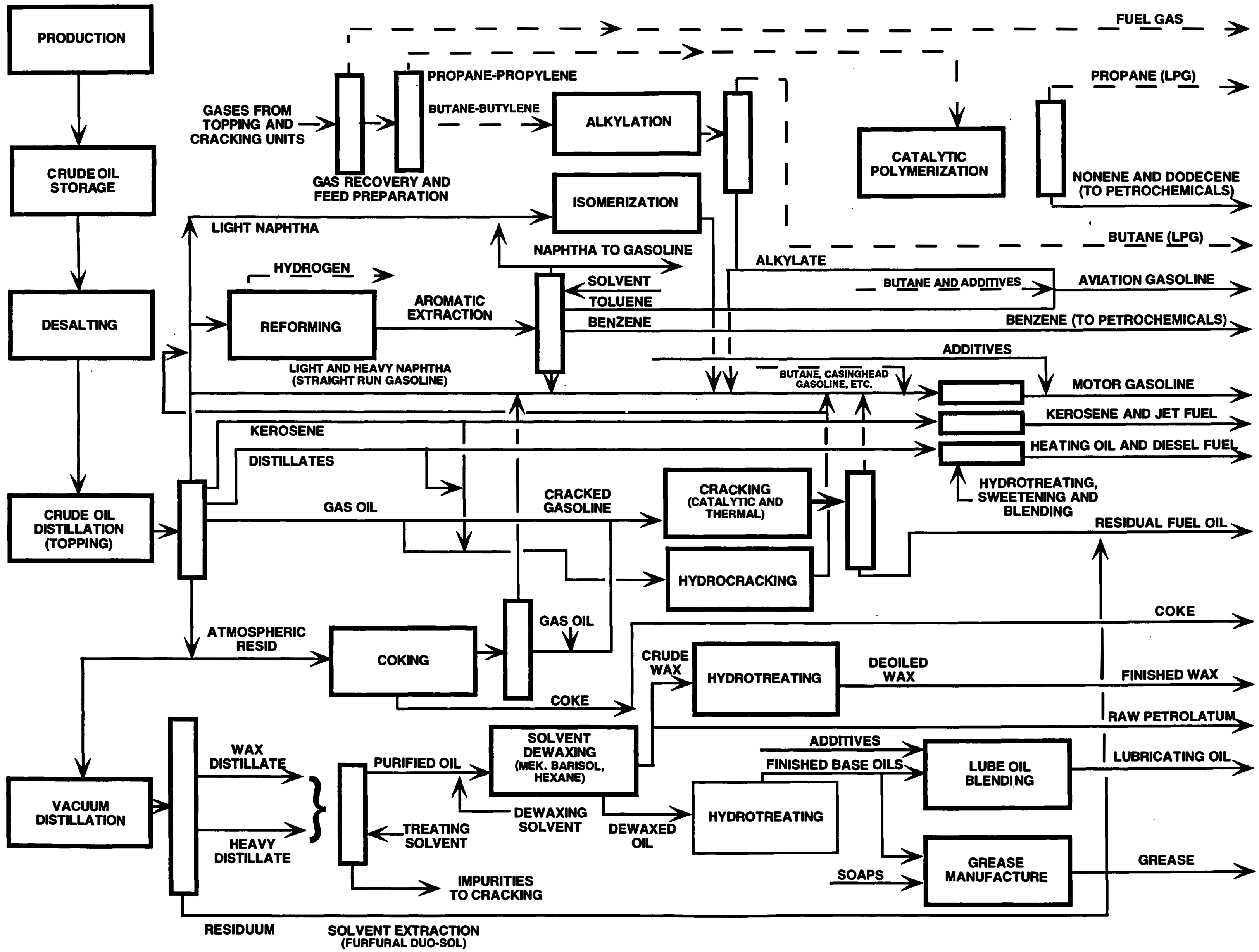


Figure H-10. Simplified Flow Chart of a Complex Refinery.

erating systems, flare and blowdown systems, cooling water systems, receiving and distribution systems, and refinery fire control systems. In addition, garages, maintenance shops, storehouses, laboratories, and necessary office buildings are considered offsite facilities.

- *Emission and Effluent Control.* Refineries generate air emissions, wastewater, solid waste, and noise, which must be controlled for efficient processing and environmental protection. The control of pollutants that can damage the environment is an important part of refinery operations.

Separation of Crude Oil

Following salt and water removal (desalting), crude oil is separated into the desired boiling range fractions by atmospheric and vacuum distillation.

Desalter

The desalter is normally the starting point of the separation process. The crude oil is pumped from tankage, preheated by heat exchange with various product streams (fractions), and sent to the desalter. Desalting removes inorganic salts from crude oil so that these salts will not contribute to the fouling and corrosion of process equipment. The process also removes the soluble trace metals present in the water phase, which can poison downstream process catalysts. Chemicals and water are added to the crude oil, and oil/water separation occurs by gravity in the presence of a high voltage electrostatic field. This helps agglomerate the water droplets, which contain the salts, and separates the water from the oil. The oil is removed from the top of the desalter vessel, and the water and sludge are removed from the bottom. The water is then sent to the wastewater treatment plant.

Atmospheric Distillation Unit

Crude oil from the desalter is pumped to a furnace where the oil is further heated and fed to the atmospheric distillation unit. All petroleum distillation processes are fundamentally the same and require the following equipment: heat exchangers; furnaces or other heaters; a fractionating tower or column; condensers and coolers; pumps and connecting lines; storage and accumulator tanks; and instrumentation. In adapting these units of equipment, many factors must be considered. Among the most important are:

- Boiling range of the stocks
- Heat stability of the stocks
- Product specifications.

As shown in Figure H-11, the atmospheric distillation tower separates the crude oil into fractions having specific boiling point ranges. The fractions with the lowest boiling range are recovered as overhead streams and are either fuel gas, light naphtha, or straight-run gasoline. These fractions are used as reformer feedstocks, isomerization feedstocks, gasoline blending stocks, petrochemical feedstocks, solvents, and LPGs. The intermediate boiling range fractions are gas oil, heavy naphtha, and distillates. These fractions are used to produce kerosene, diesel fuel, fuel oil, jet fuel, blending stocks, and catalytic cracker feedstocks. The high boiling point stream, or atmospheric bottoms, is used to produce No. 6 fuel oil, occa-

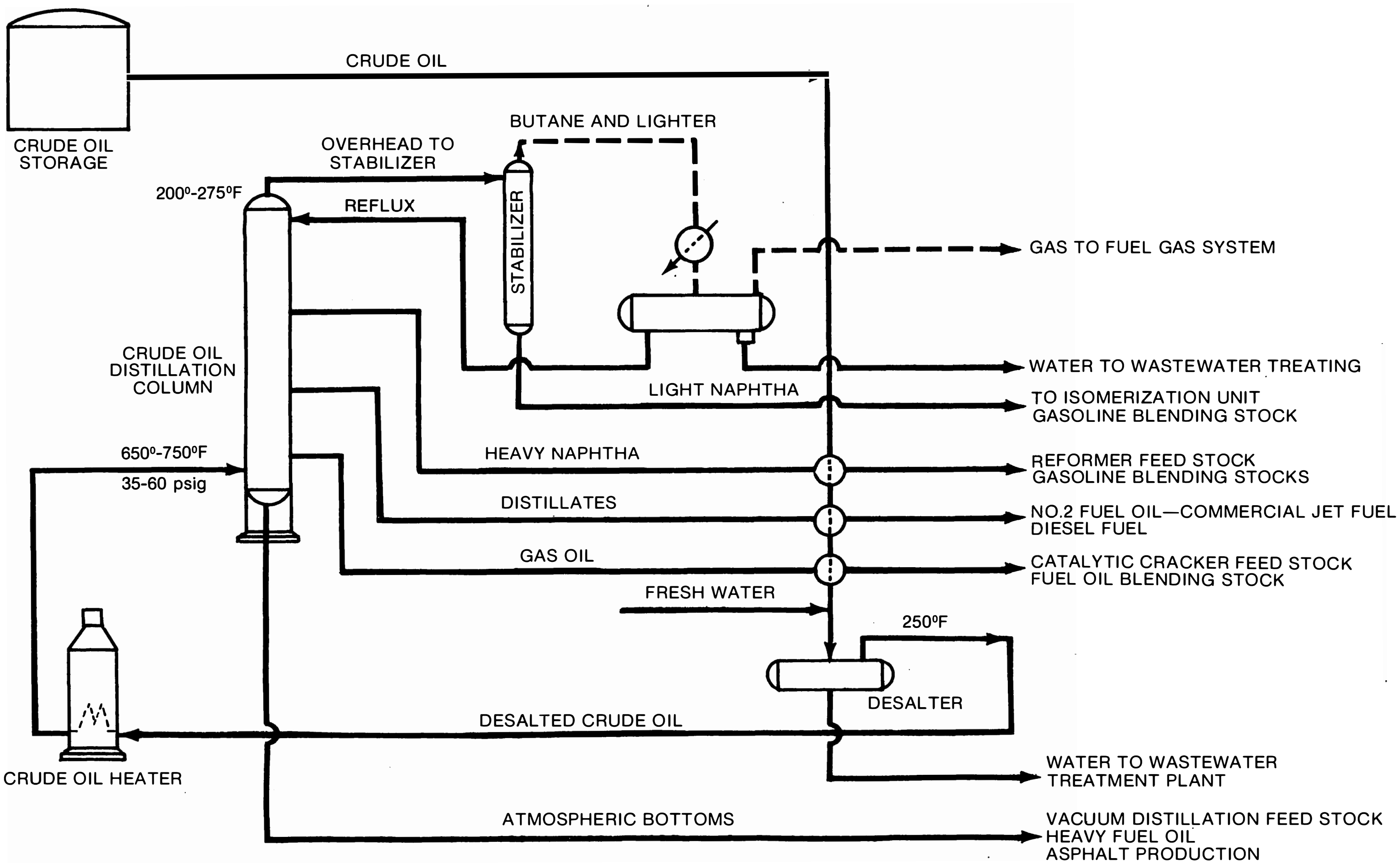


Figure H-11. Crude Oil Distillation Unit.

sionally as asphalt plant feedstock, or as feed a vacuum distillation unit for the recovery of wax distillates for cracking or lube feedstocks.

Vacuum Distillation Unit

The charge stock for the vacuum distillation unit (Figure H-12) is heated atmospheric bottoms from the crude oil distillation unit. The vacuum can be produced by using steam ejectors or vacuum pumps. The equipment commonly used are two-stage steam-jet ejectors and surface condensers. At the reduced pressure, the oil vaporizes at a lower temperature, allowing the distillation to occur with a minimum of high–temperature cracking.

The product streams from the vacuum tower include light vacuum gas oil, heavy vacuum gas oil, and vacuum tower bottoms or residuum. These streams can be further processed depending upon the desired products. The vacuum gas oil may be sent to the catalytic cracker to produce gasoline blending stocks, to fuel oil blending or it may be recovered for lube oil feedstocks. The vacuum bottoms may be used as fuel oil, used for the production of asphalt and lubricants, or sent to a coker for conversion to gasoline components, gas oils, coke, and gas.

Restructuring of Hydrocarbon Molecules

Restructuring processes change the size or structure of the hydrocarbon molecules, altering them into higher value products. The more common processes are:

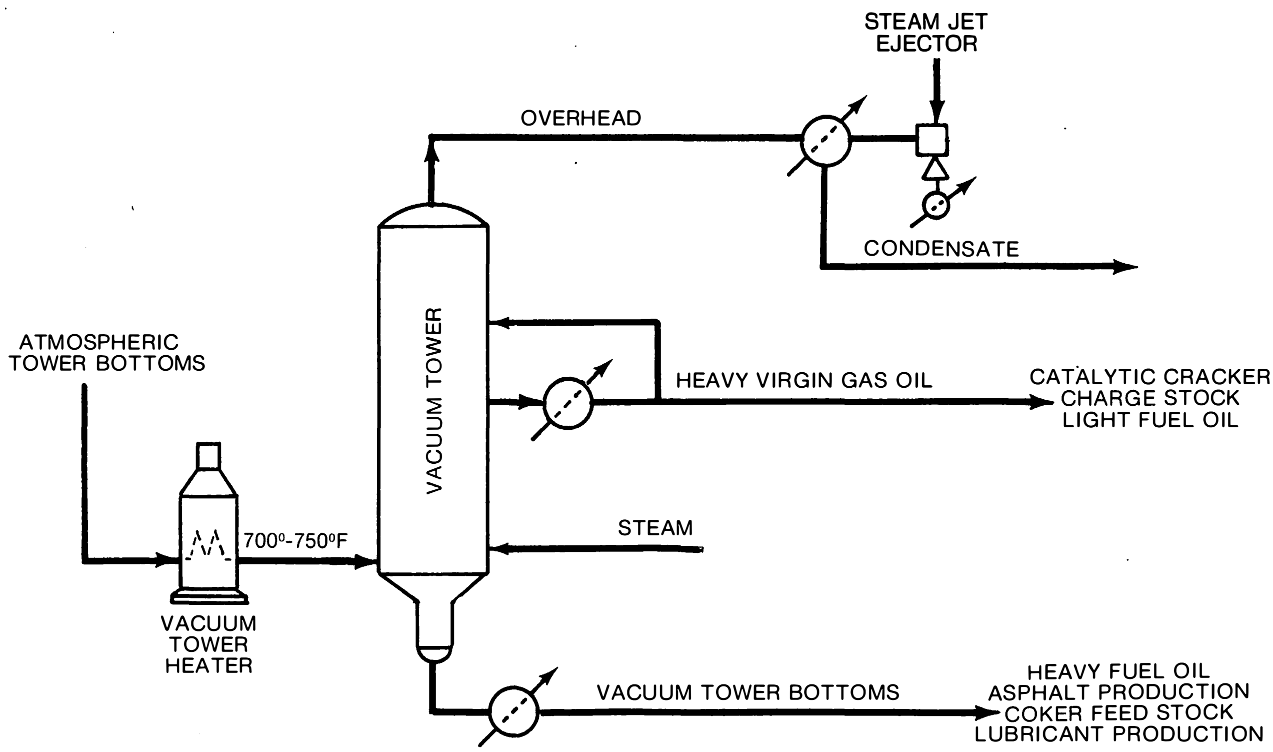


Figure H-12. Vacuum Distillation Unit.

- Conversion processes (thermal cracking, coking, viscosity breaking, catalytic cracking, and hydrocracking)
- Combining/Condensing processes (alkylation, etherification and polymerization)
- Rearranging processes (catalytic reforming and isomerization).

Conversion Processes

Conversion processes break large hydrocarbon molecules into smaller, lower-boiling-point molecules. During the process, some of the molecules combine to form larger molecules. The usual products of cracking are gaseous hydrocarbons, gasoline and jet fuel blending stocks, gas oils, fuel oils, and coke. Sour water generated is sent to the sour water stripping unit. The off-gases are treated by amine scrubbing, which removes the H2S. The H2S then is sent to the sulfur recovery unit.

Thermal Cracking. In the past, thermal cracking was accomplished solely by application of heat and pressure. The thermal cracking process was widely practiced during the 1920-1950 period. Today, thermal cracking is practiced mostly in two forms, coking and viscosity breaking.

Coking. Coking is a severe form of thermal cracking. There are two coking processes that are employed extensively–delayed and fluid coking. Coking is accomplished at a high temperature and low pressure. It is a valuable process for upgrading heavy charge stock such as residual and very heavy crude oils to cracking feedstocks and fuel oil components. In the coking unit, atmospheric bottoms or vacuum residuum are cracked to produce fuel gas, gasoline blending stocks, gas oils, and petroleum coke. A delayed coking unit is shown in Figure H-13.

The coker charge is fed directly to the fractionator, where the feed combines with the heavy recycle oil from the coke drums. The combined feed is pumped to the coker furnace, where it is heated. This heating produces partial vaporization and mild cracking. The liquid/vapor mixture then fills the coke drum, the flow is stopped and the liquid undergoes further cracking/condensation converting it to hydrocarbon vapors and coke.

The delayed coking unit typically has one or more pairs of coke drums. In normal operation one drum is in service while the other is being decoked. Decoking involves cooling the coke, and then cutting it from the drum with a high-pressure water drill. The coke and water drop from the drum into a pit where the coke dewaters, and the cutting water is recovered for reuse. The coke is loaded into transport vehicles or is stored offsite.

Fluid coking is a similar thermal cracking process, producing similar products, but coking occurs in a fluid bed. This is a continuous process, unlike delayed coking. Flexicoking is a fluid caking variant in which the coke is converted to a low Btu-value fuel gas. Only a small quantity of ash or coke residue is produced.

Viscosity Breaking. Viscosity breaking, or visbreaking, is a mild form of thermal cracking that is used primarily to reduce the viscosity of heavy fuel oil. The decomposition process is usually conducted at lower cracking temperatures (860–F to 900–F). This process produces small amounts of gasoline blending stocks, gas oil, and a high yield of fuel oils.

Catalytic Cracking. Catalytic cracking uses a catalyst in combination with high temperatures to convert atmospheric and vacuum gas oils and stocks derived from other refinery

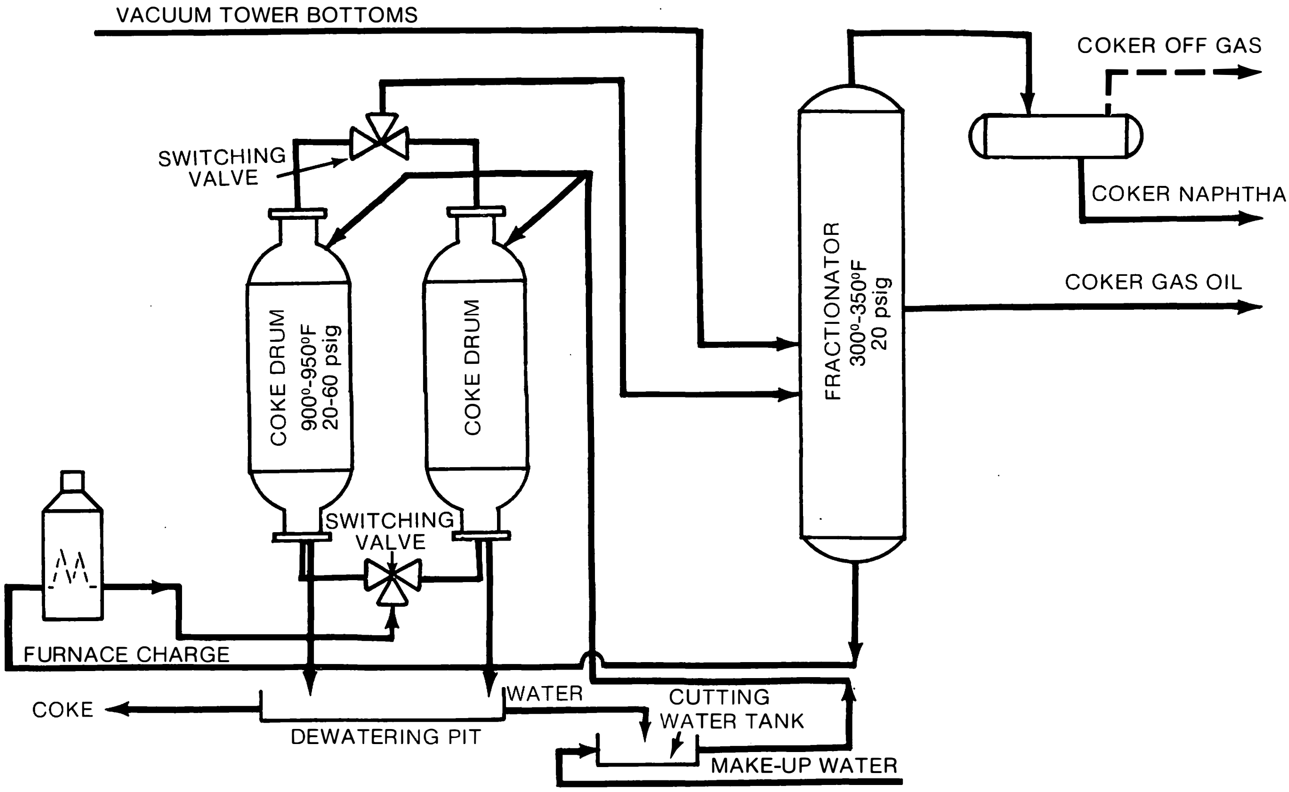


Figure H-13. Delayed Coking Unit.

operations into fuel gases, light gases, and gasoline and distillate fuel components. This process normally takes place in the fluid catalytic cracking unit (FCCU). Olefin-rich light gases are normally directed to alkylation, etherification or polymerization operations to produce high-octane gasoline blending stocks. Typically, yields of gasoline boiling range products will exceed 50 to 65 volume percent of the FCCU feed.

