

QUARTERLY FOCUS

LNG TRADE: PAST, PRESENT, FUTURE (?)

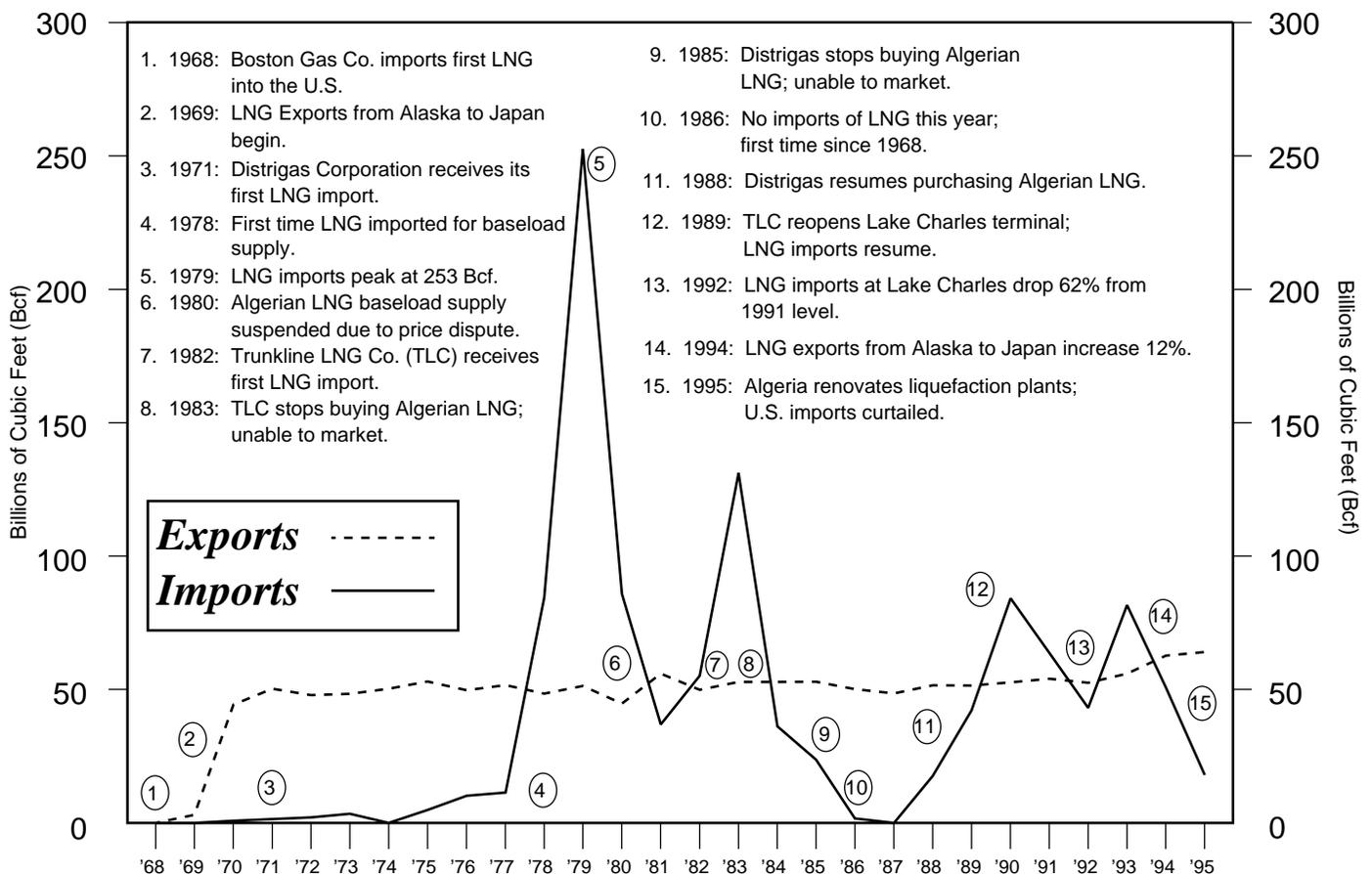
The United States has been both an importer and exporter of liquefied natural gas (LNG) since the late 1960's. This *Quarterly Focus* provides an abridged history of this trade, describes current U.S. LNG trade activity, and reviews five proposed projects which could affect future LNG trade in the United States, as well as the Commonwealth of Puerto Rico.

PAST

This section briefly discusses the history of LNG import and export trade in the United States from its beginnings in the 1960s to the present. The section outlines some of the major market developments, regulatory and policy decisions, legislation, and commercial business decisions which affected the history of such trade. **Figure 1**, shown below, illustrates the level of U.S. import and export trade from 1968 through 1995 and also identifies certain major milestones which influenced the history of such trade.

Figure 1

History of LNG Imports and Exports in the United States: 1968 - 1995



1960s

Ever since the first transoceanic trip carrying LNG from Louisiana to England in 1959 proved that it was technically feasible to transport natural gas that had been changed to a liquid state by cooling it to -260° F, many entrepreneurs saw the enormous commercial potential for such trade. During the early 1960s, the United States, particularly the Northeast region, began to experience problems with meeting peak seasonal demand for natural gas due primarily to inadequate pipeline and storage capacity. Additionally, by 1968, domestic natural gas production exceeded new natural gas discoveries added to proved gas reserves for the first time. It was under these market and supply conditions that LNG imports looked attractive as a means of supplementing domestic gas and high cost alternatives; i.e., synthetic natural gas (SNG), propane.

In November 1968, Boston Gas Company received the first shipment of LNG imported into the United States at Commercial Point, Dorchester, Massachusetts. The LNG supply came from Algeria. Algeria was already the established pacesetter in international LNG trade. Five years earlier, Algeria was party to the first regular commercial international LNG trade arrangement, involving LNG being delivered to England and France.

