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PHYSICAL ASPECTS
OF THE U.S. OIL AND GAS SYSTEMS

J. D'ACIERNO AND A. HERMELEE

November 1979

TECHNOLOGY ASSESSMENT GROUP
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
DEPARTMENT OF ENERGY AND ENVIRONMENT

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ABSTRACT

The purpose of this report is to describe the physical operations which take place within the petroleum and natural gas industries of the United States. This information was the basis for the overall network design and the detailed data requirements for the Emergency Management Information System (EEMIS) of the United States Department of Energy (DOE). Since EEMIS represents the entire oil and gas systems this report can be used to obtain a basic understanding of the entire energy system, from production to consumption, that is composed of the U.S. oil and gas industries.

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I. INTRODUCTION

This report is a description of the physical system for petroleum and natural gas that underlies the Reference Energy System. Activities from production through refining, conversion, and transportation are described for typical processes as they occur in industry. A basic understanding of these processes is required to gain a proper perspective of the energy system for those responsible for managing an energy emergency. The information presented here was used in the design of the EEMIS sector structures for petroleum and natural gas in order to incorporate appropriate data elements for resolving energy emergencies as specified in the EEMIS Program Plan.

Production of natural gas and petroleum is described in one section since they often occur together in nature, and extraction of these two resources is interrelated. Demand for both fuels is also described in one section. Transportation, refining, conversion, and storage operations for oil and gas are described separately. Descriptions include general background information, with relevant data to give the reader perspective, as well as a detailed explanation of activities for each operation. General descriptions are used for the major equipment associated with each activity.

Often the physical system for operations is highly diversified, in which case a complete description is impossible since it would be too lengthy to include in this work. References which can be used to gain a more complete understanding are provided for these cases.

Production of natural gas and petroleum is described in Section II. Petroleum Storage Terminals, the Strategic Petroleum Reserve, oil refineries, and transportation of crude oil and petroleum products are described in Sections III through VI. Demand for both petroleum and natural gas is described in Section XII. Transportation and demand for petroleum and natural gas are also described whenever these operations interface with other activities in the energy system. Natural gas processing plants, underground storage, gas transmission and distribution systems, Liquefied Natural Gas (LNG) terminals, and natural gas pricing are described in Sections VII to XI.

II. DOMESTIC PETROLEUM AND NATURAL GAS PRODUCTION

Origin and Accumulation

Petroleum and natural gas are derived from organic material - most likely from marine life - which was buried below ancient seas in a geologic process called sedimentation. The most widely accepted theory for the transformation of organic substances into crude petroleum is the combined effect of severe conditions of pressure and temperature over long time periods. Each day for thousands of years new deposits of organic substances, sand, and mud were

distributed as layers on the sea floors. Under the weight of new beds the ocean floors sank slowly. The thick series of mud and sand thus formed were squeezed by the weight of thousands of feet of overlays and eventually became sedimentary rocks - sandstones, shales, limestones, and dolomites in which petroleum is now found. Organic substances buried in the ocean bottom and sealed off from oxygen were further protected from normal decay by salty sea water. As time went by natural forces of pressure, temperature, and bacterial activity caused the organic remains to change into oil and natural gas.

The movement of crude petroleum from the place of origin to the traps where accumulations are now found most likely occurred in an upward direction. The oil continually rose by water displacement until its slow migration was halted by an impermeable barrier called a "cap rock." Natural gas which is often dissolved under natural pressure in crude petroleum sometimes rises above the oil when gas is present in large enough amounts (see Figure II-1). The natural pressure from both natural gas and salt water is used beneficially in transporting oil to the surface of oil wells. For this reason both natural gas and salt water are commonly extracted together with oil from the well.

Figure II-1

Cross Section of a Typical Oil Field, Showing the Distribution of Natural Gas, Petroleum, and Salt Water in the Porous Sandstone Reservoir

Source: Battelle Memorial Institute

General Characteristics

Crude petroleum exists in virtually every part of the globe. Its appearance varies considerably in nature whether it be from country to country or field to field. Crude oil has a color that can vary from brownish yellow

through green to black. Viscosity, which is the measure of fluidity, can also vary. Some petroleums are viscous, others flow freely, and some contain a suspension of paraffin which can accumulate in pipes and fittings in the well and in storage and transportation equipment, interfering with normal flow.

Petroleums have a characteristic heavy odor that may at times be masked by a noxious smell similar to rotten eggs which is characteristic of hydrogen sulfide, an extremely toxic gas, or mercaptans, a group of sulfur-bearing compounds dissolved in the oil. The nasty odor of such high-sulfur crudes is the origin of the loose terms "sour" for high-sulfur and "sweet" for low-sulfur petroleums.

Crude petroleums are generally found in porous layers of sedimentary rocks located as much as seven miles below the earth's surface. They can also appear on swampy lands as a slow ooze from below. Oil shales are sedimentary rocks containing a high content of kerogen, and 30 to 60% organic matter and fixed carbon. Kerogen, a bituminous substance, yields an oily substance when heated in the absence of air; however, this substance is not true petroleum.

Natural gas sometimes coexists in nature with petroleum, and the two are often produced from the same well simultaneously. Natural gas produced from a reservoir that contains petroleum is termed associated gas if it exists as free gas in a gas cap, or dissolved gas if it is in solution with crude oil (see Figure II-1). Although natural gas commonly exists in the same geologic formations as petroleum, it is excluded from crude oil by definition. Gas produced from a reservoir that does not contain crude oil (i.e., from a gas well) is referred to as nonassociated gas because it is not directly associated with oil underground. Over 80% of the natural gas produced in the U.S. is from gas wells. In certain fields, these terms assume particular importance because regulatory and control measures applied to associated gas are directed toward a consideration of the effect of gas production upon oil production rates and ultimate recovery, whereas the production of nonassociated gas does not involve such considerations.

Crude oils are chiefly nonuniform mixtures of hydrocarbons with small amounts of sulfur, nitrogen, and oxygen compounds and traces of metallic substances called ash. The overall chemical compositions of crude oils are surprisingly uniform although their physical characteristics vary widely. The elementary composition usually falls within the following ranges: carbon 84 to 87%, hydrogen 11 to 14%, sulfur 0 to 2%, and nitrogen 0.2%. The hydrocarbons, which make up the most valuable portion of crude oil, fall within groups distinguished by basic chemical similarities: paraffins occur as straight chains of carbon-to-carbon linkages, naphthenes consist of rings of carbon atoms each bound to two unique hydrogen atoms, and aromatics are derivations of benzene - a six-membered carbon ring structure* (see Figure II-2). Paraffins are called saturated compounds because they contain the largest number of hydrogen atoms possible. All the other groups are unsaturated. In the United States crude oils are classified as paraffin base, naphthene base, asphalt base, or mixed base.

*For more detail on composition, see pp. 3-12 in Ref. 4 and pp. 20-23 in Ref. 10.

Paraffins

Methane

Propane

Butane

Isobutane

Naphthenes

Cyclohexane

Decalin

Aromatics

Benzene

Ethylbenzene

Figure II-2

Molecular Structure for Typical Hydrocarbon Constituents

The specific gravity or density (measured as mass per unit volume) of crude petroleum is a rough indication of its composition. API gravity, expressed in degrees API, is mathematically related to specific gravity in such a way that it usually indicates the relative gasoline and kerosine contents of the crude petroleum. Light crudes with API gravity between 30 and 50 generally contain high levels of gasoline and kerosine, while heavy crudes, which have lower numerical API gravity than light crudes, contain low levels of these products and large amounts of asphalt and residuum.

Sulfur compounds which exist in crude oil are corrosive to handling and processing equipment in the refinery. A very low sulfur level in the feedstock to catalytic reforming, cracking, and hydrocracking is critical for these refining processes to perform normally. These processes rely on catalysts to convert a large portion of crude oil into valuable high-octane gasoline. However, the expensive catalysts can be "poisoned" by coming in contact with sulfur which makes them less efficient and sometimes totally useless in performing as originally designed. In order that these processes function properly to meet demand for high-octane gasoline, the refiner must desulfurize feedstocks containing high amounts of sulfur. Other important reasons for desulfurization are that sulfur in gasoline has an offensive odor, and that it can destroy engine parts in automobiles. Finally, fuels must be low in sulfur to conform with environmental guidelines.

The heavy metals that make up ash in crude oils tend to build up in the heavier streams, e.g., residuum and heavy gas oils in refineries. When these streams must be processed further, metals such as vanadium, nickel, and iron can poison catalysts with the same effects as sulfur. In some cases heavy metal poisoning is irreversible, while sulfur poisoning can be remedied by simply burning off the sulfur.

Reserves

Proved reserves of crude oil and natural gas are defined as those estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Natural gas liquids, lease condensate, as well as oil from coal and shales are excluded by definition.

Domestic end-of-year reserves and annual production are shown graphically in Figures II-3 and II-4 for both oil and gas. In 1970 both production and proved reserves of domestic crude oil peaked and from 1971 to 1977 reserves and production have decreased such that the ratio of reserves to production has remained at between 10.3 and 11.5. Between 1971 and 1974 the net decrease in oil reserves was about 1 billion bbl/yr and from 1974 to 1977 it was about

Figure II-3
Proved Reserves and Production of Petroleum
in the United States

Figure II-4
Proved Reserves and Marketed Production of
Natural Gas in the United States

1-1/2 billion bbl/yr. Between 1971 and 1977 natural gas reserves decreased more rapidly than production so that the indicated supply of natural gas decreased from 12 years to about 10 years. Since 1967, natural gas reserves have decreased at about 10 trillion ft³/yr, approximately one-half of annual production.

More than 34 states hold oil and gas reserves in the U.S. It is interesting to note that Texas holds approximately one-third of estimated reserves, and together with Alaska and Louisiana accounts for almost 75% of total proved reserves. When the reserves of Kansas, New Mexico, California, and Oklahoma are added to those of Texas, Louisiana, and Alaska, the combined reserves represent over 90% of the U.S. total.

Overall Production Operation

There is no single extraction scheme to describe each of the more than 500,000 producing oil wells and 145,000 gas wells in the U.S. Nevertheless, the description that follows is an attempt to represent what might be a "typical" operation. Many of the features relating to origin, reservoir characteristics, and well equipment apply to the production of both natural gas and crude oil because of the close interrelationship of gas and oil in nature.

A mixture of petroleum, natural gas, and salt water is pumped to the surface and/or flows under natural pressure from a petroleum reservoir below the surface through a special pipeline called a well. The product from each well on a lease flows through a pipeline to a header which can combine the streams and direct them to a separation and treatment system (see Figure II-5) in the lease tank battery.

Part of the separation and treatment system is an oil and gas separator which physically separates natural gas from the oil. An additional test gas separator is provided as part of the lease tank battery to allow separate periodic measurement of gas and oil production for each well, and maintain production within the value set by the state for the well or oil field.

Another part of the separation and treatment system breaks down any oil-water emulsion that may be present using a chemical and/or thermal process. In some cases natural gas contains water vapor, which can combine with gas constituents under certain conditions to form icelike crystals called hydrates. Gas must be treated to remove this water vapor because hydrates can cause restriction or stoppage of flow in the pipeline if allowed to accumulate.

Salt water removed from the valuable hydrocarbons is a by-product of the separation and treatment processes. This water is often sent through a pipeline back to the lease for injection into the oil formations for dual purposes: Water injection can enhance ultimate oil recovery in certain cases; it also disposes of contaminated water.

Figure II-5

Petroleum and Natural Gas Extraction Operations

Crude petroleum, unlike gas, can be stored easily and thus it is sent to a storage system consisting of steel tanks capable of storing three to seven days' production. For the entire U.S. this amounts to between 26 MM and 61 MMbbl on the basis of the average daily production of 8.667 MMbbl for 1978 (total daily stocks of crude for 1978 averaged 330 MMbbl - excluding strategic petroleum reserve). Individual tank capacities can vary from 90 to 10,000 barrels.

All oil transactions are made on the basis of the mass of oil transferred. Since petroleum contains basic sediment and water (BS&W) and has a density which fluctuates with temperature, measurements of specific gravity, temperature, and BS&W are made for each transaction. Such measurements are made directly before and after oil is pumped out of a storage tank into a

pipeline, railroad tank car, or tank truck. An automated transfer system called Lease Automatic Custody Transfer (LACT) can perform routine operations and make these measurements automatically when oil is transferred to a pipeline. These operations are performed manually where automated units are not installed. The facility that is used to collect oil or gas from wells and transport these streams to primary destinations is called a gathering system.

Oil and Gas Leases

Oil and gas production is usually controlled by each state which obtains revenue based on the amount of petroleum or gas produced within the state boundary. In addition, state agencies maintain production at levels which will ensure maximum ultimate recovery of petroleum resources. For these reasons the producing states have established a system whereby producers pay a fee for a license to produce crude oil and gas in a geographic area. This license is called a lease and there is only one company (operator) on each lease. On average, there are usually more than one well producing oil on a lease. For example, in the State of Texas there are about 164,000 producing oil wells (Table II-1) and an inventory of approximately 47,000 producing leases, which corresponds to more than three wells per lease.

Oil and Gas Wells

An oil well or gas well is simply a pipeline extending from a formation that contains a petroleum or natural gas reservoir to the surface through which crude oil, salt water, and natural gas flow. The pipeline consists of many sections (also called strings) of special pipe (casing) screwed together to form a continuous pipeline string. In order to protect the hole from underground water and loose earth which might tend to cave in, two or more concentric casings are cemented into the hole as it is drilled. This also protects fresh water zones from contamination with drilling mud, which is pumped from the surface to lubricate and cool the drill bit, and from contamination with producing fluids when the well is operating normally. Figure II-6 is a drawing of a typical well.

The surface string (upper well section) varies from 200 to 1,500 ft, depending on local conditions. The intermediate string is also called a "salt string" because it extends far enough down to seal off salt and anhydrate formations and can be set at depths of 5,000 ft or more. The final string is called the "oil string" which extends through the other strings and sometimes protrudes further down through the producing zone at total depths of 20,000 ft or more. The deepest well ever drilled was 31,441 ft, almost 6 miles deep.

The string is a continuous length of tubing which ranges in size from 1-1/4 in. to 4-1/2 in. in diameter. This tubing may also be used to support a pump for artificial lift which may be needed, especially in the later life of the well. Tubing is used as the oil flow string because its repair or

Figure II-6

Cross Section of a Typical Oil Well

Source: Primer of Oil and Gas Production, API, 1973

Table II-1
Producing Oil Wells in the United States
(by State as of December 31, 1977)

State	No. of Wells
Alabama	631
Alaska	298
Arizona	29
Arkansas	7,756
California	43,525
Colorado	3,027
Florida	140
Illinois	23,752
Indiana	5,076
Kansas	42,450
Kentucky	14,046
Louisiana	23,881
Michigan	3,903
Mississippi	2,806
Missouri	175
Montana	3,330
Nebraska	1,382
Nevada	18
New Mexico	14,338
New York	4,800
North Dakota	1,608
Ohio	17,338
Oklahoma	73,338
Pennsylvania	28,400
South Dakota	69
Tennessee	283
Texas	163,746
Utah	1,448
Virginia	4
West Virginia	13,900
Wyoming	11,123
Total	507,034

Source: Basic Petroleum Data Book, API,
January 1979.

replacement is easier and more economical than that of the casing, and because casing is usually too large to permit the well to flow efficiently. In some cases it is more practical and economical to drill a smaller diameter hole and use conventional tubing as casing in the well.

Wellhead

The wellhead is used to maintain surface control of the well. It forms a seal to prevent blowing or leaking at the surface and may be a simple assembly to support the weight of tubing or pump in the well, or it may be made of special heavy fittings designed to contain pressures up to 20,000 psi when formation pressure is high. When production and pressure are low, such as in stripper wells that produce less than 10 bbl/day, the simple wellhead (Figure II-7) may be used. A Christmas tree (Figure II-8) is the name for the configuration of control valves and special fittings needed for wells which are expected to have high pressures.

Figure II-7

A Typical Wellhead Assembly

Source: Primer of Oil and Gas Production, API, 1973

Figure II-8

A High Pressure "Christmas Tree" Wellhead

Source: Primer of Oil Well Drilling, University of Texas at Austin, 1979.

Lift

Oil is produced at the well using the natural pressure in the oil reservoir to force oil to the surface whenever possible. When reservoir pressures fall to the point where a well will not produce in this way, some means of artificial lift is needed. Approximately 90% of all wells require an artificial lift system.

Three groups of oil well pumps at the bottom of the well are used in this case, depending on the means of power: string rods, high pressure liquids, and centrifugal pumps. High pressure gas can also be used to lift the oil from the reservoir. Figure II-9 is a sketch of a surface pumping unit which is used to transmit work via polished rods to a rod pump located in the well. Power is transmitted - via a crankshaft, walking beam (with counter weight to operate more efficiently), and polished rods - to the rod pump which converts the power into mechanical lift needed to pump oil to the surface. A hydraulic pump and hydraulic liquids can be used to work a hydraulic engine which pumps oil to the surface. A specially designed electric submersible pump can be suspended in the well by the tubing string, and used to pump oil out the top. A typical submersible pump may lift from 250 to 25,000 bbl/day depending on the size of the casing and the depth of the well. Gas under pressure can be used to lift oil by (1) aeration of the fluid column in the well; (2) work of expansion of compressed gases; or (3) displacement of fluid by the compressed gas. Special gas lift valves supplied by an air compressor at ground level are suspended by the tubing string in the well so that these processes can work at the desired location.

The production capacity of gas wells depends upon reservoir characteristics, wellhead equipment, and pressure required at the wellhead for flow into a pipeline. If the producing pressure at the surface is less than pipeline pressure, a compressor is needed to pump gas into the pipeline. Producing rates may vary widely depending upon well capacity and gas sales contracts. Production from a low pressure shallow well usually will not vary appreciably because of the narrow margin of available pressure. A deep gas well with high formation pressure may be required to produce 500 Mcf one day and 5000 Mcf or more the next.

Separation of Oil and Gas

Three fluids are produced at an oil well: oil, gas, and salt water. Before gathering lines can handle associated natural gas, the gas must be directed to a separator installed at the well where crude oil and other heavier hydrocarbon components that liquefy easily are removed. Figure II-10 is a diagram of a typical vertical oil and gas separator. The oil and gas mixture enters the separator near the middle. Most of the oil is separated from the gas by a combination of gravity and centrifugal force created by swirling the mixture at high velocity. Oil particles strike the inside wall and flow down the walls to the bottom. Additional chambers are used near the top to extract additional oil entrained with the gas in a fine mist. Oil is withdrawn from the bottom, and "wet" natural gas is withdrawn from the top of the separator.

There are three other types of oil and gas separators: Horizontal, stage, and low temperature separators may be used to separate the two products. In addition to the separation of the liquid and gaseous phases of petroleum, salt water must be removed from the petroleum liquid. Water and any sediment are separated from oil by their differences in specific gravity in a series of simple settling tanks. The proportion of liquid to gas in nonassociated gas is

Figure II-9

A Surface Pumping Unit

Source: Primer of Oil and Gas Production, API, 1973

Figure II-10

A Vertical Oil and Gas Separator

Source: Primer of Oil and Gas Production, API, 1973.

generally low enough to permit gathering lines to transport the gas either to a gas processing plant or directly to the pipelines without the use of a well-stream separator.

Storage System

Crude petroleum is transferred to a tank battery which usually has a total capacity of three to seven days' production and can serve up to 60 wells or more. There are usually two or more tanks so that while one tank is drawn down another tank can receive production. A "thief" is a device that is lowered into the tank to obtain oil samples to determine the BS&W content and the API

gravity. Whenever oil is sampled, the temperature is taken. Automatic devices called liquid level controllers signal when the tanks are full, and valves open and close according to a prearranged schedule. The outlet valve from oil storage tanks is always about one foot above the bottom to minimize contamination of shipped product with sediment and water.

Measurement

State regulations usually limit the quantity of oil that can be produced from each field on the basis of the current market demand for oil or gas and the efficient rate of production. This is necessary to ensure that the maximum overall quantity of oil be recovered because withdrawal at too high a rate can permanently limit the recovery of oil from a given reservoir. For production control purposes the volume of oil, gas, and salt water produced by each lease is usually checked or measured by the lease operator over each 24-hour period.

The amount of gas produced from a well is measured by passing the gas flowing out of the separator through an orifice meter, a device that measures flow rate based on pressure drop of the stream flowing through a constriction in the pipe. Flow rate of oil out of the separator is measured by a meter or by the change in height of the liquid as it flows into a calibrated tank during a measured time period. Before measurements of oil volume are taken the BS&W is drained from the tank. With each height measurement the BS&W content of the oil, its temperature, and API gravity are also recorded. These three additional measurements must be taken because oil transactions are in terms of net barrels of oil adjusted to the standard base temperature of 60°F at which crude oil prices are posted. When oil is emptied from a tank and delivered to a pipeline, tank car, or tank truck, the volume shipped is also measured in this manner.

In the older lease installations measurements are made manually, but steps have been taken toward automation. New equipment provides for LACT. This system allows for unattended transfer of oil or gas from the lease to the pipeline. The unit takes samples, records temperatures, determines quantity and net volume, does other routine tasks, and even shuts itself off and sounds an alarm when something goes wrong.

Fluid Injection

Maximum oil recovery efficiency and savings in natural gas can be achieved by injecting fluids, including oil and gas, back into the formation at, or close to, its natural pressure. Injection of gas into an oil pool increases oil recovery and sometimes results in a savings of natural gas. Injection is also useful as a means to dispose of the salt water produced with the oil. The injection takes place in a pipeline which is separate from the producing well. Gas injection requires the use of compressor plants to achieve the higher pressures which occur in the formations. Where water cannot be injected by gravity alone, a pump is necessary to achieve the desired rate.

III. CRUDE PETROLEUM AND OIL PRODUCT BULK TERMINALS

Overall Operation

A bulk terminal is a major storage facility where large shipments of crude oil and oil products flow en route to and from refineries on a regular basis. DOE defines a product bulk terminal to be "a facility which is primarily used for storage and for marketing of gasoline, kerosene, distillate, and residual fuel oils and which (1) has total bulk storage capacity of 50,000 barrels or more, or (2) receives its petroleum products by tanker, barge, or pipeline."* The storage criterion differentiates the oil product bulk terminal from wholesale dealers (also called jobbers) which have much smaller storage capacity. Bulk quantities of oil products are usually shipped from a refinery terminal directly to a product bulk terminal. Jobbers generally receive supplies from bulk terminals and, in turn, distribute oil products to the retail distributors. The largest oil users, such as industry and electric utilities, receive supplies from refineries and bulk terminals, jobbers sometimes sell direct to smaller consumers such as institutions. Retail distributors supply only the smallest users such as individual residences and the smallest users in the commercial sectors.

The primary function of a bulk terminal is to provide an efficient means to load, unload, store, and distribute large volumes of crude petroleum or oil products shipped from producing or refining regions on route to distant demand regions. One measure of the importance of bulk terminals is the volume of imported crude and refined petroleum passing through terminals each day. Table III-1 shows that more than 6 MMbbl of crude oil and about 2 MMbbl of oil products on average passed through terminals each day in 1978. The U.S. depends on port bulk terminals alone to ensure the efficient passage of 41% of crude oil demand and 11% of oil products demand. Bulk terminals are also needed for domestic crude petroleum to reach refineries and for refined products made at domestic refining centers to reach demand throughout the entire country.

Size and operations vary widely for the estimated two to three thousand bulk terminals in the U.S. At one product terminal in the Northeast a typical operation is the unloading of 200,000 to 300,000 barrels of oil products from a tanker over a 24 hour period. Storage capacity can vary from 50 thousand to 5 MMbbl or more at a single facility. Because of the large dimensions of operation, product bulk terminals operate most efficiently by selling products directly to large end users in the industrial, commercial, and electric utility sectors and supplying bulk quantities (normally 7,000 gallons and up at one time) to jobbers and retail or distributors for resale.

