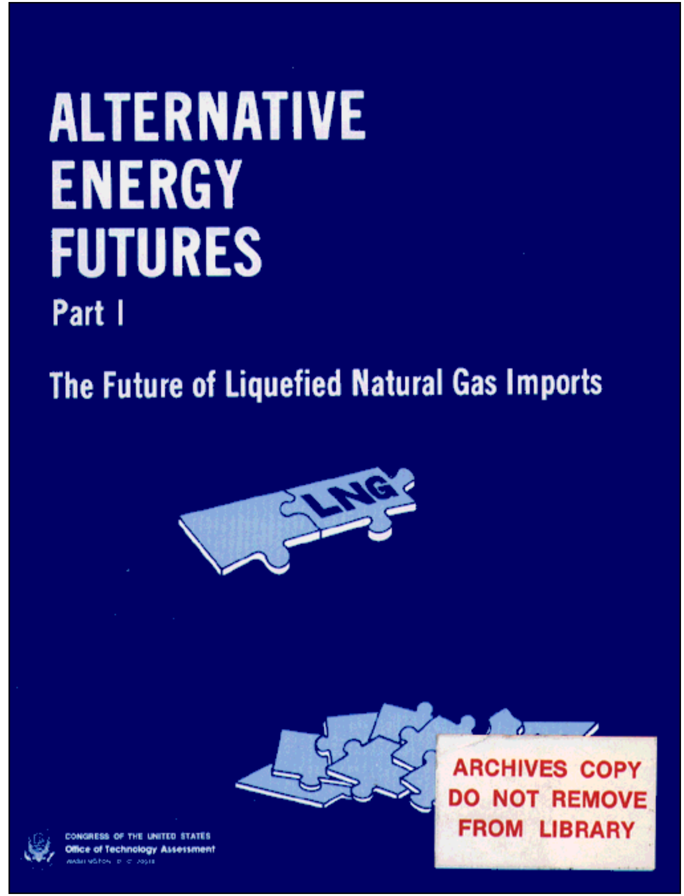
Alternative Energy Futures: Part I-The Future of Liquefied Natural Gas Imports

March 1980

NTIS order #PB80-173552



Library of Congress Catalog Card Number 80-600046
For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402 Stock No. 052-003 -00743-6

Foreword

This assessment responds to a request by the Senate Committee on Finance for an evaluation of the economic and energy implications of any future liquefied natural gas (LNG) imports. This part of OTA's continuing examination of Alternative Energy Futures complements and expands upon an earlier OTA report, *Transportation of Liquefied Natural Gas.*

Highlights of the study include a discussion of worldwide availability natural gas for U. S. import as LNG, in the context of projected U.S. gas demand, alternative North American oil and gas resources, and the security of foreign supplies. The report also contains sections on LNG project structure, cost, and financing with observations about balance-of-payment impacts and public exposure to financial risk. Finally, an analysis of the behavior of gas markets in determining who receives additional supplies by virtue of LNG projects, and who pays for them, illustrates some of the practical effects of the Natural Gas Policy Act of 1978.

We are indebted to the members of the advisory panel and to numerous other individuals and institutions for suggestions, information, and critique. Also, the contribution of several contractors, who performed background research, is gratefully acknowledged.

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Overview

Further projects to import liquefied natural gas (LNG) from overseas could be desirable as elements of a strategy to meet future U.S. energy demand, despite current disfavor of such projects by the Department of Energy. Specific proposals should be evaluated on their individual merits in the light of the following findings.

- **LNG imports could expand from the currently approved level of 0.8 trillion cubic feet per year (Tcf/yr) to between 1.3 and 1.8 Tcf/yr by the middle of the next decade. This amount, less than one-tenth of present domestic gas production, is limited by political instability in Iran, absence of any economic advantage in exporting gas for some other Middle Eastern oil producers, shorter transportation distances to competing European and Japanese markets, and restrictions on trade with the Soviet Union. The most likely sources of U.S. imports, other than by pipeline, include Nigeria, Indonesia, Australia, Malaysia, Trinidad, Colombia, and Chile.**

- **Not all potential LNG exporters are major oil producers or members of OPEC, so curtailments of foreign gas supplies are less likely to coincide with those of oil than they would be otherwise. Also, LNG exporting nations generally have greater financial incentives than oil producers do to maintain uninterrupted shipments, because of the difficulty in finding alternative purchasers with appropriate terminal facilities, and the large amount of debt incurred for liquefaction facilities that must be paid by the exporter from project revenues. To the extent that Maritime Administration and Export-Import Bank programs promote involvement of U.S. owners and creditors in LNG ships and facilities, the exporter's stake in uninterrupted revenues diminishes. In the event of an interruption, the resulting shortfall could be managed to minimize adverse impacts through the present priority curtailment system and by sales and exchanges among gas wholesalers.**

- **Over the next decade, domestic gas production will probably satisfy essential requirements, but neither domestic sources nor pipeline imports from Canada and Mexico are likely to meet additional marginal demand except at costs equal to or greater than that of LNG. Delivered gas from LNG is likely to cost approximately the same as competing fuels; less than synthetic fuels and distillates from foreign crude oil, and more than currently regulated domestic natural gas. Consumers also assume part of the financial risks associated with an LNG project by paying gas prices regulated to allow investors to recover portions of their initial costs, regardless of the project's subsequent commercial success or failure.**

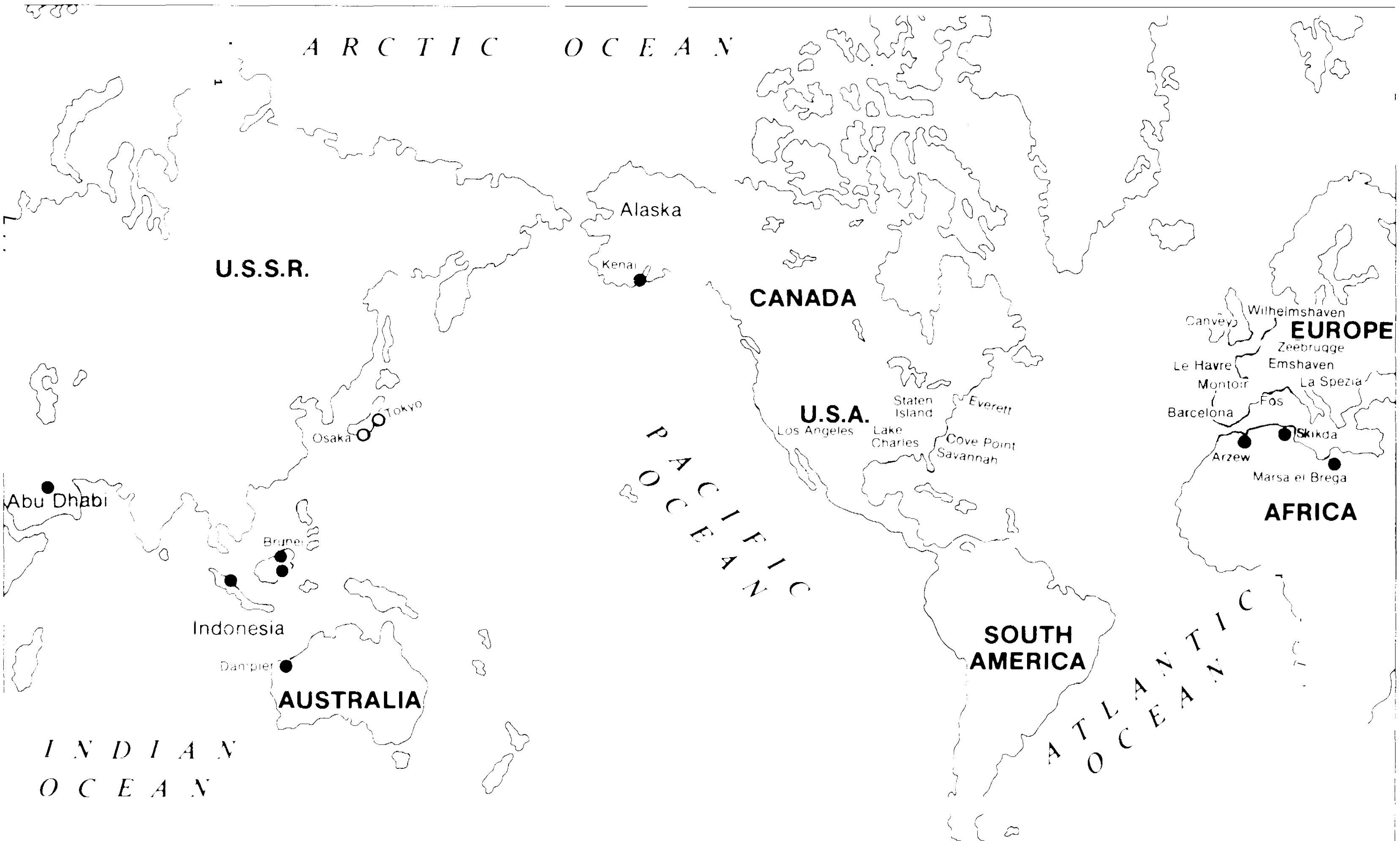
- **Although the disposition of added supplies in gas markets is complex and will vary greatly from one case to another, gas made available as a result of LNG imports will generally be used at least partly, and possibly entirely, in manufacturing and electric-generating applications. Also, under the Natural Gas Policy Act of 1978, the cost of added supplies will not necessarily be borne by the customers receiving them. Of the types of consumers likely to obtain more gas from LNG proj-**

ects, industrial customers will probably pay a price close to that of alternative fuels and of the LNG itself, and electric utilities and purchasers of electricity will receive a subsidy in the form of "exempt" prices under the Act. Although households and commercial establish= ments would probably receive little additional gas, at least initially, the price levels in these sectors will rise or fall in response to the higher cost of LNG and to any savings that may result from improved utilization of transmission and distribution capacity.

- Importing LNG entails a significant outflow of dollars from the United States compared to domestic alternatives, but its direct impact on the balance of payments is less severe than that of purchasing equivalent amounts of foreign oil. Furthermore, the effect of being able to choose the lowest cost alternative from among LNG, foreign oil, and domestic production and conservation may outweigh the influence of direct payments associated with any specific trade by improving the competitive position of U.S. industry generally.

1. Summary

International LNG Trade Routes



Key:
Routes in Operation
Probable Routes
Routes Approved, Not in Operation
Terminal Sites
● Liquefaction Sites

1. Summary

Introduction

This assessment addresses whether or not additional liquefied natural gas (LNG) imports should be encouraged or restricted in the context of future national energy requirements and supply alternatives. In the past, public debate on this question has focused on both the safety and economics of LNG from overseas as a fuel resource.

On one side of the issues, proponents of increased imports point to:

- declining domestic oil and gas production,
- proven LNG technology,
- lower costs compared to gas from Alaska or synthetic fuels,
- opportunities to diversify sources of foreign hydrocarbons,
- less severe impacts than oil imports on the balance of payments,
- environmental advantages of gas, and
- savings from any improvement in utilization of present gas transmission and distribution infrastructure.

opponents draw attention to:

- the high cost of LNG compared to regulated domestic gas,
- the potential of conservation to diminish the demand for additional fuels,
- the fact that LNG involves flows of dollars out of the United States,
- the concern over security of foreign supplies,
- the possibility that demand for gas from higher cost sources like LNG is an artifact of Government regulation and indirect subsidy,
- the desirability of protecting markets for synthetic fuels or Alaskan gas in order to encourage development of these resources, and
- the hazardous nature of LNG itself.

Some advocates of conservation and solar power argue further that the United States should not import more LNG until less costly efficiency improvements and renewable energy alternatives have been exhausted. At the same time, others feel that this position holds LNG hostage to fuel-efficiency measures which are equally likely to be adopted, regardless of any foreseeable volume of imports.

An OTA report, Transportation of *Liquefied Natural Gas*, published in September 1977, describes the technology, reviews the physical and institutional components of the LNG import system, and explores public awareness and concerns. Partly in response to questions raised by that study, the Senate Committee on Finance asked OTA to examine LNG import policy in the context of other energy alternatives, with emphasis on economic costs and benefits. The request arrived after President Carter, through the National Energy Plan, had relaxed a policy of the previous administration to limit LNG imports, and after the General Accounting Office (GAO) had suggested in a report to Congress that this new policy required reevaluation and further improvement, essentially because insufficient rationale appeared in the plan.

This assessment is part of an ongoing examination of alternative energy futures, and in response to the Senate Finance Committee's inquiry, it focuses on the economic and energy supply implications of the technology. Safety of LNG facilities has been excluded, in order not to duplicate the material in an earlier congressional report, *Liquefied Energy Gases Safety*, issued in July 1978 by GAO.

The purpose of this analysis is to assist Congress and Federal and State regulatory bodies in establishing or reevaluating the circumstances under which LNG imports are in the public interest, and to aid in any further debate over policies that would encourage or restrict LNG imports in the future. Possible policy measures that could result from resolution of the present debate on this subject include the following:

- imposition of formal limits on the amount of LNG that may be imported from a particular supplier or from all foreign sources;
- reversal of the Department of Energy's present assignment of a low-priority status to LNG among potential future gas supplies;
- change in the treatment of LNG as an incrementally priced supplemental gas source under the Natural Gas Policy Act of 1978 (NGPA);
- refinement of criteria for case-by-case import project approval by Federal and State regulatory agencies;
- alteration of the balance of Federal, State, and local authority and autonomy in LNG project approval and regulation;
- change in present Maritime Administration and Export-Import Bank policies, under which components of LNG projects are eligible for credits and direct aid for specific purposes;
- encouragement or discouragement of LNG trades as an element of foreign policy; and
- decisions by private individuals and institutions to invest or not in LNG import projects.

This assessment does not decide which if any of these options would be appropriate, but it does provide the many participants in policymaking with information and analysis they will need in order to choose more wisely.

The project consisted of seven separate but related analytical tasks:

1. a compilation of the history of Government LNG import policy;
2. a review of' U.S. gas demand projections under alternative price and policy assumptions;
3. a survey of North American gas and oil resource estimates;
4. an investigation into the availability and cost of LNG in world markets;
5. a description of the cost and structure of LNG import projects, including financing and the distribution of risk among the public and other participants;
6. an analysis of the distribution of costs and benefits of imported LNG in domestic gas markets; and
7. a brief discussion of the broader social and environmental impacts of LNG imports.

The remainder of this chapter contains a list of issues and findings extracted from the rest of the study. They represent the principal conclusions from the the subsequent analysis.

The policy history, which comprises chapter 2, traces the development of administration attitudes toward LNG imports from President Ford's February 1976 energy message through the National Energy Plan and the formation of the Department of Energy to the present. The chapter also describes relevant programs of such agencies as the U.S. Export-Import Bank and Maritime Administration, and it includes expressions of congressional interest as evidenced by studies or recently introduced legislation. Finally, California provides an example of State involvement in LNG import decisions.

Chapter 3, on future gas availability and use, begins with a discussion of projected U.S. gas demand by specific categories of end use under different price and policy assumptions, reflecting the results of studies by several institutions. Following the demand discussion is an analysis, based on available studies, of North American gas and oil resources (since oil can often be substituted for gas) including conventional and unconventional extraction technologies, synthetic fuels, and reserves in Alaska, Canada, and Mexico. The latter part of the chapter addresses the volume of foreign gas available to be imported as LNG, taking into account such factors as reserves, proximity to competing markets like Europe or Japan, prior contractual commitments, and political considerations.

The next chapter (chapter 4) includes a description of the structure of LNG import projects, beginning with pricing policies of exporting nations and followed by the capital and operating costs of cryogenic tankers and of facilities in the producing and receiving countries. After an extensive discussion of the possible sources of debt and equity financing and their practical implications, the chapter ends with a section on the distribution of financial risk associated with investment in LNG projects, with particular attention to any public liability for unforeseen economic losses.

Social costs and benefits are the subject of chapter 5. It begins with an analysis of who would receive additional gas if more LNG were imported and who would pay, given the complexities of the natural gas transmission and distribution system and of the regulatory framework within which it operates. The results are useful in ascertaining the value of the gas in terms of what would happen without it, and they are instructive as an example of the influence of NGPA as it affects gas markets generally. The effect of reduced gas supplies in the event of a curtailment of foreign deliveries is also treated in this part of the report. The rest of the chapter is devoted to the possible influences of gas availability on air quality and employment and the impact of LNG import projects on the balance of international payments.

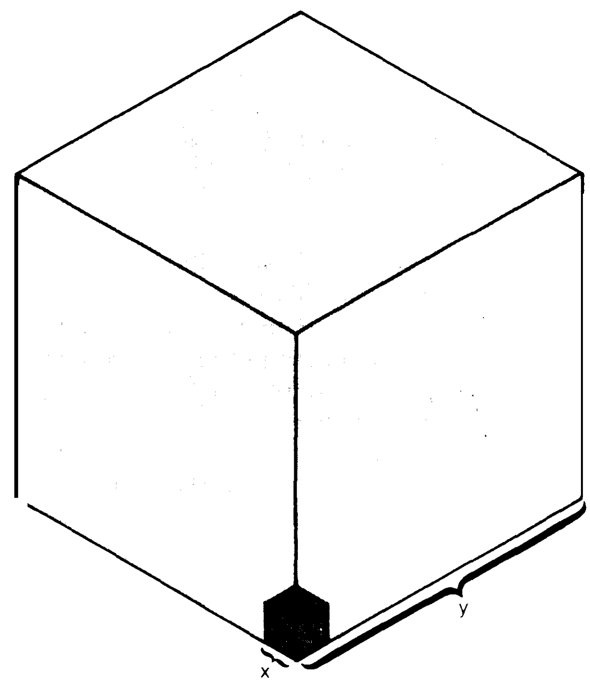
Three working papers prepared for this project contain more detailed material supporting chapters 3 through 5. These reports, referred to occasionally in the pages that follow, are published in a separate *Background Reports* volume and will be made available through the National Technical Information Service.

Background

Since the first voyage in January 1959, of the Methane *Pioneer* from Lake Charles, La., to Canvey Island on the Thames River near London, England, ocean transport of LNG at –2600 F has been a technological reality. The first regular commercial trade in the commodity began 5 years later, in 1964, with shipments from Arzew, Algeria, to Canvey Island and the French port of Le Havre. Today, 12 operating projects, 3 of which involve the United States, account for 1.75 trillion cubic feet (Tcf) of gas traded annually. The United States presently exports ().0.5 Tcf/yr from Alaska to Japan and imports 0.45 Tcf/yr from Algeria. Two more approved projects involving Algeria and Indonesia would add 0.38 Tcf/yr to import levels over the next few years.

The virtue of LNG lies in its high density. In liquid form, methane, the principal constituent of natural gas, fits into one six-hundredth of the space it requires as a gas at room temperature and atmospheric pressure (see figure 1). The gas industry has taken advantage of this property for storage purposes for half a century. With rising energy costs, more efficient liquefaction processes, and reliable performance of specially designed cryogenic tankers, the economics of

Figure 1.—Volume Reduction From Natural Gas to LNG



$\frac{x}{Y} = .119$ $\frac{x^3}{Y^3} = 1/600$

SOURCE Office of Technology Assessment

shipping gas in this form over ocean distances have proven to be attractive.

The advantages and disadvantages of further LNG imports depend in large part on expected future levels of gas availability and use. As described in chapter 3, one part of U.S. gas demand involves applications in which conservation or fuel substitution is costly, and the other consists of applications in which alternative fuels or improved productivity could be substituted readily, depending on public policies or relative differences in fuel prices. The first category, or the "basic" demand, is projected at a level of 14 quadrillion Btu per year in 1990. In the same year, however, an additional 12 quadrillion Btu could be used in "marginal" applications if it were available at prices comparable to those paid for gas today, and if electric utilities were permitted to burn oil and gas. Under those circumstances gas would be used in place of coal, oil, nuclear power, and conservation.

Findings

At least over the next decade, domestic gas production will probably satisfy essential requirements, but neither domestic sources nor pipeline imports from Canada or Mexico are likely to meet additional marginal demand except at costs equal to or greater than that of LNG. Furthermore, North American oil production will probably not be sufficient to alter the demand for gas by substitution. Viewed in this way, LNG imports are no more or less imperative than other potential energy supplies of equal size. The Nation has alternatives to LNG from overseas, but gas in this form may be desirable as part of a portfolio of energy sources and strategies to meet the projected future demand.

The advantages and disadvantages of LNG in relation to improved efficiency and fuels from other sources will depend on such factors as availability, security of supply, cost, specific use, distribution of costs among consumers, effect on the balance of payments, and environmental impact. Characterized in these terms, broad gas resource categories are not susceptible to simple ranking, and projects must be compared on their individual merits.

In many instances, choices are complicated because action by the Federal Government is limited to decisions on individual project proposals from the private sector. Denying one application for a license does not necessarily bring forth a better application, and a series of sound decisions taken one at a time does not always lead to a cohesive program. For example, advocates of energy conservation argue that LNG imports should be restricted, because they feel that improvements in energy productivity to save fuel are less costly than paying LNG prices, and hence that a rational policy would not include the imports. However, keeping LNG out of the country will not necessarily bring about any investment in demand reduction, and indeed according to one argument, LNG and other new supplies would promote conservation and improved energy technologies, because they would increase the average gas price paid by consumers. What follows are conclusions concerning the major issues to be faced in deciding the future of LNG imports.

1: *How much gas is available for import as LNG?*

The United States could import between 0.5 and 1 Tcf/yr of additional gas during the 1980's above the current approved level of 0.8 Tcf/yr. The maximum total of 1.8 Tcf/yr would represent between 7 and 13 percent of projected 1990 domestic gas use and would require three or four large terminal facilities in addition to those already planned.

The availability of gas was determined by surveying world proven gas reserves and assigning them to categories as follows:

- *Inaccessible or flared:* gas reserves that are too small or remote either to justify recovery of flared gas or full field development of nonassociated gas.
- *Deferred reserves:* reserves in large gas caps or undergoing gas injection for oil re-

covery, such that they are unlikely to be committed to market projects until some future time.

- *Committed to domestic markets:* gas reserves that either are contracted to domestic markets or set aside to assure that domestic requirements will be covered.
- *Remote from existing market systems:* gas reserves that are clearly destined for a major industrial market but whose remoteness from this market raises questions about the feasibility of commercialization now. Examples would include North Slope and Arctic Island gas in North America and some North Sea gas reserves in Europe.
- *Committed to export markets:* gas reserves covering required deliveries usually under firm export contracts.
- *Exportable surplus:* blocks of remaining gas reserves that are large enough and adequately located to support export projects. In a limited number of cases, local national policy suggests that this gas will not be exported, and in other cases, discussions to sell the gas to other countries have proceeded to the point where it is no longer available to the U. S. market.

Most of the gas available for export in the near future is located in the U.S.S.R. and the nations surrounding the Persian Gulf, principally Iran and Saudi Arabia. The reliability of Iran and the Soviet Union can be questioned on political grounds, and some other major oil producers in the Middle East feel at present no economic need to export gas. Also, shorter transportation distances to European and Japanese markets make sales to the United States less attractive for these and other producing countries. For example, remaining Algerian supplies are now mostly committed to European purchasers, due in large part to regulatory delays affecting U. S. import projects. The most likely sources of LT. S. imports, other than by pipeline, include Nigeria, Indonesia, Australia, Malaysia, Trinidad, Colombia, and Chile.

Substantially more gas could become available to import as LNG during the 1990's if U. S. policy were to shift in such a way as to as to encourage this type of trade. Nations with undiscovered resources could actively search for new reserves if they perceived the United States as a more interested and reliable customer. Also, the impediments to the purchase of Soviet gas lie primarily in U.S. foreign policy.

z: now ***does security of supply affect the desirability of LNG imports?***

Four of the six largest actual or potential exporters of natural gas from the Eastern Hemisphere—Algeria, Iran, Indonesia, and Nigeria—are members of OPEC. The fifth is the Soviet Union. Only the sixth, Australia, is a member of the Organization for Economic Cooperation and Development (OECD). Although not alone in this regard, OPEC members have demonstrated their readiness to impose increases in oil prices at short notice on existing contract terms. Some of them also have embargoed crude exports for political reasons. Curtailments and other abrogations of contract terms are thus possible and must be assessed for their likelihood and potential impact.

Typical LNG projects are technically and financially integrated, with ships and facilities dedicated to specific trade agreements covered by 15- to 25-year contracts. The producing country must invest as much as $2 billion for pipeline, liquefaction, and terminal facilities, and the funds are obtained through long-term loans often guaranteed by the central government. Therefore, exporters depend on a project's revenues and are unlikely to find alternative purchasers if trade ceases. For this reason, LNG suppliers and their governments face stronger incentives to continue shipments than do oil producers. The producer's stake in uninterrupted shipments to the United States increases when U. S. institutions are not involved in the ownership and financing of liquefaction and shipping facilities. A country willing to curtail supplies on political grounds could also be prepared to postpone or temporarily}' halt payments to U.S. creditors and shipowners, thereby softening the impact of forgone revenues. For this reason, Maritime Administration and Export-Import Bank financial participation does not enhance reliability.

Another important consideration is that since some potential LNG suppliers are not members of OPEC and others produce relatively small amounts of oil, interruptions in oil and gas imports are less likely to coincide than they would be otherwise. During the oil embargo of 1973, for example, Algeria stopped oil shipments but did not interrupt LNG traffic to the United States. Therefore, LNG can help to diversify energy supplies with respect to fuel type and geography.

In the event of a curtailment, management of the shortfall could minimize the adverse impacts, partly because the distribution of added gas supply from LNG probably will be geographically diffuse. The present national priority curtailment system established in the winter of 1973-74, should preserve remaining gas for critical uses within the market served by any given transmission company, and voluntary sales and exchanges among transmission companies will alleviate inequities further. Also, the President is empowered by NGPA to redistribute gas among pipeline systems in an emergency. Finally, increased storage capacity, although costly, could ensure further against the impact of an interruption.

3: How *much will LNG cost in the future?*

Delivered gas from LNG is likely to be approximately equivalent in cost to competing fuels—less expensive than synthetic fuels and distillates from foreign oil, and more costly than regulated domestic natural gas. * This equivalence is a deliberate outcome of the objectives of the parties in negotiating supply contracts. To the extent that LNG permits more economical use of present transmission and distribution capacity, the average price to the final consumer will be less, while any requirement for increased storage or additions to pipeline networks by utilities will add to the expense.

The cost of shipping LNG in tankers varies with the distance and other technical and financial features of a specific project, but it is expected to range between $2.60 and $3.50 in **1978** dollars per million Btu delivered in 1990 by a project beginning operation in 1985. This estimate encompasses all steps required to deliver the gas from the foreign wellhead to a domestic pipeline, including gathering, liquefaction, loading, shipping, unloading, vaporization, storage, and delivery (see figure 2).

An additional amount to cover production costs and the value of the resource to the supplier nation is the subject of extensive negotiation between the importer and exporter, and is included in the f.o.b. price provided in a supply contract. Generally these negotiations begin with the presumption that the delivered price must be competitive with those of petroleum products in the U.S. market, and that the exporter must recover his investment. Unless the distance is very great, the U.S. market price of gas from LNG, after subtracting the total transportation cost, will exceed the minimum required by the exporter, especially after several years of project operation with fixed capital charges and rising world energy costs. At least some of this surplus value will probably accrue to the foreign producer as a result of price formulas containing escalation provisions and periodic renegotiation of supply contracts.

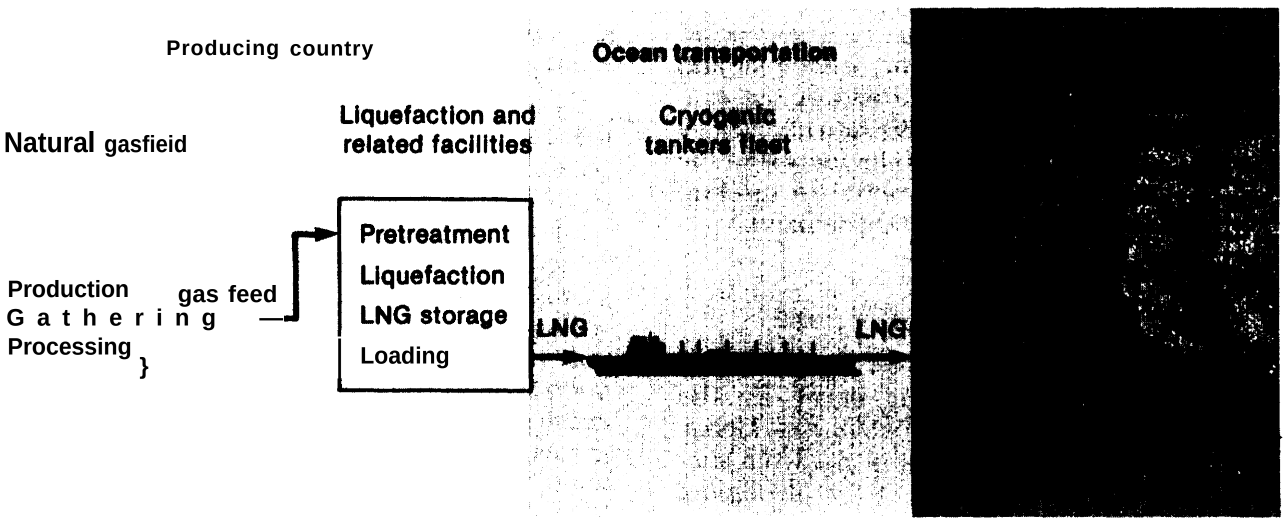
An important but subtle element of cost involves the consumer's exposure to financial risk. In a regulated utility environment, the final purchaser of gas is inevitably a partner in large energy projects, since financing depends on guarantees in the form of prices designed to allow investors to recover portions of their cost notwithstanding some kinds of failure or loss. * In two recently approved LNG projects, the consumer assumes: 1) the liquefaction facility investor's risk that the gas may not be economically attractive in the U.S. market for the life of the supply contract, 2) the shipowner's risk that shipments may be interrupted or reduced,** and 3) all of the creditors' risk related to receiving terminal and revaporization facilities after gas has begun to flow. In addition, the Federal

" Alaskanl gas would cost more initially than LNG, but its price would probably rise less rapidly in the future.

"'1'tl[' The Federal Energy Regularory Commission and State public utility commissions are not bound by earlier decisions, so investors do assume some risk that regulation will change over the life of any energy project.

* " According to Columbia LNG Corporat ion of t icials, at least one possible future LNG project under discussion entails no consumer exposure to shipowners' risk.

Figure 2.—Major Segments of an LNG Import Project



SOURCE. Jensen Associates, Inc

Energy Regulatory Commission may permit tariffs to cover some types of project failure, delay, or overrun depending on the outcome of evidentiary hearings to determine the circumstances and the prudence of management actions.

Another part of the cost involves public services. The range of transportation and processing costs mentioned above includes taxes as a surrogate for public expenses, but does not include the value of Export-Import Bank credit for foreign liquefaction facilities and ships purchased from the United States, or for Maritime Administration subsidies and loans for building American-owned ships. The latter programs are designed to make U.S. goods competitive in the world market by equalizing the cost of U.S. and foreign goods, and thus they have little impact on LNG project viability or the amount consumers pay. This assessment does not address the wisdom of these programs and assumes they are worth what they cost in terms of employment, balance of trade, and health of the shipping and LNG equipment industries. Finally, LNG projects, like all waterborne trade, benefit from activities of the Coast Guard and navigation improvements by the U.S. Army Corps of Engineers.

4: *How would added gas supplies from LNG be used?*

The disposition of added supplies in gas markets is complex and will vary greatly from one case to another. The critical determinants include the mix of interruptible and firm customers in the service area, extent of present curtailments, availability of storage capacity, local regulatory policy concerning connection of new customers, and climate. In general, however, gas made available as a result of LNG imports will be used at least partly and possibly entirely in interruptible industrial and electric-generating applications. In this context, although the Power Plant and Industrial Fuel Use Act of 1978 (FUA) prohibits burning of oil and gas for most electric power generation after 1990, LNG is specifically exempted under certain circumstances to meet air quality standards. The important implication is that the appropriate comparison in economic and environmental terms is not exclusively between LNG and No. 2 (home) heating oil derived from foreign crude, but must also include coal, residual oil, nuclear power, and improved energy productivity among the alternatives.

Over a long period of time, gas utility load patterns may change in such a way that higher priority consumers receive a larger portion of the gas made available from LNG. If this shift occurs, present long-term import contracts could effectively reserve supplies for residential and commercial users toward the end of the century. Also, to the extent that the rate of delivery from a receiving terminal can be increased for brief periods, LNG can contribute to meeting short-term peaks in space-heating demand.

5: *How is the cost of LNG distributed among consumers?*

In regulated markets the cost of added supplies will not necessarily be borne by the customers receiving the additional gas. Under NGPA, part of the higher cost of gas from supplemental sources defined in the Act, including LNG projects not in operation or planned before May 1, **1978,** are paid exclusively by certain "non-exempt" large industrial purchasers, provided that these buyers do not pay a price higher than that of competing petroleum fuels. Once the "non-exempt" industrial price reaches this maximum, it will not increase further, and residential, commercial, electric utility, and the remaining "exempt" industrial customers will begin to pay higher prices resulting from subsequent purchases of more expensive gas by suppliers. *

Under the latter conditions, the price paid by "non-exempt" industrial customers, although high initially, would not increase as a result of LNG imports. The rest of the buyers, including electric utilities, commercial establishments, and households, would experience price increases, although all or part of the higher cost of gas could be offset by savings from the allocation of fixed charges for present transmission and distribution capacity over a broader volume of sales.

Variations on this pattern will occur if nonexempt industrial prices have not reached the maximum corresponding to alternative fuels. In this instance, prices would rise more rapidly for large industrial customers, while exempt purchasers would enjoy equally any savings from improved pipeline utilization, provided the LNG project was initiated after May 1,1978. The cost of prior projects is averaged with that of domestic gas and affects the price paid by all customers approximately equally, as long as non-exempt prices are below the alternate fuel ceiling.

Thus, of the types of consumers likely to receive additional gas from LNG projects, industrial customers will probably pay a price close to that of alternate fuels and of the LNG itself; while electric utilities and purchasers of electricity are likely to receive a subsidy from other sectors in the form of '(exempt" prices, which will rise more slowly than "non-exempt" industrial prices, under NGPA. Although households and commercial establishments would probably receive little additional gas at least initially, the prices in these sectors would rise or fall depending on the costs and volumes of LNG purchased by transmission and distribution companies as well as the extent to which added sales alter the efficiency of the pipeline system's use.

6: *How strongly do LNG imports affect the balance of payments?*

Importing LNG entails a significant outflow of dollars from the United States compared to domestic alternatives. On the other hand, the direct impact on the balance of payments of purchasing equivalent amounts of foreign oil is more severe. With the exception of about 1 cent per million Btu for a small amount of U.S. shipping, almost all of the price of oil leaves the country, while as much as one-third of the transportation and processing cost of LNG may be returned to the United States in the form of purchases of equipment, construction services, shipping, and receiving port facilities. The returned portion of the cost consists primarily of amortized initial capital expenditures in the United States, so the favorable component of the impact of importing LNG is immediate and short term. After the facilities and ships are constructed the balance-of-trade impacts are more nearly comparable to those of oil.

The effect of being able to choose the lowest cost alternative from among LNG, foreign oil, domestic production, and conservation may outweigh the influence of direct payments associated with any specific trade by improving the competitive position of U.S. industry generally. As mentioned earlier, LNG prices will probably

* State public ut i lit ies commissions may alter this outcome by declining to IN) I1Or t he intent of I IN Natural Gas Policy Act.

be slightly less than those of fuels from foreign crude oil.

In conclusion, importing LNG appears more advantageous than buying foreign oil to a significant but uncertain extent due to differences among projects in terms of facility sales by U.S. firms, and to the fact that lower LNG costs relative to world oil may be the dominant factor. Nevertheless, LNG can represent a substantial outflow of dollars.

7: *How are present Federal policies likely to affect future LNG imports?*

While LNG represents only a single element of energy supply and foreign trade, a variety of Federal policies affects its future. Regulatory delays increase costs, and present Department of Energy policy discourages LNG imports in favor of sources located in North America. The attitude reflected in recent actions of the Department has been that even initially higher cost Alaskan gas and products of coal conversion technology are preferable to foreign LNG by virtue of the perceived public interest in developing domestic resources for the future.

Recent initiatives by the President to establish an energy mobilization board and to impose oil import quotas could facilitate LNG trade by eliminating foreign oil as a choice for some consumers and by removing obstacles to project approval. The effect of these programs would be reversed, however, if all foreign hydrocarbons are included in the quotas, or if the board adopts a policy to encourage domestic production in preference to energy imports of all forms.

Maritime Administration and Export-Import Bank programs, while ameliorating the balance-of-payments impacts of some LNG projects and providing benefits to the U.S. shipbuilding industry, tend to reduce the financial stake of foreign suppliers in uninterrupted deliveries. As mentioned earlier, the aid of these two agencies equalizes costs of domestic- and foreign-produced facilities and therefore does not encourage LNG projects except to the extent that sponsors appear more likely to gain Government approval if ships and machinery are built in the United States.

Both FUA and NGPA provide incentives to encourage domestic production of gas and conversion of oil- and gas-burning facilities to the use of coal. To the extent that this legislation is successful, demand for LNG may be slowed or reduced. The effect of FUA is partly to prohibit use of oil and gas for electric power generation after 1990. However, the law contains numerous exemptions and exceptions, including one permitting utilities to burn gas from LNG if necessary for regional air quality. NGPA establishes an elaborate pricing mechanism for gas, which affects the distribution of LNG costs among purchasers, as mentioned before.

2.
Policy Background

2.
Policy Background

In recent years, the U.S. natural gas industry has shown considerable interest in importing liquefied natural gas (LNG) to supplement the decline in domestic production. However, the lengthy and often confusing project approval process has made the importation of LNG difficult, if not impossible. Consequently, only four LNG import projects have been approved.

The Department of Energy (DOE) has only begun to clarify the regulatory review process and formulate the Carter administration's import policy. Critics of DOE argue that because of the lack of a clear policy, projects have been delayed, resulting in an increase in the cost of LNG and loss of potential supplies to other buyers. To assist in the overall understanding of LNG use in the United States, this chapter describes both past and present LNG policy and the roles of participating Federal agencies in its formulation.

Administration import policy

President Ford proposed the first explicit administration LNG import policy during his energy message of February 1976. Out of a concern for our growing dependence on foreign energy supplies, Ford initially proposed to hold LNG imports to a maximum aggregate of 1 trillion cubic feet (Tcf) per year and directed the Energy Resources Council (ERC), which had been created to coordinate energy policy among Federal agencies, to develop a more refined national LNG import policy. At that time, Government agencies involved in the importation of LNG included the Federal Power Commission (FPC), the Maritime Administration (MarAd), the Export-Import Bank, and the Department of Transportation (DOT). Prior to the President's message, several Federal agencies had expressed reservations regarding Government financial assistance to LNG projects and advocated developing our domestic energy sources instead. A Federal Energy Administration issue paper, dated February 20, 1975, clearly discouraged Government financial assistance for LNC ventures, an attitude also shared by the State and Treasury Departments. However, MarAd viewed LNG as a useful addition to U.S. energy supplies and supported LNG shipbuilding programs. According to MarAd, any Government action to discourage LNG imports could result in unemployment and the loss of invested tax dollars.

In response to President Ford's request, ERC created an LNG task force to recommend a new LNG import policy. The task force analyzed such issues as the level of LNG imports, pricing provisions, Government financial assistance, contingency plans, and siting and safety. Public hearings were also conducted in Washington, D. C., and Los Angeles to obtain the views of interested parties. While some witnesses expressed considerable concern regarding the siting and safety problems associated with LNG facilities, others supported the importation of LNG to supplement our own declining natural gas production.

The results of the task force analysis were announced on April 5, 1976:[1]

- LNG is needed to supplement our natural gas supplies, but it must be limited for supply security reasons. ERC recommended a limit for LNG imports from a single country of 0.8 to 1 Tcf/yr and a total acceptable import level from all countries of 2 Tcf/yr. The limitation was not intended to be a strict quota but rather a means by which to limit U.S. dependency on foreign energy supplies, and ERC avoided explicitly mentioning Algeria as the one nation likely to

[1] "Federal Energy News," Federal Energy Office News Release, Aug 5, 1976.

exceed 1 Tcf. ERC categorized LNG-exporting countries as either relatively secure or insecure, based on the country's political and economic interests. The relatively secure supply sources were Indonesia and, ironically in retrospect, Iran. The relatively insecure sources were Algeria, Nigeria, and the U.S.S.R. At the time of ERC'S recommendation, pending and approved Algeria projects could supply 1.1 Tcf/yr, which was above the recommended import level. Consequently, pending LNG applications would have to be evaluated carefully, and only those projects that provided the most desirable pricing provisions and assured uninterrupted supplies would be considered.

- The higher price of LNG should be passed directly through to low-priority and new users, and averaged with the lower cost of domestic sources for high-priority users. This principle would assure reasonably priced gas for residential customers and reinforce full energy resource costing for industry. Implementation of pricing provisions would be left up to FPC and State and local authorities, but pricing provisions would be reviewed by ERC continually.
- ERC recommended that contingency plans be submitted with each application to deal with supply interruptions. The plans should include underground storage, interpipeline transfers and exchange agreements, and curtailments of lower priority users.
- No changes were recommended regarding Government financing. ERC believed that if U.S. subsidies were not available, tankers would be available elsewhere. Therefore, MarAd financial assistance for LNG tankers was not considered essential to LNG projects.
- No recommendations were made regarding siting and safety issues. The task force expressed a willingness to cooperate with FPC and State and local authorities to resolve these issues.

On completion of its initial recommendations, ERC identified several issues that required additional analysis and directed the LNG task force to conduct the analysis. These issues included LNG safety and siting, development and implementation of contingency plans, the identification of State and local concerns, and mechanisms for implementing policy recommendations. While this analysis was being conducted President Carter introduced the National Energy Plan (NEP) and the Energy Organization Act to Congress.

Introduced in April 1977, NEP included LNG import policy guidelines that replaced those established by ERC in 1976. NEP places no upper limits on LNG imports, which is the major difference from ERC policies. It provides for a case-by-case review of each LNG import application, with emphasis on security of supply, vulnerability to interruptions, safety and siting, and pricing. In addition, NEP calls for the "equitable" distribution of supplies and the development of contingency plans for use in the event of a supply disruption. It also proposes siting criteria that would foreclose the construction of LNG facilities in densely populated areas.

The LNG task force was reestablished* under the leadership of DOE to develop a more comprehensive, detailed LNG import policy, based on guidelines set forth in NEP. DOE staff prepared reports on LNG import policy issues with recommendations to then Energy Secretary Schlesinger. Dr. Schlesinger did not formally endorse the staff findings and recommendations, preferring to establish LNG import policy by building case-by-case precedents. To date, Energy Secretary Duncan has not formulated a new LNG policy. The major findings and recommendations made by DOE staff included:[2]

- LNG is a low-priority gas source and as such should generally be discouraged. The mechanisms by which to discourage LNG imports except where economically justi-

*The LNG task force was abolished with the creation of DOE but continued to advise on LNG matters as an *ad hoc* group.

[2] *Inside DOE*, May 8, 1978, pp. 8-9; Aug. 7, 1978, p. 3; and Aug. 28, 1978; personal communication with DOE official, June 20, 1979.

fied include stringent regulatory requirements, such as requiring importers to contract directly with local distribution companies before the project would be approved, and encouraging States to require incremental pricing. However, if need is sufficiently demonstrated from a national standpoint, LNG projects should be approved.

- Price escalation provisions in supply contracts should be based on broader economic indicators than world oil prices.
- LNG imports do not add to foreign dependency but displace imported oil by serving as an alternative fuel.
- Although LNG viewed in isolation would appear to have a slight negative balance-of-payments impact, the net payments effect would likely be positive, a result of cost structure differences between LNG and foreign oil.
- OPEC influence on LNG prices would be limited because of the relatively small amount of LNG in world energy markets and the limited number of purchasers.
- LNG would have a less adverse impact on the environment than other energy sources, such as coal, oil, and nuclear power. LNG accidents are unlikely, but additional safety analysis and reporting are needed.

DOE staff did not address pricing issues, because natural gas pricing legislation was being considered by Congress at the time.

On August 4, 1977, President Carter signed into Iaw the Energy Organization Act (Public Law 95-91) which created DOE. This law abolished the Energy Research and Development Administration, the Federal Energy Administration, and FPC and transferred their functions to the new Department. The Economic Regulatory Administration (ERA) and the Federal Energy Regulatory Commission (FERC) were created within DOE to perform regulatory functions, including the approval of LNG imports. ERA, pursuant to section 3 of the Natural Gas Act (NGA), is responsible for ruling on whether natural gas import projects are in the public interest. FERC has certain statutory functions regarding LNG terminal facility certification as well as the price and other terms under which regasified LNG is sold in interstate commerce, pursuant to NGA, sections 4 through 7.

As mentioned earlier, DOE has not formally adopted an explicit LNG import policy. Each case is resolved individually on its own merits, and approval is based on whether or not the project is consistent with ‘(national energy policy. ” The national energy policy, as defined by the present administration, is to provide secure, adequate energy at reasonable prices while reducing U.S. dependency on foreign supplies. The extent to which an LNG project is perceived to conform with this policy determines its acceptability, and the precedents established in import policy decisions illustrate the prevailing DOE attitude toward imported LNG.

While DOE recognizes the need for imported and unconventional energy like LNG to supplement our own supplies, the Department prefers that our natural gas comes first from conventional sources within the United States. Therefore, each LNG application is viewed cautiously in light of DOE’s order of preference for new natural gas supplies as outlined in ERA’s Tapco decision:[3] ‘(proximate, ” “intramarginal,” and ‘(marginal. ” Ranking criteria include generalized cost and proximity of the supply to U.S. markets, but not size or timing of development relative to demand. DOE also considers whether the import project has the potential to discourage the development of future domestic gas sources, such as Alaskan gas or synthetic gas from coal. As a result, DOE considers preferred proximate sources to be those within the contiguous United States, including the Continental Shelf, which are within reach of conventional drilling technology and located near established pipelines. Intramarginal sources include gas from Alaska; various supplies from advanced technology applied to domestic resources, such as coal gas, gas from unconventional sources, and enhanced recovery; and over land supplies from neighboring sovereign countries, i.e., Mex-

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‘I) OE/ERA opinion 1%0, 2, Pac ıı ıdonesi a ı .NG Co and Western LNG Terminal Associates, Rehearing, Sept. 29, 1978 ico and Canada. The least preferred marginal supplies include synthetic natural gas from petroleum and LNG from overseas.

The capital intensiveness, long-term contract commitments, vulnerability to interruption, and relatively high price make LNG a marginal supply in DOE's view. In addition, long leadtimes needed to construct terminal facilities and tankers as well as potential cost overruns on shipping and liquefaction make it difficult to determine whether LNG will be competitive with other energy sources. In early 1979, the administration began encouraging imports from Latin America, because transportation costs are lower and energy supplies from this region are considered politically more reliable. These short-haul imports are categorized somewhere between "intramarginal" and "marginal" energy supplies. In addition, DOE expects the Natural Gas Policy Act of 1978 (NGPA) and the Power Plant and Industrial Fuel Use Act of 1978 (FUA) to make more gas available to high-priority markets by establishing incentives for exploration and production and by promoting long-term conversion of oil- and gas-burning facilities to coal. (Although FUA generally prohibits the use of gas for electric generation after 1990, LNG is excepted and may be burned in new powerplants after that time for air quality reasons.) Furthermore, the import reduction program introduced by president Carter in July 1979 provides new incentives for the development of synthetic fuels, unconventional gas, heavy oil resources, and oil shale and establishes an oil import quota of 8.5 million barrels per day (MMbbl/d) for 1980 and a goal of 4 to 5 MMbbl/d in 1990. LNG was not included explicitly under the import quota, so if the import quota cannot be met, the administration may look more favorably on the importation of LNG. If, on the other hand, the administration chooses to include LNG in the quota, expanded imports may be impossible.

Each LNG project application is jointly submitted to ERA and FERC. While ERA conducts an analysis to reach DOE's initial decision, FERC begins preparation of the environmental impact statement (EIS) but does not otherwise act on the application during this initial phase. ERA reviews each application in light of such issues as the security of supply, national and regional needs, cost, the effect on the U.S. balance of payments, and the project's consistency with DOE's natural gas import policy.

Supply security implications are carefully weighed by ERA. ERA will consider the adequacy of the exporting country's reserves to fulfill the sales contract and the degree of susceptibility to natural, political, or technical disruption within the country, along shipping routes, or at the receiving terminals, Because uninterrupted delivery of LNG supplies cannot be guaranteed, ERA requires that contingency plans be submitted with the application. Before approval, ERA must be satisfied that the contingency plan is adequate to compensate for long-term supply interruptions. For example, one of the reasons the El Paso Algeria project application was denied was that ERA felt the contingency plan relied too heavily on voluntary conservation measures.

In determining need, ERA looks to the end-user market, rather than to the interstate pipeline company's contractual obligation to deliver. According to ERA, contractual obligations do not always reflect the real need of a particular area, and a good test for regional need is the degree to which gas distribution utilities will contract directly for preferred gas.[4] It is the applicant's responsibility to provide ERA with an analysis of the region's particular requirements and to assess whether these requirements can be satisfied by an alternate energy source within a reasonable time. Only those projects are approved in which the need for gas cannot be met by more conventional sources.

