Cited as "1 ERA Para. 70,104"

El Paso Eastern Company, et al.
ERA Docket No. 77-006-LNG
December 21, 1978.

Application to Import LNG from Algeria.

[Opinion and Order]

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Glossary of Abbreviations

the Act	The Department of Energy Organization Act
AGA	American Gas Association
Algeria II	The instant proposal to import LNG from Algeria
ALJ	Administrative Law Judge

applicants	El Paso Eastern Company, El Paso LNG Company, El Paso Terminal Company, El Paso Natural Gas Company, United Gas Pipe Line Company, and United LNG Company
Atlantic	El Paso Atlantic Company
Bcf	Billion cubic feet
Brooklyn Union	Brooklyn Union Gas Company
Btu	Billion cubic feet
the Commission	Federal Power Commission or Federal Energy Regulatory Commission
cm	centimeters
Council	The Council on Wage and Price Stability
CPUC	California Public Utility Commission
DEIS	Draft Environmental Impact Statement
DOE	Department of Energy
Eastern	El Paso Eastern Company
EIS	Environmental Impact Statement
El Paso II	El Paso Eastern Company, et al. the instant proposal to import LNG form Algeria
El Paso LNG	El Paso LNG Company
EOC	East of California
EPNG	El Paso Natural Gas Company
ERA	Economic Regulatory Administration
ETA	Energy Tax Act
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission

FPC	Federal Power Commission
FUA	the Power Plant and Industrial Fuel Use Act of 1978
GM	General Motors Corporation
HAS, et al.	Houston Audubon Society, the Houston Sierra Club, et al.
I.D. or Initial Decision	the Initial Decision upon Application to Import LNG from Algeria, ALJ Southworth
km	Kilometers
LaSalle Terminal	The import terminal and regasification plant proposed for location on Matagorda Bay, Texas
LNG	Liquefied Natural Gas
m \3/	Cubic meters
Mcf	Thousand cubic meters
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMm \3/	Million cubic meters
NECPA	The National Energy Conservation Policy Act of 1978
NEPA	National Environmental Policy Act of 1969
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act of 1978
OPEC	Organization of Petroleum Exporting Countries
Opinion One	DOE/ERA Opinion Number One, "Opinion and Order on Importation of Liquefied Natural Gas from Indonesia," December 30, 1977, ERA Docket No. 77-001-LNG, Pacific Indonesia LNG Company and Western Terminal Associates

Opinion Two	DOE/ERA Opinion No. Two, "Opinion on Rehearing--Issues Related to the Escalator and Currency Adjustor Contract Provisions," September 29, 1978, Pacific Indonesia LNG Company and Western LNG Terminal Associates
Opinion Three	DOE/ERA Opinion No. Three, "Opinion and Order on Importation of Liquefied Natural Gas from Algeria," December 18, 1978, ERA Docket No. 77-010-LNG, Tenneco Atlantic Pipeline Company, et al.
PEMEX	Petroleos Mexicanos, the National Oil and Gas Company of Mexico
PGA	Purchase Gas Adjustment Clause
PG&E	Pacific Gas and Electric Company
PURPA	The Public Utilities Regulatory Policy Act of 1978
Sales Contract	LNG Sales Contract between Atlantic and Sonatrach
SoCal	Southern California Gas Company
Sonatrach	Societe Nationale pour la Recherche, la Production, le Transport, la Transformation et la Commercialisation des Hydrocarbures (Algerian National Oil & Gas Company)
Staff	Staff of the Federal Power Commission or Federal Energy Regulatory Commission
Tcf	Trillion cubic feet
Terminal	El Paso LNG Terminal Company
UGP	United Gas Pipe Line Company
United LNG	United LNG Company
USG	Government of the United States of America

Metric Conversion Factors

This Order is using the metric system to denote all units of measure and energy. In the text, the traditional units of measure and energy as used previously in this proceeding will be shown first, with the metric standards shown immediately afterwards in parenthesis.

1 million standard cubic feet of gas (MMscf)	= 28,316 standard cubic meters of gas (m \3/)
1 Btu	= 1055.06 Joules adopted in 1956 per "ASTM Standard Metric Practice Guide"
1 million Btu	= 1.05506 Gigajoules (1.05506 X 10 \9/ Gigajoules)
1 Joule	= 9.488 X 10 \-4/ or 0.0009488 Btu
Megajoules (10 \6/)	= MJ = 948 Btu
Gigajoules (10 \9/)	= GJ
Terajoules (10 \12/)	= TJ
Petajoules (10 \15/)	= PJ
Exajoules (10 \18/)	= EJ
1 cubic meter (liquid)	= 6.28981 API bbls liq.
1 mile	= 1.609 km
1 kilometer	= 0.62 miles
1 inch	= 2.54 centimeters (cm)

A. Project Description

El Paso Eastern Company (Eastern), a wholly owned subsidiary of El Paso LNG Company (El Paso LNG), seeks authority under Section 3 of the Natural Gas Act (NGA) to import into the United States approximately 1.0 billion cubic feet per day (Bcf/d) (28.316 million cubic meters (MMm3/) of Algerian liquefied natural gas (LNG). Eastern proposes to import the LNG for a period of 20 years with initial deliveries to begin in 1983.

El Paso Atlantic Company (Atlantic), a wholly owned subsidiary of El Paso LNG, proposes to purchase LNG from Societe Nationale Pour la Recherche, la Production, le Transport, la Transformation, et la Commericalisation des Hydrocarbures (Sonatrach), the Algerian national oil and gas company. The base purchase price stated in the LNG Sales Contract between Atlantic and Sonatrach (sales contract) 1/ is $1.30 per million British thermal units (MMBtu) ($1.232/Gigajoules or GJ) subject to semiannual escalation based on the New York Harbor prices of No. 2 and No. 6 fuel oils.

The LNG would be transported by twelve cryogenic marine tankers, each with a design capacity of 125,000 m3/ of LNG. Six of the ships would be provided by Sonatrach, at a total estimated cost of $856 million in 1976 dollars, and six ships would be provided by Atlantic. Atlantic estimates its six vessels would cost a total of $858 million in 1976 dollars, whether constructed in a foreign shipyard or in a U.S.A. shipyard with construction differential subsidies. Atlantic plans to establish three domestic corporations and three foreign corporations, each of which would own and operate one of Atlantic's vessels.

The LNG would be sold, with transfer of title and risk of loss, by Atlantic to Eastern as each vessel entered international waters off Algeria. Atlantic would arrange for the transportation of the LNG by the 12 vessel fleet to an import terminal and regasification plant (the La Salle Terminal) located at a site on Matagorda Bay near Port O'Connor, Texas. The La Salle Terminal facilities would be built and operated by El Paso LNG Terminal Company (Terminal), another El Paso LNG subsidiary, under an agreement between Terminal and Eastern.2/ The La Salle Terminal is estimated to cost $456 million at fourth quarter 1976 dollars. Terminal would not acquire title to the LNG.

The La Salle Terminal would consist of tanker berths capable of serving two tankers at a time, LNG storage capacity of 1.9 million barrels (302,076 m3/ liquid), a vaporization plant with the design capability of vaporizing 1048 million cubic feet per day (MMcf/d) (29.675 MMm3//d) of LNG for 365 days per year, and associated support facilities.

Eastern would sell 65 percent of the regasified LNG at the tailgate of the La Salle Terminal to El Paso Natural Gas Company (EPNG), for resale to distribution companies and direct customers, and 35 percent to United LNG Company (United LNG). United LNG, a wholly-owned subsidiary of United Gas Pipe Line Company (UGP), would deliver and sell the gas to UGP for resale to other interstate pipeline companies, distribution companies and direct customers. The cost of the regasified LNG at the La Salle Terminal gate during the first year of deliveries is estimated to be $3.26 per MMBtu ($3.09/GJ) in 1975 dollars, subject to several cost escalations. Approximately 50 percent of the gas from this project, or .5 Bcf/d (14.16 MMm3//d) would end up in California.

EPNG proposes to construct and operate 463 miles (745 kilometers or km) of pipeline between the outlet of the La Salle Terminal and its existing interstate transmission system at its Waha natural gas processing plant in Reeves County, Texas.3/ The new pipeline would be 36 inches (91.44 centimeters or cm) in diameter for the 31 miles (50 km) from the regasification terminal to its intersection with UGP's existing Refugio-Sterlington line near Victoria, Texas. The remaining 432 miles (697 km) of line to Waha would be 30 inches (76 cm) in diameter. The estimated cost of the entire pipeline is about $263 million (in 1975 dollars).

The applicants estimate a delivered cost per MMBtu to UGP at Victoria, Texas, of $2,84 ($2.692/GJ), and to EPNG at its Waha plant of $3.03 ($2.872/GJ) in the third full operating year (1987).4/

The volumes of regasified LNG would be added to the overall gas supplies of EPNG and UGP. In practice, EPNG makes almost eighty percent of its deliveries to California, so that California would receive 50 percent of the LNG EPNG's east-of-California (EOC) customers would receive 15 percent of the LNG, and UGP's customers would receive 35 percent.

B. Procedural History

1. Prior Proceedings

In 1976 and 1977, Eastern, Terminal and EPNG filed applications and amended applications pursuant to Section 3 of the NGA with the Federal Power Commission (FPC) seeking authorization to import LNG into the United States from Algeria; and pursuant to Section 7 of the NGA for certificates of public convenience and necessity.5/

FPC Docket CP77-330--Eastern seeks authorization to import, each year for a period of 20 years, LNG containing about 410,625,000 million Btu's (389 EJ) (about 1 Bcf or 28,316 Mm3/ of gas equivalent LNG) from Algeria.

FPC Docket CP77-331--Eastern seeks a certificate authorizing the sale, in interstate commerce, to EPNG for resale of approximately 65 percent of the LNG proposed for import under Docket CP77-330.

FPC Docket CP77-270--Eastern seeks a certificate authorizing the sale in interstate commerce to United LNG for resale of approximately 35 percent of the LNG proposed for import under Docket CP77-330.

FPC Docket CP77-269--Terminal seeks a certificate authorizing the construction and operation of its proposed LaSalle receiving terminal on Matagorda Bay near Port O'Connor, Texas.

FPC Docket CP77-332--EPNG seeks certificates (1) authorizing the construction and operation in interstate commerce of approximately 463 miles (745 km) of pipeline and related facilities, and (2) authorizing the transport of gas in interstate commerce in such facilities.

FPC Docket CP77-272--United LNE seeks a certificate authorizing the sale of natural gas in interstate commerce to UGP.

FPC Docket CP77-271--UGP seeks a certificate authorizing the construction and operation of a tap (and related facilities) to receive gas requested in FPC Docket CP77-272 and connecting with the pipeline proposed in Docket CP77-332.

The various applications contained issues of common fact and law, and the FPC consolidated all the proceedings under FPC Docket No. CP77-330, et al., (hereafter referred to as "El Paso II").

Because of the applicants' concern that Algeria might cancel its contract of supply, the FPC adopted an expedited hearing schedule in an effort to render a decision by December 31, 1977.6/ The hearings in this proceeding were held in two phases: Phase I addressed nonenvironmental issues and Phase II examined the environmental considerations. Both phases of the hearing were concluded on September 19, 1977.

On October 1, 1977, the Department of Energy (DOE) was activated pursuant to Executive Order No. 12009, dated September 13, 1977,7/ and the function to approve natural gas importation under Section 3 of the NGA was automatically transferred to and vested in the Secretary of Energy pursuant to Sections 301 and 402(f) of the Department of Energy (DOE) Organization Act (Pub. L. 95-91) (the Act). The Secretary delegated to the Federal Energy Regulatory Commission (FERC) the authority to carry out this function with respect to cases pending before it.8/ By a DOE Final Rule issued October 1, 1977, entitled "Transfer of Proceedings to the Secretary of Energy and the Federal Energy Regulatory Commission," (Final Rule) 9/ El Paso II was to continue under FERC jurisdiction until after the timely filing of all briefs on exceptions and opposing exceptions to the Initial Decision (ID) of the presiding Administrative Law Judge (ALJ) whereupon the record was to be transferred to the Secretary for decision.

ALJ Walter T. Southworth issued an Initial Decision on October 25, 1977,10/ in which he approved the applications, under Sections 3 and 7 of the NGA, subject to conditions. All briefs on exceptions and briefs opposing exceptions to the Initial Decision were filed with the FERC November 28, 1977. On December 7, 1977, the record in El Paso II was forwarded to DOE in compliance with the Final Rule.

Pursuant the DOE Delegation Order No. 0204-4,11/ the Secretary has delegated the authority to issue a final order in this proceeding to the Administrator of the Economic Regulatory Administration (ERA). By Delegation of Authority dated December 10, 1977, the Administrator of ERA redelegated the same authorities set forth in Delegation Order No. 0204-4 to the Deputy Administrator of ERA (except the authority to propose or adopt rules).

On April 17 and 18, 1978, the Administrator of ERA held an oral argument in Houston, Texas, on a broad range of issues raised by the ALJ's Initial Decision.12/ An on-site inspection of the proposed terminal site was conducted by the Administrator at the close of the oral arguments.13/

On April 28, 1978, ERA issued an order giving notice that written comments addressing, responding to or supplementing statements made during the oral argument would be accepted for filing until May 16, 1978, and that all comments would become part of the public docket in this proceeding.14/

2. Initial Decision

On October 25, 1977, the presiding ALJ issued his Initial Decision15/ in which he approved the project as presented by the applicants, subject to certain conditions.

