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LNG Export Opportunities for Developing Countries and The Economic Value of Natural Gas in LNG Export

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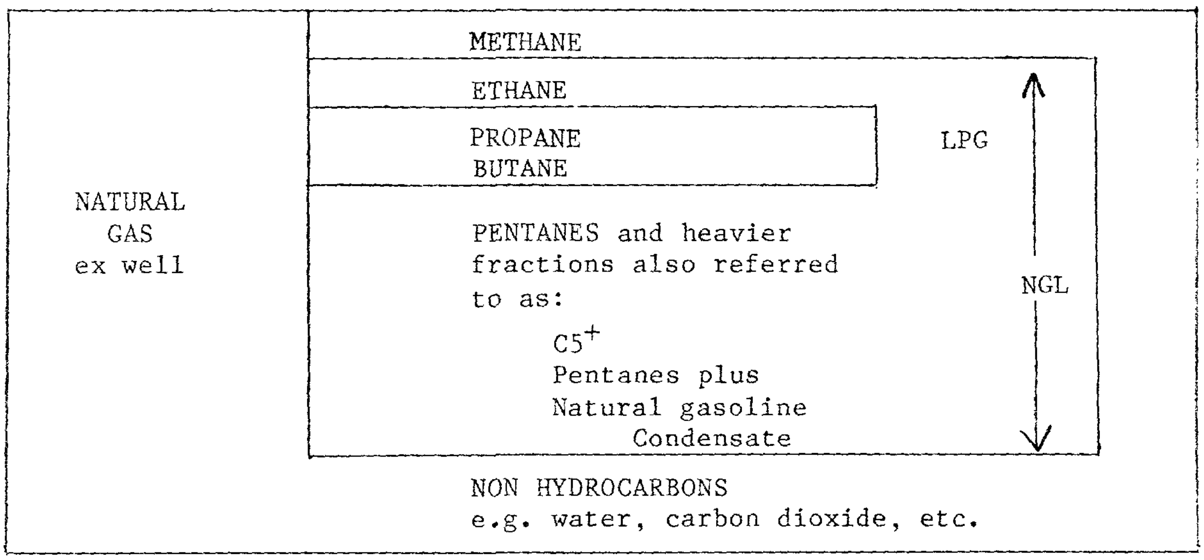
Natural Gas and Gas Liquids

A. Definitions

Natural gas is a simple hydrocarbon that exists in association with oil or separately as non-associated gas. It is generally a composite product. The simplist member methane (C1) is by far the most abundant component, and is always present in a gaseous form. Both associated and non-associated gas often include a high proportion of natural gas liquids (NGLs). These NGLs include ethane (C2) and LPGs, [propane (C3), and butane (C4)], as well as pentanes and natural gasoline condensate (+5).

Terminology And Constituents of Natural Gas



B. Abbreviations

Btu - British Thermal Unit
ft^3 - Cubic foot
SCF - Standard cubic foot
MCF - Thousand cubic feet (10^3)
MMCFD - Million cubic feet per day (10^6)
BCF - Billion cubic feet (10^9)
TCF - Trillion cubic feet (10^{12})
m^3 - Cubic meter
toe - Ton of oil equivalent

C. LNG Volumetric Equivalents

1 million tons of LNG

= 77 million ft^3 (liquid)
= 2.2 million m^3 (liquid)
= 52 BCF (gas)
= 1.4 billion m^3 (gas)
= 1.2 million toe
= 52 trillion Btu

LNG EXPORT OPPORTUNITIES FOR DEVELOPING COUNTRIES AND THE ECONOMIC VALUE OF NATURAL GAS IN LNG EXPORT

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Abstract

Many developing countries are about to embark upon gas development. They face complex questions regarding optimal allocation of their gas among competing alternatives. World Bank staff are preparing a series of papers on the value of natural gas measured by netbacks in major domestic and export options.[1/] One of the objectives of these papers is to develop a comparable information base and a consistent framework of analysis which can be used to provide a preliminary economic evaluation of alternative gas utilization plans.

It is hoped that these studies will be useful to project staff, as well as energy economists and policy makers who are facing complex questions of strategy for gas development in developing countries. These studies do not eliminate the need for site-specific analysis of the economic, financial and technical aspects of projects. They do, however, define the circumstances under which certain options are worth further study. They also attempt to provide a sharper focus for country specific studies and in this way reduce the time and cost of these studies.