Pricing has often overshadowed other issues in the application approval process. To be advantageous to the Nation, the cost of LNG should be competitive with alternative fuels or conservation measures over the lifetime of a project. The fact that a gas wholesaler could market LNG under past pricing policies has not necessarily meant that LNG was the least costly alternative. The reason was that the cost of LNG or other relatively expensive sources was aver-

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[4] 1 X) E/ F; R/\ opinion No. 3. Opinion and Order on Importation of LNG from Algeria by Tenneco Atlantic Pipeline Co. and '1' enneco Gas Pipeline Co., a Division of Tenneco, Inc , Dec. 18, 1978,

aged or rolled-in" with the less expensive flowing gas from old domestic sources. Therefore, the price to the consumer was less than the actual cost of the LNG. The arguments against "rolled-in" pricing were that it masked the true cost of some forms of new energy and provided fewer incentives to conserve or to convert to other less costly fuels. Rolled-in pricing also served to expand the use of gas, thereby improving the utilization of the gas transmission and distribution system, and spreading the associated fixed costs over a larger number of customers. Because rolled-in pricing encouraged the sale of LNG, investors have felt that it was both appropriate and necessary to secure financing. On the other hand, the Council on Wage and Price Stability and others have argued that the projects should fail if the gas cannot be sold when potential buyers must pay the full cost .

Historically, elements of FPC and DOE staff have favored "incremental" pricing, at least in theory, and industry has opposed it. Under this pricing mechanism, gas from each category is sold at a price that reflects its specific cost. The main argument against incremental pricing is that there is no perfect mechanism for deciding which customers may buy the less expensive gas and which must pay the incremental cost of supplemental supplies. Another argument is that incremental pricing would be difficult to administer during a shortage. Under NPGA, interstate pipelines and distribution companies may contract for gas from any producer, intrastate pipeline, or distribution company to meet high-priority user requirements during a shortage. However, if the shortage is not alleviated through purchase authority, Government allocation of gas supplies will result, and some seriously doubt that a purchaser of LNG at its incremental price would continue to receive the gas under these conditions. Consequently, LNG purchasers may find themselves questioning the value received for the price paid.

The pricing issue has been resolved at least for the present by NGPA which stipulates that LNG from projects planned after May 1, 1978, and gas from other unconventional sources be priced incrementally and paid for by certain large industrial customers, whether or not they benefit from or receive the incremental gas supplies. However, if the price paid by these purchasers reaches the price of the equivalent amount of oil, the higher cost of unconventional gas is shared by other users. Thus, NPGA shields residential consumers from the higher cost of new resources as long as industrial gas prices do not reach a level that would induce industry to switch to foreign oil.

Of utmost importance to ERA is the protection of consumers from unwarranted costs and risks. The project must show an equitable distri bution of risk between project sponsors and consumers regarding unexpected shipping costs, project failure, f.o.b. cost escalation, and long-term future prices of alternatives.[5] Because the characteristics of LNG import projects make them more risky than conventional energy sources, ERA expects the applicants to bear some of the risk of supply interruptions. Therefore, extraordinary circumstances must prevail for ERA to entertain recovery of equity on non-delivered supplies under minimum bill provisions in supply contracts. In genera], ERA finds it inconsistent with public interest for consumers automatically to bear the risk of supply interruptions, although the consumer does in effect guarantee through tariff provisions some of the debt portion of the financing and possible return of equity if the applicants can show good and just cause.

Energy imports involve at least some outflow of dollars from the United States. Therefore, ERA also requires a detailed analysis of the project direct impacts on the balance of trade.

If ERA determines that the application or components of the application are not consistent with the public interest, a rehearing and judicial review may be scheduled under section 19 of NGA. If ERA decides favorably, FERC then begins proceedings to decide on the remaining issues: safety, siting, construction, and operation of port facilities, and prices charged for the resale of the gas in interstate markets. FERC can reject the entire application if it determines that ERA's decision is inconsistent with FERC's pol-

[5] Ibid

icy, but it cannot reject components of the decision.

Although DOT is responsible for formulating minimum safety standards, FERC has the authority to impose more stringent ones if necessary and to require that LNG facilities be located away from densely populated areas. The siting issues in the El Paso H and Tenneco projects were decided by ERA, because the division of responsibility between ERA and FERC had not been formalized until the project approval process was well underway. Siting decisions in the Pac Indonesia project are shared by ERA and FERC. ERA has expressed a willingness to cooperate with States in deciding siting issues and recommended the use of independent technical experts to judge the quality of design and construction of terminal facilities to assure project safety further.[6]

[6]DOE/ERA opinion No. 6. Opinion on Rehearing—Issues Related to Treatment of Costs, Safety, and Siting, Pac Indonesia LNG Company and Western LNG Terminal Associates, Apr. 24, 1979.

FERC also approves prices for the resale of interstate gas. Prior to NGPA, if FERC had ruled in favor of incremental pricing for interstate resales, it was up to the State regulatory commissions to decide whether or not costs should be rolled-in or incrementally priced to the ultimate consumer. If FERC ruled in favor of rolled-in pricing, direct users were not confronted with incremental prices. Recently, FERC has proposed procedures for interstate pipelines and distributors to pass through increased costs of unconventional natural gas, including LNG, to large industrial users as required by NGPA. This will reserve for high-priority users the benefits of access to less expensive gas sources, at least for the time being. FERC also established three incremental price ceilings, based on No. 2, and high- and low-sulfur No. 6 fuel oils, for each region of the country in an attempt to prevent customers from switching from gas to imported oil.[7]

[7]"Procedures Set to Pass on Incremental Gas (: st," *Oil and Gas Journal*, June 11, 1979, p.47.

Maritime Administration

MarAd is part of the Department of Commerce. -Its primary purpose is to promote the development of the U.S. shipbuilding industry and U.S. shipping capabilities through various financial assistance programs: construction and operating subsidies, mortgage guarantees, and tax deferral via the capital construction fund. Of these four programs, mortgage guarantees (title XI) for U.S. owned and operated LNG tankers are the most significant. By mid-1979, MarAd had guaranteed mortgages amounting to $1.24 billion for 16 LNG tankers under title XI; the interest rate for such mortgages was then 9.35 percent. MarAd had also provided $270.5 million for 11 LNG tankers in construction differential subsidies under title V.[8] However, MarAd does not provide operating subsidies for LNG tankers because the operating expense differential between U.S. owned and operated and foreign-flag vessels is insignificant.

Like DOE, MarAd reviews financial assistance applications on a case-by-case basis. Before subsidies/guarantees are granted for LNG tankers, MarAd must be convinced that the LNG project is economically sound and be assured that, at the very least, the cost of the vessel will be repaid. MarAd will no longer finance LNG vessels on a "no guarantee required" basis as it did for the Algeria I project. This policy developed out of a concern that MarAd was concentrating too large a portion of its total funds in one area—LNG tankers. Title XI guarantees for LNG tankers represent 22 percent of total MarAd commitments. Concern over long delays in the LNG application approval process and lower estimates of the market for LNG tankers also contributed to the development of the debt assurance policy.[9] Because of the long delays, some tankers have been idle. Although section 905(a) of the Merchant Marine Act, amended, allows

[8]Personal communication with Mar Ad official, May 9, 1979. These figures do not include the required national defense features or engineering changes.

[9]*Inside DOE*, May 15, 1978,

the use of LNG tankers for other purposes, alternative employment is not practical, except in liquid petroleum gas trade, because the tankers are specially built for their unique cargo.

Export-Import Bank

The Export-Import Bank aids in financing and facilitating export sales to foreign countries. This is accomplished through direct lending at favorable interest rates or issuance of loan guarantees and insurance to foreign purchasers of U.S. goods.

Export-Import Bank policy regarding LNG projects has been to consider loan applications for U.S.-made liquefaction equipment and port facilities only after the project has been approved by DOE/ERA and FERC. Each project is assessed in terms of the financial conditions of the foreign borrower, the viability of the project, and the economic and political situation of the country in which the project is located. Before approving a loan, the Bank must be satisfied that the project is economically, financially, and technically sound and be reasonably assured of repayment. The Bank requires security either in the form of a guarantee from the government, a bank, or a parent company or based on the financial strength of the borrower. Because Algerian LNG facilities are State-owned, the Export-Import Bank requires that the guarantees be from the government. 10

Section 2(b)(3) of the Act (amended) requires that Congress be notified of any proposed loans or guarantees for $100 million or more. Notification must generally be at least 25 days of continuous session prior to the date of final approval, with certain exceptions covering long adjournments. If either House is adjourned for a period of 10 days after notification, the Bank may approve the loan after 35 calendar days unless Congress dictates otherwise.

Under the Trade Act of 1974 and the Export-Import Bank Act Amendments, the Bank is prohibited from extending credit to the U. S. S. R., a potential supplier of LNG, and other Communist countries unless the President determines the transaction to be in the national interest. Additional Presidential approval and congressional notification are required for loans of $5o million or more. Furthermore, Congress must be notified of loans of $25 million or more to the U.S.S.R. for goods or services involving the research, exploration, or production of fossil fuel energy resources. These limitations on trade and economic assistance to Communist countries are clearly linked to human rights and emigration policies. Given the present political climate, potential LNG ventures with the U.S.S.R. may not receive Export-Import Bank financing.

By mid-1979, the Export-Import Bank had provided $715.7 million to Algeria and Brunei in overseas LNG-related loans and guarantees to promote American exports. (It should be noted that Export-Import Bank loans/guarantees are not necessarily tied to U.S. trade. For example, Algeria and Brunei export LNG to Europe and Japan.) Out of this total, $674.3 million was still outstanding (all to Algeria). In addition, the Export-Import Bank has tentatively approved a $313.5 million loan at an annual interest rate of 8.5 percent to Sonatrach for the construction of its third LNG terminal at Arzew. Because of the size of the loan, Congress must be notified before final approval. No loans have been made to Indonesia, because the project has only recently cleared all of the major regulatory hurdles. 11 The Export-Import Bank's commitments for LNG projects have increased due to contractor problems in Algeria. The Bank, thus far, has financed $67 million out of $167.5 million in cost overruns for Algeria's Arzew I project.

[10] "Export Financing and the Role of the Export-Import Bank of the U.S.," *Journal of International Law and Economics*, 101.2, No.1, 1976, p 123.

[11] Personal communication with Export-Import Bank official, June 21, 1979

Department of Transportation

DOT formulates the general minimum Federal safety standards for LNG facilities. In April 1979, DOT and FERC drafted an agreement that allows FERC to override and tighten DOT's safety regulations for LNG facilities if the situation warrants. The agreement will settle a dispute between FERC and DOT over LNG safety standards. [12]

The U.S. Coast Guard (USCG) is responsible for vessel traffic management. To ensure the safety of vessel movements the Coast Guard has authority to escort tankers to and from the terminal facilities and establish security zones around or near a vessel or facility. In addition to traffic control, USCG establishes regulations governing the design, construction, inspection, and operation of U.S. and foreign-flag LNG carriers. USCG also works with the Inter-Governmental Maritime Consultative Organization (IMCO) in developing uniform worldwide standards for the safe transport of liquefied gases. If U.S. or foreign-flag vessels do not appear to be in compliance with the IMCO standards and U.S. requirements, USCG has authority to review the vessel's technical plan to ensure such compliance. Furthermore, USCG has authority to examine vessels prior to authorizing the transport of liquid gases and at specified intervals and to conduct safety boardings prior to entry into a U.S. port. [13]

USCG and the Materials Transportation Bureau (MTB) cooperate to ensure the safety of LNG facilities and participate in technical conferences with LNG import applicants. Within DOT, primary responsibility for establishing standards for siting LNG facilities rests with MTB unless otherwise stated. Under the terms of a memorandum of understanding dated February 7, 1978, MTB and USCG agreed to a division of regulatory responsibility with regard to waterfront LNG facilities. USCG is responsible for establishing regulations for facility site selection as it relates to vessel traffic management in and around a waterfront facility, fire prevention and protection methods used at waterfront facilities, and security of waterfront facilities.

On February 8, 1979, MTB proposed more stringent safety standards for the design and construction of LNG facilities, which include establishing a thermal exclusion zone around an LNG terminal to protect individuals and property from heat radiation caused by vapor ignition.[14] MTB also expected to propose new operation and maintenance standards for LNG facilities by the end of 1979.

[12] *Inside DOE*, Apr. 23, 1979, p. 3

[13] 50 U.S.C. 191.

[14] *Federal Register*, vol. 44, No. 28, Feb. 8, 1979, p. 8142.

Department of Defense

The Army Corps of Engineers reviews and issues permits for work performed in U.S. navigable waters. Any major obstruction that would interfere with navigation requires the approval of Congress as well. The Corps also issues (with the concurrence of the Environmental Protection Agency) permits for the disposal of dredge or fill material in U.S. waters. Other Corps activities may indirectly affect LNG projects. For example, the Corps has dredged a ship channel from the Gulf of Mexico to Lake Charles, La., where the Trunkline LNG terminal and many other industries, such as oil refineries, and petrochemical, chemical, and fertilizer plants, are located. Trunkline along with the other industries will benefit from this project, which was authorized by Congress. [15] Based on a 1960 cost/benefit analysis, the Corps estimated that savings of $0.28 per ton and $590 per round trip (1960 dollars) would accrue to larger tankers using the channel. [16] This savings represents a very small fraction of the Trunkline project's ship-

[15] Personal communication with Army Corps of" Engineer official, New Orleans District, June 19, 1979; Aug. 21, 1979.

[16] House Document 86-436, Calcasieu River and Pass, La., 1960, p. 24.

ping costs. In 1978, Congress requested the Corps to conduct a cost/benefit analysis of further improving the channel. These proposed improvements include the construction of a passing lane and holding area which are desired by local interests because of increasing oil tanker traffic and impending LNG tanker traffic.[17]

[17] U.S. Army Corps of Engineers, *Preliminary Report, Lake Charles Channel.*

Congressional interest

Thus far, congressional interest in LNG has focused on the hazards of transporting LNG, siting and safety of LNG facilities, and the regulatory process. The 96th Congress is no exception. Five LNG-related bills have been introduced in the 96th Congress and fourteen in the 95th Congress.

Recently, substantial interest has emerged in establishing a liability and compensation fund for the repayment of claims arising out of an LNG accident and setting forth a liability limit for such an accident, unless caused through gross negligence or violation of safety, construction, or operation standards.

Brief summaries of bills before the 96th Congress are presented below:

H.R. 51—Fuels Transportation Safety Amendments Act of 1979

Introduced by Congressman Markey, January 15, 1979
Referred to Subcommittees on Energy and Power, Surface Transportation
Hearings held March 1 and June 8, 1979
Passed House September 18, 1979
S. 411, as amended, passed in lieu, September 18, 1979

1. Provides for the safe operation of pipelines that transport natural gas and liquefied petroleum gas.
2. Requires DOT to establish minimum siting, construction, and operation standards for new LNG facilities and to promulgate standards for existing LNG facilities.
3. Establishes civil and criminal penalties for the violation of safety and financial responsibility standards and the willful destruction of pipeline or gas facilities.

H.R. 1414—Liquefied Gas Marine Transportation Safety Act of 19?9

Introduced by Congressman Biaggi, January 24, 1979
Referred to Subcommittees on Energy and Prover, Coast Guard and Navigation, Merchant Marine, and oceanography
Joint hearings held on July 18-19, 1979.

1. Prohibits ownership, design, construction, and operation of an LNG facility without certificate of safety or license.
2. Directs DOT to prescribe siting, safety, environmental, and operation standards for both onshore and offshore LNG facilities.
3. Establishes a liquefied bulk gas incident liability and compensation fund in the Treasury and limits liability for an accident to $50 million, except for accidents determined to be caused by gross negligence or violation of safety, construction, or operating standards.

H.R. 3749—Coastal Area Liquefied Gas Facility Safety Act

Introduced by Congressman Murphy, April 25, 1979
Referred to Subcommittees on Energy and Power, Coast Guard and Navigation, Oceanography, and Merchant Marine
Joint hearings held on July 18-19, 1979.

1. Establishes a coordinated Federal-State regulatory approach related to siting, construction, and operation of LNG facilities in or near the coastal zone.
2. Sets forth minimum siting, construction, and operation standards for LNG facilities.
3. Prohibits siting, construction, or operation of an LNG facility within or near coastal

zones unless the State has applied for or been granted exempt status.

4. Imposes civil and criminal penalties for violations of the Act.

S. 411—*Fuels Transportation Safety Amendments Act of 1979*

Introduced by Senator Cannon, February 9, 1979
Referred to Senate Committee on Commerce
Hearings held April 25-26, 1979
Passed Senate June 4, 1979
Passed House September 18, 1979 (in lieu of H.R. 51)
Became Public Law 96-129 November 30, 1979.

1. Provides for the safe operation of pipelines that transport natural gas and liquefied petroleum gas.
2. Requires DOT to conduct a cost/benefit analysis of increased fuels transportation safety regulations and study the risks associated with the production, transmission, and storage of LNG or liquefied petroleum gas.
3. Requires DOT to establish minimum siting, construction, and operation standards for new LNG facilities and to promulgate minimum standards for existing facilities.
4. Requires an LNG facility operator to submit a contingency plan in the event of an LNG accident prior to operation of the facility.
5. Established civil and criminal penalties for violation of safety or financial responsibility standards and willful destruction of interstate pipelines or LNG facilities.

S. 666—*Comprehensive Liquefied Energy Gas Siting, Safety, and Liability Act of 1979*

Introduced by Senator Durkin, March 14, 1979
Referred to Senate Commerce Committee

1. Prohibits construction of new LNG facilities without DOT's approval.
2. Provides standards for siting, construction, and operation of LNG facilities.
3. Establishes a comprehensive liability and compensation fund in the Treasury derived from tax on LNG sales and limits liability for an accident to $100 million except for accidents caused by gross negligence or violation of safety, construction, or operating standards.

* * *

To assist Congress in debating LNG-related legislation, several reports have been prepared by OTA, the General Accounting Office (GAO), and the Congressional Research Service (CRS). The OTA report, *Transportation of Liquefied Natural Gas,* reviews the major areas of concern in transporting LNG, such as tanker construction, operation, and safety, and the siting of LNG facilities. OTA staff also testified at oversight hearings on liquefied energy gases held by the Senate Committee on Commerce, Science, and Transportation during December 1978. These hearings focused on siting and safety issues, regulatory delays, jurisdictional conflicts, liability, and compensation. GAO[18] reviewed safety issues, LNG import policy, and the regulatory process under the Carter administration. In February 1978, CRS conducted a seminar entitled "Liquefied Natural Gas: Safety, Siting and Policy Concerns" which provided Congress with background information on public policy issues associated with the importation of LNG.

[18] GAO, *Liquefied Energy Gases Safety*, 3 volumes, July 31, 1978; *Need to Improve Regulatory Review Process for Liquefied Natural Gas Imports*, July 14, 1978; *The New National Liquefied Natural Gas Import Policy Requires Further Improvements*, Dec. 12, 1977,

States

Because of the controversy surrounding the Pac Indonesia project proposed by Pacific Gas & Electric Company and Southern California Gas Company, attention has been focused on California's response to the LNG issue. To improve the site selection process, the California LNG Terminal Siting Act was signed into law in 1977. The keystone of this law is remote siting, Under the law, the California Public Utilities Commission (PUC) has exclusive authorization to issue permits to construct and operate an onshore LNG terminal and thus is the final arbiter of the site location. The law also requires the California Coastal Commission to evaluate and rank proposed terminal sites and report their findings to PUC, and it authorizes the California Energy Commission to study the natural gas supply and demand picture to determine whether or not LNG is needed.

The siting law was first applied in the Pac Indonesia LNG project. The major impact of the law was to eliminate Oxnard, which had already been approved by an FPC Federal administrative Iaw judge, in favor of Point Conception as a terminal site. But before the judge's decision could be reviewed by the five-member FPC, it was stripped of its authority to rule on import matters and the case was transferred to the new ERA. ERA found Oxnard to be an acceptable site but expressed reluctance to approve Point Conception without new hearings. The Agency, however, was not opposed to the other site and expressed willingness to cooperate with State authorities in selecting the best location.

The applicant requested that Point Conception be considered as a terminal site, and the approval process began once again. FERC staff prepared an EIS on Point Conception and asserted that the site was unsuitable because of earthquake hazards. In addition, Native Americans opposed the Point Conception site because of its spiritual significance. FERC staff again recommended Oxnard and Rattlesnake Canyon as an alternate. Hearings were held on the EIS and on August 13, 1979, a FERC administrative law judge approved Point Conception as a suitable terminal site. However, the judge's ruling was subject to final approval by both FERC and ERA. On September 26, 1979, ERA reaffirmed its approval of the importation of LNG and the price at the point of importation into either Oxnard or Point Conception. However, ERA made no determination as to the appropriateness of Point Conception as a site for LNG-receiving facilities. In October 1979, FERC was given authority to approve/disapprove applications for the construction of LNG facilities at Point Conception and ERA retained authority to approve the construction of facilities at Oxnard. The final decision by FERC in October 1979, was to approve the Point Conception site.

Other States

Other States have established guidelines and/or councils to deal with the energy facility siting issue. For example, Massachusetts has established an energy facilities siting council. Its purpose is to establish guidelines for the siting and safety of LNG facilities. The Council proposed guidelines that would require a demonstration of facility need, a cost analysis, a comparison of alternative sites, and an EIS. In addition, the guidelines specify thermal radiation and vapor performance standards, *[8]

The State of New York established an LNG program which is assigned to the Bureau of Mineral Resources in the State Department of Environmental Conservation. Also, the State of New Jersey has formally expressed positions on the siting and safety of LNG facilities. The State opposed the Tenneco project out of concern for the safety of its citizens and claimed that the project was contrary to sound energy policy. According to the State, LNG should be limited to peak-shaving and very low-priority baseload use.

[19]Commonwealth of Massachusetts Energy Facilities Siting Council, "liquefied Natural Gas Siting Guidelines, An Explanation ," attachment to testimony given by James Connelly, Deputy Director, Massachusetts Energy Office, before the Senate Committee on Commerce, Science, and Transportation," Dec. 12-13, 1978, p. 332.

3.
Future Gas Availability and Use

3.

Future Gas Availability and Use

Policy alternatives related to future liquefied natural gas (LNG) imports can only be evaluated in the context of the possible ranges of gas availability and use over the duration of a supply contract. Although such projections are highly speculative, this chapter presents the results of a review of the relevant literature.

On examining the forecasts from several econometric demand models, one observes that projected U.S. gas use falls between 14 and 25 quadrillion Btu (Quads) in 1990 depending on such factors as future fuel prices, energy productivity, and public policy. Table 1 indicates by sector what portions of expected demand are "basic" in the sense that alternatives are costly or unlikely, and what are "marginal," i.e., possible if supplies are available at attractive prices and policies are favorable.

Since LNG is just one of many possible sources from which to meet demand, this chapter also includes a survey of North American gas and oil production potential. As shown in table 2, domestic production, now at a level of about 19.6 trillion cubic feet per year (Tcf/yr) in 1979, may decline to as low a level as 14.6 Tcf/yr by 1990, barely enough to meet '(basic" demand. It could also possibly satisfy "marginal" demand, but only at high prices. Furthermore, Mexico and Canada will probably not significantly alter the balance, and oil production in the continent is not likely to increase either,

In the rest of the world, large gas reserves occur particularly around the Persian Gulf and in the Soviet Union. However, for political or economic reasons, most of these resources either would not be exported or would flow to closer markets, in Japan and Europe, for example. Thus, only perhaps 0.5 to 1 Tcf/yr could presently be committed to future LNG sales to the United States beyond those imports already approved. These remaining available volumes are located in Nigeria, Southeast Asia, and South America.

Table 1.—Projected Levels of Potential Gas Demand in 1990 by Consuming Sector Under Alternative Policies and Prices (quadrillion Btu)

Sector	Basic[a]	Marginal[b]	Total
Buildings	5	3	8
Industry	8	2	10
Utilities	.5	4	4.5
Other	.5	3	3.5
Total	14	12	26

[a]Basic demand includes applications for which alternatives are relatively costly or unlikely.
[b]Marginal demand includes other economical uses that are Possible if supplies are available at attractive prices, and policies are favorable
SOURCE: Of fice of Technology Assessment, based on data from several separate studies (see text for assumptions).

Table 2.–Potential Gas Supply in 1990 (trillion cubic feet; approximate quadrillion Btu)

	NPGA prices[a]	Over $3/Mcf[b]	Over $5/Mcf[b]
Domestic			
Conventional	12.5-16.6	12.5-16.6	12.5-16.6
Alaska North Slope	—	—	1.6
Unconventional	2.3	3.6-8.4	3.6-8.4
Synthetics	—	—	0.3-1.4
Subtotal	14.8.18.9	16.1 -25.0	18.0-28.0
North American imports			
Canada	—	0.6	0.6
Mexico	—	0.7-1.2	0.7-1.2
Subtotal	—	1.3-1.8	1.3-1.8
LNG imports			
Present & approved	—	0.8	0.8
Possible additions	—	0.5-1.0	0.5-1.0
Subtotal	—	1.3-1.8	1.3-1.8
Total	14.8-18.9	18.7 -28.6	20.6 -31.6

[a]Prices specified in the Natural Gas Policy Act of 1978 (Public Law 95-621)
[b]1978 dollars per thousand cubic feet.
SOURCE: Office of Technology Assessment.

U.S. gas demand

This section presents a survey of recent studies of energy and natural gas demand, particularly those that emphasize the tradeoffs between gas use and efficiency improvement technologies in the residential, commercial, industrial, and powerplant sectors. The resulting range of estimates of likely demand for natural gas in the next 10 to 20 years is then contrasted with projections of available gas supplies.

The projections analyzed here were performed by the Energy Information Administration, American Gas Association (AGA), Brookhaven National Laboratory, Dale Jorgenson Associates, Energy and Environmental Analysis, Inc., Jensen Associates, and the National Academy of Sciences Committee on Nuclear and Alternative Energy Systems (CONAES). The underlying models and analytical methods, described in the *Background Reports* volume of this report, generally account formally for potential changes in end-use efficiency and technology, consistent with assumed energy prices, economic growth rates, and Government policies,

As the differences among the projections listed below illustrate, analytical modeling is an imprecise art, requiring judgment as well as logic and facts. The inclusion of many studies here is intended to indicate how varying assumptions affect the results, and to dramatize the uncertainty associated with any given projection. As a result, the premises underlying the individual studies are not necessarily mutually consistent, although in most cases the long-term real economic growth is assumed to be 3.5 percent per year. Direct comparisons, such as those that follow, must be tempered with these considerations in mind.

Comparisons of projection results

The level of gas demand predicted in any particular study is a function of both the structure and data input to the demand-side model, and the exogenous inputs to the model such as price and economic growth. Generally, models with more detail on the demand side may be expected to capture a higher degree of consumer response to price increases, provided the costs and efficiencies of end-use technologies are represented accurately. In addition, the higher the assumed price of fuels and the economic growth rate, the lower the predicted demand for gas and other fuels, all else being equal.

Because of the importance of world oil prices as a pacing variable for energy prices generally, the summary gas demand for the studies considered are presented in two separate tables. Table 3 presents the gas demand for the projections that assume little or no increase in the real price of world oil. Table 4 presents the results of several projects that begin with assumptions of between 50- and 150-percent real increases in world oil prices between 1978 and 1990.

Effect of prices

Since imported oil is the principal alternative fuel for many uses, the price of substitutes will tend to rise to world oil price levels, absent regulation. In a theoretical free market, the price of natural gas might be expected to rise to the price of distillate oil refined from foreign crude. Most world oil price projections fall in the range between no real price increase ($15 to $20/bbl in constant 1978 dollars)* and increases to approximately $4o to $50/bbl by 1990.

Gas demand projections assuming nearly constant world oil prices, fall fairly consistently in the range of 7 to 9 Quads in buildings and 8 to 11 Quads in industry, if gas prices are limited to no more than the Btu equivalent of imported oil. In the high world oil price cases, however, the difference between gas prices at Btu equivalency with oil and at lower regulated levels is striking. The projections by Jensen Associates and Brookhaven assume gas to be priced well below Btu parity. Gas demand for buildings and industry in these cases is not very different from the projections shown in table 3, indeed, gas demand may be slightly higher due to substitution for oil. A more dramatic contrast is between the CONAES scenarios, in which gas is priced at a slight premium over oil due to its

*This lower limit has become outdated in recent months.

Table 3.—1990 Gas Demand for Low Oil Price Cases (quadrillion Btu)'

Report	EIA(l) A	EIA (1) B	EIA(l) C	EIA(l) D	EIA(l) E	AGA (2) low supply	AGA (2) high supply	BNL (3) DJA L	BNL (4) BECOM L
Oil									
Imported									
1978 $/bbl	16.00	23.50	18.50	15.60	21.00	19.06	19.06	15.83	16.59
Gas									
Well head									
1978 $/Mcf	1.99	3.27	2.40	2.01	2.79	2.05	2.05b	2.50	2.74
Residential ., .	5.57	5.33	5.41	5.48	5.35	5.80	5.80	(6.80 space heat)	6.91
Commercial. , .	2.75	2.38	2.37	2.45	2.29	3.20	3.20	16.80	
Industry.	8.24	8.60	9.98	9.60	7.97	13.50	10.90	(3.95 process heat)	N/S
Utilities	0.52	0.54	0.51	0.52	0.60	2.20	2.20	3.10	NIS
Other	0.47	0.48	0.53	0.47	0.45	3.00	3.10	N/s	N/S
Total.	17.55	17.33	18.80	18.52	16.66	27.70	25.20	19.90	N/S

N/S Not specified
[a]10[15] Btu = 0.98 Tcf of gas = 1 Quad
[b]Supplemental priced comparable to world oil.

SOURCES: 1. Energy Information Administration, *Energy Supply and Demand* in *the Midterm 1985, 1990, and 1995, 1979.*
2 American Gas Association, *A Forecast of the Economic Demand for Gas Energy in the* U.S. *Through* 1990, 1979.
3 R J Goettle, E. A Hudson, and J. Lucachinski, *A Comparative Assessment of Energy-Econorrry Interactions: Price Versus Growth,* BNL 50923, Upton N Y , 1978
4 S C. Carhart, S S. Mulherker, and J. Schwam, *Energy, Employrrrent, and Environmental Irnpact of Accelerated Investment in Conservation and Solar Technologies m Buildings,* BNL 50918, Upton, N.Y.,1978

Table 4.—1990 Gas Demand for High Oil Price Cases (quadrillion Btu)[a]

	JAI (1)	BNL/DJA-H (2)	BNL BECOM-H(3)	CONAES A(4)	CONAES B(4)	CONAES B' (4)
World oil price.	42.00	29.12	49.20	45.09	25.15	25.15
Gas wellhead price.	2.50	3.49	3.46	9.76	4.78	4.78
Residential	5.32	16.55	6.14	4.6[b]	5.1[b]	5.7[b]
Commercial.	2.77					
Industry.	9.37)		N/S	8.0[b]	7.1[b]	8.4[b]
Utilities , ...	4.80	1.75	N/S	N/S	N/S	N/S
Other	2.48	N/S	N/S	N/S	N/S	N/S
Total.	24.74	18.30	N/S	N/S	N/S	N/S

N/S Not specified
[a]10[15] Btu = 098 Tcf of gas = 1 Quad
[b]Adjusted for 3.5 percent per *year* GNP growth for comparability with other forecasts.

SOURCES 1 Jensen Associates, Inc., *Imported Liquefied Natural Gas, 1979 (vol.* II of this report).
2. R. J Goettle, E. A. Hudson, and J. Lucachinski, *A Comparative Assessment of Energy-Economy Interactions Price Versus Growth,* BNL 50923, Upton N Y , 1978
3. S. C. Carhart, S. S. Mulherker, and J. Schwam, *Energy, Employment, and Environmental Impact 01 Accelerated Investrmen! in Conservation and Solar Technologies in Buildings,* BNL 50918, Upton, N. Y,,1978.
4 National Academy of Sciences, Committee on Nuclear and Alternative Energy Systems, *Alternative Energy Demand Futures,* Report of the Demand/Conservation Panel, 1980.

ease of use and cleanliness, and the other high oil price cases. The results are substantial reductions in gas demand—to 5 Quads in the buildings sector and to 8 Quads in industry.

The implication of the latter figures, while preliminary and not strictly comparable, is that substantial conservation in buildings and industry is economically justified between the $2,05 per thousand cubic feet (Mcf) price contemplated in the AGA high-demand case and the $5 to $10 Mcf assumed by CONAES. On the basis of these studies taken together, one concludes that 1990 buildings and industry demand will probably lie in the 12- to 14-Quad range if gas is priced on a Btu equivalency basis with higher priced oil, in contrast with 16 to 20 Quads for the lower gas price cases.

Effect of public policy

The range of demand for utilities and miscellaneous uses falls between 1 and 7 Quads. The main difference in these projections arises from varying interpretations of the Power Plant and Industrial Fuel Use Act, which calls for negligible levels of natural gas use in powerplants by 1990, but provides for numerous exemptions and exceptions. Regulatory interpretation of the law over the next decade will be a key factor in resolving this uncertainty.

Another major element of Government policy concerns incremental pricing and use of natural gas for the generation of steam. The AGA study, which explores what type of energy service in industry would absorb marginal supplies of gas, illustrates the effect of these policies. A "high supply" case assumes that supplemental supplies, such as LNG, will be used by, and priced incrementally to, industrial users. In the "low supply" case, no supplemental gas is included, and prices stay at the average level for conventional supplies. The effect of incremental pricing in industry is to reduce demand by 2.6 Quads, the bulk of which would have raised steam, largely through displacement of other fuels, as shown in table 3. The incrementally priced high-supply case projection of 10.9 Quads in industry is quite comparable with other projections. However, if all gas to industry is incrementally priced, and world oil prices are in the $40 to $50/bbl range, CONAES case A suggests that total demand in industry might be expected to fall to around 8.0 Quads.

Domestic supplies

This section reviews U.S. gas and oil resources and potential supplies in terms of quantity, time of availability, and cost. In the context of projected demand, this discussion is designed to aid in assessing the need for imports. The method of analysis draws heavily on numerous available supply forecasts. The results, presented in greater detail in the *Background Reports* volume, rely on secondary resources and do not represent yet another supply projection,

Table 5 summarizes U.S. gas production from all sources. The ranges in estimates are indicative of the uncertainty associated with each source. Production is principally dependent on the rate at which new reserves can be added, and Alaska's contribution also hinges on the construction of the Alaska gas pipeline. Realization of the potential of unconventional gas sources will require time and technological progress, and coal gasification also will require large capital outlays.

Maintaining current levels of U.S. liquid petroleum production over the next decade or two will be extremely difficult. Natural gas liquids production may decline with declining production of natural gas, and conventional oil production from proved reserves will continue to decline. At the same time, enhanced oil recovery (EOR) processes and new discoveries may not add enough to reserves in time to offset declin-

Table 5.—U.S. Gas Supply Conventional, Unconventional, Coal Gas (trillion cubic feet)

	Lower-48 NGPA-prices[a] Low	Med	High	Alaska $5.00-$6.00 1978$	Unconventional $1.75 1972	$3.00	$3.00 High	Coal gas $5.00-$6.00 1978$
1980	18.8	18.8	18.8	—	.3	.5	.5	—
1985	14.7	16.3	17.8	.8	1.3	1.9	4.1	.2-.7
1990	12.5	14.5	16.6	1.6	2.3	3.6	8.4	.3-1.4
1995	11.4	12.4	13.6	2.5	2.8	4.4	8.4	2.4
2000	10.8	11.6	12.2	3.6	2.8	4.4	9.0	4.0

[a]According to the Natural Gas Policy Act of 1978 (Public Law 95-621).
SOURCE: Office of Technology Assessment.

ing production from older fields. Progress in developing oil shale and coal will be slow, and synthetics production on a large scale is not anticipated before the mid-1990's) even if potential environmental problems are resolved.

Future U.S. liquid petroleum production could consist of the components in table 6. In spite of the inherent uncertainty, the forecast does suggest that domestically produced liquid petroleum will not be available to substitute for shortfalls in gas or other energy sources. Indeed, large quantities of imported oil will continue to be required to meet liquid petroleum demand in the foreseeable future.

Conventional natural gas

Five forecasts of conventional gas production, summarized in table 7, have been examined in this study, representing a range of institutional perspectives. They were chosen in part to represent the widely different levels of optimism expressed by analysts in this field, but all forecasts (except one by AGA) project a decrease in U.S. conventional natural gas production from about 19.6 Tcf in 1979 through the end of the century.

As of year-end 1978, U.S. proved reserves of natural gas totaled 200.3 Tcf, including approximately 30 Tcf of North Slope, Alaskan gas for which no transportation and delivery system is available, at least for the next 5 years. Estimates of indicated and inferred reserves range from 52 to 202 Tcf, reflecting differences in the definitions of categories, less certain geology, and lack of interest in exploration (particularly for nonassociated gas) due to Government price regulations. Estimates of undiscovered, recoverable natural gas resources varying from 361 to 920 Tcf, are even more speculative. Estimates of remaining recoverable U.S. conventional gas resources are summarized in table 8.

Proved reserves are the most significant determinant of production in the immediate future, since the ratio of reserves to production, 8.5 to 1 in the United States, excluding Alaska, is close to its technical limit. In the lower 48 States, proved reserves have declined every year since 1968 as production has exceeded additions. With no net additions to reserves, a lower reserve-to-production ratio, even if technically feasible, would delay but not reverse the decline in natural gas production which began in 1973.

Over a period of several years, however, additions to production potential would arise from revisions and extensions of existing fields, new discoveries, and Alaskan reserves. Since 1970,

Table 7.—Forecasts of U.S. Conventional Natural Gas Production
(trillion cubic feet)

	American Gas Association[a]	EXXON	Shell	Lewin[c]	Tenneco
1980	18-19	17.0	17.0	17.0	18.0
1985	16-18	15.3	14.0	14.0	16.0
1990	15-17	14.3	13.0	13.0	15.0
1995	14-15	NA	NA	NA	14.0
2000	12-14	NA	NA	11.0	12.0

[a]The higher estimate assumes gas price deregulation.
[b]Excludes Alaska.
[c]Includlng developments of unconventional gas already underway.
SOURCE: Office of Technology Assessment.

Table 6.–Possible Future U.S. Liquid Petroleum Production
(million barrels per day; 25.381978 **dollars/bbl)**

	1985	1990
Conventional liquid petroleum known fields.	5.6	4.2
Enhanced recovery	1.0	1.8
New discoveries	2	2
Shale oil	—	.1-.4
Coal liquids	—	.1-.5
Total	8-9	8-9

SOURCE Office of Technology Assessment

Table 8.–Potential Supply
(trillion cubic feet)

Year of estimate	Source	Old fields	New fields	Proved	Total
1974 . . .	Hubbert	135	361	200	696
1974/5. .	Mobil	52	485	200	737
1975 . . .	National Academy of Sciences	118	530	200	848
1975 . . .	Institute of Gas Technology	(633-1 ,138)		200	833-1,338
1975 . . .	U.S. Geological Survey	202	322-655	200	724-1,057
1978 . . .	EXXON	(202-860)		200	400-1,060
1978 . . .	Potential Gas Committee	199	820	200	1,219

SOURCE: Office of Technology Assessment

additions to reserves outside Alaska have averaged 9.3 Tcf/yr, consisting mostly of new reservoir discoveries in old fields and revisions and extensions of presently producing fields. The contribution of new field discoveries to this total has averaged only 1.8 Tcf/yr since 1971. To maintain current production at the 8.5:1 reserves to production ratio, additions to proved reserves would have to equal current production, about **20** Tcf/yr, so an additional 10 Tcf above historical reserve additions would have to be found to maintain current production levels.

Optimism or pessimism in the forecasts cited above turns on the likelihood of large additions to reserves in the future, in the light of uncertain geology and the unknown effect of higher prices of drilling rates.

Alaska contains an estimated 225 Tcf of potential gas, including indicated and inferred reserves and speculative resources, representing perhaps 23 percent of the U.S. total. Of the 31.8 Tcf of proved reserves within the State, the major portion is located in the Prudhoe Bay field of northern Alaska, and gas resulting from oil production there is being reinfected into the gas cap. None of this gas will be available until an Alaska pipeline project is completed, in 1984 at the earliest, and the financing for the venture is still problematic. When completed, the pipeline would have a nominal design capacity of 0.9 Tcf/yr. When a west coast LNG terminal is built, 50 billion cubic feet (Bcf) of Alaskan gas from southern Alaska, which is currently shipped to Japan, could come to the United States.

Conventional oil

The United States has already reached the 1:10 production-to-reserves technical limit. To maintain current production levels, additions to reserves, whether through enhanced recovery or new discoveries, would have to equal current production—about 3 billion barrels per year (bbl/yr). In fact, the United States has been adding to reserves at a rate of about 1.8 billion bbl/yr (excluding Prudhoe Bay). For this reason the United States will probably be unable to maintain current production levels over the next decade, since enhanced recovery and new discoveries are not likely to offset the decline in older producing fields.

Five domestic oil production forecasts appear in table 9. Although difficult to compare because of inconsistent and inexplicit assumptions, most forecasts project no increase before 1990 in U.S. liquid petroleum production from the 10.3 million barrels per day (MMbbl/d) level achieved in 1978. Indeed, EXXON and Shell project a decline from current levels, and in general, the more recent the forecast the lower the projected production figures. *

The extent to which any of these forecasts are borne out depends on petroleum reserves, recovery factors, and the rate at which resources are discovered. The following analysis examines each of these factors.

At the end of 1978, U.S. proved crude oil reserves stood at 27.8 billion bbl. Typically, as exploration and development work yields greater information on a field, inventories of proved reserves will change, and estimates of additional oil include 4 billion bbl of indicated reserves and 23 billion bbl of inferred reserves. The importance of these potential additions to proved reserves is their near-term availability (1 to 3 years).

Table 9.—Forecasts of U.S. Conventional Liquid Petroleum Production
(millions of barrels per day)

	Energy Information Agency/ DOE 1978	Petroleum Industry Research Foundation 1978	EXXON 1978	CIA 1978	Shell 1978
1980. .	NA	9.8	9.6	10.4	9.8
1985. .	10.8	10.3	8.5	10.2	9.7
1990. .	10.4	10.4	7.2	10.3	9.9

NA = Not available.
[a]Including natural gas liqulds.
SOURCE: Office of Technology Assessment

*These estimates may not fully reflect more recent large world oil price increases and the President's decision to deregulate domestic oil production,

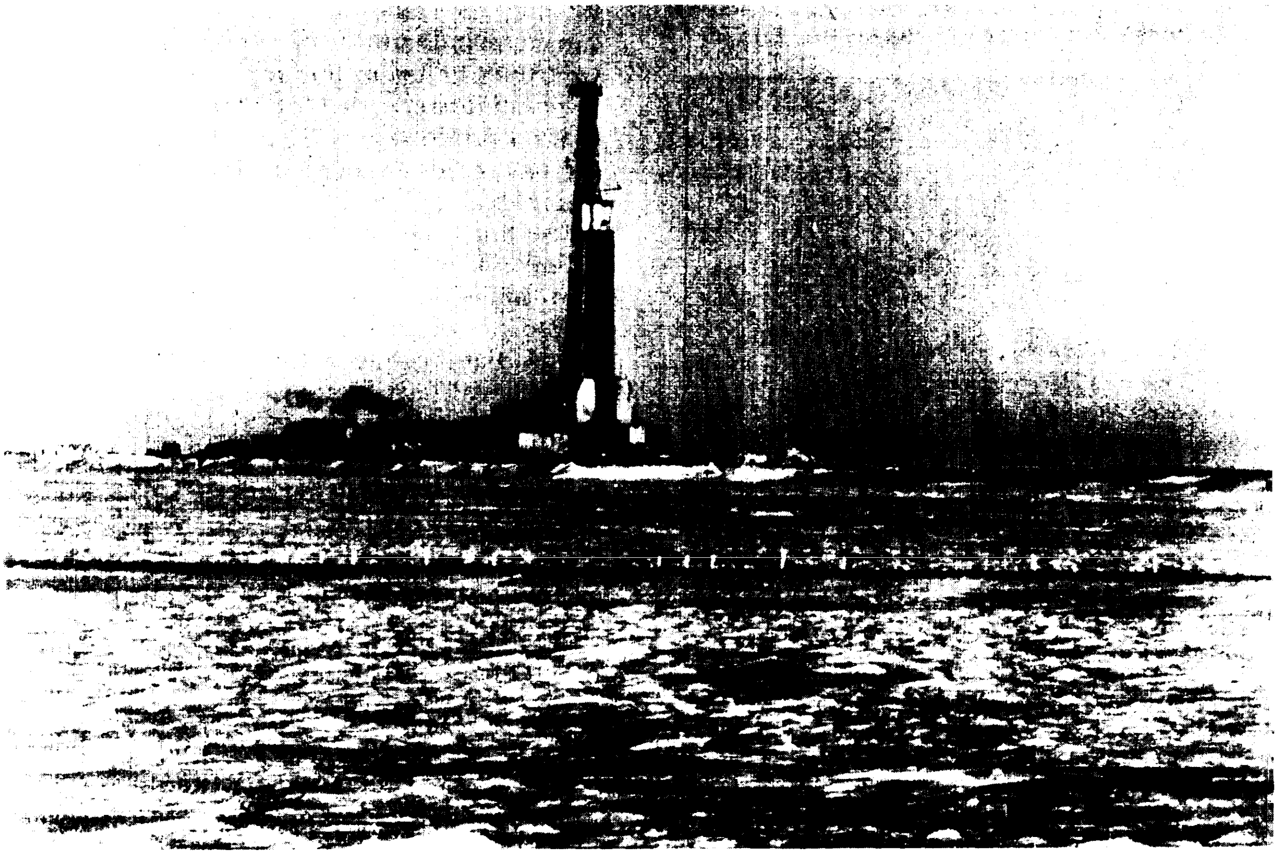


Photo credit Courtesy of American Gas Association

Alaska's North Slope contains new reserves of natural gas. At Prudhoe Bay, this rig is typical of initial exploratory and production efforts

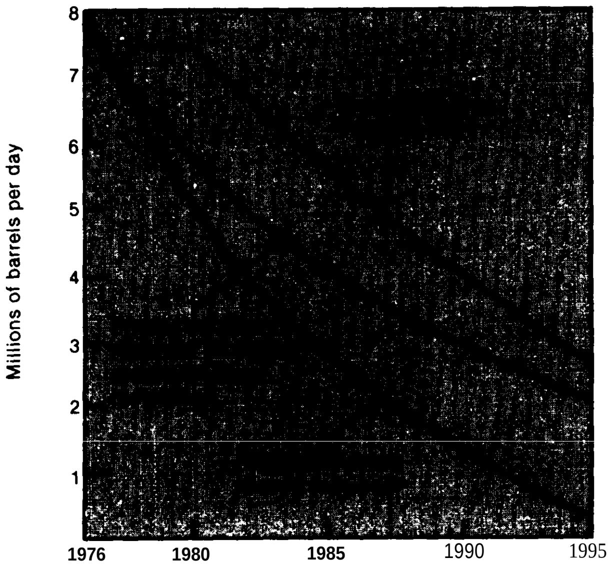
In the lower 48 States, annual production has exceeded additions to reserves since **1970.** Also, as indicated in figure 3, the addition of Prudhoe Bay reserves will permit only a temporary increase in production, after which North Slope's contribution will be insufficient to offset the decline in older producing fields. The extent to which production can be maintained or increased depends on the existence and availability of additional reserves represented by EOR and new discoveries.

Primary oil recovery takes advantage of the natural flow of oil in a reservoir to a producing well, and the application of secondary recovery techniques, water flooding and gas injection, increases the proportion of oil-in-place that can be recovered and accounts for approximately 50 percent of the current U.S. oil production discussed above. These established techniques leave significant quantities of oil in the ground, and the future availability of this remaining oil depends on the development and application of EOR technology, including thermal, chemical, and miscible processes.

Predictions of the quantity of oil to be recovered by enhanced recovery technology and potential production rates are beset with uncertainty. While interest in EOR is longstanding, most of the processes, with the exception of steam injection, remain unproved. Nevertheless, the results of three production estimates appear in table 10, reflecting varying assumptions about future price and process performance.

Further additions to production will have to come from new discoveries, and estimates of

Figure 3.—Projected Oil Production by Conventional Methods From Known U.S. Reservoirs, 1976-95



NOTE: The decline curves for proved reserves do not include enhanced oil recoveries recorded within these categories.

SOURCES: [a]Federal Energy Admintstration, *National Energy Outlook,* 1976.
[b]us, Geological Survey, *Circular* 725, 1975.
[c]American petroleum Institute, *Reserves* of *Crude 0il, Natural Gas Liquids, and Natural Gas m the u.S. and Canada* as of *December 30, 1975,* Lewin & Associates, Inc., for Federal Energy Administration, *Decline Curve Analysls, 1976.*

Table 10.—Estimated Potential Production From Enhanced Recovery (millions of barrels per day, $10-$25/barrel[a])

	OTA[b]	Lewin[c]	NPC[d]
Poor process performance			
1985	.4- .9	.5- .7	.4-1.0
1990	.5-1.8	.5- .9	.8-1.9
1995	.5-2.3	.5-1.0	.8-1.9
High **process** performance			
1985	.5-1.3	1.7-2.5	1.6-2.3
1990	1.1-2.3	2.6-4.3	2.9-3.9
1995	1.7-6.0	2.8-4.5	3.3-4.6

[a]1976 dollars.
[b]Enhanced 01/ *Recovery Potential m the United States,* Office of Technology Assessment, 1978.
[c]Research and *Development in Enhanced Oil Recovery, Lewin and Associates, 1976.*
[d]*Enhanced 01/ Recovery,* National Petroleum Council, 1976.

undiscovered resources vary widely, converging in recent years around a figure of 60 to 100 billion bbl (figure 4). Recent exploration results in south Alaska and the Baltimore Canyon generally confirm the downward trend. Since undiscovered resources, to the extent that they exist, must be found and developed before they can contribute to U.S. oil supply, their potential contribution lies in the longer term, and most forecasts assume that by 1990, 25 percent of U.S. oil production will have to come from reserves not yet discovered. Since 1970, 10.8 billion bbl of oil have been discovered in new fields, but if Prudhoe Bay is excluded only 1.0 billion bbl of this category of discovery have been added to reserves in the entire **1970-7?** period. If undiscovered resources are to contribute significantly to U.S. oil supply, the finding rate will have to increase.