In 1969, Distrigas Corporation (Distrigas) began building the first marine LNG receiving terminal in the United States at Everett, Massachusetts (near Boston). During the same year, the three sponsors to the so-called El Paso I LNG Project (Columbia LNG Corporation, Consolidated System LNG Company, Southern Energy Company) signed a 25-year, base load supply contract with Sonatrach, the national oil and gas company of Algeria. Under this contract, one billion cubic feet (Bcf) per day of LNG would be delivered at two new planned LNG receiving terminals that were to be built at Cove Point, Maryland, and Elbe Island, Georgia. Once regasified, the LNG would be sold to each of the three companies' respective gas distributor affiliates.

In addition to plans in 1969 to increase the importation of LNG, an export project commenced operation. Under a 15-year gas sales contract, Phillips Petroleum Company (Phillips) and Marathon Oil Company (Marathon) jointly began to export Alaskan natural gas (Cook Inlet Basin supply) to two Japanese utilities, Tokyo Electric Power Company, and Tokyo Gas Company Limited. Once the project was fully operational, the two companies exported about 50 Bcf of LNG per year from their liquefaction facility and terminal located at Kenai, Alaska.

1970s

The 1970s can be characterized as a decade of oil embargoes, oil and natural gas shortages, rapid price escalations, regulatory price controls, and legislation aimed at reducing oil and gas demand. The natural gas industry experienced a period nearly as turbulent as the oil industry. The industry struggled with wellhead price controls, bifurcated market (interstate/intrastate), shortages, steadily declining production-to-reserves ratios, curtailment plans, inflexible long-term supply contracts (take-or-pay, indefinite price escalators), and increasingly higher prices for foreign supplies. By the later part of the decade, administrative and legislative steps were taken which ultimately would lead to reduced regulatory and market controls over both oil and natural gas; i.e., administrative removal of oil allocation and price controls on a product-by-product basis, Natural Gas Policy Act of 1978 (NGPA).

Beginning in 1971, the Federal Power Commission (FPC) ordered all interstate pipeline companies to prepare individual curtailment plans for dealing with possible shortages. These shortages continued occasionally throughout the remainder of the decade. The worst shortage in the decade probably occurred in the 1976-77 winter, when service to high-priority (residential/commercial) customers was threatened, and over a million workers were estimated to be idled. Although the causes of gas shortfalls during this period were numerous, a good share of the blame was later attributed to the fact that there were administrative price controls on interstate gas supplies (gas sold to out-of-state customers), but no similar price controls over intrastate gas supplies (gas produced and sold within a state). As a result of this bifurcated market structure, gas supplies in producing states received a higher price and were fairly abundant within the state, but supplies going to the price-controlled interstate market declined because producers could not obtain a fair market value for their commodity.

This bifurcated marketplace and the perception of natural gas shortages during this period lead many U.S. firms to commit to large, capital intensive, long-term LNG import projects. From October 1969 to October 1976, there were six long-term LNG supply contracts signed, totaling over 1.5 Tcf per year.

In 1971, Distrigas received its first shipment of LNG from Algeria at its Everett, Massachusetts, terminal. The LNG was sold to 11 natural gas distribution companies in the Northeast to meet peak winter demands.

In 1973, the FPC gave final regulatory approval to the El Paso I LNG Project. This was 4 years after the three sponsors to this project had signed a supply contract with Algeria's Sonatrach.

In 1975, Trunkline LNG Company (TLC) signed a long-term LNG supply contract with Algeria's Sonatrach. Under this contract, Sonatrach was to provide TLC with 165 Bcf of LNG annually for a period of 20 years. The LNG was to be delivered to TLC's regasification plant and terminal located at Lake Charles, Louisiana.

In 1976, the Energy Resources Council (ERC), the agency created to coordinate energy policy among federal agencies, was asked by President Ford to develop a national LNG import policy. In the same year, the ERC conducted a study and concluded that "LNG is needed to supplement our natural gas supplies, but it must be limited for supply security reasons." The ERC recommended a limit for LNG imports from a single country of 0.8 to 1 Tcf/year and a total acceptable import level from all countries of 2 Tcf/year (*Alternative Energy Futures, Part 1: The Future of LNG Gas Imports*, Office of Technology Assessment, Congress of the United States, 1980).

In 1977, the FPC authorized TLC to import from Algeria approximately 165 Bcf equivalent of LNG annually for a period of 20 years and to construct and operate the necessary terminal facilities at Lake Charles, Louisiana. In the same year, President Carter replaced the LNG import policy adopted in 1976 with one which set no U.S. or per country limits, and which provided for a case-by-case review of individual LNG projects (*Implications of the U.S. - Algerian LNG Price Dispute and LNG Imports*, (GAO Study), U.S. General Accounting Office, 1980, p. 14). The new policy focused on security of supply, vulnerability to interruptions, safety and siting, and pricing issues.

On October 1, 1977, the Department of Energy (DOE) was activated, and the authority to approve natural gas imports and exports was transferred from the FPC to DOE. In its first decision in December, the DOE approved, subject to renegotiation of certain pricing provisions, a proposal by Pac Indonesia LNG Company to import 200 Bcf of Indonesian LNG annually for 20 years into Oxnard, California. Under this project, the two customers were Southern California Gas Company and Pacific Gas & Electric Company. **(Due to difficulties in negotiating new pricing provisions, regulatory delays, environmental concerns, and changes in the marketplace, the sponsors filed notice with the DOE in 1985 formally cancelling this project.)**

In March 1978, the El Paso I LNG Project (approved in 1973) finally commenced operation. In this project, three companies were to collectively import 1 Bcf of Algerian LNG per day for 20 years. The LNG, delivered to the LNG receiving terminals located at Cove Point, Maryland, and Elbe Island, Georgia, was the first time imported LNG was used by U.S. gas companies for base load supply.