The ALJ concluded that based on the record evidence, the LNG from the project was needed in order to meet high-priority gas requirements of the EPNG and UGP systems. Although none of the parties or interveners questioned the need for the gas, the ALJ noted Commission Staff's contention that the beneficiaries of the gas during the second or third years of the project would not be the highest priority users. The ALJ concluded, however,

> . . . that there are no alternative methods for providing the needed volumes of gas at rates and conditions more advantageous than those which can be achieved through the Algeria II project. (ID, p. 19.)

The ALJ approved, with modifications, the LNG sales contract between Sonatrach and Atlantic. The Commission Staff and the California Public Utility Commission (CPUC) had raised objections to the FOB pricing formula that would twice yearly adjust the invoice price in accordance with the posted New York Harbor prices of No. 2 and No. 6 fuel oils. The Staff suggested that the escalator should be based instead on the prices of goods and services as reflected in the consumer price index. CPUC objected to the escalator because it was not "cost-based." Moreover, CPUC stated the use of New York Harbor prices would not reflect accurately California's cost for similar energy products and the automatic flow-through of all costs via the Purchase Gas Adjustment Clause (PGA) would not allow sufficient review of the project costs.

The ALJ rejected these assertions on the grounds that the escalator would ensure Algeria that the net delivered cost of its LNG remained competitive with other supplies of energy imported into the U.S.A., and he approved the escalator provisions as proposed by the applicants. However, the ALJ took exception to some of the cost flow-through and financing plans of the applicants and directed that the Sonatrach contract be revised to provide for a floor price of less than $1.30 per MMBtu ($1.232/GJ) should that occur through the operation of the escalator (ID, p. 42).

The ALJ also reduced Eastern's requested rate of return on its equity from 16 percent to 14.75 percent, the same as that approved previously by the Commission in EPNG's pipeline rate proceeding16/, since he concluded that the capital risks were similar. The ALJ also concluded that an equity-to-debt ratio should not be imposed prior to completion of the first full year of operation, and thereafter should not exceed 30:70 equity:debt percentage. The ALJ deferred a decision on the overall rate of return pending determination of Eastern's financing arrangements.

As in the case of Eastern, the ALJ reduced Terminal's requested rate of return on equity from 16 percent to 14.75 percent for reasons similar to those stated above. In addition, the ALJ approved Eastern's proposed flow-through of all of its costs to EPNG and United LNG via cost-of-service tariff agreements, thereby rejecting Staff's recommendation of a straight line or volumetric rate tariff with minimum bill and currency adjustment provisions. Also, the ALJ approved the tariff proposal of rolled-in pricing.

As part of the overall cost flow-through proposal, EPNG and UGP requested revisions to their respective PGA's to permit them to pass on to their customers all costs of gas purchased in this project. Both the Commission Staff and San Diego Gas and Electric Company had stated that they recognized the necessity for some rate treatment guarantees to permit recovery of all properly incurred costs.

Based upon substantially unchallenged evidence of record,17/ the ALJ concluded that Algerian natural gas reserves were sufficient to provide the volumes of gas contracted for by Atlantic for the life of the project.

With regard to shipping, the ALJ found the initially estimated freight rates of $0.8701 per MMBtu ($0.8247/GJ) for the Sonatrach ships and $0.84428 ($0.8002/GJ) for the Atlantic ships (does not include shore based and other project capital costs) reasonable in the context of the project and of the customs and practices of the shipping industry. The ALJ did, however, adopt as a condition the recommendation of the Staff that appropriate adjustments be made in the freight rate applicable to any Atlantic vessel which would be eligible for an investment tax credit or liberalized depreciation or both.
The ALJ also set a limit of 3.5 percent as the maximum amount by which the

freight rate on Sonatrach's vessels could exceed the Atlantic freight rate.

The ALJ approved the location of the LNG terminal and regasification facilities on Matagorda Bay, Texas, as well as the proposed route of EPNG's 463-mile (745 km) pipeline, based on evidence of record and the absence of any objections from national or local citizens groups.

3. Briefs on Exceptions to the Initial Decision and Briefs Opposing Exceptions

Several of the parties to the proceeding filed briefs on exceptions and briefs opposing exception to the Initial Decision.18/ The briefs on exceptions and opposing exceptions addressed a broad range of issues, including cost and tariff issues, incremental pricing, need for the gas and environmental issues.

FPC Staff reiterated its earlier position that the FOB escalator tied to the full flow-through did not comply with the NGA in that the public interest would not be fully protected without a full review of such costs. Staff also reiterated its position that escalator would be sensitive to political judgments of foreign nations.

EPNG took exception to the condition imposed by the ALJ in the Initial Decision requiring Atlantic to flow-through to consumers any investment tax credits and deferred taxes from liberalized depreciation. EPNG argued that this condition violates sections 46(f) and 167(l) of the Internal Revenue Code, and section 203(e) of the Revenue Act of 1964, 78 Stat. 35. EPNG also took exception to the condition which limits Sonatrach's freight rate to a maximum of 103.5 percent of Atlantic's freight rate, because this condition could prevent Sonatrach from recovering all of its costs.

General Motors Corporation (GM) criticized the absence of measures for the protection of consumers in the event of project noncompletion or interruption of service. GM recommended that the burden of noncompletion be borne by investors and in the event of service interruption the burden should be equitably balanced between the consumers and investors.

The CPUC took exception to approval of Eastern's full cost-of-service tariff arguing instead in favor of a volumetric rate with minimum bill and escalation provisions pursuant to Section 4 of the NGA.

The issue of incremental versus rolled-in pricing received attention in several of the briefs. The parties arguing in favor of rolled-in pricing stated that project financing would be unobtainable with incremental pricing and that it would be difficult to administer. Those parties supporting incremental pricing urged that such a mechanism would promote the development of domestic gas supplies and conservation in gas consumption.

The FPC Staff criticized the Initial Decision for failing to discuss the implications of this project on the U.S.A. balance of payments. Staff argued that approval of the project would have positive net effects on the U.S.A. balance of payments deficit since the least-cost alternative to the importation of LNG, in Staff's view, would be the importation of higher priced foreign fuels.

With regard to environmental issues, Staff reiterated its previous recommendations that a study should be conducted of the possible effects the proposed project might have on the thermal, circulation and salinity conditions in the Matagorda Bay and that the Cultural Resources Program as outlined in the Final Environmental Impact Statement (FEIS) prepared in this proceeding should be required for this project.

In its brief, the Houston Audubon Society, Houston Sierra Club, et al., (HAS et al.) criticized the environmental evidence in the record as being ". . . one-sided due to the whirlwind expedition of proceedings implemented by the Commission." (Br. on Ex. p. 5.); and moved that the ERA ". . . remand the matter for further study and the filing of an adequate environmental impact statement . . ." (Br. on Ex., p. 1.)

4. Oral Argument

Oral argument was held in Houston, Texas, on April 17 and 18, 1978, Administrator Bardin presiding.19/ Issues for argument included the need for and supply of natural gas in the market areas served by EPNG and UGP, the mechanisms by which the cost of the gas would be determined, the effect on U.S.A. balance of payments, and the environmental and safety implications of the proposed project. The oral argument was supplemented by written statements and comments filed with ERA by participants and other interested parties.20/

The applicants submitted extensive background and supplemental materials which asserted that (1) the provisions of the Sonatrach sales contract are reasonable and necessary to assure financing of Algerian facilities and feasibility of the project in general; (2) the provisions of the sales agreement between Atlantic and Eastern, including recovery of shipping costs, are reasonable and provide adequate protection to the consumer against unreasonable costs and inefficient operation; (3) the cost-of-service tariff is necessary to allow Eastern and Terminal to recover their costs and a fair return; (4) rolled-in pricing of the regasified LNG is essential to obtaining financing for the project; (5) if required by DOE, marketing arrangements could be made for the direct sale of gas from Eastern to EPNG's customers; (6) the LNG is needed to serve high-priority customers on the EPNG and UGP systems; and (7) all substantive and procedural requirements of the National Environmental Policy Act (NEPA) of 1969 have been satisfied.

One of the issues which Administrator Bardin raised at oral argument was whether the gas utilities which would receive LNG from this project would be prepared to contract for the gas directly with the applicants. Mr. Bardin addressed this question specifically to Pacific Gas & Electric Company (PG&E), Southern California Gas Company (SoCal), and Southern Union Gas Company. He also raised the issue with the CPUC. The three utilities, which are customers of EPNG,21/ stated that they would be prepared to purchase the LNG directly from Eastern if the gas could be purchased on a firm basis not subject to curtailment, and if the pricing issue could be adequately resolved with the appropriate state utility commission.22/ The CPUC basically voiced no objection to direct purchase arrangements, provided they were subject to conditions similar to those stated by the three gas utilities.23/ Subsequent to oral argument, Eastern stated:

> If an otherwise acceptable order approving the Algeria II Project should issue which requires El Paso Eastern [Eastern] to sell Algeria II gas directly to El Paso Natural's [EPNG] customers, El Paso Natural [EPNG] believes that viable marketing arrangements could be made.24/

On the other hand, Mr. Stephen Wakefield, representing United LNG and UGP, stated to Administrator Bardin:

> Since you have asked several of the California distributors their position as to the direct purchase, I would like to indicate to you that a year or year and a half ago when we first became involved, United LNG sought to market this gas direct rather than through United Gas Pipeline Company [UGP] and determined that none of its customers were interested in purchasing the gas directly, but all of them that expressed an interest wished to have it purchased as part of the overall system supply of United Gas Pipeline Company [UGP].
>
> United [UGP] serves approximately 400 town and city gate customers in its direct market area in the Gulf South.
>
> It also serves seven interstate pipeline companies. All of them were contacted.
>
> The response was negative from all of them. (Tr., pp. 241-242.)

When Administrator Bardin asked whether UGP had contacted any of the distribution companies which are customers of the interstate pipelines served by UGP, Mr. Wakefield replied:

> I am not sure they did directly. . . .
>
> I believe some of the larger ones were contacted, but I do know for a fact that all of the direct service distribution companies were contacted, and I feel relatively confident the larger distribution companies were at least aware. (Tr., p. 243.)

When asked if UGP had contacted any of the large industrial customers within the UGP's Gulf Coast area, Mr. Wakefield replied:

> I do not believe so, for the reason that under all of United's [UGP] projections by the time gas from this project would be made available, there would no longer be any, even including these volumes, any service made available to those industrial customers, so they are considered outside this project, outside of the benefits of the gas as it would be made available from this project. (Tr., pp. 243-244.)

a. Escalator

There was considerable discussion at oral argument as to whether or not the LNG price escalation provisions in the sales contract are in the public interest. The National Consumer Law Center, objected to the escalation provisions being tied to the posted price of No. 2 and No. 6 fuel oils in New York Harbor.

> The oil which enters New York harbor is OPEC [Organization of Petroleum Exporting Countries] oil. We have seen in the past that OPEC can quadruple oil prices over a few years almost at will. The current world price of OPEC oil is set at inflated price by cartel agreement, despite any play of relatively inelastic demand for oil. (Tr., p. 421.)
>
> . . . since Algeria is an OPEC member, this contract [sales contract] will allow it to initially at its discretion, raise LNG prices by merely raising the price of OPEC oil, without ever having to break the LNG contract (Tr., p. 422.)

According to the Commission Staff, a restriction on Eastern should be imposed whereby regulatory approval would be required,

> . . . whenever the invoice price determined by the formula in the Sonatrach contract, [sales contract] when discounted by the Consumer Price Index to July, 1975 dollars, exceeds the $1.30 per million Btu [$1.232/GJ] base price.

This condition would provide that the guidelines for assessing the reasonableness of an invoice price based on imported fuel oils is the change in prices in general. (Tr., pp. 368-369)

The Council on Wage and Price Stability in its post hearing submission, "Written Comments of the Council on Wage and Price Stability," dated May 8, 1978, (henceforth Written Comments) rejected these proposed alternative escalation provisions.

> . . . we see no advantage in tying LNG prices to crude oil or petroleum product prices in general rather than #2 and #6 fuel prices. We see no merit--indeed we see dangers--in using broad indices of general economic conditions. These introduce a major element of uncertainty in that they can vary as a result of many unpredictable changes in domestic and international economic factors which are unrelated to the two fuels or to natural gas, or to energy in general, and certainly would be affected by U.S. domestic economic policy. Such uncertainty constitutes an avoidable real burden on both sides. (Written Comments, pp. 39.)

According to Eastern, an escalation clause tied to #2 and #6 fuel oils is preferable to all alternatives mentioned since:

> Market prices of fuel oils represent amounts that people are, from time to time, in fact willing to pay for fuels that are in some applications substitutable for natural gas and therefore in competition with it. (Post Hearing Memo p. 18.)

> The question is then asked, why not escalate the price of LNG in accordance with the Consumers Price Index, or some worldwide or western hemisphere price index? That would indeed be advantageous to Sonatrach, but El Paso Atlantic [Atlantic] having in mind the interests of U.S. consumers could lever advocate it. As to the United States CPI, it is based on a market-basket of commodities, some of whose prices--such as coffee's--are subject to wild fluctuations, wholly unrelated to energy values. Inflation in the U.S. is less than in most, though not all, other countries. To use an index that included Argentina or Italy would `e grossly unfair to U.S. consumers; to use one that included only countries like Switzerland would be unfair to Sonatrach. (Post Hearing Memo pp. 19-20.)

b. Incremental Pricing v. Market Clearing

One of the issues on which ERA requested oral argument was whether a market would exist for all of the volumes of LNG involved in the project if the gas were priced incrementally (a) at the wholesale level; or (b) at the retail level. Applicants stated that:

> . . . this gas has already been sold incrementally (or will be before parties make final commitments to go forward) at its full cost, in that the customers of the pipelines United Gas [UGP] and El Paso Natural (EPNG] will have to be committed to take it all, along with other available supplies, and at rates which provide to the pipelines the full cost of both, even though rolled-in with each other.
>
> . . , the uncontradicted evidence is that this gas is needed for the rest of this century to serve consumers who must have gas or return to an eighteenth-century standard of living. Their demand cannot be very much elastic with respect to price [footnote omitted] and they will buy the gas because they require it to meet their human needs . . . .
>
> El Paso Natural [EPNG] is satisfied beyond any doubt whatsoever that all of this gas could be sold at its full cost . . .. (Post Hearing Memo, pp. 44-45.)