Unconventional domestic oil and gas sources

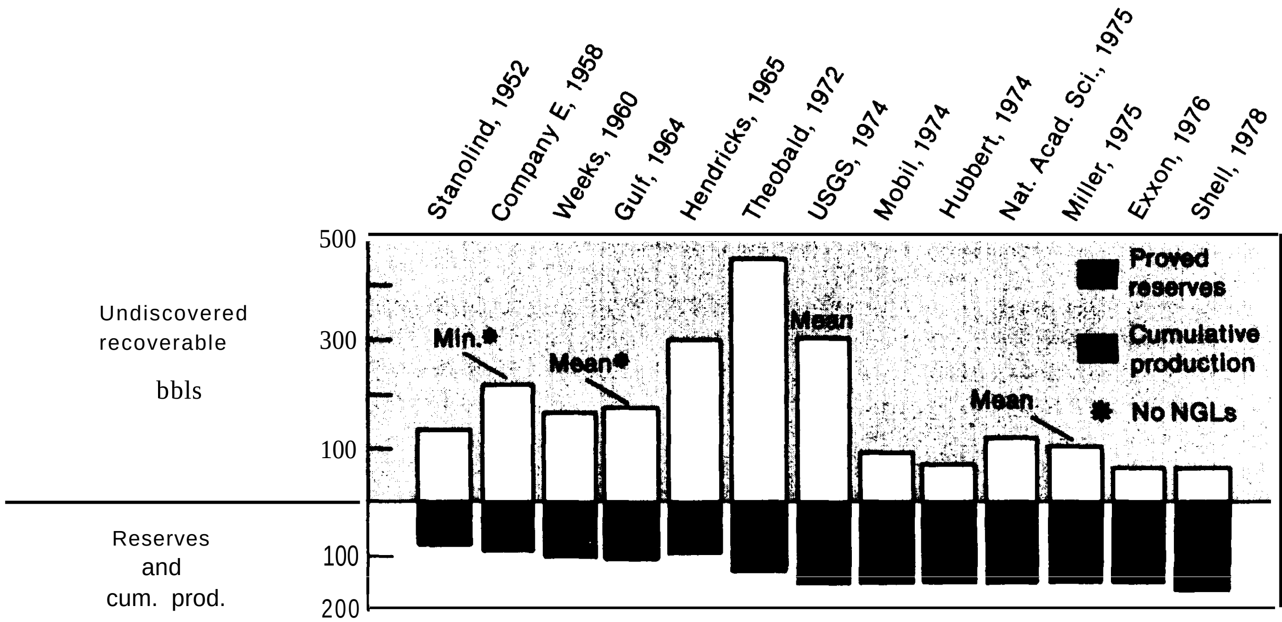
In addition to conventional supplies, oil and gas may be available from other sources including unconventional gas, synthetic fuels from coal, and oil shale. This section evaluates these potential sources.

UNCONVENTIONAL GAS

In addition to conventional natural gas, significant quantities of methane are found in Devonian shales of the Appalachian Basin, low-permeability formations in the Western and Northwestern United States, coal seams in the Eastern and Western United States, and geopressured aquifers located primarily near the coast of Louisiana and Texas. Although gas is known to be present in each of these locations, its extent and commercial recoverability are uncertain. Nevertheless, for the purposes of this analysis, the projections by Lewin and Associates presented in figure 5 are representative of a reasonable range of expectations. The contributions of individual resource categories appear in table 11, based on varying technology and price assumptions. The President's 1979 energy message suggests that 1990 unconventional gas production could be between 1 and 2 Tcf/yr.

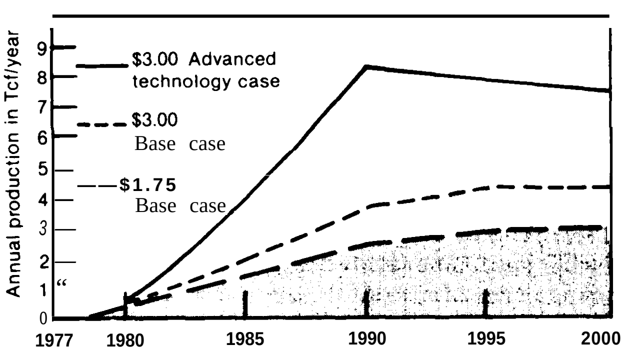
Devonian shales are low-permeability, sedimentary rocks present throughout an area of 210,000 square miles stretching from New York to Alabama. The low permeability of the shale restricts gas production to very slow rates, albeit for long periods of time, and requires artificial stimulation to enhance recovery. Thus, while the total resource base is large, the recov-

Figure 4.—Comparative Estimates of Undiscovered Recoverable Resources of Crude Oil and Natural Gas Liquids (NGLs) in the United States as of Date of Estimate



SOURCE: Charles Masters, "Recent Estimates of U.S. Oil and Gas Resource Potential," U.S. Geological Survey, Open File Report 79-236, 1976.

Figure 5. —Annual Production From Unconventional Sources to the Year 2000 at $1.75 and $3.00/Mcf (except geopressured aquifers)



SOURCE. Lewin and Associates, *Enhanced Recovery of Unconventional Gas,* February 1978

erable resource may be no more than 1 to 10 percent of the gas-in-place. Estimates of recoverable resources range from 3 to 285 Tcf, and studies by OTA[1] and Lewin and Associates[2] agree that production is unlikely to reach 1 Tcf in the next 20 years.

Natural gas is also present in tight basins of low-permeability sandstone, siltstone, and chalk formations located primarily in the Western United States, the northern Great Plains, and parts of Texas and Louisiana. Although the gas in these formations cannot be recovered economically using conventional technology, it may contribute about 1 Tcf to U.S. annual gas production already and appears to hold the greatest near-term potential for contributing significantly to U.S. gas supply, depending on progress in resource characterization, stimulation technology, and higher gas prices. Estimates of total gas-in-place for tight basins range from 400 to 1,200 Tcf. In some places, recoverability may approach 70 to 80 percent, but in most, recoverability will be in the 40- to 50-percent range. At $3.00 (1977) per Mcf, production could reach 7 to 8 Tcf/yr in the 1990's given technological advances from Federal and industry R&D efforts.

Methane in coal mines constitutes a major safety hazard, and research in the United States

[1]Gas *Potential From Devonian Shales of the Appalachian Basin* (Washington, D.C.: Office of Technology Assessment, November 1977).

[2]Lewin and Associates, *Enhanced Recovery of Unconventional Gas,* October 1978.

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Table 1 1.—Annual Production From Unconventional Sources to the Year 2000 at $1.75 and $3.00/Mcf[a] (trillion cubic feet)

	1985			1990			2000		
	$1.75	$3.00	$3.00 Advanced	$1.75	$3.00	$3.00 Advanced	$1.75	$3.00	$3.00 Advanced
Devonian shale	.05	.1	.3	.1	.3	.6	.04	.3	.5
Tight gas	1.2	1.8	3.8	2.2	3.2	7.7	2.7	4.0	7.0
Coalbeds	.02	.02	.02	.04	.05	.05	.05	.07	.08
Geopressured aquifers				(Uncertain)					(I-2?)
Total	1.3	1.9	4.1	2.3	3.6	8.4	2.8	4.4	9.0?

[a]1977 constant dollars.
SOURCE: Data from Lewin and Associates, *Enhanced Recovery of* Unconventional Gas, October 1978.

has concentrated on disposing of the gas. However, several European countries—notably the United Kingdom, Belgium, the Netherlands, and West Germany—have recovered and utilized methane from coal seams as a fuel. In the period 1971-75, 200 bituminous coal mines emitted about 80 Bcf/yr, mostly in the Appalachian region. Further development of methane recovery from minable coal is hampered by difficulties of resource definition, economic uncertainties and high costs, institutional questions involving ownership of the gas, and conflicting economic interests of mine operators and gas producers. In spite of these problems, a small amount of gas, about .05 Tcf/yr, could be produced from mines in the Appalachian Basin by 1990. Recovery of an additional but uncertain small amount of gas may be possible from coalbeds that are too deep or thin to sustain mining.

Geopressured aquifers contain methane dissolved in water trapped at higher than normal pressures in sedimentary deposits underlying a large portion of the northern shorelines of the Gulf of Mexico. Estimates of gas-in-place vary widely reflecting geological uncertainty and inconsistent analytical techniques. Also, the recoverability of natural gas depends on the amount of water that can be produced by wells tapping these reservoirs, and the requirement of high flow rates limits the number of geopressured aquifers that might be suitable for recovery of methane. The economics of natural gas recovery from geopressured aquifers might be improved by the simultaneous exploitation of hydraulic and geothermal energy. However, water production may be limited by declining pressure to about 2 to 5 percent of a reservoir's capacity over a 30-year period. Institutional and environmental constraints on the recoverability of natural gas from geopressured aquifers include: questions of ownership of the gas, possible land subsidence problems, and problems of water disposal. Less than 5 percent of the gas-in-place may be recoverable even assuming favorable reservoir properties and high methane extraction efficiency, and estimates of recoverable resources range from **42** to 1,146 Tcf. Although Lewin and Associates considered the uncertainties too great to forecast production potential, other sources indicate that geopressured aquifers may yield 1 to **2** Tcf/yr of natural gas by 1995-2000, assuming gas prices of $3.00 to $4.50/Mcf (1977 dollars).

SYNTHETIC FUELS FROM COAL

Coal is the Nation's most abundant fossil energy resource, and coal conversion technology is not new. Gas from coal was distributed as town gas in the United States before the advent of an extensive natural gas pipeline network. Coal liquefaction processes are also well-known. Germany produced synthetic oil from coal in the 1930's and South Africa currently produces coal liquids on a limited scale. Nevertheless, coal conversion does not overcome all of the safety and environmental problems associated with conventional coal use and has yet to result in oil or gas that is competitive with alternative sources in terms of price. Further development may improve the efficiency of individual processes and the economics of coal conversion generally, but only in time.

Estimates of potential coal gas production have been repeatedly scaled down. In 1973, the Federal Power Commission (FPC) National Gas Survey estimated 1985 production at 0.7 to 1.9

Tcf. By 1975, FPC announced that the lower end of the range appeared more realistic. Other projections of coal gas production (table 12) agree that coal gasification's most significant contribution to U.S. energy supply will probably be after 1990. Even the realization of these forecasts would require Government incentives, advanced technology, and possibly some relaxation in environmental regulations.

Coal liquefaction is presently thermally inefficient and costly. It also poses the same environmental problems as coal mining and introduces some new ones, The promise of significantly greater efficiencies of future liquefaction technologies may make investors reluctant to apply present technology on a large scale. Given long leadtimes associated with the development of improved technology, high plant costs, and heavy capital investments, the need to scale-up pilot plants to commercial size, greater interest in oil exploration and enhanced recovery on the part of the oil companies, and water availability problems, rapid development of a substantial synthetic fuel industry is not anticipated. AI-though the President's July 1979 energy message suggested that gas and liquids from coal could contribute between 1.0 and 1.5 MMbbl/d to domestic fuel supplies in 1990 at a cost of $38 bbl, recent forecasts, shown in table 13, indicate that production will be significantly less than this amount, at least without massive Government participation.

OIL SHALE

Oil shales are fine-grained sedimentary rocks containing significant quantities of an organic material, which, when heated, yields gas, residual carbon, and a highly viscous liquid oil product. With the addition of hydrogen, shale oil is upgraded to become a synthetic crude feedstock, which can be refined to produce conventional fuels. While oil shale resources are widespread throughout the United States, attention has focused on the extensive and rich deposits in the Green River formation of Colorado, Utah, and Wyoming. Although estimates of shale oil resources recoverable with currently available mining technology and aboveground processing are in terms of billions of barrels, potential large-scale shale oil production will be constrained by environmental considerations, water availability, construction logistics, Federal leasing policies, land title conflicts, leadtimes needed to scale-up and construct commercial plants, and the marginal economics of shale oil vis-a-vis natural crude oil. Estimates of potential shale oil production have been consistently scaled down since 1974 (see table 14).

Table 12.—Projections of Coal Gas Production
(trillion cubic feet)

	1985	1990	1995	2000
American Gas Association (1977)	.1	.6	1.8	3.3
Department of the Interior (1975)	.4	N/A	N/A	4.7
Shell Oil Company (1978)	.6-.7	1.4	N/A	N/A
Frost and Sullivan (1976)	.2	.6	N/A	N/A
Congressional Research Service (1978)	N/A	.3-.5	N/A	N/A
EXXON (1978)	.5	.7	N/A	N/A

N/A = Not available
SOURCE Off Ice of Technology Assessment

Table 13.—Potential Syncrude Production From Coal
(million of barrels per day)

	1985	1990	1995	2000
DOE	.09	.5	1.5	4.0
Shell	.04	.3	N/A	N/A
NPC	.08-.9	N/A	N/A	N/A
EXXON	—	.1	N/A	N/A

N/A = Not available.
SOURCE: Off Ice of Technology Assessment

Table 14.—Shale Oil Production
(thousands of barrels per day)

	1980	1985	1990
Project Independence (1974)	50-100	250-1,000	450-1,600
Synfuels interagency task force	NA	100-830	NA
Shell (1978)	0	40	300
EXXON (1978)	0	0	100
President Carter (July 1979)	NA	NA	400

NA = Not available.
SOURCE Office of Technology Assessment

Canada and Mexico

Pipeline imports from neighboring countries in North America represent another potential source to meet projected demand for gas and oil. Under present Canadian policy, which may change in the future, gas exports to the United States would increase from a present level of 1 Tcf to a peak of 1.8 Tcf before declining to about 0.6 Tcf/yr by 1990, reflecting depletion of reserves and a policy of self-reliance. Mexico could have 0.7 to 1.2 Tcf/yr of gas available for export by that time to make up for reduced supplies from Canada, depending on how attractive sales to the United States are compared to domestic consumption. Prospective oil imports from these two nations will not alter the situation. Mexico could increase petroleum exports as much as 0.5 MMbbl/d by 1990 if markets are found for associated gas, but under official Mexican policy, the United States would receive no more than 60 percent of this amount. Also, Canadian production is not as likely to increase, and given domestic requirements, exports will probably be small in volume, interruptible if Canadian demand requires, and tied to exchange agreements. Selling to the United States at substantially less than competing fuel prices in the world market is not in the interest of either country.

Canada

Throughout the decade of the 1960's and into the early 1970's, Canada was a major energy supplier to the United States. By 1970, the United States was importing 760,000 bbl/d of liquid petroleum from Canada, and in 1978 the United States purchased approximately 1.0 Tcf of Canadian gas,

In the early 1970's however, a deteriorating domestic resource position, higher international oil prices, and concern with the security of foreign oil supplies led Canada to adopt a policy of self-reliance which was reaffirmed by the recent conservative government.

Balanced against the self-reliance policy and arguing in favor of Canadian energy exports are domestic economic and political considerations. Energy resources are concentrated in western Canada, and the provincial governments exercise a great deal of power over their resources. Western provinces, eager to encourage further exploration and development and concerned with controlled domestic prices, favor exports as a means of earning greater revenue. The quid pro quo for lower domestic energy prices is often some level of allowable exports. Finally, given the distances involved in moving western resources to eastern markets, economics often favor exports to closer U.S. markets, since payments for crude imports for eastern Canada are more than offset by earnings on western exports.

Generally, only oil and gas supplies surplus to Canadian needs will be available for export. In assessing Canada's energy potential, one must rely heavily on the projections prepared by Canada's National Energy Board (NEB), which is responsible for forecasting Canadian energy supply and requirements and for recommending export policy for Government approval. Thus, projections from this source have a major impact on the volumes available for sales to the United States quite apart from their technical validity.

Higher Canadian gas prices have led to expanded drilling activity in recent years, and a decline in proved reserves in **1972** and 1973 was followed by increases beginning in 1974. The NEB gas production capability forecast for conventional areas (table 15) is based on established reserves, historic finding rates and reserves-to-production ratios, and estimated leadtimes for the construction of gas delivery systems. While the frontier areas appear promising in terms of gas resources, NEB does not include potential production from them in its forecast of producing capability, since no delivery system has been built or approved to bring frontier gas to market.

NEB has devised three tests all of which must be satisfied if new export licenses are to be granted, in order to protect Canadian requirements. NEB anticipates that gas exports already contracted will be fulfilled, and it recently approved an additional total of 3.75 Tcf of gas for

Table 15.-Canadian Gas Potential
(trillion cubic feet per year)

Year	Producing capability, conventional areas	Total Canadian demand
1980	4.1	1.9
1985	4.6	2.4
1990	3.8	2.6
1995	3.0	2.9
2000	2.3	3.3

SOURCE. Canadian National Energy Board, November 1979.

export to the United States in the period 1980-87. Under the new decision, total exports are expected to reach a peak of about 1.8 Tcf/yr in 1982, declining to about 1.0 Tcf by 1987. After that time, only gas under existing contracts would continue to be delivered, at volumes declining rapidly to 0.6 Tcf/yr in 1990 and zero shortly thereafter, unless new exportable surpluses are identified.

The NEB projections of exportable surplus are conservative in that estimated demand is high and supply is low. Demand is inflated by the inclusion of eastern Canadian markets, while hearings still are underway to determine the economic advisability of expanding the transmission system beyond Montreal. Supply excludes the frontier areas, even though the Alaskan highway gasline and the proposed Dempster lateral could bring Mackenzie Delta-Beaufort Sea gas to market by the mid-1980's. Some Arctic Islands gas might also be available for export to the U.S. east coast if a proposed LNG project is approved.

The price of Canadian gas exports is not tied to the price of any particular oil product, but instead to the cost of alternative fuels in selected U.S. markets and the cost of imported oil in Toronto. A new official price of $4.47/Mcf took effect on February 17, 1980.

Potential Canadian liquid hydrocarbon supply derives from conventional producing areas, oil sands, and frontier areas. The conventional areas include those already producing oil. Proved reserves total about 6 billion bbl, and Alberta and Saskatchewan account for approximately 95 percent of the total. Since 1970, annual production has exceeded yearly additions to reserves. As in the United States, Canadian production potential depends on the existence of additional resources and the rate at which they are found and developed. NEB estimates that 4.9 billion bbl of reserves might be added from enhanced recovery, revisions and extensions of known fields, and new discoveries. Nevertheless, production in conventional producing areas is forecast to decline through 1995.

While the resource potential of heavy oil and oil sands deposits is large, technological and economic considerations will slow development. NEB projects 155,000 bbl/d of oil sands production in 1980, increasing to 255,000 bbl/d in 1985 and 755,0OO bbl/d in 1995. Although representing over 50 percent of prospective Canadian oil supply in 1995, oil sands production will merely offset the decline in production anticipated for conventional producing areas.

The frontier areas—the Mackenzie Delta-Beaufort Sea region, the Arctic Islands, the Labrador Shelf, and the Atlantic Shelf South—are characterized by their distance from markets and harsh environments. The existence of oil resources in these regions and the economic attractiveness of production are both uncertain. Important recent discoveries have involved natural gas more often than oil. Even if large discoveries occur in the next few years, Ieadtimes associated with production in hostile environments are long. Indeed, NEB does not anticipate any production from the frontier regions at least until 1995.

NEB oil demand and base case supply forecasts project imports of 300,000 bbl/d in 1980, 700,000 bbl/d in 1985, and 900,000 bbl/d in 1990 and 1995, assuming no exports. Given the Canadian oil supply/demand situation and the official policy of self-reliance, large volumes of Canadian crude are unlikely to be sold to the United States. Small quantities may be available as further development of indigenous resources requires temporary access to the larger U.S. markets, and considerations of logistics, crude quality, and refining capacity also may argue for some exports to the United States. However, under Government policy, light crude exports are to be phased out completely by 1981, and heavy crude exports are determined quarterly.

Mexico

Estimates of Mexico's resource and production potential are uncertain. Since the 1938 ejection of foreign oil companies and the nationalization of the petroleum industry, Mexican hydrocarbon development has been the sole responsibility of the national oil company, PEMEX, which considers the information necessary for independent resource and production estimates to be proprietary. Moreover, the PEMEX monopoly may constrain petroleum development. While the company has a long operating history and a core of highly skilled personnel, the scale of present developments may strain its manpower and equipment resources. The strength of nationalist sentiment and the petroleum workers' union militate against heavy reliance on foreigners, although some have been hired for work in highly technical areas. Finally, uncertainty as to Mexico's potential relates also to the fact that only 10 percent of Mexico's potential hydrocarbon-bearing areas have been explored.

Domestic and international politics are also important in determining Mexico's production potential and export policy. A domestic concern is that oil revenues should be consistent with Mexico's ability to absorb the added income for balanced economic growth without major social and political dislocations. Mexicans are also convinced that their oil and gas resources are to be exploited for their own benefit and not prematurely exhausted for the benefit of foreigners. Finally, Mexico can avoid increasing dependence on the United States by diversifying its export markets.

On the other hand, transportation costs are lower to the United States than to other markets, especially for gas, and U.S. reliance on Mexican fuels could counter Mexican dependence on the United States as a major purchaser. Also, increased production provides the opportunity to gain international prestige as a major oil exporter and to alleviate pressing internal economic problems and a heavy foreign debt burden. While resources and domestic demand place outer limits on availability of imports from Mexico, political and economic factors will determine the actuality. However, the available evidence suggests that while Mexico may become a major hydrocarbon exporter, that nation alone does not represent an answer to U.S. energy problems.

Mexico's official estimates of proved oil and gas reserves have increased steadily from 5.8 billion bbl oil equivalent at the end of 1974 to 40.2 billion bbl as of January 1979. Depending on assumed associated gas/oil ratios and the fields included in the estimates, this figure could include 26 to 32 billion bbl of oil and 45 to 80 Tcf of gas. In addition, PEMEX estimates 44.6 billion bbl oil equivalent of probable reserves (34.4 billion bbl of liquids and 72,4 Tcf gas) and 200 billion bbl of potential hydrocarbon resources. The resource base appears sufficient to sustain increased levels of production.

Mexican oil production has increased rapidly from 0.5 MMbbl/d in 1973 to over 1.4 MMbbl/d in 1978, and gas production reached 0.9 Tcf in 1978. PEMEX development plans call for oil production of 2.25 MMbbl/d and gas production of 1.5 Tcf/yr by the early 1980's. While official plans do not extend beyond the early 1980's, available forecasts suggest that, on the basis of resources alone, Mexico could continue to increase oil production after that time, but unofficial reports suggest that oil production will be limited to less than 3.8 MMbbl/d.

In a 1978 study,[3] the Congressional Research Service (CRS) developed two cases for potential Mexican oil and gas production. Case I assumed that gas would not be exported and oil production would be constrained by the inability to utilize associated gas. Case II assumed that oil production would not be constrained, and gas would be available for export. In a later study,[4] Lewin and Associates developed three scenarios of Mexico's oil and gas potential. Their base case assumed development of already discovered fields, and alternative cases included assumptions regarding future exploratory success. CRS Case I projects somewhat lower levels of oil production than does the Lewin base case assess-

[3] Congressional Research Service, *Mexico's Oil and Gas Policy: An Analysis* (Senate Foreign Relations Committee and Joint Economic Committee, December 1978).

[4] Lewin and Associates, *The Potential of Mexican Oil and Gas*, May 1979.

ment, reflecting in part a lower resource estimate. However, both studies note that even their lowest cases are likely to strain Mexico's technical and managerial capabilities, and in the light of expected 1979 production estimates of 1.5 MMbbl/d official targets may be missed. Interviews with industry sources also suggest that Mexican oil production is more likely to resemble CRS Case I, with the Lewin base case an upside possibility.

With regard to gas production potential, Lewin's figures are lower, particularly after 1985, reflecting lower associated gas-oil ratios than those used in the CRS study. The high gas-oil ratios of 1,200 to 2,000 cf/bbl prevailing in the Reforma field are not obtained in the fields of Campeche or Chicontepec as CRS assumes, so the Lewin assessment represents a more reasonable range of potential Mexican gas production than the CRS study. However, given the greater likelihood of lower oil production figures than those assumed by Lewin even the base case may prove to be high.

Adding to the uncertainty of export projections are trends in Mexico's domestic energy consumption, in terms of both aggregate level and fuel types, and domestic energy policy still is undefined. For example, the greater use of gas domestically would leave less available for export but might free additional oil for foreign purchasers. Also, oil production may be limited by the ability to export or to utilize associated gas internally.

Based on the preceding analysis of production potential, CRS oil estimates and Lewin gas estimates are assumed to be the most reasonable to derive the potential export 1evels shown in table 16.

The Lewin gas production figures are somewhat overstated, and gas exports to the United States would probably be less than those indicated in the table. Mexico could readily convert enough industries to use gas to absorb 1.5 Tcf annually, thereby precluding gas exports at least in the near term. Presumably, gas could also be exported as LNG, but the return would be quite low, on the order of $0.27/Mcf. Mexico also has some discretion in gas production. The estimates presented above include 0.4 Tcf of production from the Northern, nonassociated gasfields, which could be shut in without constraining oil production. In addition, Mexico might elect to develop oilfields with less or more associated gas depending on domestic needs and export opportunities.

On the other hand, Mexico does have somewhat less than 1 Tcf of gas for export to the United States within a short period of time if the conditions are advantageous. In 1977, six U.S. interstate natural gas companies signed a letter of intent for the purchase of Mexican gas, and a pipeline was to be constructed linking Mexican gasfields with the U.S. gas transmission system in Texas. The entire line from the southern fields to the north was to cost $1 billion and

Table 16.—Mexican Oil and Gas Export Potential

	Oil					Gas		
Year	Production	Domestic demand		Exports		Production	Domestic demand	Exports
	(M Mbbl/d)					(Tcf)		
		1	2	1	2			
1980	2.2	2.2	1.1	1.1	1.5	1.5	.7	.8
1981	2.3	1.1	1.2	1.2	1.1	1.5	.7	.8
1982	2.4	1.1	1.3	1.3	1.1	1.5	.8	.7
1983	2.5	1.2	1.4	1.3	1.2	1.6	.8	.8
1984	2.6	1.2	1.5	1.4	1.1	1.6	.8	.8
1985	2.7	1.2	1.5	1.5	1.2	1.6-1.8	.9	.7-.9
1986	2.8	1.2	1.5	1,6	1.3	1.6-1.9	.9	.7-.9
1987	2.9	1.3	1.6	1.6	1.3	1.7-2.0	1.0	.7-1.0
1988	3.0	1.4	1.8	1.6	1.2	1.7-2.2	1.0	.7-1.2

1 = no gas exports.
2 = with gas exports
SOURCES Congressional Research Service; Lewln and Associates

would have eventually carried 0.7 Tcf/yr to the United States.

The gas deal met domestic opposition in Mexico from the political left and *campesinos*, who resented the land confiscations required to build the pipeline. Moreover, a public debate surrounded the proper rate of exploitation of Mexican hydrocarbon reserves, particularly if the United States was to be the main beneficiary of rapid development.

To secure domestic agreement on gas exports the Mexicans drove a hard bargain, demanding a take-or-pay contract, gas prices tied to distillate fuels delivered in New York harbor ($2.60/Mcf at the time and $3.00/Mcf in May 1979), and the option to lower or halt exports as required by domestic needs. The U.S. Economic Regulatory Administration failed to approve the terms, and the Mexican Government allowed the agreement to lapse.

Intergovernmental negotiations were renewed in 1979 resulting in a limited agreement involving about 0.1 Tcf/yr at $3,625 /Mcf. It now seems that Mexico will make every effort to utilize the gas domestically, and barring a change in political relations, Mexico may be satisfied to free up additional oil for export.

Gas from overseas

Natural gas constitutes 42 percent of the known proven world supply of gaseous and liquid hydrocarbons. While natural gas resources are widely scattered around the globe, the largest proven reserves are in North America and the Persian/Arabian Gulf. The amount of gas that can be dedicated to LNG projects is far less than the total reserves. Most gas, such as that found in Europe, is dedicated to local markets, and other resources are too remote or too small to support a world-scale LNG project. Additional exportable supplies, such as those in Canada and Mexico, are likely to move to consuming markets by pipeline rather than as LNG. Table 17 summarizes, by geographic area, the important LNG export countries and the amount of LNG that might come to the United States from operating, approved, and possible projects.

Algeria is currently the only supplier of LNG to the United States, but as her remaining gas reserves have now been committed to European buyers, additional Algeria-U.S. projects are not likely in the near future. Moreover, the prospect of a higher netback price to the Algerian natural gas wellhead because of the expected

Table 17.—Availability of Foreign LNG to the United States Beginning in the 1980's
(trillion cubic feet per year)

	Operating and approved projects	Exportable surplus as of 12/31/78	Possible projects	
Algeria	0.63	8	—	Existing reserves are committed to Europe.
Nigeria	—	33	0-0.59	Europe a strong competitor. Possible political problems.
Southeast Asia	0.2	41	0.15	Japan a strong competitor.
Western Hemisphere	—	19	0.39	Scattered small potential projects. Four are anticipated including the Arctic Island project from Canada.
Persian/Arabian Gulf	—	231 plus	—	Locational disadvantage relative to Europe and Japan. No projects to United States likely before 1990.
U.S.S.R.	–	439	—	No shipments to United States *like/y* before 1990.
Total	0.83		0.54-1.13	

SOURCE: Jensen Associates, Inc

success of the trans-Mediterranean pipeline, combined with the heavy capital costs of LNG and the apparent concern in Algeria with the allocation of large amounts of capital to hydrocarbon development, raise strong doubts about additional LNG trade with the United States before 1990, However, as is the case of Russian gas, if the U.S. Government were to seek Algerian LNG aggressively and provide substantial financing, additional Algerian LNG is a possibility, most likely from new gas discoveries. Russian LNG trade is possible before 1990 but will also require financing and the encouragement of the U.S. Government. Otherwise, imports of Russian LNG before 1990 seem unlikely.

Gas from additional LNG projects in Southeast Asia is expected to flow mostly to Japan, but Australia may sell perhaps 0,15 Tcf/yr to the United States. Nigeria will probably develop one or two large LNG projects, and the resulting supplies are likely to flow either to Europe or to the United States, or both. Anticipated projects in the Western Hemisphere, principally in Trinidad, Colombia, and Chile could bring LNG to the United States, and a Canadian Arctic Island LNG project may be developed. Projects likely to be approved in the next 5 to 7 years could bring an additional 0.54 to 1.13 Tcf/yr to the United States. The higher figure is less probable because Europe will be a strong competitor for Nigerian LNG. It is also possible that Japan will take all of the LNG that Australia has thus far approved for export.

Worldwide natural gas reserves and exportable surpluses

Estimated proved reserves of natural gas as of the end of 1978 amounted to 2)5575 Tcf, constituting 42 percent of the energy content of the world's combined proved reserves of oil and gas. Since the oil embargo of 1973, worldwide additions to proved gas reserves reported by the Oil and *Gas Journal* have amounted to 55 percent of combined oil and gas additions. Growth in gas reserves should continue, since the lack of a market outlet in many cases has relegated gas discoveries to the noncommercial category, and the amount of gas that has been found or indicated probably substantially exceeds the proved reserve figure.

Despite the magnitude of worldwide reserves, the role of gas in international trade is quite small, and worldwide consumption is less than 30 percent of the total of oil and gas combined. In 1978, international oil trade, primarily in tankers, was at a level of 33.8 MMbbl/d while gas trade was only 2.9 MMbbl/d of oil equivalent, of which only about 470,000 bbl/d moved in LNG tankers instead of pipelines. Thus, despite the major worldwide gas reserve base and optimism about gas discoveries, LNG tanker trade represents only 1.4 percent of oil trade.

The reasons for this disparity involve the high cost of gathering and transporting natural gas compared with oil. Oil valuation almost anywhere in the world can be related through quality differentials and transportation costs to the price of the marker crude, Arab Light f.o.b. Ra's at Tannurah. Gas generally competes with other fuels, predominantly oil, so in determining whether natural gas will be sold in any given location, one estimates the equivalent oil value and determines whether it covers distribution, transportation, gathering, and production of natural gas. If the answer is no, as is often the case, the gas will not be marketed. For example, the U.S. Bureau of Mines estimates that in 1976 over 12 percent of world natural gas production was disposed of by flaring.

Determining the outlook for world LNG trade requires looking beyond the gross numbers representing reserves or production to identify those special combinations of large uncommitted gas reservoirs, geographic location, and political stability that will form a basis for a viable project. Viewed in this light, less than one-third of total world gas reserves (less than one-quarter of free-world reserves) appear favorably situated for international trade.

Gas reserves may be either associated/dissolved or not associated with oil. Production of nonassociated gas is discretionary in the sense that the discovery can be shut-in and not developed until the economic climate is appropriate. Associated/dissolved gas is produced along with

[54] *Oil and Gas Journal,* American Gas Association, Canadian Gas Association, PEMEX.

oil. Unless it can be sold or reinfected for EOR or for later withdrawal, it has to be flared. Some associated gas is contained in large gas caps in oilfields where its premature extraction will deplete reservoir pressures and reduce ultimate recovery of the oil. While one usually cannot delay production of dissolved gas, one often cannot practically accelerate the production from associated gas caps. An estimated 28 percent of world gas reserves are associated/dissolved while the remainder are nonassociated.

While the flaring of dissolved gas often focuses attention on the potential availability of "free" gas as a basis for international trade, the costs of gathering and compressing it, together with difficulties of controlling its rate of production, often make it less desirable as a basis for export projects than large, high-pressure, nonassociated gasfields. With the exception of projects in Libya and Abu Dhabi, all LNG projects to date have been based on nonassociated rather than associated gas.

A gasfield's location relative to markets is important, as mentioned earlier, because of the high cost of transportation. Figure 6 shows estimates of world proved gas reserves as of December 1978, subdivided both geographically and by political grouping, including proportions of associated and nonassociated gas. Political categories include the developed world as the Organization for Economic Cooperation and Development (OECD), the Sine-Soviet countries, and the less developed nations subdivided into OPEC and NOPEC (or non-OPEC) groups. In this table, the U.S.S.R. appears in Europe, despite the fact that large portions of its substantial gas reserves are physically located in Asia. Note that the role of OPEC is much less dominant in gas than in oil. Whereas OPEC constitutes 77 percent of total world proved oil reserves and 90 percent of free-world oil reserves, it represents only 38 percent of world gas reserves and 60 percent of free-world gas reserves.

Estimates of gas reserves are much less reliable than those for oil. Where gas has no commercial value, either because it will be flared or because the size of the deposit does not justify marketing it, discoveries have often not been included in the figures. The amount of gas that remains to be discovered from future exploration is also very large. Some recent estimates place the undiscovered gas resource base in the vicinity of 6,500 Tcf of natural gas or roughly 2.5 times present proved reserves.[6]

The development of a new outlet for gas reserves, such as a pipeline or LNG project may generate specific field development or even exploration. Proved reserves can therefore increase rapidly to provide a basis for an export project where present estimates do not suggest such a potential. The figures reported for Trinidad, for example, are significantly lower than those which would be required to justify a world-scale export project of 500 MMcf/d or more. However, there is considerable optimism in Trinidad that additional exploration and development will generate more than enough reserves to support such a project.

Without local markets, recovery of dissolved gas is difficult to justify, and flaring is likely to continue. Similarly, many small nonassociated fields are too remote to warrant the gathering and transmission expense of moving the gas to market. Thus, a significant portion of reserves might be considered as noncommercial because they are either inaccessible or likely to be flared.

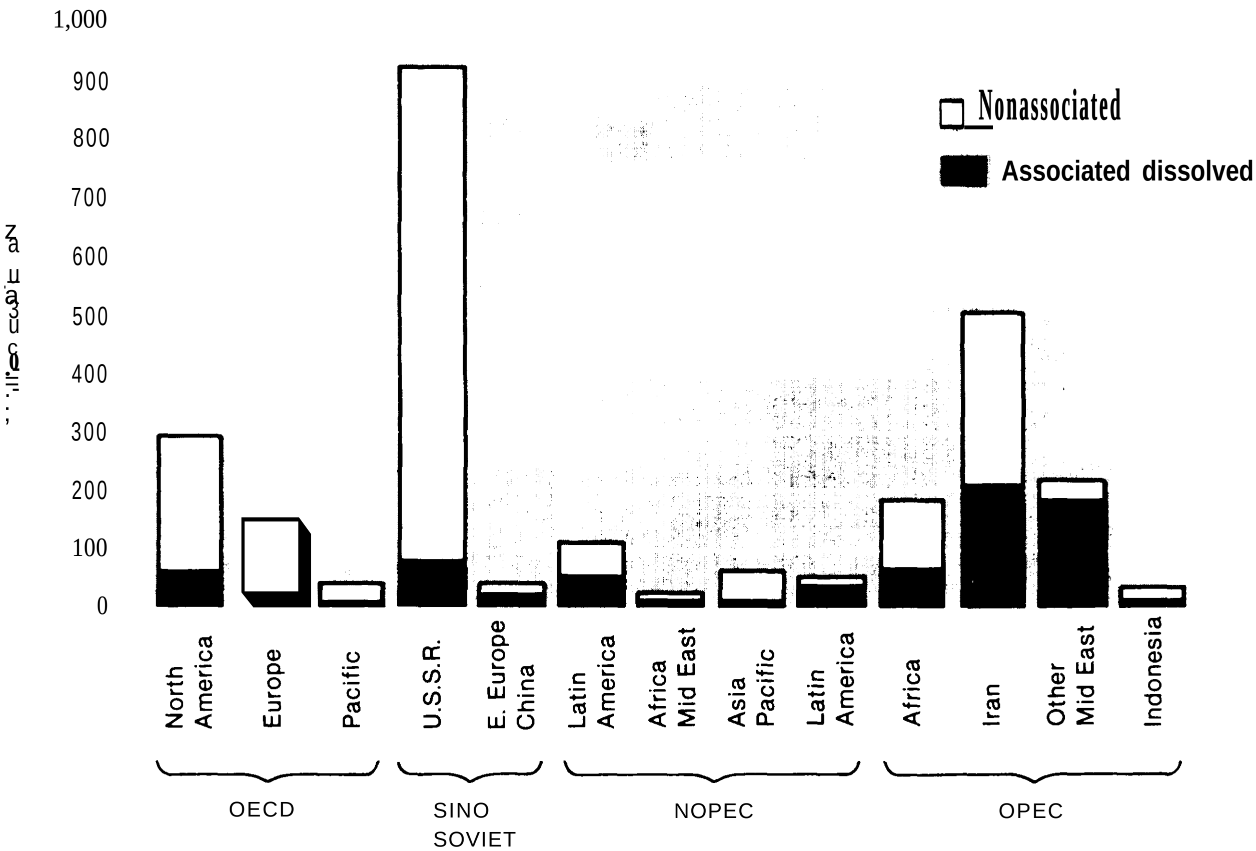
In order to determine the extent to which gas reserves are potentially available to support LNG trade in the future, they have been analyzed country-by-country to determine those potential blocks of reserves that are not presently committed and are large enough to support LNG and pipeline export projects. * The basis of this analysis is the proved reserves figures just mentioned, subdivided into six different categories of commercial status as follows:

1. */accessible or flared:* gas reserves that are too small or remote either to justify recovery of flared gas or full field development of nonassociated gas.
2. *Deferred reserves:* reserves in large gas caps or undergoing gas injection for oil recovery that are unlikely to be committed to markets until future time.

[6] For example, see *Energy Topics, Dec. 5, 1977.*

*For further discussion, see the *Background Reports* volume of this report.

Figure 6.—World Natural Gas Reserves (trillion cubic feet)



SOURCE Jensen Associates, Inc , based on *Oil and Gas Journal,* American Gas Association, Canadian Petroleum Associatlon, and PEMEX Reserve Estimates

3. *Committed to domestic markets:* gas reserves that either are contracted to domestic markets or set aside to assure that domestic requirements will be met. Without detailed information about many such set-asides, a modified Canadian formula, which provides for 30-year coverage of present domestic consumption has been applied.

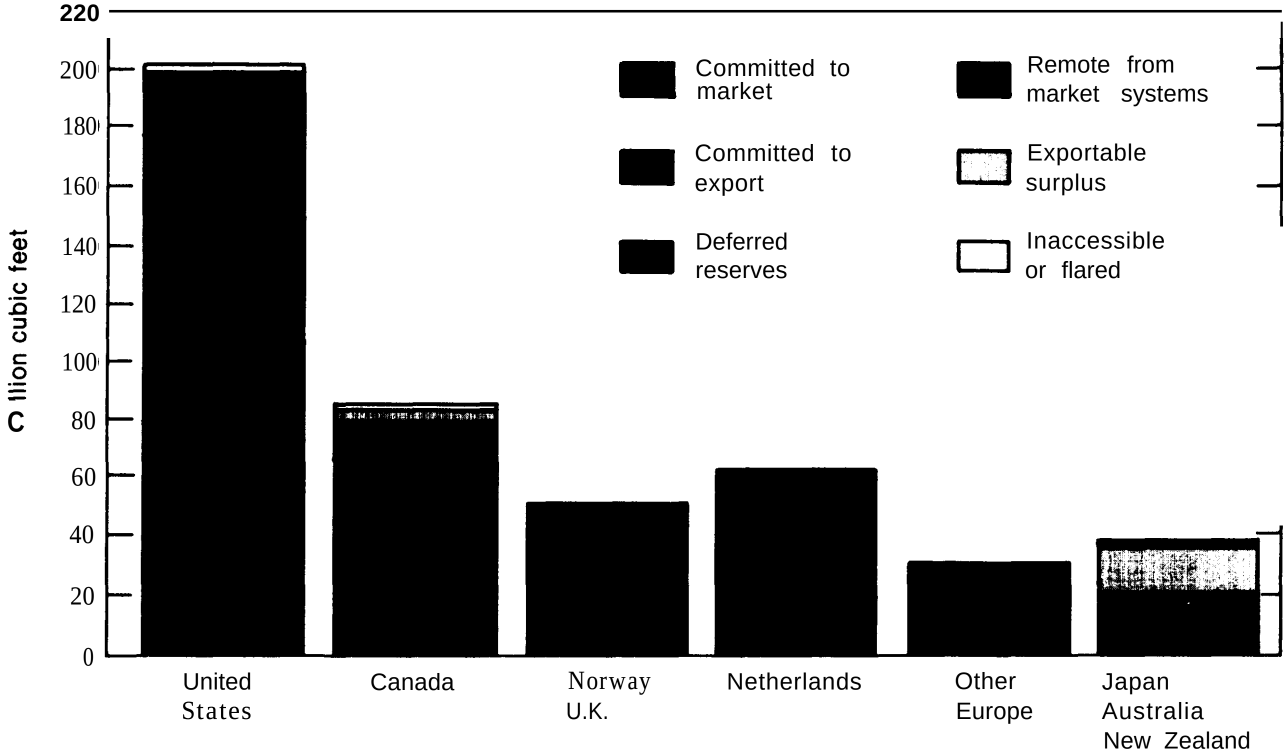
4. *Remote from existing market systems:* gas reserves that are clearly destined for a major industrial market, but whose remoteness from this market raises questions about the feasibility of commercialization. Examples would include North Slope and Arctic Island gas in North America and some North Sea gas reserves in Europe. Some of this gas will prove feasible for commercialization and thus may later belong to the "committed to market" or "exportable surplus" classifications.

5. *Committed to export markets:* gas reserves usually in firm export contracts covering the deliveries over the life of the contract.

6. *Exportable surplus:* blocks of gas reserves that are large enough and well-located enough to support export projects, In a limited number of cases, current national policy suggests that this gas will not be exported and, in other cases, discussions to commit the gas have proceeded to the point where it is no longer available.

Figures 7 through 10 show these market status estimates in somewhat greater detail for the

Figure 7.—Market Status OECD Gas Reserves



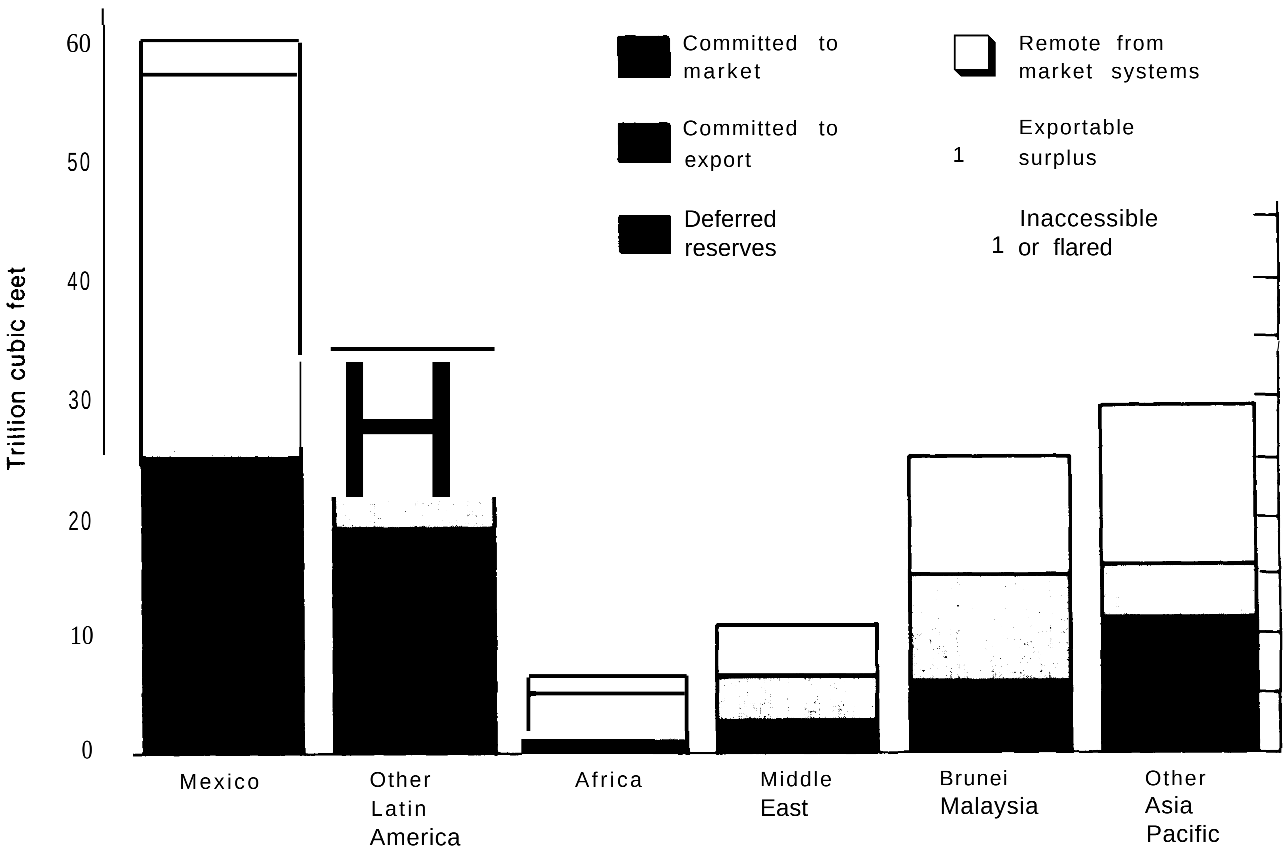
SOURCE: Jensen Associates, Inc.

OECD, NOPEC, OPEC (excluding Iran and Algeria), and for the large gas export areas of the U. S. S. R., Algeria, and Iran. (It is important to note that the scale on each bar chart varies with the relative magnitudes of reserves typical of the group,) An estimated 812 Tcf of world reserves are in the exportable surplus category, representing about 32 percent of the world total. Three-quarters of the exportable surplus is concentrated in the Soviet Union and Iran. The failure of Iran to be able to deliver associated gas to the Soviet Union through the IGAT system during the Iranian revolution and the resulting inability of the Soviet Union to honor some of its export commitments to Europe have focused attention on supply security from these two countries. With Iranian and Russian reserves out of the exportable surplus category, only 7.2 percent of the world proved gas reserves remain. Figure 11 shows where the major exportable volumes are concentrated. About 32 Tcf of reserves worldwide are likely to be exported by pipeline, including the 2 Tcf which NEB in Canada has deemed surplus to Canadian requirements, as well as the 25 Tcf of Mexican gas reserves (consistent with the January 2, 1979, PEMEX gas reserve estimate of 65.1 Tcf proved) which is in excess of Mexican domestic commitments. The U. S. S. R., Iran, and Algeria have all operated or considered both pipeline and LNG export schemes.

U.S.S.R.