During 1978, Congress passed the NGPA and the Powerplant and Industrial Fuel Use Act (FUA). Both laws resulted in major impacts on the supply and demand for natural gas in the United States. The NGPA sent mixed signals to the natural gas industry. Although it extended wellhead price controls to the intrastate market and required incremental gas pricing for certain low-priority (industrial/utility) users, it initiated the phased-in deregulation for gas discovered after 1977. The immediate effect of this law was to move surplus gas from the intrastate market to the interstate market, provide additional incentives for expanded drilling, and reduce demand for low-priority users. The FUA restricted the use of natural gas and petroleum by electric utilities and large industrial firms on the perception that natural gas supplies were scarce. The effect of this law was to reduce the use of natural gas and petroleum by utilities and industrial firms, and encourage increased consumption of coal and other fuels.

In December 1978, the DOE disapproved two projects to import LNG from Algeria. Both projects were to import 365 Bcf annually over a 20-year period; one to the Texas Gulf Coast, and the other to the U.S. Northeast, via New Brunswick, Canada. The reasons for denial included the following: (1) projects failed to satisfy DOE's presumption in favor of direct LNG sales by importing companies to gas distribution utilities; (2) sponsors did not demonstrate a national or regional need for the gas; (3) the enactment of the NGPA and FUA would make more natural gas available, both in terms of overall quantities produced nationally and quantities available to the interstate market;

(4) the price escalation clauses were tied to world oil prices; and (5) there were inadequate contingency plans to respond to possible future supply interruptions.

In January 1979, the Secretary of Energy gave a speech informally outlining U.S. policy on future sources of gas for domestic use, including LNG imports. Under this policy, long-haul LNG imports ranked last in priority as a supplemental source of gas, and were only to be used if other lower cost sources of gas did not materialize. Supplemental sources of gas were ranked by their attractiveness in descending order, as follows: (1) Alaskan gas; (2) Canadian & Mexican gas; (3) short-haul LNG (Western Hemisphere); (4) domestically produced synthetic gas; and (5) long-haul, high-cost imported gas from the Eastern Hemisphere (*GAO Study*, p. 14).

Throughout 1979, the three sponsors to the El Paso I LNG Project, and Algeria's Sonatrach continued to have a dispute over the proper price for the LNG supply. Despite this ongoing dispute, the United States imported 253 Bcf of LNG in 1979, or about 1.3 percent of total U.S. gas consumption. To date, this remains the historic high level for LNG imports.

1980s

In April 1980, Algeria stopped delivering LNG to the three companies in the El Paso I LNG Project because of their continuing price dispute. Sonatrach had requested a 200 percent increase in the price of its LNG supply. The average price for LNG imports rose dramatically during the first years of this decade. From 1979 to 1982, the average price of LNG imports rose by 188 percent (\$1.81/MMBtu v. \$5.21/MMBtu). By 1982, the price paid for LNG imports was over twice the price paid by interstate pipeline companies for domestic gas supplies, and for the first time exceeded the price paid for pipeline imports (Energy Information Administration (EIA), DOE, *U.S. Imports and Exports of Natural Gas*, DOE/EIA-0188(80)(81), *Natural Gas Monthly*, EIA-0130(83/07).

In September 1982, the TLC Project received its first shipment of Algerian LNG at its Lake Charles, Louisiana, receiving terminal. The project was designed to provide a base load supply for various local gas distributors in the Midwest. However, an announcement by TLC in August of the planned project start-up triggered numerous complaints, petitions, and protests by the states, Congressmen, and customers to be served by this supply asking the DOE to suspend or revoke TLC's import authorization. The complainants maintained that the gas was no longer needed, the price was too high, and Algeria was no longer a reliable trading partner. Five months later, DOE denied the petitions to suspend or revoke TLC's import authorization, and deferred a decision on the issue of price for at least six months in order to better assess changing market conditions and other developments. In July 1983, TLC filed with the DOE an amendment to its authorization reflecting new pricing, volume, and related provisions that had been negotiated with Algeria's Sonatrach. In December 1983, TLC notified the DOE that it had temporarily suspended purchases of LNG, invoking the *force majeure clause* in its contract with Sonatrach, stating that the price of the gas made it unmarketable. With the suspension of TLC's LNG imports, Distrigas remained the only importer of LNG in 1984.

In February 1984, DOE adopted new natural gas import policy guidelines that were more compatible with changes in the natural gas market. The new import guidelines were written in growing recognition at the time that free trade and free markets offered tremendous economic advantages for both producers and consumers. In addition, the passage of the NGPA and FUA in 1978 increased domestic gas supplies and diminished the need for high-cost imports. The guidelines were designed to encourage natural gas import arrangements that would be competitive, flexible, and market-responsive. The guidelines also streamlined DOE's review of gas import arrangements by moving away from an intense regulatory review to a broader test of competitiveness. The issuance of the new import policy guidelines resulted in the emergence of two types of import arrangements: new and renegotiated long-term contracts containing provisions which fluctuate to changes in the marketplace; and short-term, spot market type transactions made under two-year "blanket" import authorizations. These revamped arrangements enabled importers to adjust to the continually changing natural gas marketplace.

In May 1984, the FERC issued Order 380 stating that pipelines could no longer recover variable costs under minimum commodity bills to their customers and could only charge commodity costs for gas actually taken. Thus, while Distrigas had a 100 percent take-and-pay purchase obligation with Sonatrach, Distrigas' customers only had to pay for gas actually taken.