A typical FCCU is shown in Figure H-14. While there are many FCCU designs currently in use, they employ similar operating principles. The process employs a catalyst in the form of micron sized particles which behave as a fluid when aerated with a vapor. The catalyst is circulated between the reactor and the regenerator continuously. With the advent of more active zeolitic catalysts, the recent trend has been to design the units so that more of the cracking occurs in the riser section of the reactor, reducing the size of the overall unit or increasing capacity of older units.

The catalyst used in the process must be continuously regenerated to remove coke that forms on its surface during the reaction. This is done in a separate regenerating vessel by passing air through the catalyst to burn off the coke. The catalytic regeneration produces carbon monoxide (CO2), carbon monoxide (CO), sulfur oxides (SOx), nitrogen oxides (NOx), and particulates. Many installations recover energy from the process through the use of CO boilers and gas turbines.

Hydrocracking. Hydrocracking differs from catalytic cracking in five distinct ways: fixed catalyst beds are used, hydrogen is used in the process; operating pressures are substantially higher; temperatures are somewhat lower; and a different type of catalyst is employed.

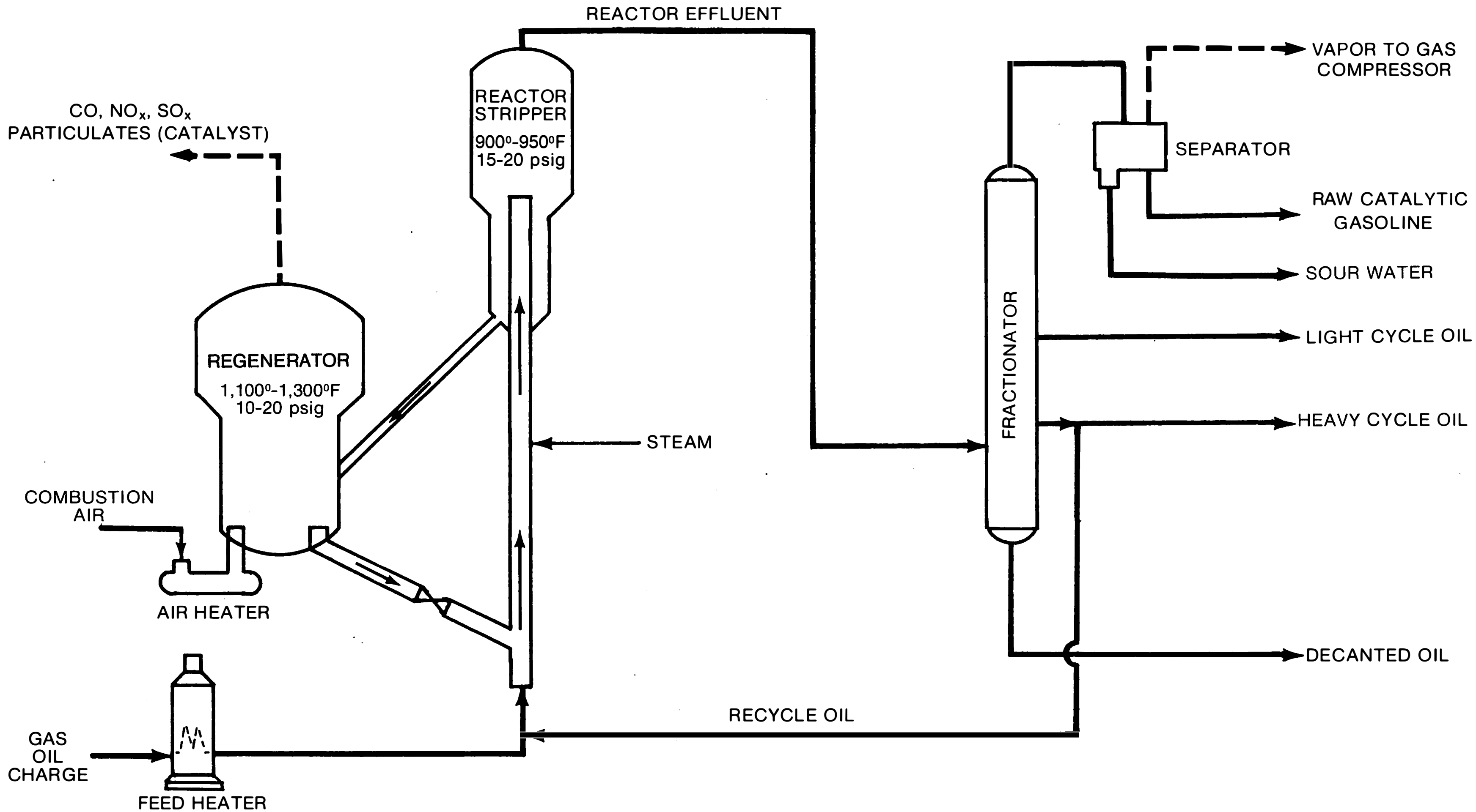


Figure H-14. Fluid Catalytic Cracking Unit.

The process has an advantage over catalytic cracking in that high-sulfur feedstocks are concurrently desulfurized. The yield of specific products will depend upon how the hydrocracking unit is operated. For example, yields of jet fuel plus diesel fuel equal to approximately 85 to 90 volume percent of feed can be achieved, with concurrent production of LPG and gasoline. Alternatively, the unit can produce all gasoline components. The process accepts a variety of feedstocks, including naphthas, gas oils, and heavy aromatic feedstocks. Hydrogen used for this process is generated by a hydrogen plant or is a byproduct from the catalytic reformer. A typical two-stage hydrocracker is shown in Figure H-15.

Combining Condensing Processes. These processes use small hydrogen-deficient molecules (olefins) that are recovered from thermal and catalytic cracking to produce more valuable gasoline blending stocks.

Alkylation. The alkylation process combines light olefins, preferably butylenes, or a mixture of propylene and butylene and occasionally amylenes, with isobutane to produce a blending stock that is one of the highest quality components of motor gasoline. The final product, called alkylate, has excellent antiknock and low emission properties. It is clean burning, has high Research and Motor method octane number ratings, and has excellent performance ratings. The union of the olefins and isobutane takes place in the presence of a catalyst, either hydrofluoric or sulfuric acid, under conditions selected to maximize product yield and quality.

The process using hydrofluoric acid as the catalyst is shown in Figure H-16. The unit feed, consisting of C3 and C4 olefins and isobutane, is mixed with recycled acid and fed to the reactor-settler where the alkylation reaction takes place. The combined products are sent to a fractionator where the alkylate product is separated from the unreacted feed, catalysts that carry over, and propane and butane that was formed by the reaction. The product or alkylate may first be debutanized before being sent to storage for gasoline blending.

The process using sulfuric acid is somewhat similar and at the same operating conditions the products are also similar. The choice of the process for a given location is dependent on several factors including environmental restrictions, cost of acid and disposal and safety.

Etherication. Ethers such as MTBE, ETBE and TAME can be manufactured in the refinery from refinery iso-butylene or iso-amylenes and purchased methanol or ethanol. MTBE has been used as an octane enhancer. Because of environmental legislation, it is being used as an oxygen carrier. It is an attractive gasoline component as it has an octane blending number of about 108 (R+M)/2 and a RVP of 8 psi. Similarly TAME is being considered for this purpose - octane blending number of about 105 (R+M)/2, RVP about 3-5 psi. ETBE properties are also in these ranges.

Polymerization. Polymerization combines light olefins from thermal and FCC units to form hydrocarbons of higher molecular weight. Two molecules of isobutylene (C_4H_8) may be combined to form one molecule of di-isobutylene (C_8H_{16}). This product, formed by the union of two olefin molecules, is called a dimer. That formed by three such molecules is known as a trimer. Two unlike olefins may also be combined, resulting in a product known as a copolymer. Byproduct gases are used to produce a wide variety of products ranging from gasoline blending stocks to solids that can be used as plasticizers. Polymerization of a mixture of propylene and butylene to produce a blending stock for gasoline is the most common polymerization operation. The most commonly used process employs phosphoric acid as a catalyst.

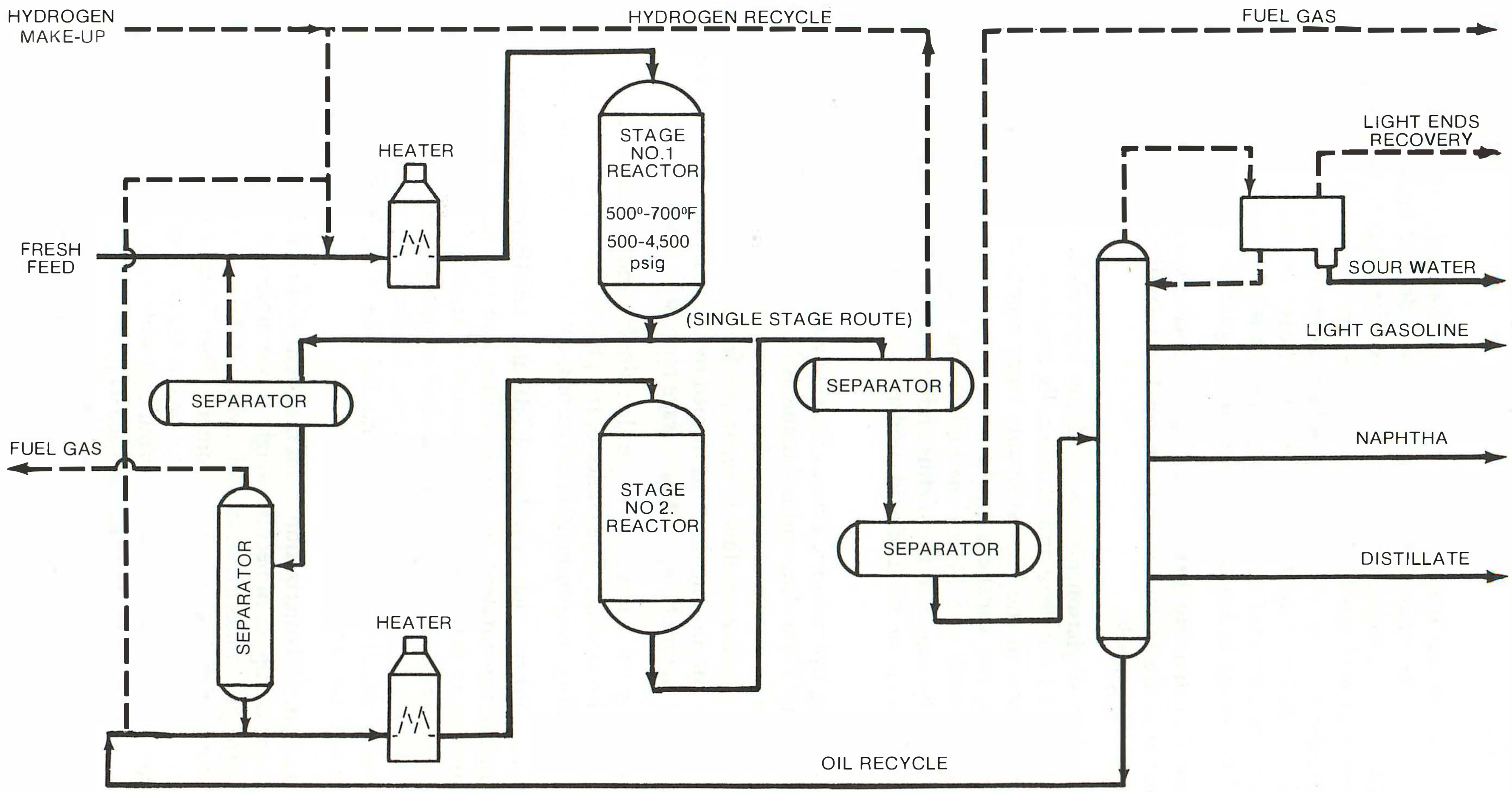


Figure H-15. Typical Two-Stage Hydrocracker Unit.

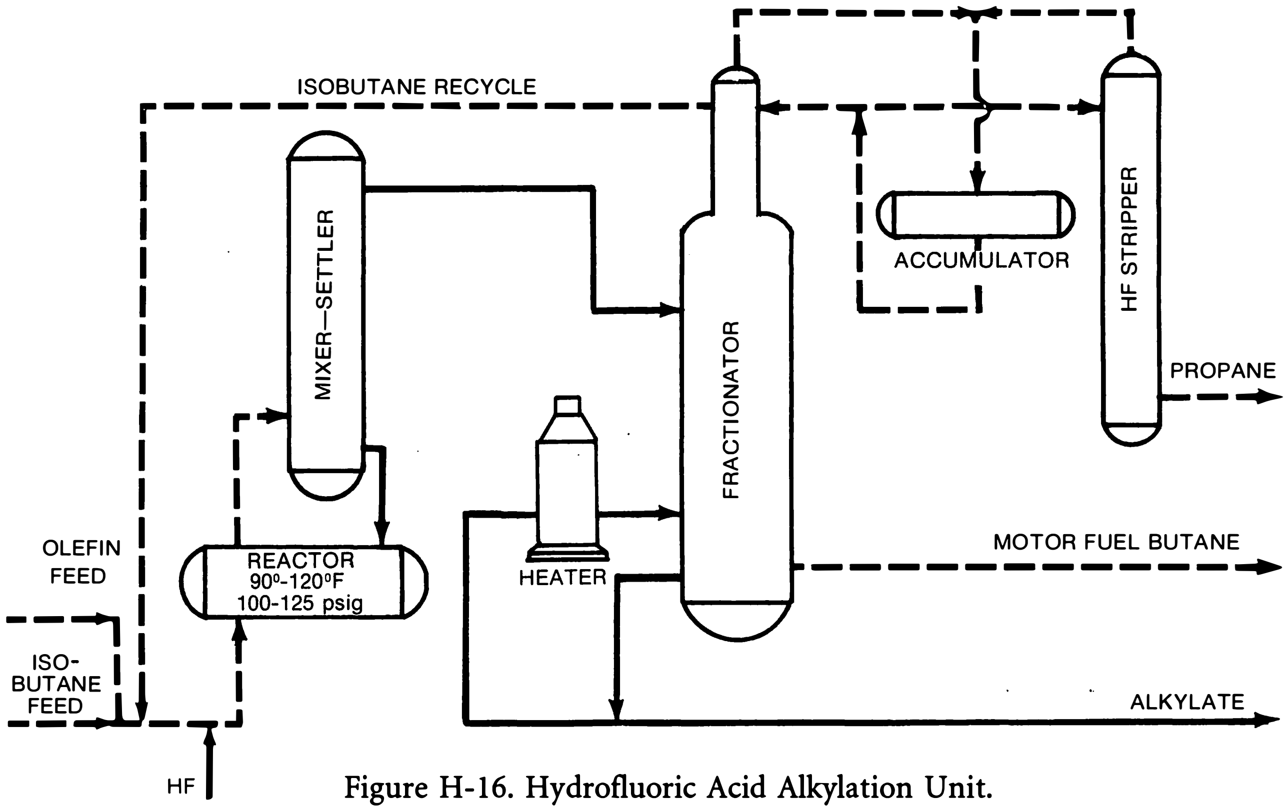


Figure H-16. Hydrofluoric Acid Alkylation Unit.

Rearranging Processes

Rearranging processes are those in which the molecule is changed to produce a product of different characteristics. The two most widely used rearranging processes are catalytic reforming and isomerization.

Catalytic Reforming. Catalytic reforming is a process used to upgrade low-octane naphthas to produce high-octane blending stocks or high yields of aromatic hydrocarbons for petrochemical feedstocks (i.e., benzene). The final product will depend on reactor temperature and pressure, the catalyst used, and the hydrogen recycle rate. Reforming catalysts contain platinum and other noble metals and are readily deactivated (poisoned) by sulfur and nitrogen, so the feedstock must be pretreated before being charged to the reforming unit.

Catalytic reforming is the octane number generator for most gasoline-oriented refineries with the end of the use of lead additives. The gasoline blending stocks from other operations such as FCCU, alkylation, hydrocracking, and polymerization are of relatively fixed octane number quality. The catalytic reforming process is capable of efficiently yielding gasoline blending stocks within an octane number range from the low 80s to over 100 Research clear (unleaded). As operation severity is increased to raise the octane number, gasoline yield decreases. Based on the gasoline produced per unit of feedstock, typical yields can range from 70 to over 90 volume percent for high-to low-octane-number operations. This process also generates hydrogen that is required for many of the operations employed in modern refineries.

A typical catalytic reforming unit is shown in Figure H-17. The naphtha feedstock is mixed with recycle hydrogen-rich gas, heated in a furnace, and fed to the first reactor. Because the reforming reaction requires heat (endothermic), the product must be reheated before entering the next reactor. This process typically is repeated in three subsequent reactors. The liquid product passes to a separator to remove the hydrogen-rich gas and then to a stabilizer for final separation of light gases and product. The reformate product then goes to storage for blending into gasoline. The light gases, consisting of mostly propane and butane, are sent to the light ends recovery unit.

The catalyst requires regeneration, which may be accomplished by utilizing a swing reactor, as shown in Figure H-17. As in hydrotreating and FCCU, coke deposited on the catalyst surface is burned off under controlled conditions.

Isomerization. Isomerization units are employed to convert n-butane, n-pentane, and n-hexane (low-octane, straight chain hydrocarbons) to high-octane, branched chain isomers.