Out of the total exportable surplus of 812 Tcf, 635 is located in the U. S. S. R., Iran, and Algeria. The Soviet Union has 35 percent of the world's gas reserves. Although the Soviet reserve estimates are somewhat less conservatively stated than those in much of the rest of the world, including not only proved and probable but some possible resources, they are, nonetheless, impressive in magnitude. Earlier, Russian oil and gas exploration was concentrated in the south near the Black Sea and Caspian Sea. The major

Figure 8.— Market Status NOPEC Gas Reserves

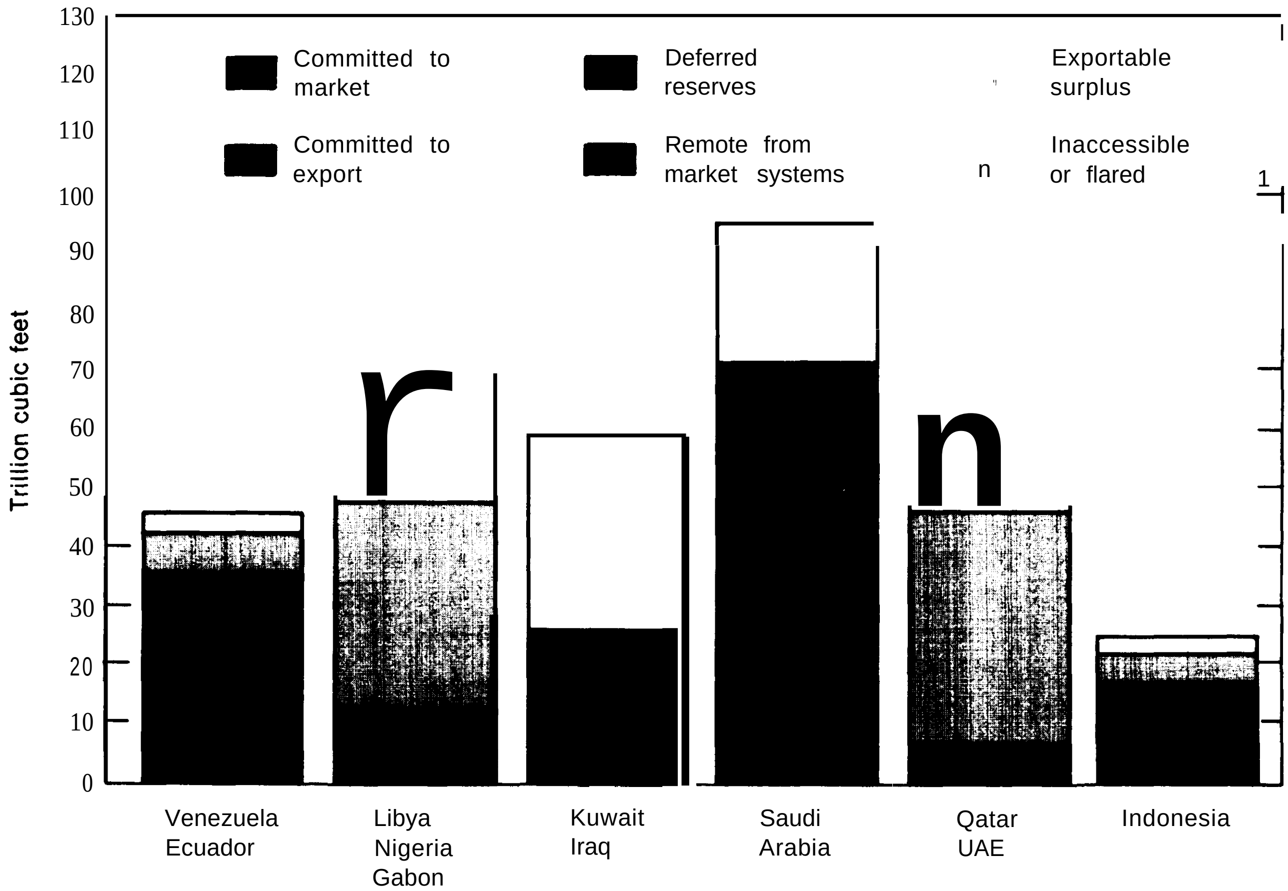


SOURCE Jensen Associates, Inc

gas discoveries of more recent vintage are located in west Siberia, particularly in the giant fields of the Ob Peninsula, such as Urengoy, Yamburg, and Zapolyarnoe. Approximately 75 percent of Russian reserves are concentrated in West Siberia. Areas to the south and west, such as Turkemenistan, Uzbekistan, and the Volga-Urals region, constitute another 20 percent, The rest of the gas is scattered throughout the country in several producing basins.

The Soviet Union currently imports small quantities of gas by pipeline from Afghanistan. It also has been supplementing its more limited southern reserves by importing about 1 billion C/d from Iran through the IGAT- 1 pipeline system, while at the same time delivering 1.45 billion cf/d to West Germany, Italy, and Austria from its northern reserves. While not a formal exchange agreement as IGAT-2 was intended to be, the arrangement has similar effects. Iranian shipments under the IGAT-1 contract ceased during the winter of 1978-79 and have still not returned to contractual levels as of July 1979. Also, the Iranian Government has publicly announced the cancellation of all planning on IGAT-2, which would have delivered an additional 1.65 billion cf/d ultimately to Europe via the Russian exchange route. Since Russian deliveries to Europe were reduced to compensate for the loss of Iranian gas, the question of the future level of European reliance on the very large Soviet gas reserves as well as the reliability of Iran is being reevaluated. While most immediate plans for utilization of Russian gas contemplate pipeline expansions, LNG projects have been discussed both for the U.S. east coast from west Siberia reserves and to the U.S. west coast

Figure 9.—Market Status OPEC Gas Reserves



SOURCE: Jensen Associates, Inc.

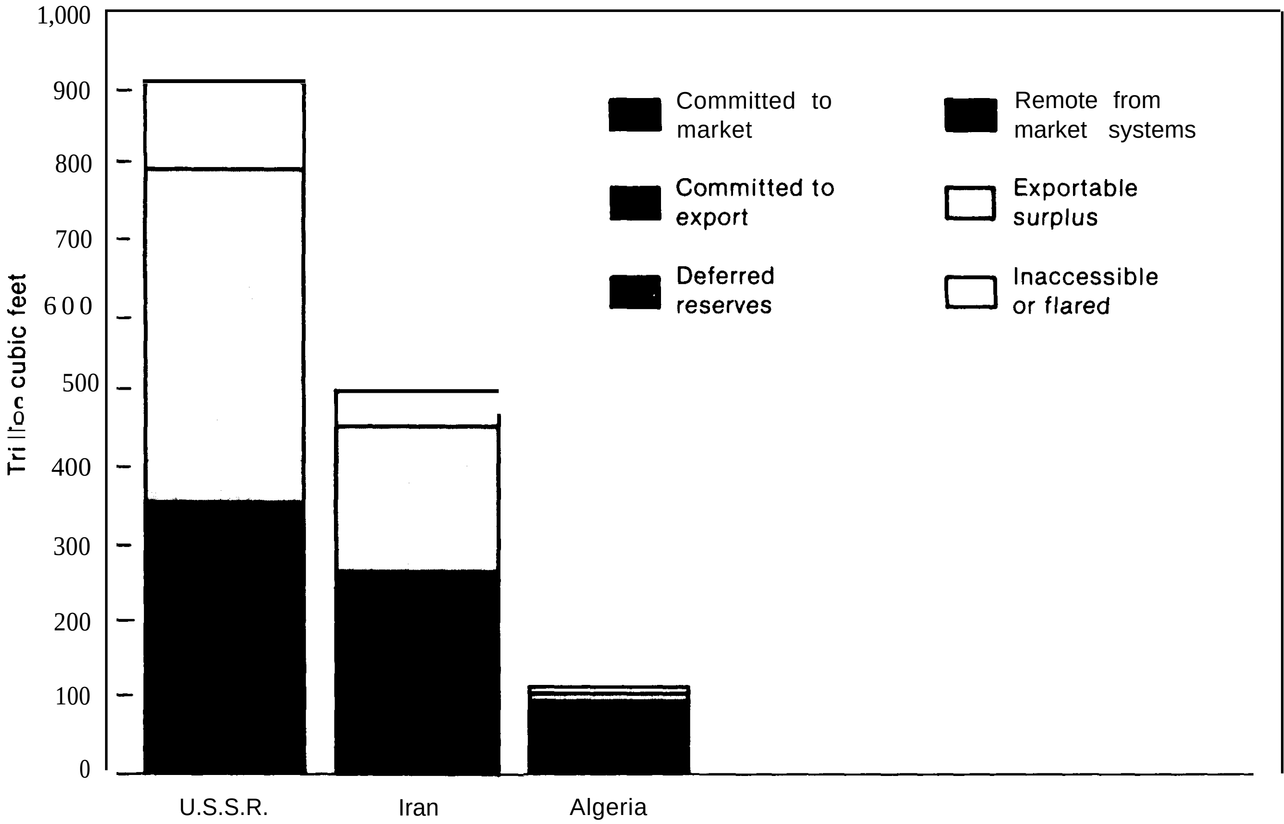
and Japan from the Yakutsk area of eastern Siberia. 'None of these projects appear particularly active at present.

IRAN

Iranian gas reserves are second only to those of the Soviet Union. Approximately 210 Tcf of the 500 Tcf of Iranian gas reserves are associated/dissolved, and a large portion of these are concentrated in the very large gas caps of some of the Khuzestan oilfields. About half of the Iranian gas reserve is contained in very large nonassociated gasfields, both onshore near Kangan and extending out into the central Persian Gulf. Smaller quantities are located near the Straits of Hormuz, around Bandar Abbas, and scattered throughout the country.

Oil recovery in the Khuzestan fields is particularly sensitive to bottom-hole pressure decline. Before the overthrow of the Shah's government, the National Iranian Oil Company was experimenting with a major gas injection program which, if successful, was to be extended to virtually all of the Khuzestan fields. The program, designed to increase oil production, would not only have postponed production from the gas caps but would have reinfected significant quantities of dissolved and nearby nonassociated gas into the oil formations for later recovery. Injecting gas in this way would have deferred production of almost half of the Iranian reserves, so Iran represents the largest single volume in the deferred reserve category worldwide. Iran had also planned to export gas to Europe via the

Figure 10.—Market Status: U. S. S. R., Iran, and Algeria



SOURCE Jensen Associates, Inc.

planned IGAT-2 pipeline and had discussed a large LNG project from the Kangan area to Japan and the United States. The reserves that would have been dedicated to IGAT-2 and the Kangan LNG project would probably have amounted to almost 21 Tcf.

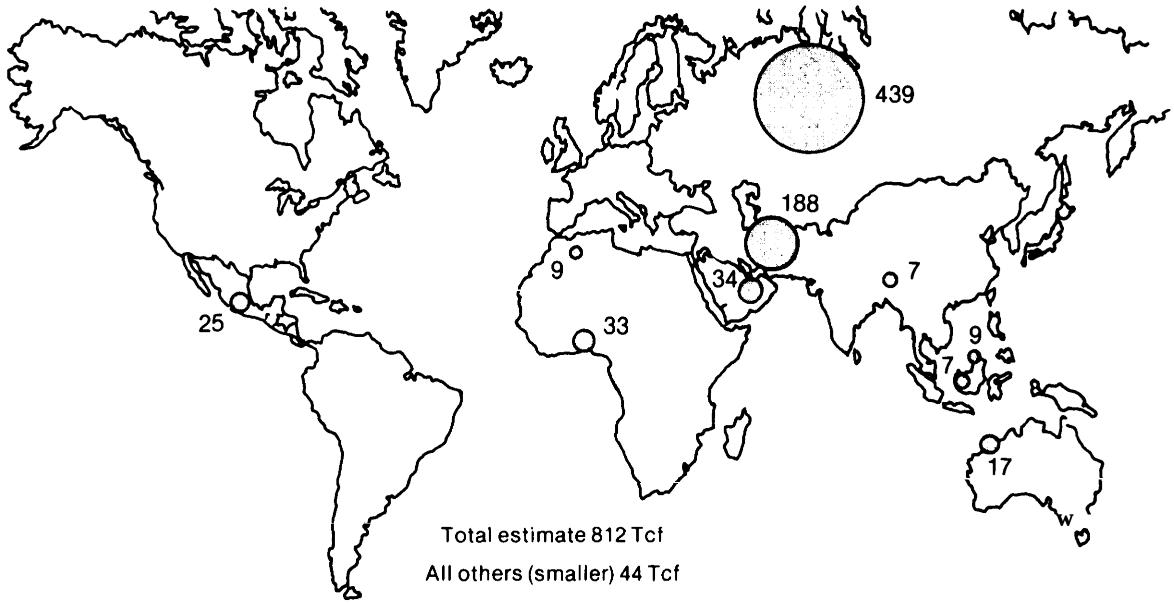
However, the uncertainties surrounding future Iranian gas policy call into question whether any of these projects will come to fruition in the foreseeable future. Both IGAT-2 and the Kangan project are now canceled, and contract commitments under IGAT-1 may not be honored. The future of the major gas injection scheme also is in doubt. Thus, in spite of an estimated 188 Tcf of exportable surplus for Iran, new projects are not likely to be initiated soon.

Had Iran gone ahead with its earlier plans, manv of the large gasfields, which are most economically situated to support export, would have been committed to the gas injection program instead. The remaining exportable" reserves, including the very large "E," 'I F," and "G" structures, which are quite far out in the Gulf, together with some of the "C" structure (or Pars gas reserves) both onshore and offshore near Kangan, would have been more expensive to commercialize than some of the onshore gas. However, they might lend themselves well to barge-mounted LNG facilities in the future if Iran is prepared to discuss exports again.

ALGERIA

Algeria was the first country to export I.NG on a commercial scale and has the most extensively developed programs for LNG export. Figures 6 and 10 are based on Algerian proved reserves of 105 Tcf. Approximate}' another 25 Tcf are classed by the Algerians in the "possible" category, and the 25-year master Algerian gas devel-

Figure 11 .—Major Uncommitted Gas Reserves Exportable to World Markets (trillion cubic feet)



SOURCE: Jensen Associates, Inc.

opment program is designed to handle all of the proved plus a portion of the possible resources. The program is designed to be scaled down if possible reserves fail to materialize. Firm commitments for 11 LNG projects and the pipeline across the Mediterranean to Italy account for nearly 60 Tcf. Local markets are expected to take about another 30 Tcf, and a certain amount of oil well gas flaring would leave an estimated 8 Tcf in the exportable category. Most of this surplus has already been virtually committed. This volume includes the provisions for the Algeria 11 and Tenneco St. John's projects, and when these projects were disapproved by the U.S. Government, a scramble in Europe developed to take over these contract commitments. The Italian pipeline and negotiations with several potential European LNG purchasers now appear to have accounted for all of the available volumes, and Algeria is essentially sold out, barring further discoveries in the future. The 8 Tcf of exportable surplus shown in figure 10, though not yet firmly contracted for and approved, is spoken for.

OTHER SOURCES

A remaining 116 Tcf of reserves are located in countries that could be considering world-scale LNG export schemes, projects of a thousand-cubic-feet-per-day export capacity or greater. The map in figure 11 indicates where some of these projects might be located. Qatar has discovered Permian Khuff gas in the Northwest Dome offshore, reported at 34 Tcf. Although it is too early to estimate reserves with any accuracy, the field could range up to 100 Tcf when fully developed. Clearly, this large block of reserves could serve a major LNG trade, although its location well out in the Gulf may make it expensive. The Permian Khuff formation is deeper than the typically oil-productive zones on the Arabian Peninsula. The number of Permian Khuff tests to date has been limited, but geologists have expressed optimism that the formation could provide Saudi Arabia, Kuwait, and the Emirates with large future reserves of nonassociated gas.

Nigeria has been anxious to develop gas markets for its associated gas to reduce the level of flaring. A number of earlier proposed LNG projects have been consolidated into one large export scheme with Phillips as the operator, and discussions are being held with a number of U. S. and European companies about possible markets for the gas. The project, if it materializes, could require approximately 14 Tcf to support the large volume of planned exports. Nigeria also has large reserves of nonassociated gas, which could support further LNG exports, if an initial project with associated gas were successful.

Australia has discovered large volumes of nonassociated gas in the Northwest Shelf region, remote from limited Australian markets, and promoters have attempted to organize projects for both Japan and the U.S. west coast from an exportable surplus on the order of 17 Tcf. Smaller projects have been considered from Malaysia (Sarawak), which would move the gas to adjacent Brunei for export, and from Bangladesh, which could have about 7 Tcf of exportable gas available.

Indonesia has an estimated 7 Tcf remaining of exportable surplus. Indonesian market commitments include both Badak I and the Japanese portion of the Arun project. Badak 11 still requires additional reserve development. The Pac Indonesia portion of the Arun project is included with Badak II in the 7 Tcf of exportable surplus.

Abu Dhabi has discussed a second project for Japan based on the estimated 5 Tcf of onshore gas reserves of Bu Hasa and the Bab Dome (the old Abu Dhabi Petroleum Co. producing area). Also, Bahrain could support a small project with 4.4 Tcf of excess exportable reserves in a deep gas reservoir.

In a number of other areas, the size of the individual discoveries together with commitments to protect local markets, prevent the assembly of enough reserves to support a 500 MMcf/d export project worldwide, approximately 28 Tcf may be concentrated in these small blocks.

Trinidad, which currently falls into this category, has been anxious to utilize gas for local industrial development in fertilizer plants and a steel mill, and to protect its local market with a 40-year reserve coverage. Developing enough gas reserves to support LNG exports has therefore been difficult. Nonetheless, the Government has expressed great optimism that further exploration and development will provide reserves sufficient to support a project of between 600 and 750 MMcf/d.

Although possible U.S. imports from Colombia, Chile, Ecuador, and Venezuela have been mentioned in the past, none of these countries have exportable surplus great enough to support a major project now. Venezuela has retreated from extensive earlier plans for LNG export and now plans to keep all of its gas at home, although the country could export at a level of about 350 MMcf/d. Chilean reserves are small and remotely located in Tierra Del Fuego, at the southern end of South America. Argentinian exploration in the San Sabastian area, also in Tierra Del Fuego, is discovering nonassociated gas in excess of Argentinean requirements, and the possibility of some type of joint venture appears at least technically possible.

Tunisia has discovered offshore Mediterranean gas, which it may provide for LNG export in the future, and exploration offshore in Thailand has resulted in some gas which could conceivably form the basis for a future project to Japan. Libya has gas in excess of current market requirements, which might not justify an expansion of present LNG facilities but might enable Libya to negotiate the extension of contracts with Italy and Spain in the future.

Thus, despite the extent of world gas reserves, the number of countries that could export LNG to the United States is quite limited. Algeria appears to be sold out and is not prepared to make further commitments to the United States in the immediate future. The next most likely alternative sources would appear to be Nigeria and Trinidad. Gas from the Middle East will probably be expensive. Much of the gas in South America is in such small blocks that world-scale projects are not likely without some form of integration.

Competitive importers of LNG—Europe and Japan

International trade in LNG began abroad, from North Africa to Western Europe, in the

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mid-1960's. Japan, too, was importing its first cargos (of American LNG from Alaska) by 1969, about 2 years before deliveries under the first U.S. import contract (by Distrigas in Boston from Algeria) commenced. In 1980, the United States will be importing nearly as much LNG as Europe (approximately 0.5 Tcf/yr) but much less than Japan (0.79 Tcf annually), in spite of the fact that the total American gas market is nearly 3 times as large as Europe's and 30 times as large as Japan's.

Historically, demand for gas imports into Western Europe has developed as a complement to the successive discoveries of large-scale gas reserves there (notably in the Netherlands and the North Sea), and the decline of traditional coal-gas making. In 1977, local output was over 6 Tcf, covering about 90 percent of consumption. But since production from most of the known reserves is now peaking or leveling off, European utilities are actively seeking further imports, both as LNG from Algeria and by pipeline from the U.S.S.R.

Japan has been unable to discover significant reserves of natural gas (or of any other fuel), so it is planning much greater imports of LNG during the 1980's and 1990's, particularly as its nuclear prospects have been revised downwards. Its main imports so far are from Southeast Asia (Brunei, Indonesia, and in the future, from Malaysia), and it will compete strongly for LNG from Australia and possibly New Zealand.

Japan has also begun the only LNG import scheme yet developed from the Middle East (of associated gas in Abu Dhabi). All of the several projects put forward in recent years for LNG exports to Japan from Iran's huge nonassociated gas reserves now appear to have been canceled (along with the European contracts for substantial "indirect imports" of Iranian gas through trades with the U.S.S.R.). Notwithstanding this setback for Middle East gas exports, soaring oil prices may now be approaching the levels at which exports as LNG of associated gas produced with Gulf crude will begin to become commercially viable.

If so, Japan and Europe would again have a transport advantage over the United States, as they each have from Southeast Asia and Africa respectively. In addition, they experience fewer administrative delays in governmental approval of gas import projects. Initially, both regions paid delivered prices for LNG related to local market values for fuel oil. But in Europe, where low-sulfur content had little value, prices were significantly lower than in Japan, where LNG commanded high premiums along with low-sulfur crudes and fuel oils, U.S. premiums for low-sulfur, and hence landed values for LNG, came in-between those in Europe and Japan. So even allowing for higher transport costs, the netback value to Algeria from landed prices under U.S. contracts could be higher than Europe was paying. Since the mid-1970's, however, European buyers appear to have paid Algeria prices representing comparable netback values to those from American contracts.

European and Japanese markets for gas will never compare with the sheer volume of the U..S. market. But for LNG from Africa, Southeast Asia, and the Pacific, and potentially from the Gulf, both regions may offer strong competition to U.S. importers.

WESTERN EUROPE

Natural gas imports into Western Europe have been forecast to rise from their recent annual level of 0.83 Tcf (1977) to around 4 to 5 Tcf by 1990 (see table 18). How much of that gas will be brought in as LNG will depend on the amounts available by pipeline, which are at the moment liable to particular uncertainties (table 19).

In 1977, Western Europe imported about 0.5 Tcf of natural gas annually from the U.S.S.R. That amount represented about one-half of total Soviet gas exports, which account for about 9 percent of total Soviet production. The rest of Russian gas exports go to Eastern Europe, As mentioned earlier, the U.S.S.R. has been importing about 0.3 Tcf annually (1977) of Iranian gas through the IGAT-1 pipeline to the Caspian Sea region.

Implementation of plans to formalize and expand this indirect export of Iranian gas to Europe now seems unlikely. In 1975, a trilateral deal for a second, parallel IGAT-2 pipeline

Table 18.—Natural Gas Supply/Demand Projections for 1985 and 1990, European Economic Community (trillion cubic feet)

	1985			1990		
	Production	Imports from outside Europe	Consumption	Production	Imports from outside Europe	Consumption
EEC	6.12	2.84	9.75	5.25	3.45	10.41
Belgium	—	.23	.50	—	.24	.55
France	.22	.77	1.40	.14	1.20	1.66
Germany	.61	.89	2.61	.53	.87	2.66
Italy	.55	.72	1.47	.42	.97	1.67
Netherlands	2.89	.15	1.47	2.16	.16	1.45
United Kingdom	1.70	— [a]	2.12	1.80	— [a]	2.23

NOTE These import figures exclude imports from Norway, which is within OECD Europe but outside EEC Community governments in fact expect to import some 1 15 tcf from Norway in 1985, and perhaps about 1.40 tcf by 1990 (though that would imply higher gas exports than Norway is yet counting on to make by then) Also, for particular EEC countries, the import figures also exclude intra- EEC trade in natural gas, essentially Dutch exports to Belgium, France, Germany, and Italy

[a] United Kingdom projections do not include imports from Algerla under its orlglnal LNG contract, which may be renewed

SOURCE. Jensen Associates, Inc , from EEC member governments estimates, 1978 (made before Iran announced to cancel IGAT-2 plpellne exports)

Table 19.—LNG and Pipeline Gas Import Projects to OECD Europe (trillion cubic feet per year)

	Startup	Form of import	Contracted delivery volumes	Notes
Operational				
Algeria-United Kingdom	1964	LNG	.04	Due to end 1979: renewable?
Algeria-France	1965	LNG	.02	
U.S.S.R.-Austria	1968/80	Pipeline	.09	
Libya-Italy	1969	LNG	.11	
Libya-Spain	1971	LNG	.04	
Algeria-France	1972	LNG	.14	
Algeria-Spain	1974	LNG	.18	
U.S.S.R.-Germany	1974/78	Pipeline	.36	
U.S.S.R.-Italy	1974/78	Pipeline	.27	
U.S.S.R.-Finland	1974	Pipeline	.11	
U.S.S.R.-France	1976/80	Pipeline	.15	Starting up to 1980
Total			1.51	(.53 LNG) (.98 pipeline)
Possible before 7985				
Algeria-France	1980	LNG	.20	
Algeria-Italy	1981	Pipeline	.45	
Algeria-Belgium	1982	LNG	.20	
Algeria-Germany	1984	LNG	.41	
Algeria-Netherlands	1984	LNG	.15	
Total			1.41	(.96 LNG)
Possible before 1990				
Algeria-Germany	1985	LNG	.15	
Algeria-France	1985	LNG	.18	May be alternatives
Algeria-Spain/France	?	Pipeline	.54	
Iran/U.S.S.R.-Germany	?	Pipeline	.20	Exchanges via U.S.S.R.
Iran/U.S.S.R.-Germany	?	Pipeline	.13	Iran plans to cancel, 1979
Iran/U.S.S.R.-Austria	7	Pipeline	.07	
U.S.S.R.-France	?	LNG	.18	Linked with U. S. S. R.-U.S.A.
Total			**1.45**	
Nigeria-Europe	?	LNG	**up to .59**	Or to U S. A.?

NOTE Projects are also being discussed for Algerian LNG to Sweden, Switzerland, and Yugoslavia

SOURCE Jensen Associates Inc.

would have raised the system capacity to 1.0 Tcf/yr, and would have enabled Russia to export another 0.4 Tcf/yr to Germany, Austria, and France, beginning in the early 1980's. However, the new authorities in Tehran have announced that the contract for deliveries through IGAT-1, halted for a time during the Iranian revolution and since reported to be running below the volumes planned for this period, might not be renewed when it expires in 1985. They also said they would cancel the IGAT-2 line, jeopardizing the exchange supplies onward to Western Europe. The German and French gas utilities involved hope that the original contracts with Iran will finally be honored, perhaps with inevitable delays to the earlier timetable. As an alternative, they might hope to secure extra deliveries from Russia, eventually to restore the whole planned volume, without the Iranian backup. (The Economic Commission for Europe currently reckons that natural gas availability for net export from the U.S.S.R. might reach 1.8 Tcf/yr by 1990.) Russian reserves are ample, but the development of additional reserves, pipeline capacity, and infrastructure would probably strain Soviet engineering resources, even though the investment might be financed from Western Europe.

The uncertainty about further pipeline supplies from the East may increase Europe's demand for LNG supplies from Africa, notably from Nigeria. European utilities have also recently contracted for much of the gas remaining available for export from Algerian reserves so far developed, about 1.4 Tcf/yr by 1985 in added projects over and above the 0.45 Tcf/yr due for Europe by then under earlier contracts. However, 0.44 Tcf/yr of these extra imports are now planned to move from Algeria by pipeline across the Mediterranean to Italy and north into the European gas grid. Another pipeline across the Mediterranean might move up to 0.5 Tcf/yr of Algerian gas to Spain and perhaps from there to France. Recently, however, new gas discoveries onshore in northern Spain and offshore in the south could be sizable in relation to the country's consumption. The resulting addition to Spanish energy may increase the uncertainty of this second European pipeline import project. If the pipeline links to Italy are completed successfully, it may eventually prove more economical to double those up. In any case, tying Algerian supply by one pipeline or two into the European gas network may secure for European customers some continuing advantage in access to additional reserves of uncommitted gas that Algeria may find and develop in the future.

Much of the gas Europe expects to begin importing in the 1980's was originally to be shipped as LNG to the United States. European buyers took advantage of administrative and regulatory delays over American LNG projects to negotiate alternative standby contracts with Algeria's Sonatrach for the same supplies, to take effect if the U.S. purchasers could not meet agreed timetables. Because only three of the U.S. contracts were eventually approved by the regulatory authorities, Algeria has allotted the gas covered by the others to Europe. Algeria reasons, therefore, that all of its planned gas production for export in the 1980's, some 2.6 Tcf/yr, is committed.

Europe appears now to have contracts for some 1.9 Tcf/yr of LNG and pipeline gas from North Africa by 1985, possibly reaching 2.5 Tcf/yr by 1990. It might be able to secure up to 1.4 Tcf/yr from Russia with or without exchanges of Iranian gas, but to meet total import requirements of perhaps 4 to 5 Tcf by 1990, it will still remain interested in further LNG imports during the later 1980's, possibly the 0.59 Tcf that may become available as LNG from Nigeria.

During the 1990's, local production may decline more rapidly, even allowing for North Sea fields not yet discovered. Projections assuming that natural gas will provide 15 percent of total energy requirements, and that growth in OECD Europe's gross domestic product will continue at 3 percent annually (which may be optimistic), call for total LNG imports of perhaps 7 Tcf/yr at the end of the century. In contrast, gas consumption may not grow at all if European production falls sharply, and even to hold consumption level would require increasing imports or rapid development of synthetic natural gas. '(Near-in" sources of LNG for Europe seem hardly able to offer larger volumes by then on a continuing basis, though even heavier import dependence on gas pipelined from Russia may be possible. By that time the only other major potential source of extra gas supplies, as LNG or by pipeline, may be the Middle East for *all* importers.

JAPAN

Relative to its total energy use, gas consumption in Japan is small. In 1977, only 4 percent of Japan's total energy requirements were served by gas, compared with 26 percent in the United States. Japanese consumption is concentrated in residential, commercial, and electric power generation sectors, while in the United States, industry is the largest consumer.

The oil embargo of 1973 and subsequent rapid increase in crude oil prices in world markets increased Japan's attraction to LNG. In 1973, imported petroleum comprised 75 percent of the energy used in Japan, compared with 58 percent of the energy used in OECD Europe and, even though oil imports have increased dramatically since then, only 16 percent of the total energy requirement of the United States. During the 17-year period, from 1960 to 1977, the growth rate of industrial energy consumption in Japan was 8 percent per year, far higher than in the United States and in Europe. The remarkable growth in Japanese industry during this period was fueled largely by imported oil. Because most petroleum flows to Japan from relatively few countries in the Middle East, the Japanese economy and society are heavily dependent, more so than the United States and Europe, on stable oil supplies from that part of the world. But the oil embargo of 1973, the 1979 revolution in Iran, and rapid price increases have caused the Japanese to look for ways to diversify their fuel supplies. Importing LNG is one route they are taking.

A report entitled "Japan's Energy Strategy Toward the Twenty-First Century" states,

> Liquefied gas has many advantages: among others, the volume of natural gas deposits is more comparable to that of petroleum, natural gas is relatively more widely distributed than petroleum, and liquefied gas is a clean energy. Therefore, natural gas is considered as an energy source Japan should actively try to introduce as a petroleum substitute.[7]

To implement these objectives, the report continues,

> In promoting the introduction of LNG, Japan needs to construct liquefied gas plants and LNG carriers, locate receiving terminals and other receiving facilities, prepare a pipeline network, and organize users. These preparatory activities need to be supported through measures such as financial assistance by the national government.[8]

Substantial quantities of nonassociated gas are located outside of the Middle East in Indonesia, Brunei, Malaysia, the U. S. S. R., Australia, and New Zealand. Japan imports LNG from the United States, Indonesia, Abu Dhabi, and Brunei; and projects from other nations including Iran and Qatar are being considered, as shown in table 20.

Table 20.—Japanese LNG Import Projects
(trillion cubic feet per year)

	Startup date	Contracted delivered volumes	Total
Operations			
United States (Alaska)	Nov. 1969	0.05	
Brunei	Dec. 1972	0.26	
Abu Dhabi (Das Island)	May 1977	0.10	
Indonesia (Badak)	Oct. 1977	0.16	
Indonesia (Arun)	Aug. 1978	0.22	
Total operations		0.79	O.G[b]
Possible additions by 1985			
Indonesia (Badak) expansion	1983	0.16	
Malaysia (Sarawak)	1983	0.31	
Indonesia (Arun) expansion	1984-85	0.12	
Australia (NW Shelf)	1984-85	0.17-0.32	
Abu Dhabi (inland)	mid-1980's	0.25	
Qatar	mid-1980's	0.31	
Total additions		1.32-1.47	
Total			2.11-2.26
Possible addition before 1990			
Iran	?	0.13	
U.S.S.R.	?	0.38	
Thailand	?	?	
Bangladesh	?	?	
China	?	?	

[a]At 52 MM Btu/tonne and 1,020 Btu/cf.
bActual receipts year ending Mar 31, 1979
SOURCE Office of Technology Assessment

7 "Report of the Advisory Committee for Energy Conference on Fundamental Issues-March 1979" [Background Information, Ministry of International Trade and Industry BI-33), p.7.
8 Ibid., p. 24.

If all possible projects were to come to fruition by 1985, Japan would have nearly quadrupled its LNG imports and would have exceeded the planned import levels for 1985 as shown in table 21. The Advisory Committee for Energy sets tar-

Table 21.—Comparison of LNG Import Project Volumes and Planned Import Levels—Japan (trillion cubic feet)

	1985	1990
Operating and possible LNG import projects (table 20)	2.1	1-2.26
Advisory Committee for Energy[a].	1.53	2.24
Institute of Energy Economics.	1.33	1.79

[a]"Japan's Energy Strategy Toward the 21st Century," a report of the Advisory Committee for Energy, Conference on Fundamental Issues. Published by the Ministry of International Trade and Industry, BI-33, March 1979.
[b]"Energy in Japan," report No. 44, March 1979, by The Institute of Energy Economics, Tokyo.

gets for energy development, and the Institute of Energy Economics has forecast imports based on its perception of Japan's ability to absorb LNG. Both the targets and the forecast are exceeded by the volumes represented by existing and possible projects.

The 1979 OPEC price increases for crude oil, as well as agreements among the leaders of the industrial nations at the 1979 Tokyo summit meeting, heightened Japan's need to reduce oil imports from the Middle East. In 1977, Japanese industry consumed oil which would be the equivalent of 8 Tcf of gas. If industry would switch to LNG, considerably more could be imported. But historically, gas has been too expensive for industry, and distribution systems for the regasified LNG would have to be developed, and processes and appliances adapted for natural gas.

A factor which favors industrial use of LNG is that a large segment of Japanese industry is located within a few miles of existing LNG import terminals, and new pipelines to serve large industrial customers could be built quickly. With the financial support of the government for pipelines, expanded terminals, and conversion equipment, Japan could easily accept all the LNG available by 1985, shown in table 20, i.e., 2.1 to 2.4 Tcf. Industry would need only to increase its LNG consumption from .05 Tcf to between 0.8 and 1.0 Tcf. To meet its goals of geographical and political diversity of energy sources, one would expect Japan to give priority to LNG from Southeast Asia.

Foreign LNG potentially available to the United States

LNG must be carried further to the United States from major export points than to either the European or Japanese markets. Table 22

Table 22.—Distances Between LNG Liquefaction Ports and Typical Import Locations (nautical miles)

Europe and United States	Arzew Algeria	Bonny Nigeria	Bushehr Iran via Cape of Good Hope	Bushehr Iran via Suez
Rotterdam.	1,637	4,390	11,222	6,469
Philadelphia.	3,594	5,185	11,906	8,426
Lake Charles, La. .	4,961	6,102	12,479	9,793
Yokohama.			6,624 (east from Arabian Gulf)	

Japan and United States	Lhakseumawe[a] Sumatra Indonesia
Yokohama.	3,369
Los Angeles	8,347

[a]Lhakseumawe is the liquefication port for the Arun field gas.
SOURCE: Jensen Associates, Inc.

shows the distances between major sources of LNG and ports of northwest Europe, the U.S. east coast, and Japan. Algerian LNG will travel less than half the distance to Europe than to either the U.S. east or gulf coast. The relative advantage of Europe is less for Nigerian LNG, but Europe still has a 800- to 1)800-nautical-mile advantage. Both Japan and Europe are closer to Iran and other Arabian Gulf ports than is the United States, and Japan is far closer than the United States to the gas deposits in Southeast Asia.

This locational disadvantage influences the availability of LNG to the United States from outside the Western Hemisphere. In order to compete with Europe and Japan by offering the same price at a liquefaction plant, the United States must accept a higher landed price for the LNG because of the increased distance and shipping costs. Table 23 summarizes the possible

Table 23.—Potential Availability of Foreign LNG to the United States Before 1990 (trillion cubic feet per year)

Country	Remarks	Tcf/year
Algeria	Operating and approved projects	0.63
	Additional amounts only from new reserves, if any	?
Nigeria		0.0-0.59
Western Hemisphere		**0.3**
Southeast Asia		**0.35**
Persian/Arabian Gulf	Not likely before late 1980's	?
U.S.S.R.	Not likely before 1990	0.04 ?
Canada (Melville Island)		0.1

SOURCE Jensen Associates, Inc.

supplies of LNG to the United States in light of this limitation, and individual sources are discussed below.

ALGERIA

Algeria has become the world's largest exporter of LNG and seems likely to remain so for the rest of the century. It has perhaps the most elaborately coordinated master plan for optimized joint development of all its petroleum resources—natural gas, crude oil, condensates, and liquid petroleum gas (LPG)—of any producer. Its pricing policies are also the most fully spelled out. It is becoming a significant supplier of LNG to the United States (0.63 Tcf by 1985), but for the present, it has no more gas to offer. The State company, Sonatrach, says it has already committed in long-term contracts the 2.6 Tcf/yr* of exports that it plans to build up by 1985 and maintain until after 2000. Under these contracts, a total of about 60 Tcf would be exported over the period 1976-2004.

In the past, some Algerian authorities have suggested that the country might have an additional 30 Tcf "available for export, " but the Government has given no sign that it wishes to contract for this amount. It is making any further negotiations conditional on the results of exploration, which can only be uncertain and delayed. The effort and investment required to implement present contracts are enormous.

Algeria's Valorization Hydrocarbon Development Plan (VALHYD) aims at

> . . . maintaining a level of gas sales volume as high and as stable as possible during the longest period of time while taking into account gas needs for cycling operation, re-injection in oil-fields, and gas lift.

Covering the period 1976-2005, at a capital cost of $33.4 billion (1976 dollars), the plan provides for national production rising to about 4 Tcf/yr by 1985, and thence to nearly 5 Tcf by 2000, from 130 Tcf of reserves. Of these volumes, a plateau level of about 2.6 Tcf/yr will be exported from about 1985 to about 1998. Exports theoretically return to nil before 2005, because VALHYD does not count any "potential and possible" reserves in known and other basins, nor does it allow for the uprating of reserves in fields recently discovered.

One of the VALHYD objectives is "re-injection of gas, particularly associated gas, whenever this will lead to a better oil reserves recovery. " Moreover, losses in the recovery, gathering, transmission, and processing of gases for export from fields far from coastal terminals, will represent a sizable debit against total gas production, approaching 1 Tcf/yr at the plateau level. Thus, the total gas for disposal under this plan, for home use and export, will be around 4 Tcf/yr. Algeria's own domestic consumption of gas, which was only about 0.35 Tcf in 1977, is expected to treble by 1985, and to reach about 1.5 Tcf/yr around 2005. By that time about 60 percent of the reserves for development under VALHYD may have been used up, unless more of this gas is released for export in the meantime.

After the cancellation of the Tenneco and Algeria 11 projects, the United States will have difficulty obtaining more Algerian LNG. Europe is even more interested in Algerian LNG with the cancellation of the Iranian IGAT-2 contract and a reduction in Russian gas last winter. Further, the Netherlands is refusing to extend long-term contracts, and the amount of gas that Europe

* Some 2.2 Tcf will move as LNG and 0.4 Tcf by pipeline. The pipeline contract across the Mediterranean to Italy (which was at 01)() t ime replaced by an I, NC; plan, then changed hark) does not appear to be included in this 2.6 Tcf yr. The second pipeline project, to move gas to Spain and France, is not included, nor are the American Algeria II and Tenneco projects. All three are classified as depending on the results of further exploration

believes it needs in 1990 exceeds what appears to be available. Although Algeria seeks to diversify its markets and feels over committed to Europe, the United States should expect vigorous competition for the remaining Algerian gas. Even if Algeria proves up additional reserves, Europe will remain competitive, especially if the trans-Mediterranean pipeline is completed.

Since 1975, Sonatrach has sought to obtain a base f.o.b. price of $1.30/MMBtu, calculated to yield a return on investment in gathering and trunk pipelines, liquefaction facilities, and export terminals, plus a commodity value of $0.30 to $0.40 /MMBtu for gas at the wellhead. That f.o.b. price escalates automatically with the prices of competing oil products in the import market concerned, and contracts provide for additional review of the base price every 4 years. The specific price escalation formula in each contract has depended on individual negotiations, and for U.S. contracts, as Sonatrach soon discovered, on their approval by Federal regulatory bodies.

Algeria has recommended a similar pricing formula based on a minimum wellhead commodity value, to other OPEC gas exporters, but it has never recommended uniform OPEC prices for LNG. Its objective for the price of LNG regasified in final markets would be comparability with the cost of incremental alternative fuels, which it recognizes, will depend on the prices that OPEC has the power to set for crude, not on any leverage through LNG supply per se. The Algerian Government has consistently been a "hawk," supporting the highest possible level of basic OPEC prices. Its own low-sulfur crudes enjoy quality and often freight differentials over the OPEC base level, and its sales contracts provide for quarterly adjustment of these differentials.

Algeria participated in the 1973-74 oil embargo against the United States. If the occasion were to arise, it would probably do so again. At the time, its only LNG shipments were to France and the United Kingdom, and those destinations were not embargoed. Interruptions of LNG shipments to the United States (Distrigas in Boston) were ascribed to problems in the liquefaction lines and the contract with Distrigas, which provided only for LNG which was surplus to the United Kingdom and French commitments. Sonatrach argues that producers are as dependent on uninterrupted revenues as purchasers are on secure supplies:

> When a country has earmarked over half' of its largest natural resource for export, entailing the investment of half of its current GNP while raising its debt burden to the limit, there can be little reason for consumer concern over security of supplies.[9]

Although its Government remains committed to revolutionary Arab nationalism, Algeria is also perhaps the most businesslike and sophisticated technically and commercially of the OPEC governments from whom importers can presently hope to buy LNG.

NIGERIA

Although LNG from Nigeria has been discussed for many years without result, negotiations with potential buyers have begun for a new project with Phillips Petroleum as operator. Reserves are ample, and a large project of 0.59 Tcf/yr (1,500 MMcf/d) able to serve more than one receiving terminal is being considered. This LNG is available to U.S. buyers but they will face aggressive competition from Europe, which enjoys a small distance advantage. Politics may intervene, as well. Nigeria is allocating oil to those nations that adhere to its African policies and has recently reduced British Petroleum's (BP) offtake by 100,000 bbl/d. The U.S. Government may not allow energy availability to influence U.S. foreign policy, and U.S. gas buyers and investors will be exposed to clear political perils to an LNG supply. In fact, U.S. antiboycott legislation may make contracting with Nigeria difficult.

Proposals to export Nigerian gas go back as far as the mid-1960's, before the country's civil war, and before the British, then the most likely prospective customer, discovered its own natural gas in the southern North Sea. Nigeria has **large, never** fully measured, known reserves of gas far exceeding likely domestic consumption during the rest of this century, Perhaps two-

[9] M. Belguedj, Director, Gas Exports, Sonat rach, *Petroleum Economist*, December 1978

thirds of the reserves maybe nonassociated, but Nigeria would probably first gather associated gas for export, to avoid the visible waste of flaring. Two parallel proposals were being considered until last winter, when they were amalgamated. The combined scheme would now be owned 70 percent by the Nigerian National Oil Company (since BP, with 10 percent, has been nationalized), and the other 30 percent would be shared among American, Anglo-Dutch, French, and Italian companies.

Nigeria's crude oil is of a high gravity and low-sulfur content now in very strong demand in the United States. The Nigerian Government has always sought to maximize the price differentials that it can secure for this quality, and it is reported recently to have sought higher than the OPEC "official selling prices" from its contractual customers for all except "equity" crude. *

Politically, Nigeria, like most other OPEC members, is committed to an embargo of oil to South Africa. This year, stricter application of that embargo, regarding tankers, first threatened to embroil two of the non-American companies operating there with U.S. laws against compliance with such restrictions, and then, after reports that the United Kingdom might indirectly sell North Sea crude to South Africa, led to the nationalization of BP's Nigerian interests. A further serious political conflict could arise for all companies operating in Nigeria and prospective customers for gas and oil as well, if the United States, the United Kingdom, and other European countries lift economic sanctions against Rhodesia and recognize its newly reconstructed government. Such an action could affect deliveries of Nigerian crude and the tenure of the American and Anglo-Dutch companies producing oil there, including most of those involved in promoting LNC exports. The most important government in Black Africa, a conservative military regime planning to hold elections and hand power over to a civil government, is unlikely to ignore the political attitudes towards African sovereignty that its most important customers for petroleum choose to adopt.

* Equity crude is what Nigeria receives in proportion to the 45 percent that it retains ()! equity ownership in former concessionary opt lolls.

WESTERN HEMISPHERE

LNG from Trinidad, Colombia, and Chile, which could total about 0.3 Tcf/yr, would norreally flow to the United States, which is much closer than Europe and Japan. The lower shipping costs would give the LNG exporters better prices than they would obtain from the more distant markets.

In addition, a project to ship LNG from the Arctic Islands of Canada to Savannah, Ga., has been suggested. This gas might flow alternatively to the Maritime Provinces in Canada or through pipelines to other Canadian and U.S. markets. Canadian policy about shipping the Arctic Island gas south and supplying gas to eastern Canada has not yet been resolved.

In 1972, Peoples Gas of Chicago contracted with the Standard Oil Company of Indiana (AMOCO) to import LNG from AMOCO's gas finds offshore to the east of Trinidad. However, the Government of Trinidad canceled the project in 1974, because it wanted the gas for internal industrial development, especially for fertilizer and ammonia plants and a steel mill at Point Lisas on the western coast. By 1973, oil production in Trinidad had risen to 159,000 bbl/d from reserves that were thought to amount to 2.2 billion bbl. 10 By the first of 1979, oil reserve estimates had been revised downward to 500 MMbbl. At the 1978 production level of 240,000 bbl/d, the reserves to production ratio had fallen to about 6, and exports are expected to decline. At the same time, gas reserves had increased to an estimated 8 Tcf by January 1979, and two strikes to the north of Trinidad led many observers to think that this figure could be understated. Proved gas reserves now represent more than 21/2 times the energy content of the oil reserves, and LNG exports appear to be the only way in which Trinidad can maintain the income stream from hydrocarbon exports as oil production declines. Existing reservoirs are more than ample to meet the 40 years of internal requirements that Trinidad requires before permitting exports.

Trinidad is not a member of OPEC, and the number of rigs drilling in Trinidad has in-

[10] *Oil and Gas Journal* estimates.

creased steadily over the past few years. While the Government is participating in some new ventures, its take from some production is still in the form of royalty and income tax.

The Government is likely to buy the natural gas from a producer and to maximize the price it receives for the LNG. However, Trinidad will not easily be able to shut down an operating LNG project to force the price up, The revenues would represent a significant part of GNP, which the people, having become accustomed o a rising income, might be unwilling to forgo.

Both Chile and Argentina have discovered oil and gas on the very southern tip of South America, bordering the Straits of Magellan and on the Tierra Del Fuego Islands. Argentina pipelines gas up the length of the country, serving Buenos Aires and towns along the way. Chile is actively developing its oil reserves and producing liquefied petroleum gas to relieve heavy imports at rising prices. For example, in 1977 Chile imported 77 percent of its total petroleum needs.[11] During the mid-1970's, the nation faced a serious decline in oil production and increased dependence on expensive imported oil, so in 1974, it ended a 50-year Government monopoly in the oil industry by a constitutional reform and invited foreign companies to assist in the exploration and development of oil through service contracts. Resulting new discoveries in the Straits of Magellan have increased production. Although Chile has substantial gas reserves in this region, the Andes Mountains make pipelining to population centers uneconomic.

In the early 1970's, a project to liquefy approximately 0.08 Tcf/yr for delivery to two LNG terminals elsewhere in Chile was proposed but dropped. Another LNG project to California of about the same size is currently being formulated, since receiving terminals on the Chilean coast appear uneconomic. Chile's need for foreign exchange and the absence of markets for the gas would reduce the likelihood of supply interruption once exports began. On the other hand, Chile, which was once considered one of the most stable democracies in Latin America, has undergone political turmoil during the 1970's and is experiencing rising inflation and other economic problems.

At the end of 1978, Colombia had an estimated 750 MMbbl of oil and an equivalent amount (4.8 Tcf) of gas in its hydrocarbon reserves. Until 1976, the Colombian Government kept petroleum prices low. Consumption was high, oil production declined over a 10-year period, and Colombia ceased exporting oil and became a net importer. With financial incentives, exploration improved in 1977.

Natural gas reserves are sufficient for internal use plus 0.05 Tcf/yr of exports. If Colombia wants to sell gas abroad, LNG shipments to the United States are the only possibility. Since not enough gas is available to support an independent project, Colombian LNG would need to share a receiving terminal with gas from some other source.

SOUTHEAST ASIA

Although Pacific nations appear to have more gas than Japanese markets can absorb, Japan has a strong incentive to buy LNG in Southeast Asia to diversify its energy supply geographically and politically. The Japanese have also demonstrated the ability to take action quickly and could utilize all gas from this region as industrial fuel. In addition, the greater distances from Southeast Asia LNG sources to the U.S. west coast allow Japan to offer better prices and other terms. However, the countries of Southeast Asia may prefer to diversify their markets and sell to the United States as well as Japan as long as they suffer no significant economic penalty.

Indonesia, Australia, and Malaysia together have considered LNG exports totaling 1.,1 Tcf/yr, most of which would flow to Japan. The United States could probably obtain 0.35 Tcf/yr, including 0.2 Tcf from the recently approved Pac-Indonesia project.

