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.

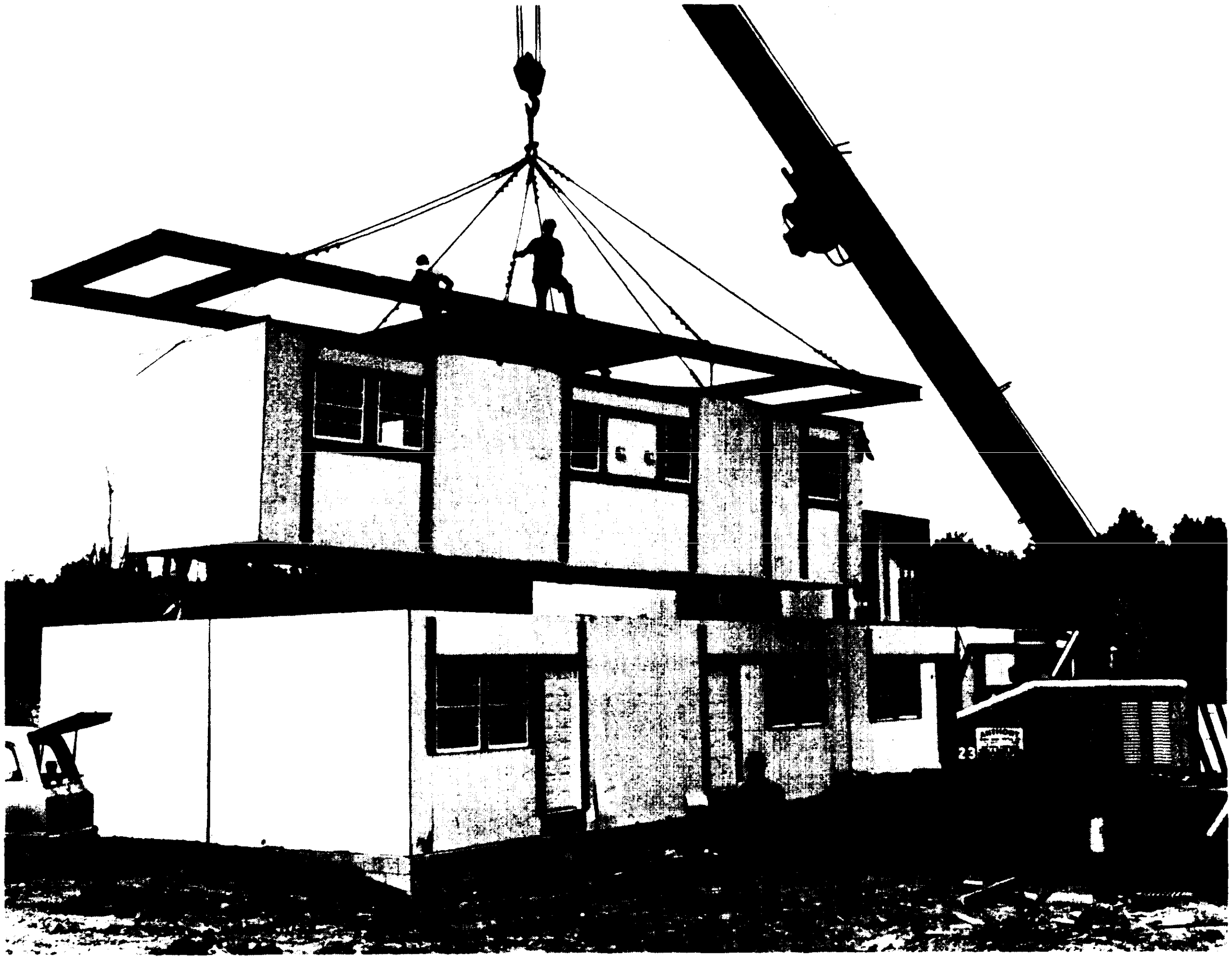


Photo credit Courtesy ot Columb/a Gas Transm/ss/on Corporation

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.