In February 1985, the DOE approved a request by Cabot Energy Supply Corporation, an affiliate of Distrigas, to import 5 cargoes of LNG per year on a short-term or spot market basis. This approval represented the first time DOE had granted an import authorization to a prospective importer without a specific gas purchase contract with a supplier or identification of customers. The purpose of the two-year, blanket import authorization was to provide importers the opportunity to participate in the new, but growing, spot market in the United States.

In April 1985, some of Distrigas' customers notified Distrigas that they would not be purchasing LNG during the summer. As a result, in September of the same year, Distrigas notified Sonatrach that it would not be taking any further shipments of LNG. Following this announcement, Distrigas declared bankruptcy, citing its liability to Sonatrach and its inability to pass this liability on to its customers.

From 1985 through 1987, the FERC issued a number of regulatory decisions which were intended to provide for a more market responsive, competitive natural gas marketplace; i.e., encouraging open-access transportation, renegotiation of contracts, eliminating the vintaging of "old" gas, and mitigating take-and-pay liabilities. In 1987, Congress repealed Title II of the NGPA, which mandated incremental pricing to certain customer classes, and amended the FUA by eliminating the restrictions on the use of gas or oil burning for electric utilities and large industrial users.

In December 1986, Cabot Energy Supply Corporation, using its two-year, blanket import authorization, received a shipment of LNG from Indonesia. This one tanker was the only LNG imported into the United States during the entire year. The next year, for the first time since 1974, no LNG was imported into the United States.

In June 1987 and June 1988, Pan National Gas Sales, Inc. (Pan National), an affiliate of TLC, and Distrigas filed respectively, applications with DOE requesting authority to import Algerian LNG under long-term contracts. Both of these proposed import arrangements indicated Algeria's new willingness to enter into flexible, risk-sharing purchase agreements with importers and to compete in U.S. energy market. Under Pan National's proposal, there were no minimum purchase obligations, and the company would market the LNG to individual customers and negotiate the terms of each sales contract to reflect current market conditions. Algeria would receive 63.24 percent of the sales price, F.O.B. Algeria. Under the Distrigas proposal, the strict take-and-pay provisions were eliminated, and the price of the LNG was determined by using one of the following which resulted in the highest price: a formula indexed to the price of alternative fuels; a minimum price established in the contract; or 63 percent of the actual LNG sales price received by Distrigas' affiliate, Distrigas of Massachusetts Corporation (DOMAC).

In July 1987, Phillips 66 Natural Gas Company and Marathon Oil Company filed a joint application with the DOE requesting authority to amend their existing LNG export authorization to allow them to charge more market-responsive prices to their two Japanese customers. The proposed changes were designed to keep the LNG supply of these two companies competitive with other sales of LNG in the Japanese market. In November 1987, the DOE approved the proposed amendments to this LNG export arrangement.

In December 1987, the Yukon Pacific Corporation (Yukon Pacific) requested authority from DOE to export annually up to 660 Bcf of LNG from Alaska to the Pacific Rim Countries of Japan, Korea, and Taiwan. In the following month, January 1988, President Reagan issued a finding which stated that Alaskan North Slope natural gas could be available for export.

In September and December 1988, the long-term Algerian LNG import projects of Distrigas and Pan National were approved respectively, by DOE.

In February 1989, Distrigas requested authority from DOE to import Algerian LNG under another long-term purchase contract. In July 1989, the DOE approved this import request.

In July 1989, the Wellhead Decontrol Act of 1989 was passed. It repealed Title I of the NGPA and all maximum lawful prices for natural gas as of January 1, 1993. It also allowed immediate deregulation of prices for first sales under expired or terminated contracts or contracts entered into after July 26, 1989.

In November 1989, DOE approved Yukon Pacific's request to export 660 Bcf per year of Alaska North Slope gas to the Pacific Rim Countries for a period of 25 years. The North Slope gas would be transported by means of the proposed Trans-Alaska Gas System (TAGS) to a tidewater site at Port Valdez, Anderson Bay, on Alaska's southern coast. At Valdez, the gas would be converted to LNG for ocean transport to the Pacific Rim Markets.

In November 1989, Pan National requested authority from DOE to import about 30.4 Bcf per year of Algerian LNG over a term of 15 years. The LNG supply would be resold to Citrus Trading Corporation (Citrus). Citrus, in turn, would sell the gas to an affiliate, Florida Power and Light Company, an electric utility, for use in electric generation.

In December 1989, TLC reopened its Lake Charles, Louisiana, facility and Pan National received its first shipment of Algerian LNG since December 1983. Under this arrangement, Algeria, the LNG supplier, received 63.24 percent of the average sales price.

1990s

In November 1990, Pan National's request to import Algerian LNG for 15 years for resale to Citrus Trading Corporation was approved by DOE.

In July 1992, Distrigas requested approval from DOE to import 28 Bcf of LNG annually from Nigeria over a period of 20 years. The request was based on a June 1992 sales and purchase agreement signed by Distrigas and Nigeria LNG Limited.

In October 1992, the Energy Policy Act of 1992 was enacted. This law, among other things, amended section 3 of the Natural Gas Act of 1938. As a result of this amendment, all LNG imports are now "...deemed to be consistent with the public interest..." and, as a result, all applications to import LNG must be granted by DOE without modification or delay. Although LNG exports to countries with whom the United States has a free trade agreement requiring national treatment for trade in natural gas are also deemed to be consistent with the public interest, LNG export projects involving non-free trade countries, such as Japan, must be reviewed by DOE to determine whether they are inconsistent with the public interest.

In November 1992, DOE approved the proposal by Distrigas to import up to 28 Bcf of LNG annually from Nigeria over a 20-year period, beginning in 1997.