Indonesia is now supplying Japan with LNG under two projects, and the Pac Indonesia proposal for shipments to the United States has been approved but awaits a west coast terminal. Together, these exports should eventually reach a level of about 0.6 Tcf/yr from the large Arun

[11] U.S. Department of Energy, Energy Information Agency, *International Petroleum Annual 1977,* June 1", 1979.

and Badak gasfields in Sumatra and Kalimantan, remote from Indonesia's main centers of population and energy consumption in Java. Exports have been described as a second-best option:

> If we have the gas in such huge quantities and in such remote locations that there will be no significant domestic uses in the near future, then export may be the more beneficial alternative. 12

In general, however, Indonesia would rather use gas for local development and maximize exports of oil, which fetches much higher f.o.b. prices with less local investment. Moreover, gas reserves, if located close to markets, can be developed for domestic consumption more quickly.

Indonesia is a huge country with by far the largest population in OPEC, and rapidly rising local energy consumption, Its oil production is modest by OPEC standards and can perhaps be maintained around 1.6 to 1.8 MMbbl/d throughout the 1980's. Gas, along with coal, will have to provide a much larger share of domestic energy supply as consumption increases. Exploration may still discover large gasfields far from practicable markets that might offer further LNG possibilities. However, Indonesia is hardly eager to develop gas exports beyond present schemes,

Indonesia maintains closer and more amicable relations with its production-sharing operators, which are mainly American companies, than do most OPEC governments. Its relationships with customers, primarily in Japan, are also close, and Indonesia has never participated in an oil embargo. Political considerations, indeed, appear to influence petroleum operations less there than in most OPEC countries.

Approximately 12.2 Tcf of gas are located about 80 miles off the northwest coast of Australia at 400 to 450 ft. A consortium of Australian and foreign companies is considering whether to proceed with a project, estimated to cost $2.8 billion to $3.3 billion (1977 dollars) to export up to 0.33 Tcf/yr as LNG and to supply the city of Perth by pipeline. Although the Northwest Shelf project is almost certain to be approved by the consortium, its prospects have not always seemed assured. At various times, Australia's opposing political parties have expressed sharply contrasting views generally about the development of natural resources, including Northwest Shelf gas, and particularly about export policy and the participation of foreign companies.

Concerned about the high level of foreign investment in Australia's resources, the Labor governments of 1972 to 1975 introduced several measures to "buy back the farm. " They imposed restrictions on the level of foreign equity in new projects and established a "variable deposit rate" whereby a high proportion of foreign loan capital had to be deposited at zero interest in the Federal Reserve Bank. Even if the participants in the Northwest Shelf venture at that time had met these restrictions, the Labor government opposed the export of gas with a view to tying the reserves into a proposed national pipeline system to supply Sydney and the eastern states.

Following the December 1975 election, a Liberal and National Country Party coalition government removed restrictions on overseas borrowing for projects costing more than $615 million. A target of 50-percent Australian equity in new projects (and 75 percent in uranium developments) was announced, but not strictly applied. In any event, the Northwest Shelf project could virtually meet this target, because the Broken Hill Proprietary Co. purchase of Burmah Oil's interest, in 1976, raised the Australian equity share to about 48 percent.

In the August 1977 budget, the Federal Government announced its approval in principle of the export of LNG and condensate from the Northwest Shelf. In so doing, it acknowledged the consortium's view that gas could not be delivered economically to the eastern states, nor could reserves be developed for the market in Western Australia without LNG exports. The Government's approval covered 6.5 Tcf of gas (53 percent of proven reserves), equivalent to exports of up to 0.33 Tcf/yr for 20 years.

The guiding principle of the Liberal government's gas export policy is that exports will be permitted "subject to satisfactory evidence that

12 Wijarso, Director-General of Pertamina, IPA convention, Jakarta, May 1977.

every reasonable effort has been made to market the product in Australia. " This principle was confirmed by the Minister for National Development.

Should a Labor government be elected to office in the future, it would be unlikely to reverse the approval of gas exports from the Northwest Shelf. In its last months in office, the 1975 Labor government relaxed or abandoned many of its restrictive policies relating to the development of natural resources. It also conceded that some gas exports may be necessary to make the Northwest Shelf project viable. Nevertheless, some of the tax allowances granted to the project by the Liberal government could be reduced, and the disposition of gas reserves discovered in the future may be restricted.

Export prices for Northwest Shelf LNG will be commercially negotiated within long-term (20-Year), take-or-pay contracts. All but one of the participants have appointed Mitsui/Mitsubishi "seller's helpers" in negotiating contracts with Japanese buyers. However, the participants have also met recently with the U.S. west coast utilities, Pacific Gas & Electric and Southern California Gas Company.

The Northwest Shelf participants are expected to sell their LNG at the price which, when netted back from a particular market, provides the highest value for gas at the wellhead. In the Japanese market, they will probably seek a price for delivered LNG that is equivalent on a heating-value basis to the price of competing fuels, such as low-sulfur fuel oil, LPG, or even LNG from alternative sources. Thus, in order to be competitive, potential U.S. buyers would need to offer a price for LNG equivalent on a netback basis to the Japanese market price.

PERSIAN/ARABIAN GULF

Although the nations in this area possess large reserves of gas, the gulf is farther from all three of the main regional markets for imported gas than Africa or Southeast Asia. Netback values for gas exports from there might in many cases be negative, or at best, miniscule in comparison with the high economic rents that exporters can exact for their oil. Both Europe and Japan are closer than the United States to the Arabian Gulf and thus have a competitive commercial advantage. Abu Dhabi currently is exporting LNG, and Iran has canceled proposed projects with the United States and Japan. The only uncommitted gas, other than in Iran, is in Abu Dhabi and Qatar, where the Japanese are discussing LNG purchases. Some gas from additional reserves may be available to the United States eventually, but projects are not likely in the near future.

In June of 1979, the Iranian Government announced that it expected to cancel the second IGAT scheme for pipeline exports of gas to the U. S. S. R., even though a considerable mileage of the large-diameter pipeline involved is reported to have been laid. The immediate direct effect of this indication of the revolutionary government's attitude towards gas exports would be on the Soviet gas system, but indirectly, it would also affect Western markets for gas imports substantially.

As mentioned earlier IGAT-2, feeding up to 1 Tcf/yr into the Russian network by the early 1980's, would have enabled the U.S.S.R. to export 0.4 Tcf/yr to Western Europe and 0.4 Tcf/yr to Czechoslovakia in the mid- to late-1980's. If European countries are deprived of these pipeline imports, they may become even stronger competitors for available supplies of Eastern Hemisphere LNG.

A restrictive policy of the Iranian Government could represent official adoption of an attitude expressed by some of the country's petroleum authorities in the past. They argued that Iran can afford to wait to develop what may ultimately be its more important petroleum resource, gas, until its oil reserves are closer to depletion. Earlier LNG export schemes, for example, were postponed for that reason.

The new Islamic revolutionary government, in any case, appears to look forward to slower depletion rates for oil than in the past. It has cut its oil exports sharply and canceled some of the arms and industrial development projects that drew heavily on foreign exchange earnings. It is even reported to be cutting back on exploration and development drilling in the oilfields. * Initially, denouncing Western-style materialistic ambitions, the Islamic regime appears ready to accept substantial reductions in oil income. The surge of international prices that its cuts in production set off, however, may indeed now provide Iran with higher total oil revenues in current dollars, and perhaps even in real terms, than its larger export volumes in 1978. If so, financial incentives to invest large sums in gas exports will diminish.

The Iranian Government has also announced that it will place extra emphasis on conversion of the country's industrial, commercial, and domestic usage to gas, and it is cutting back nuclear energy plans. These actions will accelerate domestic demand beyond the considerable growth planned already, but local consumption increases can hardly take up more than part of the gas that had been committed earlier to injection in the oilfields. More associated gas may therefore be flared and lost, but nonassociated gas can be left in the ground.

So long as Government policy is against gas exports even by pipeline, LNG projects appear unlikely. Questions about Iranian pricing policy become academic. As to political security, recent months have demonstrated how insecure what once looked like the strongest and most stable governrnent of any gulf exporter really turned out to be. It is too early yet to guess whether and when any settled pattern of commercial and contractual practice in foreign trade under the Islamic regime will emerge.

Elsewhere in the gulf region, the present small-scale Abu Dhabi LNG trade with Japan, when first planned in the early 1970's, appeared likely to yield an exceptionally low netback value for the contracted ().1 Tcf/yr of associated gas. By the time deliveries began in 197'7, prices in Japan had roughly doubled, and though construction costs had inflated too, much of the liquefaction and terminal facilities had been constructed on fixed-price contracts. Thus, Abu Dhabi, in spite of technical problems in its early operations, may achieve an acceptable return on investment, and LNG exports from there may increase. However, the experience hardly offers much commercial precedent for other LNG exports from the gulf.

Qatar has very large reserves of nonassociated gas in the deep Permian Khuff strata which extends, and may also contain gas, underneath the Kuwait oil reservoirs). It has also less opportunity than neighboring gulf exporters to expand oil production, which has remained at around .500, ()()()" bbl/d for some years. If the Government wants to increase petroleum exports, development of this gas offers an alternative opportunity, but whether and when this tiny and rich State will decide to proceed with LNG remains uncertain.

Kuwait has been drilling deep wells to ascertain whether the Khuff strata under its territory, too, contains gas but has reported 110 finds. Any gas found would first severe local consumption, and then exports of' LPGs and natural gas liquids (NGLs). At present, Kuwait limits oil production to 2.2 MMbbl/d and associated gas appears at times insufficient to meet local demand. Also, the LPG/NGLs facilities that Kuwait brought into operation this year were designed to accommodate 3 MMbbl/d of crude production. The Kuwait Government is perhaps the firmest exponent in the gulf of the policy of keeping petroleum in the ground for the benefit of future generations, SO even if it **now** finds new reserves of nonassociated gas, early development of LNG exports is unlikely.

Saudi Arabia is estimated to possess the second largest gas reserves in the gulf, primarily in the associated category. Some nonassociated gasfields have also been discovered there, but none have been developed. However, the country has never shown an interest in exporting any of this gas as LNG. Government spokesmen, on the basis of technical studies, have consistently dismissed both I. NC, and methanol as too costly ways of exporting their abundant energy.

"It ith 101$(11" oil product Ion) less associated gas will be produced. The N, ii ional Iranian ( )11 Company ii lso cut back the large-scale plans t ( )1' re-injection of ii ssociated ga s Into some of" t 11(' oil reservoirs iii the Khuzestan Province Those plans had been designed 10 maintain reservoir))1'['ss11 res and increase total I'('('()\'('l'}' by stretching out the 1)(' riod during which Iranian capacity (() pro-(111('(' a t the ('ill' lier level of ()\'('I' 6 MM 1)1)1 (1 per (iii\' could be maintained Abandonment may iii('ill) accepting ('ill' ii('I' declines in a number of Iran Iii n fields a t ter production peaks, as against prolonging the peak product ion ()\ er sev ('I'ill years

Instead, Saudi Arabia is committed to huge investments in gathering most of its associated gas, using the methane and ethane inside the country for petrochemical and other industrial purposes and for domestic fuel supplies, and stripping out the LPGs and NGLs for export. This effort is likely to transform the world market for LPGs by the mid-1980's, and may offer supplementary supplies for the gas utilities of Europe and Japan. Even assuming changes in governmental attitudes, early development of LNG exports is not probable in the light of this major component of the Saudi industrialization program.

No proposals for LNG exports from Iraq have been publicized, either. The limited indications are that this country too, may be adopting a policy, comparable with those of Saudi Arabia and Kuwait, to use the dry gas from its northern oilfields for internal consumption, and to strip out LPGs for export from its southern operations.

Notwithstanding those negative signs, changing oil prices must be shifting the balance of economics for gulf LNG projects. In 1977, Sonatrach of Algeria reckoned that the market price for OPEC crudes, then $12.70/bbl, would need to rise 50 percent in real terms to about $19/bbl, to make the gathering, processing, and export of associated gas in the gulf as commercially worthwhile. The market price applied for most OPEC crudes had reached $20/bbl by mid-1979. Construction costs in the gulf have continued to rise since 1977, and the dollar has fallen, but OPEC crude prices have risen sharply in the past year in real terms and could reach the threshold of economic viability for LNG exports from the gulf well before 1985. *

U.S.S.R.

The U.S.S.R. is a substantial exporter of gas (about 1 Tcf in 1977) from the largest reserve base in the world. Only about half its exports go to Eastern Europe. Exports to the non-Communist world are rising and could possibly be trebled by 1990. So far, all exports have moved by pipeline, but could be available to the United States as LNG in the future. Two projects have been proposed, but international politics may be more important than commercial feasibility in determining their success. Any export of Russian LNG to the United States is unlikely to start before 1990.

Details of the border prices charged for Russian gas exports to Western European customers are not known. But the delivered prices have had to compete with Dutch gas, and hence with fuel oil values. The U.S.S.R. needs foreign exchange, so in the past its gas exports, moving very long distances, must have returned relatively low-commodity values at the wellhead. From now on, as Dutch supplies decline, and the prices of competing oil products rise, the U.S.S.R. can raise its tariffs. It is also seeking financial and possibly technological support from prospective customers for field development and pipeline construction, including pipe to supplement its own production.

Proposals for LNG exports of Siberian gas to the United States and France, or the United States and Japan, have not progressed in recent years. Western Europe may prefer to seek additional supplies by pipeline, with or without the backup of Iranian gas.

Politically, Western exports of gas run the same strategic risks, no more and no less, as imports of other goods from the U.S.S.R. The European community has always monitored the level of energy imports from Eastern Europe and is likely to be vigilant about possible excessive dependence on Russian gas. On the other hand, in the mid-1990's) unless very large-scale LNG exports from the Middle East develop, gas moving from or through Russia may be the only major source of incremental supply to Western Europe and perhaps Japan. However, that the United States would ever develop sufficient imports of LNG from Russia to become significantly dependent on that one source seems hardly conceivable.

* Mr. Ait Laoussine of Sonatrach has suggested a steady 15-percent rise yearly in OPEC prices, which with 10-percent inflation would mean a 50-percent increase in real terms by 1985.

4

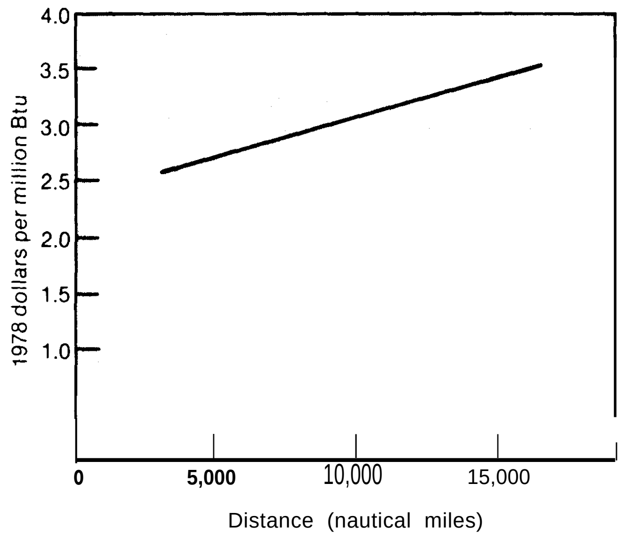
Project Structure, Cost, and Financing

Project Structure, Cost, and Financing

The only present way to transport natural gas across ocean distances is to ship it as a liquid at — 260o F in specially insulated tankers. Methane, the principal constituent, is 600" times denser in liquid form than as a gas at room temperature, and this reduction in volume permits economical use of ships notwithstanding the cost of specialized liquefaction, revaporization, storage, and other terminal facilities.

Liquefied natural gas (LNG) projects are expensive. The total capital required for a world-scale venture involving 1 billion cubic feet per day (Bcf/d) beginning in the early to mid- 1980s is nearly $.5 billion (1978 dollars). Approximately 40 percent of this cost is applied to the gas production and liquefaction facilities in the exporting nation, about 40 percent is needed for ships, and the balance of about 20 percent is for the import terminal and revaporization facilities in the United States. The cost of service, including operating~ expenses and amortization of the initial investment, for a typically structured project appears as a function of distance in figure 12.

Figure 12.— Cost of Service as a Function of Distance for a Typical LNG Import Project in the Fifth Year of Operation (1990)



SOURCE OTA, based on Jensen Associates data

An LNG importer must pay in addition to transportation costs a return to the producing country for the wellhead value of the gas, and supply contracts generally contain f.o.b. price provisions calculated to make imported gas competitive with distillate fuels in the U.S. market. However, escalation formulas in present contracts are such that delivered LNG prices should rise more sIowly than those of products from foreign crude oil.

Financial risk represents another element of cost, and the public guarantees in part the commercial success of' an LNG project through regulated retail prices designed to allow investors to recover portions of their cost notwithstanding some kinds of failure or loss. on the other hand the risk of' unilateral interruption of shipments by the supplier country is reduced by high capital costs and a project structure that ties buyer and seller into a tight economic partnership.

LNG projects

Commercial I.NG trading began in 1964 with the Algeria- United Kingdom project, involving ().()4 trillion cubic feet (Tcf) of gas per year. Over the past 15 years, the international trade has grown to 12 currently operating projects totaling 1.75 Tcf/yr from six producer countries (table 24). Japan has the largest portion of present imports (45 percent), f'ollowed by Western Europe (29 percent) and the United States (26 percent). However, the rate of future expansion in international LNG trade is uncertain. Should all the projects listed in table 24 materialize, worldwide trade in LNG would increase to 6.44 Tcf/yr by the mid-1980's, of which U.S. imports

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Table 24.–Operational LNG Projects, as of July 1,1979

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract Volumes[a] Tcf/year	Remarks
			OPERATING			
Algeria						
Arzew	United Kingdom	Canvey Is.	British Gas Corp.	1964	0.04	Contract has been extended
Arzew	France	Le Havre	Gaz de France	1965	0.02	
Skikda	France	Fos	Gaz de France	1972-73 1971-77	0.14	
Skikda	United States	Everett, Mass.	Distrigas	1978	0.05	
Skikda	Spain	Barcelona	Enagas	1976	0.55	
Arzew	United States	Cove Pt., Md. Savannah, Ga.	Columbia Gas, Consolidated Gas, Southern Energy	1978	0.40	
Alaska						
Kenai	Japan	Negishi	Tokyo Electric Tokyo Gas	1969	0.05[b]	
Brunei						
Lumut	Japan	Negishi Sodegaura Semboku	Tokyo Electric Tokyo Gas Osaka Gas	1972	0.26[b]	
Libya						
Marsa el Brega	Spain	Barcelona	Catalana de Gas	1971	0.04	
Marsa el Brega	Italy	La Spezia	Snare	1970	0.09	
Abu Dhabi						
Das Island	Japan	Sodegaura	Tokyo Electric	1977	0.10[b]	
Indonesia						
Badak (Bontag)	Japan	Himeji Chita	Kansai Electric Chubu Electric	1977	0.16[b]	
Arun (Lhakseumawe)	Japan	Tobata Semboku	Kyushu Electric Osaka Gas Nippon Steel	1978	0.22[b]	
			APPROVED			
Algeria						
Hassi R'mel (gas pipeline)	Italy	Sicily	ENI	1981	0.44	Pipeline replaced an LNG project
Arzew	Belgium	Zeebrugge	Distrigaz	1982	0.20	Terminal site uncertain
Arzew	France	Montoir	Gaz de France	1980	0.20	
Arzew/Skikda	United States	Lake Charles, La.	Trunk line	1980	0.18	
Arzew/Skikda	West Germany Netherlands	Wilhelmshaven Emshaven	Ruhrgas, Salzgitter, Gasunie	1984	0.41	
Arzew/Skikda	West Germany	Wilhelmshaven	Brigitta-Thyssen	1985	0.16	
Indonesia						
Arun	United States	Pt. Conception	Pacific Gas & Electric So. California Gas	1983	0.20	Approved Sept. 26, 1979.
Alaska						
Cook Inlet	United States	Pt. Conception	Pacific Gas & Electric So. California Gas	?	0.15	Approved Oct. 12, 1979. Added reserves needed
			PROBABLE			
Australia						
Dampier	Japan	Tokyo	Tokyo Electric Tokyo Gas, etc.	1984-85	0.33	

Table 24.—Operational LNG Projects, as of July 1, 1979—continued

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract volumes[a] Tcf/year	Remarks
Malaysia						
Bintulu	Japan	Sodegaura	Tokyo Electric Tokyo Gas, etc.	1983	0.31[b]	
Indonesia						
Badak (exp.)	Japan	Various	Chubu Electric Osaka Gas Kansai Toho Gas	1983	0.16[b]	
POSSIBLE (active)						
Nigeria						
Bonny	United States/ Europe		Columbia, Consolidated, Southern, Mich-Wis, Trunkline and others	Mid 1980s	0.6	
Trinidad						
Pt. Lisas	United States	Gulf coast	Tenneco Peoples	1984-85	0.18	
Canada						
Melville Is. (Arctic Is.)	Canada/ United States	St. Lawrence	Southern Natural Gas	1982-83	0.09	
Australia						
Dampier	United States	Pt. Conception	So. California Gas Pacific Gas & Electric	late 1980's	0-0.15	
Cabo Negro	United States	Pt. Conception	So. California Gas Pacific Gas & Electric	1983-85	0.08	
Indonesia						
A run (exp.)	Japan	Various		1985	0.12	
POSSIBLE						
Algeria						
not announced	Sweden	Wilhelmshaven	Swedegas AB	1984-85	0.07	Trends in Swedish energy policy cast doubt on this project
not announced	France		Gaz de France		0.18	
not announced	Switzerland				0.000018	
not announced	Austria	Ferngas; OMV			0.07	
not announced	Yugoslavia				0.07-0.11	
Arzew	United States	La Salle	United, El Paso El Paso	mid 1980's	**0.40**	
Qatar						
not announced	Japan	Tokyo	Tokyo Electric Tokyo Gas Mitsubishi Shell	mid 1980's	**0.31**[b]	
Abu Dhabi						
Rubais	Japan		C. Itoh & Co.	mid 1980's	0.25[b]	
Colombia	United States				**0.05**	
U.S.S.R.						
Yakutsk	United States Japan		Tokyo Gas Tokyo Electric El Paso Occidental		0.75	

Table 24.—Operational LNG Projects, as of July 1, 1979—continued

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract volumes[a] Tcf/year	Remarks
Murmansk	United States Europe				0.75	
United Kingdom						
North Sea	United Kingdom				0.75	Floating barge liquefaction plant.
Iran	Japan				0.13	
Thailand	Japan					
China	Japan					
New ***Zealand***	Japan					Maui gas, Mobil has proposed an automotive fuel project

[a]At I,1020 Btu/cf Normally contract volumes are given f o b the lilquefaction plant
[b]Indlcates c. i. f. volumes, i e , delivered.

SOURCE Jensen Associates, Inc.

would account for about 36 percent. Not all of these projects will come to fruition, however, and most past projections regarding the future of LNG trade have overestimated the rate of growth. The possible level of LNG imports is particularly uncertain in the U.S. market, where Government policy regarding LNG imports has been difficult to predict. The Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and State Public Utilities Commissions decide on all aspects of individual projects case-by-case in regulatory proceedings that take years, Given the present uncertainties, a more reasonable expectation would be that worldwide trade in LNG will reach 4.19 Tcf/yr by 1985, of which 46 percent will move to Western Europe, 34 percent to Japan, and 20 percent to the United States.

A baseload LNG project is a complex and highly capital-intensive venture, consisting of' three primary segments (figure 13):

1. liquefaction, storage, and loading facilities in the producing country;
2. transportation facilities (cryogenic tankers); and
3. terminal and revaporization facilities in the receiving country.

Total capital investment of a 1 Bcf/d project can exceed $5 billion (1978 dollars). The cost varies with such factors as the gas-gathering system, shipping distance, and new delivery pipelines required. The cost of liquefaction and related facilities in the producing country can account for as much as 50 percent of overall project costs. [1]

What follows is a more detailed description of the physical and cost structure in LNG import projects, including the price policies of the exporting countries. Two LNG projects are used for the purpose of illustration: Pac Indonesia and Algeria 11. Although only one of them has received final U.S. Government approval as of this writing, * the projects are good examples, because their costs and pricing provisions are recent and represent current LNG trade.

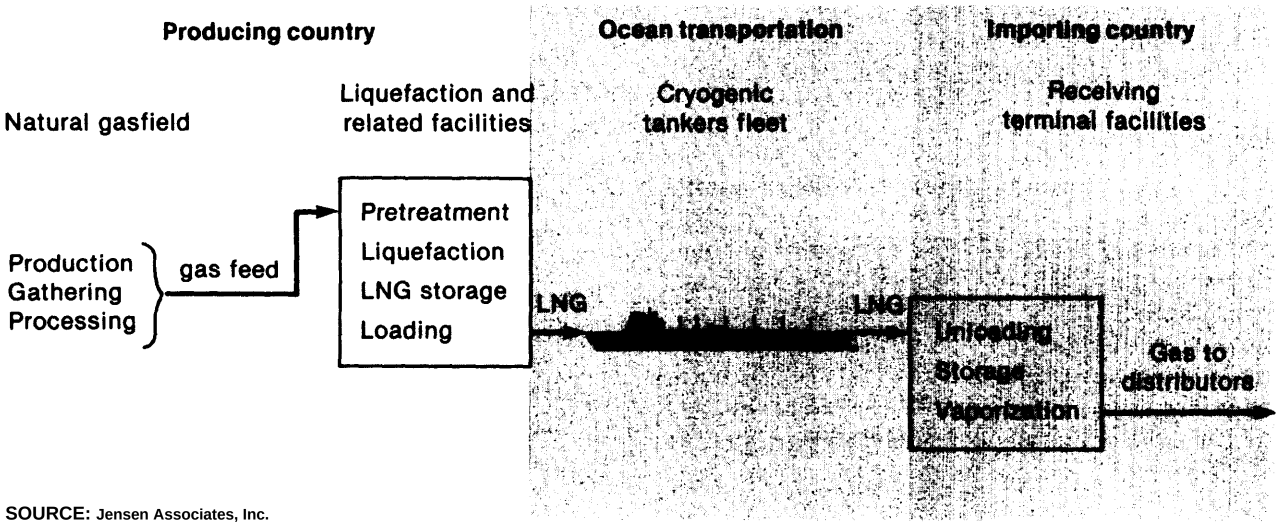
Algeria II

The proposed project was based on an October 28, 1975, contract, as amended, between Sonatrach (Societe Nationale pour la recherche,

[1]For development of typical LNG cost estimates, see K. N. Di Napoli, "Estimating Costs for Base-load LNG Plants," *Oil and Gas Journal*, Nov. 17, 1975.

*The Algeria II project was conditionally approved by the FPC (FERC) administrative law judge on Oct. 25, 1977. However, under the Department of Energy Organization Act effective Oct. 1, 1977, import jurisdiction was transferred to DOE's Energy Regulatory Administration (ERA). DOE ERA reversed the initial decision in its Opinion No. 4 of Dec. 21, 1978. Permission for rehearing has been recently granted.

Figure 13.— Major Segments of an LNG Import Project



SOURCE: Jensen Associates, Inc.

1a production, le transport, la transformation et la commercialization des hydrocarbons) and El Paso Atlantic Company (a subsidiary of El Paso).[2] It provided for the sale of LNG containing 410,625 billion Btu annually, for a term of 20 years. This amount is equivalent to approximately 1 Bcf/d of natural gas at 1,125 Btu/cf.

The gas was to be produced by Sonatrach, the Algerian State oil and gas company, in the Sahara, pipelined 315 miles to the Mediterranean coast, and there liquefied, stored, and loaded aboard LNG tankers. El Paso Atlantic, which would acquire the title to the LNG at the tanker's receiving flange, would arrange for the transportation by a fleet of 12 cryogenic tankers to an import terminal and regasification plant (the La Salle terminal) located near Port O'Connor, Tex. Six of the ships would be provided by Sonatrach and six by Atlantic. As each vessel entered the international waters off the coast of A]geria, the title to the LNG would pass to El Paso Eastern, the legal importer. The La Salle terminal facilities would be built and operated by the El Paso LNG Terminal Company which receives, stores, and revaporizes the LNG. At the outlet of the terminal, the gas would be sold by El Paso Eastern: 65 percent to the El Paso Natural Gas and 35 percent to the United LNG Company. The entire quantity would be pipelined to the United Gas Pipeline Company's existing mainline facilities near Victoria, Tex. There, United LNG's 35 percent of the gas would be sold to its parent, United Gas Pipeline, which serves other major pipelines that deliver gas throughout the area east of the Mississippi. The remaining 65 percent of the gas would be transported via a new 432-mile-long pipeline to be built by El Paso Natural to its Waha treating plant located in Reeves County, Tex., where it would enter the present El Paso system serving the Southwest and California.

In 1977, at the time of the participants' initial application to the Federal Power Commission (FPC) for import authorization, the total capital costs of the project were estimated as follows:*

- $2,300 million for gas wells, pipeline, and liquefaction facilities in Algeria (including $391 million for interest on funds used during construction);

'The El Paso Companies involved in the project, and their genealogy, are as follows:

The El Paso Company

El Paso LNG Company | El Paso Natural Gas Company
El Paso Eastern Company ("Eastern") | [El Paso Natural)
El Paso LNG Terminal Company ("Terminal")
El Paso Atlantic Company ["Atlantic")

SOURCE *Initial Decision, Upon Applications to Import LNG from Algeria,* FERC 01. 1 2.5, 1979, Docket Nos CP 77.330, et al p 4

• In 1975-76 dollars.

- $1,752 million for 12 vessels and shoreside facilities required for ocean freight; and
- $719 million for receiving terminal, regasification plant, and new pipelines in Texas.

Pac Indonesia

Two gas utilities in California—Pacific Lighting Corporation (PLC) and Pacific Gas and Electric Company (PG&E)—have formed a partnership to import LNG from Indonesia through two subsidiaries. The first subsidiary, Pac Indonesia, has entered into a contract with Pertamina, the Indonesian Government-owned oil and gas company, for the purchase of 226,194 billion Btu annually (approximately 550 MMcf/d) for a period of 20 years. *

The gas for the project would be produced in the Arun field of Northwest Sumatra by Mobil Oil Indonesia, Inc., under a production-sharing contract with Pertamina. From the field, the gas will be transported via a 20-mile pipeline to the liquefaction plant, which will be owned and financed by Pertamina.

Pac Indonesa has entered into contracts for the hire of nine cryogenic tankers to transport the purchased LNG from North Sumatra to California. Three of the vessels have already been completed in foreign shipyards and plans call for the remaining six to be constructed in the United States.

The LNG would be delivered to a proposed receiving terminal to be constructed by Western LNG Terminal Associates, the second subsidiary, near Point Conception, Calif. After storage and revaporization, the gas will be transported via a new 112-mile pipeline to the transmission systems of PLC and PG&E, which will jointly own the pipeline. Pac Indonesia will sell half of the gas to Southern California Gas (So Cal), a wholly owned subsidiary of PLC, and the other half to PG&E. The two utilities combined comprise the transportation and marketing mechanism that handles virtually all natural gas consumption in California.

Based on 1976-77 cost estimates, the capital expenditures for the project are as follows:

- $869 million for the pipeline, liquefaction plant, and related facilities in Indonesia, (including an estimated $164 million for interest during construction but not the cost of developing the Arum gasfield);
- $1,230 million required for nine chartered tankers, including $930 million for six vessels to be built in the United States (at $155 million per ship);
- $436 million allocated for the receiving terminal and pipelines in California. These facilities, estimated to cost a total of $749 million, are to be shared by Pac Indonesia and Pac Alaska. On the basis of the contracted throughputs, the cost allocated to Pac Indonesia would be just over 58 percent of the total.

Pricing policies of exporting countries

As a consequence of large crude oil price increases in 1973-74, the LNG projects negotiated or renegotiated after 1974 contain fuel-related escalation clauses applicable to their base f.o.b. ship's rail prices, the purpose of which are to establish parity between LNG and alternative fuels. Minimum (floor) price levels designed to remove the producing country's investment, or to assure the timely repayment of project-related debt, have also become standard contractual provisions. In addition, the pricing formulas usually contain safeguards against currency fluctuations. Sonatrach has adopted a fairly uniform f.o.b. pricing policy for all of its recent contracts—U. S. and European alike. A review of the major price provisions in the Algeria II and Pac Indonesia contracts provides a good indication of a LNG pricing mechanism that typifies all recent LNG trades.[3]

*The original contract between Perusahaan Pertambangan Minyak Dan Gas Bumi Negara (Pertamina) and Pac Indonesia's predecessor—Pacific Lighting International, S, A.—was signed in September 1973. Since then, it has been amended three times in regard to its pricing provisions. The last amendment was introduced in July 1978.

[3]For a more detailed discussion of LNG pricing mechanisms, see "Economic Considerations and Operating History of Base-Load LNG Projects, " Philip J. Anderson and Edward J. Daniels, Institute of Gas "technology, December 1977.

The procedural history of pricing clauses negotiated and approved in the Pertamina-Pac Indonesia contract illustrates the evolution of policy involved in f.o.b. pricing. Under the original September 6, 1973, Pertamina contract, the price to be paid by Pac Indonesia's predecessor would be $0.63/million Btu (MMBtu) plus 2-percent annual escalations, adjusted by a currency reevaluation factor and subject to certain floor and ceiling levels. The Indonesian Government did not, however, approve the contract on the ground that the price formula which contained a fixed escalator would not reflect the development of world energy prices in general and, in particular, was not linked to the price of Indonesian crude oil. Consequently, the first amendment issued January 9, 1975, established a new f.o.b. base price of $l.25/MMBtu—approximately double the prior price—and deleted the fixed 2-percent-per-year price escalator. A new escalation formula reflected equally changes in Indonesian crude oil export prices and U.S. energy prices as measured by the Bureau of Labor Statistics wholesale index for fuels. The renegotiated formula no longer contained a floor or a ceiling, so it offered no protection to either party against potentially wide fluctuations in LNG price through the operation of the escalation clause. The possibility of a fall in crude oil prices presumably led to the minimum bill provision, which assured Pertamina's lenders that the price of LNG would be at least sufficient to service Pertamina's debt and to meet operating and maintenance expenses (second amendment, issued October 28, 1975).

Although the FPC administrative law judge conditionally approved the proposed project and its pricing provisions, one of FPC'S successor agencies, DOE's Economic Regulatory Administration (ERA), did not allow the automatic flow through of cost increases under the price escalator clause, charging that the provision was tied too directly to future movements in OPEC-administered prices, and that the U.S. fuels index would be influenced by future domestic energy pricing policy and by the price of the import itself; thus creating a significant self-compounding effect.[4] This rejection of the escalator later led to yet another price amendment, issued July 28, 1978, and approved by DOE/ERA shortly thereafter.

Under the renegotiated escalation clause, the Indonesian half of the escalator will still be tied to Indonesian crude oil export price, but with the added constraint of a 15-percent absolute limit on annual fluctuations in that price. Any adjustment above the 15-percent absolute limit or below the floor can be carried forward until it can be applied. The U.S. half of the escalator was changed to substitute the broader based Bureau of Labor Statistics "all commodities" index for the former fuels-related index.

The pricing formula, as finally approved, is shown in figure 14. The calculated contract sales price is $1.25/MMBtu multiplied by the equally weighted changes in the Indonesian crude price (subject to a limit on annual fluctuations) and in the U.S. wholesale index for all commodities. A contract sales price is then multiplied by a currency reevaluation factor to arrive at the billing prices. *

If at any time during the debt amortization period, the calculated contract sales price should be lower than the minimum price calculated by Pertamina, the latter will be the billing prices

The Pertamina-Pac Indonesia contract includes a "most favored nation clause" under which Pac Indonesia would be entitled to a contract sales price for LNG no higher, on an f.o.b. equivalent basis, than that paid by any other importer under any other contract with Pertamina in existence as of January 9, 1975. Otherwise, the contract does not provide for future price reviews.

The Algerian pricing system has a twofold purpose: 1) to ensure that imported *gas is* com-

[4] DOE/ERA, Opinion No. 1, Dec. 30, 1977.

' However, operation of the currency factor cannot reduce the billing price below what it was on the date of first deliveries, nor increase it more than 25 percent above the otherwise applicable price in any given calendar quarter.

[5] The FPC administrative law judge who conditionally approved the Pac Indonesia project interpreted the minimum bill subject to all the provisions of the sales contract. Thus, Pac Indonesia would not be required to pay for quantities *not delivered* "whether by reason of Pertamina's fault or force majeure or assimilated circumstances occuring in any part of the facilities, including the ships or terminals" (Initial Decision, p 62)

Figure 14.—Pricing Provisions of Pac Indonesia and Algeria II Import Projects (U.S. dollars per million Btu, gross heating value, loaded f.o.b.)

Pac Indonesia

Contract sales price

Calculated quarterly.

$$P = P_o x (0.5 \frac{A}{\$11.00} + 0.5 \frac{W}{135.0})$$

P = calculated contract sales price.

P_o = $1.25.

A = applicable Indonesian crude oil price.

W = applicable value of the index of wholesale prices—all commodities

Currency revaluation factor

Applies to the contract sales price.

$$B = 1 + \frac{\Sigma \frac{c2}{c1} - 1}{11}$$

cl = the commercial rate of exchange in effect on the date of initial deliveries for each of the currencies.

C2 = the arithmetic average of the commercial rates of exchange on the applicable dates in each quarter for each of the currencies.

B = 1 until its absolute value changes at least by 0.1 o/o. Thereafter new value for B used only if it differs from old by 0.1 % or more.

Maximum B = 1.25.

Minimum contract sales price

During its debt amortization period Pertamina will calculate a price sufficient to meet:

1) repayment of principal amount (including interest during construction),
2) payment of interest when due, and
3) payment of projected costs of operation and maintenance.

Algeria II

Contract ("invoice") price

Calculated semiannually.

$$P = P_o (0.5 \frac{F}{F_o} + 0.5 \frac{F^1}{F^1_o})$$

P = invoice price.

P_o = base price equal to $1.30 as of July 1, 1975.

F = price of No. 2 fuel oil for New York harbor.

F_o = $12.642.

F^1 = price for No. 6 fuel oil, low pour, max. sulfur of 0.30%, delivered New York harbor.

F^1_o = $13.505.

Minimum price

Calculated monthly.

MP = MP_o (E + 1).

MP = minimum price.

MP_o = base minimum price equal to $1.30/MMBtu as of July 1, 1975.

E = arithmetic average of the results obtained by applying the formula: $\frac{R}{A} - 1$ to each of **6** currencies.

A = average commercial exchange rate for each currency during July 1975.

B = average commercial exchange rate for each currency as measured by average purchase and sales rates for telegraphic transfer for each business day of preceding month.

E = O until its value increases by at least 0.1% as compared to O. Thereafter new value for E used only if it differs from old value by 0.1 % or more.

Floor MP = U.S. $1.30.

Recalculations of the minimum price will be made *once* according to the following formula:

$$MP^1 = \$.80 \frac{X}{2,300} + \$.15 \frac{Y}{60} + \$.35$$

MP^1 = recalculated minimum price.

x = actual capital costs incurred by Sonatrach (in millions of dollars),

Y = actual operating costs of Sonatrach during the first year of operations (in millions of dollars).

adjust the minimum price only upwards, and with no upper limit.

Since oil prices are likely to continue rising, the contract ("invoice") price rather than the minimum price will probably determine Sonatrach's billing price. Recently, Sonatrach and El Paso's subsidiary have renegotiated the invoice price formula in a 1969 contract which underlies the Algeria I project. * Under the 1969 contract, the current price for LNG f.,o.b. Algeria would amount to some $0.363 / MMBtu. In rationalizing the price renegotiation, Sonatrach has observed that "in the decade since signing of the contract, the capital cost and operating costs of the project have increased substantially, and that, as a result, Sonatrach is suffering a huge financial burden while providing the cheapest incremental source of natural gas to the United States,"7 The renegotiated base price will be $1.75/MMBtu, effective as of July 1, 1979. A series of discounts will be applied to this price ranging from $0.60/MMBtu for the remainder of 1979 and then decreasing by $0. 10/MMBtu increments until mid-1983. The price escalator is tied to No. 2 and No. 6 fuel oils as described for the Algeria 11 project.

Unlike the Pertamina contract, the Sonatrach agreement provides for the regular review of the contract sales price. The parties are expected to meet during the first year after regular delivery begins, and every 4 years thereafter, to ascertain whether the prevailing price of the gas resulting from this project is still competitive in the U.S. energy markets. Furthermore, either party may request a meeting at any time if the particular indices selected to reflect fuel oil prices in the U.S. market fail to do so adequately.

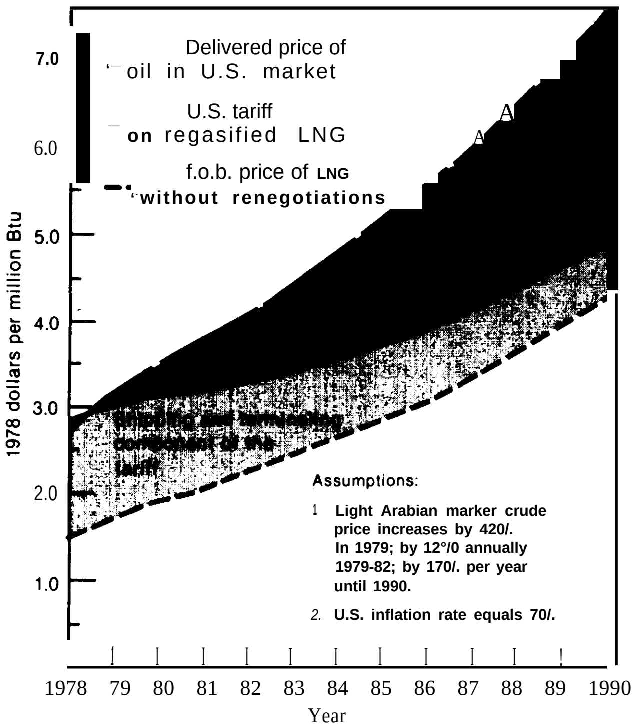
This important price provision may result in significantly higher f.o.b. prices to Sonatrach than would otherwise prevail without renegotiations. The reason is the disparity, which is

*In the Algeria I project El Paso Algeria purchases 1 Bcf/day equivalent of LNG from Sonatrach and delivers it to three importing pipeline companies—to subsidiaries of Consolidated Natural Gas Company and Columbia Gas System, Inc., at *Cove Point, Md.*, and to a subsidiary of Southern Natural Gas Company at Elba Island, Ga. Deliveries of LNG under the Algeria I project commenced on Mar. 1, 1978.

[7] *The Wall Street Journal*, May 14, 1979.

likely to develop over time, between the U.S. tariff imposed on the regasified LNG and the price of oil in U.S. markets (figure 15). In light of

Figure 15.—Comparison of the Forecast U.S. Tariff on Regasified LNG in the Algeria II Project With the Delivered Price of Fuel Oil*



. Every 4 years a portion of the difference between the delivered price of oil and the U.S. tariff on regasified LNG is liable to Sonatrach's claims through the operation of the price renegotiation clause.

SOURCE: Jensen Associates, Inc.

the price review provision, Sonatrach may claim this potential price differential for its own benefit. The price disparity–represented on the graph by the darker tone–will occur for the following reasons:

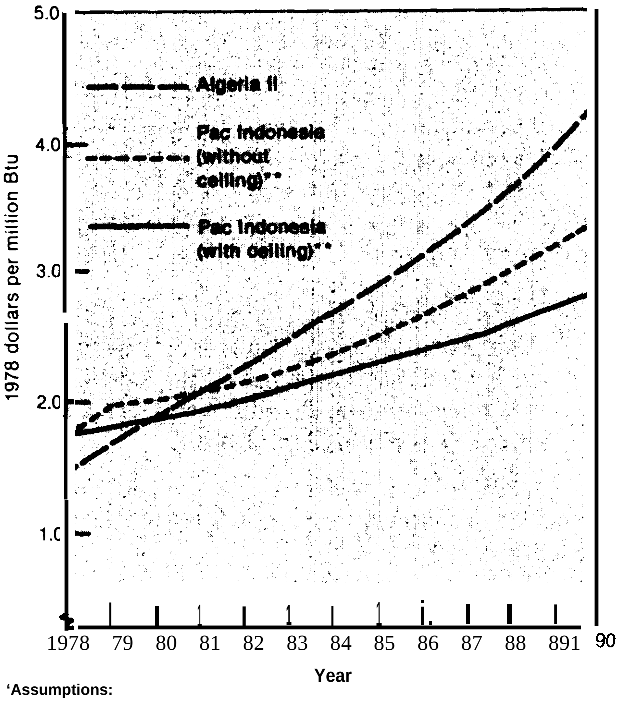
- The LNG (f.o.b.) price component of the tariff grows in the same proportion as the oil price, but since this rate of growth applies to a smaller base, the dollar difference between the oil price and the f.o.b. price for LNG increases in time.
- The shipping and terminating components of the tariff consist largely of capital charges, which are either fixed or declining in time–depending on how the tariff is designed. Operating costs are subject to inflation, but they constitute a small portion of the tariff. For simplicity, the graph reflects the assumption that the shipping and terminating components of the tariff will remain fixed.
- Because the f.o.b. price of LNG grows more slowly in terms of-absolute dollars than the oil price, while the shipping and terminating costs are fixed, a gap develops and grows between the price of oil and the tariff for the regasified LNG.

Revisions of f.o.b. price may well serve as a vehicle for liquidating such disparity by adding the price differential to Sonatrach's f.o.b. price for LNG. It should also be noted that by keeping the price of the gas competitive with that of oil, the price revision clause assures the marketability of Algerian gas in the United States. For instance, should the regasified LNG become more expensive than reference New York harbor fuel oils, the price renegotiation clause may be invoked to bring the price of Algerian gas down to the competitive level.

Conditional approval of the Algeria 11 project by the FPC/FERC administrative law judge on October 25, 1977, was subsequently reversed by DOE/ERA. Much of the ERA criticism of Sonatrach's price provisions echoed its earlier objection to the Pac Indonesia pricing mechanism prior to the issuance of the last amendment. ERA objected mostly to the fact that the Sonatrach price escalator is entirely linked to future changes in OPEC-determined prices of premium petroleum products. The formula was found lacking safeguards against extreme oil price increases, since it imposed no limits on the annual price fluctuations. ERA also criticized the use of No. 2 and No. 6 posted prices rather than the weighted average of the actual transaction prices (the latter practice is proposed for the Pac Indonesia project). DOE/ERA, however, indicated that its approval of the Pac Indonesia project did not create a precedent for subsequent decisions. In other words, should Sonatrach adopt exactly the same price provisions as Pertamina, the project would not necessarily be approved on those grounds alone.

Figure 16 depicts the forecast f.o.b. prices derived from Sonatrach's and Pertamina's formulas assuming no price renegotiations. Under the

Figure 16.—Forecast f.o.b. Prices Paid for LNG in Pac Indonesia and Algeria II Projects*



'Assumptions:

1. Light Arabian marker crude price increases by 420/. in 1979; by 12°/0 annually 1979-82; by 17°A per year until 1990.

2 U.S. inflation rate equals 70/. annually.

3. Sonatrach's formula is not periodically revised.

•"The two curves for Pac Indonesia show f.o.b. price calculated with and without the 15 percent ceiling on the annual fluctuations In the value of the Indonesia half of the price escalator.

SOURCE: Jensen Associates, Inc.

listed assumptions, Algeria 11 prices would increase considerably faster than Pac Indonesia's. This difference is due to two factors:

1. the expected rate of growth in the price of imported fuel oil is well above the presumed U.S. inflation rate; and
2. the annual ceiling on the Indonesian crude price increases limits the impact of the project price hikes.

Producing country facilities and related costs

PAC INDONESIA

The Pac Indonesia project entails the following operations in Indonesia:[8]

1. Production and gathering by Mobil Oil Indonesia of natural gas from the Arun field in North Sumatra and transportation of the gas via pipeline to Pertamina's liquefaction plant and marine terminal on the north coast of Sumatra.
2. Liquefaction, storage, and delivery of the LNG by Pertamina to the LNG vessels chartered by the Pac Indonesia LNG company at Pertamina's marine terminal.

The source of the gas is specified in the Pertamina contract as Contract Area "B" in the Aceh Province, * which contains the inland Arun gas condensate field discovered by Mobil Oil Indonesia in late 1971. Arun's proven reserves consist of an estimated 13 Tcf of nonassociated gas. For an LNG import project, nonassociated gas is preferable because the availability and stability of its supply is not adversely affected by potential interruptions and other problems in crude oil production.** Pertamina has contracted to sell LNG produced from Arun not only to Pac Indonesia by also to a group of five Japanese purchasers, who are scheduled to receive a slightly greater average daily volume.

The field is being developed by Mobil Indonesia, a wholly owned subsidiary of Mobil Oil Corporation, under a production-sharing contract with Pertamina. Eventually, 64 wells (with an average depth of 11,483 ft) will be needed to maintain an adequate gas supply for both Pac

'For description, see *Initial Derision on Importation of Liquefied Natural Gas From Indonesia,* FPC, July .22, 1977, *Docket NO.. CP 74-10* et al.

● Other producer countries, for instance Algeria, do not dedicate specific gas reserves to the fulfillment of individual contracts All Algerian gas reserves stand twhind all of its contracts.

* *For instance, Libyan gas is normally f'ound associated with crude oil and therefore gas availability depends to a great extent on crude oil production. Conservation policies in I.ihyan crude oil production will limit the quantities of gas available for liquefaction.