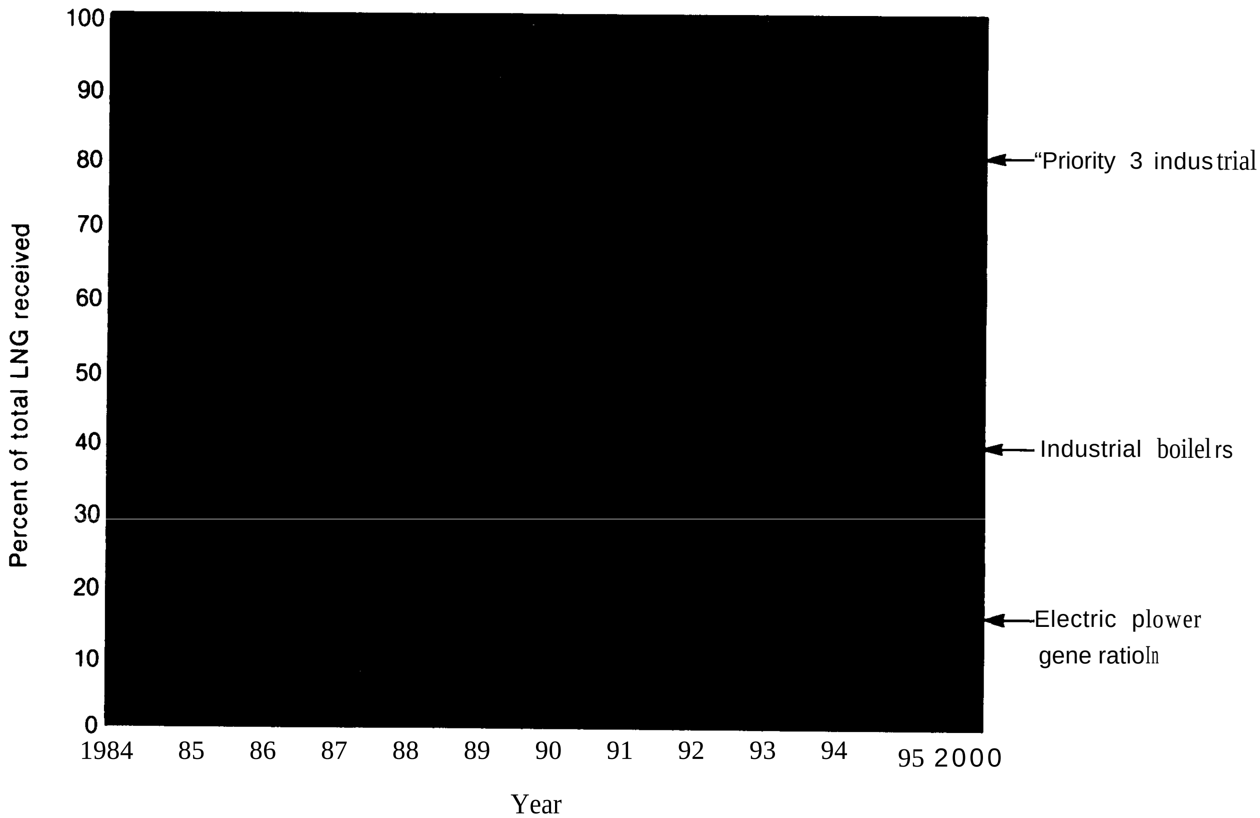
59-406 0 - 80 - 9

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

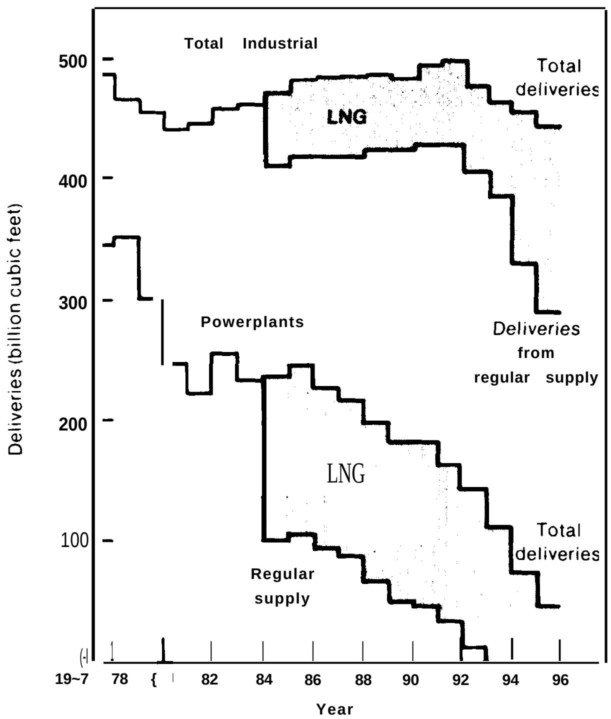
Thus far, the discussion has concerned the allocation of an incremental supply at the distributor's level. Since an LNG project would normally be a fixed addition to a pipeline's supply, the question of how the pipeline allocates its supplies among its various distribution companies and direct industrial 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.