During calendar 1992, LNG imports by Pan National at the Lake Charles, Louisiana, terminal declined 62 percent from the 1991 level (33.3 v. 12.6 Bcf). This decline could be attributed to the fact that LNG imports were not cost effective for Pan National because it had access to less expensive domestic supplies, and Algeria had better marketing opportunities in the European market.

In 1994, LNG exports from Alaska to Japan increased by about 12 percent over the 1993 level. The increase was the result of a renegotiated contract between the two exporters with their two Japanese customers and the commissioning into service of two new, larger LNG tankers in June and December 1993.

During 1994, Distrigas and Pan National were the only two importers of LNG, importing a total of 50.9 Bcf from Algeria. Distrigas imported 65 percent of this volume (32.9 Bcf), while Pan National imported the remaining 35 percent (17.9 Bcf). All of the LNG imported by Distrigas was done under its two long-term gas purchase contracts; however, Pan National imported under both long-term and short-term contracts.

Figure 2 shows the estimated consumption of LNG imports by state for 1994. Distrigas markets its LNG supplies in the Northeast, predominantly in Massachusetts, while Pan National sells most of its supplies to Florida.

ESTIMATED CONSUMPTION OF LNG IMPORTS BY STATE

1994

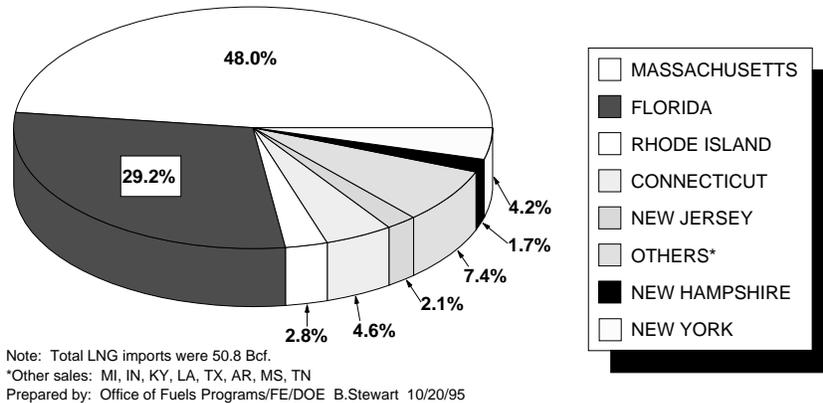


Figure 2

Figure 3 illustrates the purchases of imported LNG by class of customer from the two importers, Distrigas and Pan National, during 1994. Although Distrigas continues to sell the majority of its supplies to local gas distributors, increasingly large volumes are being sold to other types of customers; i.e., cogenerators, marketers. This reflects the changes that have occurred in the natural gas marketplace over the past decade. In the past, Distrigas' sales were totally confined to gas distribution companies. The vast majority of Pan National's LNG sales were made to Citrus, which, in turn, sold the gas to Florida Power & Light Company.

CONSUMPTION OF LNG IMPORTS BY TYPE OF CUSTOMER

1994

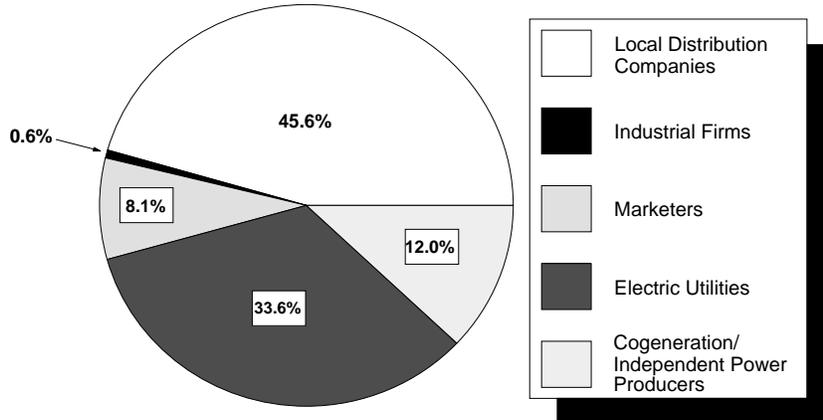


Figure 3

PRESENT

During the last half of 1994 and all of 1995, Algeria has been in the process of renovating its gas liquefaction facilities. This renovation project, which is expected to be completed sometime in 1996, is intended to bring the facilities back to the original design capacity when they were built in the 1970s and early 1980s. In the interim, Algeria has been forced to curtail sales to all of its customers, including Distrigas and Pan National.

In September 1995, the LNG facility located at Cove Point, Maryland, was recommissioned into service. This facility had been mothballed since the suspension of Algerian LNG imports in April 1980. The two owners, Columbia Gas System, Inc. and Potomac Electric Power Company, have established an LNG peaking service. They installed a liquefaction unit and restored 4 storage tanks, vaporizers, and a couple of gas turbines at a cost of approximately \$26 million. The liquefaction plant has the capability of liquefying up to 15,000 Mcf/day. The maximum storage capacity will be 5 Bcf, with a maximum sendout of 400,000 Mcf/day. Ultimately, the two owners want to refurbish the facility in order for it to accept LNG tanker shipments, perhaps as soon as the year 2000 for spot market purchases.

Through the first nine months of 1995, the only importers of LNG, Distrigas and Pan National, brought in 12.9 Bcf of LNG from Algeria (5 tankers). This compares with 50.6 Bcf imported during the same nine months in 1994, or a 75 percent decline from the 1994 level. During the last quarter of 1995, company officials of the two importers have indicated that Distrigas will receive two more LNG shipments into its Everett, Massachusetts terminal, but the next shipment for Pan National probably will not occur until January 1996. With the two additional tankers, the estimated total LNG imports for 1995 will approximate 18 Bcf, or the lowest import level since 1988, when 17.5 Bcf was imported.