Figure H-18 shows a typical light naphtha isomerization process. In this process, desulfurized pentane/hexane (Cs/C6) mixtures are fed to the de-isopentanizers to remove the isopentane present in the feed. The n-pentane and n-hexane mixture is dried, mixed with organic chloride catalyst promoter and hydrogen, and fed to the reactor. The product is cooled and fed to a separator, where excess hydrogen is removed to be recycled. The product is then fed to a stabilizer to remove low-boiling light hydrocarbons. The stabilizer bottom products are used for gasoline blending stocks or may be further fractionated to remove unreacted n-pentane, n-butane, and n-hexane for recycling.

Treating Intermediate Fractions

With continuing emphasis on producing greater yields of higher octane gasoline and low-sulfur fuel oil, it is necessary to upgrade materials that are used directly as gasoline components or blended into fuel oil. Components such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as high-sulfur naphthas and distillates from crude oil distillation containing sulfur and nitrogen, require treating.

Hydrodesulfurization

Hydrodesulfurization is a catalytic process used to remove sulfur, nitrogen, olefins, arsenic, and lead from liquid petroleum fractions. Typically, hydrodesulfurization units are employed before such processes as catalytic reforming because the process catalysts used in reforming become inactive if the feedstock contains these impurities. Hydrodesulfurization may be used before catalytic cracking to reduce the sulfur emissions from the regenerator and improve product yields. It may also be used to upgrade petroleum fractions into finished products such as kerosene, diesel fuel, and fuel oils.

Hydrodesulfurization processes are used on a wide range of feedstocks from naphtha to heavy residual oils. In general, the hydrodesulfurizing of cracked process streams requires greater quantities of hydrogen than does hydrodesulfurizing of virgin crude oil fractions. Higher severity operations providing increased removal of the impurity require higher pressures and temperatures.

In a typical hydrodesulfurizing process (Figure H-19), the feed is mixed with make-up hydrogen from the reformer or hydrogen manufacturing plant. The mixture is heated and

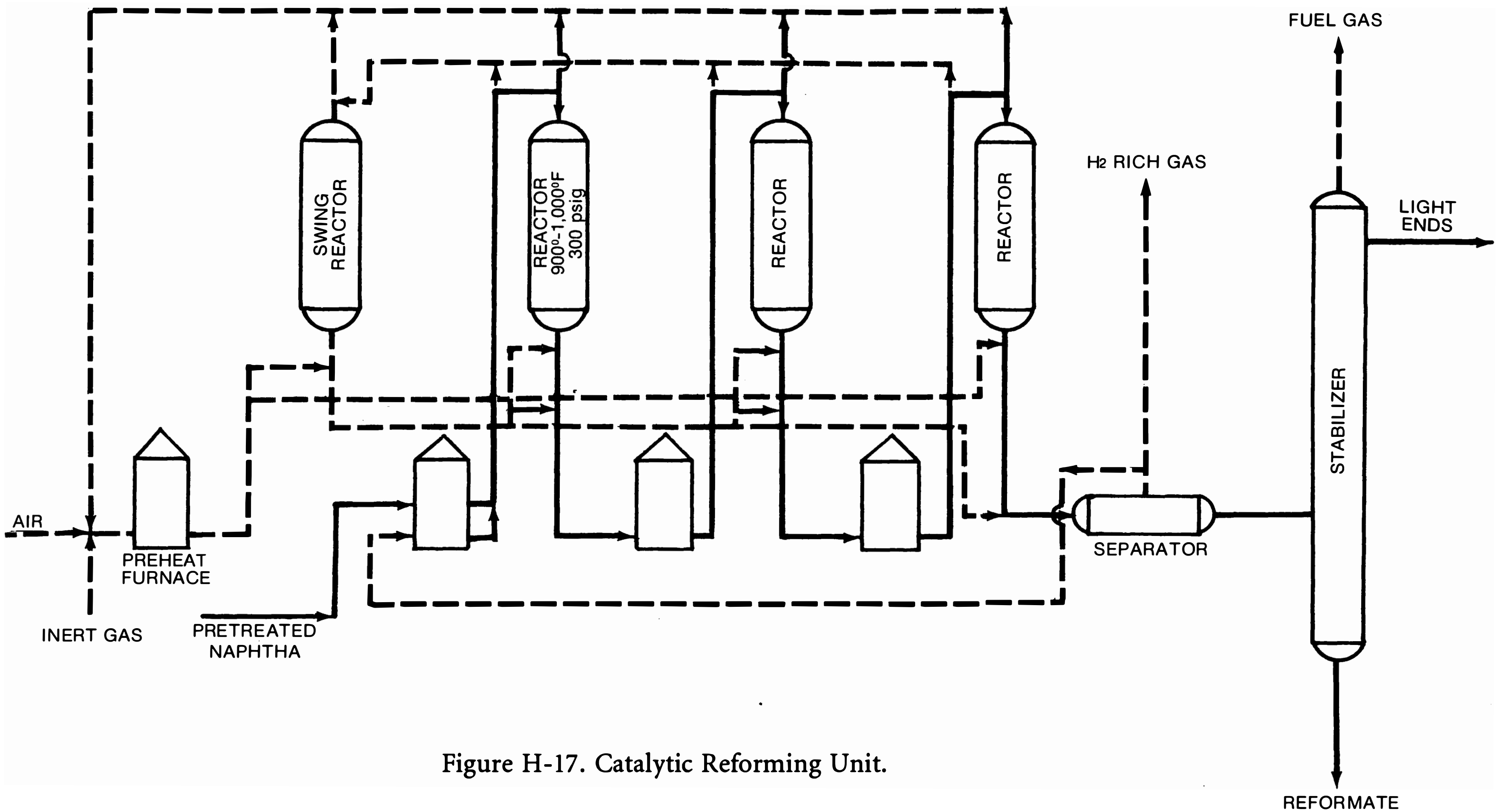


Figure H-17. Catalytic Reforming Unit.

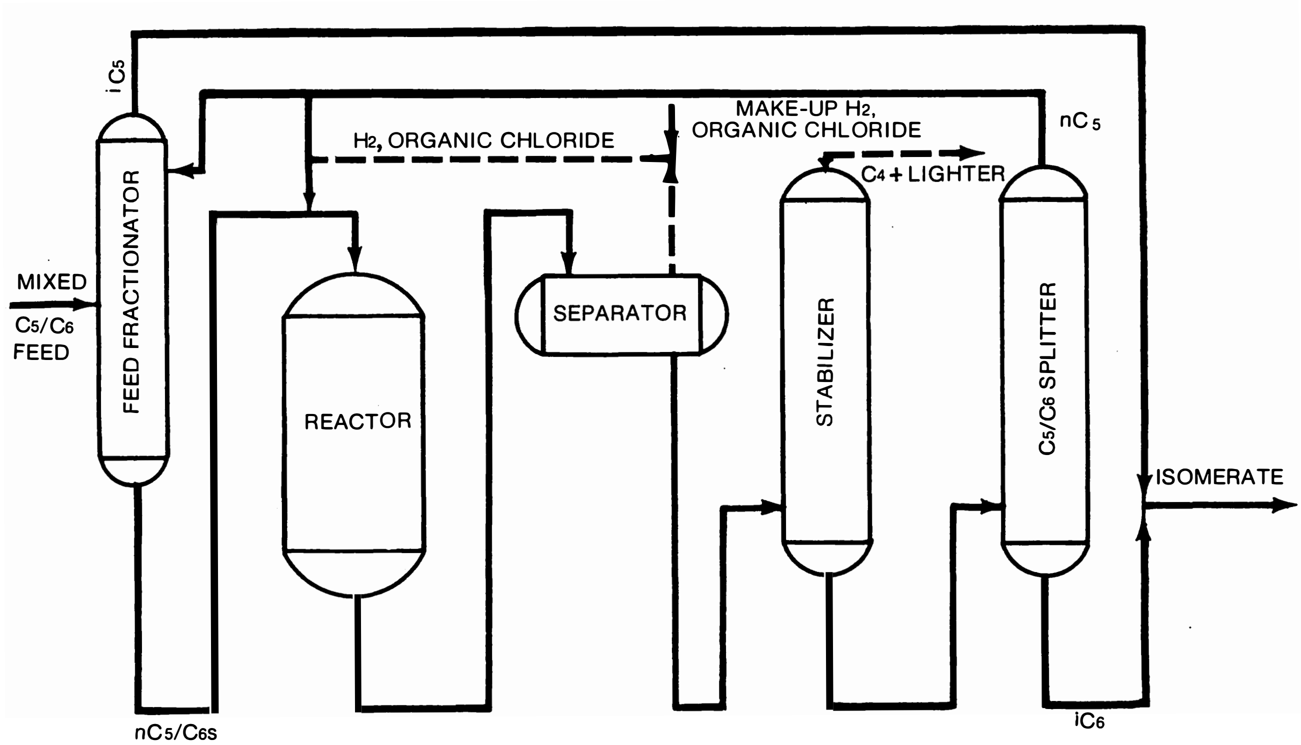


Figure H-18. Pentane/Hexane (C5/C6) Isomerization Unit.

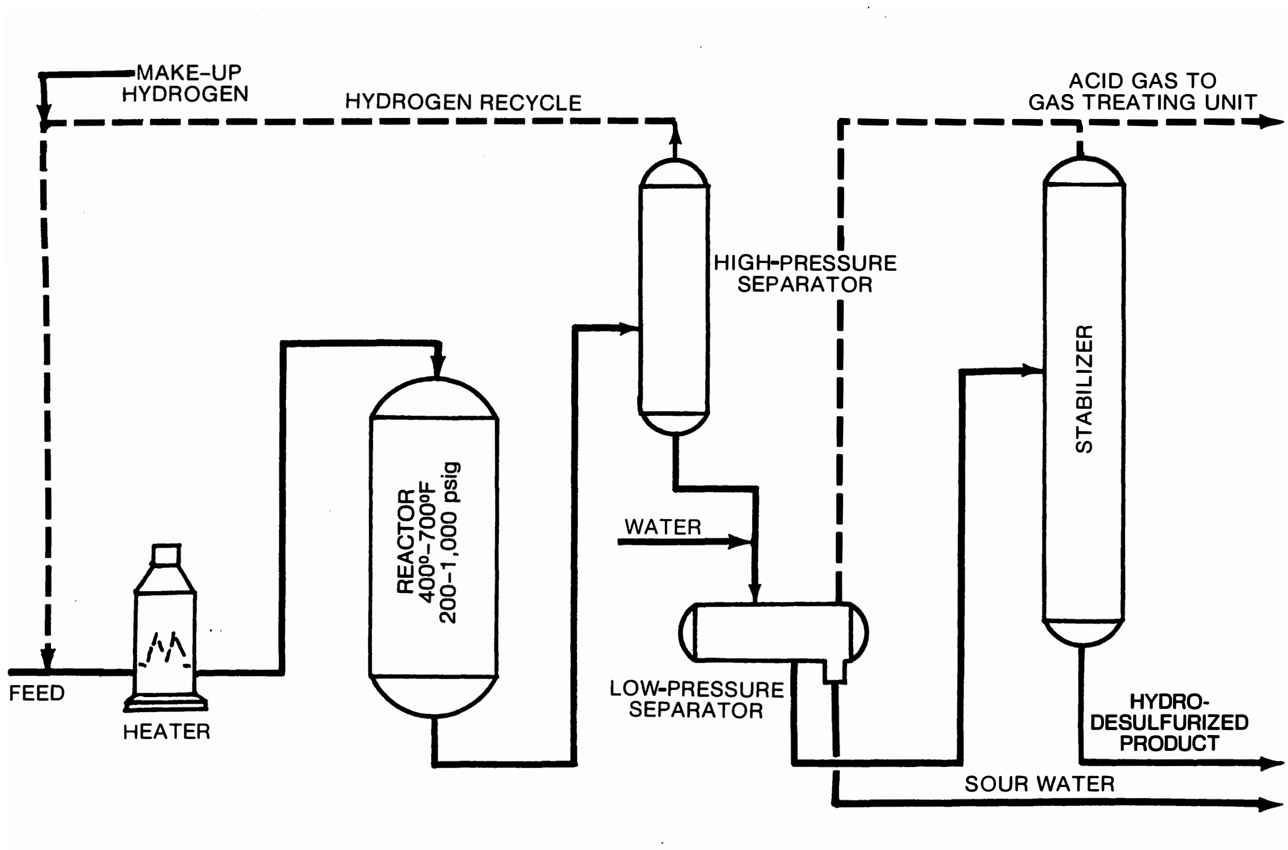


Figure H-19. Hydrodesulfurizing Unit.

fed to the catalyst reactor, where sulfur and nitrogen are converted into H2S and ammonia (NH3).

Product from the reactor goes to the high-pressure separator, where excess hydrogen is flashed off and returned to the reactor. The product then passes to the low-pressure separator where H2S, NH3, noncondensable hydrocarbon gases, and hydrogen are removed. The gases from the low-pressure separator are sent to the gas treating system to remove H2S. The liquid product is then sent to the stabilizer where the remaining light material is stripped and is sent to the fuel gas treating system. The sour water generated during the process is sent to the sour water stripping unit.

Chemical Treating

The use of chemical treating to remove sulfur from petroleum fractions has declined as hydrodesulfurization has increased. Chemical treating processes are used, however, to remove such impurities as carbon dioxide (C02), oxidants, and various corrosive compounds from processing systems.

A variety of gasoline sweetening (mercaptan removal) processes are available. The most widely used process employs sodium hydroxide with added catalysts or promoters (Figure H-20). The process converts the mercaptans to less objectionable disulfides. The use of sweetening is primarily dependent upon the sulfur and/or mercaptan content of the crude oil, the sulfur specification of the gasoline, and whether the original feedstock had been hydrodesulfurized prior to catalytic cracking.

Blending Hydrocarbon Products

The last major step in the refinery operation is the blending of various fractions into finished products. All grades of motor gasoline are blends of various fractions, including reformate, alkylate, straight-run gasoline, thermally and catalytically cracked gasoline, coker gasoline, butane, and necessary additives. Furnace oil and diesel fuels may be blends of virgin distillates and cycle oil. Jet fuels may be straight-run virgin distillates or include naphtha in the blend. The vast number of lubricating oils are blends of a relatively small number of refined based stocks plus additives to impart specific properties to most crankcase and specialty lubricants. In some cases these additives may total more than 15 to 20 percent of the finished lubricant. Asphalt is blended from select residual base stocks according to the application desired.

For example, in gasoline blending, the components or blending stocks from the process unit, such as butane, alkylate, isomerization stock, reformate, catalytic gasoline, naphtha or straight-run gasoline, coker gasoline, ethers, alcohols, and additives, are blended to meet gasoline specifications. The mixing of the components is normally accomplished by automated inline blending (Figure H-21). Gasoline blending components are fed into a system of proportional metering pumps and control valves to the gasoline header. The metering pumps ensure that each component is fed in the proper proportion. The components are mixed by the flow turbulence in the header and sent to a series of on-stream analyzers, which continually monitor the product for octane number and vapor pressure. The monitors automatically control the metering systems to ensure proper portions of each component.

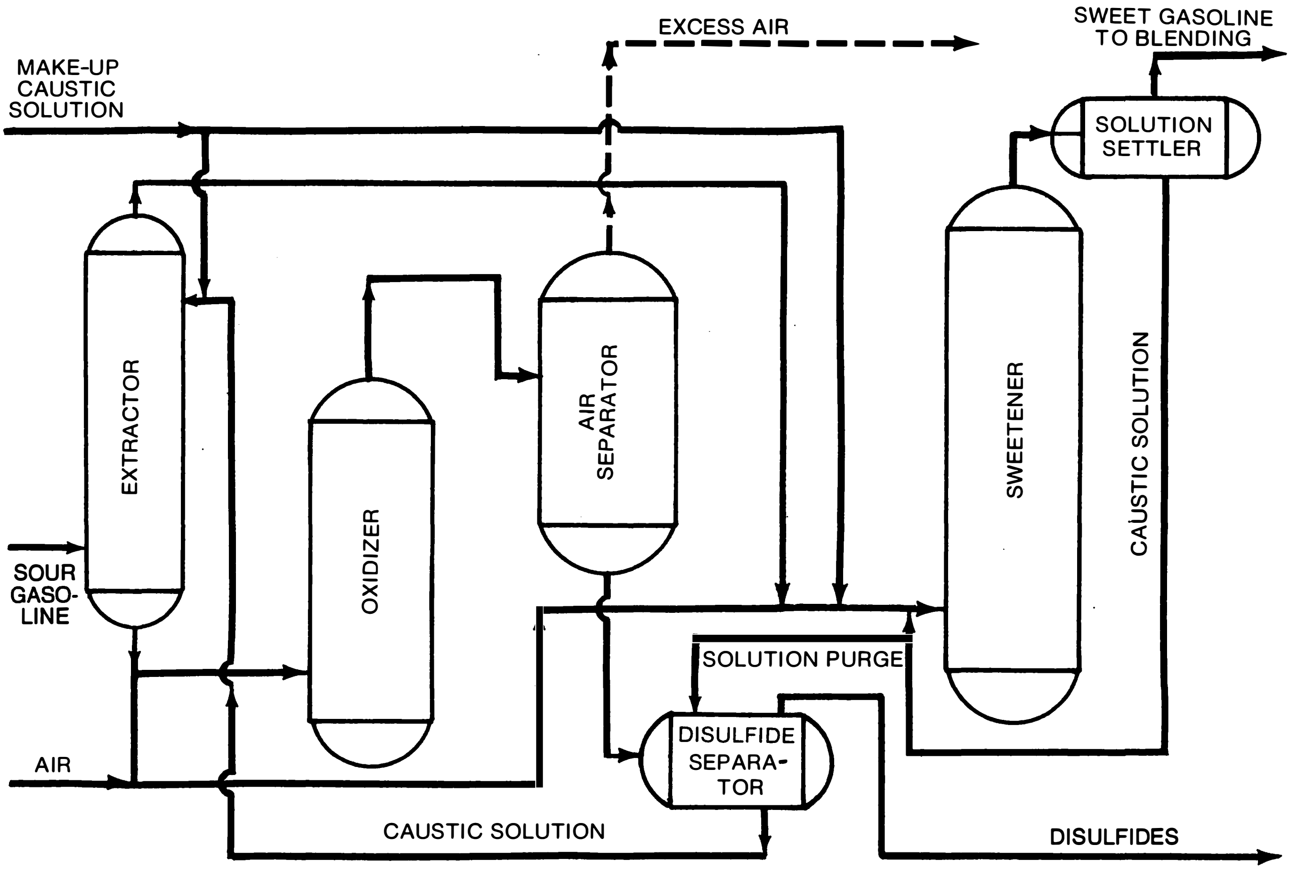


Figure H-20. Gasoline Sweetening Unit.