However, according to the applicants, rolled-in pricing:

> . . . moves gas to where it is most needed in the quantities in which it is needed, at rates designed to enable the pipeline to recover its costs, and to distribute those costs fairly among the people who receive the gas. (Post Hearing Memo, p. 45.)

UGP stated that it would not be in a position to gamble on the existence of a market for the gas if incrementally priced unless its customers were willing to contract for a 20-year supply. UGP contended that its customers are not willing to do so. According to UGP, its opportunity to earn a return on investment is practically nonexistent, and therefore the risk associated with incremental pricing is too high.

The Mississippi River Transmission Corporation (MRT) contends that while a market will undoubtedly exist for the gas even if incrementally priced, none of UGP's customers would be willing to commit themselves to take-or-pay, long-term contracts.

> The primary reason that customers should balk at assuming this obligation to purchase this future supply of gas is as noted by the FPC in both the Columbia and Trunkline LNG cases, there is no assurance that future deliveries of this supply will be noncurtailable. (Tr., pp. 312 -313.)
>
> . . . such a commitment would provide no greater hedge against curtailment than does the status quo. (Tr., p. 313.)

Without having completed a formal market study, SoCal stated that the incrementally priced gas would clear the market since electricity is the only alternative. However, like MRT, SoCal is not sure it would be willing to enter into the long-term contracts under incremental pricing since there are no assurances that the gas will be noncurtailable.

EPNG somewhat modified its previous position25/ that incremental pricing would probably cause UGP to drop out of the project, thus causing delays while EPNG negotiated long-term noncurtailable contracts with its customers, and submitted those contracts for DOE approval. According to EPNG these delays would kill the project. Subsequent to oral argument EPNG stated:

> Despite our unwavering advocacy of rolled-in pricing, the project would not be destroyed from El Paso Natural Gas Company's [EPNG] standpoint, under one form of incremental pricing, or under incremental marketing of the general kind. We do not support these ideas; we are convinced they are wrong; we think the project would be a better one without them; but if they are imposed to further some perceived economic or social goal, El Paso Natural [EPNG] can live with them. (Post hearing Memo, p. 42.)

The Council on Wage and Price Stability (Council) also addressed various pricing and marketing issues.

> The superiority of incremental pricing [footnote omitted] over rolled-in pricing is now widely recognized, at least at the theoretical level. (Written Comments p. 43.)

> . . . the Council's view is that incremental pricing (or, as we would prefer to call it, modified marginal cost pricing) is less inflationary, more conducive to efficient use and more equitable than rolled-in pricing. (Ibid, p. 46.)

> . . . "rolled-in" pricing frustrates efforts to conserve on energy use; is unduly inflationary; dissipates the gains from regulation by encouraging acquisition of higher cost supplemental gas; and encourages importation of foreign high cost gas which exacerbates balance of payments difficulties. (Ibid, p. 8.)

Concerning UGP's and Texas Gas Transmission Company's contention that incremental pricing would render the project unfinanceable, the Council stated,

> If the capital market would not fund an LNG project contemplating MMC [modified marginal cost] pricing but would do so if it contemplated rolled-in pricing, then this is prima facie evidence that

> the project is of dubious economic value . , . . (Written Comments, p. 21.)

The National Consumer Law Center argued in support of incremental pricing at the wholesale and retail level.

> There is no basis in economic theory, special gas industry characteristics or the Administration's national energy agenda for importation of LNG at less than its actual costs. This principal must govern the design of LNG pricing . . . . (Tr., p. 399.)

Brooklyn Union Gas Company (Brooklyn Union), an indirect customer of UGP through Texas Gas Transmission Company, urged that incremental pricing at the wholesale level be adopted, and that all costs should be allocated proportionately in relation to quantities of gas purchased. The Commission Staff, in response to the position that the administrative burdens associated with incremental pricing are insurmountable, advocated incremental pricing under separate rate schedules. The Staff noted that "pipelines now render service under different and separate rate schedules." (Tr., p. 386.)

c. Contingency Planning

DOE, in its Notice of Oral Argument,26/ requested that participants address what contingency plans, if any, should be required as an integral part of the project in order to protect the areas to be served by EPNG and UGP from interruptions in supply.

According to EPNG, it has already submitted a contingency plan; UGP took the position that a meaningful contingency plan cannot be filed until within one year of initial deliveries.

Brooklyn Union stated that requiring Sonatrach to agree to a binding contingency plan to allocate LNG among alternative foreign customers during periods of reduced or suspended supply arising from technical problems could have deleterious effects:

> . . . it would be wholly inappropriate for ERA to condition import authorizations for the "El Paso II" project upon Sonatrach's agreement to such a binding contingency plan. Such action by ERA could well have the effect of insulating Sonatrach from liability or responsibility resulting from its failure to provide LNG in accordance with its existing export contracts. [Footnote omitted]
>
> If, notwithstanding the foregoing, ERA elects to proceed to develop a contingency plan for allocation by Sonatrach of LNG among its customers, Brooklyn Union recommends that, as a minimum, those "natural

gas company" customers of Sonatrach which are wholesaling LNG on an incremental basis to their customers should receive the highest priority for the gas, and that those `natural gas companies' which are wholesaling LNG on a rolled-in basis receive no LNG during periods of shortage until the contract requirements of the former class of Sonatrach customers are fully satisfied.27/

d. Need for the Gas

EPNG asserted that its total system requirements approximate one trillion cubic feet (28.316 Bm3) per year, of which about 840 Bcf/year (23.79 Bm3) serves high-priority consumers. According to EPNG, without supplemental sources of gas it would have to curtail priority 2 deliveries in 1981, and priority 1 deliveries shortly thereafter.28/

EPNG contended that the conversion of present high-priority gas consumers to alternative fuels would be impossible in the 5-10 year time frame being discussed in connection with the LNG project.

EPNG stated that if the PEMEX project 29/ were to be implemented, EPNG would be able to continue to serve priorities 1 and 2 and a small portion of priority 3 until 1983, when priority 2 would be curtailed. Priority 1 would be curtailed as early as 1991.

Concerning the issue of why EPNG's gas supply projections did not include, with the exception of the PEMEX project, such potential supplemental supplies as Alaskan gas, EPNG stated:

> . . . that El Paso [EPNG] is committed to the fulfillment of its share of the California market, and under its curtailment plan its customers call upon it every day for gas to supply El Paso's [EPNG] share of the California market, and that's all that this shows.
>
> This doesn't concern itself with any other sources of gas that might be available to California, because El Paso's [EPNG] job is to do what it can to fulfill its commitments to its customers in California and east of California, [EOC] and that is of no concern to the question of what other projects may or may not become available on the California market. (Tr., p. 73-74.)
>
> The Alaskan gas situation continues to present many imponderables including the price of gas on the North Slope, the timing of producer contracts, the results of El Paso's [EPNG] gas acquisition efforts, and perhaps most significantly, the financing, construction and implementation of the delivery system. However, even assuming that El Paso Natural [EPNG] can hold on to the royalty gas, can attach the

Brooks Range gas, and can buy a substantial phase of North Slope gas, El Paso Natural [EPNG] cannot reasonably rely on the expectation of timely actual receipt for delivery to its customers of enough Alaskan supplies to obviate its need for the Algeria II gas. (Post Hearing Memo, pp. 4-7.)

According to PG&E, even if all of the gas projects in which it is involved were to be realized (including Prudhoe Bay, South Alaska, Pacific Indonesia, PEMEX, a Rocky Mountain project, and this project), it would still have "600 million cubic feet (17 MMm3) of gas per day less in 1990 than we have today." (Tr., p. 146.)

When asked why PG&E was selling 1.8 Bcf/d (50.97 MMm3) of its available supply of approximately 2.0 Bcf/d (56.63 MMm3) PG&E explained that:

> . . . the problem today is that we have had, . . . a pricing formula in California which has, at the present time, placed the gas at a very high price to some of our customers who can switch, and they have switched to oil.
>
> As a consequence, we have lost that market which is a valuable market during the interim period while you are building up the project, because it's an interruptible market.
>
> . . . But more importantly than that, as you know, we are a gas and electric company, and we had a severe drought for two years running in California and it was necessary for us to obtain a great deal of fuel oil in order to be assured we could continue with our steam electric generating operation in the absence of hydroelectric power, and in the absence of having the Diablo nuclear power plant on the line, and we have a glut of oil at the present time, and so during the warm season when we would be able to use gas we were unable to do that and we ape putting it in storage and cutting back on some of our gas. (Tr., pp. 149-150.)

Mr. E.R. Island, representing the SoCal, stated that:

> . . . we are an intervenor in this proceeding, and we are . . . El Paso's [EPNG] largest customer.
>
> I might add . . . that SoCal is the largest natural gas distributor in the United States in terms of customers served . . . .
>
> We are here this afternoon basically for one purpose, and that is to urge the expeditious approval of this project. We need the gas. (Tr., p. 165.)

Mr. Island further stated that:

> . . . in light of your recent Opinion No. 1 30/ in our Pacific-Indonesia case the market need for southern California is very clear, and I think you would rightly be entitled to rely on that analysis. (Tr., p. 166.)

Also arguing in support of California's need for the gas from this project, the CPUC stated:

> It is our belief that even if all of the other projects which are intended to serve California actually do come into being, that by the end of the 1980's there is still going to be a substantial need for each one of these projects based upon recent CPUC staff studies.
>
> Looking at the real world and considering that it is possible that not all of these projects will come on line at the time they are proposed to come on line, we can only see that the need for any individual projects that do come in on service is simply going to heavily substantiate the need for that particular project.
>
> Therefore, we would respectfully suggest that each project must be considered, each on its own merits, as if none of the other projects were to come into being at the time proposed. (Tr., pp. 182-183.)

According to Texas Gas Transmission:

> The ultimate receipt of volumes of natural gas by Texas Gas from the proposed El Paso II project are necessary in order to . . . permit Texas Gas to maintain continuity of service in the future to its high priority market. (Tr., p. 326.)
>
> As I mentioned, LNG and SNG, coal gasification and we are participating in the HIOS project, and possibly we are looking to get into, hopefully, to receive some Alaskan gas, but even if we were able to be successful on several of these projects, we just don't perceive that in the future that we will be able to serve anything probably above Priority 2 . . . . (Tr., p. 333.)

The American Gas Association (AGA) contended there is an overall national need for gas and that, for the near term, LNG is the most advantageous supplemental supply. According to the AGA, other alternatives such as coal gasification and solar technology are too uncertain at this time.

The Commission Staff viewed the need for the gas in a different light:

> Testimony has been presented in this case which shows that

commercial and industrial customers are the most likely end use beneficiaries of the gas from this project. (Tr., p. 383.)

In short, things are not as bad as they look. This past winter is an example. Major pipelines were curtailing into Priority 1, yet except for one industrial consumer, no shutdown of end users without alternative fuel facilities occurred last winter.

The reason for this is simple. Pipeline purchasers may only be partial requirement customers; they may have intrastate supplies, they may have peak shaving and storage facilities, they may have gas transported for them by the pipeline, and their industrial customers may be acquiring gas under the Order No. 533 and Order No. 2 program. (Tr., pp. 382-383.)

In rebuttal of the Staff's position, UGP stated:

Staff's counsel's hypothesis that this LNG supply will not be required for high priority needs of United's [UGP] customers is apparently based on the testimony of staff witness Moriarty. It should initially be noted that Moriarty admitted that his study did not indicate that this supply was not necessary to meet the high priority needs of customers on United's [UGP] system in 1985. (Tr. 1600-01). He also testified that he had no reason to dispute United's [UGP] evidence that 100 percent of this LNG would go to Category 1 residential and commercial users. (Tr. 1529). Moriarty presented a `model' which purported to compare the gross gas supply available to United [UGP] and to all pipelines within the five states directly served by United [UGP] with the projected demand for natural gas within these states in 1985. The `model' only considered supply projections for 1985, at the initial stage of this twenty-year project (Tr. 1157-58), whereas all evidence, corroborated by Moriarty (Tr. 1158), demonstrated that United's [UGP] downward supply trends would continue well beyond 1985.

Although staff counsel also alluded to the natural gas situation of the past winter, it would be totally irresponsible to use that period as a basis for projecting to 1984 and two decades thereafter. First, as indicated at oral argument, during that winter period United [UGP] and other interstate pipelines were able to avoid the projected levels of curtailment through the purchase of emergency gas supplies. It is not anticipated that such supplies will be available in substantial quantities in 1984 and thereafter. (Transcript of Oral Argument, at 537). In addition, United [UGP] has experienced a higher than anticipated deliverability rate on its system which, although alleviating to a certain extent recent supply shortages, has resulted in a decrease in the projected future supplies on United's [UGP] system.