During the first nine months of 1995, the two exporters of Alaskan LNG, Phillips Alaska Natural Gas Company and Marathon Oil Company, increased their aggregate sales to Japan by about 9.5 percent compared with the same time period last year (48.4 Bcf v. 44.2 Bcf). The two firms' combined annual contract quantity (ACQ) with their two Japanese customers is currently 64.4 TBtu; the contract volumes increased from 56 TBtu to the current level in the contract year beginning April 1994. If market circumstances warrant, the two exporters may sell as much as 68.3 TBtu annually (6% above ACQ). Since 1995 is the first entire year in which the new contract volumes are in effect, exports to Japan this year are expected to exceed the 1994 total of 62.7 Bcf.

In October 1995, the Secretary of Energy forwarded proposed legislation to the President of the Senate, to sever the FERC from the DOE, and make FERC a fully independent agency. The proposed legislation, among other things, would further amend section 3 of the Natural Gas Act. With respect to LNG imports, the legislation would no longer require a prospective importer to file an application with DOE requesting authority to import, regardless of source or whether the supplying country has a free trade agreement with the United States. With regard to LNG exports, sales to countries with whom the United States has a free trade agreement requiring national treatment for trade in natural gas, no DOE export authorization would be necessary. However, LNG exports which involve non-free trade countries; e.g., Japan, the DOE would continue to make public interest determinations and issue export authorizations.

Despite the fact that there are only four U.S. firms actively engaged in either importing or exporting LNG at this time, numerous firms have been granted two-year, blanket authorizations by DOE, allowing them to import or export LNG. As of December 1995, there exist 52 valid LNG import authorizations having an aggregate import authority totaling 9.4 Tcf. In addition, there are 38 existing LNG export authorizations having an export authority totaling 5.5 Tcf.

FUTURE

This section of the report looks at five different proposed LNG import/export projects which may directly or indirectly affect natural gas trade in the United States and Puerto Rico. Four of the five LNG proposals involve the possible importation of LNG into the United States and Puerto Rico. The fifth project, the Yukon Pacific LNG Proposal, involves the planned exportation of LNG from Alaska to the Pacific Rim countries. There follow brief descriptions of these five LNG projects, as well as maps showing the general location of facilities construction, and possible markets.

YUKON PACIFIC LNG EXPORT PROJECT

Owner(s): Yukon Pacific Company L.P. (subsidiary of CSX Corporation)

Location/Description: Under the proposed project, Yukon Pacific would export, via tanker, about 660 billions of cubic feet (Bcf) of liquefied natural gas (LNG) per year for 25 years to the Pacific Rim countries of Japan, South Korea, and Taiwan. The natural gas supply would come from Alaska's North Slope. In order to effectuate this proposal, Yukon Pacific plans to construct a gas liquefaction plant and marine terminal at Anderson Bay, Port Valdez, Alaska. The project also would involve the construction of the Trans-Alaska Gas System (TAGS), an 800-mile pipeline which would run parallel to the Trans-Alaska Pipeline System (TAPS), an existing crude oil pipeline that runs from Alaska's North Slope to Port Valdez.

Summary: In December 1987, Yukon Pacific filed an application (Docket 87-68-LNG) with the Department of Energy (DOE) requesting authority to export approximately 660 Bcf of LNG over 25 years. In November 1989, DOE issued Order 350 approving Yukon Pacific's request. The decision was challenged by the sponsors of a competing project, the Alaskan Natural Gas Transportation System (ANGTS) which would transport natural gas from Alaska, through Canada, to the lower 48 states. On March 1990, DOE issued Order 350-A denying rehearing of its Order 350. ANGTS' sponsors appealed this decision in the U.S. Court of Appeals for the District of Columbia Circuit. On May 10, 1991, the court ordered that the appeal be held in abeyance pending final disposition by the Federal Energy Regulatory Commission (FERC) of its project-related regulatory proceedings.

In December 1987, Yukon Pacific filed an application (Docket CP88-105) with the FERC requesting authority to site, construct, and operate a LNG plant and related facilities at Anderson Bay, Port Valdez, Alaska. After having completed its environmental review, the FERC issued an order on May 22, 1995, granting Yukon Pacific authorization to site, construct, and operate its proposed LNG facility. On September 14, 1995, the FERC denied a rehearing request of its May Order filed by the sponsors of the ANGTS.

Projected In-service Date: 2005 (?)

Daily Liquefaction Plant Capacity: 1800 MMcf

Capital Costs: \$15 billion (including \$7 billion for TAGS construction)

Status: On October 16, 1995, the ANGTS' sponsors, Foothills Pipe Lines Ltd. and Alaskan Northwest Natural Gas Transportation Company, filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit for voluntary dismissal of their petitions concerning DOE's decision in Opinion Nos. 350 and 350-A, as well as FERC's regulatory decisions on the proposed project.

ECOELECTRICA PROJECT

(Liquefied Natural Gas Import Into Puerto Rico)

Owner(s): EcoElectrica, L.P. (EcoElectrica) is a Bermuda limited partnership consisting of KENETECH Energy Systems, Inc. (KES) and Enron Development Corp (Enron).

Location/Description: EcoElectrica has entered into a power sales agreement with the Puerto Rico Electric Power Authority (PREPA) to construct a combined-cycle, 461 MW powerplant on the south coast of Puerto Rico near the city of Ponce. PREPA is the government-created public utility which supplies virtually all of the electric power consumed in Puerto Rico. The proposed power plant would be fueled by imported liquefied natural gas (LNG).