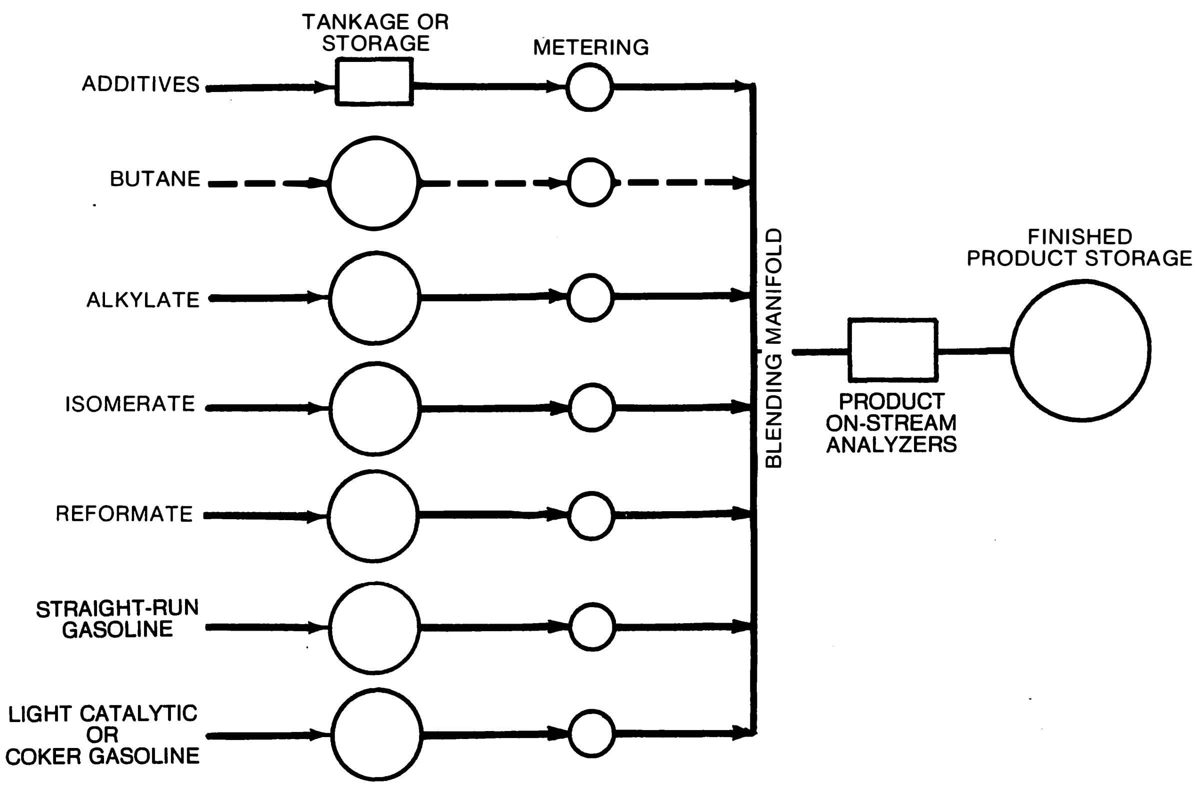


Figure H-21. Gasoline In-Line Blending System.

Auxiliary Operating Facilities

Auxiliary operating facilities are necessary to support process units requiring hydrogen, collect and treat gases for refinery fuels, control air emissions, meet water effluent standards, and re-use water.

Hydrogen Manufacturing Unit

Hydrogen is required for a number of refining units, including hydrodesulfurization, hydrocracking, and isomerization. The primary source of hydrogen in most refineries is the catalytic reforming process. Additional hydrogen may be produced by the steam reforming of available hydrocarbons such as methane, refinery fuel gases, propane, butane, or desulfurized light naphtha, or by the partial oxidation of heavier hydrocarbons.

The flow diagram for manufacturing hydrogen by the steam reforming process is shown in Figure H-22. The hydrocarbon feed to the unit normally contains traces of sulfur, which are removed by absorption or activated carbon. The removal of the sulfur is necessary to avoid poisoning the process catalyst.

Desulfurized hydrocarbon (methane, naphtha, etc.) are mixed with steam and passed through catalyst-filled tubes in the reformer furnace. The reformer gas containing hydrogen, CO, CO2, and excess steam is passed through a shift converter where CO and steam are converted to hydrogen and CO2. The CO2-rich gas is treated with an alkaline stream to absorb practically all the CO2, yielding 95-98 percent pure hydrogen with the balance principally methane with trace amounts of carbon oxides. The hydrogen stream is sent to the methanator for conversion of the carbon oxides to methane and then to compression.

In the manufacture of hydrogen by the partial oxidation process, the feed to the units is typically bottom products from the atmospheric or vacuum distillation unit or other heavy stream such as heavy coker gas oil. This process avoids using more valuable hydrocarbons as hydrogen plant feedstock.

In the partial oxidation process, the residual oil is fed to a combustion chamber where it is partially burned in the presence of steam and oxygen. Gases leaving the combustion chamber are composed primarily of hydrogen and CO and have a temperature of 2,000–F to 2,800–F. The gases are then quenched with water and steam, desulfurized, and fed to a shift converter for further conversion of the CO and steam to hydrogen and CO2. The hydrogen stream is then purified by CO2 absorption and methanation.

Light Ends Recovery Unit

The term "light ends" refers to light hydrocarbon gases having four or fewer carbon atoms in the molecule. These include methane, ethane, propane, and butane. Included in this group are C3 and G4 olefins and isobutane. The purpose of this unit is to separate these gases for further use in product refining.

The flow diagram for the unit is shown in Figure H-23. The feed to this unit is desulfurized gases that have been collected from the various process units. The gases are first liquefied by compression and cooling, then sent to a surge drum to remove condensed moisture. The mixture is pumped to the de-ethanizer where methane and ethane are separated from the mixture and recovered for refinery fuel. The de-ethanized bottoms are sent to the

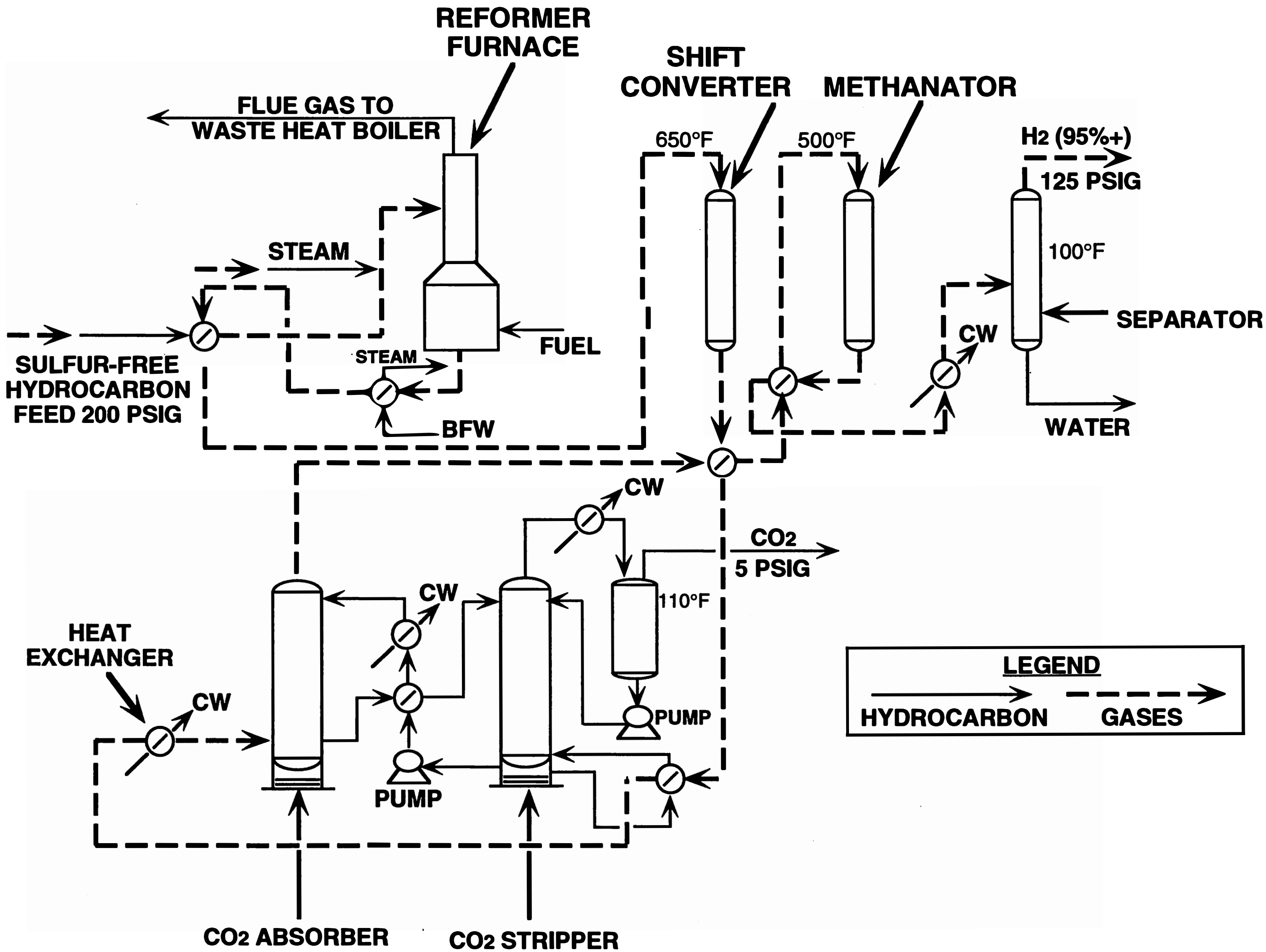


Figure H-22. Hydrogen Manufacturing Unit.

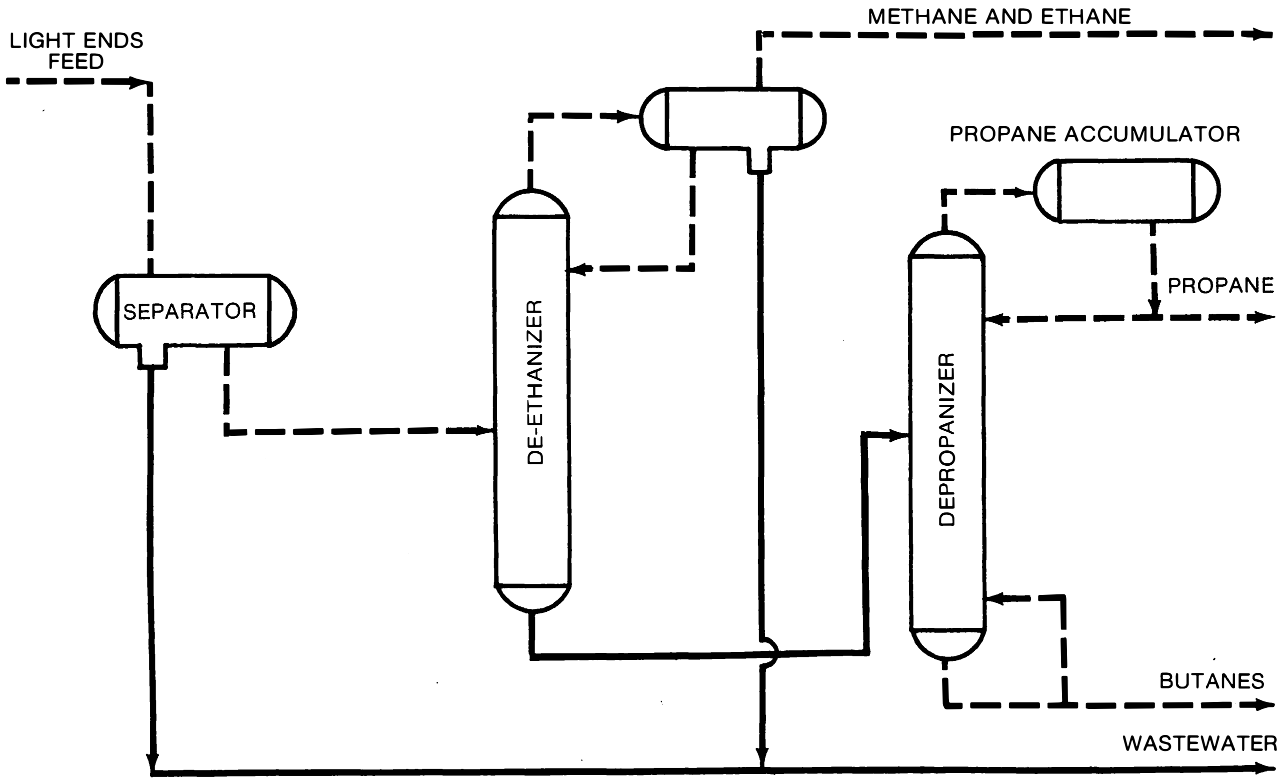


Figure H-23. Light Ends Recovery Unit.

de-propanizer, where propane and butanes are separated. These streams may be further processed to separate the olefins and isobutane from the propane and normal butane. The propane is recovered for LPG and normal butane is sent to gasoline blending.

Acid Gas Treating Unit

H2S and CO2 are acid gases, and a fuel gas stream containing these compounds is called sour gas. Sour gas is produced in several refinery processes, including catalytic cracking and hydrotreating. Refinery-produced gas is generally sour and it is sometimes necessary to remove H2S before use as a refinery fuel in order to comply with environmental standards.

Acid gas is typically removed by absorption in alkaline solution. A typical acid gas treating system is shown in Figure H-24. The alkaline material is chosen so that the chemical bond formed during absorption can be broken by heating to regenerate the solution. Absorption solutions containing acid gas are termed "rich" and the regenerated solutions are termed "lean." The most widely used absorbents in the refinery are monoethanol amine and diethanol amine. The processes differ only in the absorbents used.

Sulfur Recovery Unit

The sulfur recovery plant is used to convert H2S to elemental sulfur. The most widely used recovery system is the Claus process, which uses both thermal and catalytic conversion reactions.

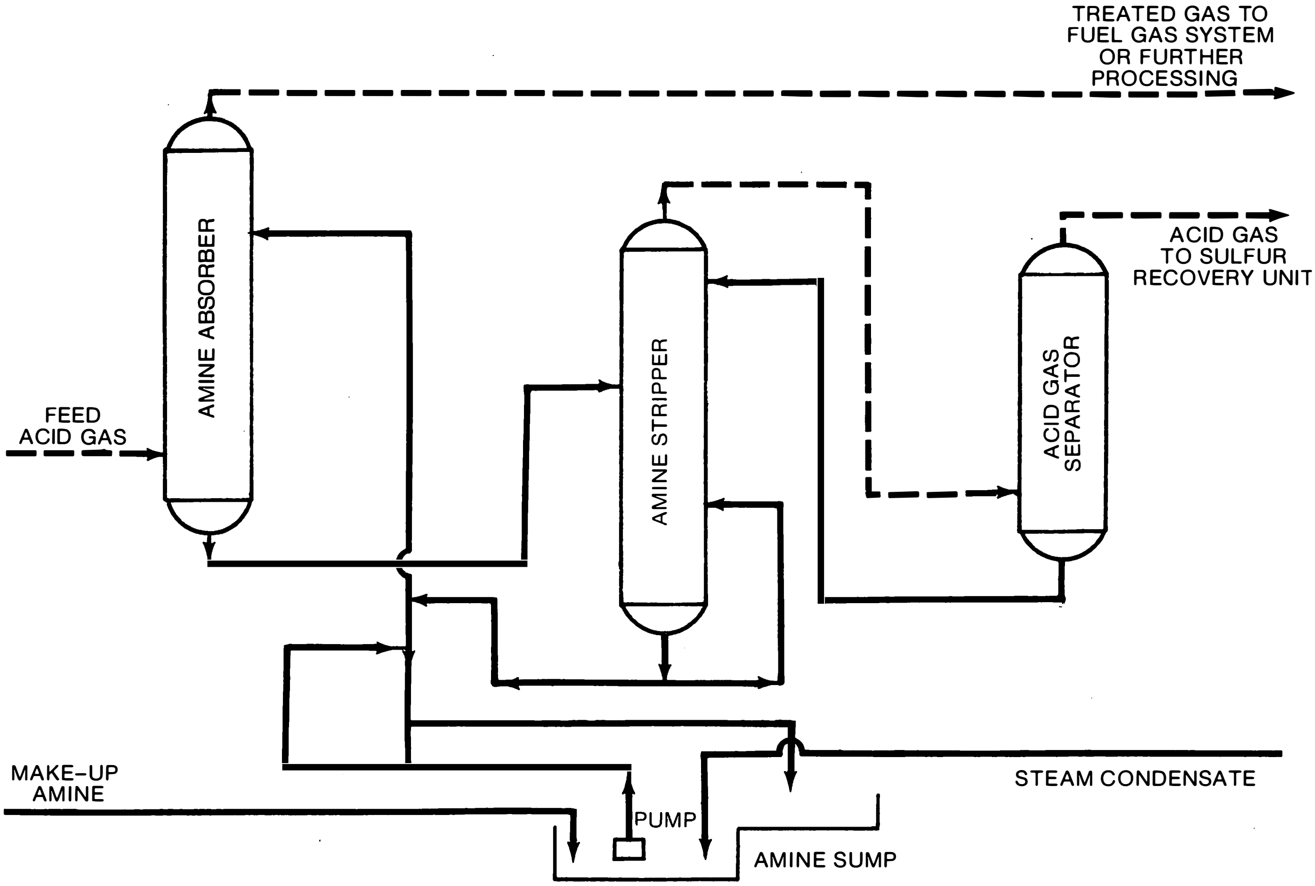


Figure H-24. Acid Gas Treating Unit.

Tail Gas Treating Unit

Many processes are available to treat tail gas from the Claus sulfur recovery unit. They include the Beavon-Stretford, Shell Claus Off-Gas Treatment, and Wellman-Lord processes.

Sour Water Stripping Unit

Water containing sulfides and ammonia is called "sour water condensate." Refinery operations produce sour water from processes such as catalytic cracking and hydrotreating and whenever steam is condensed in the presence of gases containing H2S. Sour water usually contains H2S, NH3, and small amounts of phenol and other hydrocarbons. Sour water stripping is used to reduce H2S and NH3 levels.

There are many different stripping methods, but most of them involve the downward flow of sour water through a trayed or packed tower while an ascending flow of stripping steam or gas removes the H2S and NH3. A typical sour water stripper is shown in Figure H-25. The acid gases from the process are sent to the sulfur recovery unit, stripped sour water goes to the desalter, and recovered oil goes to the slop oil recovery tank.

Wastewater Treatment Unit

Treatment of refinery wastewater to remove contaminants typically involves a variety of treating processes. The proper treatment combined with in-plant source control of wastewater provides an effluent suitable for discharge. A typical wastewater treatment unit may contain an equalization basin, an API separator, slop oil recovery equipment, a dissolved air flotation unit, biological treatment, and filters.

Refinery Offsite Facilities

Although the offsite equipment and facilities do not enter directly into the operations of the various process units, they are critical to the operation of the refinery.

Storage Tanks

Tankage in a refinery is required for storage of crude oil and intermediate and finished products, in both liquefied and gaseous forms. The requirement for tankage will vary, depending upon such factors as the storage levels for crude oil, the number of products and their storage levels, and the variety of blending and intermediate stocks.