(Transcript of Oral Argument, at 540). Clearly, staff counsel's belief that last winter's experience is indicative of adequate future supplies is entirely unwarranted.31/

UGP further stated:

> Although there were some suggestions made at the oral argument that other alternatives may exist in United's [UGP] service area to provide energy supplies for high priority requirements, the plain fact is that those responsible for planning for adequate energy supplies for these customers cannot afford to engage in bothersome speculation as to the availability of these alternatives in the relevant time frame. To gamble that these alternatives would somehow become available is to risk economic chaos, or worse, should the wager be lost. While gas in the intrastate market may be available in limited quantities and for short periods of time today, there is nothing to suggest that such supplies will be available in adequate quantities to meet the high priority requirements of United's [UGP] customers over the next quarter century. (Supplemental Comments p. 4.)

General Motors Corporation (GM), on the other hand, asserted that many of the markets that would receive LNG from this project were continuing to allow high-priority load additions.

> It seems incredible to us . . . to hear company after company get up and say that we are going into actual Priority 2 and Priority 1 curtailment, while at the same time throughout the region served by these two pipelines [EPNG and United] there are unabated high-priority load additions.
>
> California is one. When I say high priority, I mean residential and small commercial.
>
> In Ohio . . . there is a proceeding going on right now in which it seems a virtual certainty that the Ohio Commission will lift the previous moratorium.
>
> In Illinois, there are rapid load additions. (Tr., pp. 352-353.)

GM's representative at oral argument further stated, with regard to the alleged inability of intrastate gas companies in Texas and Louisiana to find new reserves:

> Well, I suspect on that point . . . that if deregulation were given a fair shot we might find out how much gas there really is. (Tr.,

p. 353.)

e. Risk of Failure

According to General Motors, the consumer should not have to assume any risks or make any payments in the event of noncompletion or total project failure. In GM's view this:

> . . . may mean that there has to be enough equity capital involved in the project to pay off all of the debtors if it should ultimately fail or it shouldn't be completed. (Tr., pp. 356-357.)

Regarding service interruption, GM stated,

> . . . we do think, however, that it is appropriate for consumers to participate in the problem if there are temporary service interruptions. (Tr., p. 357.)
>
> We do believe that equity should always be at risk and that in times of some extended interruption there should be a cessation of recovery of equity through depreciation charges as well as a recovery of return on it.
>
> However, once the project comes back in we would not object to a make-up. (Tr., p. 357.)

The council stated that each entity involved in the project should be required to assume risks commensurate with the benefits likely to be received. For example:

> In assessing the risks imposed on high priority users, the question to be asked is, how reasonable are the terms of the contract between the utility and the LNG company/pipeline as regards the price of the supplemental gas to be delivered? Let us assume that customers of the local gas utility will be charged an incremental price for the supplemental gas. Although some customers may conceivably consider that the price of the supplemental gas is too high and decide to reduce their purchases of it, the utility, having committed itself to purchase a certain quantity at a certain price from the LNG company/pipeline, will attempt to recover its costs from the remaining customers by raising the price accordingly. The ability of the utility, in view of its monopoly position, to pass on its costs in this manner, unlike firms in a more competitive market, implies that it can reduce its risks at the expense of its customers. This obviously can introduce an element of indifference in its (the utility's) negotiating stance with the LNG company/pipeline. (Written Comments pp. 26-27.)

CPUC contended that:

> . . . in the event of project collapse before or after the project goes on stream, to the extent that the project is approved and the money has been lent on the basis of that approval, capital investments made and costs sunk in the project, it is appropriate for some type of proceeding to take place to evaluate the justness and reasonableness and prudence of those costs, and perhaps an amortization schedule worked out that would allow for recovery of those amounts through rates over time. (Tr., p. 92.)
>
> Once the rate payers have committed themselves to taking that gas there is an obligation on his part to return over time the just and reasonable vested capital in that project. (Tr., p. 93.)

EPNG alleged that the risks of project noncompletion and project failure after completion are minimal. The consumer must, however, assume some risk.

> The consumer guarantees to these companies return of capital and interest on debt, nothing more. That guaranty must come from somewhere; no project participant except the consumer can give it; without it the project cannot be financed. (Post Hearing Memo, p. 18.)

United LNG submitted in its "Prepared Summary of Oral Argument of United Gas Pipeline Company and United LNG Company,"

> Since the project gas is being obtained for the benefit of the ultimate consumers in the markets of United [UGP] and El Paso Natural, [EPNG] it is appropriate that such consumers share in the risks involved in the project. Under the structure of the project, the El Paso [Eastern] participants bear the first risks of any decrease in deliveries through reduced equity returns. However, if the large capital amounts required for the project are to be committed, the consumer must ultimately guarantee payment of certain costs through the minimum bill provisions and thus share in the risks of the project as well as the benefits as recipient of the gas supply. (Prepared Summary, p. 2.)

f. Environmental Considerations

A number of interested parties addressed various procedural and substantive environmental issues. HAS, et al., alleged that proper procedures were not followed in preparing the Environmental Impact Statement (EIS):

> We would take the position that the staff has violated a federal law already in preparing or failing to coordinate their

activities as required by Title XVI, Section 622(a), which is known as the Fish and Wildlife Coordination Act.

> Prior to the filing of the draft EIS and final EIS there has not been any coordination with the other federal agencies that are required by statute to be considered and to help formulate the National Policy on a particular project involving dredging with respect to the wildlife, and to the fish, and to the impacts thereon.
>
> The other procedural things that we think occurred was [sic] an over expeditious or over zealous handling of the entire environmental aspects by the Administrative Judge in setting extremely short times that systematically excluded both state and federal comments from actually being included and being considered in the presentation. (Tr., pp. 469-470.)

HAS, et al., further alleged that the EIS itself is inadequate since it failed to adequately consider offshore terminals,32/ the effects of thermal changes in the water on the ecosystem in Matagorda Bay, disposal of dredge material, and secondary environmental considerations such as the effects of the possible expansion of the proposed facility and growth in Calhoun County resulting from the facility.

According to the Army Corps of Engineers, the EIS does not adequately evaluate the effects of disposal of dredged material in Matagorda Bay and in open water, and the effects of the project on navigation in Matagorda Bay. They propose that DOE do a supplement to the EIS to correct these deficiencies.

Mr. Robert E. Clegg of R.E. Clegg Trawlers, Inc., a company that presently operates 15 shrimp trawlers on the Gulf of Mexico in the vicinity of Matagorda Bay, expressed concern about possible inadequacies of the EIS. Procedurally, Mr. Clegg stated that the expedited schedule did not provide adequate opportunity for federal and state agencies to sufficiently review and comment on the environmental impact issues raised in the EIS:

> I feel this project is being hurried and pushed too much in the interest of energy without enough proper study and thought to the environmental impact. (Tr., pp. 46-47.)

According to Mr. Clegg, the EIS does not adequately address the impacts of dredging and deep channelization on tidal flow, salinity level and bottom conditions as they would affect shrimp and other marine life.

> The environmental impact statement contains many statements

> concerning currents, salinities, sedimentation, plankton productivity, etc., but it does not provide any information as to what we can expect or what can be estimated to happen to a particular species of marine life, such as shrimp as a result of the alteration of the bay system. (Tr., p. 50.)

Mr. Clegg also contended that further study of the effects of operation of the plant are warranted:

> How many larvae or juvenile shrimp will be killed by being sucked into the water intake; and how many will be killed as a result of the cold water shock at and around the point of discharge? (Tr., p. 50.)
>
> Also, how will the loss of these small shrimp from this and other operations and alterations affect the total production capability of the bay system as expressed in dollars and in percentage? (Tr., p. 51.)

Mr. Clegg recommended that a supplemental EIS be prepared. He further proposed that any authorizations granted by DOE be conditioned upon applicants' immediate cessation of operation if the environment is adversely affected by the project. He also stated that applicants should be required to restore the environment to its previous condition and make monetary compensation for any loss in the productivity of marine life as a result of the project.

In conclusion, Mr. Clegg stated:

> I want the record to state that I am in favor of the plant in Calhoun County, but I do have some reservations about it, as proposed.
>
> But I do think there is a balance that can be reached, that we can have the plant with a minimum of disturbance to our marine life and wildlife. . . . (Tr., p. 54-A.)

In response to these assertions, FPC staff stated at oral argument:

> Concerning offshore terminals, the FEIS's analysis highlighted regulatory and legislative delays and the need for additional research and development before these alternatives could be considered feasible. NEPA does not require that an agency develop new technologies as alternatives. . . .
>
> The staff discussed the expected impacts of dredging to the extent these impacts could be determined, and recommended certain conditions to minimize dredging's environmental impact . . . .

Concerning the possibility of secondary developments, it is unreasonable and speculative to assume that the limited channelization proposed by El Paso [Eastern] will convert Port O'Connor into a major port and industrial center. (Tr., pp. 364-365.)

g. Balance-of-Payments Impact

EPNG contends in its "Post Hearing Memorandum,"

. . . that while importation of LNG would contribute some small deficit to our balance of payments, it is an immeasurably superior choice to any real alternative. (Post Hearing Memo, p. 10.)

The AGA takes the position that the importation of LNG would have positive net effects on U.S.A. balance-of-payments when compared to the importation of equivalent volumes of oils.

Importation of 1.6 quads [1.7 million EJ] of LNG in 1985, when you compare that to an equivalent amount of oil will reduce the net foreign payments for energy by an estimated 1.9 billion dollars per year depending on the extent of U.S. financing, and so forth, but for each dollar paid for imported LNG we estimate about 45 cents of that would be returned to the United States for all of the various U.S. things that were involved there, the shipping, the capital goods, the labor and the financing.

When you compare that to oil, you would have about one-third of that 45 cents for every dollar paid for the imported oil being returned to the United States. (Tr., pp. 347-348.)

C. Discussion of Proposal

1. ERA's Responsibilities on Review of Natural Gas Applications and General Considerations

Sections 301 and 402(f) of the DOE Organization Act give the Secretary of Energy the authority to authorize the import or export of natural gas pursuant to the NGA, and to permit the building and operation of border facilities pursuant to Executive Order No. 10485. This responsibility was delegated to the Administrator of the ERA by the Secretary on October 1, 1977.33/ Delegation orders redefining the areas of jurisdiction between the ERA and the FERC in deciding natural gas import and export applications were published in the Federal Register on October 17, 1978.34/

Under the October 17 delegations, the Secretary assigned to ERA responsibility to review proposed natural gas imports under Section 3 of the

NGA, insofar as the proposed importation may concern energy policies on an international, national and interregional level. DOE Opinion No. Three discusses the specific responsibilities of ERA and FERC.35/

In determining whether to approve natural gas import applications the NGA requires a determination of whether the proposed import "is not inconsistent with the public interest." The Secretary (or his delegate) is charged with weighing each proposed natural gas import project, taken as a whole, against the objectives of national energy policy.

In previous decisions, DOE discussed the issues considered by ERA in evaluating LNG import proposals; as defined in the October 17, 1978 delegation. The considerations include a review of the security of supply, the national and regional need for the gas, and the balance of payments impact. Other areas to be evaluated include, but are not limited to, the proposed import price and the eligibility of purchasers and participants in their respective shares of the proposed import.

In these decisions, DOE also outlined a preferred order for supplemental gas supplies. DOE remains committed to the concept that our natural gas supply should come first from conventional sources, and LNG should be used only where the need for gas cannot be satisfied by more basic sources of supply.

As stated in DOE Opinion Number Three, at the present time, LNG represents a marginal supply of natural gas to U.S.A., and national policy dictates a careful assessment of each project on its merits. As we stated therein, this does not mean that all applications to import LNG will be rejected. Rather, it indicates that we intend to view proposals to import LNG in the context of the importance of gas supplies to the U.S.A. and of the costs of enhancing the domestic gaseous fuel base. In this regard, DOE expects the new national energy legislation to make more natural gas from domestic and proximate sources available to residential, commercial and industrial users. To that extent, the immediate need for large quantities of imported LNG to meet high priority requirements has been alleviated. This increased availability of natural gas for high priority users and others is another consideration to take into account when reviewing LNG import proposals.

As we stated in Opinion Three, we are

> . . . mindful that while Federal policy allows some new imports, it does not promote them, we will be particularly reluctant to exercise the full panoply of Federal statutory power on behalf of an LNG import project. (Opinion Three p. 38)

In short, proposals to import LNG will be rigorously reviewed and decided on the overall merits of a particular project in the context of national energy policy.

2. Security of Supply

In the Initial Decision in this proceeding the ALJ discussed the reliability of service of this foreign supply with respect to political developments, adequacy of reserves and technical support facilities, and contingency plans.

The ALJ found that Algeria's high financial stake in this project would enhance its long-term reliability. He also cited the FPC's positive findings with respect to the reliability of supply in Trunkline.36/ Moreover, in a letter to FPC Chairman Dunham, the Department of State in December 1976 expressed no objections to this project. These factors led the ALJ to find and conclude:

> . . . . That the project can be expected to be as reliable as any 20-year industrial operation in foreign commerce (I.D. p. 28).

Algeria's substantial reserves of natural gas appear on the record to be sufficient to support the supply requirements of this project.37/ Sonatrach has stated that it is willing to dedicate the total of its national gas reserves in support of Sonatrach's 3 Tcf/yr natural gas/LNG (84.9 Bm3) export program.38/ The revenues from Sonatrach's gas export program will be used to finance Algeria's progressive economic development program.

Algeria has been exporting LNG for approximately 13 years.39/ Sonatrach is experienced in the technology of producing liquefied natural gas for export markets. It is currently constructing support facilities which in aggregate would be sufficient to effect the liquefaction and delivery of gas to the cryogenic vessels as required for the El Paso II project and for its other contractual obligations.