*Instructions for the Preparation of the Monthly Bulk Terminal Stocks of Finished Petroleum Products Report (FES-P321-M-0).

Table III-1
Total Demand and Imported Supply of Petroleum in the U.S. for 1978
(Mbbl/day average/yr)

	1,000 Barrels/day	Percent
Crude petroleum		
Refinery input	14,742	
Imports (excluding SPR)	6,044	41.0
Domestic production	8,667	59.0
Petroleum Products		
Total domestic demand	18,734	
Imports	1,982	10.6

Data source: Monthly Energy Review, EIA, March 1979, pp. 28 and 30.

Product terminals are generally independent of oil refining or producing companies, while crude oil bulk terminals are generally (but not always) directly associated with a refinery. When this is true the size and operations for the crude terminal are based on its associated refinery. A typical day's operation for a terminal at a 300,000 bbl/day refinery might be the unloading of 500,000 barrels of foreign crude oil from a tanker while loading oil products onto several barges (over a 24-hour period).

A critical section of the port terminal is the pier or loading platform where the loading and unloading of tanker and barge cargo occur. For terminals that are not close to a deep harbor, a loading platform must be installed offshore in water that is deep enough to accommodate oil tankers. A schematic drawing of the layout of a typical terminal with offshore loading platform is shown in Figure III-1. The terminal consists of four sections: the loading platform, storage tank area, tank truck loading dock, and pipeline connected to a commercial pipeline company. A piping network with pumps, valves, and metering equipment ties the terminal sections together.

Cargo is pumped out of the vessel at the platform through submarine lines into storage tanks on shore. Each storage tank can usually be filled directly from a vessel at the platform. A pipe manifold and suitable valves on the platform allow vessels to be lightered, a term used to describe the direct offloading of one vessel's cargo onto another.

Oil from the storage tanks can be pumped to a pipeline, tank truck, railroad tank car, or a vessel at the offshore platform for transportation to users, terminals, or distributors. A special truck loading dock allows simultaneous access to many tank trucks from one or more storage tanks at the terminal.

bul
dui

Figure III-1

A Schematic Diagram of a Typical Bulk Terminal

Terminal Functions

Bulk terminals normally function in three ways: as a reserve facility, as a direct supplier, and as a transfer point. A terminal can operate as a reserve facility for its operating company or for another company such as an oil refiner. Stocks of seasonal fuels such as gasoline and heating fuel are built up during the off season and drawn upon when in demand. They can be shipped out of reserve to other terminal facilities in the same or other geographic demand regions. For example, one or more major oil companies might rent a storage tank at a bulk terminal and treat it in the same way as a storage tank at its refineries. In this case the product is owned by the oil company, but is in the custody of the terminal. The product is shipped from the storage terminal by order of the owner even if the owner is not the terminal operator. Standard terminal procedures usually include daily measurement of all stocks, with breakdown by ownership company.

Bulk terminals are direct suppliers to refineries in the case of crude oil and to jobbers, retail distributors, and large end users in the case of oil products. Contracts for supplies are negotiated on a six-month basis for large product shipments on call. Since product bulk terminals handle large volumes they generally serve only the largest customers: small oil distributors, utilities, major transportation systems (such as airports, gasoline and truck stations, and railroad terminals), large commercial users, and industry.

Residential heating fuel is supplied to homes by the small distributors which generally sell products locally to only the residential and small commercial sectors. The territory served by distributors is only a fraction of that served by the product bulk terminal. Tank trucks and barges transport the bulk of heating fuel which is supplied to the distributors from product bulk terminals. Carriers may or may not be owned by the terminal. For a typical terminal in the Northeast, when a cold spell spurs an increase in demand for heating fuel, there is usually about a three-day lag time before the terminal shipments to distributors increase. Lag time is related to the amount of products in storage at local distributors and the minimum stock level that local distributors decide to keep at any time.

Bulk terminals have port facilities which can accept bigger product carriers than the smaller distributors. For this reason large ships with drafts of 60 to 70 feet might "lighter" half the cargo at a terminal so that they can proceed to a distant terminal with less channel depth. A tanker might unload part of its cargo onto a barge at a bulk terminal, and one or both vessels could deliver the cargo to another port. Thus the terminal functions as a transfer point since some or all of the product transferred does not go into storage tanks at the terminal. Lightering operations can also take place in a suitable harbor or at sea, if necessary. In this case the two vessels must dock together in open water to transfer cargo.

Tanker and Barge Operations

An oil tanker, also called a tankship, is a self-propelled marine vessel which has the capability to store and transport large amounts of crude petroleum or oil products on water. The deadweight ton (DWT) is the unit of measure for tanker capacity. Crude capacity of a ship can be approximated by multiplying the ship's deadweight by 6.5 bbl/long ton. Tanker size can vary from 10,000 to 500,000 long tons which corresponds to 65,000 to 3.25 MMbbl of petroleum. Limiting factors for determining the number and size of tankers which can deliver to a terminal are the maximum draft and the number and size of berths available. Small tankers draw as little as 25 feet of water, medium-sized tankers draw up to 60 feet, and large tankers take as much as 90 feet or more. As ships were built larger new terminology developed to describe the large tankers. The terms supertanker, VLCC (very large crude carrier), and ULCC (ultralarge crude carrier) came into common usage. These terms have no real technical validity but refer only to the carrier's approximate size.

The flow of most of the crude oil imported by the U.S. originates in two regions, the Middle East and Northwest Africa. Crude from Northwest Africa flows to the U.S. in medium-sized tankers since no U.S. port terminals can accept large-sized ships. However, Middle East crude is shipped from the Persian Gulf and must move around Africa to reach North America. For this long route, the vessel size is limited (by economic factors) to only the largest tankers that carry about 3 MMbbl each. When fully loaded these VLCC's require 70 feet or more of water, and there is currently no port in the

U.S. capable of handling such ships.* In order that this crude enter U.S. terminals, cargo must first be transshipped onto medium-sized tankers. Much of the transshipment operations for Middle East crude en route to the U.S. occur in the Netherlands Antilles.

Oil tankers are capable of carrying more than one type of product in the same vessel, using separate cargo tanks. The 230,000-DWT tanker shown in Figure III-2 contains separate tanks for cargo oil and water ballast. Water

Figure III-2

Arrangement of a 230,000 DWT Tanker

Source: Energy Technology Handbook (Reference 3)

*The Louisiana Offshore Oil Port (LOOP) is designed to receive shipments from the largest supertankers at an offshore single point mooring (SPM). In January 1977 LOOP, Inc. announced that it would proceed with the construction of the deepwater port off of the Bay Marchand area, adjacent to Terrebonne Bay.

ballast is used to stabilize the carrier when cargo oil is not evenly distributed. Water ballast that is contaminated with petroleum and other slops sometimes cannot be disposed of at the terminal and must remain on board. Storage tank arrangements now incorporate ballast and slop tanks for this purpose. Safety developments in large tankers include inert gas systems for cargo tanks. All tank boundaries are oiltight with access from the main deck through raised oiltight hatches.

The general layout for oil tankers provides the most space for oil storage. Minimum volume is occupied by engines, pumps, the cabin, and living quarters which are located furthest aft (in the rear of the vessel). A cargo pipe manifold is located at the center of the ship for easy access to all storage tanks. Pipelines connect each tank via the manifold to pumps near the ship's engines. These pumps, which are usually powered by diesel engines, discharge cargo out of the vessel through the cargo manifold.

Barges are similar to tankers but are much smaller and not self-propelled. Barge capacity on average is between 60 to 300 Mbbl. A tugboat is needed to push or pull a barge from source to destination, or barges can be linked together and pushed as one barge train. The largest amount of petroleum shipped by barge is moved in barge trains of 10 to 12 barges linked together in a group that is pushed by a tugboat. Barges, like tankers, carry their own pumps for cargo discharge and have many storage compartments.

Loading and unloading operations that are necessary for supplies to reach a terminal can occur at a conventional pier or an offshore facility. Depending on the type and location of the facility, there is a loading platform and/or one or more buoys that provide (1) a means to hold the oil carrier securely, (2) a means to transfer the cargo from the carrier's manifold to a terminal manifold, and (3) a submarine or conventional pipeline from the terminal manifold to the storage system on shore.

A conventional pier or a sea island contains a manifold situated adjacent to that on the carrier when the ship is properly berthed. The two facilities are similar except that a sea island is more exposed to the elements than a pier. The carrier normally proceeds to a point 200 to 500 feet from the berth and two or more tugboats either push or pull it up against breasting dolphins designed to take the impact of the ship's weight during berthing and while the ship is moored. Quick release hooks are attached to mooring dolphins to fasten the ship's lines and secure the vessel within a suitable envelope in order that loading and unloading operations can proceed. The loading arm is a flexible pipeline connecting the tankship and pier or platform manifolds. It has a special coupling that allows armlike motion as the ship rises or falls with tidal or wave action, or from shifting of the vessel due to the loading or unloading operation. Most terminals now use loading arms, although some older facilities simply use flexible hoses for this purpose.

Weather conditions can put limitations on the mooring or berthing of tankships. Sea height can prohibit tugboats from controlling tankers. When the waves come from ahead or astern, 10-ft sea heights are considered to be

limiting. Seas that approach the side (beam) of the ship are more critical: 3- to 4-ft sea heights from abeam limit the ability to maneuver safely. These severe conditions rarely occur in the harbors where U.S. port terminals are located. Ice must be broken up so that tankers can access a terminal. Most berthing areas are provided with a system to prevent ice formation, but channels must be cleared by ice breakers where necessary. Each terminal establishes policy concerning weather conditions and the usage of tugboats for oil tanker maneuvers. The terminal manager keeps in contact with tankers, barges, and workers at the pier or platform to direct the entire operation.

Large crude carriers often unload at multiple or single-point buoy mooring facilities, which use methods unlike those for the pier or offshore platform. The ship is secured to one or more mooring buoys instead of a pier or platform, and crude is pumped through floating hoses coupled to a buoy which is connected to submarine pipelines. A mooring master boards the tankship before mooring and, with the captain, plans a safe approach to the buoy(s), prepares the ships manifold, and performs other preparatory functions before unloading cargo. The mooring master or his relief normally remains on board during unloading and aids in the disconnection and departure from the buoy. Transshipment operations usually occur at buoy mooring facilities. Currently there are no such facilities in the U.S., although a deepwater port (LOOP) is planned for Louisiana.

Each terminal provides a means to receive oil directly in storage tanks as it is pumped from the vessel. This includes a loading arm or hose, a pipe manifold with suitable valves, and a pipeline system to direct the cargo to storage. Oil is pumped from the carrier into the pier or platform manifold through the loading arm. The terminal manager can direct cargo to storage tanks on land or to another vessel on the platform using the platform manifold, a pipe and valve arrangement which permits the operator to select a variety of inlet and outlet lines at the loading platform and on shore. Lightering, the direct loading of one vessel from another at the pier or offshore platform, is often performed to reduce the draft of large vessels so that they can proceed to other terminals which have smaller draft limitations.

When large amounts of cargo are transferred from one company to another, an oil inspector is assigned by the product owner to certify the transaction. The inspector takes samples and measures the amount of oil on board the tanker and in the storage tank on land before and after the cargo is discharged. Samples are analyzed by a private laboratory so that the inspector can identify type of product, BS&W, and other specifications.

The discharge flow rate is limited by the size of pumps on board the carriers. These centrifugal pumps deliver at an average rate of about 20,000 bbl/hr although actual rates vary between 5 and 40 Mbbl/hr for medium-sized tankers. The actual discharge rate is in general related to the deadweight of the carrier. Terminal criteria for unloading specify the minimum discharge rate for carriers to be no less than 5% of its deadweight tonnage per hour, so

that the maximum stay in berth will be one day. Piping systems for terminals are usually rated higher than carrier discharge rate so that terminal facilities are not a limiting factor. When the storage tanks on land are at substantial heights above sea level, the terminal will usually provide booster pumps to provide the discharge head pressure needed to push the oil uphill. In this case, pumps on board the carrier are only needed to deliver oil to the booster pumps.

Storage System

There are an estimated two to three thousand product bulk terminal facilities in the United States having a minimum storage capacity of 50,000 barrels each. The number of smaller storage terminals (owned by jobbers) is estimated to be twenty to thirty thousand. Steel tanks ranging in capacity from 10,000 to 500,000 barrels or more are used to store products at bulk terminals. Jobber and distributor terminals tanks fall within a smaller size range. Tanks are usually placed in many groups of two or more and each tank group is reserved for one product. Pumps, a pipe manifold, and valves are installed in each group in such a way that two tanks can be filled or drained at the same time. A dike and sealed floor surround each group to contain spillage.

For each product there is one main line extending to the tank truck and railroad loading areas and to the major pipelines serving the terminal. Branches run from this line to the appropriate storage tank groups. Since main lines are always charged with the same product, contamination is less of a problem. Sea terminals are generally provided with one major pipeline for each berth at the loading platform or pier. For offshore platforms submarine pipelines, anodized and encased in concrete for protection from the corrosive nature of sea water, run on top of the sea floor to shore. These lines, which are usually 24 or 36 inches in diameter, branch on land for direct access to each group of storage tanks and to major pipelines leading out of the terminal.

Common practice for product bulk terminals is to combine (in one storage tank) products made by different refining companies. Since fewer storage tanks are needed, this practice results in an overall savings for the terminal operator and refiner companies. Refiners often rent one tank together for use as reserve storage. Only commodities such as regular, unleaded, and premium gasolines, heating and diesel fuel oils, residual fuel oils, and light products can be legally commingled in storage. When special additives are combined with a product to make it unique, it is no longer a commodity and the product cannot be commingled. The terminal operator keeps a daily record of the amount of product at the terminal as well as the amount owned by the terminal and other companies.

Often the only mode of transportation between the bulk terminal and smaller distribution facilities or end users is the tank truck. A loading dock allows many trucks to be loaded efficiently with products from one or more

storage tanks. Tank trucks may or may not be owned by the terminal, depending upon contract arrangements. Final shipments by tank truck are measured by meters installed in the line at the delivery point.

Any given tank at a storage facility can hold more than one product. To prevent product contamination, all residual product is drained out of the tank before a change is made. The tank is then entered, wiped out manually, and inspected. In certain cases the operator may choose to wash the tank with the new product and the slops are blended to upgrade other products in storage. The entire cleanup operation lasts an average of three days.

IV. STRATEGIC PETROLEUM RESERVE

Overview

The objective of the Strategic Petroleum Reserve (SPR) Plan is to store one billion barrels of petroleum in order to reduce U.S. vulnerability to the effects of disruptions in petroleum supplies. The SPR system is designed to store crude petroleum and oil products in areas where oil distribution pipelines and port terminals are accessible to the reserve. In this way the supplies can be rapidly withdrawn and enter the normal crude distribution system as quickly as possible, if necessary. The Gulf Coast was chosen by DOE as a desirable location where the existing commercial distribution system can be used most effectively. Crude stored in this area can quickly reach major markets in the Midwest and interior of the country, the East and Gulf coasts, and the Caribbean refineries.

Storage capacity for the system is being developed in a three-phase program (Table IV-1). Phase I storage will consist of 248-MMbbl capacity in existing underground caverns and mines at five sites. For Phase II 280 MMbbl of additional storage will be obtained by expansion of two of the existing five sites. In Phase III, 222 MMbbl storage capacity will be provided at new sites yet to be determined.

All three phases of the plan are in the working stages at this time. At the end of 1978, three sites contained a total of 68.5 MMbbl petroleum (Figure IV-1), but drawdown capability was not available. This level of storage was built up gradually from no storage over an eleven-month period. The average monthly import rate to the reserve was 6.09 MMbbl. As stocks are continually built up and new equipment installations become completed, drawdown capability will become available and increase continually. By November 1979, a total of about 1.1 MMbbl/day drawdown capability is scheduled to become available at four of the storage sites. A total of nine SPR sites are planned, of which six are now under construction. Construction of the seventh site is scheduled to commence in June 1979, and construction and oil fill schedules are being negotiated for the two remaining sites. Seven of the SPR sites are located in Louisiana, one is in Texas, and one is located in Irontown, OH.

Table IV-1
Three-Phase Program for SPR Storage Capacity*

Phase	Storage Capacity Development	Storage capability (MMbbl)		Drawdown Capability (MMbbl/day)
		Net	Cumulative	
I	Existing caverns and mines - at five sites	248	248	1.7
II	New leached caverns - expansion of two of the existing five sites	280	528	3.5
III	New sites - to be determined	222	750	4.5

*Source: Annual Strategic Petroleum Reserve Report, February 16, 1979, DOE/US-0003.

Figure IV-1

Total Strategic Petroleum Reserves

Source: Annual Report to Congress 1978, EIA. DOE/EIA-0173/2.

Description of the Storage System

Location of petroleum storage for the SPR is in large underground caverns called salt domes. Storage capacity for each cavern is estimated to be between 5 and 32 MMbbl. The vast size of these domes can be gauged by comparison to storage capacity for a large oil terminal which is on the order of 5 to 10 MMbbl. One modest-sized cavern is as big as a large bulk terminal, and each SPR site typically contains four or more caverns.

The process flow system for a cavern is shown in Figure IV-2. Oil is supplied from a port terminal through a site pipeline system to the cavern. The cavern is initially filled with brine, a strong solution of salt dissolved in water. Oil is injected into the top of the cavern and remains above the brine layer. An equal volume of brine is displaced by the oil and is forced out through a pipeline from the base of the cavern to the surface. Brine is disposed of by injection into deep underground wells, by pumping into the Gulf of Mexico through special pipelines, or by supplying it to nearby brine chemical companies.

Petroleum is withdrawn by reversing the filling process. Fresh water supplied by a large nearby water source is pumped through water lines on site and injected into the bottom of the dome. An equal volume of petroleum displaced by the water is forced out the top of the dome. The oil then flows through the oil pipeline system to a distribution terminal where it is transported to refineries in commercial pipelines, tankers, and barges.

Different types of foreign crude oil are received at a site and mixed to specifications for SPR blends. The blends of petroleum are broken down into five types; type I is sour and types II through V are sweet crude oil blends. Only one type of crude can be stored in any given cavern.

Each SPR site is located near a port terminal where imported crude oil can be received. A commercial pipeline or distributing terminal must be accessible to the site so that SPR petroleum can enter the existing crude oil distribution system. In addition, the site must be near a large source of water and a suitable location where brine can be disposed of. Transportation linkages (usually pipelines) must be provided so that oil, brine, and water can flow efficiently during filling and drawdown. Figure IV-3 is a map showing a typical SPR site, Bryan Mound, which is located three miles southwest of Freeport, Texas.

The link between Seaway Pipeline Company docks and Bryan Mound is a 30-inch-diameter crude oil pipeline. SPR oil can be delivered by pipeline to the docks or to a junction in the Seaway Pipeline (which can then deliver the oil to Cushing, Oklahoma). Brine solution can be dumped via a pipeline into the Gulf of Mexico or delivered to nearby Dow Chemical Company. All the pipeline linkages to these facilities were provided under the SPR plan. A detailed diagram of the Bryan Mound site is shown in Figure IV-4. Water is supplied from the adjacent Brazos River.

Figure IV-2

Fill and Withdrawal Operations for an SPR Storage Cavern

Source: Annual Strategic Petroleum Reserve Report, February 16, 1979,
DOE/US-0003

BRYAN MOUND

Figure IV-3

Crude Oil and Brine Linkages for the Bryan Mound SPR Site

Source: Annual Strategic Petroleum Reserve Report, February 16, 1979,
DOE/US-0003

Figure IV-4

Oil, Water, and Brine Distribution System for the Bryan Mound Site

Source: Annual Strategic Petroleum Reserve Report, February 16, 1979, DOE/US-0003

The SPR sites are essentially the same as Bryan Mound in facilities, overall operations, and equipment needed for filling and withdrawal of caverns. Storage capacity for the caverns depends upon their sizes, which are determined and certified by a private engineering company. Quantity of each type of crude in storage is monitored regularly. Separate piping distribution systems are installed on the sites for oil, brine, and water. Special pumps, which are part of this system, are sized to deliver specified amounts of oil, brine, and water so that desired fill and withdrawal rates can be ultimately achieved.

Aboveground storage tanks can hold 800 Mbbl of oil at Bryan Mound, but not every site has such facilities. Two of the nine sites will use submersible electric pumps to withdraw oil from caverns, and therefore will not need to handle brine for these operations. However, special inert gas systems are needed to "blanket" the crude to prevent formation of combustible mixtures of oil and air in the empty space above oil in the cavern.

For the six sites where brine displacement methods are used for filling caverns with oil, brine injection wells are available either within or outside the site. Only two of these sites can utilize nearby brine chemical plants as a means of brine disposal.

Oil input and drawdown capabilities during the construction stages will be dependent upon the extent of completion for the system at each particular site. However, once construction is completed these capabilities should remain relatively constant. The carrying capacity of links to the existing commercial distribution system could be a limiting factor for overall site drawdown capability. Each SPR site is unique and therefore the storage, input, and drawdown capabilities and transportation linkages will be site specific once construction is completed.

For the oil displacement method of withdrawal, drawdown rate is related to the amount of oil stored within a given cavern. According to construction and storage schedules, 750 MMbbl of oil in storage will gradually be built up by 1985 from the 69 MMbbl in storage in 1978. Thus, storage capability and quantity as well as drawdown capability for some of the sites will be changing at least until 1985.

V. PETROLEUM REFINERIES

Refinery Feedstocks

Crude oil is a mixture of thousands of different hydrocarbon compounds as well as compounds containing sulfur, nitrogen, and various metals (Section II). The proportions of the compounds comprising a given crude oil determine its properties. Petroleum refining is the process of separating crude oil into various hydrocarbon groups, removing undesirable compounds, and breaking up, combining, or rearranging the hydrocarbon molecules. The resulting streams are blended to produce useful and relatively uniform finished products for diverse uses.

Since petroleum is very complex, no attempt is made by the refiner to analyze for the pure components contained in crude oil. Relatively simple analytical tests are run on the crude, and the results of these are used with empirical correlations to evaluate the crude oils as feedstocks for the particular refinery. The refinery normally has quick access to the results of analyses for crude oils which are expected to become available at any future time. Purchasing as well as production scheduling strategy for each refinery is based upon comparisons among the crude oil feedstocks available. The more useful properties of crude petroleum feedstocks are as follows: gravity (density) expressed in degrees API, sulfur content expressed as percent sulfur by weight, pour point in degrees Fahrenheit, carbon residue, salt content, nitrogen content, metals content, and boiling range.

Sulfur content and API gravity are the two properties having the strongest influence on the value of crude oil. Most crudes fall in the 20° to 50° API range and 0.1% to > 5% sulfur range. High-API gravity and low-sulfur content (< 0.5% sulfur) are desirable in crude oils. Pour point of crude oil is a rough indicator of the relative paraffinic and aromaticity of the crude. Carbon residue, determined by boiling away the crude oil in the absence of air to a coke residue, is roughly related to the asphalt content and to the quality of the lubricating oil fraction that can be recovered from the crude. When salt content is greater than 10 lb NaCl/1,000 bbl of crude oil, the refiner generally must desalt the crude before processing to prevent corrosion problems. A high nitrogen content, generally above 0.25%, is undesirable in crude oils because organic nitrogen compounds cause severe poisoning of catalysts used in processing. Metals content of crude oil can vary from a few parts per million to more than 1,000 ppm (0.1%). Minute quantities of some of these metals (nickel, vanadium, and copper) can severely affect the activities of catalysts used in processing equipment. The boiling range of the crude gives an indication of the quantities of the various constituents present in the crude oil.