Many tank designs are available for storage of liquid products and gases. The type of storage required will depend primarily upon the vapor pressure and pour point of the material. To minimize hydrocarbon emissions, products such as motor gasoline are stored in floating roof tanks. Many tanks are equipped with steam coils and are insulated to store products such as highly viscous oils and asphalt. Products with low vapor pressure are stored in fixed roof tanks.

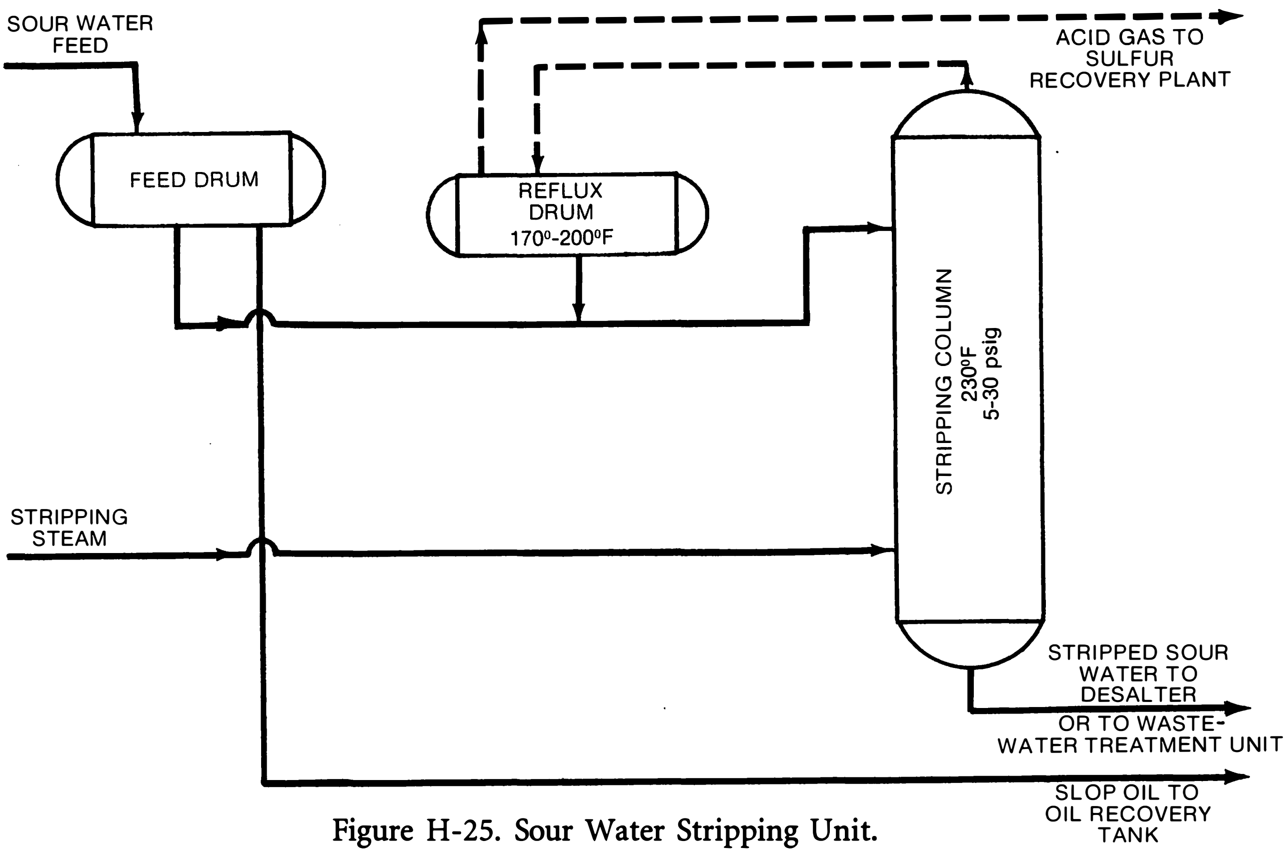


Figure H-25. Sour Water Stripping Unit.

Steam Generating Systems

Steam is needed for many of the refinery processes. These include steam distillation, steam stripping, steam-jet eductors for vacuum distillation, steam turbines for driving blowers and other equipment, steam reforming to produce hydrogen, and power generation.

Steam is provided to the refinery processes through either a closed loop or an open loop system. In the closed loop system, the steam generated yields its heat to the product process streams in heat exchangers by condensation. The steam condensate is then returned to the boiler. The open system uses steam for stripping in fractionating towers, for example, and the steam lost is made up by feedwater to the boiler.

Figure H-26 shows a typical steam generation system. Fresh make-up water is first treated by softening and de-ionization to get the desired feedwater quality. After treatment, the fresh water is preheated with the boiler blowdown and pumped to the de-aerator to remove dissolved oxygen. The treated make-up water is then mixed with the returned condensate and pumped to the boiler.

Co-generation also can be used in the refinery energy balance. In this process a refinery stream such as fuel gas is used to generate high pressure steam. The steam is passed through turbines to produce electricity that can be sold into the local utility grid. The low pressure steam from the turbines is then used for process purposes in the refinery.

Flare And Blowdown Systems

The flares are the main safety valves for the refinery operation. They safeguard personnel and protect the plant from damage during process unit upsets and plant emergency conditions, such as power failures and extreme pressure conditions in process units. To protect the refinery equipment from damage, and for operating safety, pressure relief valves are set below the design pressure of the equipment.

A flare system consists of piping to collect the gases, devices to remove entrained liquid, and a terminal burner operating in the open with no provision to recover heat or to treat the combustion products. As shown in Figure H-27, the system consists of the following elements:

- Flare header from the process units
- Knockout drums to remove and store condensable and entrained liquids
- Proprietary seal, drum, or purge gas to prevent flashback
- Flare stack to raise the burner to the desired height
- Gas pilots and an igniter
- Steam injection for smokeless flaring.

Under emergency conditions, the released hydrocarbons flow from the flare header to a knockout drum, where entrained liquids are separated. The vapors from the drum flow through a liquid seal to the flare and are burned. Steam is injected into the flare gas or flame to provide a smokeless exhaust. The liquid is pumped to the slop oil system for reprocessing. This system avoids the uncontrolled discharge of hydrocarbons to the wastewater treatment system, the release of hydrocarbon to the air, and the loss of valuable petroleum material.

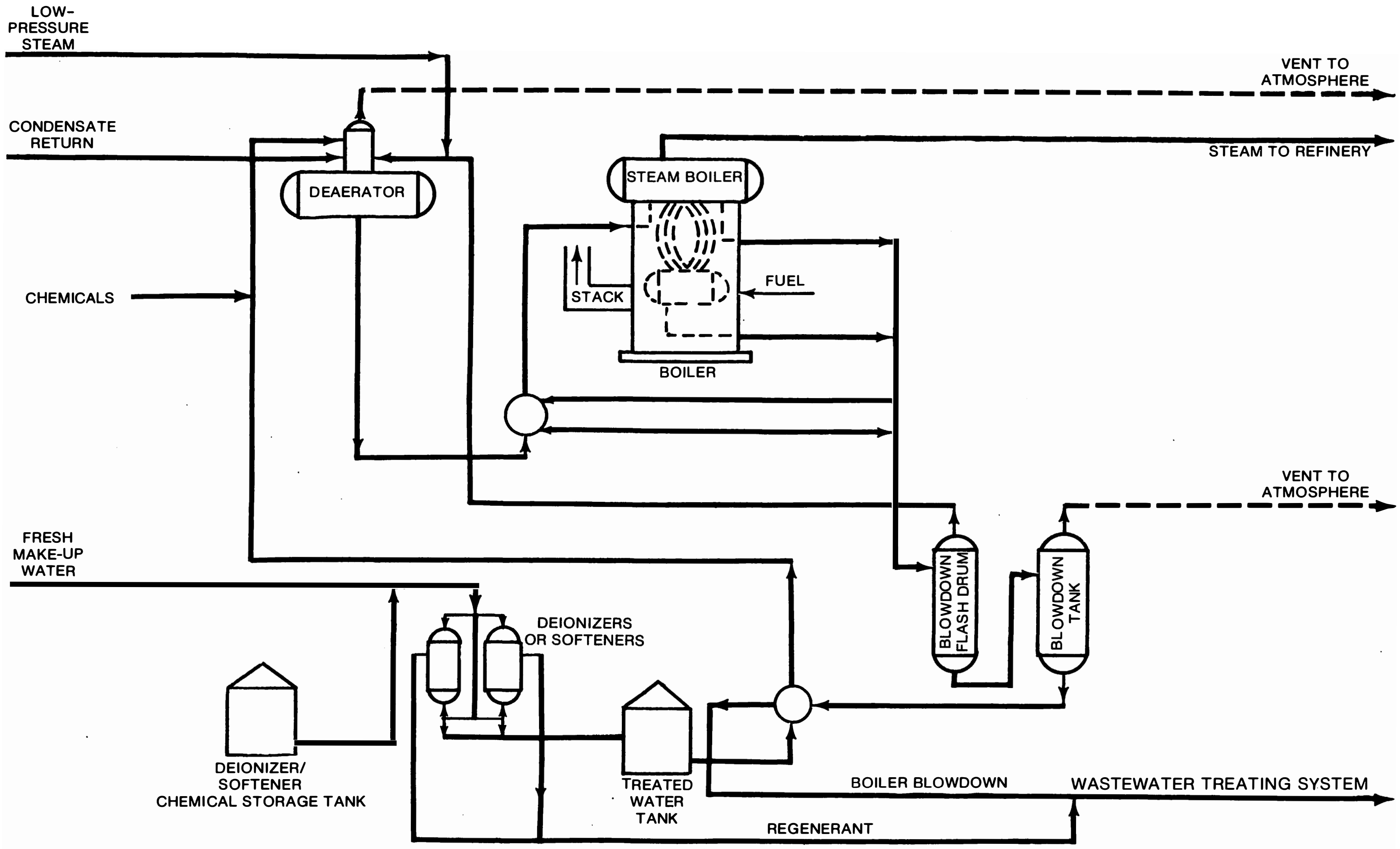


Figure H-26. Steam Generation System.

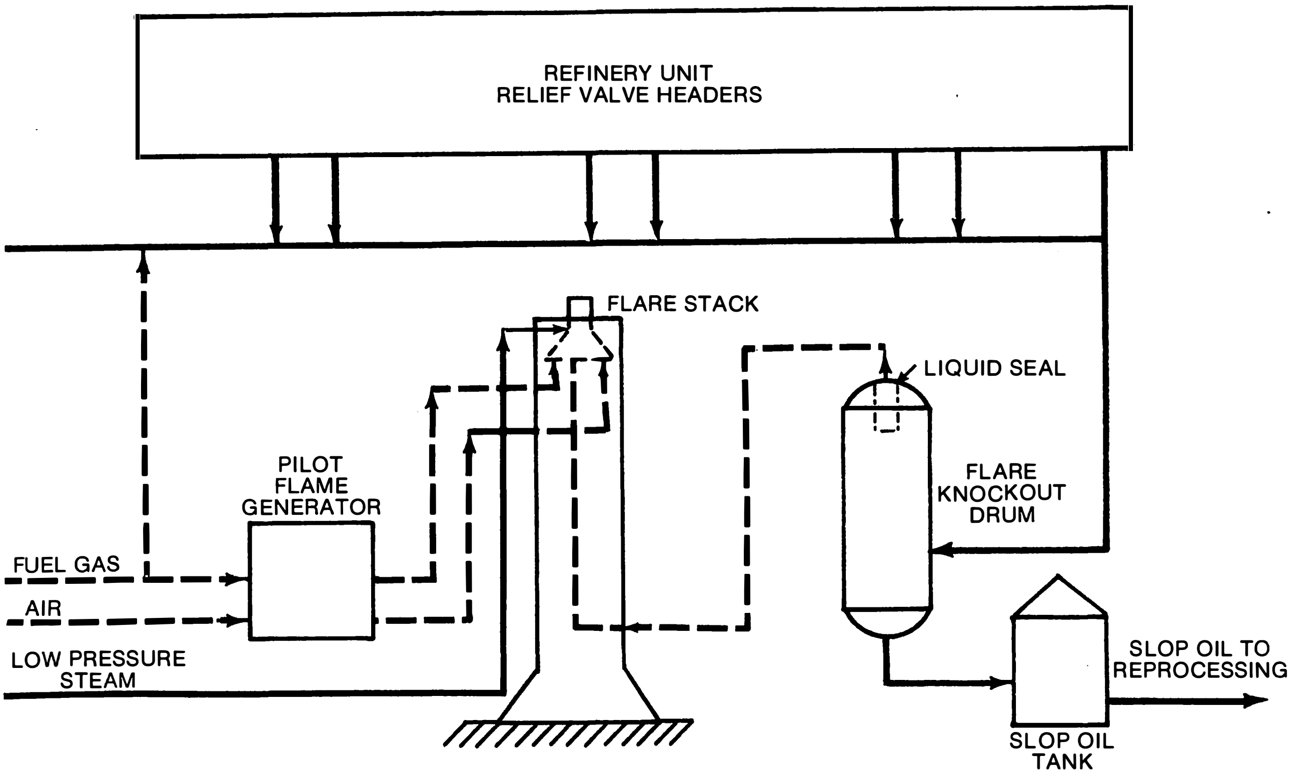


Figure H-27. Refinery Flare System.

Several types of flares are available, but all must operate safely and efficiently under widely varying conditions. The flow of waste gas can range from almost zero, when the only discharges are leakages from relief valves, to very large quantities in emergencies. Further, the required capacity of the flare varies with the crude oil throughput, the complexity of refining, and capacity of the recovery system.

Since it is difficult to design a single flare to handle efficiently such extreme variations in flow, many systems have two flares. One flare is designed to provide smokeless combustion for the normal flow, and the other is activated to handle excess flow resulting from an emergency. There also may be flares designed to serve single specialized units.

Cooling Water Systems

Water is typically used for removing heat from the various product streams. Fans are employed, however, for air cooling in some refineries to reduce water requirements and effluent volume. Figure H-28 is an illustration of a typical recirculating water cooling system. Water from the cooling tower basin is circulated to heat exchangers, where it picks up heat and returns to the top of the cooling tower. The tower, which is open to the atmosphere, contains a wood or plastic packing, which provides the surface necessary to maintain high heat-transfer efficiency. Air is either forced or flows by natural convection countercurrent to water, and the water is cooled by evaporation.

Receiving And Distribution Systems

Receiving and distribution systems are a combination of pumps, pipelines, storage tanks, barges, tankers, tank cars, tank trucks, and loading and unloading facilities. These facilities are used to receive and collect materials, crude oil, and products, and to distribute final products to the consumer by pipeline, to trucks, tank cars, barges, and/or tankers.

Refinery Fire Control Systems

Most refineries are completely equipped and maintain trained personnel to fight a fire. The refinery fire water system is a separate system with designated storage, pumps, and piping. Process areas maintain permanent installed water spray devices called monitors, which provide virtually instantaneous firefighting capability. Sewer systems, particularly those in process areas, are designed with seals, covers, traps, fire baffles, etc., to prevent the spread of fire between areas. Refineries maintain a foam system, fire trucks, and other fire-fighting equipment. Appropriate training is an essential ingredient of fire protection.

CRUDE OIL CHARACTERISTICS

Crude oil is a substance comprised of a complex mixture of hydrocarbons, which are molecules consisting almost solely of carbon and hydrogen atoms in various arrangements. Crude oil contains thousands of different molecules of varying sizes, their size being determined by the number of carbon and hydrogen atoms aggregated together. Because of the different sizes and configurations, the molecules boil at different temperatures from ambient to something more than 1,500-F. The characteristics and yields of a range of crude oils are presented in Table H-1.

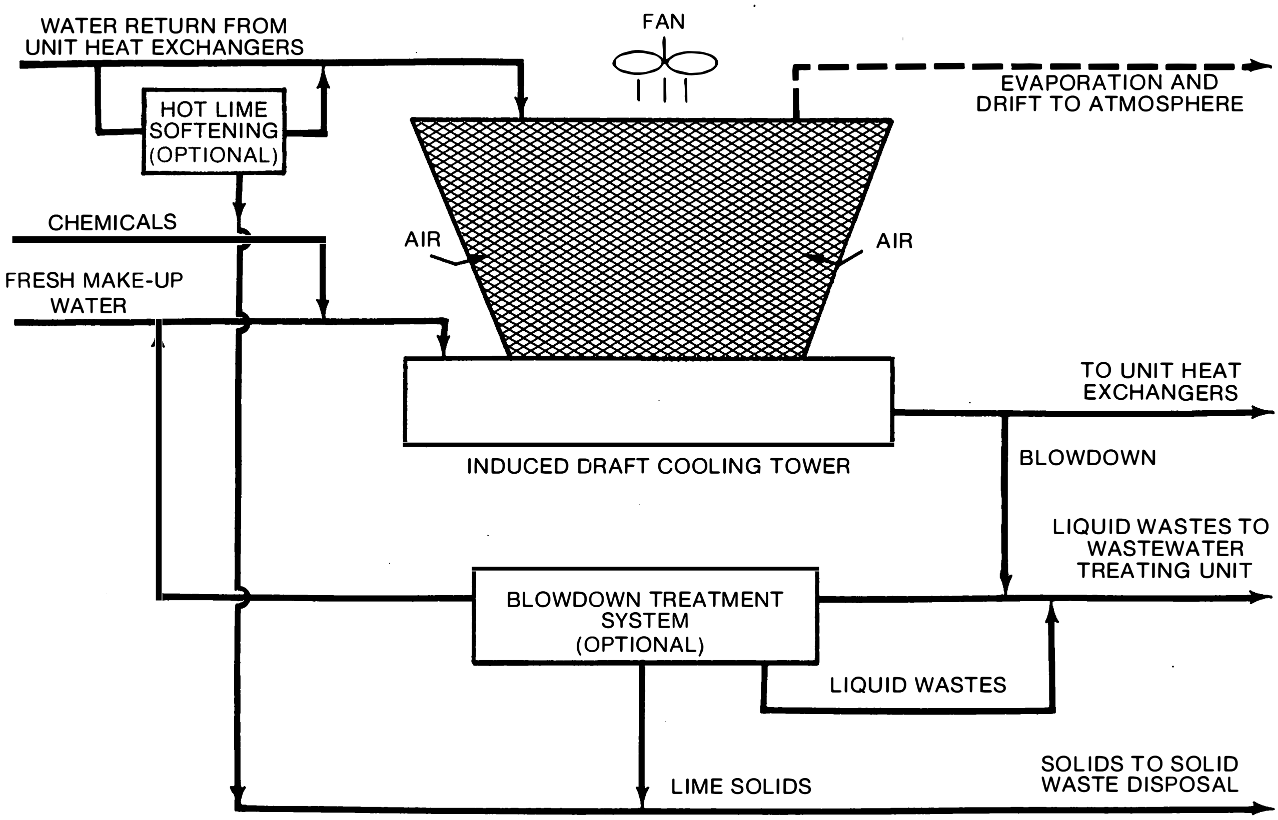
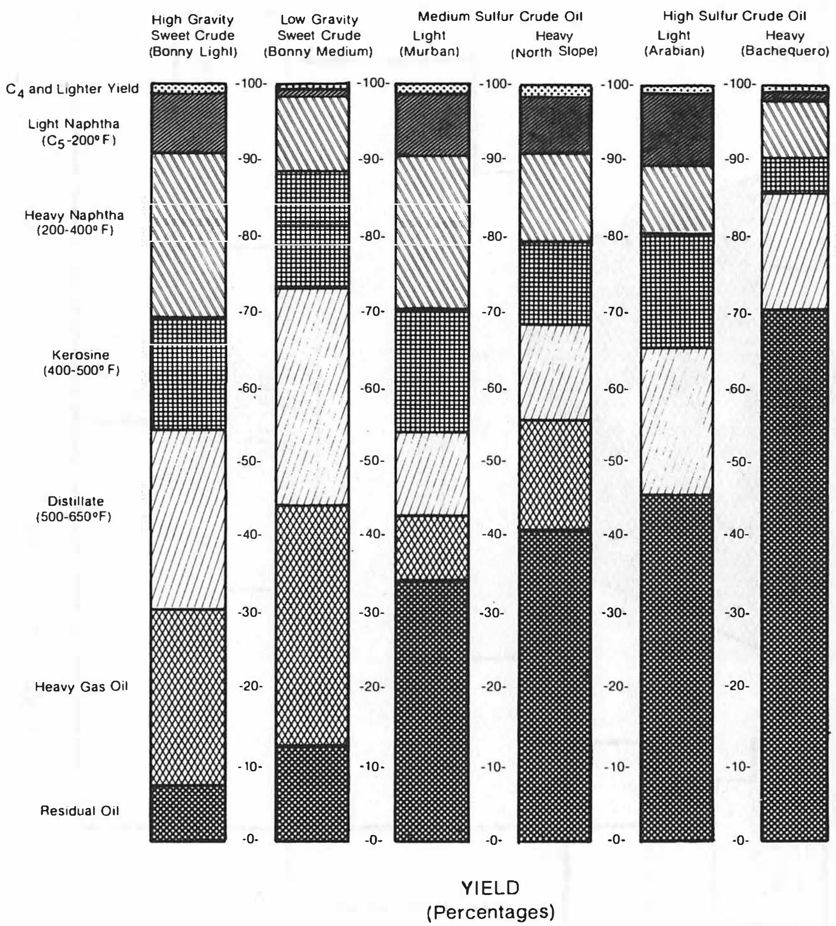


Figure H-28. Recirculating Water Cooling System.