In Opinion Number Three, however, we addressed the failure of the exporter to dedicate specific facilities or reserves to fulfill a given project and the lack of a contingency plan to allocate available gas to various foreign customers. Sonatrach appears not to have dedicated any particular reserves or any specific liquefaction or other facilities to the instant project. At the Oral Argument the applicants contended that the sales contract requires Sonatrach to dedicate a particular facility to the production of LNG for this project. "Seller agrees: (a) to dedicate its own facilities to the production from the facilities designed to produce the quantities of LNG covered by this agreement . . . (Article VI, 3a)." In our view, this provision in the sales contract is vague.

Unlike the Distrigas long-term project,40/ the exporter in this case has not provided a contingency plan to allocate available gas to foreign customers during periods of reduced or suspended delivery resulting from technical problems. Sonatrach does not specifically warrant or guarantee the volumes it will deliver under the sales contract in the El Paso II project. If there are insufficient reserves, or technical problems impede deliveries, U.S.A. consumers could be exposed to undue financial risks under the cost-of-service tariff provisions requested by the applicants.

In connection with this project, EPNG submitted a contingency plan designed to assure continuity of gas service to high priority customers in the event of supply interruptions during the winter heating season. UGP, which would ultimately receive 35 percent of the gas from this project, did not file a contingency plan with FERC. UGP contended that a meaningful contingency plan cannot be formulated until one year prior to commencement of the initial deliveries of gas from this project.

The EPNG plan would rely on various voluntary conservation measures, the use of inventories aboard LNG vessels in transit to the U.S.A., and supplementing the interrupted supply in LNG with gas from underground storage. EPNG's plan also would encompass possible emergency exchanges with other pipelines and gas distributors.

The energy conservation measure with the greatest potential for savings in the contingency plan, according to EPNG, would be thermostat reductions of between 4 degrees--8 degrees D (2.2 degrees C--4.4 degrees C) by residential customers. EPNG introduced evidence indicating a potential savings of 80 Bcf (2.548 @m3) with a 4 degrees F (2.2 degrees C) reduction and 150 Bcf (4.247 Bm3) with an 8 degrees F (4.4 degrees C) reduction. The above estimates assumed 100 percent compliance with the plan during the regular five-month heating season, November through March.

EPNG's plan represents a good faith effort to insure continuity of service in the event of suspended or reduced deliveries. However, the reliance on voluntary conservation as the primary contingency measure is overly optimistic. Abnormal weather or dramatic changes in regional supply configurations could limit the potential for voluntary conservation. Similarly, there is no certainty that gas from emergency exchanges and sales would be available to the consumers served by EPNG.

DOE is of the opinion that these measures are inadequate in the event of an emergency such as a long-term interruption of LNG shipments.

3. Need for the Gas

The applicants' assertions regarding the need for this import have focused primarily on an analysis of EPNG's and UGP's contractual supply commitments to their customers. The record developed by the parties and evaluated by the ALJ included a limited assessment of the requirements of California as a distinct region, and scant information on the need for gas in the regions served by UGP, or those regions other than California served by EPNG. The record also failed to address in any meaningful way the issue of national need for the gas.

A. National Need Considerations

Over two years have elapsed since the applicants filed for certificates from the Commission to implement the El Paso II project. During that time the President and the Congress were engaged in an intensive effort to develop a comprehensive and coherent national energy policy. Recently, that effort has resulted in the passage of five major laws which DOE believes will have a significant impact on national supply and demand for natural gas.41/ These laws are: The National Energy Conservation Policy Act (NECPA); the Powerplant and Industrial Fuel Use Act of 1978 (FUA); the Public Utilities Regulatory Policy Act (PURPA); the Natural Gas Policy Act (NGPA); and the Energy Tax Act (ETA).

The NGPA, for example, will quickly make increased intrastate gas supplies available to the interstate market and, by gradually decontrolling interstate wellhead gas prices, the result would be an increase in domestic interstate supplies. The NECPA and the ETA also will increase gas supplies by encouraging conservation and providing incentives for solar heating and cooling. For the longer-term, the FUA will increase gas supplies to high-priority consumers by prohibiting the use of natural gas in power generation and other low-priority applications.

Nationally, residential and small commercial users, generally the highest priority users of gas for curtailment purposes, are expected to consume approximately 7 to 8 Tcf (198.2 to 226.5 Bm3) per year by 1985. Another 10 Tcf (283.2 Bm3) per year will be consumed by industry, both for energy purposes and as a chemical feedstock. The remaining supply of natural gas, estimated to be from 2 to 3 Tcf (56.6 to 84.9 Bm3) per year, will be consumed by large commercial users and for electrical generation, primarily intermediate and peak load generation. Of the industrial fuel consumption about 4 Tcf (113.3 Bm3) per year will be considered to be premium fuel use--that is, process fuel, chemical feedstock and agricultural use. Nationally, the total premium gas demand in 1985 is expected to be at a maximum of 12 Tcf (339.8 Bm3) per year, well within the total projected domestic supply level for that year of 19 to 20 Tcf (538 to 566.3 Bm3) per year.42/

Though the issue of approval of a scaled down El Paso II project was specifically raised in the notice of oral argument,43/ neither EPNG nor UGP lent any support at the oral argument to approval of such a project. Moreover, EPNG indicated that a restructuring of this project to reduce the volume of LNG imported would be impossible since the Sonatrach sales contract has expired and any additional time would probably cause cancellation of the project.

B. California's Market Need

EPNG submitted evidence in support of its need for the gas which showed that by 1984 it will have enough gas to serve CPUC priority 1 and 70 percent of priority 2 needs.44/ By 1986, EPNG stated that it would fall short by 8 percent in meeting its share of priority 1 requirements for its two largest customers PG&E and SoCal. Collectively, these customers accounted for 78 percent of EPNG's interstate sales in 1976. EPNG further claimed that without the El Paso II gas supply its CPUC priority 0 customers would be totally curtailed by 1985.

In Opinion One, DOE examined the need for the gas in California. The record in Pacific Indonesia proceeding indicated a need for additional sources of supply for California markets, and curtailments projected by SoCal and PG&E for future years supported this conclusion. The ALJ concluded in his Initial Decision in Pacific Indonesia that it would be "overly optimistic" to assume that all of the various other projects (Pacific Alaska, Wesco, Prudhoe Bay and Pacific Interstate) which are being planned to provide gas for California's future requirements will come on line as scheduled, or that they will be sufficient to meet requirements. The DOE concurred, and concluded, for the reasons set forth fully in the ALJ's Initial Decision in Pacific Indonesia, that there was a need for the Pacific Indonesia project which would import up to 226 Bcf (6.4 Bm3) of LNG into the California regional market.45/ The Pacific Indonesia proposal also met DOE's direct sales presumption.

In addition to the sources of gas examined in Pacific Indonesia, up to 5Tcf (141.6 Bm3) of new natural gas could be made available to the interstate market in 1985 by the recent enactment of the NGPA.

DOE further notes that the California Gas Producers Association has argued before FERC in the Northwest Alaska Pipeline Company (Northwest Alaska) proposal 46/ that there was no basis for the grant of even conditional import approval to Northwest Alaska in view of the lack of need for additional short-term (4 to 7 years) supplies, particularly in the California market.47/

As noted in DOE Opinion Number Two, LNG represents a marginal source of supply for U.S.A. gas markets.48/

> We must take care . . . that decisions taken with respect to

LNG imports from remote sources do not discourage the ultimate development of proximate resources . . . . (p. 6)

In this regard, we note that in June 1978 the FERC granted conditional authorization to Northwest Alaska to import 380 Bcf/year of Canadian Alberta bubble gas for six years. SoCal and UGP both have made commitments to purchase part of this gas. SoCal recently filed an application before FERC to purchase about 90 Bcf/year of this Alberta Gas. Northwest Alaska has also agreed to sell 140 Bcf/year (3.964 Bm3) of this gas to UGP.49/

Pacific Indonesia already offers California access to imported LNG. In the absence of a clear showing that El Paso II LNG also is needed for the California market, DOE favors reliance on proximate sources of supply and development of new domestic supplies.

Finally, the record in this proceeding fails to analyze adequately the potential natural gas savings by SoCal and PG&E customers arising from conservation measures and solar energy application. Home insulation and improved appliance efficiency, will also contribute to energy savings by California consumers.

C. UGP's Market Need

UGP stated that volumes available for delivery to its customers from traditional sources will decline from 510 Bcf (14.441 Bm3) in 1984 to 348 Bcf (9.854 Bm3) in 1986; it also estimated that it will be forced to curtail its category 1 customers in 1984 and thereafter without the El Paso II supply; and that even with this LNG there will be insufficient gas to serve all of the category 1 requirements of its existing customers commencing in 1985.50/

UGP's natural gas market is somewhat unique in that only 15 percent of its gas is sold directly to powerplants and industrial consumers with the remainder being sold to other pipelines.51/ It appears that at least 40 percent of UGP's sales are for low priority users who generally have an alternate fuel use capability and further, some of these sales of gas which may be boiler fuel could be prohibited by FUA. If, as UGP claims, by 1986 05 percent of its supply would come from this project, a reduction in low priority sales could serve to offset UGP's need for El Paso II gas.4. Purchasers and Participants

4. Purchasers and Participants

As in TAPCO, the natural gas that Eastern proposes to import into the U.S.A. would be sold to EPNG and UGP who would in turn roll-in the volume of LNG as part of their base gas supply. This gas would be sold by EPNG and UGP to meet their contract commitment of deliveries to other pipeline companies and natural gas distribution utilities for final delivery to the end-user and to direct end-use sales. Neither EPNG nor UGP would be selling any of the LNG in specific contracted-for quantities directly to the natural gas distribution companies that serve the ultimate user of the gas.

EPNG stated that it "believes that viable marketing arrangements could be made" 52/ to enable Eastern to sell the gas directly to EPNG's customers, but it has not undertaken to do so.

SoCal and PG&E, EPNG's two California utility customers have stated a willingness to purchase Eastern's LNG directly only if necessary and only if the supply were noncurtailable. United LNG stated at oral argument that it had offered its LNG to its customers on a direct sale basis but none of United's customers were interested in purchasing the gas directly.

As stated in DOE Opinion Three,53/

. . . DOE applies a presumption that any LNG import scheme should enable distribution utilities individually to determine in cooperation with state regulatory agencies their requirements if any for supplemental natural gas supplies. The utilities would then have the option to either develop their own sources of supply or contract directly with LNG importers for specific volumes to be delivered directly to their system. That presumption has been satisfied in all LNG imports approved by DOE.

> The approach which DOE favors imposes on natural gas distribution utilities the risks and responsibilities of choosing from a diversity of supplies instead of imposing on them high-cost, long-term foreign LNG supplemental gas supply. By making each utility free to contract for its own high cost foreign supplies, competitive forces should operate more effectively. Here, there is no overriding national interest preventing each distributor served by TGP from determining what supplemental supplies, such as LNG, if any, to purchase and thereby stimulate.

As in previously approved LNG import cases, Pacific Indonesia and Distrigas, DOE prefers that natural gas distribution utilities buy LNG directly from the importer. This satisfies DOE's concern that each utility is free to determine its individual supplemental gas supply needs.

5. Import Price

The import price in this case is comprised of the most expensive cost components of the project, the FOB Algerian sales price and the LNG vessel freight rate. These cost elements account for about 88 percent of the applicant's estimated cost of the gas, $2.84 per MMBtu ($2.692/GJ) at the tailgate of the LaSalle Regasification Terminal.54/ Moreover, under the applicants' proposal the United States Government (USG) would have no control over changes in the costs or operations of the nonjurisdictional FOB and shipping components over the life of this 20 year project.

The ALJ relied on the applicants' computations in their preparation of estimates of the cost of the LNG (see Appendix C, Initial Decision). The applicants' estimates were based on 1975 costs for onshore Algerian facilities and operating expenses and late 1976 costs for other facilities and expenses. Although the FOB sales price and the LNG tanker freight rate represent the significant cost elements of the import price, the applicants have not submitted estimates of the escalated project capital costs and the import price at the time of the commencement of initial deliveries in 1983.55/ The absence of this data makes it difficult to analyze the long-term cost of this project to U.S.A. consumers, or to evaluate the contention of the applicants that the cost of this gas supply will be cheaper than the cost of alternate energy sources.

a. Base Price

The base price in this case is identical to the base price calculation concept used in the TAPCO proposal.56/ The base price for LNG to be sold to El Paso Atlantic is $1.30 per MMBtu ($1.232/GJ) FOB Algeria as of July 1, 1975.57/ Sonatrach derived this price by taking an equally weighted combination of the daily prices for No. 2 home heating oil and No. 6 low sulfur fuel oil in New York Harbor as listed in Platt's Oilgram Price Service for the period January-June 1975. Sonatrach then deducted this estimated LNG transportation charge between Algeria and New York Harbor and the terminalling charges to derive the $1.30 per MMBtu ($1.232/GJ) base price.

Opinion Three indicated that the calculation of the base price was significant because Sonatrach had used this price scheme not only to establish the initial value of its product; but also to establish a method of commodity-based rather than cost-based valuation in determining the future FOB price escalation over the life of this long-term project. Moreover, in that opinion we indicated that in the event that potential shipping-related cost overruns were not absorbed in the FOB sales price, the delivered price of this gas could exceed the cost of competing petroleum products.

b. Contract Sales Price

The FOB LNG sales price in the Sonatrach Sales Contract (Article VII) would be the higher of the base price plus escalation formula or the floor price. The escalation formula is identical to formulas in Sonatrach's sales contracts with other U.S.A. gas companies.58/ The base price is adjusted on a semiannual basis (January and July) to account for changes since July 1975 in the prices of No. 2 and No. 6 oils in New York Harbor. Daily postings under Platt's Oilgram Price Service headings "South and East Terminals, New York Harbor District" and the "Atlantic and Gulf Cost Resid, New York Harbor District," are utilized to track changes in the prices of No. 2 and No. 6 oils respectively.