In the United States crude oils are classified as paraffin base, naphthene base, asphalt base, or mixed base. Table V-1 shows analysis of some United States crude oils. An example of asphaltic base crudes are as follows: San Ardo, California, and Wyoming (sour). These are heavy crude types as indicated by the low API gravities, 13.3° API and 17.9° API, that contain relatively large amounts of asphalt, 48.8 and 39.9%, respectively. API gravity and the amount of gasoline present in these crudes are roughly related: crudes with API gravity from 36 to 41 in Table V-1 contain the highest amounts of gasoline, 26 to 38%.

A guide to world crude oil export streams, Table V-2, was published by the Oil and Gas Journal. Refiners identify foreign crude oils by crude designation, country of origin, API gravity, sulfur content, and pour point as shown in this table. These crudes are commodity items in the international oil market. Arabian light is a benchmark crude and its price is used as a reference for determining value of different crude types.

Table V
Analyses of United States Crude Oils

	McComb, Mississippi		Southwest Texas		East Texas	Wyoming (Sour)	New Mexico	N. Kenai Penin., Alaska	San Ardo, California	Ospelousas, Louisiana		Velma, Oklahoma
Gravity, °API	40.7		36.5		39.1	17.9	37.5	25.9	13.3*	38.2		29.1
Distillation, °F:												
Type	D 86†	UOP 76‡	D 86	UOP 76	D 86	D 86	D 86	D 86	UOP	D 86	UOP 76	D 86
IBP (initial boiling point) . .	152	152	158	158	125	306	118	160	IBP 180 0.3†	127	127	145
5% over	192	192	208	208	191	408	162	196	180- 380 1.6†	206	206	224
10	224	224	244	244	211	476	224	220	380- 550 16.1†	256	256	482
30	344	344	461	461	355	633	354	514	550- 650 10.6†	438	438	659
50	504	506	700	770	539	675	530	660	650- 900 17.3†	545	575	712
70	635	703	760+	1075	702	710	626	690	900-1000 6.0†	672	720	748
90	760+	977	...	...	760	732‡	728	710‡	1000+ 48.1†	760+	905	748+
EP (end point)	...	1062	...	...	760+	732+	734+	710+	...	...	978	...
% recovered	98.5	95.5	98.5	90.5	97.0	89.0	93.0	80.0	...	98.5	96.0	95.5
% bottoms	...	4.5	...	9.5	...	...	...	...	...	...	4.0	...
% coke, wt.	1.6	...	1.8	...	2.8	11.0	5.6	...	...	0.7	...	...
% recovered	...	...	...	...	...	...	...	...	...	...	...	...
At 400°F	37.0	...	32.0	...	34.5	4.5	35.0	...	1.9*	26.5	...	22.5
525°F	53.0	...	48.0	...	54.0	15.0	55.0	...	17.9*	46.0	...	33.5
572°F	60.0	...	54.0	...	...	20.0	...	...	...	54.0	...	39.0
Total sulfur, wt %	0.07		0.45		0.2	3.33	1.0	1.036	1.93*	0.08		1.13
Reid vapor pressure, psi	4.6		3.4		...	0.2	8.8	4.2	...	8.4		4.0
Pour point, °F	60		30		55	-5	25	...	...	40		< -30
Bottom sediment and water, . .												
vol %	0.10		0.10		0.1	0.3	0.3	2.5	...	0.15		0.2
Conradson carbon residue, wt % .	0.79		1.74		...	...	...	...	...	0.52		...
Salt (as NaCl) lb/1,000 bbl. . . .	4		<0.5		31	0.6	14.0	76.0	...	5.0		78.0
Gasoline, vol%	35.5		32.0		29.0	6.3	37.8	14.4	1.9	26.1		22.3
Kerosine, vol %	18.1		12.1		10.1	9.1	...	18.0	16.1	18.9		17.3
Diesel fuel, vol %	14.6		38.0		13.8	14.0	...	18.4	10.6	22.9		8.5
Gas oil, vol %	28.1		12.6		...	30.7	41.2	22.3	23.3	27.9		31.9
Asphalt (bottoms), vol %	3.7		5.3		(47.1)	39.9	20.8	25.7	48.1	4.1		20.0
Metals (in gas oils), ppm:												
Nickel	0.06		...		...	...	...	...	0.15	...		...
Vanadium	0.08		...		...	...	...	...	<0.1	...		...

From Douglas M. Considine (ed.), "Chemical and Process Technology Encyclopedia," McGraw-Hill Book Company, New York, 1974.

*Calculated.

†% over in indicated boiling range.

‡Cracked at 80% over.

§ Designates data from Method of Test D 86, Committee D-2 on Petroleum Products and Lubricants, ASTM.

§ Designates data from UOP Laboratory Test Methods for Petroleum and Its Products, No. 76, Universal Oil Products Company.

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Source: "Energy Technology Handbook," Considine, McGraw-Hill, NY, 1977.

Table V-2

World Crude Oil Export Streams*

Most common designation of crude stream	Producing country	Gravity °API	Sulfur wt %	Pour point	Shipping point	Operators, participants or producers§
Amna	Libya	36.1	0.15	+ 75° F.	Ras Lanuf, Libya (SBM)	Mobil/Gelsen./LNOC
Anguille*	Gabon	32.0	0.74	+ 3° C.		Elf
Arabian heavy*	Saudi Arabia	28.2	2.84	- 30° F.	Ras Tanura, Saudi Arabia	Aramco/Saudi Arabia
Arabian light-Berri	Saudi Arabia	38.8	1.10	- 30° F.	Ras Tanura, Saudi Arabia	Aramco/Saudi Arabia
Arabian light	Saudi Arabia	33.4	1.80	- 30° F.	Ras Tanura, Saudi Arabia Juaymah, Saudi Arabia (SBM) Sidon, Lebanon	Aramco/Saudi Arabia
Arabian medium	Saudi Arabia	30.8	2.40	+ 5° F.	Ras Tanura, Saudi Arabia	Aramco/Saudi Arabia
Arabian medium-Zuluf*	Saudi Arabia	30.7	2.51	- 40° F.	Zuluf field (SBM)	Aramco/Saudi Arabia
Arjuna*	Indonesia, Java	37.7	0.12	+ 80° F.	Arjuna field (SBM)	ARCO
Arzew blend	Algeria	44.3	0.10	- 21° C.	Arzew, Algeria	Sonatrach
Attaka*	Indonesia, East Kalimantan	43.2	0.07	- 30° F.	Santan Term., E. Kali.	Union Oil
Bachequero, 16.8° API	Venezuela	16.8	2.40	- 10° F.	La Salina, Venezuela Bachequero, Ven. (13° API) Puerto Miranda, Ven.	Venezuela
Bai Hassan Jambur	Iraq	34.1	2.40	- 18° C.	Tripoli, Lebanon	INOC
Bu Attifel	Libya	40.6	0.10	+ 39° C.	Zueitina, Libya	AGIP/LNOC
Basrah	Iraq	33.9	2.08	+ 15° C.	Khor al Amaya, Iraq (SBM)	INOC
Bekapai*	Indonesia, East Kalimantan	41.1	0.08	- 32.5° C.	Field (SBM)	Total
Beryl*‡	U.K.	39.5	0.36	< - 65° F.	Beryl field (SBM)	Mobil et al
Bonny light	Nigeria	37.6	0.13	+ 36° F.	Bonny, Nigeria (SBM)	BP/Shell
Bonny medium	Nigeria	26.0	0.23	< - 5° F.	Bonny, Nigeria (SBM)	BP/Shell
Boscan	Venezuela	10.3	5.4	+ 50° F.	Bajo Grande, Ven.	Venezuela
Brass River	Nigeria	43.0	0.08	- 5° F.	Mouth of Brass (SBM)	AGIP/Phillips/NNOC
Brega	Libya	40.4	0.21	+ 30° F.	Marsa el Brega, Libya (SBM)	Esso Libya/LNOC
Bunju	Indonesia, E. Kalimantan	32.2	0.08	+ 17.5° C.	Balikpapan, E. Kali.	Pertamina
Burgan (Wafra)	Neutral Zone	23.3	3.37	- 5° F.	Mina Saud, Neutral Zone	Getty

*Printed in March 29, 1976 issue of Oil & Gas Journal.

Table V-2 (cont'd)

World Crude Oil Export Streams

Most common designation of crude stream	Producing country	Gravity °API	Sulfur wt %	Pour point	Shipping point	Operators, participants & producers§
Cabinda*	Angola (Cabinda)	32.9	0.15	+ 65° F.	Molongo field (SBM)	Gulf
Cinta*	Indonesia, Sumatra	32.0	0.08	+ 95° F.	Field (SBM)	liapco
Cyrus*	Iran	19.0	3.48	- 10° F.	Field (SBM)	Amoco/NIOC
Darius*	Iran	33.9	2.45	0° F.	Kharg Island, Iran	Amoco/NIOC
Dubai*	Dubai	32.5	1.68	- 5° F.	Field (SBM)	Dubai Pet. Co.
Duri	Indonesia, Sumatra	20.6	0.21	+ 57° F.	Dumai, Sumatra	PT. Caltex
Ecuador crude (Oriente)	Ecuador	30.4	0.87	+ 20° F.	Puerto Balao/Esmeraldas, Ecua.	Gulf/Texaco
Ekhahinskaya	U.S.S.R.	30.7	0.37	- 17.5° F.	Okha, Sakhalin, U.S.S.R.	U.S.S.R.
Ekofisk*	Norway	35.8	0.18	+ 15° F.	North Tees, U.K.	Phillips
El Bunduq*	Abu Dhabi	38.5	1.12	- 10° C.	—	—
Emeraude*	Congo (Brazzaville)	23.6	0.50	- 36° C.	Djeno, Congo (SBM)	Elf
Eocene	Neutral Zone	18.6	4.55	- 20° F.	Mina Saud, N.Z.	Getty
Escravos*	Nigeria	36.2	0.16	+ 50° F.	Escravos River, Nigeria (SBM)	Gulf
Es Sider	Libya	37.0	0.45	- 1° C.	Sidra, Libya	Oasis
Fereidoon blend*	Iran	31.0	2.60	- 10° F.	Kharg Island, Iran	Amoco/NIOC
Forcados blend	Nigeria	30.5	0.18	+ 5° F.	Forcados, Nigeria (SBM)	BP/Shell
Forties*	U.K.	36.6	0.28	+ 30° F.	Firth of Forth, U.K.	BP
Gamba	Gabon	31.8	0.11	+ 23° C.	Gamba (SBM)	Shell
Gulf of Suez blend*	Egypt	31.5	1.40	+ 40° F.	Ras Shukheir, Egypt	Amoco/E.G.P.C.
Handil*	Indonesia, E. Kalimantan	30.8	0.09	+ 35° C.	Field (SBM)	Total
Hassi Messaoud	Algeria	44.0	0.14	- 24° C.	Bougie, Algeria	Sonatrach
Hout	Neutral Zone	34.1	1.7	0° F.	Ras Khafji, N.Z.	Arabian Oil Co.
Iranian heavy	Iran	30.8	1.6	- 5° F.	Kharg Island, Iran	NIOC & former IOP
Iranian light	Iran	33.5	1.4	- 20° F.	Kharg Island, Iran	NIOC & former IOP
Isthmus (see Reforma)						
Jatibarang	Indonesia, Java	28.9	0.11	+ 110° F.	SBM	Pertamina
Kerindingun*†	Indonesia, E. Kalimantan	21.6	0.30	< 10° F.	Santan Term., E. Kali.	Union Oil
Khafji	Neutral Zone	28.7	2.88	- 35° C.	Ras Khafji, N.Z.	Arabian Oil Co.
Kirkuk	Iraq	35.9	1.95	- 36° C.	Banias, Syria, Tripoli, Lebanon	INOC
Klamono	Indonesia, Irian Jaya	18.7	0.97	+ 40° C.	—	Pertamina
Kuwait	Kuwait	31.2	2.50	0° F.	Mina al Ahmadi, Kuwait	Kuwait/Gulf/SP
Labuan light* (Samarang)	Malasia, Sabah	36.0	0.07	+ 60° F.	Labuan, Sabah (SBM)	Shell
Lagomedio	Venezuela	32.0	1.3	- 15° F.	Puerta de Palmas, Venezuela	Venezuela
Mandji blend	Gabon	29.0	1.26		Cap Lopez, Gabon	ERAP
Melahin*	Indonesia, E. Kalimantan	24.7	0.27	< 10° F.	Santan Term., E. Kali.	Union Oil
Minas (Sumatran light)	Indonesia, Sumatra	35.2	0.09	+ 90° F.	Dumai, Sumatra	P.T. Caltex
Montrose*‡	U.K.	41.9	0.23	+ 20° F.	—	Amoco et al
Mubarras*	Abu Dhabi	38.1	0.93	- 30° F.	Field SBM	ADOC

Table V-2 (cont'd)

World Crude Oil Export Streams

Most common designation of crude stream	Producing country	Gravity °API	Sulfur wt %	Pour point	Shipping point	Operators, participants or producers§
Murban	Abu Dhabi	39.4	0.74	- 15° C.	Jebel Dhanna, Abu Dhabi	ADPC
Ninian*†	U.K.	35.1	0.41	+ 45° F.	—	Chevron, et al
North Rumalia	Iraq	34.3	1.98	- 19° C.	Fao/Khor al Amaya, Iraq	INOC
North Slope†	U.S.A.	26.8	1.04	- 5° F.	Valdez, Alaska	ARCO, Exxon, et al
Oman	Oman	34.7	0.97	- 24° C.	Mina al Fahal, Oman	Pet. Dev. Ltd. Oman
Pennington*	Nigeria	37.7	0.08	+ 37° F.	Apoi (offshore)	Texaco/Chevron
Poleng*	Indonesia, Java	43.2	0.19	+ 15° F.	Surabaya	P.T. Cities, Ashland
Piper*†	U.K.	08467(S.G.)	0.92	- 9° C.	Kirkwall, Orkney Is.	Occidental et al
Qatar land (Dukhan)	Qatar	40.9	1.29	- 5° F.	Umm Said, Qatar (SBM)	QPC
Qatar marine*	Qatar	37.0	1.50	+ 25° F.	Halul Island, Qatar (SBM)	QPC
Qua Iboe*	Nigeria	37.4	0.106	+ 50° F.	Qua Iboe, Nigeria (SBM)	Mobil
Ratawi	Neutral Zone	23.5	4.07	+ 15° F.	Mina Saud, N.Z.	Getty
Reforma (Cactus Reforma)	Mexico	33.0	1.56	-5 to 10° F.	Pajaritos, Mexico	Pemex
Romashkinskaya	U.S.S.R.	32.6	1.61	- 20° F.	Ventspils (Baltic) Odessa, U.S.S.R.	U.S.S.R.
Rostam*	Iran	35.9	1.55	- 22.5° C.	Lavan Island, Iran	Iminico/NIOC
Sarir	Libya	36.5	0.14	+ 26° C.	Marsa el Hariga, Libya	AGEC
Sassan*	Iran	33.9	1.91	- 5° F.	Lavan Island, Iran	Lavan Pet. Co.
Sepinggan*†	Indonesia, E. Kalimantan	37.9	0.10	+ 15° F.	Lawi-Lawi Term., E. Kali.	Union Oil
Seria light*	Brunei	38.8	0.05	+ 60° F.	Field SBM	Shell
Statfjord*†	Norway	38.2	0.27	+ 20° F.	—	Mobil/Statoil
Sirip blend 27.1° API	Iran	27.1	2.45	- 33° C.	Ras Bahrgan, Iran (SBM)	Sirip/NIOC
Taching	China (PRC)	33.0	0.04	95° F.	Dairen, China	P.R.C.
Tarakan (Pamusian)	Indonesia, E. Kalimantan	19.5	0.14	- 45° F.	Tarakan Island	Tesoro
Tembungo*	Malaysia, Sabah	37.4	0.04	+ 25° F.	Field (SBM)	Exxon
Thistle*†	U.K.	37.4	0.31	+ 40° F.	—	Conoco/Burmah et al
Trinidad blend	Trinidad	33.6	0.23	+ 57° F.	Point Galeota, Trinidad (SBM)	Amoco
Tyumen	U.S.S.R.	34.0	0.97	- 20° C.	—	U.S.S.R.
Umm Shaif*	Abu Dhabi	37.6	1.38	+ 5° F.	Das Island, Abu Dhabi (SBM)	Abu Dhabi Marine Areas
Walio Export Mix	Indonesia, W. Irian	35.4	0.68	+ 20° F.	Kasim Term., W. Irian	Petromer Trend
Zakum*	Abu Dhabi	40.1	0.98	+ 5° F.	Das Island, Abu Dhabi	ADMA
Zarzaitine	Algeria	42.0	0.08	- 9° C.	La Skhirra, Tunisia	Sonatrach
Zueitina	Libya	39.6	0.23	+ 55° F.	Zueitina, Libya (SBM)	Occidental/LNOC

* Wholly or partially offshore † Production not stabilized, values could change

‡ Field not in production. Development expected

§ Participation or ownership in foreign crude-oil production is in a state of flux in many areas and agreements are often too complex to describe in detail in this limited space. For more information and clarification of abbreviations see 1975 and forthcoming 1976 editions of the International Petroleum Encyclopedia, published by the Oil & Gas Journal's parent company, Petroleum Publishing Co., Tulsa, Okla.

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Refinery Products

A survey of the petroleum refineries and petrochemical plants conducted by API revealed over 2,000 products made to individual specifications. Table V-3 shows the number of individual products in 17 classes.

Table V-3 Products Made by the U.S. Petroleum Industry	
Class	No.
Fuel gas	1
Liquefied gas	13
Gasolines	40
Motor	19
Aviation	9
Other (tractor, marine, etc.)	12
Gas turbine (jet) fuels	5
Kerosenes	10
Distillates (diesel fuels and light fuel oils)	27
Residual fuel oils	16
Lubricating oils	1,156
White oils	100
Rust preventives	65
Transformer and cable oils	12
Greases	271
Waxes	113
Asphalts	209
Cokes	4
Carbon blacks	5
Chemicals, solvents, miscellaneous	300
Total	2,347

Source: Petroleum Refining Technology and Economics, Gary and Handwerk, Marcel Dekker, NY, 1975.

In general, the products which dictate refinery design are relatively few in number, and the basic refinery processes are based on production of the large-quantity products such as gasoline, and the middle distillates No. 2 fuel. Storage and waste disposal are expensive, and it is necessary to sell or use all of the items produced from crude oil even if some of the materials must be sold at prices lower than the cost of crude oil. Economic balances are required to determine to what extent certain crude fractions should be processed in order to optimize product value.

Knowledge of the physical and chemical properties of both the unfinished (intermediate) and finished petroleum products is necessary for an understanding of the day-to-day operations of the processing units that make up the refinery. General information about uses as well as physical and chemical properties for each product is described in the following paragraphs.

Light Products. The lowest boiling products made at the refinery are included in this group. Methane is natural gas dissolved in crude oil in the resource formation that is liberated by simple atmospheric distillation at the refinery. Methane is used as refinery fuel and as feedstock for hydrogen production. Hydrogen is generated by pyrolytic cracking, a process which breaks down methane into carbon and hydrogen gas at high temperatures in the absence of air. Hydrogen is an essential raw material used in many processes at the refinery. Methane production at refineries (Table V-4) was 3.4% of total production, about twice the production of LPG (2.1%) during 1978.

Table V-4
Production at U.S. Refineries (1978)

	1,000 barrels	Percentage
Motor gasoline	2,615,929	44.1
Aviation gasoline	13,879	0.2
Naphtha-type jet fuel	66,597	1.1
Kerosene-type jet fuel	288,606	4.9
Ethane (including ethylene)	4,150	0.1
Liquefied gases total	125,359	2.1
Propane (including propylene)	98,224	1.7
Butane (including butylene)	18,523	0.3
Butane-propane mixtures	6,437	0.1
Isobutane	2,175	0.0
Kerosene and special naphthas	92,369	1.6
Distillate fuel oil	1,149,746	19.4
Residual fuel oil	611,004	10.3
Petrochemical feedstocks (excluding ethane and LPG)	221,216	3.7
Miscellaneous**	432,402	7.3
Still gas for fuel	201,419	3.4

*Energy Data Reports - Petroleum Statement, EIA, DOE/EIA-0109(78), December 1978.

**Includes lubricants, wax, coke, asphalt, road oil, and other miscellaneous products.

Ethane and propane are also frequently used as refinery fuels. Ethane also serves an important role as a feedstock to produce hydrogen or ethylene which are used in petrochemical processes. Ethane and ethylene are grouped together into one fuel type since historically refineries have used this convention in presenting data.

Liquefied gases (also called LPG) are a group of light products composed of butane, propane and butane-propane mixtures. Propane accounts for about 80% of all LPG production at refineries. Propane is used as a high-purity fuel needed by the food industries, a standard alternative for natural gas, a portable home heating fuel, and a major petrochemical feedstock.

Together with propane, the liquefied gases include butanes and butane-propane mixtures. Butanes produced by refinery processes are used as components of gasoline and in refinery processing. On a volume basis, the sales value of gasoline is higher than that of LPG; thus it is desirable for a refinery to blend as much normal butane as possible into gasoline. Although isobutane is present in crude oil, it is principally made by hydrocracking at the refinery and has its greatest value when used as a feedstock to alkylation units. In addition to their fuel usages, all LPG products are used as feedstocks for the petrochemical industries.

Motor Gasoline. Although an API survey reports that 40 types of gasoline are made by refineries, most of the gasoline is made for automobiles in three grades: regular, premium, and unleaded. The trend in major gasoline production has been a continuous switch from leaded to unleaded grade to meet the increased demand for unleaded fuel. From February 1976 to June 1978 the percentage of total unleaded gasoline increased steadily from 17.8 to 34.1%, and this trend is expected to continue since the majority of new cars require unleaded fuel. Most refiners are producing two grades of unleaded gasoline, regular and premium.

The principal difference between regular and premium fuels is the anti-knock performance as measured by two types of octane numbers: the motor method (MOM) and the research method (ROM). The ROM represents the performance during low-speed driving when acceleration is relatively infrequent, and the MOM is a guide to engine performance at high speeds or under heavy load conditions. The difference between the research and motor octane numbers of a gasoline is an indicator of the changes in performance during both highway and city driving. In 1973 the ROM of regular gasolines was about 94, that of premium gasolines about 99, and unleaded gasolines averaged about 91. Posted octane numbers are the arithmetic average of ROM and MOM, and average about four points below ROM.

Gasolines are complex mixtures of hydrocarbons that are produced by a variety of refinery processes. Components are blended to promote high anti-knock and other desirable fuel characteristics. Light straight-run gasoline is made by atmospheric distillation of crude petroleum, and catalytic reformat is the gasoline product of the catalytic reformer. Other gasoline components made at the refinery are catalytic cracker and hydrocracker gasoline, polymer gasoline, alkylate gasoline, and normal butane.

Tetraethyl lead (TEL) is a chemical compound which, when added to gasoline at levels up to five grams metallic lead/gal, increases the octane number of the resulting blend. For example, three grams of lead/gal can affect an eight point increase in octane number. The cost of TEL is such that it is economical for a refiner to add small quantities of the compound to gasoline than to blend up the octane number with higher-octane-blend stocks. For this reason, unleaded gasoline which is needed to achieve low emission standards for automobiles is more expensive and more difficult to make than leaded gasoline with the same octane number.

Aviation Gasoline. For obvious reasons of safety in airplanes, aviation gasoline has higher quality control standards than motor gasoline. Antiknock control is especially critical because the pilot cannot hear an engine knock over the high ambient noise level. Volatility (related to vapor lock in aircraft engines) and freezing point are very important specifications that must be met for fuels used in aviation.