TABLE H-1

CHARACTERISTICS AND YIELDS OF SELECTED CRUDE OILS



	High Gravity Sweet Crude (Bonny Light)	Low Gravity Sweet Crude (Bonny Medium)	Medium Sulfur Crude Oil: Light (Murban)	Medium Sulfur Crude Oil: Heavy (North Slope)	High Sulfur Crude Oil: Light (Arabian)	High Sulfur Crude Oil: Heavy (Bachequero)
Crude Oil						
Gravity (°API)	37.6	26.0	39.4	26.6	33.4	16.8
Sulfur (Wt.%)	0.13	0.23	0.74	1.0	1.60	2.40
Pour Point (°F)	5	<-5	+5	-5	-30	-10
Sulfur Range (Wt.%)	0-0.5	0-0.5	0.51-1.0	0.51-1.0	1.0+	1.0+
C_4 and Lighter Yield	2.2	0.7	1.8	1.8	1.7	0.4
Light Naphtha (C_5-200°F)						
Yield (Vol.%)	6.4	2.1	6.76	5.6	9.0	2.5
Gravity (°API)	79.9	79.2	62.2	68.3	76.5	65.0
Sulfur (Wt.%)	0.0002	0.001	0.012	0.01	0.024	—
Naphthenes (Vol.%)	21.5	24	—	30.0	10.4	51.9
Aromatics (Vol.%)	1.5	3	—	—	2.4	4.7
Paraffins (Vol.%)	77.0	73	—	48.8	67.2	43.4
Octane No. (RONC)	78	60	69	65	54.7	—
Heavy Naphtha (200-400°F)						
Yield (Vol.%)	22.0	8.7	21.2	12.6	6.4	6.0
Gravity (°API)	53.6	50.1	56.9	49.7	59.6	49.0
Sulfur (Wt.%)	0.003	0.01	0.013	0.02	0.027	—
Naphthenes (Vol.%)	55	56.5	20	56.4	18.2	58.5
Aromatics (Vol.%)	11	14.0	17	—	12.3	13.9
Paraffins (Vol.%)	34	27.5	63	43.6	69.5	27.6
Kerosene (400-500°F)						
Yield (Vol.%)	15.4	14.7	16.14	12.3	15.0	5.0
Gravity (°API)	40.2	34.4	45.4	37.4	38.5	36.4
Sulfur (Wt.%)	0.03	0.063	0.058	0.20	0.094	0.48
Pour Point (°F)	-70	<-70	—	—	—	-60
Distillate (500-650°F)						
Yield (Vol.%)	23.2	29.7	10.4	12.1	19.6	15.5
Gravity (°API)	33.2	27.5	37.6	31.3	37.1	—
Sulfur (Wt.%)	0.13	0.16	0.47	0.56	1.05	0.99
Cetane No.	51	40.0	54	47	—	—
Pour Point (°F)	20	-15	0	—	0	—
Viscosity (@ 100°F)	40.3 SUS	44.6 SUS	4.2 cSt	—	3.26 cSt	—
Heavy Gas Oil					*	*
Yield (Vol.%)	23.1	31.3	9.24	14.7		
Gravity (°API)	25.4	19.7	33.6	25.6		
Sulfur (Wt.%)	0.21	0.31	1.06	0.90		
Pour Point (°F)	105	80	41	55		
Viscosity (@ 210°F)	46.1 SUS	53.1 SUS	—	77 SUS 100°F		
Residual Fuel Oil						
Yield (Vol.%)	7.7	12.8	34.5	40.7	46.1	70.6
Gravity (°API)	11.8	10.1	22.6	13.0	17.6	—
Sulfur (Wt.%)	0.39	0.46	1.49	1.74	3.06	3.0
Pour Point (°F)	—	—	85	475	40	60
Viscosity (@ 210°F)	2,030 SUS	3,690 SUS	—	391 SUS	21 cSt	—
Total (%)	100.00	100.00	100.00	100.00	100.00	100.00

*Data for Heavy Gas Oil included in Residual Fuel Oil.

Paraffinic-type crude oil is generally of high-API gravity and low in sulfur content, and contains a lesser amount of other contaminants such as metals and nitrogen. The straight-run gasoline derived from this type of crude oil is low in octane quality. The naphtha fraction is a poor reformer charge stock but an excellent SNG feedstock and cracking stock for olefins. The heavy naphtha and kerosene fractions give problems in meeting product freeze point specifications, and the diesel fuel fractions have problems in meeting pour point specifications. The residual fuel oils also have high pour points, and the asphalt quality is often poor. However, the heavy naphtha and kerosene have good smoke point characteristics, and the heavy naphtha, kerosene, and light gas oil have high cetane indices. The volumes of residuals are low and often can be cracked without too much penalty.

The physical properties of naphthenic crude oils vary widely between different producing fields. They are generally of low-API gravity, may be either high or low in sulfur content, and are often high in nitrogen and metals. The straight-run gasolines from this source are higher in octane but often of lesser volume. The naphtha is excellent reforming charge stock. The heavy naphtha has a poor smoke point and cetane index, and should be reformed. The kerosene and light gas oils have very poor cetane indices and are not suitable for domestic distillates. Pour points and freeze points of this latter fraction are very low. The residual fuel oil may be of high or low volume, high or low sulfur content, and high in metal content. The metals are corrosive to boiler tubes, and the use of high-sulfur fuel oils is becoming more restrictive. These crude oils are the source of naphthenic lubricating oils, and their asphalt quality is often good.

Intermediate-type crude oils are, as their name implies, somewhere in between the paraffinic- and naphthenic-type crude oils. These crude oils generally will fall in the medium to high gravity range. Sulfur content may fall between 0.1 and 2.5 wt.% sulfur. The distillate from these crude oils generally has pour point and cetane index characteristics suitable for No. 2 fuel oil and diesel fuel.

Besides the paraffinic, naphthenic, and intermediate types of crude oils already discussed, there exist many combinations of these crude oils.

Crude oils are also classified as low-sulfur content (below 0.5 wt.% sulfur), intermediate-sulfur content (between 0.5 and 1.0 wt.% sulfur), and high-sulfur content (over 1.0 wt.% sulfur). In general, the definition of a sweet crude oil is one that does not contain hydrogen sulfide and has below 0.5 wt.% sulfur content, with only a minor portion of the sulfur content being present as mercaptans. Mercaptans (sulfur compounds) are the most malodorous contaminants of crude oil and petroleum products.

PRODUCT CHARACTERISTICS

Motor Fuels

Motor Gasoline

Since World War II, gasoline has changed in hydrocarbon composition and is now a product made by blending of refinery stocks prepared by involved processes and special additives developed in extensive research programs. The most outstanding change in gasoline over the years has been a vast improvement in antiknock quality. The 1970 Clean Air Act established a schedule for reducing lead additives and required automobile manufacturers to design and build engines that could run on low-lead and unleaded gasolines starting in 1974. After 1974, the gasoline octane has remained almost the same, but the clear pool octane has increased as to compensate for the lead additives removed and for the increasing amount of unleaded gasolines. Federal air quality regulations starting in 1988 limit lead alkyls in motor gasolines to 0.1 gm/gal. In 1992, leaded gasoline was less than 1% of the pool; use of lead must cease entirely by 1995.

The clear pool octane has increased by adding octane generating processes and through increased operating severity of the processing units. High-octane ethers and alcohols have been used also to replace the lead.

As a further step in controlling air quality, the EPA implemented a two phase program in 1989 and 1992 to reduce the vapor pressure of gasoline (RVP). As noted in this report, the CAAA of 1990 are expected to alter further the characteristics of gasoline through control of hydrocarbon type, addition of oxygenates and additives and RVP reduction.

Diesel Fuels

Distillate fuels for use in automotive diesel engines have been improved during the past several years to meet requirements imposed by changes in legislation and engine design and operation. The most significant change in diesel fuels has been to reduce sulfur content, primarily with hydrodesulfurization. Fuel improvements have resulted in decreased engine deposits, smoke, and odor. The use of additives in diesel fuels has become more common to provide improvement such as lower pour points, ignition quality, and storage stability. Railroad diesel fuels have not changed significantly as the large diesel engines used in railroad service operate satisfactorily on fuels with less exacting specifications.

Aviation Fuels

Jet Fuels

Commercial kerosene was first used as a fuel in early development on jet aircraft, since it provided the necessary volatility and was a readily available commercial product of uniform characteristics. Jet fuels are exposed to both high and low temperatures in use; therefore, these fuels must have very low freezing points and must be stable when exposed to high temperatures. The JP-4 and JP-5 military jet fuels and equivalent commercial fuels have thermal stability properties satisfactory for operations up to speeds of Mach 2.

Industrial and Heating Fuels

Liquefied Petroleum Gas

The extensive use of catalytic cracking and catalytic reforming processes and the growth in hydrocracking have resulted in large quantities of LPG in addition to the production from natural gas processing. Before the use of LPG in ethylene production, its major use was in household and industrial fuel, although LPG has long been used to a limited extent as a motor fuel.

Distillate Fuel Oil

Distillate fuel oil can be defined as Nos. 1, 2, and 4 heating oils, diesel oil, and industrial distillates. Grade No. 2 fuel oil is the designation given to the heating or furnace oil most commonly used for domestic and small commercial space heating.

The period since World War II has seen marked changes in both the quality of home heating oils and the manufacturing techniques employed in producing them. Domestic heating oil should form no sediment in storage and leave no measurable quantity of ash or other deposits on burning. It should be fluid at storage conditions encountered during the winter months. The composition of the product must be controlled to help in reducing smoke emission. Low sulfur content has become important. The fuel must have a light color, an attractive appearance, and an acceptable odor. It is these properties, along with sulfur removal, that have undergone the greatest changes in the past 20 years.

In the early 1950s, hydrogen treating was adopted for reducing the sulfur and nitrogen compounds content of distillate fuel oil. With this process, carbon residue is reduced to less than 0.10 percent. Hydrotreated products are of excellent quality from the standpoint of a change in both color and sludge formation during storage.

Residual Fuels

Residual fuel oil can be defined as Nos. 5 and 6 heating oils, heavy diesel, heavy industrial, and Bunker C fuel oils. Typically, these fuels are used to provide steam and heat for industry and large buildings, to generate electricity, and to power ships.

Since World War II, refining processes in the United States have continued to favor the breaking up of the heavier residuum into lighter petroleum products until residual fuel manufacture in 1992 amounted to 6.4% less the crude oil refined. The desulfurization of high-metal-content fuel oil and stack gas desulfurization has become widespread.

Other Petroleum Products

Petrochemical Feedstocks

Petrochemical feedstocks, such as benzene, toluene, xylene, ethane, propane, naphthas and gas oils are used in such diverse products as synthetic rubber, synthetic fibers, and plastics. Tremendous growth in the petrochemical industry has resulted in many new and improved uses for petrochemicals.

Lubricants

Lubricants fall generally into three categories: automotive oils, industrial oils, and greases. Engine oils, gear oil, and automatic transmission fluids are three major lubrication products used in automotive operations. These products function to lubricate, seal, cool, clean, protect, and cushion. Industrial oils are formulated to do a broad range of functions under a variety of operating conditions. The major functions provided include lubrication, friction modification, heat transfer, dispersancy, and rust prevention. Greases are basically gels and are composed of lubricating oil in a semirigid network of gelling agents such as soaps, clays, and more recently, totally organic substances.

Petroleum Solvents

A variety of petroleum solvents are produced, and critical specifications are largely a function of the end-product use. For example, rigid specifications are required for petroleum solvents used in the paint industry. These products must contain no materials that would dis-color pigments and must possess low odor for interior paints. Control devices make it possible to maintain consistent product quality even under the most rigid specifications.

Asphalt

The heaviest fractions of many crude oils include natural bitumens or asphaltenes and are generally called asphalt. Actually this material is the oldest product of petroleum and has been used throughout recorded history. However, new uses and new demands for asphalt are continually being developed. The industry has satisfied these demands by changing processing and types of crude oils and by improving storage, transportation, and blending facilities.

Appendix I

Environmental Operations Primer

This appendix describes the control methods and techniques used at petroleum facilities to obtain compliance with environmental regulations controlling air, water, and waste discharges.

AIR POLLUTION CONTROLS

This section describes techniques used at refineries and at terminals and transportation facilities.

Refineries

Air emissions vary significantly both in quantity and type among refineries and their effect on the environment varies according to the location of the refinery. Air pollution is unique in the sense that the pollutants may travel across national and state boundaries. Refinery emissions are affected by crude oil feedstocks, processes, equipment, control measures, and maintenance practices. Generally, air pollution control systems are associated with specific process units and designed to remove specific contaminants.

Table I-1 shows the major types of air contaminants associated with refining along with the major sources. The following sections discuss the sources and control methods for hydrocarbons, sulfur oxides, nitrogen oxides, carbon monoxide, particulates and odors from refinery sources.

Hydrocarbons

Hydrocarbon emissions are potentially the largest type of emissions from refineries, and considerable attention is given to reducing these emissions. Sources include process stacks (primarily the process heaters), storage tanks, the product loading terminal and fugitive sources such as valve stems, pump and compressor seals, drains, and oil/water separators. Specific sources of hydrocarbon emissions (both point source and fugitive) and methods to control them are discussed below.

Storage Tanks

A major source of hydrocarbon emissions to the atmosphere from a refinery is evaporation loss from tankage. The most commonly used storage for volatile hydrocarbons is the floating roof tank. Recent use of double seals on the floating roof tank has improved this technique so that very little hydrocarbon can escape to the atmosphere, even under adverse conditions such as high winds.

Evaporation from a storage tank is the natural process whereby a liquid is converted to a vapor which then is lost to the atmosphere. Where a vapor space exists, as in a fixed roof tank, the space tends to become saturated with hydrocarbon vapors, depending on the volatility and temperature of the stored liquid. The tank subsequently loses these vapors to the atmosphere, primarily from: breathing loss, which results from thermal action and the daily expansion and contraction of the vapor space; and filling or withdrawal loss, where vapors are expelled from a tank as a result of filling or withdrawing. In a refinery, the usual method for reducing storage tank losses is to install a floating roof in place of, or by converting, a fixed roof tank. Pressure tanks designed to withstand relatively large pressure variations without vapor loss are generally used to store highly volatile refinery products.

TABLE I-1

Pollutants	Sources
Hydrocarbons	Loading facilities, turnarounds, sampling storage tanks, wastewater separators, blow-down systems, catalyst regenerators, pumps, valves, blind changing, cooling towers, vacuum jets, barometric condensers, air-blowing, high pressure equipment handling volatile hydrocarbons, process heaters, boilers, compressor engines, distillation towers, and separators.
Sulfur Oxides	Boilers, process heaters, cracking operations, regenerators, treating units, H_2S flares, decoking operations.
Nitrogen Oxides	Process heaters, boilers, compressor engines, catalyst regenerators, flares.
Carbon Monoxide	Catalyst regeneration, decoking, compressor engines, incinerators, boilers, and flares.
Particulate Matter	Catalyst regenerators, boilers, process heaters, decoking operations, incinerators, flares.
Odors	Treating units (air-blowing), steam-blowing) drains, tank vents, barometric condenser sumps, wastewater separators, and biotreatment units.
Aldehydes	Catalyst regenerators.
Ammonia	Catalyst regenerators.

Transportation Facilities

In moving and handling gasolines and crude oils, evaporation and entrainment losses occur in both loading and unloading operations. The transport carriers are usually tank trucks, tank cars, barges and tankers. Pipeline deliveries are the most efficient and pipeline losses are considered negligible.

The greatest determinant in total loss in loading tank cars and trucks is the method of loading: splash loading, submerged fill or bottom loading. In splash loading, the liquid is discharged by a short spout into the upper part of the compartment. The resultant free fall increases evaporation and may result in a fine mist of liquid droplets. In submerged surface loading, the bottom of the loading pipe is within a few inches of the bottom. At first, until the tip of the loading arm is covered, higher losses result. When the bottom of the loading arm is covered, there is a marked decrease in turbulence and evaporative losses are reduced. Bottom loading is a complete type of subsurface loading, where the liquid in introduced from the bottom of the tank, and results in less evaporative loss. Bottom and submerged loading are standard practices, while splash loading use has decreased significantly. Losses in loading may be reduced further by vapor recovery, with 95 to 99 percent effectiveness; they are now used frequently.