The ALJ approved the Sonatrach price escalator formula and the applicants' request to automatically flow through the cost resulting from the operation of the escalator. He cited Trunkline LNG, FPC Opinion 796A, as support for his decision. In that case, the FPC approved the flow through of costs triggered by an escalator based upon the prices of No. 2 and No. 6 oils landed in New York Harbor. The ALJ also concluded that gas is part of Algeria's national patrimony and it is unreasonable to expect that country to sell its gas on a cost-based rather than a commodity-based formula (Initial Decision, page 42).

The applicants, PG&E and SoCal argued before the ALJ that failure to approve this escalator formula may jeopardize the entire project. On the other hand the CPUC expressed concern during this proceeding about the use of New York Harbor as the basing point to measure competitive fuels price escalation for gas consumed in California. They also cited the small home-heating oil market for No. 2 oil in California, and the fact that No. 6 fuel oil would have "a relatively low priority usage where natural gas is concerned." 59/

The FERC staff argued before the ALJ for modification of the Sonatrach escalator formula so as to require Commission approval when the prices of imported fuel oils increase at a faster rate than the Consumer Price Index (CPI). The ALJ, however, found that "Staff's proposal amounts to a major revision of the terms of the Sonatrach contract, to which there is no reason to believe Sonatrach would or should be expected to agree." (ID p. 58)

DOE recognizes that periodic adjustments in the sales price of a commodity are necessary to insure that the price a seller receives over the life of a long-term contract will be a fair price. In this project, however the Sonatrach price escalator is linked entirely to future changes in the prices of premium petroleum products. World oil prices in turn are determined by agreement among major oil-producing countries rather than through the interplay of free market forces. The operation of the petroleum-based escalator formula in this contract could result in consumers paying prices over the life of this contract which do not reflect the true value of this commodity.

The Sonatrach price escalator formula lacks safeguards to protect consumers from the impact of sudden and drastic oil price increases. There are no limitations on the maximum annual price increases which can be passed on to consumers through the operation of this formula.60/

In the event of rapid and substantial oil price increases, Sonatrach would earn revenues which were not anticipated when the parties concluded this agreement.

The Platts' price quotation mechanism tracks daily changes in the prices of No. 2 and No. 6 oils which are based upon posted rather than the weighted average actual transaction prices. Consumers would not `e able to benefit from those instances in which the actual transaction prices were lower than the posted prices. Additionally, the use of the average of the highest daily price for No. 2 and No. 6 oil limits Sonatrach's exposure to, and the gas consumer's ability to benefit from, lower sales prices for No. 2 and No. 6 oil.

Under the Sonatrach sales contract, the parties are required to meet during the first year after regular delivery and every four years thereafter to review the FOB sales prices (Sales Contract, Article VIII). The purpose of this price renegotiation provision is for the parties to ascertain whether the prevailing FOB sales price is competitive with the market for imported natural gas and other forms of fuel which are imported into the U.S.A. on a long-term basis. Adjustments to the sales price stemming from the operation of this provision could further place consumers at risk.

c. Floor Price

The inclusion of a Floor Price in the sales contract (Article VIII, 3) is for the purpose of protecting the exporter against sudden and rapid declines in the invoice price. The floor price of $1.30 per MMBtu ($1.232/GJ) as of July 1975 would be calculated on a monthly basis. The calculation would represent the sum of the initial floor price plus a currency adjustor which tracks the relationship between the U.S. dollar and a basket of six European currencies.61/

The Floor Price provides an asymmetrical relationship with respect to the risk borne by the seller and the buyer. Whenever the dollar changes one percent or more from its initial July 1975 level against the basket of European currencies, the Floor Price is adjusted. There is no annual or cumulative ceiling on the maximum increase which is permitted over the life of the contract. However, while the floor price can decline through the working of the currency adjustor, it can never fall below the base minimum sales price of $1.30 per MMBtu ($1.232/GJ).62/

In addition to the currency adjustor, the Floor Price is required to be recalculated on the date of first regular delivery (Sales Contract, Article VIII, 2). This recalculation would consist of adjustments to the capital and operating and maintenance elements of the initial floor price. The $0.80 per

MMBtu ($0.758/GJ) capital element, which corresponds to the 1975 capital estimate of $2.3 billion for Sonatrach's land-based facilities, is readjusted once to reflect actual capital costs at the date of first regular delivery. The $0.15 per MMBtu ($0.142/GJ) operating and maintenance element is readjusted once to reflect the actual first full year operating and maintenance expenses. The parties are also required to select an appropriate U.S.A. economic index and apply it on an annual basis, commencing in the second year of regular delivery, to the variable operating and maintenance element of the Floor Price.63/

d. Shipping Costs

This project would require twelve 125,000 cubic meter cryogenic tankers to deliver the gas to the proposed receiving terminal on Matagorda Bay. The applicants estimate that shipping costs will add $1.14 per MMBtu ($1.081/GJ) to the import price.64/ This estimate assumes that Atlantic and Sonatrach will each provide six ships.

Sonatrach

The Sonatrach Transportation Agreement includes two freight rate formulas. The Freight Rate is computed pursuant to a formula which includes Sonatrach's actual capital investment, debt cost, taxes, and return on equity capital. Sonatrach will also be reimbursed on a monthly basis for its actual operating expenses. At the time of the Initial Decision the estimate of the freight rate was $0.8701 per MMBtu ($0.825/GJ). This estimate is based on an LNG tanker cost in late 1976 dollars of $142.6 million. The freight rate also includes an after tax rate of return on equity capital of 19 percent which is based upon delivery of full contract volumes. The return on equity declines with respect to reduced volumes carried.

Among the largest components of the freight rate is an income tax which the Sonatrach-Atlantic contract appears to assume is payable by Sonatrach to the Government of Algeria. The Government of Algeria which owns Sonatrach in its entirety is to receive as income tax revenue 50 percent of the profits from Sonatrach's transportation of LNG. As a consequence of this tax, the return on equity component for Sonatrach's venture capital could turn out to be up to double the 19 percent return stated in the application.

The Additional Freight rate calls for additional payments by Atlantic to Sonatrach in the event that freight rate payments are insufficient to cover debt service charges as well as equity capital on the six Sonatrach vessels. Along with the payment of monthly operating expenses, the Additional Freight payments would appear to constitute a minimum bill provision, payable several times per year to cover break-even costs after the return on equity has been reduced to zero. This provision also requires the application of a currency adjustment factor to the 2.5 percent return of equity but not debt component. This currency adjustor is to account for changes in value of the dollar towards a basket of six European currencies. In the event that Sonatrach claims "force majeure" based upon its government's actions, Sonatrach loses its right to Additional Freight rate payments.

On balance the Sonatrach transportation agreement provides a return on equity which is geared to the delivery load factor from this project, and a minimum bill which will allow Sonatrach to recover its break even costs under normal circumstances. Thus, it appears that the El Paso Atlantic-Sonatrach Transportation Agreement would obligate consumers to guarantee Sonatrach's return of equity in the event of potential prolonged interruptions in service or project failure. The only circumstance in which Sonatrach would lose additional freight payments is if it claims force majeure.

Atlantic

The LNG Transportation Agreement is part of the LNG sales contract between Atlantic and Eastern. The determination of the freight rate payable by Eastern to Atlantic is computed through the use of several formulas. The Freight Rate Project covers Atlantic's capital costs other than those directly related to the vessels (e.g., shore-based facilities). The second freight rate formula, Freight Rate Vessels covers vessel capital costs and preoperating expenses. Eastern is also required to pay separately Atlantic's operating costs on a monthly basis.

Atlantic estimates its capital costs of $895.6 million (fourth quarter 1976 dollars) which includes $855.5 million for six ships. This figure breaks down into an average 1976 cost estimate of $142.5 million per tanker. Based upon these estimates, the freight rate attributable to vessel capital costs as well as shore based and other project capital costs (FRV) are $0.8442 and $0.0360 per MMBtu ($0.800 and $0.034/GJ) respectively.65/

The FRV and FRP are designed to yield a total after tax annual return on equity of 18.41 percent when the project is operating at 100 percent load factor. As in the Sonatrach-Atlantic shipping contract, the annual return on equity from shipping is geared to the volume of LNG carried in EPNG's ships. The rate of return declines from 18.41 percent at 100 percent load factor to zero percent at 30 percent load factor.

The Additional Freight Provisions in the Atlantic-Eastern LNG Sales contract is nearly identical to the comparable provision found in the Sonatrach-Atlantic Transportation Agreements. This provision is to insure the payment of sums sufficient to service Atlantic's debt charges and return of (but not on) equity. As in the case of Sonatrach's Transportation Agreement with Atlantic these payments together with the required payment of monthly operating expenses constitute a minimum bill provision, payable twice a year, to cover break even costs after return on equity has been reduced to zero.

The applicants maintain that failure to approve the Additional Freight payments provision and the automatic flow through of increases in vessel construction and operating charges will jeopardize the financing of this project. They contend that consumers must share in the financial risks associated with this project. The applicants maintain that return on equity is at risk, but they must be guaranteed return of equity in order for them to go forward with this project.

The ALJ's approval of the applicants' requested transportation agreement differs from the handling of this issue in other cases. In Trunkline and Pacific Indonesia, the FPC and DOE/ERA respectively, required that the increases in the shipping cost component, above the initial approved level, be subject to a "prudent cost incurrence" test.66/

e. Cost of Service Tariff

In the Initial Decision the ALJ approved the applicants' tariff proposals. Eastern received a cost of service tariff which allows it to flow through to EPNG the costs associated with this long-term project. The ALJ allowed EPNG and UGP to automatically include in their PGA's all of the costs associated with this import project. Both EPNG and UGP were also allowed to treat this gas as part of their overall system supplies for the purpose of resale to customers.

The ALJ denied Staff and CPUC's requests to substitute an initial fixed rate and minimum bill for Eastern's cost-of-service tariff. He also rejected CPUC's request that EPNG undergo a separate Section 4 hearing before being allowed to flow through project costs to their PGA's. These actions were necessary, according to the ALJ to assure the financing of this project.

The tariff treatment in this case differs from previous LNG decisions. In Trunkline and Pacific Indonesia (Opinion Number One) the Commission and DOE established initial fixed rates with minimum bills which did not permit the automatic recovery of equity capital when deliveries fell below a certain level.67/ The parties were required to submit cost increases above the initially approved level for Section 4-type filings. Here, the cost-of-service tariff granted to Eastern would allow the automatic flow through of all project related costs. The cost-of-service tariff allowed by the ALJ would also appear to constitute a minimum bill which allows the applicants to recover their equity capital under all events.

Under the applicants' requested tariff proposals, the USG would have no control over the costs and operations of this project other than a piecemeal after the fact review of EPNG and UGP PGA clauses. However, the PGA is simply a means for collecting costs, rather than a mechanism to provide a comprehensive review of project costs and a detailed justification for the rates to be charged.

f. Project Failure

The issue of whether applicants were entitled to automatically recover all project related costs in the event of project failure prior to or after project start up was not specifically addressed in the Initial Decision. However, it would appear that the applicants feel that their requested cost-of-service tariff would guarantee the recovery of their equity capital and related expenses in the event of project failure after the commencement of initial deliveries. The Initial Decision leaves unanswered the question of whether Eastern and Sonatrach would be entitled to recover their equity capital, particularly the shipping expenses, in the event of project failure prior to the commencement of initial deliveries.68/

Approval of the applicants' requested tariff treatment in the case of established LNE technology raises fundamental issues with respect to the sharing of risk in foreign supplemental gas supply projects. Unlike gas from advanced technology such as synthetic natural gas from coal, the technology to liquefy, transport, and regasify conventional natural gas has been established and proved to be commercially viable and reliable from the standpoint of international base load energy projects. While the applicants contend that the prospects of project failure are remote, they seek to shift the burden of risk normally borne by U.S.A. LNG project sponsors to the consumers.

6. Balance of Payments

The issue of the balance of payments impact of this import project was not addressed in the Initial Decision. In written materials prepared for the Oral Argument, Eastern contended that the negative balance of payments impact of this project would to a large extent be offset by capital inflows from U.S. firms involved in financing and constructing Sonatrach's land-based and maritime facilities. However, the applicants have not presented a detailed analysis of the balance of payments issue.

Energy imports have at least some negative balance of payment impact. In future import proposals DOE will require that the applicants present a full analysis of the balance of payment impact of their project.

7. Environment

In his Initial Decision, the ALJ concluded that:

> The environmental acceptability of the Algeria II project from the standpoint of siting, safety and environmental impact has been thoroughly examined in the record established by the parties. (ID, p. 90.)

> . . . the environmental record is replete with reports, studies, testimony, comments and responses examining in minute detail the environmental aspects of the Algeria II project, including the factors listed in section 2.80 of the Commission's Regulations under the Act. It is found and concluded that the FEIS and associated environmental record of the proceeding comply with the relevant requirements of the National Environmental Policy Act and the Commission's regulations relating thereto. (ID, p. 91.)

However, several commenters on the draft and the final EIS's, as well as the HAS, et al., have cast serious doubt on the ALJ's findings.

By notice issued June 23, 1977, the Commission fixed the time for filing comments at thirty days from the publication in the Federal Register of notice of availability of the Staff's DEIS. Such notice was published on July 8, 1977, and, according to the ALJ:

> . . . all comments to the DEIS received on or before August 9, 1977, . . . were carefully reviewed and analyzed by Staff. . . . (ID, p. 90.)

Staff published its FEIS on September 1, 1977.