Distillate Fuels. Distillate fuels can be divided into three types: jet fuels, diesel fuels, and heating fuel oils. Like gasoline, these products are blended from a variety of refinery streams to meet desired specifications. The combined production of distillates in 1978, 25.4%, ranked second only to gasoline, 44.1% of total U.S. refinery production (Table V-4). Heating oil is produced in the largest volume of all middle distillate products.

Jet Fuels. The two basic types of jet fuels are naphtha-type and kerosene-type. Kerosene jet fuel is used in commercial jets and naphtha jet fuel in the military. Kerosene jet fuel amounted to 4.9% of total refinery output and naphtha jet fuel production was 1.1% in 1978.

Commercial kerosene was used as a fuel in early developmental work on jet aircraft in the United States. The choice of kerosene over gasoline was based on its low volatility, to avoid occurrence of vapor lock under certain flight conditions. Modern commercial jet fuel is a material in the kerosene boiling range and must be clean burning.

One of the critical specifications of jet fuel is its smoke point. This limits the quantity of products that have high amounts of aromatic compounds that can be blended into jet fuel. Specifications limit the aromatic concentration to 20%. The freeze point specification is very low (-40°F max). The products made in cracking units are the best candidates for blending stocks for commercial jet fuel. However, aromatic and paraffinic compounds must be reduced first to meet these requirements. The refinery process called hydrocracking changes the aromatic compounds to saturated hydrocarbons. In addition, this process changes paraffins (which have relatively low freezing points because of their long molecular structure) into different molecular shapes called isomers that have higher freezing points. Thus commercial jet fuel is blended from low-sulfur or desulfurized kerosene, cracked, and hydrocracked blending stocks.

Naphtha (or military) type jet fuel is a stock that includes a wider variety of compounds found in the refinery. Naphtha is a wide boiling range mixture of hydrocarbons that is produced, among other ways, by simple distillation of crude petroleum, and (after processing) is the major constituent of gasoline. Naphtha-type jet fuel has a wide boiling range (150° to 500°F) which permits a great flexibility in blending so that kerosene, naphtha, and low-octane gasoline can be used. The amount of each component is typically naphtha 90 to 100%, gasoline 25 to 40%, and kerosene 35 to 45%. In case of a national emergency, there would be a tremendous demand for jet fuels, and to meet the requirements, both gasoline and kerosene production would be needed for increasing the production of military jet fuels.

Diesel Fuels. There are two groups of diesel fuels, automotive and railroad. Automotive diesel engines are used in trucks, buses, heavy equipment, marine engines, and automobiles. Volatility, ignition quality, and viscosity are important properties.

There are two types of automotive diesel fuels. No. 1 diesel fuel (sometimes called super diesel) has a more narrow boiling range than No. 2 diesel, and is used in high-speed engines in trucks, buses, and automobiles. No. 2 diesel fuel is essentially the same as No. 2 fuel oil used for home heating, except the sulfur level is lower in diesel fuel. Both can be blended from naphtha, kerosene, and light cracked cycle oils; No. 1 diesel fuel has a boiling range close to that of kerosene.

The ignition properties of diesel fuels are expressed in terms of cetane number. This is very similar to octane numbers in gasoline, and expresses the volume percentage of a compound called cetane in a mixture with another compound that has a lower ignition quality than cetane.

Railroad diesel engines provide a large market for diesel fuel. Railroad fuels have much higher boiling ranges and lower cetane numbers than automotive diesel fuels.

Heating Fuel Oils. Domestic heating oil (No. 2 fuel oil) is a clean product that does not form sediment in storage or leave a quantity of ash or other deposits upon burning. Since it may be stored at low temperatures, it has a low freezing point. Sulfur content (0.5% maximum) is an important specification.

Originally, heating fuel oil was composed of selected straight-run stocks (products from distillation of crude oil) blended to meet product standards. Today, No. 2 fuel oil contains cracked stock and is blended from naphtha, kerosene, diesel, and cracked-cycle oils. No. 2 fuel oil is very similar to No. 2 diesel fuel, and the two can be interchanged easily without damage to diesel engines.

Residual Fuel Oil. Residual fuel oils are the "bottom of the barrel" of crude oil, generally being the residual after the crude is distilled twice--once at atmospheric pressure and once in a vacuum. The term, "topped crude,"

is therefore sometimes used to describe residual fuels oils. These fuels are burned to generate steam and heat for the industrial and commercial sectors, to generate electricity, and to power ships. Since residual fuels compete directly with coal and natural gas, the price of the fuel must be competitive. Accordingly, it has not been economically practical to improve the quality of residual fuels. These fuels have historically sold for a very low price--sometimes less than the value of the crudes from which they were produced.

Residual fuel oils are by nature high boiling and contain stocks which are difficult to burn. Accordingly, such fuels are generally burned in equipment which permits steady operation in an environment where firebox temperatures can be high. No. 5 and No. 6 are the most common residual fuel oils, sold as Bunker B and Bunker C types, respectively. Both require preheating of fuel lines and combustion chambers for proper flow and combustion characteristics; No. 6 must be preheated to higher temperatures than No. 5. No. 4 fuel oil is intended for burner installations not equipped with preheating facilities. No. 4 fuel oil is a blend of residual fuel oil and middle distillates.

Critical specifications for residual fuel oils are viscosity, to achieve the desired flow properties; and sulfur content, to meet environmental emission standards when burned. In certain areas 0.5 wt% sulfur content is the maximum level for residual fuel oils that can be burned without special permit.

Gas Oil. Gas oil is an intermediate product that is made from many processing units. The boiling range of gas oil usually includes kerosene, diesel fuel, heating oils, and light fuel oils.

Naphtha. Naphtha is a pipestill cut that boils in the range of C₅ (pentane) - 420°F. Naphthas are the major constituents of gasoline, and generally need processing to make gasoline of. Naphthas are subdivided in accordance with actual cuts (portions) from the pipestill: C₅-160°, light virgin naphtha; 160°-280°, intermediate virgin naphtha; 280°-330°, heavy virgin naphtha; 330°-420°, very heavy virgin naphtha.

Straight-Run Gasoline. This is gasoline distilled directly from crude and not processed in catalytic cracking units. Straight-run gasolines contain primarily paraffinic hydrocarbons and have lower octane numbers than cracked gasolines from the same feedstocks.

Virgin Stocks. These are the constituents of crude petroleum generally obtained by distillation only (a physical separation process). Virgin stocks are petroleum oils which have not been cracked or otherwise treated in a way that would produce appreciable chemical change.

Petroleum Coke. This is the end product of a high-temperature process called coking which breaks down residuum from vacuum distillation into more valuable byproducts. Depending upon the amount of impurities as well as its molecular structure, petroleum coke can be used as an important raw material for the manufacture of graphite and specialty carbon products, or it can be used as a reducing agent in the production of aluminum and other metals. Coke can also be burned like coal to generate heat.

Overall Refinery Flow

The sophisticated refining technology in use in the U.S. had its genesis in the acceptance of the automobile as the primary mode of personal transportation. As automobiles became popular, demand for gasoline increased beyond the relatively small amount that may be distilled from crude oil. Conversion processes (e.g., catalytic cracking) were developed to enable refiners to produce gasoline from hydrocarbons that are not in the acceptable range for gasoline. With the development of more powerful engines with higher compression ratios came the need for higher octane (a measure of antiknock characteristics) gasolines, and the processes required to produce them (e.g., catalytic reforming).

The U.S. refining industry produced an average of 1.1×10^6 bbl/day (derived from Table V-4) of gasoline in 1978 (46% of crude run). Demand for refined products for use in the transportation sector (primarily gasoline, jet fuel, and diesel) averaged 10.09×10^6 bbl/day. The demand for these high-priced products determines to a large extent investment in refinery processes.

The high domestic demand for transportation fuels has led to extensive industry investment in the complex (and expensive) conversion processes to a degree unmatched elsewhere in the world. An oil refinery is a facility where crude oil is distilled (separated) into its basic components, which must be refined further in a combination of complex processes to produce blending stocks. The final step of production is the optimum combination of these stocks to make a specific array of products. Refinery processes may be divided into three categories:

Separation (primarily fractional distillation)

Conversion (altering hydrocarbon structure: catalytic cracking, polymerization, alkylation, isomerization, catalytic reforming, hydrocracking, coking)

Treating (primary sulfur removal)

Figure V-1 is a flow diagram in which each process is shown as a box, and the flow of crude petroleum and intermediate and finished oil products are indicated by arrows. Although storage is vital to the operation of a refinery, storage facilities are not included in the diagram. A description of the overall flow is given in the next paragraphs, followed by a more detailed description of each major process.

Crude petroleum is pumped out of storage tanks, heated in a furnace, and charged to a distillation tower in which the total pressure is near atmospheric. The atmospheric distillation tower and a stabilizer (crude light ends towers) are designed to separate by volatility the components in crude petroleum. These components, in order of increasing density, are the following: LPG (liquefied petroleum gas) and gas, naphthas, distillates, atmospheric gas oil, and atmospheric residuum (also called topped crude).

Topped crude is appropriately named since it is the volume of petroleum left after the lighter fractions are removed by simple distillation. If this product is boiled at higher temperatures the distillation would only proceed with significant breakdown of valuable crude components. However, by reducing the pressure this step can proceed without product decomposition. Topped crude is therefore separated into its constituents in a distillation tower at vacuum pressures. At least two components are recovered in the vacuum section: vacuum gas oil and residuum.

The coker is a unit that can convert residuum into intermediate products by a high temperature (cracking) process delayed over a relatively long time that breaks down some of the residuum into petroleum coke. Another method of coking is called fluid coking because the cracking takes place within a fluidized bed of coke particles. Product streams recovered from the coking process are light products, gasoline, naphtha, middle distillates, coker gas oil, and petroleum coke.

Gas oils produced in the atmospheric and vacuum distillation towers and the coker are a wide boiling range material. The range of components usually includes kerosene, diesel fuel, heating fuel oils, and light fuel oils. To meet the increasing demand for gasoline and distillate fuels, heavy molecules in gas oils are cracked into smaller molecules that boil within gasoline and distillate fuel ranges. Two units perform this function: the catalytic cracker and the catalytic hydrocracker. The cracker processes the lighter fraction of the gas oils which is easiest to split. The hydrocracker cracks a smaller amount of the more refractory portion (the heavier oils) by using more severe operating conditions and by adding hydrogen. These units are essential for the refinery to produce large amounts of gasoline and distillates. Operations for the entire refinery are based upon production from the cracker units.

An important product distinction is whether or not it is saturated or unsaturated. A saturated molecule contains the maximum amount of hydrogen possible and has a higher heating value than the same molecule when unsaturated. For this reason saturated products are generally desirable in fuels, and the refinery is equipped with catalytic reforming and hydrotreating units that saturate the products made in the catalytic cracker. The products from the hydrocracker are saturated.

The gasoline streams from the crude distillation tower, coker, and cracking units are fed to the catalytic reformer unit to improve their octane numbers. The products from the catalytic reformer are blended into regular and premium gasolines for sale, or used as petrochemical feedstocks.

The light product precursors made in the crude unit, coker, and cracking units are called wet gas streams because they contain heavy molecules such as propanes and butanes mixed in with methane and ethane gases. The wet gas streams are fractionated (a separating process) in the vapor recovery section of the refinery into fuel gas, liquefied petroleum gas (LPG), unsaturated hydrocarbons (propylene, butylenes, and pentenes), normal butane, and isobutane. Fuel gas is burned in furnaces to produce heat and steam needed throughout the refinery. Normal butane is blended into gasoline or LPG.

Unsaturated hydrocarbons called olefins can be combined by chemical reaction with isobutane to form compounds called isoparaffins, which boil in the gasoline range. An alkylation unit performs this process using a special catalyst, either sulfuric or hydrofluoric acid, and the product is called alkylate. This is a high-octane product blended into premium motor gasoline and aviation gasoline.

Diesel fuels, jet fuels, and heating oils are produced from component streams called middle distillates made in the crude unit, coker, and cracking units. Blending operations produce desired amounts of each fuel that can be made from the component stocks at any given time. All products made at the refinery must be brought to specifications by blending. Because of the volume of products made by some refineries, realization of a fraction of a penny per gallon savings by optimum blending could amount to hundreds of thousands of dollars saved annually.

Lubricating oils are made in some refineries which process paraffinic or naphthenic base crude oils. Heavy vacuum gas oil and reduced crude (a lighter product than residuum made in the vacuum distillation tower) are feedstocks for lube oils production by a solvent extraction process followed by dewaxing and special treatment.

U.S. Refinery Operations

Each year the Oil and Gas Journal publishes a survey of refinery capacity for the United States and Canada. A summary for the 289 refineries in the U.S. as of January 1979 is shown in Table V-5. Capacity is shown for the major processing units in barrels per calendar day (an average over one year which reflects equipment downtime) and barrels per stream day (the design capacity for the equipment).

Total crude capacity is the amount of crude petroleum that can be charged to the atmospheric distillation tower. The major refining states are Texas, California, Louisiana, Illinois, and Pennsylvania (in decreasing order). Combined crude capacity for these five states is about 66% of the U.S. total. Texas alone has about 28% of total capacity. The capacity for all U.S. refineries is about 18 MMbbl/day. Roughly one-third of the crude is processed by vacuum distillation. Catalytic cracking, catalytic reforming, and catalytic hydrotreating units process large amounts of crude components. Thermal operations (which cover coking), hydrotreating, hydrocracking, and alkylation are other major units for U.S. refineries. (Catalytic hydrotreating represents processes in which 10% or less of the feed is reduced in molecular size, while hydrocracking includes processes where 50% or more of feed is reduced in size - see hydrocracking.)

Each refinery is unique and is designed to process only certain types of crude oils to make a given volume of products. These design criteria are indicated by the refineries in California, for example. California crudes are

Table V-5

Survey of Operating Refineries in the U.S. (State Capacities as of January 1, 1979)

State	No. plants	Crude capacity		Vacuum distillation	Thermal operations	Charge capacity, b/sd			Cat hydro-cracking	Cat hydro-refining	Cat hydro-treating	Production capacity, b/sd				Hydrogen, MMcfd	Coke, tons/day
		b/cd	b/sd			Cat cracking Fresh feed	Recycle	Cat reforming				Alkyl-lation	Aromatics/isomerization	Lubes	Asphalt		
Alabama	6	130,475	135,300	20,500				8,500		9,000	14,500				16,500		
Alaska	4	95,600	101,841					6,000			6,000				6,000		
Arizona	1	6,000	5,400	3,500													
Arkansas	4	62,942	64,550	25,100		15,000	3,000	5,750			13,100	4,500		4,250	6,750	2.9	
California	39	2,453,620	2,567,219	1,126,700	479,183	516,111	85,933	527,039	328,922	320,944	789,022	94,289	13,600	20,100	73,050	831.4	16,100
Colorado	3	40,100	43,000	19,500		7,000	200	11,500			17,500	1,800				0.6	
Delaware	1	140,000	150,000	90,700	44,000	62,000	15,000	42,000	20,000		110,000	8,000	470			70.0	1,500
Florida	1	9,800	9,100	5,000													
Georgia	2	22,750	24,000												14,000		
Hawaii	2	106,500	111,815	25,000		22,000	7,333	11,000			14,500	4,500	1,500		1,300	2.5	
Illinois	12	1,202,000	1,271,841	424,722	131,600	442,111	63,332	315,178	66,500	108,000	500,456	103,822	6,400	5,600	50,200	82.0	3,430
Indiana	8	604,200	647,988	282,500	25,000	212,200	6,690	109,200			206,160	29,200	15,700	6,200	58,400		1,200
Kansas	11	436,185	460,160	146,400	49,400	161,900	42,400	110,700	3,000	43,000	161,400	45,200	3,400	5,400	21,200		1,645
Kentucky	4	166,470	172,263	85,700	4,000	65,000		30,500		40,000	80,500	5,500	18,500	5,000	23,500	20.0	
Louisiana	25	2,149,950	2,263,733	788,242	196,733	567,777	106,433	402,733	78,500	203,500	457,011	131,088	29,430	27,200	60,000	73.0	5,450
Maryland	2	28,500	31,210	13,800											21,700		
Michigan	6	143,300	150,895	25,000		41,500	1,850	29,600		20,250	26,500	6,500	1,000		8,650		
Minnesota	3	217,800	224,905	121,000	23,000	82,500	8,400	30,600		65,000	75,800	11,800	1,200		49,000	14.0	1,300
Mississippi	6	340,448	359,914	157,350	7,000	72,200	6,860	95,400	68,000	56,000	53,450	14,400	6,000		9,662	109.0	320
Missouri	1	109,000	111,000	40,000	13,500	42,000	12,000	16,000			61,500	5,000			65,000		800
Montana	6	153,700	161,500	51,100	9,200	48,300	23,750	45,250	4,900	14,000	93,800	10,200	4,700		14,350	16.7	310
Nebraska	1	5,600	6,160	2,400		2,400	500	750									
Nevada	1	4,000	4,200														
New Hampshire	1	12,800	13,000														
New Jersey	4	644,000	676,973	344,652	38,144	237,444	46,333	121,944		110,000	324,043	17,133		6,400	78,000		975
New Mexico	9	115,074	121,963	11,900	1,500	17,800	5,500	17,400			23,450	2,940			3,100		
New York	3	135,000	140,000	43,000		42,000	12,900	23,000		20,000	39,500	4,500	3,000		18,000		
North Carolina	1	11,900	12,495														
North Dakota	3	61,658	63,263		1,100	24,000	7,200	10,200			11,600	2,600					
Ohio	7	589,950	615,000	207,500	27,400	205,500	43,300	160,700	81,000	45,000	157,500	35,300	11,300	2,100	34,000	72.0	1,250
Oklahoma	12	555,075	572,395	177,061	52,866	194,200	42,875	124,347	4,500	20,000	162,301	45,633	18,005	13,050	33,300	9.0	1,600
Oregon	1	14,000	14,737	15,000											8,600		
Pennsylvania	10	801,620	848,100	356,050		219,100	23,300	221,010	55,000	184,000	318,950	41,900	5,620	31,200	30,900	45.0	
Tennessee	1	42,500	43,820	12,000		12,500		9,300			13,500	3,600			3,015		
Texas	54	4,706,577	4,957,352	1,578,431	328,088	1,422,066	249,133	1,120,612	136,667	646,500	1,906,103	244,351	240,017	96,922	64,100	328.8	7,205
Utah	8	162,425	170,899	44,000	8,500	56,000	10,700	23,500	1,100	5,500	33,600	11,150	3,750		10,700		350
Virginia	1	53,000	55,000	29,000	15,000	28,000	5,000	9,500			26,500						
Washington	8	381,400	399,420	158,078	37,000	94,833	38,000	107,222	39,000	20,500	158,667	25,333	2,900		4,000	62.0	1,600
West Virginia	3	19,450	20,200	8,675				6,160		4,440	7,510			6,700		1.2	
Wisconsin	1	40,000	46,800	20,500		9,700	1,000	10,000		5,800	10,000	1,700			13,500		
Wyoming	13	194,540	201,546	72,011	4,444	62,278	15,533	31,894		16,644	59,694	7,950	1,500	1,830	14,817		125
Total	289	17,169,909	18,050,957	6,532,072	1,496,658	4,985,420	884,455	3,794,489	887,089	1,958,078	5,934,117	919,889	387,972	231,952	814,394	1,740.1	45,160

heavy and asphaltic base. Thermal operations normally process the residuum, and this is where the heavy fraction of crude appears in the refinery. Thermal operations for all refineries in California are about 19% of crude capacity. This value is about twice the national average, 9% of crude capacity. It is easiest to illustrate this point with California, since most of the crude produced within the state was processed there and oil was not imported into the state (until recently when Alaskan crude was made available). Crude is shipped by pipeline between most other states, and imported crudes are also available in other states. Thus, without examining a particular refinery, it is difficult to demonstrate this point for other states.

Refinery Storage

During normal refinery operation the major processes operate simultaneously 24 hours a day. Without a means for storage, throughout the system in Figure V-1 the output from every unit would be fed directly to another unit, and a perturbation in any unit could affect part or all of the refinery. Intermediate and finished product storage of petroleum throughout the refinery is therefore essential for production operations to continue.

Many storage tanks are provided for raw materials, and intermediate and finished products at the refinery. Some refineries even have underground storage for natural gas (refinery fuel gas). Refineries are designed to optimize overall production. In order to do this, intermediate products must be stored separately so that feed to a given unit can be a combination of outputs from different units in addition to a single output stream. Storage is very important in blending, where many intermediate products are combined optimally to meet specifications for an array of finished products. When a unit is shut down for scheduled maintenance or other reasons, the refinery manager always has the option to store feedstock until the unit is back on stream.

Crude oil storage is essential to the continuous operation of a refinery when supply can be interrupted. Refineries on average store enough crude for one week's production. Products are sold to customers directly out of product storage at the refinery. Refinery storage also serves as a reserve supply for products, especially those having seasonal demand patterns.

Storage levels and production rates for products at all refineries in June and December 1978 are shown in Table V-6. The largest volume product, gasoline, was stored in quantities equivalent to 30 days' production. Storage time for jet fuel, distillate fuel oil, and residual fuel oil was higher than for gasoline. Stocks of distillate and residual fuel oils are higher in December to meet increased demand anticipated in the winter months. Jet fuel stocks are high in the summer months when demand is greatest.

Figure V-1

Overall Refinery Flow

Source: Petroleum Refining Technology and Economics, Gary & Handwerk, Marcel Dekker, NY, 1975

Table V-6
Product Storage at Refineries in the United States*

	December 1978			June 1978		
	Stocks (1,000 bbl)	Production (1,000 bbl/ day)	Storage (days)	Stocks (1,000 bbl)	Production (1,000 bbl/ day)	Storage (days)
Motor gasoline	237,885	7,831	30	219,660	7,213	30
Jet fuel	33,667	994	34	37,408	960	39
Propane	5,151	293	18	4,858	267	18
Distillate fuel oil	216,367	3,337	65	157,515	3,105	51
Residual fuel oil	90,204	1,756	51	71,916	1,582	45

Note: Production is the average value for the month. Stocks are for the end of the month. Storage is derived by dividing stocks by production.

*Source: Energy Data Reports, Petroleum Statement, EIA, June 1978 and Dec. 1978.

A graphic representation of stocks of seasonal fuels as a function of time is shown in Figure V-2. The curve for distillate fuel oil approximates a sine wave with levels that are highest in the fall and lowest in spring. Residual fuel oil has a similar pattern over a smaller range. Jet fuel stocks are highest during May or June and December. Gasoline storage levels are highest in winter or early spring.

Crude Distillation

The crude oil distillation unit (also called crude towers or atmospheric pipe stills) is the first major processing unit in the refinery. Figure V-3 is a simplified flow diagram showing the atmospheric distillation tower and associated equipment. The crude towers are used to separate the crude oil by fractional distillation into fractions according to boiling point, so that each of the following processing units in the refinery will have feedstocks that meet their particular specifications.

When the salt content of crude oil is greater than 10 lb/1,000 bbl, the crude must be desalted prior to distillation to minimize fouling and corrosion. Some metals which can cause catalyst deactivation in catalytic processing units are partially rejected in the desalting process. Desalting is accomplished by emulsifying the crude oil with water. After the salts become dissolved in the water, the oil and water phases are separated using chemicals or an electric field.

Stocks

Stocks

Distillate Fuel Oil

Stocks

Residual Fuel Oil

Stocks

Figure V-2

Product Storage* at Refineries in the United States

*Source: Monthly Energy Review, EIA, September, 1978.

Figure V-3

Crude Distillation

Source: Petroleum Refining Technology and Economics, Gary & Handwerk, Marcel Dekker, NY, 1975

Crude oil distillation occurs at high temperatures, and for most crude towers the major heat source is the high temperature of vaporized crude oil. A series of heat exchangers preheats the crude, which is further heated in a furnace (also called a pipe still) to about 750°F and charged to the atmospheric fractionator towers. The hottest point in a tower is the flash zone where the crude vapors are first introduced. The temperature within the tower decreases from bottom to the top.