Indonesia and Japanese contracts. Due to unusually high reservoir pressure and temperature, each wellhead has to be equipped with specially designed piping and valves to control the gas stream.

From the field, the gas is transported to the Arun liquefaction plant at the north coast of Sumatra via a 42-inch-diameter, 20-mile-long pipeline with a design capacity of 1,777 MMcf/d–sufficient to transport the quantities of gas to service both the Japanese and the Pac Indonesia contracts. * As shown in table 25, the capital cost of the pipeline attributable to Pac Indonesia (half of the total) is $13 million.

Table 25.—Estimated Capital Costs of Indonesian-Based LNG Facilities for Pacific Indonesia Project' (millions of dollars)b

	Amount	Total
Pipeline		$ 13
Plant facilities		
Gas treating and liquefaction (3 trains)	202	
LNG storage and loading	81	
Plant utilities	59	
Site development, buildings, miscellaneous	88	
Contractor's home office costs	72	502
Supporting facilities		
Housing	49	
Communications facilities	6	
Other	7	62
Intangibles		
Project management	25	
Pre-startup and training costs	18	
Other (land, insurance, taxes, royalties, misc.)	35	78
Contingencies		50
Subtotal		**705**
Interest on funds used during construction:		**164**
Total		**$869**

aThese cost estimates include.
-The construction of liquefaction trains 4,5, and 6, assuming that procurement will take place in the world market and that mechanical completion of the 4th, 5th, and 6th trains will fake place in May, August, and November 1981 respectively.
-One-hlalf of the cost associated with the "common" facilities required to service all SIX liquefaction trains. Interest during construction IS not included.
bresumably 1976 dollars.
cEstlmated by Jensen Associates, Inc.

SOURCE: Testimony of President.Director of Pertamlna, Piet Harjono, before the Federal Power Commlsslon, Feb. 25, 1977. Exhibit No. 175, FPC Docket No CP-74-160.

*Mobil Indonesia estimates that its total expenditures in the Arun field will amount to approximately $1 billion of capital and operating costs over the life of the Japanese and Pac Indonesia contracts.

The liquefaction plant converts the natural gas received from the pipeline into a liquid suitable for storage. A liquefaction facility consists of three main sections.

1. *Gas preparation* section-Any constituents, such as water vapor, which freeze at liquefaction temperatures and thereby plug the cryogenic equipment, must be removed. Removal of hydrogen sulfide is also required to meet LNG product specifications.
2. *Liquefaction* section—Mechanical equipment refrigerates the gas in order to liquefy it. At atmospheric pressure, the gas becomes a liquid at – 260° F and its volume diminishes by a factor of 600.
3. *Storage and loading* section—Insulated tankers retain the natural gas as a liquid at atmospheric pressure, and the loading system transfers the product from land-based storage to oceangoing tankers.

Approximately 3 years are required for the complete design and construction of a large liquefaction plant.

The liquefaction facilities proposed for the Pac Indonesia project (the Arun plant) represent equipment, processes, and costs that are typical for contemporary large-scale LNG plants. The overall Arun plant will include six liquefaction trains (three for the Japanese project and three for Pac Indonesia) together with feed gas pretreatment, refrigerant preparation and storage, LNG loading, and required offsite and utility facilities.9 The first three liquefaction trains have already been completed and, since August 1978, are serving Pertamina's obligations to the Japanese clients. The design and construction of the first three trains anticipated the projected six-train operation in terms of sizing, location, and utilities layout. This sharing of facilities

[9]Testimony of Mr. William H. Thompson, an employee of Bechtel Overseas Corporation, before the FPC on Jan. 7, 1976 (FPC Docket No. CP 74-160, et al. Exhibits 48-53). Bechtel performed detailed design studies and procurement services for the Indonesian facilities. It also has responsibility for the construction.

[10]When completed, the LNG plant will contain 355 km (220 miles) of carbon steel pipe; 28 km (17 miles) of stainless steel pipe; 70,000 cubic meters (91,600 cubic yards) of concrete; 305,000 cubic meters (400,000 cubic yards) of rock and aggregate; 6.7 million cubic meters (12.7 million cubic yards) of dredging; and 900 km (560 miles) of electrical cable. *Oil and Gas Journal,* Mar. 13, 1978.

Photo credit El Paso Co

Frost forms at the flange and on the articulating arm as cold LNG flows onto an LNG tanker at the loading terminal

provides for convenience in operation and savings in capital costs.

Each train is designed to produce LNG equivalent to 200 MMcf'/d* in 341 days Of annual operation. Three trains would therefore produce 102 percent of the annual quantity contracted for by Pac Indonesia. Indeed, the Indonesian plants that serve Japanese contracts (Arun as well as the somewhat older Badak plant) have consistently produced well in excess of their design capacity. Reliability of production is enhanced by the fact that both gas-processing and liquefaction trains are arranged in parallel so that the failure of any one component will not result in a plant shutdown. Table 25 indicates that liquefaction equipment represents the greatest portion of direct costs-about w percent. Pertamina estimateci the cost of one liquefaction train to be constructed for Pac Indonesia at $67 million, assuming that procurement would take place in the world market and that all three trains would be completed by the end of 1981. *

LNG will be stored in four double-walled insulated tanks of 125,000 m^3 each. The combined capacity of the four tanks equals 8.5 days ful] production of' the six-train plant. The loading system utilizes four pumps (with a fifth as a spare), which drain LNG from the tanks through two insulated pipes. The pipes terminate in loading arms that accommodate the relative movement of the ship **and** the pier. The system is capable of loading a 125,000 m^3 ship in 12 hours at either of two berths. The total cost of LNG storage and loading facilities is $162 million, half of which constitutes Pac Indonesia's share.

ALGERIA II

The Algeria 11 project1[11] provides for daily delivery of approximately 1 Bcf/d, a volume close to the combined Pac Indonesia and Japanese contractual amounts. Liquefaction, storage, and loading facilities proposed for the Algeria 11 project are very similar to the ones described for the Arun plant. The six-train liquefaction facility at Arzew will use the same air products and chemicals (APCI) liquefaction process* * as in the Indonesia project. Plants are similarly arranged m parallel independent equipment trains. However, the facilities are designed to produce 105 percent of requireded yearly quantities in 330 days, thus, in theory, providing a greater allowance for downtime than the Arun plant (102 percent in 341 days). On the other hand, the Arzew plant will have relatively less storage space than the one at A run. Arzew will

*About 16 percent of the gross feed gas entering the plant is used as process fuel or lost in storage.

*The Pertamina-Pac Indonesia contract provides for delivery of LNG for maritime shipment commencing 38 months after receipt of all government approvals. Since the final U.S. approval of the terminal site has just recently been received, Pertamina will have to revise its proposed construction schedule.

[11] For more detailed discussion of the project, see *Initial Decision*, FERC, op.cit; and *Algeria II Project Summary*, El Paso, March 1977.

**This process utilizes a combined propane/mixed refrigerant cycle.

have three storage tanks, each with capacity of 100,000 m^3, to accommodate its 1,000 MMcf/d production, compared to Arun's four 125,000 m^3 tanks for the combined Pac Indonesia-Japanese production of 1,131 MMcf/d. Loading facilities are similar in both countries. Another common feature is sharing of equipment among projects. The six proposed trains for Algeria 11 will share certain supporting facilities—such as the cooling water system, steam system, and administration—with those already serving the Algeria I project, and the marine terminal will also serve other future projects.

As can be seen from table 26, the estimated capital cost of liquefaction and supporting facilities per million Btu of contracted daily production is comparable in both projects, reflecting similar processes and equipment. Sonatrach estimates the total capital cost of its Arzew plant at $1,276 million.

Table 26.—Capital Costs per Million Btu of Daily Contractual Quantity (1976 dollars/million Btu/day)

	Pac Indonesia	Algeria II
Pipeline from gasfield to liquefaction plant	$ 21	$ 360
Liquefaction, storage, and loading	1,117	1,134
Subtotal	1,138	1,494
Estimated interest on funds used during construction	265	348
Total	$1,403	$1,842

SOURCE: Jensen Associates, Inc.

The most significant difference in the costs of the two projects lies in the respective field and pipeline systems. The Hassi R'Mel field, which will Supply gas for the Algeria 11 project, * requires only 22 wells with an average depth of 7,054 ft to supply the contract quantity. In comparison the Indonesian Arun field requires 64 wells with an average depth of 11,483 ft, plus special stream control equipment, to produce a similar amount of gas. These factors influence production costs, since, for example, drilling costs rise almost exponentially with well depth. Sonatrach has estimated that its field facilities for Algeria 11 would cost $228 million.

While the Pac Indonesia project requires only a 20-mile, 42-inch pipeline between the field and the liquefaction plant, the cost of which would be shared with the Japanese purchasers, Sonatrach plans to construct a 315-mile-long, 40-inch-diameter pipeline exclusively for the Algeria II project between Hassi R'Mel and the liquefaction plant at Arzew. Gas turbines at five compressor stations will maintain the pressure and flow. The estimated cost of the pipeline is $405 million, and as shown in table 26 the capital cost it represents per million Btu of daily contracted quantity is 17 times higher in the Algeria II project than in Pac Indonesia, reelecting the difference in the mileage. * Sonatrach estimates the total construction funds to be $2,300 million, and the annual operating cost at $60 million (1976 prices).

Transportation facilities—cryogenic tankers

Although they resemble conventional tankers in many ways, LNG carriers are highly specialized, with designs strongly influenced by the unique characteristics of LNG—especially its low density, cryogenic temperature, and flammability.[12] The principal feature is extensive insulation of the tanks to minimize vaporization en route and to protect parts of the ship's structure that would be damaged by extreme cold.

For the actual arrangements of LNG shipping, several alternatives are available. An importer, or exporter, may own the vessels or operate them through bare-boat charters, contracts of affreightment, time charters, or leverage lease arrangements. The proposed shipping arrangements for Algeria 11 and Pac Indonesia illustrate two of these alternatives.

The Algeria 11 fleet would consist of 12 tankers, each with cargo capacity of 125,000 m^3. Six of the vessels would be furnished by Sonatrach,

*Hassi R'Mel is one of the largest fields of nonassociated gas in the world, and it serves a number of Sonatrach contracts.

*In terms of pipeline capital costs per million Btu-mile of daily contracted quantity, Sonatrach's costs are similar to Pertamina's.

[12]For a comparison of the principal characteristics of an LNG carrier with those of an oil tanker of equivalent size see "Algeria II LNG Project Plants Detailed," Dr. Luino Dell'Osso, the *Oil and Gas Journal*, May 29, 1978.

Photo credjt Marty Saccone

Modern LNG tankers typically carry 125,000 m^3 of liquefied gas

the other six by El Paso Atlantic, presumably through indivual shipowners.[15]

Each carrier will have an average service speed of 18.5 knots and will be capable of completing the round trip voyage of about 10, I50 nautical miles between Arzew and the La Salle terminal in an average of 28.4 days. With each ship operating from 332 to 333 days per year, the fleet will transport 143 loads of LNG annually, and a ship will arrive at the La Salle terminal approximately every 2.5 days. The energy delivered by the LNG carrier fleet for use in the United States will represent about 95 percent of the quantity loaded at the Arzew terminal. The small amount of vapor that boils off during the trip is consumed as fuel in the ship's boilers.

In addition to the double hull, other safety features of the carriers include a computerized collision avoidance system, bow thruster, lead-detection systems, dry-chemical and water fire-fighting systems, two complete navigational ra-

[15] It has not been finally decided whether Atlantic would build the six ships or charter them in some fashion. Most probably, each ship will be owned by a separate subsidiary of the El Paso LNG Company: three foreign and three domestic corporations are assumed. (*Summary of the Evidence*, El Paso Eastern Compay, et al., July 15, 1977, Docket Nos. CP 77-330, et al.)

dar systems, and five separate communication systems. 14

The estimated yard cost per vessel, constructed in a foreign shipyard—or in a U.S. shipyard, after construction differential subsidy*—would be about $106.5 million at 1976 prices. Other direct and indirect capital costs relating to the vessels (see table 27) would bring the estimated capital investment per ship to $142.6 million. Shore-based facilities for all] 12 vessels would be supplied by Atlantic at an estimated cost of $40 million. Thus, assuming that the same capital cost is required for Atlantic's and Sonatrach's vessels ($142.6 million per tanker), the aggregate investment by Atlantic would be $896 million, and $856 million by Sonatrach. The total estimated capital cost for the Algeria II tanker fleet would therefore amount to **$1,752** million, or $1)639 / MMBtu / d.

Operating costs of LNG vessels are a function of trip distance. For Algeria 11, the total fleet operating expenses per year have been estimated at $72.5 million (1976 prices). Atlantic's operating cost—for three foreign and three domestic vessels--would amount to. about $38 million annually (see table 28). The corresponding expenses for Sonatrach's vessels are expected to be the same as those estimated for Atlantic's foreign vessels, 15 and therefore would tot al about $34.5 million. The total operating costs amount to $(). 19 / MIMBtu delivered in the Algeria 11 project.

The Pac Indonesia project involves a different shipping arrangement. To transport the purchased LNG from North Sumatra to the United States (8,300" nautical miles each way), Pac Indonesia has entered into contracts for the hire

Table 27.—Estimated Capital Requirements for El Paso Atlantic—Six Vessels
(thousands of 1976 dollars)

Description	Amount	Total
Capital costs for six vessels		
Direct vessel capital costs		
Yard cost, six-125,000 m³ LNG carriers	$640,200	
Construction supervision, inspection, design, and plan approval	9,600	
Owner's outfitting equipment and expenses	10,884	
Preoperating and organizing expenses	5,829	
Sea and gas trials	1,842	$668,335
Other vessel capital costs		
Replacement cost insurance	4,104	
Financing fees	10,530	
Working capital associated with vessels	13,746	28,380
Capitalized financing charges		
Allowance for funds used during construction consisting of:		
Interest on debt funds @ 8.8%/annum	77,172	
Allowance on equity funds @ 18.41%/annum	64,867	142,039
Fleet contingency		16,776
Total capital costs for six vessels		855,550
Shore-based facilities and project capital costs		
Shore-based structures and equipment	6,953	
Precertification intangible plant	4,897	
Capitalized administrative and general expenses, consulting fees, and other	9,585	
Provision for working capital	567	
Allowance on equity funds @ 18.41%/annum	17,186	
Shore-based contingency	838	40,026
Estimated total capital requirements		$895,576

SOURCE: El Paso Atlantic Company, *Economics of Shipping Algerian LNG to Texas Gulf Coast*, Oct. 11,1976.

of nine vessels. Three of the vessels have already been constructed in foreign shipyards, and plans call for the remaining six to be built in U.S. yards. All of the ships would be available to Pac Indonesia under time charter agreements, which provide for monthly billing beginning on specified dates. The FPC'S administrative law judge described these arrangements as follows:

> An important feature of the time charters and transportation agreements for all nine ships is the offhire provisions which, generally, absolve Pac Indonesia from payment during the period when the vessel is prevented from working through no fault of Pac Indonesia (for example, through collision, stranding, fire, or other

[14] "Algeria II LNG Project Plans Detailed," *loc. cit.*, p. 67. Safety analyses for LNG projects repeatedly identify a ship accident as the most likely event that could trigger the most serious type of LNG accident (*Transportation of Liquefied Natural Gas,* OTA, September 1977, p. 18).

*Governments offer various subsidy programs to the shipbuilding industry in individual countries to keep their shipyards competitive in the LNG tanker market. In the United States, most tankers are financed with several forms of aid from MarAd, one of which is a construction differential subsidy (CDS). For Algeria II vessels to be constructed in the United States, a 25-percent CDS has been applied to the estimated $142 million yard cost per vessel (1976, 4th quarter prices).

[15] *Summary of the Evidence,* op. cit., p. 23.

Table 28.—Estimated Annual Operating Expenses for El Paso Atlantic—Six Vessels

Operating expenses for six vessels	Thousands of 1976 dollars
Crew (3 foreign, 3 U.S.)	$ 8,172
Maintenance and repair	5,856
Stores and supplies @ $103,000/ship	618
Bunker "C" fuel @ $1,371,000/ship	8,226
Nitrogen	354
Annual insurance premiums	8,484
Post charges	2,484
Shoreside expenses	3,527
Manning agent (3 foreign ships only)	42
Miscellaneous expenses @ $29,000/ship	174
Estimated total annual operating expenses	$37,937

SOURCE. El Paso Atlantlc Company, Economics of Shipping *A/ger/an LNG to Texas Gulf Coast,* Oct 11, 1976

accident or damage to the vessel, breakdown of the vessel's machinery, deficiency of men or stores). These risks are thus borne by the shipowners, not Pac Indonesia. 16

The capacity of each vessel will be about 125,000 m³, the industry's current standard. Each carrier will be scheduled to operate 345 days out of the year (as opposed to 332 to 333 in the Algeria II project) leaving the balance of the year for shipyard repairs and miscellaneous delays. At an average speed of 18.5 knots, each ship will require 18.7 days for the 8,300 nautical-mile voyage from Indonesia to the United States and will be able to complete 8.5 round trips per year. The energy delivered to the United States will be approximately 92 percent of the quantity loaded at the A run terminal, reflecting fuel use of boil-off vapors during the voyage.

To illustrate how the shipping distance affects costs, the capital and operating costs per vessel on Pac Indonesia's project are assumed to equal the corresponding costs for Algeria II. Under such an assumption, the shipping costs per million Btu of LNG delivered daily in the Pac Indonesia project would exceed by 42 percent the equivalent costs in the Algeria 11 case, as a result of the greater distance involved in the Inck)-nesian project.

The capital costs of the three foreign ships constructed in French shipyards* and chartered by Pac Indonesia are not publicly disclosed, but can be reasonably estimated at approximately $100 million per vessel. Pac Indonesia's transportation contracts with U.S. shippers, concluded in late 1975, provide for charter rates based, in part, on the estimated capital costs of $140 million per American-mack tinsel plus escalations. The FPC judge used $155 million estimated average capital cost per U.S. vessel in establishing the shipping component of Pac Indonesia's initial certificate rate. This figure represents the judge's estimate (in mid-1977) of the average cost for the six U.S. tankers assuming a specified delivery schedule between January 1980 and May 1981. The actual inflation in LNG tanker construction costs in the United States turned out to be higher, judging by the current (mid-1979) total price estimate of about $195 million (after subsidy) per 125,000 m³ vessel to be delivered in 1982-83.

Receiving country terminal and regasification facilities

A terminal for the receipt of LNG consists of three major segments-unloading, storage, and vaporization. The principal components of the unloading portion of the terminal are berthing facilities, unloading arms and lines, return vapor lines and blowers, and prov'isions for handling excess vaporization due to boil off. The storage facilities at the receiving terminal are similar in type to those at the liquefaction plant. "The regasification (vaporizing) equipment consists of liquid pumps and vaporizers. Regasification facilities represent much less sophisticated technology than do the liquefaction plants in the producing country. In terms of the total costs involved, the importing country's facilities usually account for the smallest portion of a three-part LNG project. The design and construction of the receiving terminal facilities require 2 to 3 years.

Pac Indonesia proposes the construction of an LNG terminal on the southern California coast approximately 3.5 miles east of Point [conception. * The plant will have an ultimate baseload capability of 1,300 M Mcf/d, with peak \'aporiza-

[16] *Initial Decision on Importation on Liquefied Natural Gas from Indonesia,* FPC, op. cit., p. 17.

*One was completed in 1975, the other two in 1977.

*The Public Utilities Commission of California, which considered several sites for the Pac Indonesia terminal, chose Point Conception because a 1977 State law required an unpopulated location for the site.

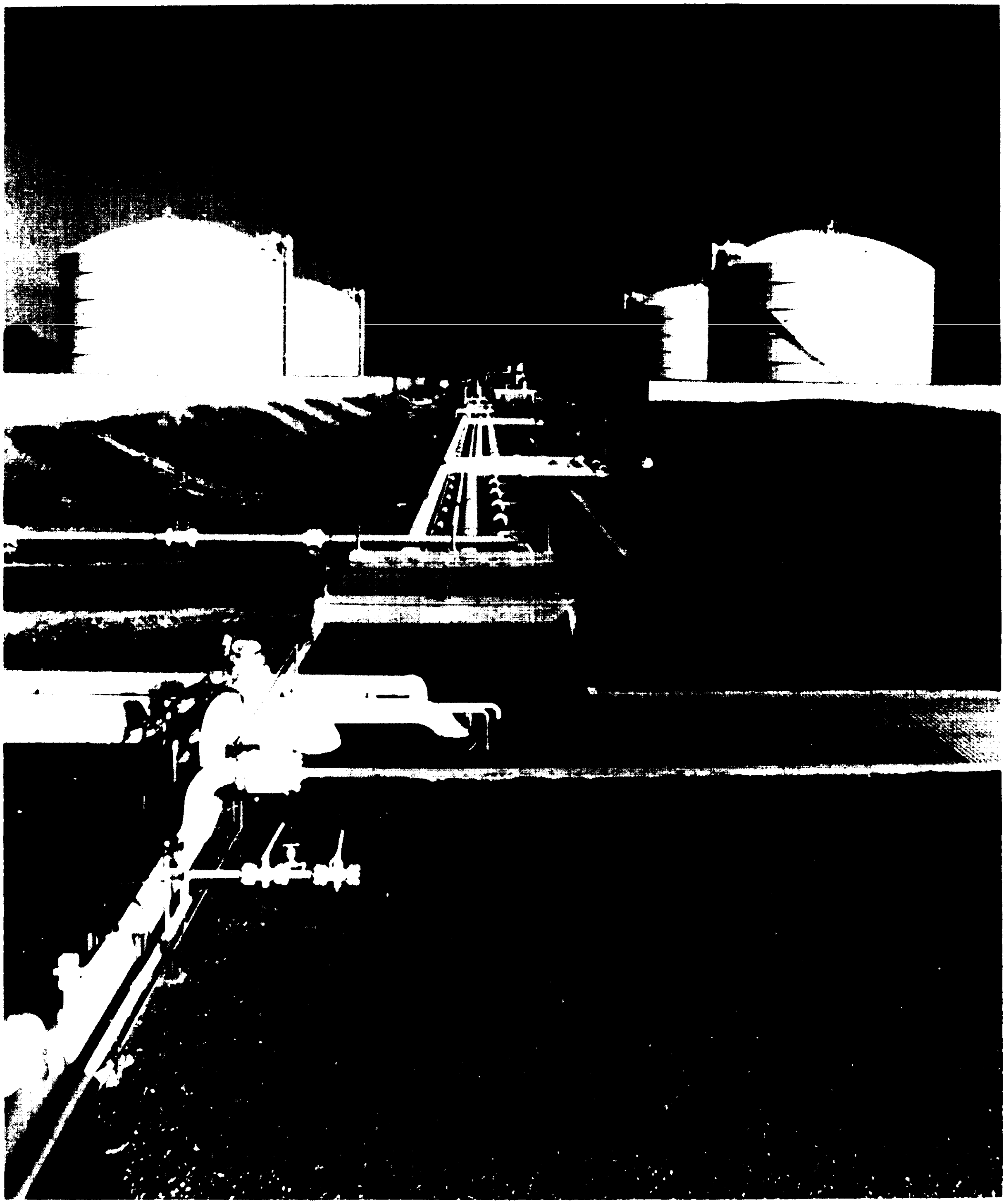


Photo credit' Courtesy of Colomb/a Gas System, Inc.., Consolidated Natural **Gas Co,** *and American Petroleum Institute*

LNG receiving terminal at Cove Point, Md. At the terminal LNG will be converted back into ordinary natural gas for use by customers of the Columbia Gas System, Inc., and the Consolidated Natural Gas Company tion capacity of an additional 300 MMcf/d. The Indonesian volume to be received at the terminal is estimated to be about 500 MMcf/d. The total baseload capacity will be shared by Pac Indonesia and Pacific Alaska LNG Associates (the latter proposes to import LNG from the Cook Inlet area of Alaska).

The marine facilities will consist of one berth located about 4,600 ft offshore. LNG from the ship will be unloaded into the land-based LNG storage tanks by onboard ship pumps. Three 550,000 barrel double-wall, insulated storage tanks are planned for the terminal.

Thirteen seawater-heated LNG vaporizers will be installed to accommodate the total baseload, and peaking capacity of 300 Mcf/d will be provided by additional gas-fired LNG vaporizers. The vaporization plant is designed to deliver natural gas continuously 365 days per year. The gas will then go through a trim heater, odorizers, and metering station, before entering the gas transmission system.

A 112-mile, 34-inch pipeline looped with another 45-mile, 34-inch pipeline will extend from the metering station at the terminal site to a point of interconnection with PG&E's existing pipeline near Gosford, Calif., with an intervening interconnection with Southern California Gas Company's present facilities at North Coles Levee. The present pipeline design requires no compressor stations. 17

The total estimated capital cost of the Point Conception terminal amounts to $632 million (in mid-1977 dollars), and the annual operating costs to $20 million—see tables 29 and 30 respectively. The estimated capital cost of the new pipeline requires another $117 million (see table 31). On a strictly volumetric basis, the Pac Indonesia share will be over 58 percent, or $368 million for the terminal facilities and $68 million for the pipeline. Pac Indonesia's costs would be higher if the facilities were built for the use of this project alone. For instance, all storage tanks would still be needed, due to the industry's practice of requiring that storage space be suffi-

[17] The proposed Point Conception terminal is described in the Western LNG Terminal Associates' Application No. 57626 before PUC of California, Oct. 14, 1977.

Table 29.—Point Conception Terminal Estimate of Capital Costs
(1.3 Bcf/d baseload capacity plus 0.3 Bfc/d peaking capacity)

	Thousands of 1977 dollars	
Construction costs		
LNG unloading	$24,828	
LNG storage	76,382	
Vaporization	48,772	
Seawater system	61,173	
Utilities and offsites	76,403	
Dock and trestle	78,027	$365,585
Engineering fees and sales tax		13,264
Contingencies and in-house costs		59,497
General terminal costs		33,955
Allowance for funds used during construction		150,623
Spare parts, working capital and financing fees		9,076
Capital costs total		$632,000

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, Dec. 14, 1977.

Table 30.—Point Conception Terminal Estimate of Annual Operating Costs
(1.3 Bcf/d baseload capacity plus 0.3 Bcf/d peaking capacity)

	Thousands of 1977 dollars
Total manpower	$ 1,102
Utilities:	
Fuel	2,650
Electricity	10,400
Nitrogen	100
Chemicals:	
Water treatment, thiophane, chlorine	500
Maintenance @ 1% of $379 million (construction cost)	3,790
Insurance @ 0.5% of $379 million	1,895
Total annual operating costs	$20,437

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, dated Dec. 14, 1977.

Table 31.—Point Conception to Gosford Pipeline Estimate of Investment Requirements

	Thousands of 1977 dollars
Construction costs	$ 91,867
Engineering fees and sales tax	4,743
Contingencies and in-house costs	11,163
Allowance for funds used during construction	7,978
Spare parts and working capital	1,090
Investment requirements total	$116,841

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, dated Dec. 14, 1977.

cient to accommodate at least two LNG shiploads. Pipeline costs also exhibit economies of scale.

The Algeria 11 project involves the construction of the La Salle terminal in Matagorda Bay, designed for a maximum sendout rate of 1.64 Bcf/d. Thus, unlike Pac Indonesia's terminal, La Salle would be serving only the Algeria 11 project. 1[8] The marine terminal consists of independent berths to accommodate two LNG carriers simultaneously. More storage will be available than in Pac Indonesia's terminal; three 629)000 barrel tanks. The estimated cost of the La Salle terminal is $456 million (4th quarter, 1976), which as table 32 indicates, amounts to a higher cost per million Btu delivered than in Pac Indonesia's project. This discrepancy is due primarily to the volumetric cost allocation for the Pac Indonesia project, and only secondarily to the physical differences between the two terminals.

[18]The terminal may be used for receiving LPG or LNG from outside this project during periods of interruption. This use would mitigate the cost of El Paso (and to consumers) in the event of supply interruption (*Summary of the Evidence*, El Paso Eastern, et al., FPC Docket CP 77-330, et al., p. 40).

Algeria II requires more extensive pipeline facilities on the receiving end than does Pac Indonesia. El Paso Natural proposes to build a pipeline capable of accepting 115 percent of the average daily output of La Salle terminal, or 1,065 MMcf. The first 31 miles of the new pipeline (36-inch diameter) will transport the gas from the La Salle terminal to United LNG's present facilities near Victoria, Tex., where 35 percent of the total quantity will be sold. The remaining 65 percent will be transported via a 432-mile (30-inch diameter) pipeline to El Paso Natural's system at Waya, Tex. Together with the required five compressor stations, the new pipeline facilities are estimated to cost $263 million. As shown in table 32, the pipeline cost per million Btu per day is 37 percent of the total capital investment in Algeria II import facilities, whereas similar costs for the Pac Indonesia project are only 16 percent.

Table 32.–Capital Costs for Import Facilities per Million Btu of Daily Delivered Quantity of LNG

	Total capital cost (1977 $ million)		Assumed throughput (billion Btu/day)	1977 $/MMBtu/day		
	Terminal and regasification	Pipeline		Terminal and regasification	Pipeline	Total
Pac Indonesia. . . .	$632	$117	$ 570[a]	$1,109	205	1,314
			978[b]	646	120	766
Algeria II	456	263	1,069	427	246	673

[a]Assuming only Pac Indonesia's volume.
[b]Assuming both Pac Indonesia's and Pac Alaska's volumes.
SOURCE: Jensen Associates, Inc.

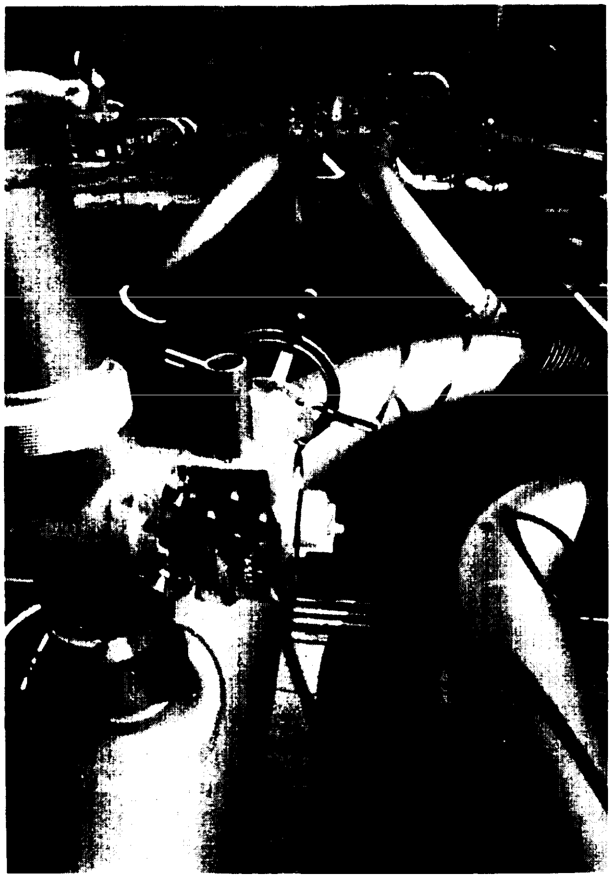
LNG financing

Because much of the cost of an LNG project is incurred at the beginning of the project, and because an LNG project has a long economic lifetime, financing terms strongly influence the unit cost (cost-of-service) of moving the gas from the field to the market. This section examines some of the major financing options open to LNG project sponsors and then, incorporating this information, derives an idealized cost-of-service.

Overview

The fundamental determinants of financibility for any capital project are risk and return. The important characteristics of an LNG project affecting perceptions regarding risk and return are:

- The total capital costs of an LNG project are large, and the return is not certain.



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- Ownership of LNG projects is often spread among parties in different countries.
- Integrated LNG projects are comprised of several stages (e.g., liquefaction, shipping), each one possessing an individual identity.

To see how the scale of capital requirements for an LNG project impacts financibility, it is useful to put the capital requirements in perspective. The estimated costs of the proposed Algeria 11 project total over $5 billion from wellhead to final consumer. By comparison, total U.S. net private fixed investment in 1978 was only $128.7 billion, * and this for the largest economy in the world.

*Figure net of capital consumption allowance

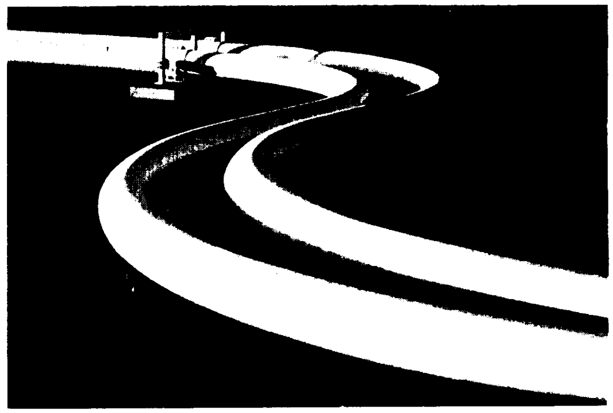

Photo *credit. El Paso Co*

Natural gas transmission lines may be seen above--ground in remote areas, but most of the Nation's pipeline system is underground

Because capital requirements are so large, project sponsors may have to look to several capital markets for funding, simply because the total exposure would be too large for one market to absorb. By using several capital markets and many lenders, project sponsors can diffuse the large financial risk of the project and thereby reduce borrowing costs. However, the use of several capital markets (or, for that matter, large financing in one capital market) may entail substantial transactions costs, offsetting the gains achieved through this strategy and, in fact, ultimately limiting the degree of diversification that is economically feasible.

Transaction costs incurred through diversification may take several forms. The requirement for documentation alone can be significant. In the U.S. institutional market, for example, each of several separate bond issues underwritten and offered publicly could require a separate prospectus and indenture, demanding significant outlays for legal, accounting, and possibly technical services. Transactions costs may also take the form of decreased flexibility. Restrictive covenants required in one capital market on, say, an issue of unsecured bonds may limit the project sponsors' freedom in obtaining financing in other markets.

In addition to the high transaction costs of reliance on many sources for financing, the size of the project ultimately limits the capacity of capital markets to absorb the risk. Whereas a modestly sized capital investment can be divided among many investors so as to represent only a small portion of any single portfolio, an LNG project is sufficiently large that enough lenders may not be available to distribute the risk adequately.

A second major factor influencing financibility is the international character of LNG projects, since financiers look to the contracts among the parties for security. Since the contract signatories are typically domiciled in different countries and, perhaps more fundamentally, since their physical facilities are located in different countries, no one legal jurisdiction can enforce the claims of one party against another.

A third factor is the multistage nature of the LNG project, and separate stages of the LNG project may have access to different capital markets for several reasons. First, for facilities to be owned, for example, by the producing country, officially supported credits may be available from countries desiring to promote exports from their own construction and capital goods industries. A second reason is that potential lenders may have different attitudes toward risk depending on the stage. An LNG import terminal, for example, can be used efficiently for one purpose only: the receipt, storage, and regasification of liquid gases at the location where the terminal is built. If the project fails because of, say, market conditions in the importing country, the terminal just sits there generating capital charges. The LNG carriers, on the other hand, if prohibited from offloading at the inoperative terminal can still be used in an LNG trade somewhere else. Thus, the potential investors might perceive less risk attendant on LNG carriers than on an import terminal.

The following sections examine, in light of these general considerations, some of the financing options open to the sponsors of LNG projects, with a particular view toward their effects on project cost. The discussion is organized by production stage: first, exporting country facilities, then ships, and finally, U.S. import terminals. For each stage, the discussion of financing focuses on the debt requirements, and the section on the financing of exporting country facilities includes overall project equity.

Exporting country facilities

Total capital requirements for exporting facilities may vary considerably with differences in gasfield characteristics, distance of field from the plantsite, cost of local labor, and other variables, but for a project of 1 Bcf/d the total cost of all exporting country facilities is likely to be well over $1 billion, and may exceed $2 billion.

The total cost of the facilities may be financed with the credit backing of the exporting country itself, as in the case of the Algeria 11 project, by outside participants, such as multinational oil companies, or a combination of both. While "project" financing, for which the security is the value of the specific facilities or contractual obligations associated with the project itself, may be possible in concept, financing is not likely to be obtained in this way without independent credit support.

Major sources of capital for producing country facilities include the eurocurrency market, private and public equity, and in the case of exporting country ownership, officially supported export credits. Each of these sources are discussed below.

OFFICIALLY SUPPORTED EXPORT CREDITS

Several Organization for Economic Cooperation and Development (OECD) countries have officially supported export credit programs, which supply direct loans and credit guarantees to promote their industries. This tied financing offers some important advantages to the LNG exporting country. While some export credit programs, such as those of the United States and Germany have tended to be on basically commercial terms, other countries, such as France, Japan, and the United Kingdom offer preferential–if not concessionary–credit supports. The lower cost of the financing available from some countries improves the economic viability of the project from the point of view of the producing country and also lowers the cost-of-service. A second advantage of officially supported export credits is that other potential lenders to the project may feel more secure in their investments with the participation of official government agencies, and in any event, will perceive that the lower cost of funds available through export credit financing provides additional capacity to service private debt.

France, through its foreign trade bank BFCE (Banque Francaise du Commerce **Exterieur),** provides financing for long-term maturities through either direct credits at subsidized rates or through discount and refinancing arrangements. The rate on the BFCE direct credit, or discount on the subsidized portion of the bank loan, is set by BFCE so that the blended rate, * exclusive of fees and premiums, is at the minimum allowed under the OECD arrangement. * * In addition, Coface (Compagnis Francaise d'Assurance pour le Commerce Exterieur) guarantees the total amount of the credit (BFCE plus private portion) for a rate premium of approximately 0.85 percent.

In some cases, however, the French "mix" credits by tying aid and loans together in one package. Such tied-aid credits may include loans at rates as low as 3.5 percent with repayment terms up to 20 years. The average cost of such a package is therefore considerably less than it would be in a strict export finance deal.

Japan, through the Ministry of International Trade and Industry and its Export-Import Bank, also provides long-term finance packages on preferential terms. As France's BFCE, Japan's Export-Import Bank will extend direct credits, up to 60 percent of the total export financing, so that the blended rate is at or near the minimum allowed by the OECD arrangement. As with Coface, their Export-Import Bank provides insurance for its own and the private loan portions of the total credit for a premium.

Japan has officially denied that it offers tied-aid credits to an extent that would derogate the OECD arrangement. However, some claim that tied-aid credits on essentially concessionary terms are widely available for export financing from Japan.

The United Kingdom through ECGD (Export Credits Guarantee Department) sets rates for commercial bank loans to buyers and pays a direct interest subsidy to banks to make up for the actual cost of funds. To relieve the overall credit burden this creates, ECGD also provides limited refinancing for sterling denominated loans used for export financing. ECGD guarantees 100 percent of the bank loans, and the rates set by ECGD are, as in the case of France and Japan, at or near the minimum allowed under the OECD arrangement. British tied-aid credit financing is also available.

The United States and Germany are more conservative in their approach to export financing. Historically neither country has typically offered tied-aid financing of exports. In addition, both countries operate their respective export programs without recourse to subsidy–in the case of Germany only a modicum of direct credits are even provided at long-term and preferential rates, the bulk of long-term credit support taking the form of insurance.

The United States through the Export-Import Bank (Eximbank) and related organizations such as the Private Export Funding Corporation, provides support for long-term export credits. Historically, Eximbank has provided direct credit at rates linked to the agency's cost of funds and has guaranteed the private bank portions of the total credit, which are usually extended at floating rates. Eximbank typically charges a guarantee fee on the private bank portion.

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*The effective average rate for the total subsidized and unsubsidized portions.

**The OECD Arrangement of Guidelines for Officially Supported Export Credits represents an attempt by participating OECD nations to forestall wasteful and commercially unsound competition among participants for export contracts. This agreement, which replaced the old Consensus Agreement, limits competition in interest rates and repayment terms. For buyers classed as "relatively poor countries" repayment terms are allowed up to 10 years. Interest rates are not permitted to be below 7.5 percent on longer maturities and 7.25 percent for maturities of 2 to 5 years. For "relatively rich countries" repayment terms are limited to a maximum of 8.5 years at a minimum interest rate of 8 percent for the longer maturities and 7.5 percent for maturities of 2 to 5 years. All export finance packages require a cash downpayment of 15 percent of the total contract value of goods and services by the purchasing country.

In addition to the 85 percent of contract value permitted to be supported by export credits, certain local cost coverage is allowed by the arrangement. Local cost coverage is limited, however, so that the total amount does not exceed 100 percent of the contract value of goods and services to be exported.

Recently, however, U.S. Eximbank policy has begun to favor improving competitiveness with foreign export agencies. This policy shift is reflected in the tendency toward increased direct coverage at reduced rates. In so-called exceptional cases, Eximbank may offer a direct credit for the total amount of the export credit (85 percent of the contract cost of the goods and services) at rates below the agency's marginal cost of funds.

An example of the use of export credit is the U.S. Eximbank's $240 million credit to Algeria to help finance $320 million U.S. goods and services component of the Arzew 11 liquefaction plant. The credit was extended to Sonatrach at 8.5 percent. Repayment is in 20 semiannual payments beginning 6 months after the last of six liquefaction trains is completed. The remainder of the U.S. goods and services component is to be financed by a Sonatrach payment of $48 million (15 percent) and private-source loans of $32 million. Payments on the total of the Eximbank credit and the private source loans will be arranged in such a way that the private-source loans are paid off first.

THE EUROCURRENCY MARKET

Another important source for financing of LNG exporting country facilities (whether owned by the country in question or by outside parties) is the eurocurrency market, in which loans are negotiated in currencies not native to the country in which the bank offering the loan is located (eurocurrency bank credits) and bonds are issued outside the country of the borrower (international bonds). The size of this market is substantial. In 1978 alone, over $70 billion in eurocurrency bank credits were negotiated, and new international bond issues totaled $35 billion. In 1978, Algeria, a major LNG producing nation, borrowed over $3 billion on the eurocurrency market, while Indonesia, another important LNG center, borrowed over $1 billion.

An important feature of the eurocurrency bank credit market is that its funding tends to be for periods of no more than 5 to 10 years. Also, loans on this market typically have floating interest rates. So, for example, a loan on this market with a repayment term of 8 years might carry an interest rate of 1.75 percent over LIBOR (the London interbank offering rate, a measure of the bank's cost of funds), reflecting maturities of 6 months. At the end of each 6-month period, the loan is effectively renewed for the amount of principal still outstanding at an interest rate corresponding to the then- current LIBOR.

One of the main advantages of the eurocurrency bank credit market is that with sufficient credit backing, such as the guarantee of the Central Bank or Development Bank of the potential LNG exporting country, considerable funds are available on this market. A second advantage is that credit obtained on this market, and private-source capital in general, tends to have fewer strings attached than, for example, the tied loans available through officially supported export-financing agencies.

Two important disadvantages of this market are the shortness of the repayment periods and the variability of the interest rates. The economics of large projects with long lifetimes sometimes are not certain until late in the project, and if the loan must be amortized over too short a period at the beginning, debt service may exceed the available cash flow after deduction of other expenses. In such an instance, borrowing from equity is required, and to the extent that this is expensive or simply not feasible, other financing arrangements are necessary,

The variability of interest rates on eurocurrency bank credit also adds a dimension of uncertainty to the management of cash flow and to the overall economics of the project. owners of long-term projects may be willing to pay a considerable premium to remove this element of uncertainty.

An example of eurocurrency bank credit is the $250 million 7-year loan raised by Sonatrach, guaranteed by the Banque Nationale de'Algerie, and jointly led by Citicorp, Bank of America, Apicorp, Bankers Trust, Bank of Montreal, and Continental Illinois. This loan carries an interest rate of 1-3/8 percent over LIBOR and will help to finance the Arzew II liquefaction plant facilities.

Fixed interest rate financing is also possible on the euromarket through the issue of bonds or notes. These international bonds, which are comparable in terms of maturity with eurocurrency bank credits (5 to 10 years), can provide added cash flow predictability at a minimum cost.

Examples of eurobonds are two recent Sonatrach issues, one 12 million dinars (DA) guaranteed by the Banque Exterieure d'Algerie, maturing in 10 years, bearing a yield of 8.5 percent; and one DA 8 million 5-year maturity bearing 8.5 percent.

PUBLIC AND PRIVATE EQUITY

A third important element of financing for LNG exporting country facilities is public and private equity. Equity capital can be generated by reinvestment of earnings, such as profits from a country's other hydrocarbon ventures or the net revenues from unrelated operations of a multinational oil company; or alternatively, through the issue of ownership shares, as exemplified by the Islamic Development Bank's equity participation in Jordan's petroleum refinery project. Equity can be public, resulting from taxation or earnings on public enterprises; or private, supplied by ownership of shares by private entities.

Generally, lenders require some equity as a buffer in the event of difficulties, but it can dilute ownership and is typically more expensive than debt. The U.S. Eximbank, for exampIe requires a 15-percent cash payment by the buyer of U.S. export goods. This 15-percent may be funded by equity or debt or both, however, and this 15-percent should therefore not be viewed as necessarily bearing "true" equity costs.

CONCLUS1ON

Whether the project owners are to be the exporting country itself, an outside entity, or a combination, many financing options are available as described above. Nevertheless, certain constraints should be recognized. The availability of officially supported export credit financing at preferential or concessionary rates may depend on who owns the producing country facilities. In addition, while project financing is possible in principle, it is rare in practice, and consequently, the total cost of the financing may exceed the prima facie cost of the borrowings because of the impact on the debt capacity of the guarantor.

Shipping

Many of the private capital markets for the financing of exporting country facilities are open also for LNG ships. In addition, as in the case of the exporting country facilities, officially supported financing is available for LNG shipping and may be provided by export credit agencies such as Germany's Hermes (Hermes Kreditversicherung) or by other government agencies such as the U.S. Maritime Administration (MarAd).

MarAd offers a loan guarantee program applicable to LNG ships if they are built in U.S. shipyards, registered under the U.S. flag, owned by U.S. entities, and crewed by U.S. citizens. Under these conditions, as much as 87.5 percent of the total cost of a ship can be financed by an issue of U.S. Government guaranteed serial or sinking fund bonds, either with maturities up to 25 years. The cost to the borrower is the yield on the bonds plus the MarAd guarantee fee (0.5 to 1.0 percent of the outstanding balance), amounting to a total in the range of a Baa industrial.

The MarAd program is not subsidized, though default claims are paid from a pool funded by MarAd's overall operations. Consequently, the public does not contribute directly to defraying the cost of funds to borrowers using MarAd credit guarantees. However, the MarAd guarantee is valuable to potential borrowers in the sense that MarAd may be better able to spread the risk in ship financing than private capital markets. In addition, the ability to issue U.S. Treasury-backed bonds affords shipowners access to other capital markets that, because of institutional or legal barriers, would otherwise be closed. Another advantage of the MarAd program is long repayment terms of up to 25 years, although the maximum term might be unusual in the case of a LNG ship.

If the owners of the ships are to be foreign to the country where the ships are built, officially supported export credits may be available. Important LNG ship-exporting countries in the OECD include France, the United States, Italy, and Norway. Financing terms are determined by the individual countries in accordance with the OECD Arrangement on Ships, which supersedes the Arrangement on Guidelines for Officially Supported Export Credits in the case of shipping and sets a minimum interest rate of 7.5 percent, a maximum repayment period of 8 years, and a maximum coverage of 80 percent of ship cost.

While the interest rate allowed on officially supported export credits for ships is preferential, the shortness of the repayment period constitutes a disadvantage of this type of financing. The heavy debt requirements during the early years of the project can, depending on the pricing or tariff provisions governing cash flow, effectively postpone repayment of expensive equity capital.

U.S. facilities

The cost of U.S. facilities, including the marine terminal, LNG storage tanks, vaporization units, and transmission lines to deliver the gas, can vary widely depending on location and design. The proposed La Salle terminal facilities and delivery lines to E] Paso United's system were estimated to cost approximately $700 million, while the proposed Tapco project, sponsored by Tenneco to bring LNG from Algeria into New Brunswick, Canada and then to the United States through a longer pipeline, would have cost nearly $1.5 billion.

In the past, construction of U.S. facilities has been accomplished through the credit of financially strong corporations. Examples include Southern Natural Gas Company's Savannah, Ga., terminal and the planned Trunkline terminal at Lake Charles, La. Each of these facilities is owned and operated by a subsidiary of a major U.S. interstate pipeline company, and debt issues to finance LNG terminals are carried in both cases on the balance sheets of the parents, which provide substantial credit support.

Southern's Savannah terminal illustrates another feature of U.S. financing, the tax-exempt bond market. Section 103(B)(4)(D) of the U.S. Internal Revenue Code, which relates to docks, wharfs, and storage facilities, may allow the issue of debt securities that are exempt from Federal, State, and local income taxes. For this type of issue, the market yield cost to the borrower is less. Southern's Savannah terminal, for example, was financed partly through the issue of tax-exempt revenue bonds by the Savannah Port Authority. These bonds were marketed at a price of 99.75 percent of par and with a coupon rate between 5.7 and 6.75 percent, depending on the maturity (serial and sinking fund bonds were in combination to permit full amortization by equal payments over the lifetime of the financing). At the time of the prospectus, Aaa bonds were yielding around 9.5 percent, considerably more than the Savannah Port Authority bonds.

Conclusion

The financing options open to LNG import sponsors are strongly influenced by the magnitude of total capital requirements, as well as the international character and multistage nature of the projects. Generally, private capital markets are open to sponsors with strong credit support, but financing costs may be high because of sheer scale.