However, HAS, et al., asserts that:

> . . . a direct request was mailed to the FPC for a DEIS on July 18, 1977, and was rejected by letter dated July 28, 1977. The comment period was so short (a large portion of it consumed by mailing time) that it was virtually impossible for citizen's groups, who are generally lacking in organization and legal assistance geared for such comment to file timely response. It is not insignificant here that a number of vast federal agencies, who are not so lacking in organization and legal expertise, namely the Environmental Protection Agency [EPA], the Department of Army `Corps of Engineers' [Corps], the Department of the Interior [Interior], and the Department of Commerce [Commerce], filed their comments after the deadline of August 9, 1977, which were branded `untimely' by the Administrative Judge.69/

The ALJ did in fact characterize the comments of the Federal agencies mentioned by HAS, et al. as "untimely" (ID, p. 91), but noted that the applicants submitted answering environmental evidence on September 12, 1977, consisting of annotated responses to the comments. The "untimely" comments were thereby introduced into the record in this proceeding by the applicants, but were not incorporated into the Staff's FEIS. This, among other factors, led the EPA to rate the FEIS as "unresponsive." 70/

Commerce, Interior, and the Corps also wrote to the Commission noting that their comments on the DEIS had not been addressed in the FEIS. In addition, the Corps stated that it "cannot issue or deny" the dredge and fill permits which the El Paso II project would require until "significant environmental considerations" not covered in the FEIS "have been adequately addressed." 71/

In view of the above considerations, ERA issued a notice of intent to prepare a supplement to the FPC's FEIS.72/

ERA indicated in that notice that a final order would not be issued until the supplement was completed. In explaining the decision the notice stated:

> Several Federal agencies and other interested organizations have expressed the concern that the EIS is substantively deficient in certain respects, including, inter alia, the analysis of offshore facility alternatives; the analysis of secondary, long-term, and cumulative impacts; and, the analysis of thermal, circulation, and salinity changes in Matagorda Bay and the resultant ecological impacts which would result from the extensive dredging and spoils disposal required for implementation of the project.73/

As indicated by the above discussion, the focus of concern with respect to the adequacy of the FEIS centered on site specific issues. Upon reevaluation of the issue as to whether a final order should await completion of the supplemental EIS, ERA has concluded that the deficiencies contained in the FEIS, focus on site specific issues which FERC would ultimately decide under the Secretary of Energy's Delegation No. 0204-26.74/ In the instant case the site specific issues are relevant only if ERA were inclined to approve the aspects of the project subject to its jurisdiction. However, we do not reach the site specific issues since, for the reasons set forth in this decision, we have determined that this project should not be approved. Thus, the question is whether the FEIS addresses adequately the environmental impacts of disapproval of the project. An evaluation of the FEIS and the comments with respect to it reveal clearly that it does. Accordingly, ERA has determined that the FEIS is adequate for the purposes relevant to this decision and a final order may appropriately be issued.

DOE intends to complete the supplement to the final EIS since that work has already begun and the information may be useful with respect to any possible future proposal involving the same location.

Conclusion

We have reviewed the facts of this case against the statutory requirements of the Natural Gas Act, ERA's delegation of authority, and national energy policy and conclude that this project demonstrably fails to meet the statutory test that it is "not inconsistent with the public interest."

The project as presently structured altogether fails to satisfy ERA's presumption in favor of direct LNG sales by importing companies to gas distribution utilities, and the applicants have not demonstrated that the public interest requires such a project at this time. In the instant case Eastern proposes to import gas into Texas and resell all of it to EPNG and UGP who would then resell all the gas as part of their overall system supplies to customers.

Approximately half of the gas proposed to be imported into Matagorda Bay, Texas, would be transported via proposed and existing pipeline to California energy markets. EPNG's California customers, SoCal and PG&E, have stated a willingness to purchase this gas as part of EPNG's overall system supplies rather than as a direct purchase from the importing company. These distributors did indicate at the oral argument that they might find the direct sales approach acceptable if the gas were not subject to curtailment. However, neither the importer nor these distribution utilities have taken affirmative steps to satisfy ERA's direct sales presumption. Moreover, United LNG, at oral argument, indicated that none of UGP's customers was interested in purchasing the gas directly.

There was some indication by the applicants of a possible willingness to restructure the project so as to provide for direct sale of one-half the gas involved by the importer to the California distributors. If California ultimately concludes that some added LNG imports are needed in addition to the Pac Indonesia supplies and the Alaskan North Slope and other overland projects, we would expect definitive proposals on an appropriate scale to that end.

In the circumstances of this case we cannot find an overriding national or regional need for this gas. Applicants have evaluated the need for this gas in terms of their present estimates of the contractual supply obligations to their customers as distinguished from the projected end-use requirements of the gas distribution utilities. The record does not convince us that the pipelines' contractual requirements necessarily reflect a real need for this gas, either on a regional or national basis. UGP has not demonstrated a need for its share of the import in any of the regional markets served by its customers. Additionally, a reduction of gas sales to UGP's large boiler fuel market may be required during the period of the proposed import under the FUA. This could make available large quantities of gas to high priority consumers.

An indication of regional need was presented by the CPUC for the State of California, which state would receive 50 percent of the total import. We take note of the fact that DOE has already conditionally approved one LNG import project for direct sales to California's gas distribution utilities. Moreover, both SoCal and UGP stand to receive Alberta Bubble Gas upon regulatory approval of the project.

As stated in DOE Opinion Number Three, we must take full account of proximate supply opportunities before sharply increasing U.S.A. dependence on LNG imports. For the short term, the U.S.A. natural gas industry enjoys substantial supply deliverability to meet residential, commercial, and industrial needs. The newly enacted energy legislation provides improved prospects to meet the gas supply requirements of EPNG and UGP in the form of quantities of gas produced nationally and quantities available to the interstate market as well as through conservation and solar application measures. Producing companies now have certainty with respect to the wellhead prices they receive for new domestic gas supplies. The legislation also unifies the interstate and intrastate gas markets thereby allowing gas pipeline and distribution companies to maximize the potential of the existing infrastructure to meet the requirements of the American gas consumer.

For the longer term which the applicants address in the proposed project, we anticipate substantial domestic prospects for other supply opportunities such as Alaskan North Slope gas and gas supplies from advanced technologies applied to domestic resources. Moreover, the energy legislation establishes a wellhead price for Alaskan North Slope gas, and provides for rolled-in pricing of the expensive transportation component of the Alaskan Natural Gas Pipeline System. This project will benefit U.S.A. gas consumers by expanding the national supply of gas. Both EPNG and UGP have the opportunity to participate in the project to bring Prudhoe Bay gas to the lower 48 States.

We also have serious problems with the FOB price escalation formula in the LNG Sales Contract between Sonatrach and Atlantic. The Sonatrach price escalator ties future price escalation over the life of this long-term contract to changes in the prices of No. 2 and No. 6 fuel oils in New York Harbor. These tend to reflect world oil prices, which are determined by agreement among major oil-producing countries rather than through the interplay of free market forces. Furthermore, the operation of the price escalator formula indicates that the price of a commodity traded between two nations would be either directly or indirectly determined by a third party.

The Sonatrach price formula contains inadequate safeguards to protect consumers from the impact of sudden and drastic oil price increases. In this regard the escalator lacks any limitation on the maximum annual increases which could be passed on to consumers. In the event of a large oil price increase, Sonatrach would earn revenues which were not anticipated by the parties when the agreement was entered into.

The price quotation indices used in conjunction with this escalator are based upon the posted rather than the actual weighted average transaction prices for No. 2 and No. 6 oils in New York Harbor. To the extent that actual sales prices are discounted from the posted price the consumer may not receive the benefit of a lower actual sales price. Moreover, the existence of an FOB sales price renegotiation clause increases U.S.A. consumer exposure without appearing to provide any reciprocal benefits.

We are also of the opinion that the applicants' proposed contingency plan is inadequate in that it places undue reliance on voluntary conservation measures which would have to be effected by all ultimate consumers of natural gas.

As we concluded in Opinion Number Three, we recognize that denial of this particular application may result in Sonatrach's selling some or all of the gas which was originally dedicated to this project to proximate European markets. We again cannot conclude that a long-term commitment to an LNG project of this magnitude is now needed. Our denial is without prejudice to any future evolution of mutually beneficial opportunities for international gas trade.

For these reasons, this application is denied.

Order

The Department of Energy orders:

Pursuant to Section 3 of the Natural Gas Act and Delegation Order No. 0204-25, the applications, as amended, of El Paso Eastern Company, et al. (Eastern), for an order authorizing importation into the United States by Eastern of LNG from Algeria for a 20-year period as applied for in FPC Docket No. CP 77-330 is hereby denied.

Issued in Washington, D.C. December 21, 1978.

--Footnotes--

1/ Dated October 28, 1975.

2/ Dated October 11, 1976.

3/ Waha is the name given by EPNG to its natural gas processing plant, and does not designate an incorporated governmental body.

4/ The delivered costs are estimated as follows: (Based on 1975-76 cost data)

FOB..........$1.39/MMBtu to EPNG and $1.38 to UGP
($1.317/and 1.308/GJ respectively)

Ocean Freight..........1.13/MMBtu ($1.071/GJ)

Terminalling & Regasification..........0.26/MMBtu ($0.246/GJ)

Cost of Service.............0.06/MMBtu ($0.057/GJ)

Pipeline Delivery..........0.19 to EPNG, $0.01 to UGP/MMBtu
($0.17 and 0.009 per GJ, perspectively)

5/ Certain of the applications were originally filed as amendments to earlier applications; these were deemed new applications by the Commission's order of April 14, 1977, and given new docket numbers, in view of the substantial restructuring of the original Algeria II project. Docket No. CP77-330 was originally Docket No. CP73-258; Docket No. CP77-331 was Docket No. CP73-259; and Docket No. CP77-332 was Docket No. CP73-260. The application (amendment) in Docket No. CP77-330 was filed October 15, 1976, and supplemented March 1, 1977; the pleadings which constitute the applications in the other present dockets herein were filed March 1, 1977.

6/ Commission Hearing Order of April 14, 1977.

7/ 42 FR 46267, September 17, 1977.

8/ 10 CFR 1000.1, 42 FR 55534, October 17, 1977.

9/ DOE Delegation Order No. 0204-1, 42 FR 55450, October 17, 1977.

10/ "Initial Decision Upon Applications to Import LNG from Algeria", ALJ Walter T. Southworth, October 25, 1977, El Paso Eastern et al., DPC Docket No. 5 CP77-330 et al.

11/ 42 FR 50726, November 9, 1977.

12/ 43 FR 11849, March 22, 1978.

13/ 43 FR 15481, April 13, 1978.

14/ 43 FR 19279, April 7, 1978.

15/ See footnote 10, p. 6.

16/ Commission Order dated August 1, 1977, FPC Docket No. RP77-18.

17/ Initial Decision, p. 27:

No issue is raised as to the sufficiency of Algeria's reserves. Commission Staff Counsel has analyzed the record and found what it believes to be some questionable circumstances; however, it concludes that when measured against the long term estimate of proven reserves, the Algerian reserves are sufficient to provide the volumes of gas contracted to El Paso Atlantic during the life of the Sonatrach contract. It is so found.

18/ List of persons filing briefs and dates:

November 18, 1977, Brief on Exceptions of The People of the State of California and the Public Utilities Commission of the State of California; Brief on Exceptions of United Gas Pipe Line Company and United LNG Company; Brief on Exceptions of El Paso Atlantic Company, et al.; Brief on Exceptions of General Motors Corporation; Brief on Exceptions of Commission Staff; November 21, 1977, Brief on Exceptions of Pacific Gas and Electric Company; Brief on Exceptions of San Diego Gas And Electric Company; November 28, 1977, Memorandum Brief Opposing Exceptions of Mississippi River Transmission Corporation; Brief Opposing Exceptions of United Gas Pipe Line Company and United LNG Company; Brief Opposing Exceptions of Commission Staff; Answer of El Paso Participants in Opposition to the Petition for Leave to Intervene Mut of Time of General Motors Corporation filed November 18, 1977; Brief Opposing Exceptions of El Paso Atlantic Company, et al.; November 09, 1977, Brief Opposing Exceptions of The People of the State of California and the Public Utilities Commission of the State of California; November 22, 1977, Motion of Council on Wage and Price Stability to Receive Brief on Exceptions and Late-filed Petition for Limited Intervention, and Brief on Exceptions of Council on Wage and Price Stability; November 30, 1977, @brief Opposing Exceptions of Commission Staff to be Substituted for Brief Filed November 28, 1977; December 2, 1977, Request of General Motors Corporation for Leave to Reply and Reply to El Paso Participants' Answer in Opposition; Supplemental Brief of General Motors Corporation Opposing Exceptions of the Council on Wage and Price Stability; December 5, 1977, Motion and Brief on Exceptions of the Houston Audubon Society, et al. Brief Opposing Exceptions of San Diego Gas and Electric Company and Motion of San Diego Gas and Electric Company for Leave to File Brief Opposing Exceptions Out of Time; December 21, 1977; Answer of United Gas Pipe Line Company and United LNG Company to Motion of Council on Wage and Price Stability to File Brief on Exceptions Out of Time.

19/ Notice of Oral Argument was issued by ERA on March 14, 1978 (43 FR

11849, March 22, 1978).

20/ Dates and list of parties making filings.