The fractionation process separates molecules according to their relative volatility. A simple example of relative volatility is the principle that some heavier (bigger) molecules have higher boiling points than lighter (smaller) molecules. All the crude oil is fed to the tower as vapor at the flash zone and flows up the column. Since temperature decreases as the vapor flows up the tower, the heaviest molecules start to condense nearest the flash zone, lighter molecules condense at a point above that, and the process continues all the way to the top of the tower.

Condensed products flow as liquids in a downward direction, and this phase is mixed with the upward flowing gas phase at many trays located at different levels in the tower. This provides intimate contact between the gas and liquid streams flowing in opposite directions through the column. At a given tray the heaviest portion of the vapor phase is condensed if the temperature of the tray is below its boiling point. Some of the heat released by condensation vaporizes the lightest portion of the liquid phase. As a result, the amount of heavy molecules present in the liquid and gas phases decreases in increments

from the bottom to the top of the tower. The overall result is that the heavy portion of the crude is left in the liquid flowing from the bottom of the column, and the lightest gases leave at the top of the column. The refiner can therefore select liquid or gas composition for intermediate products by removing the appropriate stream from the tower.

The lower temperature at the top of the tower is achieved by a process called reflux. The vapors which pass out the top of the column are condensed, and the liquid phase is recycled to the top of the tower in a stream called reflux. Since reflux is at a lower temperature than that of the column, this stream lowers the overall column temperature. Heat removal is also achieved by removing portions of the liquid near the top of the tower, lowering the temperature in a heat exchanger, and then returning the "cooler" liquid to the tower.

Side streams are drawn at various points along the tower, and product streams are obtained from the side streams after they are distilled in smaller towers called side strippers. The product can be selected on the basis of the conditions at the main tower tray and by design of the stripper tower. The heavy high-boiling component of petroleum is a liquid stream called topped crude produced at the bottom of the tower.

Fractionation towers are used in many different places throughout the refinery. They are a basic tool which refiners use to separate an intermediate product into its components.

Vacuum Distillation

The heavier fractions of crude oil that make up topped crude cannot be further distilled by atmospheric distillation without the occurrence of thermal cracking (product breakdown at high temperatures). This material can be distilled under vacuum because the boiling temperature decreases with a lowering of pressure.

Vacuum distillation towers (Figure V-4) separate topped crude into its components. Low pressure is achieved in the tower by a series of steam ejectors located on the vapor outlet stream at the top of the tower. To improve vaporization and enhance the overall performance, steam is mixed with the feed. The effect of steam is the lowering of actual pressure exerted on the hydrocarbons below the total vacuum pressure in the column. The basic principle of fractionation and overall operation is the same as for atmospheric distillation. Two major differences are the use of steam and larger column diameter. The lower operating pressures cause significant increases in volume of vapor per barrel of liquid vaporized and, as a result, the vacuum distillation columns are much larger in diameter than atmospheric towers.

Figure V-4

Vacuum Distillation

Source: Petroleum Refining Technology and Economics, Gary & Handwerk, Marcel Dekker, NY, 1975

There are six main products from a typical crude distillation unit: fuel gas, wet gas, virgin naphthas, gas oils, and residuum (in order of increasing boiling points). Fuel gas consists mainly of methane, and this stream is also referred to as dry gas. In some refineries propane may be used as a fuel gas. Wet gas contains propane and butanes as well as methane and ethane. Propane and butane are separated to be used for LPG separately as a petrochemical plant feedstock. Butane is also used for gasoline blending. Naphtha or heavy straight-run (HSR) gasoline is fed to the catalytic reformer to produce high-octane reformat for gasoline blending. Gas oils (light, atmospheric, and vacuum gas oils) are processed in a catalytic cracker or hydrocracker to produce gasoline, jet, and diesel fuels. Vacuum residuum is the still bottoms from vacuum distillation and can be processed into heavy fuel oil or cracking stocks. For asphaltic crudes, the residuum can be processed further to produce asphalts.

Catalytic Cracking

Catalytic cracking is an essential refinery process for conversion of heavy gas oils into more valuable gasoline and lighter products. Catalytic cracking is more efficient than the original thermal cracking process and it is the most widely used process today. The cracking process literally breaks up

big compounds found in heavy gas oils into about twice as many smaller compounds. Special catalysts such as silica-alumina combinations (called zeolites or molecular sieves) and aluminosilicates provide a medium which the hydrocarbon vapors must contact in order to enhance the overall conversion efficiency. However, the cracking process produces carbon (coke) which remains on the catalyst and reduces its activity rapidly. To maintain the catalyst activity at a useful level, it is necessary to regenerate the catalyst by burning off the coke with air. In order to accomplish both cracking and regeneration simultaneously, the catalyst is continuously moved between a reactor and a regenerator.

There are two classes of catalytic cracking processes in use today: moving-bed and fluidized-bed units. The catalysts used in both processes differ only in physical configuration. The moving-bed unit uses catalyst beads or cylinders approximately 1/8 to 1/4 inch in diameter, and the fluidized-bed cracking catalyst has an average particle size of about 50 microns. The two types of processes use similar process flows. Hydrocarbons come in contact with the catalyst where the cracking reaction occurs. As the cracking reaction progresses, the catalyst is progressively deactivated by the formation of coke on the surface of the catalyst. The catalyst and hydrocarbon vapors are separated mechanically. The oil vapors are taken to a fractionation tower for separation into the desired product streams. The spent catalyst flows into the regenerator and is reactivated by burning off the coke deposits with air.

Cracking catalysts can become contaminated (poisoned) by basic nitrogen compounds and certain metals which occur naturally in crude oil. These poisons cannot be removed like carbon and they accumulate on the catalyst until it becomes badly contaminated and must be replaced.

Catalytic Hydrocracking

Catalytic cracking and hydrocracking units work together in the modern refinery. The catalytic cracker processes the more easily cracked atmospheric and vacuum gas oils while the hydrocracker uses cycle oils and coker distillates as feed. These streams resist catalytic cracking, but higher pressure and the use of hydrogen make them relatively easy to hydrocrack. It is also possible to process residual fuel oils and reduced crude by hydrocracking, but the unit must be tailored to process such heavy streams and this is difficult to do after the unit is built.

The mechanism for hydrocracking is widely accepted to be that of cracking with hydrogenation superimposed. Hydrogenation is a term for the chemical reaction between hydrogen and hydrocarbon molecules. In the reaction produced by the addition of hydrogen to the hydrocarbon, the hydrocarbon molecule becomes more saturated. A fully saturated molecule contains the maximum amount of hydrogen that is chemically possible. Thus, after the large molecules are broken apart, they are partially or totally saturated by the addition of hydrogen.

Catalytic hydrocracking can be combinations of cracking and hydrogenation reactions occurring at different levels. There are three refinery terms which identify typical classes of these reactions for the current state of the industry. Hydrocracking includes those processes where 50% or more of the feed

is reduced in molecular size; for hydrotreating, 10% or less of the feed is reduced in molecular size; and for hydrotreating, essentially no reduction in molecular size of feed occurs. Therefore the hydrotreating is a hydrogenation process only; hydrotreating is a process of hydrogenation with some cracking; and hydrocracking is major cracking combined with hydrogenation.

The hydrocracking process (Figure V-5) occurs at 550° to 750°F and very high pressures, between 1,200 and 2,000 psig. Because hydrocracking catalyst is susceptible to poisoning by metallic salts, oxygen, organic nitrogen compounds, and sulfur, the feedstock is hydrotreated first to remove sulfur, nitrogen, and oxygen compounds. The gas oils then flow as liquids down a bed of catalyst pellets where they are cracked and reacted with hydrogen. Hydrocracking catalysts are a silica-alumina combination supporting small amounts of rare-earth metals (platinum, palladium, tungsten oxide, nickel, and others). Reactor effluent goes to a high-pressure separator where the hydrogen-rich gasses are separated and then recycled. The liquid product from the separator is sent to a distillation column where gasoline, jet, and diesel fuels are recovered.

Figure V-5

Two-stage Hydrocracker Process

Source: Petroleum Refining Technology and Economics, Gary & Handwerk, Marcel Dekker, NY, 1975

Catalytic Reforming

The demand of today's automobiles for high-octane gasolines has stimulated the use of catalytic reforming. Catalytic reformato furnishes much of the United States gasoline requirements, and with the continuing use of lead-free gasolines this can be expected to increase.

In catalytic reforming the hydrocarbon molecules are not cracked and the process therefore does not increase the yield of gasoline boiling range compounds. Instead, the molecular structure is rearranged to form higher-octane aromatics. The feedstock for catalytic reforming is heavy virgin naphtha. Low-octane compounds (naphthenes, paraffins, and olefins) are converted to high-octane aromatics in a series of complex chemical reactions by the catalytic reforming process.

The active material in most catalytic reforming catalysts is platinum. Certain metals, hydrogen sulfide, ammonia, and organic nitrogen and sulfur compounds will destroy the activity of the catalyst. These materials are removed from the feed in a separate pretreatment process of hydrotreating. The hydrotreater employs a special catalyst to convert these compounds to a form which does not harm the platinum catalyst and removes the metals.

There are several major licensed reforming processes in use today. These can be classified as continuous, cyclic, or semiregenerative depending on the frequency of catalyst regeneration. The platforming semiregenerative process (Figure V-6) is a typical reforming operation. Pretreated feed and hydrogen are heated to almost 1000°F under pressure before entering the first reactor. Usually three reactors are sufficient to provide the desired degree of reaction. The mixture reacts over a catalyst consisting of platinum supported on a silica or silica-alumina base. A semiregenerative process can operate for 6 to 24 months before the catalyst must be regenerated.

Figure V-6

Catalytic Reforming

Source: Petroleum Refining Technology and Economics, Gary & Handwerk
Marcel Dekker, NY, 1975

Regeneration of the semiregenerative unit requires the unit to be shut down. Depending upon the severity of operation, regeneration is required at intervals of 3 to 24 months. Runs 3 to 6 months between regenerations are common. If another process called cyclic platforming is used, regeneration is typically performed on a 24- to 48-hour cycle, and a spare reactor is provided so that the unit is always on stream.

The reaction mixture from the last reactor is cooled and the liquid products condensed. Hydrogen removed in a separator is either recycled or used elsewhere in the refinery. Liquid products are distilled to separate gases from the liquid reformat, which is blended to gasoline or sold as petrochemical feedstock.

Delayed Coking

The delayed coking process minimizes refinery yield of residual fuel oil by severe thermal cracking of vacuum residuals and thermal tars. Fresh feed is first fractionated (Figure V-7) to vaporize any material lighter than the desired coke drum feed and to preheat this feed. The bottom from distillation is heated to a point of partial vaporization and then placed in one of two coke drums. The liquid portion settles to the bottom of the coke drum where the combined effect of retention time and temperature (initially 925°F) causes the formation of coke.

Figure V-7
Delayed Coking Unit

Source: Petroleum Refining Technology and Economics, Gary and Handwerk, Marcel Dekker, NY. 1975.

Vapors from the top of the coke drum return to the base of the fractionator. These vapors contain products of the thermal cracking reaction: gas, naphtha, and gas oils. Thus, the delayed coking process extracts the final amount of useful products out of the heaviest oil streams at the refinery. A major variation of delayed coking is fluid coking in which the same net effect is achieved by a process that is very much unlike delayed coking.

Petroleum coke has a variety of important uses, depending on such characteristics as sulfur and metals content, particle size, and molecular structure. Sponge petroleum coke can be used in the manufacture of graphite or as a carbon source for manufacture of certain chemicals. Coke is removed from the coke drum periodically by a mechanical drill or a hydraulic system. The two coke drums are filled and emptied on a time cycle so that the fractionation facilities can be operated continuously.

Alkylation

Alkylation is the reverse of the cracking process. The process is based upon one type of chemical reaction, the reaction between special low molecular weight compounds called olefins and isoparaffins in the presence of a catalyst to form high molecular weight isoparaffins. Process flows are complicated and will not be discussed here.

Catalytic cracking and coking operations are used as a source for olefins. Hydrocrackers and catalytic crackers produce much of the isobutane made at refineries. Catalytic reformers, crude distillation, and natural gas processing are additional sources for isobutane. There are four products made by the alkylation unit: propane, butane, alkylate, and tar. Alkylate is a high-octane mixture that is blended into premium motor gasoline and aviation gasoline.

Concentrated sulfuric and hydrofluoric acids are the two catalysts used to produce of high-octane alkylate. Hydrofluoric acid must be periodically removed and purified by distillation to maintain catalytic activity. Sulfuric acid must be regenerated in a special sulfuric acid plant.

Product Blending*

Increased operating flexibility and profits result when refinery operations produce basic intermediate streams that can be blended to produce a variety of on-specification (e.g., minimum-octane gasoline) finished products. For example, naphthas can be blended into either gasoline or jet fuel, depending upon the product demand. The major refinery products produced by blending are gasolines, jet fuels, heating oils, and diesel fuels. The objective of product blending is to allocate the available blending components in such a way as to meet product demands and specifications at the lowest cost, and to produce incremental products which maximize overall profit. The volumes of

*Reprinted from Petroleum Refining, Technology and Economics, Gary and Handwerk, Marcel Dekker, NY, 1975.

products sold, even by a medium-sized refiner, are so large that savings of a fraction of a cent per gallon will produce a substantial increase in profit over the period of one year. For example, if a refiner sells about one billion gallons of gasoline per year (several refiners sell more than that in that United States), a saving of one-hundredth of a cent per gallon results in an additional profit of \$100,000 per year.

Today's trend is to using computer-controlled in-line blending for blending gasolines and other high-volume products. Inventories of blending stocks, together with cost and physical property data, are maintained in the computer. When a certain volume of a given quality product is specified, the computer uses linear programming models to optimize the blending operations to select the blending components that will produce the required volume of the specified product at the lowest cost.

VI. TRANSPORTATION OF CRUDE OIL AND PETROLEUM PRODUCTS

Overview

There are two phases of movement for petroleum. First the crude petroleum fluids must be transported from the resource location to oil refineries. The second phase involves the transport of finished oil products from refineries to final destinations where the products are consumed.

The movement of petroleum may involve one mode of transportation or a combination of modes. Pipelines, ocean-going tankers, inland-waterway and ocean barges, transport trucks, and railroad cars can be used to move oil from source to destination. Pipelines transport 75% of all crude oil received by U.S. refineries from both domestic and foreign sources, tankers and barges transport 24%, and railroads and trucks carry 1% of crude supplied to domestic refineries. Finished products are more dependent on tank trucks for transportation than is crude oil. Total crude oil and finished product movement is about 47% by pipeline, 29% by tank truck, 22% by water, and 1% by rail.

In the highly competitive oil industry, transportation experts must choose not only the most efficient, but also the most economical means of transporting a given amount of oil from source to destination. When large volumes of crude oil or petroleum products must be moved overland, pipelines are usually the most economical means of transportation. When there is a choice between a water route and a pipeline for delivery of petroleum, large ocean tankers are usually more economical than pipelines. When relatively small volumes must be transported long distances, barge transportation is usually more advantageous if inland water routes are available. Shipment by tank truck and railroad, which are the most expensive modes of transport, may be necessary in circumstances where pipelines or water routes are not available. Thus, each mode of transportation has advantages, depending on the circumstances.

Transportation of petroleum is as complex as the many different situations for source and destination that exist in the oil industry. Some examples of the physical flow of crude oil are given with crude oil flow schematics in Reference 19. The following paragraphs contain descriptions of petroleum transport for each mode of transportation.

Oil Movement by Pipeline

Oil pipelines are used to transport crude petroleum or finished products, and modern lines are designed to deliver many different products in rapid sequence. Each shipment is called a "batch," and compatible crude or product batches may be sent on the same line in special sequences. The points where two batches interface can be detected by sampling, gravimeters, radio-isotopes, or dyes. A mechanical device, an inflatable rubber sphere, may also be sent through the line to separate different products.

Oil moves through pipelines at a speed of two to three miles per hour which is comparable to the speed at which a man can walk. Pressure created by pumping stations spaced at intervals along the pipeline keeps the oil moving. Steam engines, steam turbines, internal combustion engines, combustion gas turbines, and electric motors are used to power pipeline pumps depending on fuel availability and other site-specific factors. Most pump stations use crude oil from the pipeline as a fuel for diesel engines that operate at slow speeds. Diesel fuel is preferred for high-speed diesel engines because crude oil does not burn efficiently for this application. Electricity has inherent advantages over combustion fuels for powering pumps and it is used wherever electricity costs permit. Electrically driven pumps require less maintenance, smaller equipment and building size, fewer operators, and less complicated mechanical transmission of power to the pump than combustion engines.

On the older pipelines, pumping stations were spaced 40 to 50 miles apart. Stations may be spaced 80 to 150 miles apart for modern pipelines depending on pipeline diameter, the terrain, and the type of product moved. Many stations are totally automated so that an operator at one central location can control all the equipment for an entire pipeline system and monitor each shipment.

To maintain pipelines, a device called a "pig" or "go-devil" is pushed through the line ahead of a shipment to scrape away any deposits of dirt or wax that may have accumulated on the inside of the pipe. The pig can be removed at a pumping station, cleaned, and replaced in the line for delivery to another station down the line. Inspection for leakage is a regular part of maintenance for pipelines. Airplanes and helicopters are now used so that this operation can be performed efficiently from above.

Modern pipelines vary in diameter from 2-in.-diameter flow or gathering lines to 48-in. truck lines. Pipeline capacity is measured as a flowrate in bbl/hr or bbl/day. This capacity is limited by the diameter of the pipeline but is also governed by the size of pumping equipment and flow characteristics for the particular type of crude or finished product being transported.

Most pipelines are made of steel, although there has been a marked increase in the use of plastic pipe in recent years. Plastic is used for small-diameter gathering lines, salt water disposal lines, and water injection lines. Specifications set by industry and government regulations for pipeline construction include pipewall thickness, welds, testing procedures, and pipe placement. Pipelines are laid underground, and wherever a new line crosses an older line, the newer line must pass underneath the old.

There are three major categories of oil pipelines, and each stage of the flow of petroleum determines the category. These pipeline categories are gathering, transporting (trunk), and distributing.

The first link between oil leases and the pipeline network is the gathering pipeline. Gathering lines from individual leases are combined into a gathering system which feeds into a larger transportation system. Gathering pipelines are usually between four and twelve inches in diameter, and can be between a few feet and several miles in length. Although these lines are relatively small and short, the complexity of the network makes gathering lines a major segment of the pipeline industry. Gathering lines may feed into a refinery or port, or into a larger trunk line which carries the production of a number of gathering systems to a refinery. Measurement of the quality and quantity of oil entering gathering lines from each lease is a necessary procedure for proper custody transfer.

Whenever the custody of petroleum changes the volume, API gravity, sulfur content, and BS&W are recorded on a run ticket for the transaction. The run ticket can be produced by an automatic (LACT) system (Section II) or the measurements can be performed manually. Pipeline companies usually will not accept a batch of crude oil containing more than 1.0% BS&W.

Trunk lines carry crude oil from many gathering systems to central storage facilities, refineries, or larger transportation systems. A trunk line may be jointly owned by several users. The quality and quantity of oil from each gathering system must be measured as it enters the trunk line to assure that each producer is given proper payment for his oil. Much of this testing and measuring is automated, although manual checks are also frequently performed. This network of gathering and trunk lines provides the most efficient means of transporting oil from remote areas to refineries.

Distribution pipelines transport petroleum products from the refinery to the user. Since the same lines are used to carry different types of products, special techniques must be used to assure separation of each batch that is pumped through the distribution system. These pipelines leave the refinery as large lines, and decrease in diameter as smaller lines branch off to supply individual product users or terminals. Since these lines usually feed into storage tanks in densely populated areas, great care must be taken to assure their safe operation.

Pipelines that cross state boundaries are common interstate carriers and come under the regulations of the Interstate Commerce Commission (ICC). The owners of the line must publish their rates and regulations and must accept oil for shipment from any company according to ICC guidelines. There are many independent pipeline companies that gather crude oil. However, 70.2% of independent producers' sales are to the top 20 major oil companies, who control 69.8% of crude gathering lines used to collect oil from independents.*

There are currently about 110 major interstate crude oil pipeline companies and 105 product pipeline companies operating in the U.S. During 1975 the pipeline system consisted of 40,387 miles of gathering lines, 60,630 miles of crude truck lines, and 69,732 miles of product pipelines. The evolution of crude and product pipelines in the U.S. is shown in Figures VI-1 and VI-2. The largest increase in mileage during recent years has been for product pipelines. Pipeline distances increased by a factor of 3 from 1950 to 1974 and the immediate big growth is expected to remain with product lines.

Oil Movement by Water

When refineries or bulk terminals have docking facilities on a lake, inland waterway, or at a coastal seaport, petroleum can be loaded or unloaded from barges and tankers designed to carry large amounts of petroleum over long distances. Waterborne traffic is a vital factor on a worldwide basis. The world tankship fleet consists of about 5,100 tankers that carry petroleum from producing nations to those which must import part or all of their oil requirements. The U.S. must import more than 40% of its petroleum needs. Nearly all of the U.S. imports travel by tanker.

The largest modern tankers are more than a quarter mile in overall length, with capacities of 1.75 to 3.50 MMbbl of crude oil or petroleum products. The average cruising speed for a tanker is 15 knots. Section III gives information on the design and operation of tankers, and the loading and unloading operations for water transport are discussed.

Smaller tankers are vital for transport of petroleum to U.S. seaports. The VLCC when fully loaded requires more than 70 feet of water, and there is currently no U.S. port with this capability. Therefore, the small tanker permits access for shipments of oil imports to U.S. ports.

At the end of 1975 the U.S. tanker fleet consisted of 293 vessels. Most of the American tanker fleet operates in coastal and intercoastal trade (Table VI-1). The most frequent run is between the Gulf Coast-producing areas and the Atlantic seaboard - about 400 MMbbl of products moved along this route in 1978. Another major water route for petroleum is from the Gulf Coast through inland waterways to the central states. Supplies along this route travel by small tanker or barge on rivers, canals, and the Great Lakes. About 69 MMbbl of crude and petroleum products traveled from the Gulf to the center of the

*Data from Ref. 2, p. 112.

Figure VI-1

Growth of Crude-oil Pipelines in the United States

Source: Introduction to the Oil Pipeline Industry, 2nd ed., API, 1978

Figure VI-2

Growth of Products Pipelines in the United States

Source: Introduction to the Oil Pipeline Industry, 2nd ed., API, 1978

country in 1978. North America has one of the greatest inland waterway systems in the world, including 29,000 miles of rivers and canals on which about 600 MMbbl of petroleum traveled in the U.S. during 1978.

Table VI-1
Interdistrict Movements of Crude Oil and Petroleum Products
by Tanker and Barge During 1978

Route	Total Movements (Thousands of Barrels)	
	Crude Oil	Petroleum Products
Gulf Coast to New England	-	74,180
Gulf Coast to Central Atlantic	9,591	121,408
Gulf Coast to Lower Atlantic	-	222,300
Gulf Coast to P.A.D. District II*	5,752	63,308
Gulf Coast to West Coast	113	12,729
West Coast to East Coast	27,305	-
West Coast to Gulf Coast	59,588	1,841
Total	102,349	495,766

Data Source: Energy Data Reports, DOE/EIA-0109/12 (78), December 1978.