Summary/Overview: Based on estimates by PREPA, Puerto Rico will require an additional 1,000 MW of electricity by the year 2000. Because 98 percent of PREPA's existing generating capacity is provided by oil-fired units, and the remaining two percent is provided by hydroelectric units, PREPA is planning on meeting this capacity requirement by purchasing electricity from cogeneration facilities using fuels other than oil. The proposed EcoElectrica LNG Project would include terminaling facilities, two storage tanks holding up to 2 million barrels of LNG, a desalination plant to produce potable water and a powerplant. The plant would be fueled by LNG, but also could use liquefied petroleum gas and fuel oil as backup fuels.

Projected In-Service Date: October 1997 (Earliest possible date)

Annual Import/Volumes: Approximately 130 Bcf

Capital Costs: \$500-\$600 million

Supply Source: Undetermined

Proposed Market(s): Puerto Rico

Status: On October 31, 1994, as supplemented on January 9, 1995, EcoElectrica applied to DOE for authority to import LNG for 40 years from various undetermined international suppliers for delivery to Puerto Rico (Docket 94-91-LNG).

On April 19, 1995, DOE issued Order No. 1042 to EcoElectrica authorizing it to import up to 130 Bcf per year of LNG beginning on October 1, 1997, and continuing through December 31, 2037. On October 25, 1994, EcoElectrica applied with the Federal Energy Regulatory Commission (FERC) for a Section 3 Natural Gas Act siting permit to construct the proposed facilities needed to import LNG (Docket No. CP95-35). On March 14, 1995, the staff of the FERC announced that it intended to prepare a joint environmental impact statement (EIS) with the Puerto Rican Planning Board (PRPB) on the EcoElectrica Project (60 F.R., p. 14743).

EcoElectrica Project (cont.)

Status (cont.)

The FERC and the PRPB will use this joint EIS in their decision-making process. On November 3, 1995, a draft EIS was published by the FERC and PRPB; comments were to be filed with the FERC or PRPB on later than December 18, 1995.

The EcoElectrica Project is being challenged legally by the Cabot LNG Corporation (Cabot). Cabot has filed a lawsuit in the U.S. District Court in San Juan against PREPA (Civil Action 94-2036A), alleging the utility violated its own bidding requirements when it chose the EcoElectrica Proposal in March 1994. Cabot had proposed its own 460-MW LNG project, and is seeking an injunction to reverse PREPA's contract award to EcoElectrica and to another coal-fired cogeneration plan (AES Corporation), and to require that PREPA be directed to follow the bidding statute in any subsequent decision to purchase electricity.

TRINIDAD AND TOBAGO LNG EXPORT PROJECT

Sponsor(s): Atlantic LNG Company of Trinidad and Tobago (Atlantic LNG). This newly formed company is a consortium of companies comprised of Amoco Trinidad LNG (AMOCO) (34%), British Gas LNG Limited (British Gas) (26%), Repsol International Finance b.v. of Spain (Repsol) (20%), The National Gas Company of Trinidad and Tobago LNG Limited (10%), and Cabot Trinidad LNG Corporation (Cabot) (10%).

Location/Description: The islands of Trinidad and Tobago form an independent republic in the West Indies, approximately 9 miles northeast of Venezuela. This country is a member of the British Commonwealth of Nations. The consortium plans on building a liquefaction plant and marine terminal on Trinidad. The sponsors to this project plan to develop the natural gas resources off the east coast of Trinidad, and build a liquefied natural gas (LNG) facility in the Point Fortin area in the southwest of Trinidad.

Summary: The sponsors of the project state that the exact location of the LNG plant will be determined once the main engineering, procurement, and construction contracts are awarded in late 1995, or early 1996. The consortium companies have agreed in principle to sell 100 percent of the plant's production. About 60 percent of the LNG produced (80 Bcf per year) would be exported to Cabot's Distrigas of Massachusetts Corp. LNG receiving facility located in Everett, Massachusetts, with the remaining 40 percent being sold to ENAGAS, the largest importer and wholesaler of natural gas in Spain.

Daily Liquefaction Plant Capacity: 370 MMcf (146 Bcf per year)

Projected In-service Date: Early 1999

Capital Costs: \$1.3 - \$1.6 billion
(\$900 million - \$1 billion for liquefaction plant/marine terminal; \$400 - 600 million for production and transmission)

Supply Source(s): Off the southeast coast of Trinidad (East Mayaro/Southeast Galeota fields)

Proposed Market(s): Northeastern United States and Spain

Status: The project sponsors have accepted for their review two competing engineering and design proposals for the development of an LNG plant and marine terminal. In November 1994 a contract was executed with Chiyoda Corporation and Hudson Engineering Company (a wholly-owned subsidiary of McDermott, Inc.), which would use the LNG process developed by the Air Products and Chemicals Inc. In March 1995 a competing contract was awarded to Overseas Bechtel Inc. for its engineering design of the same facilities which would use the Phillips optimized Cascade LNG process.

Trinidad and Tobago LNG Export Project (cont.)

Status (cont.)

In October 1995 it was announced that Amoco Trinidad Oil Corporation had signed a contract with Atlantic LNG to supply natural gas feedstock to the gas liquefaction plant. The agreement calls for Amoco to supply as much as 475 MMcf/day for at least 20 years.

Financing efforts are expected to be launched shortly, targeted to raise up to \$600 million on a limited recourse basis from international banks, export credit agencies (including the U.S. Export/Import Bank) and the Overseas Private Investment Corporation. The final engineering, procurement and construction contract is expected to be awarded in the first quarter of 1996.

On October 30, 1995, Distrigas Corporation filed an application (Docket No. 95-100-LNG) with OFP seeking authorization to import LNG purchased from the Republic of Trinidad and Tobago and other international sources for a period of 40 years. On November 7, 1995, OFP issued Order 1115, approving the LNG import request.