In addition, low-cost subsidized financing is available for particular stages of the project, depending on such factors as ownership, location, the country supplying construction and materials, and taxes. Also financing costs may be high due to regulatory incentives, for example, to finance U.S. facilities independently. The next section examines the effects of alternative financing arrangements on the unit cost (cost-of-service) of moving gas from a remote source to U.S. markets.

Cost-of-service

The cost-of-service calculated by project stage for a hypothetical world-scale LNG project (approximately 1 Bcf/d), idealized in economic and financial structure, is described below. This cost was defined as the sum, for a particular year, of operating costs, capital costs (debt and equity), and taxes divided by the Btu's delivered into the U.S. pipeline system. The procedure allowed direct comparison by project-stage in terms of units ultimately delivered, and at the same time, allowed determination of the wellhead value of the gas given the price in the U.S. market, since fuel and loss is included in the cost-of-service.

The capital charge (service on debt and equity) was assumed to be level in constant dollars over the lifetime of the project and was calculated so that the net present value of the shareholders' cash flow would equal zero at the assumed discount rate.

Also, the cost-of-service estimate here differs from what would be typical in a regulatory proceeding in that the cost of gas expended as fuel and loss was determined at the ultimate netback wellhead value, while a "regulatory" calculation usually assumes the value of fuel and loss to reflect a fixed price, for example, the contract sale price f.o.b. the point of export. An advantage of valuing the fuel and loss at the ultimate wellhead netback, is that it allows direct comparison of the cost-of-service of LNG projects with the cost-of-service of alternative technologies to move gas from the wellhead to the market. A peculiarity of this approach is that since capital and nonfuel operating costs affect the ultimate wellhead netback, the value of fuel and loss depends, in part, on these other components.

Base case

Parameter values for the base case cost-of-service calculation were derived largely from the testimony in recent LNG proceedings. This calculation was performed for a project starting in 1985, and costs were escalated to reflect the difference in timing between the idealized base case and recent proposals. The assumed 3,736 nautical miles approximates the shipping distance from Algeria to the United States. For complete enumeration of all parameters, see volume II (working papers).

For U.S. facilities, the financing was assumed to reflect current market rates and terms for large projects in U.S. capital markets on the balance sheets of gas utility companies. For shipping, MarAd financing was assumed with an interest rate in the vicinity of *Baa* industrial bonds and a repayment term of 15 years. Exporting country facilities were assumed to hav'e access to export credit financing programs for the bulk of their financing, and rates and terms represented here are those for the recent U.S. Eximbank credit to Algeria to help finance the Arzew II liquefaction plant. The assumed rate of return on equity is 17 percent.

Tables 33 and 34 show the results of a representative base case cost-of-service calculation, expressed in constant 1978 dollars. As can be seen, the bulk of the costs are in shipping and liquefaction. Also fuel and loss represent a significant portion of the total and, for liquefaction, actually exceed the capital and operating cost component. Overall, taxes constitute less than 10 percent of the fifth year cost-of-service for this idealized project. However, much of the debt service is loaded toward the front end of the project and since interest payments are deductible, taxes as a fraction of the total cost-of-service increase over the lifetime of the project, as shown in figures 17 and 18.

Sensitivity

The sensitivity of the cost-of-service to changes in the debt ratio on U.S. facilities and the repayment period for ship financing, and to

Table 33.—Cost of Service of an LNG Project Beginning in 1985 in the Fifth Year of Operation"
(1978 dollars/million Btu delivered into U.S. pipeline system)

	Field facilities and pipeline to liquefaction plant	Liquefaction plant, terminal and loading	Shipping	U.S. facilities	Total
Capital and operating	$0.226	$0.656	$0.564	$0.273	$1.719
Fuel and loss	0.084	0.659	0.091	0.101	0.935
Income taxes	0.053	0.106	0.038	0.017	0.214
Total cost-of-service	$0.363	$1.421	$0.693	$0.391	$2.868

[a]Costs for a world-scale LNG project with a round trip shipping distance of 7,472 nautical miles and a distance from gasfield to liquefaction plant of approximately 300 statute miles

SOURCE Jensen Associates, Inc.

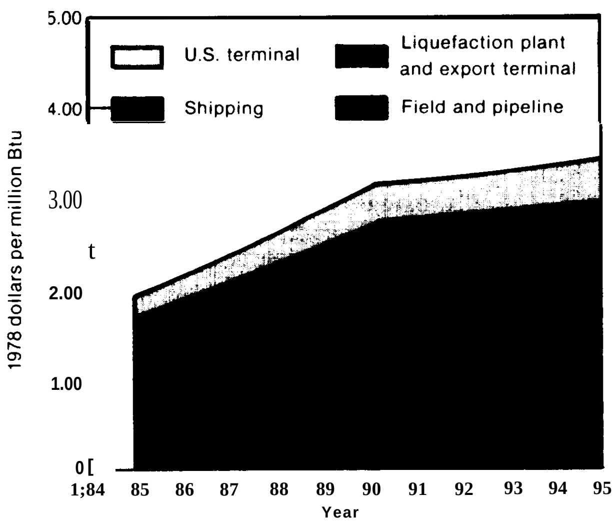
Table 34.—Sample Calculation of Wellhead Netback Price in 1989 for a Project Beginning in 1985
(1978 dollars/million Btu at wellhead)

Gas price into U.S. pipeline system[a]	$6.138
Cost of service[b]	2.868
Wellhead netback	$3.270

[a]Based on postulated price of No. 2 fuel oil in Philadelphia, netted back to Cove Point, Md.
[b]Includes fuel and loss valued at wellhead netback; 7,472 nautical miles round trip distance.

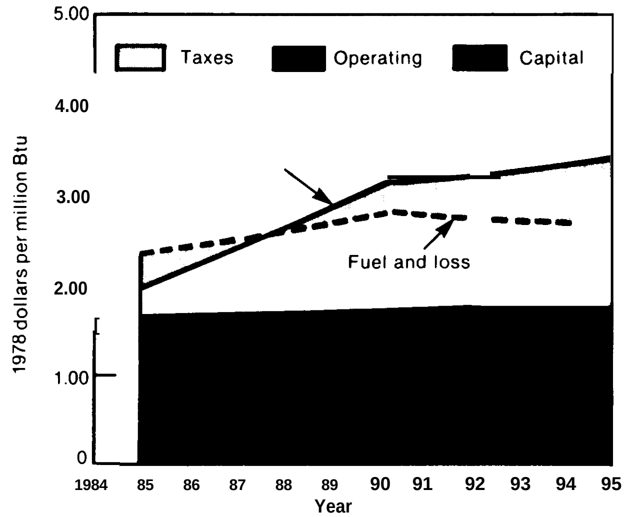
SOURCE: Jensen Associates, Inc.

Figure 17.— LNG Cost of Service by Project Section



SOURCE Jensen Associates, Inc

Figure 18.—LNG Cost of Service by Type of Cost



SOURCE. Jensen Associates, Inc.

setting the interest rate on all debt at 12 percent is relatively insignificant. These changes produced a net cost increase of $0.05 /MMBtu. However, the cost-of-service is more sensitive to changes in the return on equity in all portions of the project and to changes in the U.S. debt interest rate, Tables 35 and 36 show the effect of incereming and reducing the return on equity and the interest on U.S. debt by 2 percent. The effects are symmetrical, changing the total charges, excluciing fuel and loss, by about $0.21 /MMBtu (1978 dollars) or approximately 10 percent. However, when the fuel effects, which offset the gross changes in capital and operating cost portions of the project, are included, the net effect is a change of about $0.16/MMBtu (1978 dollars) or approximately 6 percent in the total cost-of-service in the fifth year of operation of an LNG project. Cost-of-service calculations for shipping were based on an average distance of 7,472 nautical miles. Tables 37 and 38 show that when the distance is reduced by one-half or doubled, the effect on the cost of shipping is in the same proportion. However, the netback val-

Table 35.—impact of Fifth Year Cost of Service of Reducing Return on Equity to 15 Percent and Interest on U.S. Debt to 10 Percent”
(1978 dollarsl million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Reduced return capital costs, operating costs, and income taxes.	$0.246	$0.546	$0.691	$0.244	$1.727
Base case capital costs, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross change in cost of service	**(0.044)**	**(0.056)**	**(0.072)**	**(0.035)**	**(0.207)**
Reduced return fuel and loss. .	0.106	0.095	0.692	0.088	0.981
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	0.005	0.004	0.033	0.004	0.046
Net change in cost of service. .	(0.039)	(0.052)	(0.039)	(0.031)	(0.161)

[a]From 17 and 12 percent respectively

SOURCE: Jensen Associates, Inc.

Table 36.—impact of Fifth Year Cost of Service of Increasing Return on Equity to 19 Percent and Interest on U.S. Debt to 14 Percent”
(1978 dollarsl million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Raised return case capital charges, operating costs, and income taxes	$0.337	**$0.662**	**$0.833**	**$0.314**	**$2.146**
Base case **capital charges, operating costs, and income taxes. . . . .**	**0.290**	**0.602**	**0.763**	**0.279**	**1.934**
Gross change in cost of service	**0.047**	**0.060**	**0.070**	**0.035**	**0.212**
Raised return case fuel and loss	0.096	0.086	0.626	0.080	0.888
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	(0.005)	(0.005)	(0.033)	(0.004)	(0.047)
Net change in cost of service. .	0.042	0.055	0.037	0.031	0.165

aFrom 17 and 12 percent respectively.

SOURCE. Jensen Associates, Inc

ue of the gas and thus the cost of fuel are reduced, which tends to offset the changes in capital and operating costs. Another effect of shortening shipping distance is a reduction in the amount of LNG boiled-off and used as transportation fuel. Consequently, less LNG needs to be loaded at the liquefaction plant to maintain the same deliveries to ultimate destinations. For this reason, liquefaction plants and field and pipeline facilities can be reduced somewhat in scale, as shown in table 37. on the other hand, increasing shipping distances will produce the opposite effects.

Ironically, the total fuel and loss portion of the cost-of-service for the short voyage case is higher than for the base case and similarly, total fuel and loss for the long voyage case is lower than for the base case. This result is contrary to what one would expect but comes about because of the convention adopted in this analysis, that the cost of fuel and loss is calculated at the netback

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Table 37.—impact on Fifth Year Cost of Service of Reducing the Round Trip Voyage Distance to 3,274 Nautical Miles'
(1978 dollars/million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Short-voyage capital charges, operating costs, and income taxes.	$0.290	$0.300	$0.754	$0.276	$1.620
Base case capital charges, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross change in cost of service	. —	(0.302)	(0.009)	(0.003)	(0.314)
Short-voyage fuel and loss. . . .	0.110	0.053	0.709	0.090	0.962
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	0.009	(0.038)	0.050	0.006	0.027
Net change in cost of service. .	0.009	(0.340)	0.041	0.003	(0.287)

aBase case distance IS 7,472 nautical miles.

SOURCE: Jensen Associates, Inc

Table 38.—impact on Fifth Year Cost of Service of Increasing the Round Trip Voyage Distance to 16,694 Nautical Miles'
(1978 dollars/million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Long-voyage capital charges, operating costs, and income taxes.	$0.290	$1.294	$0.784	$0.287	$2.655
Base case capital charges, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross change in cost of service	——	0.692	0.021	0.008	0.721
Long-voyage fuel and loss	0.082	0.149	0.546	0.070	0.847
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	(0.019)	0.058	(0.1 13)	(0.014)	(0.088)
Net change in cost of service. .	(0.019)	0.750	(0.092)	(0.006)	0.633

aBase case is 7,472 nautical miles.

SOURCE: Jensen Associates, Inc.

value at the wellhead. Since most of the fuel is used in the liquefaction plant, the short voyage raises the netback value of the fuel and loss which in turn increases the fuel and loss prices at the liquefaction facility. The opposite is true when LNG is shipped over long distances. Higher capital costs of boil-off reduce the netback value at the wellhead and thus the cost of fuel and losses. When the shipping distance is reduced by half the total cost-of-service for the project is reduced by 10 percent, and when the distance is doubled, the cost-of-service is increased by 22 percent.

Financial risk

Because of the size and complexity of LNG investments as well as the unpredictability of future events during a project's life, the nature and distribution of financial risk and uncertainty are important to consider. From a government policy standpoint, public exposure deserves particular attention.

Individual investments in single liquefaction facilities, import terminals, or ships separate from integrated projects are not yet possible, except perhaps in Japanese trades. In the future, if more trade develops and facilities become more widespread, such investments will occur. But now only a complete project with long-term contractual commitments and simultaneous construction of liquefaction facilities, ships, and the receiving/regasification terminal is economically feasible.

The money invested in LNG projects is at risk from a variety of perils, including technical feasibility, project failure, project interruption or delay, cost overruns, and market uncertainties. These problems are described below and illustrated in a discussion of the proposed Pac-Indonesia project.

Technical feasibility

The financiers of an LNG project are first interested in its technical feasibility, which they assess in historical terms. In January 1959, the first shipload of LNG left Lake Charles, La., on the *Methane Pioneer* and arrived at Canvey Island, England—near London. This shipment was part of a project sponsored by the British Gas Council, Continental Oil Company, and Union Stockyards to test equipment and to examine the feasibility of international LNG trade. In 1964, the first baseload, long-term commercial project started with shipments from Arzew, Algeria, to Canvey Island and Le Havre, France. Today 12 LNG projects are in operation, and the technical and economic feasibility of the technology has been demonstrated. Several shipyards and engineering/construction firms have shown their ability to build reliable LNG ships and facilities. Technical and construction risks are perceived as no greater than those for other large sophisticated international engineering and construction projects.

Project failure

Of greatest concern to the owners and financiers of an LNG project is the possibility for project failure after significant amounts of money have been spent. For example, the Eascogas Project, which was to bring LNG from Skikda, Algeria, to the east coast of the United States, was originally expected to begin some years ago. A receiving terminal at Staten Island was completed at a cost of over $100 million (1974 dollars), and two ships intended for the project were built at the General Dynamics shipyard at Quincy, Mass. Government authorities in the United States have refused to allow operation of the Staten Island terminal, which is now a complete financial loss unless the facilities are used to store LNG for peak shaving. One of the ships has subsequently been incorporated into an LNG trade from Indonesia to Japan while the other is unemployed, and thus far a loss to its owners.

As mentioned earlier, some supply contracts contain explicit provisions for periodic review of prices, while others may have to be renegotiated under changed circumstances because the parties are in separate countries not governed by a common legal jurisdiction. In either case, although producers and purchasers both face substantial incentives to come to terms, negotiations could conceivably break down after the facilities have been built and put into operation.

Project failure can also occur if facilities are destroyed by natural causes, civil strife, or war, or if a major change in attitude within one country causes project termination. For example, the Khomeini government in Iran is reported to have canceled the IGAT 11 project scheduled to sell gas to the U. S. S. R., which would in turn sell gas to Czechoslovakia and gas companies in Germany, France, and Austria, beginning in 1981. Unfortunately, Iran canceled the project after considerable investment in pipelines.

Project interruption or delay

Technical problems can delay or interrupt LNG projects. Normally, when any complex plant starts up, problems arise. In LNG liquefaction plants, typical problems include clogging of cooling water intakes by sand, seaweed, jellyfish, or debris; failures in the blading in turbines, compressors, or pumps; fouling of heat exchangers on the water side due to buildup of algae; clogging, possibly by ice, of spray rings, for cooling the storage tanks; or bearing failures in pumps. 19

However, other technical problems can cause longer delays or force cessation of LNG projects, causing severe financial impacts. For example, when the Libyan LNG plant was first started in 1969, several problems arose in the pipeline bringing gas to the liquefaction plant, resulting in additional delay of over a year. Libya also interrupted the LNG project by government edict when negotiations over prices broke down.

In another case, the main heat exchangers in the liquefaction train of the Skikda, Algeria, plant were shut down for extended periods due to a combination of mechanical wear caused by vibration, which ruptured heat exchanger tubes, and corrosion caused by mercury in the heat exchangers.

Delays have also occurred in ship construction, and at least two yards have been unable to fabricate the LNG containment systems on schedule. However, a surplus of LNG ships, some in layup and awaiting employment, could compensate for delays in the construction of new ones.

Cost overrun

The cost of any project, especially during an inflationary period, can be greater than anticipated. If construction costs rise too fast and financing for the overrun cannot be found, the project will not be completed and all investments are lost. More likely, the project will be completed with added financing, but the cost overrun must ulimately be borne by someone. Operating costs can also exceed expectations and cause either the sales price to rise or the earnings of project sponsors to fall.

Market uncertainties

Since the projects involve long-term contracts and investments, losses will result if the LNG should not be marketable up to 20 years in the future at prices that cover the sponsors' costs. Factors that contribute to uncertainty in this area are the possibility of increased domestic fuel production and conservation, the unpredictability of long-term economic growth rates, the unknown future course of world oil prices, possible changes in regulatory policy, and the outcome of any supply contract renegotiations.

Who bears the financial risk?

The costs of project failure, operating or capital cost overruns, supply interruption or reduction, damage to facilities, or adverse governmental decisions, are borne by the various parties in an LNG project. These parties are the owners of the liquefaction plant, the ships, and the receiving/regasification terminals; the lenders to the project; the guarantors of financing; the various governments who tax or otherwise receive revenues from the project; the insurers of the facilities; and the consumers of the regasified LNG. The distribution of risk is determined by contracts among the parties; the financing agreements binding owners, lenders, and those who guarantee financing; the tariffs established by regulatory agencies; tax codes; and insurance agreements. The precise way in which these contractual instruments and tariffs divide the risk will vary according to negotiations and regulatory decisions which take place when the project is financed.

In order to reduce the capital costs of the project and thus increase profits and reduce the final price of LNG to the consumer, a substantial portion of the investments need to be financed by lenders who provide long-term loans at modest rates of interest. Lenders include banks, insurance companies, and governmental finance organizations such as MarAd and Eximbank, and their need to minimize exposure strongly shapes the risk distribution of an LNG project. Banks and insurance companies lend other peoples' money, that of their depositors, other creditors, or policyholders, and they are obliged to repay in full. Therefore, lenders, especially private banks and insurance companies, want their money back no matter what happens to the LNG project. They insist on guarantees of loan repayment from creditworthy parties, who can be governments, natural gas consumers through "all events" tariffs, * or large corporations with ongoing businesses out side of the LNG project.

The owners of the project, who provide the equity capital, money which is their own, will typically absorb more risk in an LNG project than lenders, provided the potential return is greater by virtue of their so doing. If the return to the owners is limited, as it is in the United States for regulated utilities, the owner will also seek limitations of risk. The balance of risk and return that the project owners will accept is influenced by their own special circumstances and by other investment opportunities which are competing for the equity capital needed by an LNG project. Finally, as a genera] rule, those parties who control the LNG facilities usually assume risk on it.

The Pac Indonesia project— An example of risk distribution

The Pac Indonesia case illustrates how risk is distributed among the parties in an LNG project. While this project is somewhat different from early U.S. LNG import projects, it represents an appropriate example, since it is the only project to be approved under the new organization of DOE. The estimates are current and typical of recent LNG proposals, and the contractual relationships reflect more than a decade of experience. However, the reader should remember that the distribution of risk in any project is in part determined by the environment at the time of negotiations,

Although generally representative, the Pac Indonesia project is unique in sevreral ways. First, Indonesia currently is completely dependent on Japan as its primary LNG customer. Also, the California gas utilities would like to use the same west coast terminal for an additional project to bring LNG from the Cook Inlet in Alaska, and the proposed American shiponmer's have expressed reservations and have not yet committed their resources. Finally, the revolution in Iran and the subsequent rapid increase in world crude oil prices during the first half of 1979 have sharply altered perceptions about world oil availability and price from the time the project was first negotiated and approved by DOE/ERA.

LIQUEFACTION AND LOADING FACILITIES

Indonesian liquefaction and loading facilities are estimated to cost about $869 million representing the largest single capital portion of the project. Pertamina, the national oil company of Indonesia, is the owner. Mobil Oil Indonesia Inc., owns the producing facilities and bears the financial risk associated with them.

The instruments that distribute the risk are the contract for the sale and purchase of LNG between Pertamina and Pac Indonesia, and the security agreement for financing the liquefaction and loading terminal facilities. Two parts of the sales contract are important: the take-or-pay and the force majeure clauses. The take-or-pay clause requires Pac Indonesia to pay for the LNG tendered at the annual contract amount, whether or not the LNG is taken. The burden of marketing the LNG is thereby placed on Pac Indonesia, which is in a position to control its risk in this area. However, the force majeure clause is broad and provides for cessation of contract obligations for acts of God, industrial strife, or governmental decisions interrupting the operation of Indonesian facilities, ships, or U.S. facilities. This clause places most of the risk for the investment in Indonesia on Indonesian interests. Lenders to Pertamina for the liquefaction

*The "all events" cost-of-service tariff effectively insulates equity-holders from debt service risk by ensuring that payments by consumers will be sufficient to service debt in all events. Thus insulated from debt service risk, the shareholder does not increase his exposure as much with added financial leverage. Required rates of return on equity are lower than they would be otherwise, and since bond rates are lower than equity rates, the unit costs can be reduced in this way.

trains and base terminal are protected from financial loss by a guarantee of repayment from the Indonesian Central Bank.

Table 39 summarizes the risks and their distribution for the liquefaction trains and loading terminal. The perils that can occur, the mechanisms by which risk is transferred, the criteria governing the transfer, the amount transferred, who pays, and a reference to the source of the information are included in the table.

Force majeure events are borne solely by Pertamina and other Indonesian interests. If cost overruns occur in the construction of Indonesian facilities, they are borne by Indonesian interests, since the LNG price is not based on cost. An academic exception is that if the price of crude oil falls, and if the United States reverses its inflation and enters a deflationary period, the f.o.b. price for LNG may fall below a minimum established to ensure repayment of the lenders to the Indonesian facilities. In such a case, U.S. consumers are guaranteeing repayment of lenders, a risk most observers of oil markets and price behavior in industrial nations view as insignificant.

However, LNG contracts do transfer some risk to the buyer, and through the tariff, ultimately to the U.S. gas consumer. If the U.S. dollar falls on foreign exchange markets, the LNG price is adjusted to ensure that Indonesia recovers real value for LNG relative to a market basket of currencies. Also, Pertamina will not accept the risk that the buyer will desire for whatever reason not to take future LNG. Thus, if the LNG becomes unmarketable, the risk of failure in marketing the LNG is transferred to the buyer and will be passed on through the tariff to the gas consumers.

SHIPPING

The six ships for the Pac Indonesia project, to be constructed in U.S. shipyards for delivery in 1983-84, are estimated to cost approximately $155 million (1978 dollars) each, excluding the construction differential subsidy by MarAd. A total of approximately $93o million to be paid by their owners and lenders will thus be at risk. Three other foreign ships have already been constructed at costs that are unknown but estimated at an average of $100 million (1976 dollars) each. In this project, the ships will be owned by independent shipowners, Ogden Marine and Zapata, who provide the equity financing, and chartered to Pac Indonesia.

MarAd will guarantee loans of up to 75 percent of the yard cost of a U.S. ship if a construction differential subsidy is provided, or up to 87.5 percent of the yard cost if no construction differential subsidy is involved. These loan guarantees are available only to ships built in American yards, for American owners, to haul goods in a trade that includes America. However, MarAd may negotiate with the shipowner for additional money beyond the 25-percent equity interest to help protect the Government

Table 39.—Distribution of Financial Risk for Liquefaction and Loading Facilities of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid by	References
1. Supply reduction or interruption	Sales contract	Force majeure	All	Indonesian interests	LNG sales contract
2. Project failure before or after startup, liquefaction, or terminal problems		Force majeure	All	Indonesian interests	LNG sales contract
3. Cost overrun on Indonesian facilities	None. Price not cost-based	If price drops, minimum bill	All	Indonesian interests	LNG sales contract
4. Ship unavailable—no fault of Pac Indonesia, e.g., delay in ship construction	Sales contract, take-or-pay, charter hire, minimum bill	Not force majeure	Difference in LNG price when quantities made	Shipowner limited to 10% of capital cost remaining customers	LNG sales contract, charter hire
5. Dollar depreciation in foreign exchange markets	Tariff	Automatic	Ft~l	U.S. consumers	ERA 2, P.15

aERA refers to an Opinion of the U.S. Department of Energy/Economic Regulatory Administration guarantee. For example, MarAd required U.S. shipowners (Lochmar) in the Trunkline LNG project to finance the 25-percent equity portion of the ships and to put up initial working capital equivalent to 1 M years' operation to provide added protection in case the ships are not employed immediately after they have been delivered. Marine insurance covers losses from sinkings, collisions, acts of God, and hull and machinery failures.

Pending a resolution of who bears the financial risk, the proposed American shipowners for Pac Indonesia have not yet committed themselves to providing the ships. If the proposed owners decide not to provide the shipping, Japanese firms are expected to do so. However, in this discussion it is assumed that the American firms will build the ships in American shipyards, using a construction differential subsidy.

The risk of failure of other parts of the project, which would leave ships unemployed, are controlled by the charter arrangements between the shipowners and Pac Indonesia, and by the U.S. tariff which governs how Pac Indonesia passes on its costs to consumers of natural gas. Pac Indonesia has signed time charters for 20 years with the various owners, under which the shipowner guarantees to deliver a ship of specified speed, fuel consumption, and boil-off rates. Pac Indonesia pays for the capital, maintenance, and the operating costs of the ship. These payments are reduced if the ship does not meet technical requirements or is not available, and the shipowner also assumes all costs when the ship is not available for service and the fault is not Pac Indonesia's.

Through the time charter mechanism, many of the risks are transferred to Pac Indonesia. However, the arrangements also specify that Pac Indonesia need not assume the risks if they are passed on to the LNG consumer via an approved tariff for foreign ships, or in the case of a fall in the foreign exchange rate, offset by a currency adjustment clause.

ERA and the administrative law judge in their opinion and initial decision recommended a "minimum bill" provision of the tariff by which Pac Indonesia would charge Southern California Gas and Pacific Gas & Electric for the LNG. This provision specifies the costs that can be passed on even if the full amount of gas is not flowing, and includes the time charters or other arrangements for ocean transportation. In this way, the cost of shipping automatically passes to the gas consumer after the project has begun,

Table 40 shows the sources of risk, the contractual instruments for distributing them, the amounts, and who pays. As the table shows, as long as the project is operating and the ships are available, the charter-hire agreement and the tariff pass all costs of supply interruption or reduction, increases in operating costs, or reduction in the value of the dollar relative to a market basket of currencies, on to the gas consumer via minimum bill provisions. However, for events that occur before the gas begins to flow, such as cost overruns on U.S. ships during construction, or project failure before or after startup, passthrough of costs to the consumer is not automatic. In the latter case, FERC will decide if and to what extent gas consumers pay after an appeal under section 4 of the Natural Gas Act. Thus, what costs the consumer and the shipowner assume will be determined by an administrative ruling following an evidentiary hearing to determine, for example, whether cost overruns were "prudent. "

The proposed U.S. shipowners in the Pac Indonesia project have complained that they bear undue risk if they must depend on the outcome of an administrative appeal in the event of cost overruns or project failure. The shipowners (ERA Decision No. 6, p. 9) have argued that unless the customers are required through the tariff to pay for the charter obligations in the event of project failure, MarAd title XI financing will not be available. However, ERA and the administrative law judge did not find sufficient evidence to support this claim. This finding is supported by the fact that ship financing and construction for the Trunkline LNG project is proceeding with MarAd loan guarantees. However, the interests, objectives, and perceptions of the proposed Pac Indonesia shipowners, which are otherwise independent of the project, may be different from those of their Trunkline counterparts; Panhandle Eastern Pipeline Company, the

Table 40.—Distribution of Financial Risk for Ships of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid bv	References
1. Supply reduction or interruption	Minimum bill	Automatic	[illegible]	[illegible]	ERA 1, p. 30 ERA 6, pp. 11-14
2. Project failure before or after startup, liquefaction, or terminal problems	Sec. 4 type filling	Facts surrounding project failure			ERA 1, p. 32 ERA 6, p. 33 ERA 6, p. 10
3. Cost overrun	Sec. 4 hearing	Prudent	Prudent portion Imprudent portion	Customers Shipowners	ID, ERA 1 ERA 6, p.5
4. Ships unavailable, no fault of Pac Indonesia, LNG available	Charter contract			Shipowners	
5. Dollar fall in foreign exchange	Tariff	Automatic	Foreign ships	Customers	ID p. 80 ERA 1, p. 27
6. Increases in operating costs and maintenance	Tariff	Automatic subject to review	Actual costs of contract escalation	Customers, ship-owners	ERA 6, p. 11
7. Delay in startup after charters begin (foreign ships)	DOE review, tariff	Proper accounting and calculation	All minus interim hire	Customers	ERA 6, p. 8
8. Ships unavailable (force majeure)	Charter contract, minimum bill	Automatic	Charter fee, minus other recovery	Customers	ERA 1, p. 30 ERA 6, pp.11-14

[a]ERA refers to an opinion of the U.S. Department of Energy/Economic Regulatory Administration.
ID refers to the initial decision of an administrative law judge of the Federal Energy Regulatory Commission.

parent of Trunkline LNG; General Dynamics Corporation, builder of the ships; and Moore McCormack Bulk Transport, Inc., the operator of the ships.

RECEIVING/REGASIFICATION TERMINAL

The import terminal and regasification facilities, with an associated pipeline to move the revaporized natural gas to existing pipelines, represent the smallest of the investments in an LNG project but are the ones on U.S. soil. In the case of the Point Conception plan, these facilities would cost approximately $700 million (1978 dollars) and could be used as an import terminal for about 560 to 600 MMcf/d of Indonesian LNG with remaining capacity for an Alaskan LNG project of approximately 350 MMcf/d. In addition, the Point Conception site is intended to store LNG for peak shaving.

Approximately 75 percent of the costs of the terminal are expected to be financed by debt, primarily from banks or insurance companies, and the rest by equity capital. The distribution of risk is determined by the tariff and the security arrangements between the lenders and owners of the terminal as shown in table 41.

In its decisions, DOE/ERA very clearly distinguishes between risk before startup and risk that might occur after the gas is flowing.

Before project startup, ERA requires a section 4 filing with FERC in order to determine what costs would be passed on to consumers. In the case of a cost overrun, ERA suggests that only prudent costs be passed on to customers, and that shareholders bear imprudent costs. For project failure before startup, no explicit criteria for passing on costs have been established. The ERA decision clearly states that the credit before completion should be provided by private creditworthy parties, who guarantee loans. Elsewhere, the FERC staff and others argue that if the project fails, in no case should the equity costs be passed on to consumers.

ERA recommends a minimum bill portion of the tariff providing that after gas first flows, the debt portion of the terminals and other cost be passed on automatically to gas consumers even if the project fails. In the event of failure, supply reduction, or interruption after project completion, the ERA opinion (in contrast to the Trunkline LNG decision) will also consider possible re-

Table 41 .—Distribution of Financial Risk at the Receiving/Regasification Terminal of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid by	References
1. Supply reduction or interruption	a. Minimum bill	Automatic	a. When less than 900/. delivered, no return of or on equity on undelivered volumes. Recovery of other allowed costs.	Customer	ID p. 81 ERA 6, p. 13 ERA 1, p. 30
	b. Sec. 4 type proceedings	Extraordinary circumstances	b. Pro rata return of and on equtiy	Shareholders and perhaps customers	ERA 1, p. 32
2. Project failure before startup	Sec. 4 filing	Circumstances	As determined	Customers	ERA 1, PP.32-33 ERA 6, p. 11
3. Cost overrun	Sec. 4 filing	Prudent	Allowed Disallowed	Customers, Shareholders	ERA 6, p. 16-17
4. Ships unavailable—no fault of Pac Indonesia or Terminal Associates	Minimum bill is 90% deliveries	Automatic	Costs and equity on deliveries. Pro rata equity	Customers, Shareholders	ERA 1, p. 30 ERA 6, pp. 11-14
5. Project failure after startup	Minimum bill Sec. 4 filing	Automatic Circumstances	Non-equity, Equity	Customers Shareholders and customers	ERA 1, P.33 ERA 6, p. 13

[a]ERA refers to an Opinion of the U.S. Department of Energy/Economic Regulatory Administration.
ID refers to an Initial Decision of an Administrative Law Judge of the Federal Energy Regulatory Commission

turn of equity costs in the terminal regasification facilities in a section 4 proceeding if extraordinary circumstances can be shown.

SUMMARY OF RISK DISTRIBUTION

The distribution of risk in an LNG project, as exemplified by Pac Indonesia is as follows:

Financial risk of the producing country facilities: ($869 million, 1976 dollars)

- Most risks are borne by the owner of the liquefaction facility, Pertamina, the gas producer, Mobil, or the Indonesian Government through loan guarantees.
- Risk of the marketability of the LNG is born b-y the U.S. gas companies and gas consumers.

Financial risks of shipping: ($1,230 million, 1978 dollars)

- Insurance companies take normal shipping risks such as damage to the ship, grounding, storm, etc. Gas consumers ultimately pay the insurance premium.
- While the project is in operation, gas consumers bear costs if LNG flow is interrupted or reduced.
- If the project fails, the shipowner may bear the risk, at least on his equity in the ship, although FERC, after evidentiary hearings, may pass on some costs to the gas consumer.
- Cost overruns may be borne by the shipowner, unless after evidentiary hearings FERC decides to pass on prudent costs to the gas consumer.
- If all else fails, the lenders for U.S. ships with financing guaranteed by MarAd receive payment from the MarAd Federal Ship Financing Fund, and if that is exhausted, from the U.S. Treasury.

Receiving/regasification terminal: ($437 million, 1977 dollars)

- Loss due to project failure before gas flows may be fully borne by shareholders, unless FERC, after an evidentiary hearing, decides to pass some or all costs on to gas consumers.
- After gas flows, the non-equity costs of the terminal are borne by gas consumers. Shareholders bear risk of loss of equity and return on it in proportion to the reduction of LNG flows except that FERC may pass on

equity costs to consumers in extraordinary circumstances.

- Cost overruns may be borne by shareholders unless FERC, in an evidentiary hearing, passes on prudent costs to gas consumers.

Risk of LNG embargo by the producing country

Four of the six largest actual or potential exporters of natural gas from the Eastern Hemisphere—Algeria, Iran, Indonesia, and Nigeria—are members of OPEC. The U.S.S.R. is an adversary superpower. Only the last, Australia, is a member of OECD. As oil exporters, OPEC members have demonstrated their readiness to impose increases in price at short notice on existing contract terms. Some of them, also, have embargoed crude exports for political reasons.

On the other hand, the supplier as well as the purchaser experiences dependence on LNG trade and faces incentives not to interrupt shipments. LNG exports characteristically involve substantially greater capital investment than exports of oil of comparable energy content. Contracts for 15 to 25 years of deliveries after at least 5 years of negotiation and plant construction, are necessary in order to amortize huge initial financial outlays. A large proportion of this investment, in gathering and trunk pipelines, liquefaction, plants, and terminals, is in the exporting country, and in all cases so far, host governments have participated in the financing. If performance under a long-term contract were interrupted, alternative exports that would maintain revenues to pay capital charges would be very hard to arrange. The projects are technically integrated, and the only mobile capital involved, the cryogenic tankers, will often be under the effective control of foreign joint-venture partners or import customers, and until now, no "merchant trade" in LNG has developed. (Some LNG tankers have been built speculatively, and as the international trade expands, a fringe of uncommitted tonnage will no doubt become available for the occasional balancing transaction between customers with terminals.) Furthermore, selling the gas in the exporter's domestic market would be disadvantageous, because local customers do not use LNG and may not be located close to the pipelines leading to liquefaction terminals, and export volumes are generally surplus over domestic consumption anyway,

These characteristics of present international gas trade seem to lock all parties to an LNG supply contract into a closed economic loop. The costs of interruption, and of insurance against it (technical as well as financial), will be heavy. The resource is not lost (in the case of nonassociated gas), but all parties will share all the cost of downtime on a large accumulation of costly, dedicated capital.

This generalization in no sense precludes arguments over price while a contract is in force. It simply increases the pressure on all parties to settle short of interrupting the gas flow. Also, 20-year contracts in an environment of rapid inflation and rising real prices for alternative fuels require effective escalation and review clauses.

In extreme circumstances, the high cost of interruption will not necessarily prevent gas being cut off for political purposes. one of the few cases on record of an LNG contract's actually being interrupted was Libya's action against the EXXON trade to Italy and Spain, which indeed involved associated gas and was thus more costly for both sides. * That arbitrary action may have been at once commercially and politically motivated. Although interrupting a gas operation for political purposes is demonstrably more costly than interrupting oil exports, it is nonetheless possible.

The risk of supply curtailment can be reduced through policies that require the "exchange of economic hostages, " as suggested by Resources for the Future. Under such a policy, "the producing country would own liquefaction facilities and tankers, and would finance them with borrowings other than from U.S. parties or government entities such as the Export-Import Bank. "[20]

*The gas might have been, but was not, flared. Instead, the Libyan Government closed down EXXON's crude oil production from the Zelten field as well.

[20]Sam H. Schurr, et al. *Energy in America's Future—The Choices Before Us* (Baltimore, Md.: Johns Hopkins University Press, 1979), p. 437.

5.
Social Costs and Benefits

5.
Social Costs and Benefits

Under current regulation, the added cost of gas from sources such as imported liquefied natural gas (LNG) is not necessarily borne by the same consumers that benefit from increased fuel supplies. Since the distribution of costs and the extent to which prices reflect them are central to part of the debate over LNG policy, this chapter addresses the question of who receives additional gas by virtue of an import project and who pays for it.

The determination of which consuming sectors will ultimately benefit from an LNG import project is complex. The answer depends not only on which pipeline or distribution company delivers the regasified LNG through its network, but also on such specific circumstances as the location of the supplier's customers, the relative sizes of the consuming sectors it serves, the quantity and seasonality of its other supplies, and the availability of storage facilities. Given projected natural gas production, new incremental supplies, such as those provided by a baseload LNG project, ultimate consumption will probably be in the industrial and electric power generation markets, where sales of gas would he curtailed in the absence of such supplies. In some situations, however, residential and commercial markets could benefit directly from LNG imports. For example, in the event that a specific project allows a utility to remove its restrictions on new customer additions, the recipients of at least part of the LNG would be new residential and commercial consumers.

The question of how LNG project costs are allocated among consuming sectors is even more difficult to answer. In the absence of incremental pricing, the cost of a supplemental project would be simply rolled-in with other gas acquisition costs, and all consuming sectors would be affected equally. However, under the pricing rules of the Natural Gas Policy Act of 1978 (NGPA), certain categories of industrial customers are subject to a special surcharge reflecting incremental prices of gas from specific sources. The addition of an incremental supply not only increases the average pipeline cost of gas, but it also enlarges the base of customers over which the surcharge is spread and lowers the unit transmission and distribution cost. These effects have been analyzed with the aid of a computer model, which simulates the markets of hypothetical transmission companies.

Additional issues addressed below include the impacts of supply curtailments and possible measures to mitigate them. Finally, the chapter concludes with a discussion of effects of LNG imports on the balance of international payments and on local employment and air quality.

U.S. consumers of LNG

The issues addressed in this section are, "who gets the additional gas from a baseload LNG project?" and "who pays for it?" A computer model that simulates the operation of a gas pipeline company was used to answer these questions. The section begins with a brief review of the pipeline model, followed by a discussion of the two issues in the light of the analytical results.

Modeling of pipeline systems

A computer model that simulates the operation of a gas pipeline under various conditions of supply and demand has been constructed, incorporating existing curtailment plans, assumed allocation rules for distribution companies, and pricing provisions of NGPA. Customers of the pipeline are grouped according to broad characteristics as follows:

Group 1 Large distribution companies that have gas supplies in addition to those of the subject pipeline. These may include gas from other pipelines, baseload synthetic natural gas projects, imports, own production, etc.

Group 2 Smaller distribution companies that rely solely on the subject pipeline for their gas supply.

Group 3 Direct mainline industrial sales by the subject pipeline.

Eleven consuming sectors are defined for the model as follows:

1. residential
2. commercial
3. exempt industrial (including agricultural)
4. industrial priority 2
5. new industrial priority 2
6. industrial priority 3
7. new industrial priority 3
8. industrial boilers—medium
9. power generation—gas only
10. industrial boilers—large
11. power generation–gas / oil.

By specifying demand profiles (and supplementary supplies for Group 1) for the three groups, data can be assembled to simulate a prototypical load for a pipeline. Two such systems have been utilized in the current project:

Pipeline A Single customer group (Group 2) with heavy industrial and power generation load.

Pipeline B Heavy residential and commercial load in Group 2, plus significant direct pipeline sales to industry (Group 3).

The distribution companies that are served by more than one pipeline are not included in the analysis of pipeline B because of the indeterminate nature of the allocation of the surcharge gas costs required by NGPA. When a pipeline is attempting to allocate its surcharge gas cost, it utilizes the data provided by each distribution company it serves to determine the ability of that distributor to absorb a surcharge. In the case of a distributor supplied by several pipelines, the Federal Energy Regulatory Commission (FERC) has not yet determined how the absorptive capacity of that distributor is to be divided among its various suppliers. If, for instance, one of the pipelines develops a large surcharge account early, it could theoretically utilize all of a distributor's absorptive capacity. Alternatively, if each pipeline is assigned a share of the distributor's absorptive capacity (proportional to its deliveries to the company), then the distributor's absorptive capacity may not be fully utilized. Lacking a surcharge allocation rule, multisupplied companies were not analyzed in these simulations despite the fact that such distributors are not uncommon.

Brief descriptions of the program modules follow in the order in which they are applied. For a more detailed description of the model, see the *Background Reports* volume.

Market share model.—Gas demands are calculated for each consuming sector from total energy demand forecasts using gas prices, alternate fuel price, and specified demand functions. Since NGPA incremental pricing rules make gas prices a function of the gas consumption pattern, market shares for gas must be calculated dynamically within the model.

Entitlements model.—Total pipeline supplies for a given year are allocated among the various customer groups on an entitlements basis. Supplies are distributed monthly according to historic base period demands in conformance with existing curtailment plans. Since actual demands change significantly over time, the model provides for rolling the base period forward. Within each customer group, entitlements are compared with actual demands so that any surplus can be reallocated to other customer groups.

Distributor allocation model.–Monthly supplies are compared to the actual demand profile for each customer group so that storage requirements can be calculated to protect high-priority demand. A deficit of storage gas is made up by curtailing low-priority customers; a sur-

plus of storage gas is distributed to the highest priority curtailed customers. Actual monthly and annual deliveries are then determined for each consuming sector.

pricing **model.—Gas prices by consuming sector are calculated for each group of custom**ers in accordance with NGPA incremental pricing provisions. The pipeline's surcharge account is distributed among the non-exempt customers and the excess surcharge is rolled into the base price of pipeline gas. Any gas priced above the ceiling prior to surcharge allocation causes an additional cost spillover to all sectors not at the ceiling price. The detailed logic of these cost allocations is extremely complex and is reviewed in greater detail in the *Background Reports* volume, and the implications of incremental pricing are discussed later in this chapter.

The allocation issue: who gets the LNG?

This section addresses the question of who would receive additional gas and for what use if LNG imports were expanded. Tracing the physical flow from the point of regasification to consumption does not provide the answer. Assume, for example, that the addition of LNG to pipeline supply permits a distribution company to increase its summer storage injections, and that the LNG is being put into storage whenever summer deliveries from the pipeline exceed actual demand. Since storage volumes are used primarily to protect high-priority demands, it would then follow that the LNG stored during the summer is being ultimately consumed by residential and commercial customers, The fallacy in this argument becomes apparent by examining the normal behavior of a distribution company. Typically, a company will manage its supply to protect high-priority customers from interruption, even if doing so requires curtailing industrial deliveries in the offpeak season in order to build sufficient storage volumes. Thus, high-priority customers will receive uninterrupted service *with or without* the addition of incremental LNG supply. With the exception of price effects (discussed below), these customers are indifferent to the existence of a supplemental gas project such as pipeline LNG.

Photo credit El Paso Co.

The correct way to answer the disposition question is to analyze consumption patterns both with and without the existence of an LNG project, rationally allocating available supplies in each case. The results of the analyses show that the customers who receive the LNG are those whose *supplies would be curtailed* if an LNG project did not exist.

A number of cases illustrate who will be curtailed in the most common situations.

Case **1.** The distributor endeavors to protect a certain priority level (industrial process gas, for example) from interruption and because of insufficient annual supply is unable to do so.

In this case, some minimum percentage of the process gas users' requirements would be curtailed, and all lower priority customers would be 100-percent curtailed throughout the year. Any addition to pipeline supply would first reduce curtailments to the process gas users, and any excess gas would be allocated at the discretion of the distributor. The excess would most likely be sold in the offpeak (summer) season to the lower priority customers. In this situation, the beneficiaries of the LNG project are high-priority industrial customers that gain supplies year-round and the lower priority offpeak customers that benefit seasonally. It should be noted, however, that this case implies a sharply reduced total pipeline supply, that is, severe curtailment.

Case **2.** The distributor is able to protect his high-priority load with or without the LNG project,

In this case, the customers who would be curtailed without the LNG project are lower priority industrial consumers and electric utilities. The curtailment is seasonal, as opposed to year-round in Case **1,** Since the LNG project provides a constant monthly addition to distributors' supply, it produces the following effects:

a. Winter storage withdrawals required to protect high-priority load are reduced.
b. Overall industrial curtailments are reduced,
c. Summer storage injections are often (but not always) increased.

Effect (c) occurs when summer supply exceeds actual demand, a common situation that complicates the determination of who gets the LNG. Since (a) and (c) act in opposite directions, storage patterns strongly influence the distribution of supply to the various consuming sectors.

Since gas distribution companies typically have some flexibility in their allocation of gas supplies, * the question of who will receive an incremental supply has no single answer. An allocation scheme typically employed during moderate curtailments, when high-priority customers can be protected with or without the addition of new incremental supply is described below.

Based on supply estimates from the pipeline supplier, the distributor calculates the amount of storage gas that will be required to service high-priority customers in the winter months and analyzes supply and demand for the summer months. If summer supply exceeds demand, the excess gas will be stored and used to cover winter storage withdrawal requirements. All available storage gas will be used to service high-priority customers during the winter months. As summer approaches, lower priority customers will be served, and excess gas will be injected into storage as the cycle continues.

This rather ideal load balancing rarely occurs in practice. Summer storage of "excess" gas usually is either insufficient or in excess of that needed to protect seasonal heating loads. If storage gas is insufficient, the distributor will plan to curtail deliveries to his lowest priority customers in the summer in order to increase storage injection. If storage is *more* rapid than necessary to meet requirements, the distributor must decide to whom and when to sell the gas. The most typical decision probably would be to extend the period of service to the highest priority curtailed customers. For example, if the distributor is protecting industrial priority 2 and curtailing priority 3 customers for five winter months, he would reduce his period of nondelivery to priority 3 customers by as many months as possible. If all priority 3 customer demands are satisfied, the distributor would move on to priority 4 customers and extend their service period, and so on.

If supplies increase by a fixed quantity each month, as would occur with the addition of a baseload LNG project, the effect is a reduction in winter storage withdrawals and possibly an increase in summer storage injections as well, If the distributor allocates the resulting excess stored gas in the manner described above, the beneficiaries of that portion of the incremental supply that increases storage volumes are high-priority industrial customers who were previously curtailed during the winter.

The rest of the answer is found by examining summer delivery patterns. During the transition from winter heating to summer baseload demand, the distributor will allocate his supply on a priority basis, and additional gas will serve to extend the summer service period for all seasonally curtailed customers. At the height of

*The exception is a distributor operating under a curtailment plan mandated by the State Public Utility Commission.