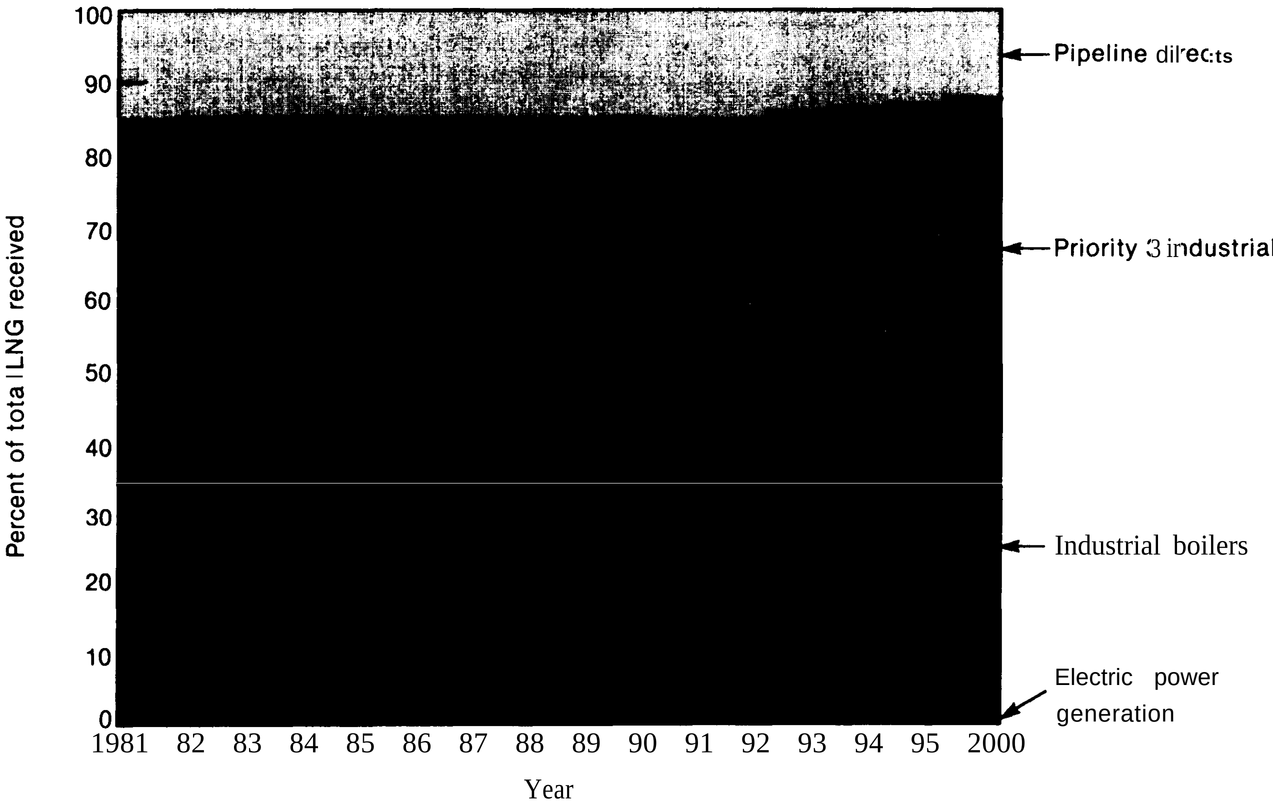
Figure 21 shows the disposition of LNG among consuming sectors for pipeline B. Because pipeline B's market includes very little power generation demand, it is not significantly influenced by FUA, and the disposition of LNG over time is relatively constant. While the direct industrial customers receive 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**