On December 12, 1995, Atlantic LNG announced that Repsol International b.v. of Spain had become the fifth shareholder in the company with 20 percent ownership. Repsol is an integrated oil, gas and petrochemical company engaged in many facets of the oil and gas business both in Spain and internationally. Repsol owns 45 percent of Gas Natural, Spain's largest natural gas distributor, which in turn owns 91 percent of ENAGAS.

NIGERIAN LNG EXPORT PROJECT

Sponsor(s): The proposed LNG liquefaction plant would be constructed near Port Harcourt on the Nigerian coast and operated by Nigeria LNG Limited (NLNG). The shareholders in NLNG are Nigerian National Petroleum Corporation (NNPC) (51%), Shell Gas b.v. (24%), Elf Aquitaine of France (15%), and AGIP of Italy (10%). The World Bank (IFC) has an option to acquire a 2% shareholding from NNPC.

Location/Description: NLNG would own and construct new natural gas liquefaction facilities on Bonny Island, Rivers State, Nigeria. Under current plans, the LNG exported from this proposed project would be destined for sale to Italy, Spain, Turkey, and France.

Summary/Overview: The Italian state-owned electric utility, ENEL, SpA, is projected to take about 64% of the LNG supply. However, ENEL's proposed construction of an LNG terminal at Montalto di Castro, 70 miles north of Rome, ran into environmental opposition. In June 1995, the Italian state-owned gas company, Snam SpA, announced its own plans to build an LNG terminal at Monfalcone near Trieste. The Italian Government has decided that work on the development of both projects should continue, with ENEL and SNAM obtaining the necessary permits and proceeding with their environmental reviews. The Italian Government has issued conditional approval for the construction of the Montalto di Castro terminal, but these approvals will be revoked if the Monfalcone terminal is approved before April 1996. In the latter case, ENEL's LNG will be delivered to Monfalcone. In addition to the environmental issue, the Italian Government also has questioned the extent that it wants to be dependent on using gas for power generation since it has abundant coal resources.

In December 1994, NLNG signed a memorandum of understanding with a construction consortium (M.W. Kellogg Corp., Technip, Snamprogetti) to build the LNG complex. Financing arrangements for this project have not yet been completed, but the shareholders have essentially abandoned any attempt to raise financing from external sources.

Daily Liquefaction Plant Capacity: 677 MMcf (247 Bcf/year)

Projected In-Service Date: 1999 - 2000

Capital Costs: \$4 billion (not including shipping)

Supply Source: Nigeria

Proposed Market(s): Europe (222 Bcf) and possibly the United States (25 Bcf)

Nigerian LNG Export Project (cont.)

Status (cont.)

Distrigas applied to the DOE on July 17, 1992, and received approval on November 6, 1992 (DOE/FE Order No. 701) to import up to ten cargoes of LNG per year (approximately 25 Bcf) from Nigeria over a 20-year term from date of first delivery. A condition of Distrigas' import authorization is to inform DOE when the Bonny Island LNG production facility reaches full production.

In October 1995, Distrigas Corporation received notification from NLNG that it had terminated its agreement to sell LNG to Distrigas. Although no specific reasons were given for the termination, the two parties at the time were having talks regarding certain contract provisions, including those pertaining to shipping issues. At this time, it is unclear whether Distrigas and NLNG will be able to reconstruct this supply arrangement.

CRISTOBAL COLON LNG EXPORT PROJECT

Sponsor(s): Sucregas S.A. (Sucregas), a joint venture company formed in 1994. Partners include Lagoven S.A., an affiliate of Petroleos de Venezuela S.A. (PDVSA) (33%), Shell International Gas Ltd. (30%), Exxon Services Venezuela Inc. (29%), and Mitsubishi Corporation (8%).

Location/Description: Venezuela, South America. The sponsors of the project plan to develop the natural gas resources off the eastern coast of Venezuela, in the state of Sucre, and build a liquefied natural gas (LNG) facility/marine terminal capable of shipping gas to Western Europe and other potential markets, such as the United States.

Summary: The proposed project takes advantage of Venezuela's vast natural gas reserves, the largest in Latin America. The venture involves developing four offshore gas fields near Venezuela's Paria Peninsula in Sucre state, processing the gas, and transporting it as LNG. Designs for the system include up to eight offshore drilling platforms, a 30-mile pipeline link to shore, a 730-MMcf/day, two-train LNG production facility, and an LNG export terminal. The project also will require 4-6 dedicated vessels to transport the LNG to markets. Currently, studies are underway to establish technical reliability and to examine the economic impact of the project. This joint effort represents the first major energy project in association with foreign companies that has received Venezuelan government approval.

Daily Liquefaction Plant Capacity: 730 MMcf/day

Projected In-Service Date: 2000 (earliest possible date)

Capital Costs: \$5.6 billion
(\$2.1 billion for liquefaction plant, \$1.75 billion for production costs, and \$1.75 billion for the purchase of ships to transport LNG)

Supply Source(s): Four gas fields located off the east coast of Venezuela, near the Paria Peninsula in the state of Sucre

Proposed Market(s): Western Europe (possibly the United States or the Caribbean)

Status: The Cristobal Colon project is in its very early stages. Its sponsors currently are conducting preliminary studies to determine overall technical and economic reliability for this large-scale effort. Recently, Sucregas partners completed the project's first feasibility stage, confirming more than 11 Tcf of gas reserves in the Gulf of Paria with an estimated production of 980 MMcf/day. However, since 1990, when the project was first proposed, international gas prices have declined, challenging the venture's initial economic forecast. In an effort to cut overall costs and to improve profitability, the sponsors are studying recent technological advances in LNG production and evaluating ways to lower transport costs. Other areas being addressed include optimization of plant design, evaluation of shipping alternatives, and completion of an offshore development plan. To date, sponsors have invested over \$240 million in the project and must make a decision on continuing their efforts by December 31, 1996.