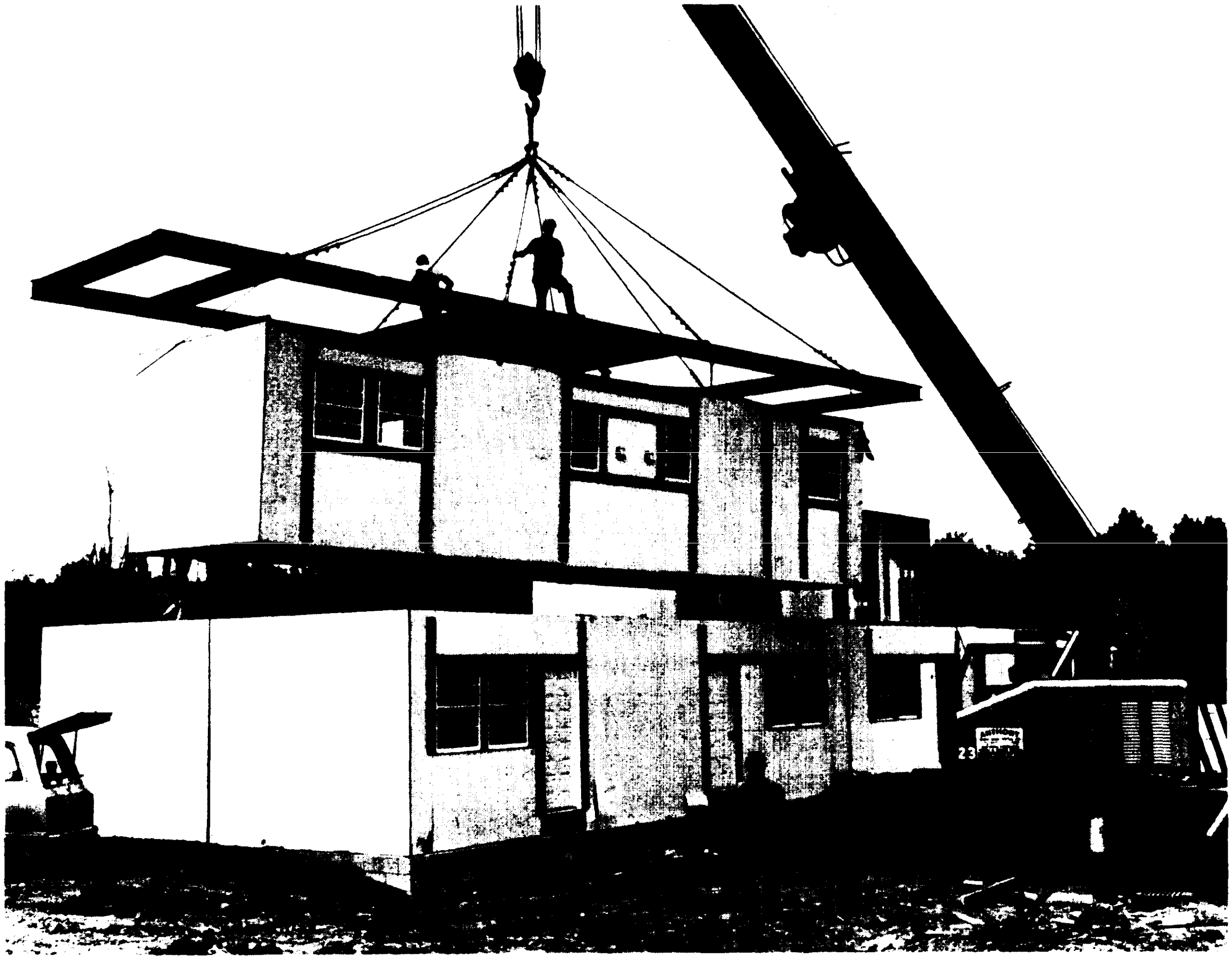


Photo credit Courtesy ot Columb/a Gas Transm/ss/on Corporation

Natural gas cooking, water heating, and house heating are utilized in these modular townhouse units

summer, the group that will benefit most from the additional gas supply are the lowest priority, severely curtailed customers, generally among the electric utilities.

The pipeline model illustrates these effects. Results for pipeline A appear first, in order to avoid confusion due to the allocation of supply to multiple consumer groups. As shown in figure 19, the model results illustrate that most of the LNG in this case is distributed initially to the electric power and priority 3 industrial sectors. The industrial boiler fuel sector, the prioritoy of which is between those of the other two, receives considerably **less,**

In the discussion so far, an even distribution of demand across the industrial and power generation sectors has been tacitly assumed. In actuality, a distributor's load is frequently (and sometimes rather sharply) skewed in favor of one or more sectors. This unevenness of demand affects the disposition of an incremental supply. For example, if a certain industrial category represents a very small total demand, its consumption of an incremental supply is obviously also very small. Figure **19 shows how** following 1990, gas demand in the electric power generation sector drops off sharply because of the Power Plant and Industrial Fuel Use Act (FUA). As actual demand declines, LNG consumption declines too, making more supplies available to the boiler fuel market. Figure 20 illustrates the same data in a different perspective.

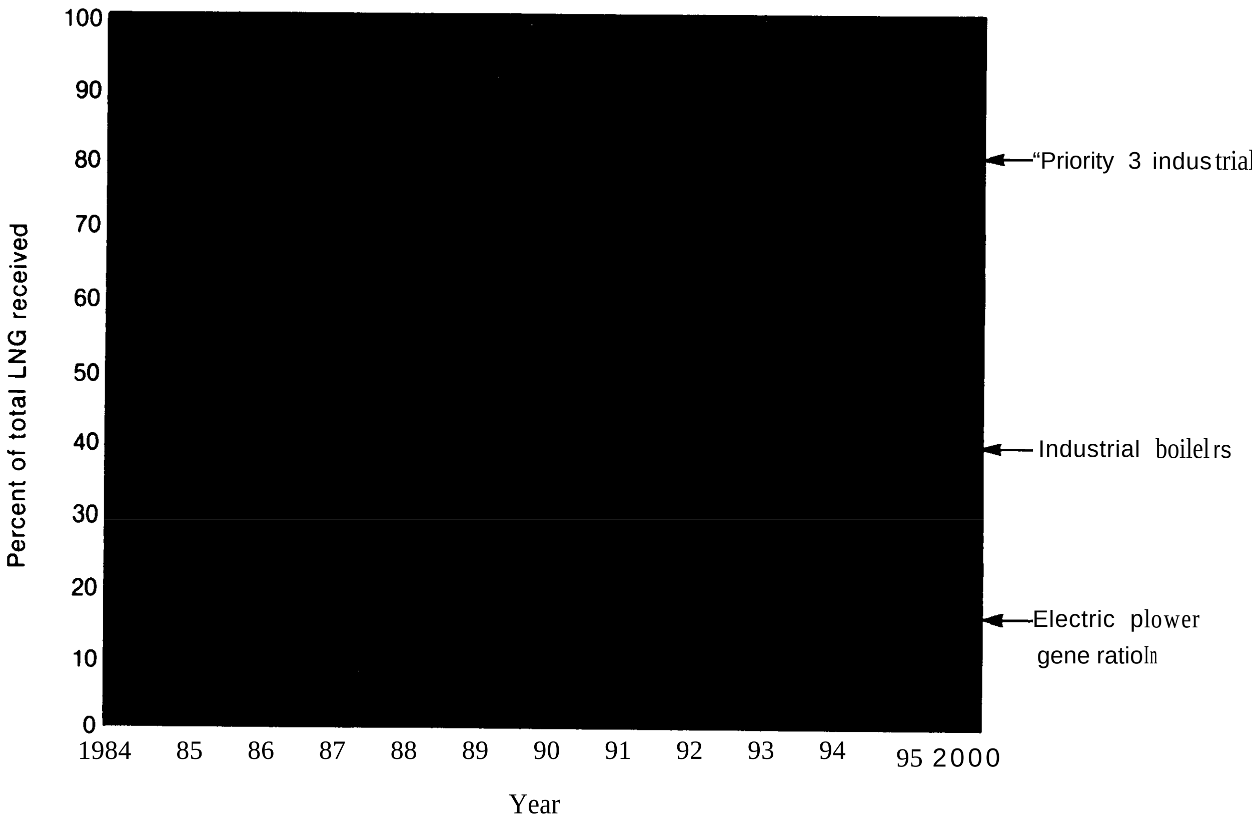
59-406 0 - 80 - 9

Photo credit Courtesy of Northern Natural Gas Company

Natural gas enables the exact amount of chocolate to cover these tortes as they pass through machine

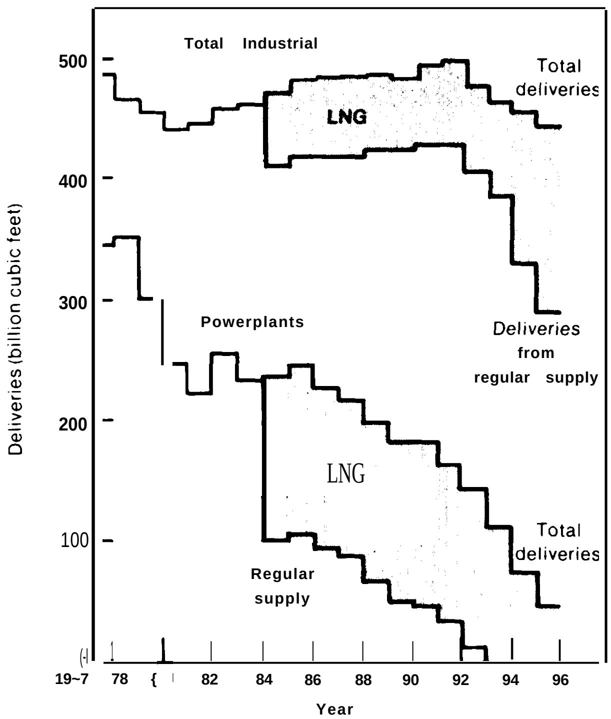
Thus far, the discussion has concerned the allocation of an incremental supply at the distributor's level. Since an LNG project would normally be a fixed addition to a pipeline's supply, the question of how the pipeline allocates its supplies among its various distribution companies and direct industrial customers remains. The pipeline model incorporates a Rule 467 B type of curtailment plan based on end-use priorities. Since actual gas demands change over time while entitlements remain fixed, "inequities" in the levels of service to different consuming sectors can easily arise. For example, current conservation levels have enabled distributors with large residential and commercial sales to develop a supply of "conservation gas" that can be sold to their industrial customers. However, distributors who lack such a residential/commercial cushion and customers served directly by the pipeline are not nearly so well off. For this

Figure 19.–Disposition of LNG (pipeline "A")



SOURCE: Jensen Associates, Inc.

Figure 20.—Consumption of LNG (pipeline "A")



SOURCE Jensen Associates, Inc

reason, each pipeline would have to be modeled separately to obtain perfectly precise results.

Pipeline B provides an example of two of the effects discussed above, inasmuch as it is characterized by significant direct sales to industry and heavily weighted residential and commercial sales. "Because of fixed base period entitlements, the pipeline's distribution company customers develop a large surplus of high-priority "conservation gas, " which can be reallocated to the industrial sector. In this case, a high level of service is maintained to the industrial customers of the distributors served by the pipeline throughout the period that was simulated. Following the introduction of an LNG project in 1981, even the large boiler customers receive virtually their entire requirement for the following 9 years, and in 1995 they are less than 40 percent curtailed. In contrast, pipeline B's *direct* industrial customers are never serviced beyond priority 2.

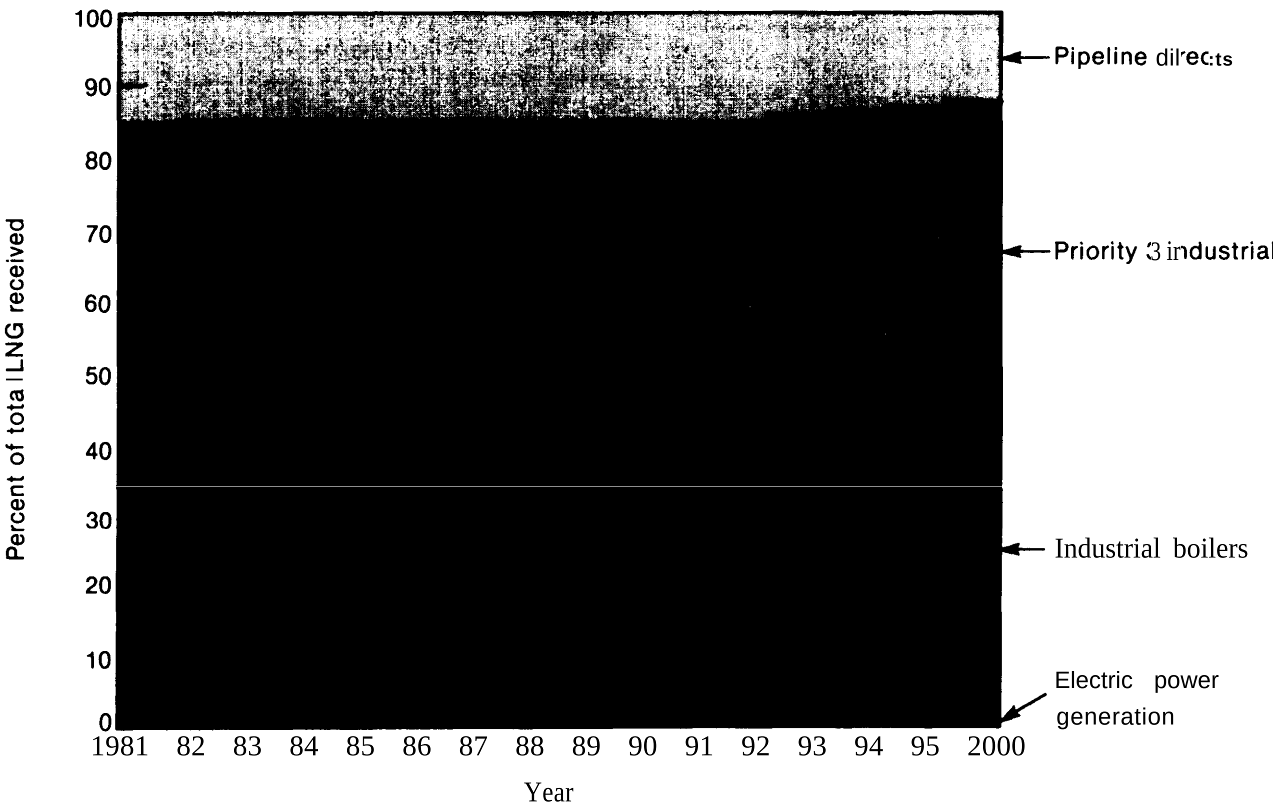
Figure 21 shows the disposition of LNG among consuming sectors for pipeline B. Because pipeline B's market includes very little power generation demand, it is not significantly influenced by FUA, and the disposition of LNG over time is relatively constant. While the direct industrial customers receive only about 15 percent of the LNG, this amount represents approximately 40 percent of their total supply. As a result of the LNG project, the priority 2 demands of the direct industrial customers are almost completely satisfied.

One last issue concerning the disposition of LNG needs to be addressed. During the early to mid- 1970's, when supplies of natural gas began to fall short of demand, a great many distributors restricted the addition of new customers. These "moratoria" were sometimes self-imposed or were mandated by the State Public Utility Commissions, and their eventual lifting was brought about by the introduction of new supplies, including baseload LNG. To the extent that these events are associated, the residential and commercial markets definitely benefit from a mnv LNG project. If future LNG imports prevent the reimposition of moratoria at least part of the LNG will be ultimately consumed by new residential and commercial customers. Finally, to the extent that the rate of delivery from a receiving terminal can be increased for brief periods, LNG can contribute to meeting short-term peaks in residential demand.

The price issue— who pays for the LNG?

In the absence of the congressionally mandated incremental pricing requirements, the question of the distribution of LNG costs among various users would be a relatively simple exercise for a project permitted to roll-in the price of LNG, The addition of LNG volumes at a price greater than the average acquisition cost of all other gas supplies would simply raise the cost of the gas to all consumers purchasing gas from that supplier. However, if the addition of LNG volume permits greater utilization of existing transmission and distribution facilities, the average fixed charges included in the delivered retail price would decline. If the increase in the

Figure 21.—Disposition of LNG (pipeline "B")



SOURCE: Jensen Associates, Inc

commodity cost of gas exceeds the decline in the average fixed costs, all gas customers who are supplied by the LNG importer, would incur some of the LNG costs. However, if the decline in the fixed charges exceeds the increase in the commodity cost of gas, all customers would benefit from the LNG project through a reduction in prices.

Under present incremental pricing regulations, however, the question of who pays for the LNG becomes quite complex. NGPA requires interstate pipelines and interstate-supplied distribution companies to pass through the portion of wellhead gas costs above a threshold level to select non-exempt industrial users until the price to these users rises to the cost of their alternate fuel. The benefits of access to the less expensive sources of natural gas have been reserved for residential, small commercial, electric utility, and certain other exempt users. As a result, the effective commodity cost of gas will no longer be the same to all users. Table 42 illustrates how the two pricing approaches differ.

An understanding of the incremental pricing system is critical to the discussion of who pays for the LNG. Without incremental pricing, the transmission and distribution costs are added to the average pipeline commodity cost of all gas in order to arrive at consumer prices. With incremental pricing, the cost of gas above an established threshold price is assigned only to non-exempt industrial users. Excluding the surcharge cost therefore reduces the average pipeline cost of gas from $2.53 to $2.21 in the case illustrated in the table. The surcharge costs are then allocated to non-exempt industrial users until they have all been distributed, or until further surcharge costs would raise the industrial costs above the alternate fuel ceiling price. In the example in table 42, a surcharge **of $1.01**

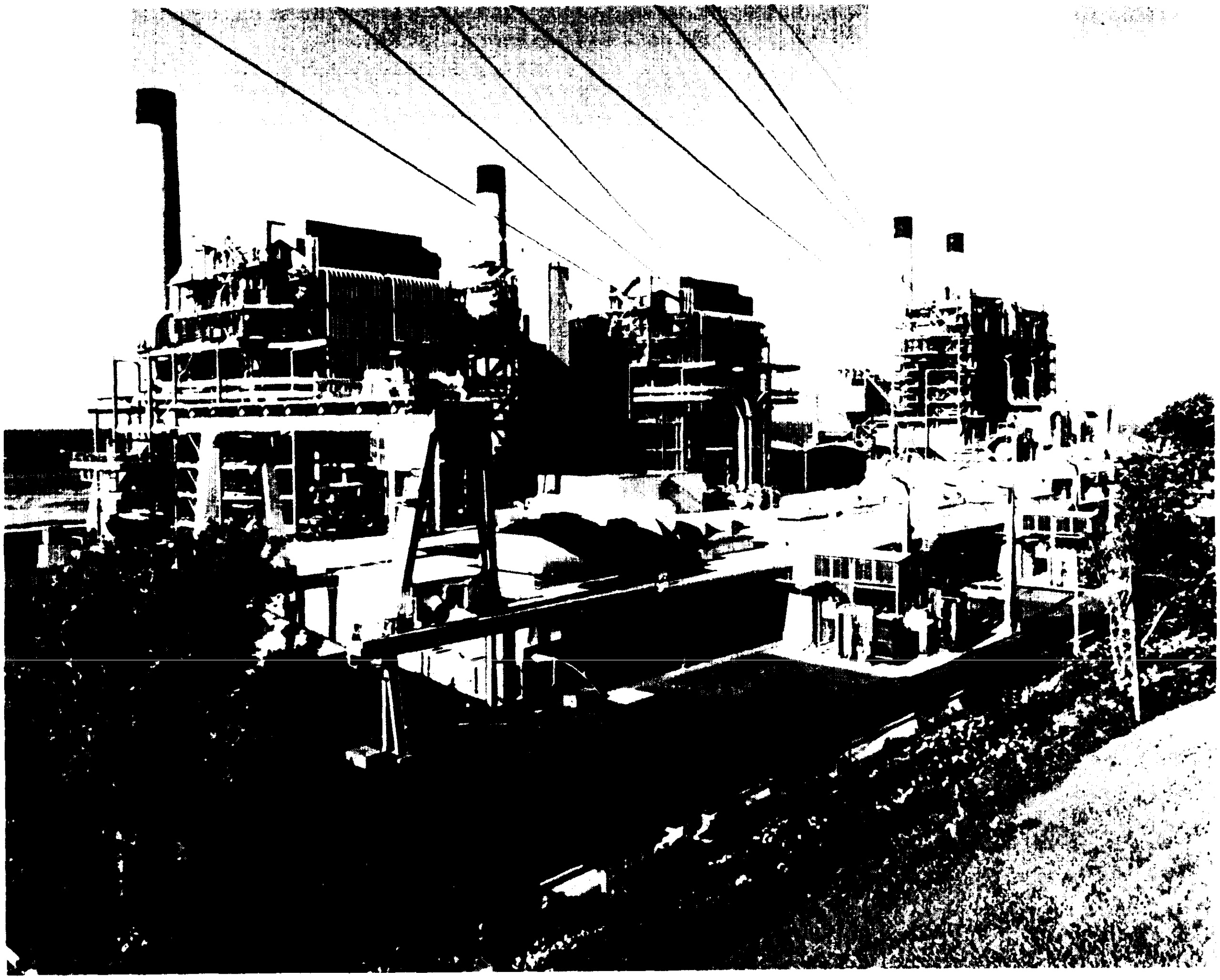


Photo credot Southern *Cal/torn/a* Ed/son Company

Southern California Edison Company's El Segundo Generating Station has four generating units with a combined effective operating capacity of 1,020,000 kilowatts. El Segundo is 1 of 13 oil- and gas-fired thermal powerplants operated by SCE

brings industrial prices to the ceiling and other gas customers must share the rest of the costs in excess of the threshold level.

The manner of allocating the remaining costs is not specified by NGPA. If the excess surcharge is distributed to *all* gas customers in a fashion similar to a purchased gas adjustment, the industrial gas price would exceed the alternate fuel price, and fuel stitching away from gas would begin. Because of this shift, remaining users would have to bear both the surcharge costs and the fixed pipeline and distribution charges previously incurred by the customers who shifted to an alternate fuel. However, Congress granted FERC discretion in selecting the alternate fuel price for the precise purpose of preventing load shifting. In order to avoid loss of load and possibly additional oil imports, once the industrial gas price reaches the alternate fuel ceiling, the excess surcharge costs must be allocated solely to the residential, commercial, exempt industrial, and power generation customers who were initially excluded

Table 42.—illustrative 1985 Residential and Industrial Gas Prices With and Without Incremental Pricing
(1978 dollars/million Btu)

	Residential		Nonexempt industrial	
	No incremental pricing	With incremental pricing	No incremental pricing	With incremental pricing
Average pipeline cost of all gas	**$2.53**	**$2.53**	**$2.53**	**$2.53**
Credit of costs above NGPA threshold price	**—**	**(.32)**	**—**	**(.32)**
Average pipeline cost of gas excluding surcharge costs (artificial gas cost)	**2.53**	**2.21**	**2.53**	**2.21**
Surcharge	**—**	**—**	**—**	1.01
Excess surcharge	—	.09	—	—
Commodity cost of gas	2.53	2.30	2.53	3.22
Transmission and distribution costs	1.50	1.50	1.34	1.34
Retail price of gas	4.03	3.80	3.87	4.56
Alternate fuel ceiling price	—	—	$4.56	$4.56

SOURCE: Jensen Associates, Inc.

from incremental pricing. In the example, the "excess surcharge, " raises the residential prices by $0.09.

NGPA allows the price of gas from currently approved LNG projects to be averaged or rolled-in with other pipeline supplies, while new projects for which import authority had not been applied for by May 1, 1978, are subject to incremental pricing under the Act. * The effects of these provisions on the distribution of added LNG costs among groups of consumers are discussed more fully in the *Background Reports* **volume**, and some general observations appear here.

Suppose the non-exempt gas customers are paying less than the alternative fuel ceiling price when LNG supplies are introduced. If LNG prices are rolled-in, charges to all consumers will tend to reflect equally the cost of LNG, adjusted for any improvement in utilization of fixed transmission and distribution facilities. The cost of incrementally priced LNG will fall more heavily, but not exclusively on non-exempt customers, while exempt purchasers will share equally the benefit of greater capacity utilization.

The distribution of costs is quite different if non-exempt customers have already reached the alternative fuel price ceiling, and part of the incremental surcharge is being paid by exempt customers. In this case, with an exception noted below, **the price paid by non-exempt purchasers does not change in response to** LNG supplies from either old or new projects, and the net cost or saving is reflected exclusively in the exempt prices. The exception occurs if non-exempt sales increase sufficiently to absorb all surcharge costs within the price ceiling, in which case, non-exempt prices could decline slightly at the expense of exempt users. Obviously, if non-exempt prices reach the ceiling as a result of an LNG project, the effect will be a combination of the effects just described.

The foregoing discussion assumes that LNG enters the country at or near the price ceiling, since import contracts are written with the objective of making LNG competitive with alternative fuels. If import costs were above or below the ceiling, these conclusions could change.

Table 43 illustrates the effect of rolled-in LNG on residential and industrial prices in 1985, based on the pipeline A model analysis. The addition of the LNG to the gas supply raises the pipeline's average cost, However, since the LNG volume (in this particular case) improves the utilization rate for the existing facilities, the fixed charges of the pipeline and distribution network are allocated over a greater volume, thereby reducing the unit cost of delivered gas. This decline in throughput charges for pipeline A offsets the increase in the commodity cost of gas. As a result, despite the higher gas costs, the delivered price to the residential sector declines marginally, while the industrial sector remains

*Exemptions may be granted by the Department of Energy

Table 43.—Illustrative 1985 Residential and Industrial Gas Prices With LNG Rolled.in and Without LNG"
(1978 dollars/million Btu)

	Residential		Industrial	
	Without LNG	With LNG	Without LNG	With LNG
Average pipeline cost of all gas	$2.53	$2.68	$2.53	$2.68
Credit of costs above NGPA threshold price	(.32)	(.28)	(.32)	(.28)
Average pipeline cost of gas excluding surcharge costs (artificial gas cost)	2.21	2.40	2.21	2.40
Surcharge	—		1.01	.98
Excess surcharge	.09	.05	—	—
Commodity cost of gas	2.30	2.45	3.22	3.38
Transmission and distribution costs	1.50	1.33	1.34	1.18
Retail price of gas	3.80	3.78	4.56	4.56
Alternate fuel ceiling price	—		$4.56	$4.56

[a]This table is based on a model simulation of pipeline A which incorporates the incremental pricing proposals in NGPA. It is **not** based on the now-abandoned incremental pricing policy proposed by FPC in the early LNG import application hearings.

SOURCE: Jensen Associates, Inc.

at the alternate fuel price ceiling due to a reallocation of the surcharge.

The cost of future LNG projects will probably not be rolled-in with that of other sources, and table 44 indicates how the components of table 43 would differ for an incrementally priced supply. Although the average cost to the pipeline would not change, a larger portion of it would be included in the surcharge account. However, the industrial price would remain the same, since it cannot rise above the alternate fuel ceiling, so the net effect is that retail prices do not depend on the pricing mechanism, as long as the industrial sector is paying maximum prices before LNG supplies become available.

The fact that the retail industrial prices in tables 42 through 44 are at the ceiling level is not assumed but derived from projected gas costs and alternate fuel prices by the model. Based on the projections, described in the *Background Reports* volume, the industrial sector is generally likely to pay the ceiling price during most of an LNG project's economic life.

Figure 22 summarizes for pipeline A which sectors receive the LNG and which pay for it. Although the relative allocation of the costs approximates the distribution of the LNG supplies, the sectors that buy the LNG generally incur costs in excess of the marginal cost of the supply. As a consequence, the residential, commer-

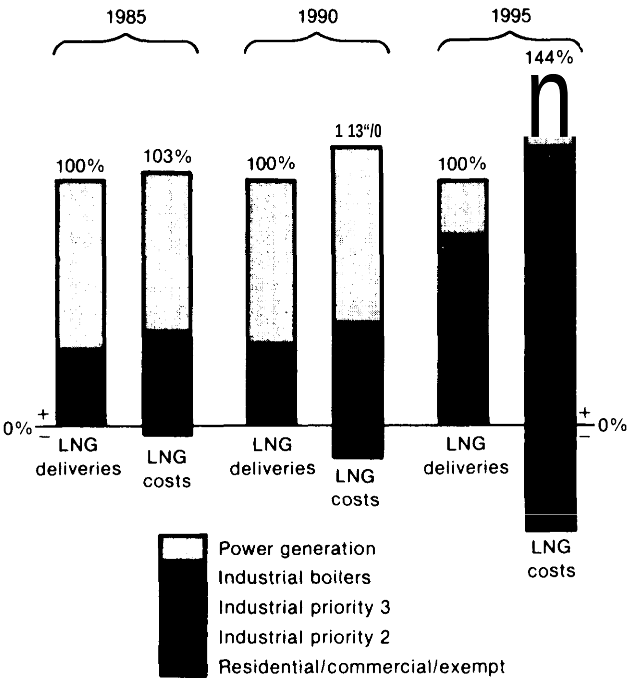
Table 44.—Illustrative 1985 Residential and Industrial Gas Prices With LNG Rolled-In and With LNG Incrementally Priced'
(1978 dollarslmillion Btu)

	Residential		Industrial	
	With LNG rolled-in	With LNG incrementally priced	With LNG rolled-in	With LNG incrementally priced
Average pipeline cost of all gas	$2.68	$2.68	$2.68	$2.68
Credit of costs above NGPA threshold price	(.28)	(.55)	(.28)	(.55)
Average pipeline cost of gas excluding surcharge costs (artificial gas cost)	2.40	2.13	2.40	2.13
Surcharge	—	—	.98	1.25
Excess surcharge	.05	.32	—	—
Commodity cost of gas	2.45	2.45	3.38	3.38
Transmission and distribution costs	1.33	1.33	1.18	1.18
Retail price of gas	3.78	3.78	4.56	4.56
Alternate fuel ceiling price	—	—	$4.56	$4.56

[a]This table is based on a model simulation of pipeline A which incorporates the incremental pricing proposals in NGPA. It is **not** based on the now-abandoned incremental pricing policy proposed by FPC in the early LNG import application hearings.

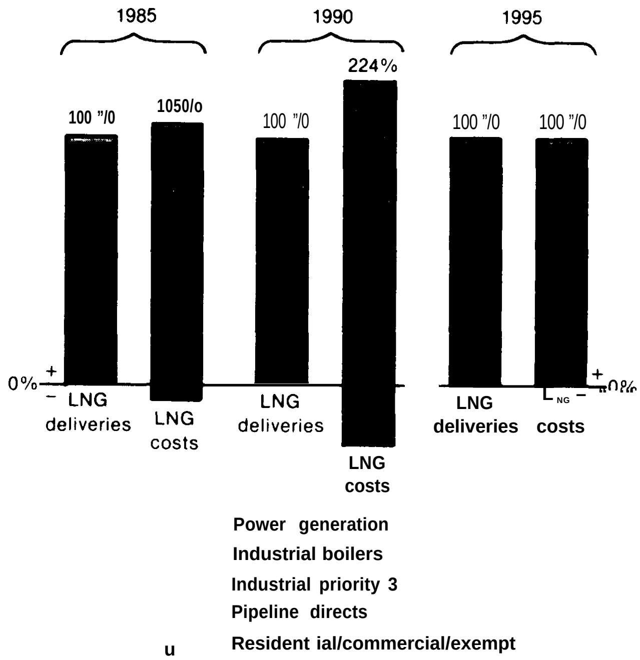
SOURCE: Jensen Associates, Inc.

Figure 22.— Percent Distribution of LNG Volumes and Costs (pipeline 66A")



SOURCE: Jensen Associates, Inc

Figure 23.—Percent Distribution of LNG Volumes and Costs (pipeline "B")



SOURCE Jensen Associates. Inc

cial, and exempt industrial customers (which receive no LNG) benefit from a reduction in their delivered price. In the early years of the project, power generation receives a small subsidy from the other sectors that receive LNG, as does the priority 2 industrial sector.

For pipeline B, the allocation of LNG supplies and costs is shown in figure 23. Again, the sectors that buy additional gas generally provide a subsidy to the residential, commercial, and exempt industrial customers, but not throughout the life of the project. After 1990, the subsidy, which has grown quite large, declines rapidly, so that by 1995, the revenues from those customers that receive LNG are approximately equal to the project costs. Although the load characteristics of pipeline B are quite unlike those of pipeline A, the dissimilarity in the distribution of costs in 1995 is due primarily to differences in the LNG pricing formulas of the supplying country. Pipeline A incorporates a pricing scheme similar to the Indonesian formula, whereas pipeline B's LNG costs are based on the Algerian formula. As a result, the delivered price of the LNG is higher for pipeline B than for pipeline A. The effect of this differential is reflected in the relative subsidy position of the residential, commercial, and exempt industrial customers in 1995. For pipeline A, the increase in the average cost of gas due to the LNG project is more than offset by the decline in the unit costs of transmission and distribution and in the excess surcharge. The addition of the LNG therefore results in a lower cost to the residential, commercial, and exempt industrial customers. For pipeline B, with higher LNG costs, the increase in the average price of gas due to the LNG is approximately equal to the decline in unit delivery costs and excess surcharges, so the addition of the LNG has little effect on the retail price of gas for the exempt categories of customers.

For another LNG project, with different customer characteristics, pipeline utilization rates, alternate fuel markets, surcharge gas accounts, and pipeline supplies, the answer to the question of who pays for the LNG could be different from that found in either pipeline A or pipeline B. In these simulations, however, although the high-priority customers never receive any LNG, they frequently benefit from the project through a subsidy that lowers the retail price of gas. In certain years, the LNG project generates no benefits for the high-priority customers and occasionally imposes a small price penalty, but this occurrence is the exception and not the rule.

Supply impact of LNG interruption

The impact of supply interruption must be assessed within the context of the role of LNG in the total supply of natural gas to a region. The actual flow of LNG sales does not indicate who would lose natural gas in case of an interruption, since imported LNG is only part of the overall supply to a natural gas distribution company. While the revaporized LNG may flow physically to a relatively small area, remaining supplies of gas from other sources would be reallocated to diffuse the impact of a shortfall.

Federal and State curtailment plans to allocate natural gas in the event of a shortage were established in the early and mid-1970's, when the supply fell below expectations and contracts could not be fulfilled. In the event of an LNG interruption this system would serve to reallocate the remaining available gas. Alternatively, the companies in the natural gas industry of an area could arrange for transfer of gas or for increased production to protect high-priority customers—homes, schools, hospitals, and stores. Under NGPA, the President also has the authority to allocate gas supplies among interstate pipelines during a gas shortage. Who would lose gas during an LNG interruption is, therefore, a question of how the remaining supply would be redistributed.

The ease or difficulty of managing an LNG shortfall will depend to some extent on how dispersed the final markets are. Table 45 shows the distribution by State of the LNG sales from each of the operating and approved projects. Both the Pac Indonesia and Distrigas projects import gas on behalf of distribution companies, and their volumes tend to be localized. on the other hand, in the Algeria I and Trunkline projects, gas flows through long-distance transmission pipelines that serve wide areas. Thirty-two States will probably receive natural gas from approved import projects, as shown in table 46 in which the flow of LNG to each State is compared with 1977 total deliveries.

Finally, the gas industry can protect against cessation of LNG deliveries by expanding storage volumes. Since this form of insurance is expensive, its appropriateness will depend on the **availability** of alternatives to the transmission and distribution companies and to the users whose supply would be curtailed. The preceding analysis does not include provisions for increased storage, which would add to the transportation cost reflected in final prices.

Table 45.—Distribution of Imported LNG by Consuming State for Each Pipeline Importer
(percent)

	Algeria I				Pacific Indonesia		
States	Columbia	Consolidated	Southern Natural	Distrigas	Pacific Gas & Electric	Southern California	Trunkline
Alabama	—	—	26.40	–	—	—	—
Arizona	—	—	—		—	—	—
Arkansas	—	—	0.01	:	—	—	0.23
California	—	—	—	—	100.0	100.0	—
Colorado	—	—	—	—	—	—	0.06
Connecticut	—	—	0.10	3.87	–	—	—
Delaware	—	—	—	—	—	—	—
Florida	—	—	3.86	–	—	—	—
Georgia	—	—	44.03	—	—	—	—
Idaho	—	—	—	—	—	—	—
Illinois	—	—	0.03	–	—	—	14.18
Indiana	—	—	0.01	–	—	—	12.22
Iowa	—	—	—	—	—	—	0.04
Kansas	—	—	—	—	—	—	1.60
Kentucky,	4.33	—	0.03	–	—	—	0.28
Louisiana	—	—	0.87	–	—	—	0.67
Maine	—	—	—		—	—	—
Maryland	11.56	—	0.04	:	—	—	0.56
Massachusetts	—	—	0.19	46.40	—	—	—
Michigan	—	—	—	—	—	—	51.28
Minnesota	—	—	—	—	—	—	—
Mississippi	—	—	4.96	–	—	—	0.36
Missouri	—	—	0.03	–	—	—	6.94
Montana	—	—	—	—	—	—	—
Nebraska	—	—	—	—	—	—	0.06
Nevada	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—
NewJersey	0.18	–	0.29	5.42	–	—	0.01
New Mexico	—		—	—	—	—	—
New York	3.10	30.61	0.42	36.41	–	—	0.15
NorthCarolina	—	—	—	—	—	—	—
North Dakota	—	—	—	—	—	—	—
Ohio	44.26	43.67	0.51	–	—	—	6.82
Oklahoma	—	—	—	—	—	—	0.22
Oregon	—	—	—	—	—	—	—
Pennsylvania	15.34	16.75	0.53	–	—	—	0.74
RhodeIsland	—	—	0.05	7.90	—	—	—
SouthCarolina	—	—	14.61	—	—	—	—
South Dakota	—	—	—	—		—	—
Tennessee	—	—	2.83	–	—	—	0.40
Texas	—	—	**0.04**	–	—	—	**0.61**
Utah	–	—	—	—	—	—	—
Vermont	—	—	—		—	—	—
Virginia	7.43	—	0.02	:	—	—	0.36
Washington	—	—	—	—	—	—	—
West Virginia	7.22	8.94	0.10	–	—	—	0.35
Wisconsin	—	—	—	—	—	—	0.36
Wyoming	—	—	—		—	—	0.02
Washington, D.C.	1.87	—	0.01	=	—	—	0.09
Other	4.71	0.03	0.02	–	—	—	1.51

NOTE: May not add to 100.0 due to rounding.

SOURCE: Office of Technology Assessment.

Table 46.—Estimated LNG Sales by State (in billion cubic feet)

State	1977a consumption	1985 LNG	LNG percent	State	1977a consumption	1985 LNG	LNG percent
Alabama.	234.07	33.74	14.4	Nebraska	144.20	0.10	0.1
Arizona.	170.41	—	—	Nevada.	65.47	—	—
Arkansas	221.78	0.40	0.2	New Hampshire.	8.32	—	—
California.	1,664.59	184.0	11.1	New Jersey	274.88	2.94	1.1
Colorado	242.39	0.10	0.1	New Mexico.	191.56	—	—
Connecticut.	66.63	1.81	2.7	New York	598.74	59.14	9.9
Delaware	13.79	—	—	North Carolina.	82.67	—	—
Florida	267.93	4.93	1.8	North Dakota.	23.38	—	—
Georgia.	289.19	56.27	19.5	Ohio	909.50	116.38	12.8
Idaho.	49.76	—	—	Oklahoma.	689.49	0.37	0.1
Illinois.	1,135.71	23.86	2.1	Oregon	92.12	–	—
Indiana	447.24	20.37	4.6	Pennsylvania.	676.24	40.12	5.9
Iowa	282.39	0.07	0.0	Rhode Island	23.98	3.50	14.6
Kansas	464.45	2.69	0.6	South Carolina.	99.67	18.67	18.7
Kentucky	192.67	5.25	2.7	South Dakota.	27.47	—	—
Louisiana.	1,518.64	2.24	0.1	Tennessee	208.03	4.29	2.1
Maine	2.11	—	—	Texas	3,954.01	1.07	0.0
Maryland & D. C..	169.41	15.86	9.4	Utah	122.45	—	—
Massachusetts	167.08	20.42	12.2	Vermont	4.52	—	—
Michigan	866.48	86.15	9.9	Virginia	108.44	8.77	8.1
Minnesota	267.83	–		Washington	153.74	—	—
Mississippi	202.20	6.94	;4	West Virginia..	175.22	20.05	11.4
Missouri.	334.43	11.70	3.5	Wisconsin	322.18	0.60	0.2
Montana.	66.66	—	—	Wyoming	71.56	0.03	0.0

SOURCE Jensen Associates, Inc

Air quality benefits of gas utilization

With present pollution control technology, natural gas is the cleanest burning fossil fuel. As shown in table 47, burning gas generally produces significantly less sulfur dioxide (SO_2) and particulate and somewhat less hydrocarbon emissions than either oil or coal because of the lower proportion of carbon in methane. Although natural gas combustion is not as environmentally acceptable as conservation, when compared to other fuels, it causes the least air quality impact. For more detailed discussions of the health and climate effects of specific fossil fuel combustion products, see OTA's report on The *Direct Use of Coal*[1] and other recent studies. z [3]4

[1]*The Direct Use of Coal* (Washington, D.C.: U.S,.. Congress, Office of Technology Assessment, April 1979), OTA-E-86.

Ninth Report of the Council on Environmental *Quality v* (Council on Envirionmental Quality v, December 1978).

[3]*National Air Aualityv and Emissions Trends Report, 1977* (Envi - ronmental Protection Agency, December 1978).

[4]*Effects of Chronic Exposure to Low Level Pollutants in the Environment* (Congressional Research Service, November 1975).

The contribution of additional gas availability to meeting requirements for clean air will depend heavily on where it is used. Air quality and capacity to dissipate pollutants vary from place to place because of differences in climate, demography, and topography, as do nationaI air quality standards. The latter are comprised of three classes: Class I areas (national parks and wilderness) are subject to the lowest allowable change in ambient air quality; Class II and 111 areas (all other lands) are subject to varying degrees of allowable change in ambient air quality and may be redesignated by States. Furthermore, the degree of compliance with national air quality standards varies with locality and time. Under the Clean Air Act, States *can impose* more stringent standards than the national ones, and State Implementation Plans under the Act impose different local requirements.

California represents an example of the variety of situations that can occur with air quality

Table 47.—Air Pollution From Burning Gas Versus Other Fuels, in Thousands of Metric Tons per Tcf/Equivalent
(percentages are of total estimated nationwide emissions of the pollutant, 1977)

Pollutant	Gas		Oil		Coal		Conservation	
	Quantity	Percent	Quantity	Percent	Quantity	Percent	Quantity	Percent
Sulfur oxide.	0.3	0	385-427	1.4-1.6	306-2,035	1.1-7.4	0	0
Particulate.	2.3-7	0	65-334	0.5-2.7	28-4,378	0.2-35.3	0	0
Carbon monoxide.	7.9-9.3	0	18.6	0	20-41	0	0	0
Hydrocarbons.	0.5-3.7	0	3.2	0	6-20	0	0	0
Nitrogen oxides	37-325	0.2-1.4	60.2-352	0.3-1.5	311-1,131	1.3-4.9	0	0

NOTES. a) O means less than 0,1 percent.
b) The two numbers represent a range of available pollutlon control technology

SOURCES American Gas Assoclatlon, *The Future for Gas Energy In the Un/ied States,* June 1979; and the Environmental Protection Agency, *National* Air *Quality and Emissions Trends Report, 1977,* December 1978. Conversion-assumptions: 22 lb per kg, 1,020000 Btu per MCF

compliance. The national and California ambient air quality standards are shown in table 48. In most areas, California complies with the national and the more stringent State standards for short-term exposure to SO, and other sulfur compounds. However, California has had difficulty complying with air quality standards on carbon dioxide, hydrocarbons, and photochemical oxidants. For example, in the Los Angeles and San Francisco metropolitan areas, the level of oxidants has on occasion approached dangerous levels. Furthermore, the SO_2 level in the South Coast Air Basin, which contains about 50 percent of the State's population, has on many occasions been higher than what is permitted under the California standard and on some occasions has reached critical levels. Because of these air quality problems, increased gas utilization would appear to be an attractive alternative for that region.

In California the use of certain types of fuel oil is already prohibited for air quality reasons, so air quality standards might also preclude gas customers from switching to more polluting fuels. Consequently, if the demand for fuel increases where air quality standards are currently violated, the availability of gas could permit local employment to expand at a faster rate. However, the effect on employment would seem to be relatively small, although an early study has predicted that 700,000 jobs would be affected, at least temporarily, in the region if Alaskan and Indonesian LNG were not available.[5] The sponsor, Southern California Gas Co., no longer supports the latter conclusion, and three other studies[6,7,8] indicated that a much smaller number of jobs, probably less than 10,000 to 18)000 would be lost or interrupted. On a national scale, the employment effect of the availability of more total energy is uncertain and probably small because higher economic growth is offset by possible substitution of labor for energy.

[5] *An Analysis of Unemployment Related to Natural Gas Shortages in the Southern California Gas Company Serving Area* (Southern California Gas Company, June 29, 1977), prepared for case 10342, 1975,

[6] *Decision Analysis of California LNG* (Applied Decision Analysis, Dec. 20, 1977).

[7] *Economic Implications of Loss of Gas Service to Industry in Southern California* (Sherman Clark Associates, Mar. 1, 1978).

[8] *Energy Analysis* (American Gas Association, Jan. 26, 1979).

Balance of payments

LNG, like oil, is imported and thus represents an outflow of dollars from the United States. This negative contribution to the balance of international payments affects the value of the dollar, which in turn accelerates inflation at home and reduces the United States' ability to obtain credit on favorable terms abroad.

The balance of payments is influenced by many factors, including international trade agreements and tariffs, and is partly self-correcting through the mechanism of floating exchange rates. Consequently, estimating the impacts of a particular trade, such as LNG, runs the risk of oversimplification and should there-

Table 48.—National and California Ambient Air Quality Standards
(concentrations in $\mu g/m^3$ unless otherwise noted)

Pollutant	National[a] primary standard[b]	National[a] secondary standard[b]	California standard	"Danger point" significant harm to human health
1. Suspended particulate matter				
Annual geometric mean	75	60	60	1,000 (or coefficient
24-hour maximum	260	150	100	of haze of 8) for 24 hr
2. Sulfur dioxide				
Annual arithmetic mean	80 (0.03 ppm)	60 (0.02 ppm)	—c	
24-hour maximum	365	260 (0.1 ppm)	131 (0.05 ppm)d	2,620 (4 ppm) for 24 hr
3-hour maximum	—	1,300 (0.5 ppm)	—	
l-hour maximum	—	—	1,300 (0.5 ppm)	
3. Carbon monoxide				
12-hour maximum	—	—	11 mg/m^3 (10 ppm)	50 ppm for 8 hr
8-hour maximum	10 mg/m^3 (9 ppm)	Same as primary	—	75 ppm for 4 hr
l-hour maximum	40 mg/m^3 (35 ppm)	Same as primary	46 mg/m^3 (40 ppm)	125 ppm for 1 hr
4. Nitrogen dioxide				
Annual arithmetic mean	100 (0.055 ppm)	Same as primary	—	3,750 (2 ppm) for 1 hr
l-hour maximum	—	—	470 (0.25 ppm)	or 0.5 ppm for 24 hr
5. Photochemical oxidants				
l-hour maximum		—	200 (0.10 ppm)	0.4 ppm for 4 hr 0.6 ppm for 2 hr 0.7 ppm for 1 hr
6. Hydrocarbons (non methane)				
3-hour (6 to 9 a.m.)	160 (0.24 ppm)	Same as primary	—	
7. Particulate sulfate				
24-hour maximum	—	—	25	
8. Hydrogen sulfide				
l-hour maximum		—	42 (0.03 ppm)	
9. Lead (in particulate matter)				
30-day average	—	—	1.5	
10. Visibility reducing particles				
(Instantaneous)	–	—	10 miles at relative humidity less than 7070	

[a]National standards, except those based on annual averages or annual geometric means, are not to be exceeded more than once per year.
[b]Primary standards are designed to protect the public health. Secondary standards are designed to protect the public welfare from any known or anticipated adverse effects of a pollutant.
[c]No standard.
[d]When such levels are in the presence of either 1-hour oxidant levels greater than or equal to 0.10 ppm or 24-hour particulate levels greater than or equal to 100 $\mu g/m^3$.

SOURCES: *Final Environmental Impact Statement, Western LNG Project*, 75-83-2, Federal Energy Regulatory Commission, October 1978.
Effects of Chronic Exposure to Low Level Pollutants in the Environment, Congressional Research Service, November 1975.

fore be regarded as a crude approximation. For example, choosing the lowest cost alternative from among LNG, foreign oil, and domestic production and conservation may have a salutory indirect effect on the balance of payments that outweighs the influence of direct payments associated with any specific trade, With the foregoing caveats in mind, the following discussion compares the immediate balance-of-payment impacts of these three general alternatives.

Although importing LNG, involves a significant outflow of U.S. dollars compared to domestic alternatitves, net foreign payments for imported oil are greater. The total cost of importing oil is almost all outflow and represents a sizable dollar amount. Over 95 percent of U.S.-bound oil arrives in foreign tankers at a transportation cost of about $0.19 per million Btu (M MBtu), [8] so the total return or balance-of-payment inflow is about 5 percent of the shipping costs, or $0.01/ MMBtu.

In the case of LNG, the most pessimistic assumption would be that the price to the final customer is the same as that of imported oil over the long term (see chapter 4 for discussion of contractual terms). However, the outflow of dollars would not include expenditures associ-

[8]Tankers, World Survey, *Petroleum Economist*, September 1978, and February 1979.

ated with LNG receiving terminals and regasification facilities in the United States. In addition, the producing country may buy U.S. equipment, and a larger portion of the LNG is likely to be carried in U.S. flag tankers. Based on cost estimates in chapter 4, table 49 shows the amount of a typical LNG project's cost to be expended in the United States, provided the liquefaction plant is purchased here and 50 percent of the tanker fleet is U.S. built and operated. In contrast to oil, about $1/MMBtu of the cost of service would be expended in this country.

The figures in table 49 consist largely of initial capital expenditures in the United States amortized over time, so the favorable component of the impact of importing LNG is actually immediate and short term. After the facilities and ships are constructed, the balance-of-trade effects are comparable to those of oil, although U.S. financing could spread payments out over a longer period of time. Finally, the worst case example discussed above is unlikely because the U.S. market will probably limit delivered gas costs to less than world oil prices because of lower competing domestic oil costs. Even if f.o.b. price renegotiations produce the worst possible outcome, the delivered price will still only reach this limit occasionally (see the discussion of the Algeria II contract in the last chapter).

In conclusion, importing LNG appears to have a less unfavorable influence on the balance of payments than importing oil to a significant but uncertain extent, due to differences in project structure and to the fact that lower LNG costs relative to world oil may be the dominant factor. Nevertheless, LNG represents a significant outflow of dollars compared to domestic alternatives.

Table 49.—Potential Expenditures in the United States Included in the Cost of an LNG Import Project in the Fifth Year of Operation in 1990
(1978 dollarslmillion Btu)

U.S. facilities	$ .29
50-percent shipping	.30
Capital cost of liquefaction plant	.43
Total return	$1.02

SOURCE: Office of Technology Assessment.

U. S. GOVERNMENT PRINTING OFFICE : 1980 O - 59-406