Sedimentation Devices

The sedimentation device used is normally an API separator but basins or other devices may also be used for sedimentation purposes. These include ponds or lagoons and, more recently, stilling tanks, all of which receive influent water directly from the refinery, prior to any settlement treatment.

In the process of sedimentation, oil contained in the wastewater rises to the top of the basins and if the area is uncovered, evaporation occurs, and hydrocarbon vapors are emitted. There are many factors which contribute to the extent of the loss, and major factors are true vapor pressure of the slop oil, sedimentation area, total time of exposure, film thickness, and average wind velocity.

There are two basic methods of control. The first involves design modifications to and suitable maintenance in the wastewater collection system upstream of the separator so as to reduce the total amount of oil. This may also reduce the volatility of the oil. The second method involves covering the separator, utilizing either a floating roof or a fixed roof.

The basic mechanism of oil evaporation from post-gravity sedimentation devices is similar to that of primary gravity separation devices. Several important differences in degree exist, however, all of which will tend to reduce evaporation losses. As a result, losses from these devices would tend to present a problem only where stringent air pollution regulations are a requirement. The major factor contributing to evaporation losses from these devices is the true vapor pressure of the oil and the carrying capacity of dissolved or entrained air when used. Losses are considerably less than in a primary device because only 10 to 15 percent of the oil remains for further or potential evaporation.

Accordingly, hydrocarbon emissions are considered negligible for most post-gravity sedimentation devices and especially for secondary ponds and lagoons in which there are no aeration devices. As regards air flotation units, a slight problem may exist. In these devices, oil and air bubbles collect on the surface in a frothy scum. Some volatilization will occur from the oil and released air bubbles will contain a slight amount of hydrocarbon vapors. Under some conditions, hydrocarbon vapors may be detected in the immediate vicinity of an air flotation unit on the downwind side. There are two types of these units.

First, the standard air flotation device is one in which the release of dissolved air causes oil and sediment particles to rise to the surface. Oil removal efficiency is 50 to 70 percent, which may be increased to 60 to 90 percent with chemical additives. Second, an induced air flotation unit is used in which atmospheric air is intimately mixed with the incoming wastewater. The oil removal efficiency has not been established but may approximate 50 to 80 percent with normally required chemical additives. Only fixed covers are used in either the standard dissolved air flotation device or the air-mixing device. If floating covers were used, they would interfere with the collection and removal of oil and scum. When a fixed cover is used, it may or may not be connected to a vapor disposal system. If it is not used, hydrocarbon emissions would be difficult to evaluate but would approach 10 percent of the loss figures shown for uncovered primary sedimentation devices as a maximum. If a vapor disposal system is used, hydrocarbon emissions are essentially zero.

Pressure Relief Systems

The generic term "pressure relief valve" includes the relief valve for liquid flow and the safety valve for gas flow, both designed as a safeguard against overpressure. These valves discharge during periods of overpressure and, in addition, usually have a slight continual leakage rate. Both sources, of course, have the potential to result in hydrocarbon emissions to the atmosphere.

Vapors are discharged primarily to flare systems and also to the atmosphere provided that this does not violate national and local regulations and that the vapors are below their autoignition temperature. Hydrocarbon vapors are discharged to the atmosphere from relief vents under varied conditions, but the most common discharge is that of flammable vapors heavier than air, but of relatively low molecular weight. This type of discharge is subject to standard safe practice provisions.

The number of pressure-relief valves in a 100M barrel per day refinery will vary considerably but might approximate 1,000 to 2,000 valves. These valves may discharge into the atmosphere or into a closed pressure-relief system that terminates in a flare. Hydrocarbon emissions from a flare may be considered negligible. From present indications, the percentage of valves in a refinery discharging into the flare system varies greatly from a low of 10 percent to a high of 90 percent.

The amount of daily or annual emission of hydrocarbons to the atmosphere or to a pressure-relief system depends on two factors: overpressuring and leakage of the relief valves. The control system most used today is for the discharge vapors to be sent to a closed pressure relief system that terminates in a flare. If the relief valve does discharge to the atmosphere then emissions can be minimized by establishing a system of periodic inspection and maintenance, or by providing each relief valve with a rupture disc.

Vacuum Devices

In refinery processing and particularly in crude oil distillation, it is frequently desirable to conduct the process under vacuum conditions to avoid excessive temperature, excessive steam consumption or both. Two common methods of producing this vacuum are barometric condensers in conjunction with steam-actuated vacuum jets (singly or in series) and surface condensers which also require auxiliary vacuum jets. Vacuum pumps are seldom used except for clean gas removal and moderate vacuum.

The source of loss to the atmosphere for either barometric or surface condensers is the noncondensable gases. The term noncondensable is related to the final water temperature obtained, with lower temperatures being associated with lower volumes of noncondensables. In vacuum distillation, noncondensables will include lighter gases, propane, butanes, and pentanes. The quantity of such vapors is dependent on many factors including composition of crude oil (or composition of charge to vacuum tower) and the pressure maintained in the atmospheric tower.

Although cooling water temperatures can be lowered to reduce noncondensables, this is frequently not practical for an existing installation. In any event, it would only serve to reduce the magnitude of the problem. There are two methods by which noncondensables may be minimized or handled to eliminate hydrocarbon emissions. First, installation of an absorption system between the vacuum tower and the first-stage vacuum jet, and, second, incineration of noncondensables or else discharging them to the vapor recovery system.

Air-Blowing

Air-blowing of petroleum products is confined largely to the manufacture of asphalt, although air is occasionally blown through heavier petroleum products for the purpose of removing moisture. Air- or steam-blowing is still used occasionally to strip spent chemicals. The use of air for general purposes of agitation, formerly quite common in treating operations, is today practically nonexistent.

Regardless of the purpose for which air-blowing is used, asphalt-blowing, moisture removal, or other, the resultant exhaust air contains hydrocarbons and aerosols. In asphalt-blowing particularly, and in the stripping of spent chemicals, noxious odors are produced and disposal is required.

The recovery of hydrocarbons from asphalt-blowing operations is important, not only because of the quantity, but also because of their malodorous characteristics. The poor quality of the gaseous hydrocarbons makes them suitable only for use as fuel.

There are two methods normally used for removal of hydrocarbon vapors in exhaust gases: (a) scrubbing vapors with water; and (b) incinerating vapors in an afterburner or heater firebox. Scrubbing of the vapors will serve to condense steam, aerosols, and essentially all of the hydrocarbon vapors. Usually, there is a small amount of noncondensable gas of pungent odor. This method requires a readily available adequate water supply as there is a high ratio of water to vapor.

Pump Losses (and Mechanical Seals)[1]

The most common refinery pumps are centrifugal pumps and positive displacement pumps. On these pumps leakage losses occur where the driving shaft passes through the pump casting. Leakage losses include volatile, as well as nonvolatile products, but our present concern is with volatile products only.

In refinery application, the pump leakage area is usually protected with a packed seal. In a typical packed seal, the driving shaft is equipped with a stuffing box which is filled with coils and spirals to form closed or nearly closed rings. This packing can be tightened around the shaft.

Lubricant is effected either by a lantern ring or else by a controlled amount of leakage to the atmosphere. The lantern ring is usually used on pumps handling volatile products. The ring provides an opening for the forced feeding of oil or grease into the packing, thus giving a constant supply of lubricant. Losses occur from packed seals, as previously described, and also from the improved mechanical seals.

Mechanical seals reduce leakage and, therefore, reduce emissions to the atmosphere. They can be specified for new pumps or can be installed in existing pumps by replacing the packed seal. The mechanical seal is recommended to reduce hydrocarbon emissions for more or less continuous pumping or products having a Reid vapor pressure of 2.3 kilograms (5 pounds) or greater.

The term mechanical seal denotes a prefabricated assembly that operates as a thrust bearing and forms a running seal between flat surfaces. The seal consists of two rings, one sta-

[1] This discussion is also relevant to compressors and mechanical seals for compressors.

tionary, the other attached to the shaft and rotating with it. The wearing faces are at right angles to the shaft and are lubricated by a thin film of material being pumped. The seal depends upon continuous contact between rotating and fixed collars to limit leakage. Both single (described above) and double mechanical seals are commonly used.

Another method is also applicable to pumps with ordinary packing or pumps that have been equipped with mechanical seals. In this application a liquid, less volatile that the product being pumped, is introduced between a dual set of mechanical seals (or between two sets of packing). This liquid is at a higher pressure than the product and, hence, passes by the packing into the product with which it must be compatible. The original product cannot leak past the packing or seal. Some of the pressure-sealing liquid, however, will pass through the outer packing or seal and should be collected at this point. Some systems also have seal pits or seal fluid reservoirs where any leakage (dissolved gases or air) from the pumped fluid can be collected. The value and effectiveness of this method in reducing hydrocarbon emissions is dependent on the use of a low-volatility liquid which will not contaminate the product. Finally, for some applications, seals vent directly to a vapor recovery system.

Miscellaneous Sources of Loss

In addition to the major sources of potential loss discussed in this document, there are various other miscellaneous sources, relatively minor, that contribute to hydrocarbon emissions. Probably the most important of these sources are equipment leakage, unit burners or furnaces, equipment turnaround, tank cleaning, cooling towers, and gas-fired engines.

Other refinery operations, such as blow-down systems, blind changes, sewers and process drains, sewer vents, and sampling, represent potential sources of loss. These losses cannot be quantified but can usually be kept to relatively minor values by suitable, normal precautions.

Sulfur Oxides (SOx)

Sulfur Oxides (SOx), one of the most common air pollutants, are most often produced when a sulfur-containing fuel is burned. In refineries, the major part of the SO2 emission arises from the combustion of refinery fuels to provide energy for the various processes and to raise steam. The major sources of SO2 emissions are the boilers, process heaters, catalytic-cracking unit, regenerators, treating units, H2S flares, and coking operations.

The amount of SO2 from refinery fuels depends on the quantities of fuels used and on their sulfur contents. As discussed in the process section, the crude oil and intermediate and finished product streams are treated to remove sulfur compounds. This not only provides low sulfur fuel oil for supplemental refinery fuel, but also improves air quality in general by providing low-sulfur products for sale.

The major source of emissions, refinery fuel combustion, can be controlled either by restricting the sulfur level in refinery fuel or by scrubbing the stack gases prior to discharge into the atmosphere. Sulfur levels may be reduced by using hydrodesulfurization, followed by sulfur recovery. In general, the capital investment requirements to install stack gas scrubbing to control SOx is at least as great as the alternative of fuel sulfur reduction, thus, in light of the additional benefits generated by removing sulfur from the refinery products, stack gas scrubbing is sparingly used.

Fluid catalytic cracking (FCC) regenerator unit SOx emissions are generally controlled by desulfurizing the hydrocarbon feed to the unit or by scrubbing the regenerator stack gas prior to discharge. Again, desulfurizing is often the preferred route, especially when the benefits of improved FCC operations are considered. When a high degree of feed desulfurization is required to meet a stringent emission limit, then feed desulfurization in combination with a sulfur oxide control catalyst or scrubbers is more desirable.

The sulfur recovery unit (typically a Clause Unit) emissions are controlled both by increasing the level of sulfur recovery and by stack gas scrubbing. An alternative, normally used is tail-gas treatment as discussed in the refinery process section.

Other sources of sulfur-oxide emissions in a refinery may include:

- Release from sulfuric acid used in processing.
- Disposal of sulfuric acid sludges, whether by processing in recovery units or by direct burning in special furnaces.
- Sulfuric acid reduction when hydrocarbon or other organic matter is oxidized, especially during the air-blowing of lubrication oils after acid treatment. Sulfur dioxide remaining in the treated oil and acid sludge may vaporize continuously under some conditions.

Nitrogen Oxides (NOx)

The major sources of NOx emissions are from combustion processes including process heaters, boilers, compressor engines and catalyst regenerators.

Oxides of nitrogen (NOx) formed in combustion processes are usually due either to thermal fixation of atmospheric nitrogen in the combustion air, leading to thermal NOx, or to the conversion of chemically-bound nitrogen in the fuel, leading to fuel NOx. For natural gas firing, nearly all NOx emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and under certain operation conditions, predominant.

The fixation of a small fraction of the molecular nitrogen in the combustion air results in the formation of thermal NOx. Overall, the main factors in thermal NO and NO2 formation are flame temperature, the length of time the combustion gases are maintained at high temperature, combustion pressure, and the amount of excess oxygen present. Therefore, in the combustion of natural gas, which is virtually free of bound nitrogen, the quantities of NOx produced in the absence of special controls may exceed 1,000 ppm in the flue gases. This fact indicates clearly that high-temperature fixation of atmospheric nitrogen occurs. It is generally accepted that thermal NOx is formed at temperatures in excess of 1,800 degrees C (3200 degrees F) in the presence of excess air.

Fuel NOx is due to the oxidation of a portion of the nitrogen combined with the fuel. This chemically-bound nitrogen reacts with oxygen much more readily than the molecular nitrogen supplied with the combustion air. However, the bound nitrogen is emitted preferentially as molecular nitrogen and only partly as NOx emissions. The role of fuel nitrogen content has been studied in laboratory fuel oil combustion experiments, which indicate that NOx formed by the oxidation of fuel nitrogen is relatively unaffected by changes in combustion conditions.

NOx control techniques for stationary sources operate either through suppression of NOx formation in the process or through physical or chemical removal of NOx from the stack gases.

NOx formation can be reduced by (1) reducing nitrogen level at peak temperature, (2) decreasing oxygen availability at peak temperature, or (3) reducing peak temperature and residence time in the combustion zone.

Combustion Modification is the most cost-effective and energy-efficient technology used to control combustion generated oxides of nitrogen and has been successfully implemented on existing gas and oil-fired boilers to comply with emission standards. (These modifications have been demonstrated for coal, as well as gas and oil-fired facilities.) This technique can result in up to 60 percent reduction in NOx emissions depending on projected baseline emissions. However, this level of reduction may not always be cost effective or even technologically feasible.

Successful combustion modification reduction techniques include Low Excess Air Combustion, Flue-Gas Recirculation (FGR), Staged Combustion, Low NOx Burners and Catalytic Combustion. Low Excess Air Combustion involves reducing the total amount of excess air supplied for combustion in industrial boilers and process heaters to decrease both thermal and fuel NOx formation. Since low excess air firing also increases efficiency (decreased fuel consumption), it is generally considered as part of an energy conservation program and has probably been already implemented in most cases.

Flue-Gas Recirculation (FGR) consists of extracting a portion of the flue gas and returning it to the furnace, admitting the flue gas to the primary combustion zone. FGR lowers peak flame temperature and reduces oxygen concentration in the fire box. FGR has been found effective in reducing thermal NOx.

Staged Combustion is based on operation with a rich primary combustion zone in the furnace to reduce oxygen availability and peak temperature, followed by secondary air injection to achieve carbon burnout. The reduced oxygen availability in the primary combustion zone reduces the conversion of fuel nitrogen to NO and the reduced peak temperature and subsequent heat removal prior to secondary air addition reduces thermal NOx.

Low NOx Burners are generally designed to reduce flame turbulence, delay fuel-air mixing, and establish fuel-rich zones where combustion initially takes place. Low NOx burners produce longer and less intense flames, as compared to conventional burners, which results in lower flame temperatures and reduced thermal NOx generation. In addition, the reduced availability of oxygen in the initial combustion zone inhibits fuel NOx conversion.

Catalytic Combustion uses a catalyst to accelerate the rate of chemical reaction so that the rate of burning is achieved at a lower temperature, avoiding the formation of NOx.

Carbon Monoxide (CO)

The fluidized catalytic cracker (FCC) regenerator, steam boilers, process heaters, compressor engines, and the gas turbines are the major sources of CO. Carbon monoxide results from the incomplete combustion of fuels. Control can be accomplished either by proper design and operation of the equipment, or, as is usually the case with the catalyst regenerators, by providing a separate means for completing the conversion of carbon monoxide to carbon dioxide.

In the case of the FCC regenerator, the best demonstrated control technology for carbon monoxide is considered to be the carbon monoxide incinerator-waste heat boiler. An alternative to the CO boiler is the use of the new catalytic crackers that use improved catalyst and high-temperature regeneration to limit CO generation. In these cases, the catalyst is regenerated at a high temperature with a promoter, and the carbon monoxide is burned in the regenerator instead of being emitted to the atmosphere.

CO emissions from the process heaters and boilers are minimized by monitoring the combustion parameters, especially oxygen, to ensure good combustion.

CO emissions from the gas turbines and compressor engines will be minimized by the same techniques as for the process heaters.

Particulates

The primary sources of particulates are the process heaters and boilers, the FCC regenerator, coke handling, the gas turbines, and the solid-waste incinerator. Particulates can be controlled by the use of wet scrubbers and high-efficiency mechanical collectors (cyclones, bag houses); electrostatic precipitators on catalyst regenerators and power plant stacks; controlled combustion to reduce smoke; controlled stack and flame temperatures, and improved burner and incinerator design.

The emissions from boilers and process heaters are largely a function of the quality of the fuel used. If a fuel has a high ash content, a large portion of that ash will appear as fly ash in the flue gases. The technology for the removal of particulates resulting from the combustion of coal or oil is quite well known, primarily high-efficiency mechanical cyclones and electrostatic precipitators. Also, particulates can be controlled by proper operating parameters and adjustments of the air-to-fuel ratio.

The principal refinery process unit subject to control of particulates is the fluid bed catalytic cracker. Particulates from the FCC are controlled by electrostatic precipitators, high-efficiency cyclones, dry scrubbers, wet scrubbers, or baghouses. The most commonly used equipment is the electrostatic precipitator.

The electrostatic precipitator removes particulates from gas streams by passing the gas between a pair of electrodes—a discharge electrode at a high potential and an electrically grounded collecting electrode. The potential difference must be great enough so that a corona discharge surrounds the discharge electrode. Under the action of the electrical field, gas ions formed in the corona move rapidly toward the collecting electrode and transfer their charge to the particulates by collision with them. The electrical field interacting with the charge on the particles then causes them to migrate toward, and be deposited on, the collecting electrode.

The dust layer that forms on the collecting electrode is removed by intermittent rapping that causes the deposit to break loose from the electrode. In effect, this returns the dust to the gas stream but not in its original finely divided state. As a result of cohesive forces developed among the particles deposited on the electrode, the dust is returned as agglomerates, which are large enough for gravity to cause them to fall into dust hoppers below the electrodes. Reduced to its essentials, the electrostatic precipitator acts as a particle agglomerator combined with a gravity settling chamber.

Where clay recovery kilns are used (as in lube oil finishing), the regeneration of the clay can result in particulate emissions that can be collected by mechanical cyclones, wet scrubbers, or electrostatic precipitators. Baghouses can also be used to control particulates, as has been done in the regeneration of copper oxide used in the desulfurization of naphtha.

Improper operation of any combustion process can create smoke which is, of course, a particulate. Smokeless flares can be used as a means of abating carbon smoke particulate emissions from this source. Smokeless flare combustion can be obtained by the injection of an inert gas to the combustion zone to provide turbulence and inspirit air. A mechanical air-mixing system is ideal, but is not economical in view of the large volume of gases handled. The most commonly used air-inspiriting material for an elevated flare is steam.