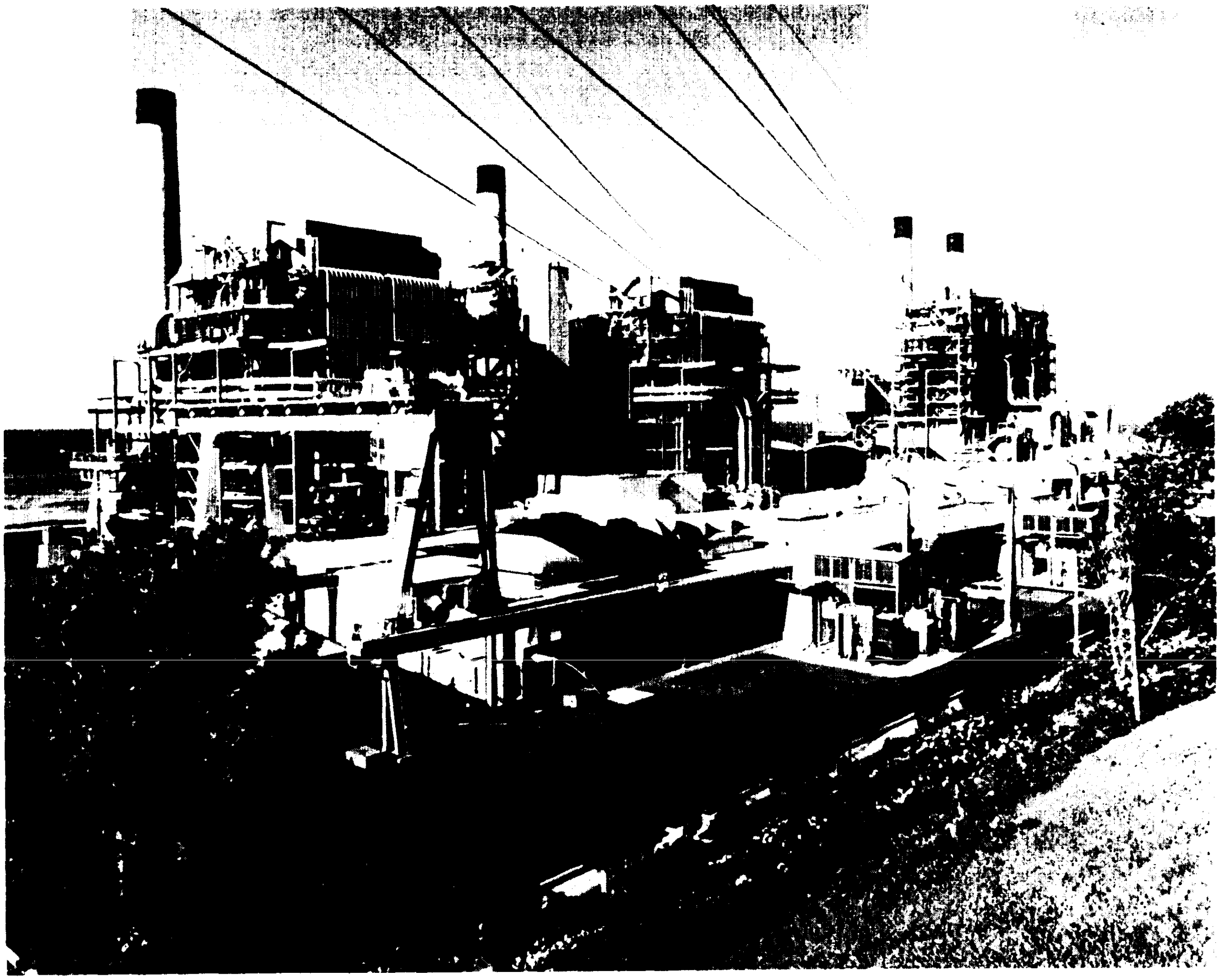


Photo credot Southern **Ca//torn/a** Ed/son Company

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* **vol**ume, 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-