April 10, 1978, Motion to Submit Written Document in Lieu of Oral Argument, Council on Wage and Price Stability; April 12, 1978, Written Comments, United States Environmental Protection Agency, Dallas, Texas; April 14, 1978, Response of United Gas Pipe Line Company to the Motion of the Council on Wage and Price Stability; April 17, 1978, Written Comments, Joe Wyatt, Jr., State Representative, 40th District of Texas, April 24, 1978, Motion of Columbia LNG Corporation for Leave to File Comments, and Comments of Columbia LNG Corporation in Lieu of Oral Argument; April 25, 1978, Request to Submit Written Statement and Statement of the Brooklyn Union Gas Company; April 27, 1978, Written Comments, Distrigas Corporation; May 8, 1978, Written Comments of the Council on Wage and Price Stability; May 9, Additional Information, American Gas Association; May 16, 1978, Post-Hearing Memorandum, El Paso Participants, Supplemental Comments of United Gas Pipe Line Company and United LNG Company, and Proposed Transcript Corrections of El Paso Eastern Company, et al.

21/ SoCal and PG&E serve California. Southern Union Gas Company serves EPNG's "East of California (EOC)" market.

22/ With regard to SoCal, EPNG's largest customer, the following exchange occurred at oral argument.

Administrator Bardin: If this gas were available in your service area only on the condition that your company signed a direct contractual commitment with the importer. El Paso Eastern, [Eastern] would the company be willing to do what or would it . . . forego the gas rather than have a direct contractual arrangement?

Mr. Island: . . . We would probably strive mightily to retain the natural gas.

It is my understanding that if the gas were noncurtailable and it were sold pursuant to long-term contract, we would probably seek to purchase it even if we had to do so directly. (Tr, pp 167-168.)

23/ The following exchange occurred at oral argument between Mr. Bardin and Mr. Thayer of the CPUC:

Administrator Bardin: Do you have any objection . . . if the transaction were restructured so the utility, gas utility of California contracted directly with importer, El Paso Eastern [Eastern], to buy gas from El Paso Eastern [Eastern] and separately arrange transportation--

Mr. Thayer: That's a very intriguing question.

I am not sure how that type of contractual arrangement would affect the rate design at this point.

Naturally, we want the gas. If it's obtained on that basis I believe it's already been stated it should be provided on a firm basis, not subject to curtailments . . . . (Tr., pp. 200-201.)

24/ Post Hearing Memorandum for El Paso Atlantic Company, El Paso Eastern Company, El Paso Terminal Company, and El Paso Natural Gas Company, filed May 16, 1978, p. 49 (henceforth, "Post Hearing Memo").

25/ Brief Opposing Exceptions, p. 17.

26/ See footnote 12, p. 6.

27/ Statement of the Brooklyn Union Gas Company, pp. 2-3.

28/ EPNG's priority of service categories, conform to FPC Order 467-B curtailment priorities. (FPC Order 467-B (38 FR 6384, March 9, 1973). FPC priority of service category 1 includes residential service and small commercial use of less than 50 Mcf on a peak day. Priority of service category 2 includes (1) large commercial use (over 50 Mcf per peak day); (2) firm industrial plant protection requirements; (3) firm industrial feedstock use; (4) firm industrial process use; (5) firm industrial use by customers whose aggregate industrial use is 300 or less Mcf/d; and (6) storage injection.

29/ EPNG was one of six companies that entered into a preliminary agreement in August 1977 with Petroleos Mexicanos (PEMEX), the national energy oil and gas company of Mexico, to import 730 Bcf per year for six years. EPNG was to receive 15 percent of the total gas deliveries. However, the preliminary agreement expired on December 31, 1977, without the parties coming to final agreement.

30/ DOE/ERA Opinion Number One, "Opinion and Order on Importation of Liquefied Natural Gas from Indonesia," December 30, 1977, ERA Docket No. 77-001, Pacific Indonesia LNG Company and Western LNG Terminal Associates.

31/ "Supplemental Comments of United Gas Pipe Line Company and United LNG Company," pp. 2-3; hereafter, "Supplemental Comments."

32/ Offshore terminals were also discussed at oral argument by Beverly Edwards, a registered engineer in Texas. Tr., pp. 511-516.

33/ DOE Delegation Order 0204-4, 42 FR 5076, November 29, 1977.

34/ DOE Delegation Order Nos. 0204-25 and 0204-26, 43 FR 47769, October 17, 1978. Delegation Order No. 0204-25, addressed to ERA, amends Delegation Order No. 0204-4.

35/ DOE/ERA Opinion Number Three, "Opinion and Order on Importation of Liquefied Natural Gas from Algeria," December 18, 1978, ERA Docket No. 77-010-LNG, Tenneco Atlantic Pipeline Company, et al.

36/ See Trunkline, Opinion No. 796, April 29, 1977, p. 10. See also ERA Opinion Number Three.

37/ We note that no participant in the proceeding challenged either the gas reserves or deliverability presentation of Sonatrach or the applicants.

38/ Based on figures supplies by Sonatrach and the applicants, the ALJ cited a figure of 95.35 Tcf (2.700 Bm3) of proven gas reserves. This figure, however, is exclusive of approximately 11.6 Tcf (328.5 Bm3) of gas reserves in the In Salah region which is not yet connected to the rest of Sonatrach's natural gas system.

39/ In Opinion Number Three we noted that since the Initial Decision, Sonatrach has been exercising options to market gas in proximate European markets via LNG projects and TransMediterranean underwater pipelines. To date Sonatrach has concluded contracts with two West German power distributors and Swedegas for the annual sale of about 0.21 Tcf (5.946 Bm3) of gas or about 5.0 Tcf (141. Bm3) over a twenty-year period (including gas used in the liquefaction process).

40/ See FERC Initial Decision on Distrigas Project, November 18, 1977, page 3 FERC Docket No. CP77-216 et al., wherein the ALJ approved the import of LNG from Algeria.

41/ Because of the many variables which must be considered in estimating natural gas supply, such as projections of the magnitude of the undiscovered resource base, finding ratios per foot of wells drilled, reserved-to-production ratios, drilling costs, the opportunity cost of capital, and expansion capability of the industry, supply response estimates have varied over a wide range. Independent studies estimating the incremental supply of natural gas due to become available after implementation of the NGPA range from .7 Tcf to 5 Tcf in 1985, as follows:

	1985 (in Tcf)	Cumulative (1978-1985) (in Tcf)

Independent Gas Producers Committee	5.0	...
American Gas Asso.	2.3	12
Draft Economic Analysis of House Conferees	up to 1.4	6.0
Energy Information Administration	1.0	4.7
Congressional Budget Office	.7 to .8	N/A

42/ Opinion Number Three, page 51.

43/ Notice of Oral Argument on Proposal to Import Liquefied Natural Gas Into United States from Algeria, Questions I.3., 4, and 5.

44/ CPUC's priority of service categories are:

Priority	Description
1	All residential use regardless of size. All other firm use with peak-day demands of 100 Mcf/d or less. All interruptible use with peak-day demands of 100 Mcf/d or less.
2-A	All service where primary use is as feedstock with no alternative. All current firm non-residential use with peak-day demands greater than 100 Mcf/d: Where conversion to alternate fuel is not feasible. Where conversion to alternate fuel is feasible. Electric utilities start-up and igniter fuel.
2-B	All current interruptible customers with LPG or other gaseous fuel standby facilities and peak-day demands greater than 100 Mcf/d: Where conversion to alternate fuel is not feasible. Where conversion to alternate fuel is feasible. Other interruptible customers with CPUC approved deviation from requirements for standby facilities.

3	All use not included in another priority.
4	Existing interruptible boiler use with peak-day demand greater than 750 Mcf/d. All use in cement plant kilns.
5	All utility steam-electric generation plants and utility gas turbines, excluding start-up and igniter fuel.

45/ In DOE Opinion Number One, the Pacific Indonesia project received conditional approval pursuant to Section 3 of the NGA, to import LNG. Rehearing of some of the issues involved is currently pending.

46/ In FERC Docket No. CP78-123 et al., Northwest Alaska Company applied to FERC for authority to import 1.04 Tcf/year (29.4 Bm3/) of Canadian Gas. Pacific Interstate Transmission Company in FERC Docket No. CP79-57 requested authority to sell up to 240,000 Mcf/D (6.8 MMm3//D) for ultimate delivery to SoCal. A decision in this case has not yet been rendered.

47/ Petition for Rehearing and Modification on Behalf of California Gas Producers Association, June 23, 1978, p. 10. FERC Docket No. CP77-123 et al.

48/ DOE/ERA Opinion Lumber Two, "Opinion on Rehearing--Issues Related to the Escalator and Currency Adjustor Contract Provisions," September 29, 1978, Pacific Indonesia LNG Company and Western LNG Terminal Associates.

49/ See Footnote 46, p. 47.

50/ An Initial Decision by the FERC (Docket No. RP71-29) containing United's curtailment plan was released on June 27, 1977. The plan stated that category 1 includes all residential and commercial customers regardless of size.

51/ See Footnote 31 p. 30.

52/ Post Hearing Memo, p. 49

53/ Opinion Number Three, p. 52-53.

54/ This estimate is for the third full operating year and includes the applicants' proposed rates of return, assumed costs of capital and proposed capitalization rate. The regasified price includes an FOB price of $1.38 per MMBtu, ($1.308/GJ) a $1.13 per MMBtu ($1.071/GJ) vessel freight rate, $0.26 per MMBtu ($0.246/GJ) for terminal costs, $0.06 per MMBtu ($0.057/GJ) for Eastern's Cost of Service, and $0.01 per MMBtu ($.009/GJ) for transportation to the existing pipeline facilities of EPNG and UGP.

55/ In this regard the applicants in the TAPCO proposal presented estimates of the cost of the gas at the start up of initial delivery. (DOE Opinion Number Three, page 4). During the FERC review of the EPNG proposal the ALJ denied CPUC and SoCal's motions for the applicants to provide estimates of the cost of the gas at the start up of initial delivery. While the applicants contend that this gas supply will be cheaper than the cost of alternate energy sources, they appear unwilling to furnish any estimates of the future costs of competing petroleum products.

56/ See DOE Opinion Three.

57/ Following the deduction of Algerian land-based costs, including liquefaction, DOE estimates that the wellhead component of the base price amounts to about $0.35 per MMBtu ($0.332/GJ).

58/ With the exception of the El Paso I Project, the base price and escalation terms in Sonatrach's sales contract with U.Q. companies include a $1.30 per MMBtu($1.232/GJ) base price and escalation based on changes in the prices of No.2 and No. 6 oils in New York Harbor. The contract sales price in the El Paso I project is based on an initial FOB price of $40.305 per MMBtu ($0.789/GJ) with future escalation, as of September 15, 1971, based upon monthly changes in the BLS Indexes for Steel Mill Products (Code No. 1013) and the Average Hourly Earnings for Production Workers in the Petroleum and Coal Product industry (Code No. C-4). Moreover, only 20 percent of the FOB price is subject to monthly price changes. Since September 1971 we estimate that the operation of this escalator has increased the FOB sales price to about $0.37 per MMBtu 0.35l/GJ) which is less than 25 percent of the estimated (November 1978) FOB sales price of $1.50 per MMBtu ($1.422/GJ) in the El Paso II Project.

59/ Transcript #2, pp. 458-462.

60/ DOE Opinions Number One and Two discuss, in detail, DOE's concerns with FOB sales price escalation clauses in natural gas import contracts.

61/ The European currencies are the Belgian Franc, the French Franc, the West German Deutschmark, the Italian Lira, the Swiss Franc, and the British Pound.

62/ In the Initial Decision (p. 40) the ALJ requested Atlantic and Sonatrach to exchange letters for the purpose of ascertaining whether the Floor Price could be lower than $1.30 per MMBtu ($1.232/GJ) if the Algerian capital investment and the first year operation and maintenance expenses were less than the originally estimated $2.3 billion and $60 million respectively. Eastern considers the matter relatively insignificant because it is certain that the invoice price rather than the floor price will govern over the life of the project.

63/ The remaining \$0.354 per MMBtu (\$0.336/GJ) element represents the wellhead price for the gas which is liquefied. This element remains fixed.

64/This figure is derived from the applicants' estimate of operating costs for the third full operating year (see Initial Decision, Appendix C, page 1).

65/ The freight rate component (FRV) associated with Atlantic's chips will vary with: (1) actual versus estimated vessel capital costs; (2) the current statutory corporate income tax rate of 48 percent per year; and/or (3) the cost of long-term debt and preferred stock dividends. The freight rate associated with shore-based facilities (FRP) will vary with changes in actual capital costs and/or the corporate tax rate.

66/ This issue is currently under rehearing in the Pacific Indonesia project, and is subject to review in ERA, an application by Columbia LNG Corporation, Consolidated System LNG Company and Southern Energy Corporation in ERA Docket No. 78-007-LNG.

67/ This issue is currently under rehearing in the Pacific Indonesia case.

68/ In the Pacific Indonesia Decision, the DOE initially affirmed the Judge's decision which approved the Trunkline approach to cost recovery in the event of project failure prior to the commencement of deliveries. However, in the event of project failure after start up the DOE permitted only certain costs to be flowed through to the consumer and required that the recovery of all other costs would be subject to a "Section 4-type" filing by Pacific Indonesia. This issue is currently under rehearing.

69/ By its "Order on Request of General Motors Corporation, Houston Audubon Society, et al., and Interstate Natural Gas Association of America to Intervene in the matter of El Paso Eastern Co., et al.," dated April 14, 1978, ERA granted intervention to HAS, et al., and to GM and denied intervention to the Interstate Natural Gas Association of America.

70/ Letter to Federal Power Commission from EPA, September 21, 1977.

71/ Letter from Corps to the Commission, November 14, 1977, p. 1.

72/ 43 FR 43063, September 22, 1978.

73/ 43 FR 43064, September 22, 1978.

74/ 43 FR 47772, October 17, 1978.