*P.A.D. District II includes: North Dakota, South Dakota, Minnesota, Wisconsin, Michigan, Nebraska, Oklahoma, Iowa, Missouri, Illinois, Ohio, Kentucky, and Tennessee

Barges are powered in several ways. Some are self-propelled and others must be towed. Most barges are pushed in groups of 10 to 12 barges by tugboats. Barges travel up the Mississippi from Gulf Coast refineries, unloading shipments at various destinations along the way. Along the Middle Atlantic Coast, barges receive ocean tanker cargoes in lightering operations (Section III) at port or on open water. They then deliver the petroleum to inland storage centers, refineries, and pipeline and tank-truck terminals.

Oil Movement by Tank Truck and Railroad Tank Car

Tank trucks are a major means of transportation for petroleum; almost 30% of total U.S. petroleum movements are by this mode. The tank truck is an especially important mode of transportation for oil products; shipments from retail distributors to end users are usually by truck since this is the most versatile means of shipment.

There are approximately 158,000 tank trucks of all kinds in operation in this country. Most tank trucks are equipped with diesel engines which are more dependable and economical than gasoline engines for long hauls. Some are built for long distance hauls of up to 13,000-gallon loads. Other trucks with smaller capacity are designed for local deliveries and supply more than 13 million households with more than 23 billion gallons of heating fuel oil each year. Tank trucks supplied 186,000 service stations and other outlets across the nation with almost 107 billion gallons of gasoline in 1976.*

Tank trucks are sometimes also needed in one stage of the delivery of crude petroleum to refineries. Many small lease-tank batteries are not connected to refinery pipelines, and the producers must depend on tank trucks to pick up their product and deliver it. For this application, trucks have the advantage of being able to reach isolated tank batteries when pipelines are not available.

Railroad tank cars carry the smallest fraction of petroleum moved in the U.S., but are nevertheless important, e.g., in the delivery of petrochemical feedstocks to chemical plants that do not have access to pipelines or barges for delivery of supplies. There are 165,000 privately owned railroad tank cars in operation in addition to those owned by the railroads. Tank cars range in carrying capacity from 4,000 to 60,000 gallons.

Railroad cars can be equipped with heating coils and insulation, to accommodate viscous and low-pour-point crude oils and oil products. Cars with heating coils are used to keep products such as asphalt in a liquid state, which makes unloading easier and quicker.

VII. NATURAL GAS PROCESSING

Natural gas as taken from the earth may contain a large number of compounds which include methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), heavier hydrocarbons, hydrogen sulfide, carbon dioxide, nitrogen, and water vapor. Natural gas containing these condensable hydrocarbons is termed "wet gas." Natural gas can also be classified as "sour" if it contains sufficient amounts of sulfur compounds in its natural state to be corrosive or offensive to the sense of smell. Sweet natural gas contains insufficient amounts of sulfur compounds to be corrosive or have an offensive odor. "Dry" natural gas is produced from wet gas by processing the wet gas to remove the condensable hydrocarbons and other compounds. These condensable hydrocarbons are categorized as natural gas liquids (NGL), while the propane and butanes separated from these liquids are marketed as LPG. Pentanes and heavier hydrocarbons are designated as natural gasoline. Some of the more important physical properties of the main hydrocarbon constituents and impurities present in natural gas are shown in Table VII-1.

*Data from "Facts About Oil," API.

Table VII-1
Physical Properties of Natural Gas Constituents

	Molecular Weight	Boiling Point at 14.696 psia (°F)	Gross Heat of Combustion at 60°F and 14.696 psia (Btu/cu ft)
Methane	16.04	-258.7	1010
Ethane	30.07	-127.5	1769
Propane	44.09	- 43.7	2518
Isobutane	58.12	10.9	3256
Normal butane	58.12	31.1	3264
Isopentane	72.15	82.1	4001
Normal pentane	72.15	96.9	4009
Carbon dioxide	44.01	-164.9*	-
Hydrogen sulfide	34.08	- 76.5	680
Nitrogen	28.02	-320.4	-

*Sublimes.

Treatment of Natural Gas

The composition of natural gas as produced in the field varies widely from one location to another as indicated by the analyses shown in Table VII-2. Gas from Rio Arriba County, NM, is 97% (mole %) methane, for example, as compared to gas from Olds Field, Alberta, Canada, which contains 36% hydrogen sulfide

Table VII-2
Composition of Various Natural Gases

Composition, Mole %, of Gas				
	Rio Arriba County, N.M.	Terrell County, Kansas	San Juan County, N.M.	Olds Field, Alberta, Canada
Methane	96.91	45.64	77.28	52.34
Ethane	1.33	0.21	11.18	0.41
Propane	0.19	-	5.83	0.14
Butanes	0.05	-	2.34	0.16
Pentanes and heavier	0.02	-	1.18	0.41
Carbon dioxide	0.82	53.93	0.80	8.22
Hydrogen sulfide	-	0.01	-	35.79
Nitrogen	0.68	0.21	1.39	2.53
Total	100.00	100.00	100.00	100.00

and 52% methane. These gases are processed as necessary to remove condensable hydrocarbons, hydrogen sulfide, water vapor, and other impurities to produce dry, sweet natural gas for sale to consumers. The average gross heating value of natural gas marketed in the U.S. is about 1031 Btu/cu ft; however, this value varies from about 1000 to 1080 Btu or higher in different locations. The specific gravity of natural gas referred to air is usually 0.6 or higher.

A variety of processes are available for the removal of heavier hydrocarbons and other impurities from natural gas depending upon the constituents and percentage recovery required. The original and also the least effective method is the compression process, used today primarily in gas cycling plants. A gas cycling plant removes the natural gasoline liquids (pentanes and heavier) with the remaining gas returned to the producing formation in order to increase the recovery of crude oil.

Adsorption processes are used to recover hydrocarbons heavier than ethane from natural gas. The production of LPG's compared with natural gasoline liquids is less by the adsorption process than that normally obtained for the same gas by the oil-absorption process. Activated carbon, alumina gel, and silica gel are used as adsorbents.

One of the fastest growing methods for removal of heavier hydrocarbons from wet natural gas is the cryogenic process. The number of cryogenic plants has increased from 1 in 1963 to 63 in 1978 out of a total of 825 gas processing plants. This rapid growth can be attributed to the cryogenic plants' high ethane and propane recovery at low initial investment and moderate operating costs, compared with other processing schemes. In the basic cryogenic process a compressed and dried natural gas stream is directed into a cryogenic processing unit, where its temperature is progressively lowered, with the subsequent effect of condensing the desired hydrocarbons. Various temperature level liquid dropouts are situated in the cold box to optimize the hydrocarbon liquid recovery. One such level is maintained by propane at -35°F . The condensed hydrocarbon phases are then directed to a demethanizer, where the methane is fractionated from the product hydrocarbon stream. The bottoms of the demethanizer contain the recovered hydrocarbons and subsequently are fractionated into the desired hydrocarbon products.

The oil-absorption process is the most common technique for removing heavier hydrocarbons from wet gas, with the percentage removal of ethane and LPG dependent upon the operating conditions of the plant. It is usually desirable to reduce the propane and heavier hydrocarbons to 0.2 gal or less per 1000 cu ft of gas to avoid condensation of hydrocarbons in high pressure transmission lines. The composition of wet natural gas may vary anywhere from 0 to 10 gal of heavier hydrocarbons per 1000 cu ft, depending upon the origin of the gas.

The basic absorption process is illustrated in Figure VII-1. Wet natural gas is fed into the bottom of an absorption tower, where the gas is contacted countercurrently by a lean presaturated absorption oil at -35°F . About 85% of

the propane and essentially all of the higher-boiling hydrocarbons are absorbed in the oil. The lean tail gas from the absorber, at about -15°F , is heat exchanged with the inlet gas and is directed back to the pipeline. The lean-oil circulation rate and temperature are determined by the product spectrum and the required percentage recovery. High percentage recovery requires large lean-oil circulation rates. The lean-oil is refrigerated for ethane recovery; hence the feed gas must be dehydrated to prevent plant freeze-ups.

Figure VII-1

Basic Absorption Process

The absorption oil removes the desired hydrocarbons from the incoming gas stream and then is directed into a demethanizing tower, where absorbed methane is removed from the absorption oil by fractionation and exits from the top of the tower. The methane is further refrigerated, combined with regenerated lean-oil, and sent to a presaturator. The vapor phase containing mostly methane is then combined with the tail gas from the top of the absorber. The presaturated liquid is used for reflux in the demethanizer and as lean-oil to the absorber.

The bottoms of the demethanizer are directed into the lean-oil still, where the desired hydrocarbon components are separated from the lean-oil. The overhead vapors containing ethane and heavier components are directed into a fractionating train, where the desired product spectrum is obtained. The bottoms liquid is then recycled through a number of heat exchangers back to the presaturator.

Gas Dehydration and Desulfurization

Water vapor is probably the most common impurity found in natural gas. As such, it is not particularly objectionable; however, liquid and solid phases which may condense or precipitate from the gas as it is compressed and/or cooled can create problems. Liquid water tends to accelerate corrosion, and solid hydrates tend to plug valves, fittings, and lines. The most commonly used dehydrating agents in the natural gas industry are diethylene glycol and triethylene glycol. A dehydration unit consists primarily of an absorption tower wherein the glycol stream flows countercurrent to the gas stream; a regenerator wherein the absorbed water is distilled from the glycol; and a solvent reclaimer, where a small "bleed" taken from the solvent stream is distilled to prevent the buildup of undesirable impurities.

Absorption processes are frequently used to remove sulfur compounds such as hydrogen sulfide and carbonyl sulfide or mixtures of sulfur compounds and carbon dioxide from sour natural gas. Pipeline quality gas generally has a total sulfur content of no more than 10 grains per 1000 cu ft. Pipeline gas having a sulfur content significantly above this value tends to be corrosive and offensive to the sense of smell. The most widely used process in the natural gas industry for removing hydrogen sulfide and carbon dioxide is the aqueous amine process. This process employs an aqueous solution of monoethanolamine, or diethanolamine if carbonyl sulfide is present. The operating cycle and equipment required for this process are quite similar to those for the oil-absorption process described above.

A combination of the glycol process and the aqueous amine process, known as the glycolamine process, is widely used in the natural gas industry. Mixtures of diethylene or triethylene glycol and monoethanolamine containing about 5% water are used as a solvent for simultaneously dehydrating natural gas and removing hydrogen sulfide and carbon dioxide.

Petrochemical Feedstocks from Natural Gas

The natural gas industry is a major supplier of fuel and hydrocarbon feedstocks to the chemical industry* (see Table VII-3). Natural gas and the heavier hydrocarbons derived from natural gas (natural gas liquids) are the basis for chemical intermediates which are further processed into finished products. Dry natural gas is utilized in the production of chemical intermediates such as carbon disulfide, methyl chloride, chloroform, hydrogen cyanide, acetylene, and carbon tetrachloride. The largest chemical use for dry natural gas is in the production of synthesis gas from ammonia. Methyl alcohol and carbon black are also manufactured from natural gas.

*25% of the LPG's produced in the U.S. are a by-product of refinery operations; remaining LPG's are produced at natural gas processing plants.

Table VII-3
Demands for LPG and Ethane* - 1977
(millions of gallons)

	Ethane	Propane	Butanes	Total
Residential/commercial	-	6761	407	7168
Internal combustion	-	981	164	1145
Industrial	-	890	153	1043
Utility gas	-	561	5	566
Chemical feedstock	6316	1963	1616	9895
Miscellaneous	-	1990	16	2006
Total	6316	13146	2361	21823

*3575 million gallons of LPG's were used in gasoline production in 1977 in addition to the above figures.

Source: Energy Data Report, Sales of Liquefied Petroleum Gases and Ethane in 1977, DOE/EIA-0115/77.

One of the largest-volume chemical intermediates is ethylene which is produced by steam-cracking ethane and propane as well as naphtha. Most of the ethylene produced in the U.S. is derived from steam-cracking ethane and propane. Since the supply of natural gas and NGL's is limited in most foreign countries, almost all the ethylene produced in other countries results from steam-cracking naphtha. Ethylene is used in the manufacture of polyethylene, styrene, and ethyl alcohol, as well as in the production of chemical intermediates such as ethylene oxide and vinyl chloride.

Propylene which is produced by steam-cracking propane or as a by-product in refinery operations is another large-volume building block for synthetic organic chemicals. Propylene is utilized in the production of chemical intermediates such as isopropyl alcohol, dodecene, propylene oxide, nonene, and cumene. Normal butane is the basic raw material for the production of butadiene, a major constituent of synthetic rubber. Butadiene is produced by catalytic dehydrogenation of normal butane, by catalytically dehydrogenating butylenes produced as by-products in refinery operations, and as a by-product in steam cracking of hydrocarbons to produce ethylene.

VIII. UNDERGROUND STORAGE

Underground storage of natural gas provides the most efficient means of balancing pipeline gas energy supplies with widely fluctuating seasonal, daily, and hourly market requirements. Gas is injected into storage during off-peak periods when market requirements are less than supply availability. It is withdrawn from storage when market demand exceeds available supply from other sources. Storage reservoirs are replenished during off-peak periods that normally run from April through October, and are then drawn down from November through March as shown in Figure VIII-1.

Figure VIII-1

Working Gas in Underground Storage.

Source: DOE Underground Natural Gas Storage Reporting System

History

In 1915 the first recorded experiment in storing gas underground was successfully accomplished in Welland County, Ontario, Canada. Several old wells in a partially depleted gas field were reconditioned. Gas was injected into the field, the pressure was built up, and during the following winter gas was withdrawn to meet peak requirements. The success of the Welland County experiment prompted the Iroquois Gas Company in 1916 to apply the same principle in the depleted Zoar Field, south of Buffalo, New York. This also proved successful, and the Zoar Project, still in use, marked the first storage operation in the United States. By 1930 there were only 6 storage reservoirs located in three different states. But, from 1935 to the end of World War II the number of storage reservoirs increased from 15 to 75.

It was realized at this time that adequate storage facilities are essential for market expansion. Storage reservoirs located in the Eastern states near industry and population centers are needed to assure high load factors for the pipelines. Unless there is nearby storage, gas companies cannot meet the winter heating needs of their customers without oversized transmission lines resulting in low load factors. One-half the underground storage capacity presently used in the United States is located in four states - Pennsylvania, Michigan, Illinois, and Ohio - where local gas and oil production has declined.

Expansion Reservoirs and Aquifers

The most common type of underground reservoir now storing gas is a previously producing gas or oil field termed an expansion reservoir (see Figure VIII-2). The supplies remaining in these pools are too small and at too low a pressure to justify continued production. But, the reservoir rock can hold gas pumped down through the same wells that once took gas out of the ground. The gas to be stored is pumped into the old wells by compressors similar to those used to move gas in pipelines. The gas is stored under about the same pressure that originally existed in the field. In developing a gas storage reservoir, a company obtains a lease from the landowners in much the same manner as gas producers.

Figure VIII-2

- (a) Typical Anticlinal Reservoir Used for the Storage of Natural Gas
- (b) Enlarged View of the Reservoir

Source: American Gas Association.

When depleted oil or gas fields are not available near large markets, aquifers have proven feasible for gas storage. An aquifer is an underground rock structure holding large quantities of water. The underground rock is porous and permeable. The pore spaces are filled with water; an impermeable rock covers the porous rock. Wells are drilled into such formations, and gas is forced into the pores under pressure. As the gas pressure increases, the gas pushes the water further down into the porous rock, making room for the gas.

Underground Storage Operations

All storage reservoirs are comprised of two basic volumetric divisions--base gas and working gas. Effective utilization of an underground gas storage reservoir requires the predelivery and permanent impoundment of a substantial

volume of gas known as base or cushion gas. Base gas is required to maintain pressure for delivery of gas during an output cycle. It consists of native gas, which is indigenous to the storage reservoir, and injected gas, which is injected from extraneous sources into the reservoir to bring reservoir pressure up to the desired base level. Working gas is the volume of gas in a reservoir above the designed level of base gas that is available for delivery.

As of December 31, 1977, there was 3,152,270 MMcf of base gas and 2,559,207 MMcf of working gas in storage in 385 reservoirs located in 26 states as shown in Table VIII-1. Total underground storage capacity is 7,223,315 MMcf compared to 5,711,477 MMcf of actual gas in storage, leaving about 1,500,000 MMcf of unused capacity. Maximum day output from all storage reservoirs in the U.S. reached 36,556 MMcf during 1977. This figure is computed from maximum day output for each state summed over all states and is a noncoincident peak.

Table VIII-1
Underground Gas Storage Summary Statistics
(all volumes in MMcf - 14.73 psia 60°F)

Description	Year Ending December 31, 1977
Number of states	26
Number of operating companies	85
Total number of reservoirs	385
Aquifer pools	52
Number of wells	16,928
Injections, calendar year	2,303,268
Withdrawals, calendar year	1,735,868
Total volume in storage reservoirs	5,711,477
Total base gas	3,152,270
Native gas	1,043,189
Injected gas	2,109,081
Total working gas	2,559,207
Maximum day output from storage	36,556
Total reservoir capacity	7,223,315
Source: Ref. 16.	

The drawdown rate of gas stored in underground reservoirs is dependent upon pressure in the reservoir and decreases as the quantity in storage decreases. The designed level of base gas is normally required to maintain adequate pressure during an output cycle. In an emergency when working gas has been exhausted, a fraction of the base gas may, in some instances, be withdrawn at a reduced drawdown rate.

In addition to gas in storage, the drawdown rate varies with the size and number of wells in the field and with the pressure against which the wells must feed. When a field has been completely activated with all wells, pipelines, compressor stations, and other equipment installed, it is possible to determine how much daily delivery can be expected from the reservoir when it contains various volumes. The curve shown in Figure VIII-3 assumes fairly uniform operating conditions. If a pressure change occurs in the pipeline which the reservoir is supplying, this curve would shift to reflect the new condition. It is therefore necessary to know specific operating conditions before reasonable accuracy can be obtained in determining deliverability from a reservoir with a given volume of gas in storage.

Figure VIII-3

Example of Daily Deliverability Estimate for a Gas Storage Field

Underground storage reservoirs are typically operated by a transmission or distribution company, or an independent operator. Thirty-two jurisdictional transmission companies* operate 210 of the 386 storage reservoirs. A trans-

*Transmission companies transporting gas across state boundaries are subject to FERC jurisdiction. See Section IX for additional detail.

mission company may be operating reservoirs in more than one state. Underground storage reservoirs typically contain gas from several gas companies. For example, a distribution company located in a region not containing underground reservoirs may require storage to balance its load curve. It will typically store gas in a facility operated by its pipeline supplier or another operator to meet the seasonal demands of its customers. Natural gas distribution companies serving the New York City Metropolitan area, for example, store gas in underground reservoirs located in Pennsylvania where 10% of the storage capacity in the U.S. exists to meet the winter heating demands of their customers.

IX. TRANSMISSION AND DISTRIBUTION

The geographic disparity between major supply sources of natural gas, primarily in the Southwest, and major markets existing in the Northeast, Pacific Coast, and Gulf Coast regions of the United States has resulted in the development of a complex system for transporting natural gas comprised of more than 260,000 miles of transmission lines presently in operation, ranging in diameters up to 42 inches and operating at pressures over 1000 psi. Transmission lines transport gas from a source or sources of supply to one or more distribution centers, to one or more large volume customers, or to a pipeline installed to interconnect sources of supply. In typical cases transmission lines differ from distribution mains in that they operate at higher pressures, are longer, and the distance between connections is greater. Natural gas is delivered to transmission lines through field gathering systems comprised of over 70,000 miles of field and gathering lines. These lines transport natural gas from individual wells to compressor stations, processing plants, or main transmission lines. Distribution systems, consisting of more than 666,000 miles of line, transport natural gas from the point of local supply (typically a transmission line) to the end-use customer.

Pipeline Construction

The growth of the natural gas transmission industry has been due primarily to technological advancements in the development of high pressure thin-wall pipe, electric arc-welding methods, mechanized equipment for laying pipe, and high-capacity reciprocating and centrifugal compressors. Manufacturing processes produce welded pipe in 5- to 36-in. diameters, but there is a strong trend toward larger-diameter lines, from 42 inches upward. Welded pipe is made

from flat steel plates in a process which involves separation of sheets, shaping the tube, making the longitudinal weld, cold expansion of the tube (1/2-in. expansion for 30-in. pipe), finishing the ends of the pipe joints, hydraulic testing for acceptance, and visual inspection of the finished joint of pipe prior to loading for shipment.

Compressors are necessary in long-distance gas transmission to restore the pressure lost in friction between the pipe and the moving gas. Compressors may range in size from small belt-driven units on the order of 50 hp to very large reciprocating or centrifugal units 15,000 hp or more. The most common type of compressor is the natural gas-engine-driven reciprocating units. Compressors are installed on the pipelines inside buildings and, together with the necessary auxiliaries, are called "compressor stations." The capacity of a pipeline can be increased by the installation of additional compressor stations following the initial construction of the line. Compressor stations are spaced to give the most economical balance between investment in pipe and in compressors, but the station spacing will usually run from 60 to 100 miles on a long-distance pipeline.

Prior to the construction of a pipeline, legal, engineering, safety, and economic requirements of the Federal Energy Regulatory Commission (FERC) must be met. These requirements are designed to serve both the gas pipeline companies constructing the lines and their customers. It would be most uneconomical to build several lines to supply a city that might be served satisfactorily by one or two lines. FERC has the right to regulate the interstate transportation of natural gas. Before a company can build a pipeline it must obtain from FERC a "Certificate of Public Convenience and Necessity," by proving that it has contracts with producers of natural gas for a sufficient supply to last a reasonable length of time, usually 20 years. The company must also prove that it has a market for the gas at the other end of the line, and that it has the engineering skill and financial resources to build a line that will operate safely and efficiently.

After the pipeline company has met FERC requirements and been given a certificate, an aerial survey of the area is conducted to determine the best route for the pipeline from the producing region to the areas to be served. The aerial survey is followed by careful study on the ground by automobile and on foot to inspect every mile of the proposed route. Legal and social impediments by environmental interest groups may delay the start of construction by months or years. Next, the right-of-way, usually about 100 feet wide, must be purchased from landowners, or the company may ask the state to exercise the right of eminent domain.

In pipeline construction, the numerous machines needed to dig the trench, weld the sections of pipe, apply protective coating to prevent corrosion, lower the pipe into the trench, and cover the trench with earth are known collectively as "mainline spread." The trench is usually 3 feet or more deep, which is sufficient to prevent damage by plowing and earth-moving equipment. Teams of welders join the pipe sections into a continuous tube with automatic welding machines. X-ray equipment is used to inspect welds.

Gas pressures in long-distance pipelines of 1000 psi are quite common. In terms of lineal velocity, natural gas may travel at about 15 miles per hour. Thus about 3 days are required to move a molecule of gas a distance of 1000 miles. All along the pipeline are placed valves and regulators that may be opened or shut by microwave radio to control the internal pressure, or to cut off the flow entirely if an unexpected break in the line is caused by a flood or some other disaster.

The construction of deep-water pipelines to transport gas from offshore wells to land terminals is expanding at an ever-increasing rate. Lines are laid in water at depths up to 2000 feet and cover distances from field to shore of over 200 miles. Many of the pipeline design factors are the same, regardless of whether the pipeline is constructed on land or at sea. The two major causes of design difference between land and marine pipelines are (1) the stresses incurred in getting the pipeline to the sea bottom, and (2) the necessity of keeping the line stable and in place while it is exposed to forces induced by current and wave.

The most common method of marine pipeline construction utilizes a floating vessel with a barge-type hull on which the pipe is assembled in a horizontal position. As additional sections of pipe are added to the already completed segment, the barge is moved forward, moving out from under the completed pipeline. The pipeline extends off the stern of the vessel and spans down to the sea bottom, supported part of the way down by a construction aid called a "pontoon" as shown in Figure IX-1.