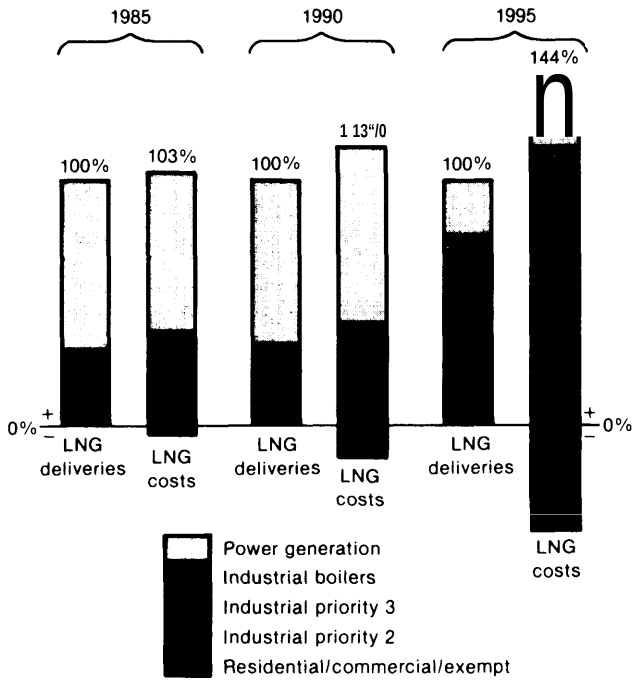
Table 44.—Illustrative 1985 Residential and Industrial Gas Prices With LNG Rolled-In and With LNG Incrementally Priced’
(1978 dollarslmillion Btu)

	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.

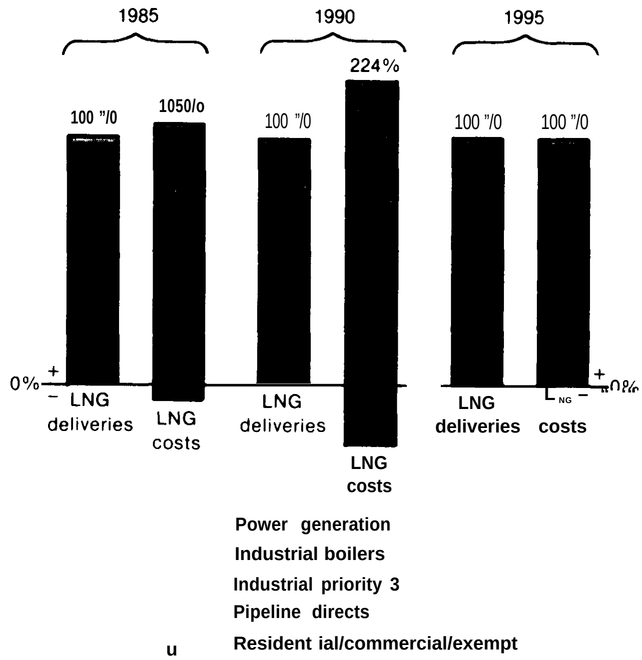
SOURCE: Jensen Associates, Inc.

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.[2,3,4]

[1] *The Direct Use of Coal* (Washington, D.C.: U.S,.. Congress, Office of Technology Assessment, April 1979), OTA-E-86.

[2] *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* (Environmental 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 im*pose 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/m³ (10 ppm)	50 ppm for 8 hr
8-hour maximum	10 mg/m³ (9 ppm)	Same as primary	—	75 ppm for 4 hr
l-hour maximum	40 mg/m³ (35 ppm)	Same as primary	46 mg/m³ (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