Particulate matter from gas turbines results from ash introduced in the fuel or injection water and from incomplete combustion of the fuel. The only feasible control techniques are to limit the ash content of the fuel and the solids content of the injection water and to operate the turbine in a manner which results in good combustion.

An additional source of particulates is fugitive emissions from sources, such as roadways and construction. These sources of emissions can best be controlled by wetting, paving, or any other appropriate means of providing ground cover.

Odors

The primary causes of bad odors from refineries are sulfur compounds, such as H2S, mercaptans and disulfides, which are known to be present in crude oil fractions and have been detected in refinery atmospheres. Hydrocarbons can give rise to offensive odors, but generally at a lower level than sulfur compounds. The processing units which may emit odors include catalytic cracking, asphalt production, lubricating oil treatment, and sulfur recovery units. Also, any open stirring, venting, or flaring is liable to create odor emissions.

In the petroleum industry, absorption and combustion are the most used odor control methods and include: aldehyde absorption in bisulfite solutions; thiols absorption in sodium hydroxide solutions; hydrogen sulfide absorption in amine solutions, activated carbon, active manganese dioxide, and on sawdust; and hydrogen sulfide absorption followed by incineration or oxidation. Flares may be associated with regeneration of caustic washing solutions to combust thiols and hydrogen sulfide. Oxygen may even be added to flares to assure complete combustion, and masking agents and odor counteractants may be used to cover up odors.

Terminals and Transportation Facilities

The emissions and effluents generated by terminal operations and the control of those emissions and effluents is dependent not only on the specific operations but also on whether crude oils or finished petroleum products are being handled. The most significant air pollutants emitted by terminals are hydrocarbons. The other air pollutants of concern include odors, SOx, NOx, CO and particulates. The sources of hydrocarbons are storage tanks (normally onshore), transportation vessel tanks, tanker refueling, tank cleaning (both storage and vessels), tank degassing (preparation for inspection and maintenance), ballasting, and fugitive emissions. The methods used for onshore facilities are the same as those described in the Refineries section. The emissions from tanker refueling, tank degassing and other offshore operations may incorporate vapor recovery or vapor collection/disposal (flaring) systems. Other techniques include segregated ballasting, tank cleaning, slow loading, short loading and the routing of vapors into tanks that are being emptied.

For product terminals, the major sources of hydrocarbons are from the storage tanks, loading facilities for transports, barges and tankers. Other sources are primarily fugitive emissions and therefore are normally small in quantity. The most common means of controlling hydrocarbon emissions in a terminal are primary and secondary seals on the external floating roof of a tank without a fixed roof, primary seals on the internal floating roof of a tank with a fixed roof, installation of a vapor collection system for both the tankage and the loading facilities, and annual inspection of tank trucks to ensure they are airtight.

WATER POLLUTION CONTROLS

This section discusses controls used at petroleum refineries, storage and transportation facilities to minimize pollution of wastewater and groundwater.

Refineries

Wastewater Treatment

Two major units are employed in the purification of refinery wastewaters: the in-plant, sour water stripping unit and the wastewater treatment unit. The sour water stripping unit is used for pretreatment of water containing hydrogen sulfide, permitting reuse of the stripped wastewater. The wastewater treatment unit is the final treatment for all contaminated waters prior to discharge.

Sour Water Stripping Units

Water containing hydrogen sulfide is termed "sour water" or "sour condensate." Refinery operations produce sour water from processes such as hydrotreating, catalytic cracking, coking and whenever steam is condensed in the presence of gases containing hydrogen sulfide. Also, sour water often contains ammonia and small amounts of phenol and other hydrocarbons, which are odorous and may cause wastewater treatment plant upsets if untreated.

There are many stripping methods, but most involve the downward flow of sour water through a trayed or packed tower while an ascending flow of stripping steam or gas removes the hydrogen sulfide and ammonia.

Wastewater Treatment Units

Wastewater treatment units upgrade the quality of effluent water so that it can be safely returned to the environment or recirculated in the refinery. Refinery wastewater typically contains oil, phenols, sulfides, ammonia, dissolved and suspended solids, and sometimes other organic and inorganic chemicals. The type of treatment process varies with the nature and concentration of contaminants, and with effluent quality requirements.

The final effluent from a petroleum refinery is made up of wastewater from several sources, including process water, cooling water, ballast water and storm water. The types of equipment used for treating wastewater discharges can be generally classified as physical, biological, chemical, and physical/chemical. Physical techniques deal mainly with the removal of suspended materials, and include such techniques as air flotation devices, grit chambers, clarifiers, granular media filters, centrifuges and oil separators. Biological processes treat the biologically degradable fraction of the wastewater, and include trickling filters, activated sludge, aerated lagoons, oxidation ponds and rotating biological contractors. These biological processes use microorganisms and oxygen to convert soluble organic contaminants to carbon dioxide and water. Chemical techniques and physical/chemical techniques rely on chemical or catalytic reactions to remove unwanted components. Prior to discharge, some refineries use a final polishing treatment with filtration, using granular media filters and granular activated carbon.

Spills

Refineries employ a number of techniques both to prevent spills and to minimize the adverse impacts of spills should they occur anywhere in the facility. Methods used to prevent spilled product from entering the ground (and hence the groundwater) include: construction of containment dikes; rendering the soil impermeable by using concrete paving, a clay or bitumen layer, plastic sheets covered with gravel and fiberglass-reinforced epoxy and chemicals to be mixed with the soil; and surface drain systems which carry all oil and oil-contaminated water to a dirty water sewer and then to an interceptor by means of a pipe system. Subsurface techniques which are used include the digging of trenches (which intercept the spread of oil and causes it to flow onto the water surface where it can be recovered), the building of walls extending below the water table to provide barriers to subsurface flow, and a technique called hydrodynamic protection which effects a change in the groundwater flow patterns such that the free oil or the contaminated water can be drawn to a specific point.

Stormwater Controls

Refineries employ techniques similar to those used for spills to keep stormwater away from petroleum liquids which may contaminate it and cause the runoff to pollute the adjacent ground and groundwater. Concrete paving, storm sewers, and other structures designed for this purpose are placed throughout the refinery, often designed for the worst-case storm anticipated for the region.

Corrosion Controls

The majority of petroleum spills which have reached groundwater resulted from corrosion of buried steel tanks and piping. There are two practical methods for preventing or reducing external corrosion of buried metal: preventing direct contact between the metal and the soil by using protective coatings, and by cathodic protection techniques, which reduce the electric current which can flow from the metal pipe into the adjoining soil, thus reducing corrosion reactions.

Monitoring

Groundwater monitoring devices are installed to detect and warn of contamination not visible from the surface. These devices are installed around petroleum storage areas, waste treatment and disposal facilities (including lagoons, land farms and landfills) or an entire facility if necessary.

Terminals and Transportation Facilities

The major environmental concern for crude oil terminals and their associated transportation facilities is contamination of wastewaters with oil and grease and the treatment of the ballast and sanitary waters prior to discharge. The largest source of wastewater at a crude oil or product terminal is the ballast water from tankers. The disposal or treatment methods include discharging directly to the harbor (for segregated ballast, which is uncontaminated water carried in tanks dedicated to ballast service, and for clean ballast waters,) and onshore treatment for dirty ballast waters. Processes used for treatment of dirty waters include simply gravity separation, physical and chemical methods for removal of residual suspended matter and biological treatment.

Spills and seepage occurring at terminals comprise a major environmental concern. The techniques used in their prevention and mitigation are essentially the same as those described above for refinery facilities.

SOLID WASTE POLLUTION CONTROLS

This section discusses the types of solid wastes generated by refineries and other petroleum processing facilities, and the control methods used to meet environmental standards.

Sources

Typical solid wastes generated at a refinery include process sludges, spent catalysts, wastewater and raw water treating sludges, and various sediments. The volume of waste generated as well as the economics of material recovery are determined to a large degree by the type, age, and condition of process units and the market for product mix. Further, refineries in different geographic areas encounter widely varying requirements and problems associated with their individual solid waste streams. Treatment and disposal methods used in oil refineries are contingent upon the nature, concentration, and quantities of waste generated, as well as upon the potential toxicity or hazardous nature of these materials. Pollution control methods are further affected by geographic conditions, transportation distances, disposal site hydrogeological characteristics, and regulatory requirements.

Refinery process solid wastes can be generally divided into two types; intermittent and continuous. Intermittent process wastes are those which generally result from the cleaning of refinery facilities and which require disposal at intervals greater than two weeks. Typical examples of these wastes are (a) storage tank bottoms, (b) process vessel sludges, vessel scale, and deposits generally removed during plant turnarounds; and (c) product treatment facilities wastes, such as spent filter clays, and spent catalyst from units such as the reformer, hydrosulfurizer, etc. Continuous process wastes result from wastewater treatment processes and from manufacturing process units, and require disposal at intervals of less than two weeks. Typical examples of wastewater treatment wastes are (a) waste biosludge, (b) separator sludge, (c) dissolved air flotation float, (d) centrifuge cake, and (e) vacuum filter cake. Typical of manufacturing process unit wastes are (a) spent catalysts and catalyst fines from the FCC unit, (b) coker wastes, such as coke fines from the delayed or fluidized coker, and spilled coke from the unloading facilities, and (c) spilled grease and wax from the lube oil processing plants. Intermittent wastes are a function of refinery size and refinery diligence in maintenance and housekeeping practices. Continuous wastes appear to be a function of refinery wastewater treatment system complexity and of refining process unit structure.

Solid wastes can also be generated at terminals. Solid wastes, such as tank bottoms and separator box solids, generally are not generated at a terminal if the crude oil storage tanks are kept well mixed and all of the contents are sent to the refinery for processing. Tank bottoms and separator bottoms are generated at product terminals. Crude oil shipping facilities, however, may generate solid wastes from the treatment of the ballast water. Management of these wastes can be accomplished by landfilling or land treatment.

Table I-2 lists the various sources of refinery wastes in addition to the general characteristics of the wastes. As indicated above, the characteristics of the waste is dependent upon several factors including crude oil compositions, refining processes, and refining procedures.

Predisposal Operations

Predisposal operations are designed to reduce the amount of waste requiring final disposal. Methods commonly employed are solids removal and dewatering, waste reduction, waste separation and concentration, energy/material recovery, and waste incineration/treatment.

Waste reduction involves changing the process to reduce the amount of waste material produced. Methods include new processes, treatment, use of different catalysts or chemicals, water reuse, and better process control.

As an example, one treatment procedure involves reducing the volume of crude oil tank bottoms by the use of polyelectrolytes. The process is performed prior to cleaning the tanks, at which time any crude oil remaining in the tank is pumped out to the sludge layer. The material in the tank is heated with steam and mixed with the crude oil tank bottoms to a temperature of approximately 54 degrees C. Two kinds of polyelectrolytes are added and the contents mixed for up to two days.

The crude oil sludge is broken down into a very distinct oil fraction and an underlying clear water fraction, both of which can be separately decanted from the tank.

Concentration by dewatering could cause the waste to be defined as hazardous even though it was not hazardous in the diluted or watered stage. In this case, the cost of handling and disposing of a smaller amount (concentrated) of hazardous waste would have to be balanced against the cost of disposing of a larger amount of nonhazardous waste.

Recovery of potentially useful substances, energy, or materials from hazardous wastes is desirable. Many wastes contain valuable basic materials, some of which are in short supply, making material recovery logical from both resource conservation and environmental viewpoints. Extraction of materials from concentrated waste usually requires less energy, and generates far less air and water pollution, than the processing operations required to produce the material from virgin resources. As material shortages become more widespread, material recovery from hazardous waste will become more attractive.

Likewise, the combustion of certain wastes to recover energy or heat value for other purposes is endorsed. Such operations usually require special high-temperature equipment with emission control systems an effluent monitors.

Other limitations are imposed by the quality control aspects of waste utilization for energy. The user facility must have an adequate supply of fuel with consistent heating value on a regular or full-time basis. Also, some provisions must be made for standby or emergency operations. These limitations must be carefully considered and integrated into the planning for any system using industrial wastes for fuel.

TABLE I-2

SOLID WASTE DESCRIPTIONS

Solid Waste	Characteristics
Crude Oil Tank Bottoms	Oil-water emulsion containing sand, dirt, inert solids, metals.
Leaded Tank Bottoms	Precipitated organic (alkyl) lead compounds, other destabilized additives, tank scale (primarily iron oxides), other metals including arsenic, selenium, mercury, cobalt, nickel, zinc, cadmium, and molybdenum.
Nonleaded Tank Bottoms	All petroleum products except slop oil, crude oil tank bottoms and leaded gasoline bottoms, tank scale and other corrosion products, metals.
API Separator Sludge	Heavy black oily mud; phenols, metals including those in leaded tank bottoms and chromium, grit, inert solids, sand.
Neutralized HF Alkylation Sludge	Relatively insoluble CaF_2 sludge; reactive; bauxite, aluminum.
Spent Filter Clays	Clay filter cake; metals, oil.
Once-through Cooling Water Sludge	Silt and other settleable solids in raw water supply, leakage from refinery processes, corrosion products, treatment chemicals.
DAF Float	Brown to black oily sludge; heavy metals.
Slop Oil Emulsions Solids	Mixture of crude and other petroleum fractions recovered from spills and separators; oil, metals.
Solids from Boiler Feedwater Treatment	Slurry of spent lime from softening of feed water inert solids.
Cooling Tower Sludge	Grey to black silt-like sludge; metals--primarily hexavalent chromium and zinc, dust, corrosion products, oil from process unit leaks.
Exchanger Bundle Cleaning Sludge	Mixture of metal scale (contains Zn, Cr, Ni, Co, Cd, Mo, Hg), coke, particulate matter and oil.
Waste Bio-sludge	Organic cell material from secondary wastewater treatment; oil, some heavy metals.
Storm Water Silt	Soil, oil, spilled solutions, metals, coke fines, etc., from storm water runoff.
FCC Catalyst Fines	Fine grey powder consisting of aluminum silicate catalyst fines with adsorbed heavy metals, primarily vanadium and nickel, inert solids, coke particles, heavy metals.
Coke Fines	Grey - black porous chunks and particle fines from coking processes; heavy metals.

Disposal Operations

Several options are available for ultimate disposal of refinery wastes including incineration, chemical fixation, landfilling, and land treatment. Table I-3 indicates the waste management options commonly used for the different refinery solid wastes. In all cases, the choices are landfilling or land treatment.

TABLE I-3

SOLID WASTE MANAGEMENT

Solid Waste	Management Options
Crude Oil Tank Bottoms	HW landfill, landfill HW land treatment, land treatment
Leaded Tank Bottoms	HW land treatment, HW landfill
Nonleaded Tank Bottoms	HW landfill, landfill HW land treatment, land treatment
API Separator Sludge	HW landfill, HW land treatment
Neutralized HP Alkylation Sludge	HW landfill, landfill
Spent Filter Clays	HW landfill, landfill HY land treatment, land treatment
Once-through Cooling Water Sludge	HW landfill, landfill
DAF Float	HW landfill, HW land treatment
Slop Oil Emulsions Solids	HW landfill, HW land treatment
Solids from Boiler Feedwater Treatment	HW landfill,* landfill
Cooling Tower Sludge	HW landfill, landfill
Exchanger Bundle Cleaning Sludge	HW landfill
Exchanger Bundle Cleaning Sludge	HW landfill
Waste Bio-sludge	HW landfill, landfill HW land treatment, land treatment
Storm Water Silt	HW landfill, landfill
FCC Catalyst Fines	HW landfill, *landfill
Coke Fines	HW landfill, *landfill

HW means hazardous waste.

* HW landfill not normally required.

NOTE: HW landfills are sometimes used for added security and not necessarily because the wastes are deemed hazardous.

Incineration is desirable to reduce waste volume and to destroy organic wastes, even without energy recovery. Nonburnable wastes should be detoxified and neutralized to the greatest extent possible through physical, chemical, and biological treatment.

Chemical fixation is another special practice which is used in treatment of both liquid and solid wastes. Among the chemical fixation methods which are in use in the petroleum refining industry the most prevalent are (a) chemical coagulants to create an insoluble precipitate, (b) sorption of solvent-like hydrocarbons on imbiber beads, and (c) use of reagents such as portland cement, lime, and flyash to produce a soil-like material. The use of a variety of chemical systems have been devised to overcome the fluidity of certain petroleum wastes. These chemical systems react with various components of the waste to form a semisolid material which effectively encapsulates or otherwise ties up the harmful constituents.

Landfilling is currently the most widely used method for disposing of all types of petroleum refinery waste products. The environmental adequacy of this method is contingent not only upon the types and characteristics of generated wastes, but also upon methods of operation and on specific site geologic and climatologic conditions. Of all the land disposal methods used by the refining industry, perhaps the greatest variations in operations and in site suitability are experienced with landfills. Landfilling operations range from open dumping of construction and refinery debris to controlled disposal in secure landfills. However, the precise impact of solid waste disposal depends on the nature of the waste (inert construction waste may not pose a problem even in an open dump) and the landfill (secure landfills involve control of run-on, run-off, leachate, etc.).

The environmental adequacy of a refinery waste landfill is affected by the following operational and management practices:

- The extent of segregation of wastes to prevent mixing of incompatible compounds, such as solids containing heavy metals with acids, or solutions with other wastes which together produce explosions, heat, or noxious gases

- The extent to which liquid or semiliquid wastes are blended with soil or refuse materials to suitably absorb their moisture content and reduce their fluid mobility within the landfill.

- The extent to which acids or caustic sludges are neutralized to minimize their reactivity.

- Selection of sites in which the active fill area is large enough to allow efficient truck discharging operations, as well as to assure that blended wastes may be spread, compacted, and covered daily with approximately six inches of cover soil; a site operated in this manner is called a sanitary landfill.

- The routing of surface waters around the landfill site, prevention of storm water run-on, and collection of storm water run-off.

Land treatment systems have been used for the treatment of petroleum industry wastes for many years. Land treatment is a managed technology that involves the controlled application of a waste on the soil surface and the incorporation of the waste into the upper soil zone. It is not the indiscriminate dumping of waste on land. Land treatment differs from landfilling. Landfills store wastes in manmade or natural excavations and use a combination of liners and leachate collection systems to control the migration of the landfilled waste or resultant by-products. Liners are not a part of a land treatment system. The land treatment waste management technology relies on the dynamic physical, chemical, and biological processes occurring in the soil. As a result, the constituents in the applied wastes are degraded, immobilized, or transformed to environmentally acceptable components.

The land treatment of most petroleum industry wastes focuses on the breakdown of the oil fraction by aerobic microorganisms in the top layer of soil where oxygen is available. Metabolism in these organisms ultimately reduces the hydrocarbons to CO2 and water.

The design and operation of a land treatment facility is based on sound scientific and engineering principles as well as on extensive practical field experience. A land treatment site is designed and operated (a) to maximize waste degradation and immobilization; (b) to minimize release of dust and volatile compounds as well as percolation of water soluble waste compounds; and (c) to control surface water run-off.

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