Figure IX-1

Pipe-Lay Vessel With Barge-Type Hull and Straight Pontoon

Gas Company Operations

Natural gas transmission lines are operated by gas transmission or integrated companies. A transmission company is one which obtains the major portion of its operating revenues from the operation of a gas transmission system or from mainline sales to large-volume customers. A transmission system, as previously defined, transmits gas from sources of supply to distribution systems, to large-volume customers, or to other transmission systems. An integrated company obtains a significant portion of its gas operating revenues from the operation of both a retail gas distribution system and a gas transmission system. For the purposes of this report the terms transmission and integrated company will be used interchangeably.

In addition to the above classification, transmission companies may be classified as interstate or intrastate. Interstate gas transmission companies transport gas across state boundaries, whereas intrastate companies do not. Under the Natural Gas Act of 1938, FERC had jurisdiction over interstate gas sales, but not over intrastate sales. Under the Natural Gas Policy Act (NGPA) of 1978, FERC has jurisdiction over the wellhead price of both interstate and intrastate sales (see Section XI for additional detail). Most intrastate transmission companies transport gas in producing states, from sources of supply to distribution systems or directly to large-volume customers. The intrastate pipelines transport about one-third of all gas consumed, while interstate lines account for the remainder.

There were 83 Class A and Class B* interstate natural gas pipeline companies for the year 1977, of which 31 are "major" pipeline companies. The major companies as listed in Figure IX-2 include those whose combined annual sales for resale and gas transported (interstate) or stored exceeded 50 billion cubic feet. These companies accounted for 83% of total gas purchased from natural gas producers and 97% of total sales by FERC-regulated pipeline companies.

Interstate pipeline companies transport gas from sources of supply (e.g., in Texas or Louisiana) to other regions of the United States for resale to distribution systems, other pipeline companies, or for direct sales to industry. Nationwide average figures concerning the disposition of gas by the transmission companies can be very misleading, for there is great diversity in sales profiles of the various pipelines. For example, as shown in Figure IX-2, Algonquin Gas Transmission Company sells over 90% of its gas to intrastate pipeline and distribution companies and makes no direct industrial sales, while direct industrial sales constitute nearly 70% of total sales by the Lone Star Gas Company.

*Classes A and B include interstate natural gas pipeline companies with annual gas operating revenues of \$1,000,000 or more. Classes C and D include those companies with annual gas operating revenues of \$25,000 or more but less than \$1,000,000. These smaller companies, Class C and Class D, altogether account for less than 1% of the sales by all interstate natural gas pipeline companies under FERC jurisdiction.

Figure IX-2

Profile of Gas Disposition for 30 Large Pipeline Companies, 1973

Source: Hearings of FPC Oversight before the Senate Committee of Commerce, 93rd Congress, 2nd Session, pt. 2 (1974), p. 656.

The gas supplies of interstate pipeline companies consist of (1) domestic in-the-ground reserves, (2) gas purchase contracts with other interstate pipeline companies, (3) foreign suppliers, and (4) supplemental fuels (LNG, propane, SNG). Domestic in-the-ground reserves include (1) recoverable, salable reserves warranted under long-term contract with independent producers, (2) company-owned reserves, and (3) short-term supplies purchased from independent producers. Long-term contracts with independent producers account for 85 to 90% of supplies.

The distribution segment of the natural gas industry is comprised of approximately 1400 distribution companies which purchase gas from transmission companies and resell it to the ultimate consumer. Distribution companies vary in size from small municipal gas systems of a few hundred customers to giant utilities like Southern California Gas Company with over 1,500,000 customers. Of the approximately 1400 gas distribution utilities, 300 are of major size.

"Local" distribution company is somewhat of a misnomer: While some distributors operate in a single urban area, others serve virtually an entire state. A characteristic of all distribution companies, however, is that they operate facilities within a single state, and are therefore regulated by state public utilities commissions. Some distribution companies are subsidiaries of holding companies that also operate interstate pipelines through other

Table IX-1
FERC Curtailment Priorities

- (1) Residential, small commercial (less than 50 Mcf on a peak day).
 - (2) Large commercial requirements (50 Mcf or more on a peak day), firm industrial requirements for plant protection, feedstocks and process needs, pipeline customer storage injection requirements.
 - (3) All industrial requirements not specified in (2), (4), (5), (6), (7), (8), or (9).
 - (4) Firm industrial requirements for boiler fuel use at less than 3,000 Mcf/day, where alternate fuel capabilities can meet such requirements.
 - (5) Firm industrial requirements for large-volume (3,000 Mcf or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements.
 - (6) Interruptible requirements of more than 300 Mcf/day, but less than 1,500 Mcf/day, where alternate fuel capabilities can meet such requirements.
 - (7) Interruptible requirements of intermediate volumes (from 1,500 Mcf/day through 3,000 Mcf/day), where alternate fuel capabilities can meet such requirements.
 - (8) Interruptible requirements of more than 3,000 Mcf/day, but less than 10,000 Mcf/day, where alternate fuel capabilities can meet such requirements.
 - (9) Interruptible requirements of more than 10,000 Mcf/day, where alternative fuel capabilities can meet such requirements.
-

subsidiaries. Columbia Gas System, Inc., is a good example. It is the parent holding company of Columbia Gas Transmission Corp., an interstate pipeline subsidiary; Columbia Gas of Kentucky, Columbia Gas of Ohio, and Columbia Gas of West Virginia are distribution subsidiaries; and Columbia LNG Corporation is an LNG subsidiary.

FERC Curtailment Plan

Since the early 1970's, demand for natural gas has exceeded supply in the interstate market, causing pipelines to curtail deliveries of gas to some of their customers. FERC is responsible for reviewing a pipeline's curtailment plan, which is used to divide this reduced supply among its customers. The FERC curtailment plan (see Table IX-1) establishes curtailment priorities which classify gas users by demand sector (residential, commercial, and industrial), size (the amount of gas used), and type of service (firm or interruptible).

Service offered to customers under schedules or contracts which anticipate no interruptions is termed firm. Low-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice is termed interruptible. Interruptible service is offered at a lower rate than firm service and customers generally have alternative fuel capabilities in the event gas supplies are not available. Under the FERC curtailment plan, residential and small commercial customers requiring less than 50 Mcf on a peak day have highest priority, while interruptible customers requiring more than 10,000 Mcf/day have lowest priority. The majority of interstate pipeline curtailment plans are based on these end-use criteria; that is, a pipeline company will curtail deliveries to distribution companies and direct sales to industry based on criteria specified in the FERC curtailment plan. Direct sales to large volume customers with interruptible service requiring more than 10,000 Mcf/day, for example, will be curtailed before sales to large volume customers requiring less than 10,000 Mcf/day. Sales to distribution companies will be curtailed similarly, that is, sales to a distributor that is contracted to sell 50% of its gas supplies to large volume customers with interruptible service will be curtailed before sales to a distributor that is contracted to sell only 25% of its gas supplies to large volume customers having the same FERC priority.

Utility Load Balancing

Transportation of natural gas by pipe implies that there is a fixed maximum capacity for any given pipeline which is determined by the diameter of the pipe and the maximum pressure which the compressor stations can build up in the line. The closer a pipeline comes to transporting its maximum capacity, the lower is the unit cost of each cubic foot of gas transported, as fixed cost is spread over more and more units. In both the gas transmission and distribution industries, load balancing is of primary concern in order to attain as high a load factor in the lines as possible. A pipeline's load factor is the ratio of average daily demand to maximum daily demand. The load factor for distribution companies is usually in the range of 35 to 50%, while transmission pipelines usually attain a factor in the range of 70 to 95%. Transmission

companies generally transport a fairly constant volume of gas throughout the year, either directly to customers or to storage reservoirs, whereas distribution companies may have their suppliers divert a portion of their contracted gas supply to underground storage, thus reducing the distributor's load factor during the summer months.

Residential and commercial consumers use natural gas primarily for space heating which peaks during the winter heating season, whereas industrial customers use natural gas for process steam, direct heat, and as a petrochemical feedstock, maintaining a fairly constant load throughout the year. Since a distribution company must maintain pipeline capacity sufficient to meet maximum anticipated daily demand, the company's load factor will depend, in part, upon the mix of residential-commercial versus industrial customers. A utility serving primarily residential-commercial customers with large seasonal fluctuation in demand may incur a low load factor. In order to reduce this supply/demand imbalance, distribution companies use a number of techniques, referred to as load-balancing practices, to flatten the load curve illustrated in Figure IX-3.

A common load-balancing technique of distribution companies is the use of underground storage reservoirs to store gas purchased from pipeline companies when supply exceeds demand and then withdraw gas from underground storage when demand exceeds supply. One-half the underground storage capacity presently used in the United States is located in four states (Pennsylvania, Michigan, Illinois, and Ohio) where local gas and oil production has declined (see

Figure IX-3
Typical Load Curve

Section VIII for additional details). These reservoirs, located near centers of demand in the Northeast and North Central states, are used by distribution companies during the winter to supplement deliveries by the pipelines. The interstate pipeline companies also use underground storage to supplement supplies received from producers in meeting seasonal customer demands. 210 of the 386 storage reservoirs in the United States are operated by interstate pipeline companies, the remainder being operated by distribution companies or independent operators.

Another load-balancing technique that is becoming increasingly common is the curtailment of gas to interruptible customers. A distributor or pipeline will deliver gas to interruptible customers when supplies (including withdrawals from underground storage) are sufficient to meet firm demand. When supplies are not sufficient, interruptible customers will be curtailed according to the FERC curtailment plan previously described. Historically, curtailments to interruptible customers have occurred only on the coldest winter days. It is becoming increasingly common for a utility to curtail deliveries to its interruptible customers for a major portion of the winter, with the customer depending upon an alternative fuel to meet its daily energy needs.

Gas furnished on an interruptible basis accounts for approximately 22% of distribution company sales, with wide variations that are regionally dependent. In the East North Central states, firm industrial volumes are four times interruptible volumes. Yet industrial users in the adjoining West North Central states obtain nearly twice as much gas under interruptible contracts as they do under firm contracts.

As an alternative to interruptible customers, a pipeline may seek seasonal summer customers to counterbalance the heavy winter peaks. The canning industry and irrigation pumping are two such possibilities; residential air conditioning is another. A pipeline may also try to build up a year-round industrial base (which shows little seasonal variation) while minimizing its residential load. As with most interruptible sales, these types of load-balancing sales typically involve relatively large volumes of gas in uses where the form value of natural gas is minimal, and where the customer's choice depends primarily on the relatively lower cost of gas.

LNG, propane, and SNG peak-shaving facilities are also becoming increasingly popular among distribution and transmission companies as a way to compensate for dwindling supplies during periods of peak demand. It should be pointed out that withdrawals from underground storage and curtailments to interruptible customers are generally relied upon before LNG, propane, and SNG as illustrated in Figure IX-3 because of the high cost of these supplemental fuels. In spite of this high cost, these fuels are being increasingly relied upon, because of decreasing supplies, to avoid curtailments to high-priority customers during peak periods.

As of June 1978 there were 59 LNG, 491 propane-air, and 13 SNG peak-shaving plants operating in the U.S. These plants are owned and operated by the transmission and distribution companies and are located on site, as opposed

to underground storage facilities which may be shared by several utilities and located some distance from a utility's service area.

Propane-air plants feed a mixture of approximately 60% propane (heating values = 2400 Btu/cu ft) and 40% air directly into the pipelines to be used during periods of peak demand. This propane-air mixture has a heating value of about 1500 Btu/cu ft, compared to methane which has an average heating value of 1031 Btu/cu ft. Injection of propane-air as a supplemental fuel into the line does not require burner adjustments or affect flame characteristics as long as excessive quantities are not injected and proper controls are carried out. Operation of a typical refrigerated propane-air plant requires the storage of liquid propane at -46°F . When propane-air is needed to supplement the natural gas supply, liquid propane is pumped from storage and passed through a heat exchanger which warms the liquid to about 100°F . Warmed liquid propane then enters a gas-fired vaporizer where it becomes vapor at 150°F . The LP-gas is then mixed with high pressure air and directed into the natural gas pipeline.

Currently, the most common process to produce synthetic natural gas is the steam-reforming of naphtha or LP-gases to produce methane. In this process the light hydrocarbons react with steam in the presence of a catalyst at temperatures above 1000°F to produce hydrogen and carbon monoxide. These substances, formed in the decomposition of naphtha or LP-gases, further react to form methane and water vapor. The advantage of using SNG rather than propane-air as a supplemental fuel, despite its higher cost, is that SNG is chemically equivalent to methane, whereas propane-air is not, and its flow must be monitored with respect to the heating value of the pipeline gas.

X. LIQUEFIED NATURAL GAS (LNG)

When natural gas is liquefied at -258°F , its volume is reduced by a factor of 600, providing the needed concentration of this energy medium for practical transportation, notably overseas, and for readily available convenient storage, particularly in areas of high and seasonal demands that are located considerable distance from natural sources. LNG facilities in the United States can generally be classified as either base-load or peak-shaving. A base-load plant receives LNG from overseas or other U.S. terminals in specially designed insulated tankers, stores the LNG in large insulated tanks, and revaporizes the liquefied gas for distribution into the pipelines. LNG terminals operate on long-term contracts with foreign suppliers at a fairly constant level throughout the year. Complete peak-shaving facilities liquefy pipeline gas for approximately 200 to 250 days a year (during periods of low or normal demand), storing the liquid in large insulated tanks on site. During the heating season, the liquid is drawn from storage and revaporized into gaseous form to meet periods of peak customer demand. Satellite peak-shaving facilities located in remote areas have no liquefaction equipment and rely upon the complete peak-shaving facilities to supply LNG to them by tank truck.

Liquefaction, Storage, and Regasification

The refrigeration and liquefaction sections of an LNG project represent the biggest single items of investment in such a scheme. In order to liquefy a low-boiling gas such as methane it has to be cooled below its dew point, that is, the temperature at which condensation starts to take place at a given pressure (-258.7°F for methane at atmospheric pressure). To cool natural gas, heat energy must be removed from the compressed gas either by means of cooling water, if this is possible, or by means of an evaporating refrigerant.

A commonly used process to liquefy natural gas is the cascade process, where several refrigerants in series are employed over the temperature range in which they are most efficient. Conventional LNG cascades usually employ propane, ethylene, and methane as intermediate refrigerants (see Figure X-1), although other combinations are possible. Water or air initially condenses propane. Propane, in turn, cools natural gas to about -34°F and also condenses ethylene refrigerant. The ethylene cools and condenses the natural gas to -116°F and condenses methane refrigerant. Methane refrigerant can then chill the liquid gas to the storage temperature, approximately -258°F .

Figure X-1

Simplified Flow Diagram of a Conventional Refrigeration Cascade

Storage facilities for LNG are required whether the liquid is to be used to meet winter shortages of gas or to supply base-load gas by long-distance pipeline. In the latter case complete ships' cargoes have to be unloaded from LNG tankers; i.e., storage capacity must be at least equal to the maximum volume of LNG expected in any one shipment.* Storage for peak-shaving, on the other hand, depends on the number of days per year during which gas is to be liquefied and on the daily capacity of the liquefaction plant.**

*Tankers transporting LNG to the Cove Point, MD, terminal have a capacity of 2.5 Bcf, whereas storage capacity at the terminal is 5 Bcf.

**The LNG peak-shaving plant operated by the Lowell Gas Company, Lowell, MA, has a liquefaction capacity of 4.5 MMcf/day and a storage capacity of 1000 MMcf. It is fairly typical of the 59 facilities presently in operation, although liquefaction capacities range from 1 to over 10 MMcf/day depending upon the requirements of the utility.

Metal LNG storage tanks are constructed of aluminum or a 9% nickel-steel alloy used as an inner liner, while carbon steel makes an effective outer covering. Resistance to stresses caused by large temperature changes and resistance to low temperature embrittlement are important material properties. Thermal stresses on inner walls when a tank is filled are due to the temperature differential of over 100°F, which may exist from liquid level to tank top, with a particularly sharp gradient immediately above the liquid.

The basic elements in an LNG regasification system are (1) a pump and piping to transport the liquid methane under pressure, (2) a heat exchanger where the liquid is first vaporized, and (3) a heat transfer medium. Liquid methane at about 100 psig is initially directed to a heat exchanger where the liquid is first vaporized. The resulting vapor is then superheated to the range of 30° to 60°F at constant volume to obtain a pressure of 500 to 1000 psig. At this pressure, gas recompression is unnecessary prior to shipment into the pipeline. The sendout should be warm enough both to be compatible with pipeline materials and to avoid problems in mixing with existing pipeline contents such as hydrates.

Safety

The technology of LNG and, in fact, the cryogenic handling and processing of numerous gases have reached a degree of proficiency and safety not visualized in the aftermath of the LNG accident in Cleveland, Ohio, in 1948 which claimed 135 lives and involved several hundred injuries. At that time, a cylindrical tank with a capacity of 150,000 cubic feet of LNG failed and released the liquid, part of which overflowed an enclosed area and entered surrounding storm sewers of the adjacent neighborhood where there were numerous ignition sources. This accident was analyzed thoroughly and is regarded by numerous authorities as having set back LNG technology by a minimum of 20 years.

A great deal of research has been conducted on safety and environmental protection issues related to the production, storage, and transportation of LNG. If LNG is accidentally released and exposed to ambient conditions, it absorbs heat from its surroundings and vaporizes. The rate of vaporization and dispersion of the resultant vapor cloud is a fundamental design and safety consideration for LNG facilities. Initial vaporization rates for ground spills are about 10 cubic feet per minute (cfm) of gas/sq ft of surface area and about 700 cfm/sq ft for water spills. A boiling pool of LNG that has reached equilibrium with the surroundings will vaporize at around 1 cfm of gas/sq ft of surface area, depending on wind and other conditions. Therefore, a 1-ft-deep pool of LNG will require about 10 hours to evaporate under equilibrium conditions.

LNG Operations

The first major base-load LNG importing terminal in the U.S. located at Cove Point, MD, began operations in March 1978 with a shipment of 2.5 Bcf of LNG from Algeria. The terminal is jointly owned by the Columbia LNG Corporation (a subsidiary of Columbia Gas System) which has agreed to purchase 300 MMcf/day and the Consolidated System LNG Company (a subsidiary of Consolidated Natural Gas Company) which has agreed to purchase 350 MMcf/day under a 25-year contract with Sonatrach, the Algerian national oil and gas agency. The terminal has a 1 Bcf sendout capacity with a 36-in.-diameter sendout line that operates at 1250 psig. The regasification system consists of banks of tubes submerged in a bath of agitated warm water heated by gas burners. As the liquid converts to gas it flows directly into the transmission pipeline for delivery to market.

Two other major base-load LNG import terminals, one to be located at Port O'Conner, Texas, and the other at Point Conception, California, are scheduled to come on line in the early 1980's. The California terminal, planning to import 900 MMcf/day of LNG from Indonesia and the Cook Inlet area of South Alaska, is currently in the final stages of the regulatory permitting process. On the basis of LNG projects either planned or under construction, LNG imports could be as high as 1.6 Tcf/yr by 1985, or 10% of the total supply of natural gas in the United States.

XI. NATURAL GAS PRICING

The marketability of natural gas is closely linked to its price, since in the short term many industrial users can switch to an alternate fuel, and in the long term most other users can switch to an alternate fuel. Understanding how producers, wholesalers (pipelines), and retailers (distributors) determine this price is therefore essential.

Natural gas has three basic price categories: the wellhead value, the city-gate price, and the end-user price. The average wellhead value in the U.S. in 1977 was \$0.79/Mcf. The wellhead value, reflecting price at first point of transfer, that is, sales made by producers, falls under FERC jurisdiction as defined in the Natural Gas Policy Act (NGPA) of 1978. The average city-gate or wholesale price in the U.S. in 1977 was \$1.31/Mcf and is regulated by FERC in interstate commerce. A city gate is a station for reducing the pressure in the pipeline, located near a point in which gas changes ownership from one party to another, neither of which is the ultimate consumer. Transmission companies generally transport gas to the city gate.

The average end-user price in the U.S. varied from a high of \$2.35/Mcf in the residential sector to a low of \$1.70/Mcf in the industrial sector and is regulated by state public utilities commissions. This price reflects the cumulative costs of production, processing, transmission, storage, and distri-

bution. The price differential across demand sectors is attributed to the variable cost of distributing gas in these sectors and the type of service a customer is receiving. Individual industrial customers typically consume large quantities of fuel compared to residential customers, thus reducing the unit cost for distribution. Industrial customers may also receive a portion of their gas under an interruptible service contract and thus at a lower price than residential-commercial customers who normally receive only firm gas. Recent pricing schemes have moved away from this form of pricing, termed declining block rate, and toward a more uniform pricing schedule that induces conservation rather than consumption.

End-user price also varies by geographic region from a high of \$4.11/Mcf for residential consumers in New England to \$1.90/Mcf for residential consumers in the Mountain census region (see Table XI-1) because of several contributing factors. Load curves in the South tend to be flattened out because of reduced demand for space heating, thus decreasing transmission, distribution, and storage costs. Transmission costs also vary with distance from producing to consuming regions. Natural gas sold intrastate in producing states such as Texas and Louisiana was unregulated under the Natural Gas Act of 1938, and is therefore priced higher than interstate gas.

Table XI-1
Gas Prices at the End-User Level

Region	Demand sector			
	Residential	Commercial	Industrial	Average
New England	4.11	3.52	2.76	3.67
Middle Atlantic	3.03	2.68	2.15	2.72
East North Central	2.23	2.04	1.82	2.05
West North Central	1.93	1.65	1.27	1.57
South Atlantic	2.68	2.21	1.57	2.09
East South Central	1.96	1.78	1.41	1.64
West South Central	2.08	1.81	1.67	1.72
Mountain	1.90	1.67	1.34	1.56
Pacific	1.93	2.08	2.00	1.99
United States	2.35	2.07	1.70	1.97

Rolled-In Versus Incremental Pricing

Traditionally, a pipeline system will "roll-in" the purchase price of gas from all its sources to yield a weighted average purchase price of gas. To illustrate rolled-in pricing, an interstate pipeline shown in Figure XI-1 that purchases gas from two Texas sources and an LNG plant will have a tariff which reflects a weighted average purchase price of gas at \$1.38/Mcf, even though supplies range in price from \$0.50 to \$3.00/Mcf. Distribution companies, therefore, purchase gas from the pipeline under a single tariff that combines the costs of all these gas supplies.

Figure XI-1
Rolled-In Pricing

Recently, national debate has turned to the merits of adopting "incremental" as opposed to rolled-in pricing. Incremental pricing in general means a system in which the price for one unit of a good is equal to the cost of producing one more unit of that good. Prior to the enactment of the NGPA, incremental pricing referred to the sale of gas from a given high-cost source under a separate service agreement and a separate rate schedule from natural gas flowing under existing agreements, thereby allowing purchasers to decide whether or not they wanted to buy the supplemental gas after comparing its cost with that of alternatives. Under this proposal, consumers would face the actual costs of the incremental gas supply, in contrast to the more common arrangement in which these costs would be averaged or rolled into a single rate schedule with lower-cost conventional gas. An incremental pricing rule of this sort effectively blocks development of any supplemental gas supply whose future cost is expected to be greater than that of alternate fuels for the "incremental," or lowest-priority customer.

Figure XI-2 illustrates incremental pricing prior to the enactment of the NGPA. Demand by residential-commercial users of 200 Mcf/day is met by gas from conventional sources at a rolled-in price of \$0.83/Mcf. Fifty percent of demand by industrial users of 200 Mcf/day is met by conventional gas at a rolled-in price of \$0.83/Mcf and 50% by LNG at an incremental price of \$3.00/Mcf. Industrial customers probably will not sign a service agreement for incrementally priced gas at more than the price of fuel oil; hence the LNG facility may not be financed.

Figure XI-2
Incremental Pricing

The only actual cases of incremental pricing have been sales of some peak-shaving or emergency supplies during winter months by means of separate rate schedules. No base-load supplies have been subject to this form of pricing.

Incremental pricing as called for in the NGPA of 1978 has come to have a somewhat different meaning. The term refers to a formula for allocating the average price of gas among certain categories of end users. Strictly speaking, all gas purchasers would continue to face a rolled-in price in the sense that final prices would reflect the average of several different prices for gas from different sources. What would be new about this scheme would be the establishment of two tiers of such rolled-in prices. The higher cost of certain incremental supplies would be rolled into only those prices faced by certain industrial users (up to a prescribed point), while households and other favored consumers would face a lower rolled-in price which did not reflect these higher costs. Once the higher of the two price tiers reached equivalence with the price of fuel oil, however, further supplies would be rolled into the prices faced by both classes of customers.

Natural Gas Policy Act

Prior to the NGPA of 1978, regulation of sales of natural gas by producers in interstate commerce was under FERC jurisdiction according to a 1954 Supreme Court ruling on the Natural Gas Act of 1938. These regulations have led to declining supplies for the interstate market, while the intrastate market has maintained or expanded service. Recently, major surpluses have accumulated in the intrastate market. The NGPA is designed to redress these fundamental market distortions by establishing prices that are applicable to both the interstate and intrastate markets, as well as removing outmoded regulatory burdens on sales in the interstate market. The price ceiling system of the NGPA is designed to provide incentives for more risky exploratory drilling, while restraining price increases on previously discovered gas to prevent significant inflationary impacts.

The NGPA gives FERC jurisdiction over producer sales in intrastate commerce. Previously, FERC had jurisdiction over the rates for natural gas sold in interstate commerce under the old Natural Gas Act of 1938, but did not have jurisdiction over intrastate commerce. Intrastate sales currently account for an estimated 40 to 45% of total nationwide gas sales.

The NGPA establishes a series of statutory maximum lawful prices for various categories of natural gas, including gas destined for both the intrastate and interstate markets. Natural gas from new onshore production wells, for example, is priced at \$1.75/MMBtu (plus inflation), while gas dedicated to interstate commerce before the NGPA was enacted is priced at from \$0.30 to \$1.45/MMBtu (plus inflation), depending upon when the well began producing. The complete schedule of prices and categories is shown in Table XI-2.

Under the NGPA, price controls will be lifted from the wellhead price of new gas and intrastate gas selling for more than \$1.00/MMBtu as of January 1, 1985. Certain high-cost gas will be deregulated on the effective date of the incremental pricing rule. Gas from certain new onshore wells will also be deregulated, but not until July 1987. All other gas will remain under price controls indefinitely.

XII. DEMAND

Demand for Petroleum Products

The total demand for petroleum products in the United States was 18.43 MMbbl/day in 1977 (Table XII-1). Motor gasoline represents 39% of total demand and is the largest oil product consumed in this country by a wide margin. Distillate fuel oil and residual fuel oil are the next two largest products. These three products represented about 74% of total petroleum demand in 1977.

Table XI-2
Maximum Gas Price Ceilings Set by the Natural Gas Policy Act

Section of the Act	Price per million Btu ¹	Category of Gas	Date of Deregulation
102	\$1.75 + inflation ² and escalation ³ (\$2.07) ⁴	<p>NEW NATURAL GAS</p> <ul style="list-style-type: none"> - new Outer Continental Shelf (offshore) leases (on or after 4/20/77) - new onshore wells <ul style="list-style-type: none"> 1) 2.5 miles from the nearest marker well⁵ 2) if closer than 2.5 miles to a marker well, 1000 feet deeper than the deepest completion location of each marker well within 2.5 miles - new onshore reservoirs <p>Gas from reservoirs discovered after 7/27/76 on old (pre-4/20/77) Offshore Continental Shelf</p>	<p>- 1/1/85</p> <p>- not deregulated</p>
103	\$1.75 + inflation (\$1.97) ⁴	<p>NEW ONSHORE PRODUCTION WELLS (wells, the surface drilling of which began after 2/19/77, that are within 2.5 miles of a marker well and not 1000 feet deeper than the deepest completion location in each marker well within 2.5 miles)</p> <ul style="list-style-type: none"> - gas produced above 5000-foot depth - gas produced from below 5000-foot depth 	<p>- 7/1/87</p> <p>- 1/1/85</p>
104	<p>\$1.45 + inflation (\$1.63)⁴</p> <p>\$0.94 + inflation (1.06)⁴</p> <p>\$.295 + inflation (\$0.33)⁴</p> <p>applicable FERC rate + inflation</p>	<p>GAS DEDICATED TO INTERSTATE COMMERCE BEFORE THE DATE OF ENACTMENT (rates previously set by FPC)</p> <ul style="list-style-type: none"> - from wells commenced from 1/1/75 - 2/18/77 - from wells commenced from 1/1/73 - 12/31/74 - from wells commence prior to 1/1/73 - other gas (gas produced by small producers, gas qualifying for special relief rates, etc.) 	<p>- not deregulated</p>

Table XI-2 (cont'd)
Maximum Gas Price Ceilings Set by the Natural Gas Policy Act

Section of the Act	Price per million Btu ¹	Category of Gas	Date of Deregulation
105	contract price ⁶	<p>GAS SOLD UNDER EXISTING INTRA-STATE CONTRACTS</p> <ul style="list-style-type: none"> - if contract price is less than Section 102 price it may escalate, as called for by contract, up to Section 102 price - if contract exceeds Section 102 price then contract price plus annual inflation factor or Section 102 price plus escalation applies, whichever is higher 	<p>- 1/1/85 - if unescalated contract price exceeds \$1.00 by 12/31/84</p> <p>- if lower, not deregulated</p>
106	<p>\$.54 or other applicable FERC price + inflation (\$.61)⁴</p> <p>the higher of expired contract price or \$1.00 + inflation (\$1.13)⁴</p>	<p>SALES OF GAS MADE UNDER "ROLLOVER" CONTRACTS (an expired contract which has been renegotiated)</p> <ul style="list-style-type: none"> - interstate - intrastate 	<p>- not deregulated</p> <p>- 1/1/85 if more than \$1.00</p>
107	<p>\$1.75 + inflation + escalation³ (\$2.07)⁴</p> <p>applicable rate under the Act or higher incentive rate as set by FERC</p>	<p>HIGH COST NATURAL GAS</p> <ul style="list-style-type: none"> - production from below 15,000 feet from wells drilled after 2/19/77 - gas produced from geopressurized brine, coal seams, Devonian shale 	<p>- deregulated on effective date of FERC incremental pricing rule called for by the Act (approximately one year after enactment)</p>

Table XI-2 (cont'd)

		- gas produced under other conditions the FERC determines to present "extraordinary risks or costs"	- not deregulated
108	\$2.09 + inflation (after 5/78) + escalation ³ (\$2.21) ⁴	STRIPPER WELL NATURAL GAS (natural gas not produced in association with crude oil, which is produced at an average rate less than or equal to 60,000 cubic feet per day over a 90-day period)	- not deregulated
109	\$1.45, or other "just and reasonable" rate set by FERC, + inflation (\$1.63) ⁴	OTHER CATEGORIES OF NATURAL GAS - any natural gas not covered under any other section of the bill - natural gas produced from the Prudhoe Bay area of Alaska	- not deregulated

¹ Under the NGPA, if natural gas qualifies under more than one price category the seller may be permitted to collect the higher price. The ceiling prices set by the NGPA do not include state severance taxes.

² These prices include an "annual inflation adjustment factor" in order to adjust prices for inflation. The price for a given month is arrived at by multiplying the price for the previous month by the monthly equivalent of the annual inflation factor. Since most of the prices set by the NGPA are as of April 20, 1977, the adjustment for inflation begins in May 1977.

³ These prices will escalate monthly, in addition to the inflation adjustment factor, by an annual rate of 3.5 percent until April 1981, after which they will escalate by 4 percent.

⁴ The estimated maximum ceiling price as of October 1978, due to operation of inflation and escalation adjusters.

⁵ A marker well is any well from which natural gas was produced in commercial quantities after January 1, 1970, and before April 20, 1977, with the exception of wells the surface drilling of which began after February 19, 1977.

⁶ The average price reported to the FERC for intrastate gas sales contracted for during the second quarter of 1978 was approximately \$1.90.

Source: The National Energy Act, Department of Energy.

Data for prior years, Figure XII-1, show that gasoline, distillates, and residual fuel oil have been the three largest products for many years. Jet fuels, about 5-1/2% of total demand, are another large volume product used in the U.S.

Table XII-1
Domestic Demand for Refined Petroleum Products in 1977

Oil Product	Domestic Demand (MMbbl/day)	Percent
Motor gasoline	7.18	39.0
Distillate fuel oil	3.35	18.2
Residual fuel oil	3.07	16.7
Jet fuel	1.04	5.6
Kerosene	0.18	1.0
Other products*	3.62	19.6
Total products	18.43	

*Includes ethane, liquefied gases, petrochemical feedstocks, lubricants, still gas, petroleum coke, asphalt, road oil, wax, and miscellaneous products.

Data Source: Annual Report to Congress 1978, EIA, DOE/EIA-0173/2.

The remaining 20% of total demand is for other products, some of which are raw materials that are not burned as conventional fuels. For example, ethane and liquefied gases (propane and butanes) are products that can be used either as fuels or as raw materials for synthetics manufacturing. Asphalt and road oil are applied to road surfaces. Petroleum coke is a valuable raw material for production of graphite, and as a carbon source in the chemical industry. Petroleum coke in some instances can be a substitute for coal and some refineries are generating steam by burning this by-product and using the steam as a heat source throughout the refinery.

Motor gasoline and jet fuel are the only two products used almost totally for transportation purposes. Over 95% of gasoline usage is by automobiles and trucks, while airplanes, tractors, and other off-highway vehicles consume the remainder. Only a small portion of jet fuel is used for generating electricity in gas turbines. The remaining oil products are used by more than one category of end users in the residential, commercial, industrial, transportation, and electric utility sectors.

Demand for natural gas and petroleum products by each sector in 1977 is shown in Table XII-2. The largest sector is transportation which consumed more than 50% of all oil products, and which has been the largest oil user in the U.S. during the entire 30-year span shown in Figure XII-2. Fuels used for

Figure XII-1

Domestic Demand for Refined Petroleum Products

Source: Annual Report to Congress 1978, EIA, DOE/EIA-0173/2

Figure XII-2

Domestic Demand for Refined Petroleum Products by End-Use Sector

Source: Annual Report to Congress 1978, EIA, DOE/EIA-0173/2

transportation include gasoline and jet fuel as well as middle distillates (diesel fuels) and residual fuel oils. About one-half of diesel fuel is used in trucks and buses, 25% is used by railroads, 5% is needed for marine use, and the remainder is consumed by industry, utilities, and the military. The industrial sector consumes about 21% of all petroleum used in the U.S. and the residential and commercial sectors consume about 16%. The electric utilities consume 10%, a smaller fraction than any other sector.

Table XII-2
Demand for Petroleum Products and Natural Gas by End Use Sector in 1977

	Natural Gas (10 ¹² cu ft)	(Percent)	Petroleum Products (10 ⁶ bbl/day)	(Percent)
Residential	4.82	24.7		
Commercial	2.24	11.5		
Residential and commercial			2.97	16.1
Industrial	8.73	44.7	3.77	20.5
Transportation	0.53	2.7	9.92	53.8
Electric utilities	3.19	16.4	1.77	9.6
Total	19.52		18.43	

Data Source: Annual Report to Congress 1978, DOE/EIA-0173/2.

The petroleum production, refining, transportation, and distribution industries are responsible for delivering the huge volumes, over 18 MMbbl/day, of oil products needed to meet the demand for petroleum. The complex system that these industries constitute is driven by demand. This means that operations at each stage focus upon delivering the amount of each product that is needed by end-use customers. In the past, whenever domestic crude oil and refinery production was insufficient to meet demand, imports have filled the gap.

The operations in the oil industry which interface with demand are refineries, bulk terminals, and retail distributors. Motor gasoline is distributed to automobiles by approximately 186,000 service stations throughout America. Refineries and bulk terminals generally supply gasoline to service stations by tank truck in deliveries of 7,000- to 13,000-gallons, depending on state, county, and local transportation regulations.

Gasoline is unique among petroleum fuels because it is distributed in such large amounts to one sector by a very limited means. However, for this reason the system must be efficient; refineries and terminals must build up stocks of gasoline during winter months when demand is at a low point. In order to build up gasoline stocks, production of middle distillates such as home heating fuel must be curtailed and gasoline production must be increased at refineries.

Because the relative production of gasolines and distillate fuel oils are strongly related, it is critical that the proper stock levels of these products be maintained at refineries and terminals to prevent shortages. Demand for distillates increases about 1.5 MMbbl/day during the winter heating season. If distillate stocks are not high enough in November and December (when refinery production usually switches to gasoline from distillates), a shortage of home heating fuel could result from an excess demand due to a colder-than-normal winter. If distillate production is maintained high during the winter, gasoline stocks will not reach levels in spring and summer needed to meet high demand during summer.

The air transportation sector uses naphtha and kerosene jet fuels and aviation gasoline. Jet fuel is burned by turbine engines in jets and aviation gasoline is used in spark ignition engines. Commercial jet engines require kerosene-type jet fuel and the military uses either kerosene or naphtha-type jet fuels. About 80% of total jet fuel demand is for kerosene-type jet fuel.

The largest airports are most often supplied with jet fuels by pipelines linked directly to refineries. Barge shipments from refineries or bulk terminals are the other major means for supply to airports. Tank truck size deliveries (13,000 gallons maximum) are not used for airports because of the large quantities of fuel used by jets. In 1975 domestic air carriers consumed 7.287 MM gallons of fuel and traveled 1.885 MM aircraft miles which on average corresponds to 3.87 gallons per aircraft mile.* Thus, a jet consumes about 5,800 gallons of fuel by traveling 1,500 miles which is equivalent to about one-half of the maximum capacity of a tank truck. Aviation gasoline is used chiefly for small propeller-driven aircraft with spark ignition engines. Mode of transport and type of supplier depend on the volume of aviation gasoline consumed at a given airport.

Tractor trailer trucks, which are essential in maintaining regional trade in the U.S., are also part of the transportation sector. These trucks are powered by diesel engines that are efficient, durable, and reliable for the heavy loads and long operating hours that are needed in long hauls. Diesel fuel, supplied from truck stops, is essentially the same as home heating fuel (No. 2 fuel oil) and the two can be interchanged. In colder climates such as in the Northern U.S., super-diesel fuel (No. 1 diesel fuel) is sometimes needed for better performance and starting in diesel engines. Kerosene can also be blended with regular diesel fuel for better performance in colder climates.

The industrial sector uses a variety of petroleum products in addition to natural gas and coal for two end-use categories: process steam and direct heat. Process steam is generated in centralized boilers at industrial plants and is distributed throughout the plant for both space and process heating. Direct-fired burners are located at specific units in the plant. For example, direct heat usage can be an oil-fired kiln at a cement plant or an oil-fired reheating furnace at a steel mill. Industrial plants normally run 24 hours a day, every day of the year, and their boiler and direct heat units must stay on stream at all times (except during shutdown for maintenance).

*Data from Rose, Energy Intensity and Related Parameters of Selected Transportation Modes; Passenger Movements, ORNL 506, Jan. 1979.

The fuel type used for a particular industrial application is usually selected on the basis of three factors: price, reliability of supply, and environmental regulations. The largest group of oil products used by industry is residual fuel oils. In order to remain competitive with coal and natural gas, residual fuel oil is the lowest-priced petroleum fuel; the price of a barrel of resid is often less than the crude oil from which it was processed. Sulfur content of resid is an important price-determining factor. In many parts of the country the maximum allowable sulfur content of resid that can be burned and still meet environmental regulations is 1/2%. Most of the sulfur present in crude processed at a refinery ends up in residual fuels which are literally the bottom of the petroleum barrel. Many U.S. refineries use special coking units to convert resid into more valuable intermediate products and petroleum coke. As a result between one-half and two-thirds of residual fuel oil demand is met by imports.

Distillate fuel oils are another class of oil products used by industry for both process steam and direct heat. Light products, chiefly propane, are also used as a substitute when natural gas supplies are curtailed.

Industry is a very large end user; a modest-sized industrial boiler unit might have a capacity of 100 MMBtu/hr. When such a unit is operating at full capacity it consumes about 2,700 barrels of residual fuel oil per week. Suppliers for such large users must be refineries or bulk terminals, which can ship barge or tank-truck-size deliveries directly to industry on a regular basis.

Petrochemicals are chemicals containing hydrocarbons derived from petroleum. A large portion of industrial petroleum demand is for petrochemical feedstocks to the chemical industries. There are over 700 petrochemical plants in the U.S. The demand for petrochemicals accounts for about 5% of U.S. oil demand, and is increasing faster than for other petroleum products. Petrochemical-derived products are penetrating large-volume commodity markets such as steel (in automobiles), fabrics, wood, and paper. There are two classes of petrochemical products made at refineries: olefins and aromatics. Products derived from olefins represent about 55% of petrochemical demand and those derived from aromatics are responsible for 40%.

Light products (ethane, propane, and butanes) make up the largest fraction of products used to make olefins. Light products are shipped to chemical plants by pipeline from natural gas processing plants and refineries. Independent chemical companies use crude petroleum to produce about 60% of total olefins demand and the remainder is produced by chemical plants owned by the oil companies. About one-fourth of olefin petrochemical feedstocks is made from naphthas and gas oils.

About 90% of total aromatic production is derived from petroleum and 10% from coal coking oven by-products. Aromatics are usually sold from refineries directly to the chemical plants by railroad tank car or tank truck.

Hydrocarbons from aliphatic feedstocks are chemically synthesized into many important end products, from plastics and synthetic rubber to drugs and detergents. Ethylene is a very important raw material which is needed to make ethanol, solvents, pharmaceuticals, cleaning compounds, and polyethylene. The principal aromatics are benzene, toluene, and xylene. Finished products which are derived from benzene alone include synthetic rubber, latex paints, polystyrene, adhesives, insecticides, varnishes, medicinal products, synthetic detergents, and explosives.

The commercial sector is a catchall category made up of those consumers not part of the industrial or residential sectors. This sector encompasses a wide variety of institutions such as small business enterprises, retail stores, churches, all levels of government, hospitals, schools, and universities. The petroleum fuels consumed by this sector include distillate fuel oil, residual fuel oil, and light products.

The type of supplier to the commercial sector can vary depending on the size and nature of the consumer. The largest schools, retail stores, and government facilities obtain barge or tank truck shipments direct from refineries and bulk terminals. However, there are many small establishments in this sector which are supplied by jobbers and retail distributors.

There were 74.1 million households in the residential sector in 1977. No. 2 fuel oil, kerosene, and propane are the primary petroleum products used in the residential sector for space heating, hot water heating, and cooking. These fuels are burned in furnaces, water heaters, stoves and sometimes in refrigerators and air-conditioning units.

Regional fuel usage patterns are common in the residential sector. Fuel oil and propane are used where the natural gas distribution network is not available and the cost of electricity is too high. Most No. 2 fuel oil demand is in nine Northeastern states. Seventy-five percent of New England homes and 57% of New York State homes are oil heated, whereas the national average is 20%.

The primary suppliers of petroleum products to the residential sector are the estimated 30,000 retail distributors. Deliveries of No. 2 fuel oil and propane are made primarily by tank truck by distributors. The retail distributors are supplied directly from refineries, bulk terminals, and wholesalers (jobbers).

The electric utility sector uses residual fuel oil as the primary oil product to fire steam-electric plants. No. 4, No. 5, and No. 6 fuel oils are burned in boilers which generate pressurized steam. The steam is allowed to expand in a turbine which drives an electric generator. No. 2 fuel oil is also used for this purpose but to a lesser extent because it is priced higher than resid. In addition, jet fuel and propane are used to generate electricity in special turbines during peak demand periods. The power plants obtain oil product supplies by pipeline or barge from refineries and bulk terminals.

Demand for Natural Gas

Natural gas is burned as fuel in a wide variety of applications. It is also used as a raw material (or feedstock) in the manufacture of a large number of petrochemical products. Demand for gas can be analyzed in terms of its various generic uses (process steam, direct heat, petrochemical feedstock) or in terms of its market demands. The four basic market demands for natural gas are in the residential, commercial, industrial, and electric utility sectors. Natural gas is also used in the transportation sector (0.53 Tcf in 1977) to power compressors for oil and natural gas pipelines.

Residential uses of natural gas constitute about one-quarter of total gas consumption. The trend has been for residential consumption to increase in comparison to other uses, although this trend had begun to decrease after the natural gas shortages of the mid-1970's, when state utility commissions were restricting new gas hookups. This policy is now being reversed with the increased availability of gas due to price decontrol and the switching of industrial customers to alternate fuels.

Over 70% of residential gas consumption is used for space heating; another 20% is used to heat water, while the remaining 10% fuels gas ranges and clothes dryers. Natural gas is generally preferred over heating oil by residential consumers because it is lower priced and has a form value which provides clean and convenient service without the need to provide and maintain storage facilities. Over the long term, residential users could convert their home heating facilities to fuel oil, but only at a considerable cost, estimated at from \$300 to \$400.*

The commercial market for natural gas accounts for approximately 12% of total gas consumption. Space heating accounts for over three-quarters of gas consumed in the commercial sector, while water heating, cooking, and air-conditioning account for the remainder. Space heating requirements for the current building inventory in the commercial sector are approximately 50 ft³ of gas per ft² of floor space; therefore, 1.35 Tcf of natural gas was consumed for space heating in the commercial sector, based on a 1977 inventory of 27 billion sq ft.

Industrial uses of natural gas account for about 43% of total gas consumption, the largest single market for gas. The number of industrial customers, fewer than 178,000, is relatively small compared to other demand sectors, while the average demand per customer is much greater. The principal gas-using industries are petroleum refineries and industries producing chemicals and allied products, primary metals, paper and allied products, food and kindred products, and stone, clay and glass products. Within these diverse industries there are certain generic uses of natural gas which cut across

*Arthur D. Little, Inc, Implications of Natural Gas Consumption Patterns for the Implementation of End-Use Priority Programs.

industry lines. The consumption of natural gas to generate process steam is the largest single use in the industrial sector, accounting for approximately 40% of all industrial uses. The average industrial boiler has a capacity of 100 MMBtu/hr, but this may vary from less than 10 million to more than 1500 MMBtu/hr depending on the specific industry's requirements. Many of the larger industrial boilers are equipped to burn an alternate fuel when gas is not available, but natural gas is the preferred fuel because of its low cost, clean burning characteristics, and ease of handling.

Natural gas is used in direct heating because it provides precise temperature and flame characteristics necessary in many different types of manufacturing. Among the processes for which natural gas is preferred are those used for food preparation, automatic soldering and brazing, and glass manufacturing. More than 500 Bcf of natural gas is used as a petrochemical feedstock in manufacturing chemicals such as ammonia for use in fertilizer production; methyl alcohol, used primarily for formaldehyde, films, and plastics; and carbon black, a pure carbon product used in the manufacture of such diverse products as automobile tires and inks.

Consumption of natural gas by electric utilities accounted for 16% of total gas used in 1977, declining in recent years because of curtailments to electric utilities caused by shortages in supply and the increased use of coal and nuclear power. The impact of gas curtailments depends on the capability of electric utilities for switching to alternate fuels. About 60% of all utility boilers are equipped to run on an alternate fuel, usually fuel oil. There are wide regional variations in the use of natural gas by electric utilities, from less than 1% in New England to more than 75% in the Southwest. Currently, there are no base-load natural gas-fired electric generating facilities being constructed in the United States, although existing fossil units may switch from oil to gas depending upon fuel availability and price.

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