This paper reviews the LNG export opportunities for developing countries and clarifies some of the issues related to economic costs and benefits of LNG projects from the point of view of an exporting country. It identifies the major technical parameters that affect costs and analyzes factors affecting the economic size of projects and the effect of scaling them down. Its principal objective is to estimate, given explicit assumptions, the netback values for gas at various stages in the LNG delivery system. It examines three basic scenarios of small and medium scale projects as well as a multi-destination project with several small markets. It also tests the sensitivity of netbacks to the level of infrastructure, discount rates, and the price of gas delivered at the importing country.

LNG projects are highly capital intensive and require a large natural gas reserve base. The netback values ex-pipeline estimated in this study are more sensitive to the delivery price of gas, discount rates, location, and the level of infrastructure than to the size of the project. The study also indicates that a relatively short distance multi-destination LNG project yields a netback close to that of a long-distance project serving only one terminal. The net present values of LNG projects and netbacks ex-well also are significantly influenced by the costs of gas production and transmission.

1/ Forthcoming papers include those on the value of gas (netback) in power, residential/commercial distribution, fertilizer, and petrochemicals uses.

The study concludes that only a few developing countries are expected to benefit from LNG export opportunities in the next decade. The long-term prospects for LNG trade in the 1990s and beyond, however, seem more favorable. The major LNG exporters are expected to be developing countries and the main potential demand will be from developed countries and from a few developing countries such as Korea, Hong Kong, and Singapore.

I. INTRODUCTION AND SUMMARY

A. Introduction

In many developing countries, following gas discovery, the immediate question has been whether or not it is exportable. The purpose of this paper is to clarify some of the issues related to economic costs and benefits of LNG projects from the point of view of an exporting country. It does not cover many of the complex issues related to the project-specific financial and legal aspects of LNG systems. The paper also briefly examines LNG export opportunities for developing countries, and provides estimates of the economic value of natural gas (netback) in selected LNG projects, based on a study done by Jensen Associates for the World Bank. 1/ Netback values for gas are calculated at various stages in the conventional LNG delivery system. The 'netback', or the average value of gas in a project, represents the gas price that would cause the project just to break even. It is defined as the present value of the net benefits of the project, excluding the cost of gas used, divided by the present value of gas consumed in the project.

This paper reviews three scenarios based on actual and potential projects to illustrate aspects of LNG trade relevant to a developing country. The eleven different cases based on these scenarios cover a technically and economically reasonable range of project sizes using the most modern available technology. They identify the major technical parameters that affect system costs and analyze the issue of the economic size of projects and the effect of scaling them down. As can be seen from Table 1, the three basic scenarios simulated here are medium scale, and small scale, single destination projects and small scale multi-destination projects.

The first basic scenario (cases I through VI) is a large LNG project with a capacity of 500 MMCFD situated about 5,000 nautical miles from the export market (e.g. North Africa to Europe), and served by five LNG tankers. The sensitivity of such a project to the level of infrastructure, discount rates as well as the price of gas in the importing country is analyzed. Scenario B (VII through IX) covers a smaller project with a capacity of 300 MMCFD. It is also 5,000 nautical miles away from the export market and is served by three LNG tankers. Sensitivity to the level of infrastructure, and the discount rate is tested. Scenario C (X and XI) is a multi-destination project with three small markets a short distance from the exporting country, and is served by one LNG tanker. Sensitivity to the level of infrastructure is investigated. In all of the simulations estimates of costs and netbacks are supported by actual data on existing or possible projects as well as by estimates provided by suppliers of LNG-related equipment.

1/ "The Economic Value of Natural Gas in LNG Export," Jensen Associates, Inc., October 1982.

Table 1

Assumptions For Eleven LNG Simulations

Scenario	Case	Volume a/ (MMCFD)	Infrastructure Available b/	Discount Rate (Percent)	Gas Price c/ (% of Crude Oil Price)	Transportation Distance d/	Number of Receiving Terminals
A	I	500	yes	10	80	5000	1
	II	500	no	10	80	5000	1
	III	500	yes	5	80	5000	1
	IV	500	yes	8	80	5000	1
	V	500	yes	12	80	5000	1
	VI	500	yes	10	100	5000	1
B	VII	300	yes	10	80	5000	1
	VIII	300	no	10	80	5000	1
	IX	300	yes	5	80	5000	1
C	X	300	yes	10	80	1000	3
	XI	300	no	10	80	1000	3

a/ Liquefaction plant input.

b/ At liquefaction plant site.

c/ Assuming that crude oil prices are $34/boe and would increase after 1985 at an average real rate of 2% per year based on mid-1982 projections.

d/ Nautical miles, one way.

Following this introduction and summary section, Part II discusses the potential supply and demand for LNG and the pricing of LNG projects. Part III presents the structure of LNG projects consisting of gas production, transmission, liquefaction, shipping, and regasification phases and the respective costs of each phase. Part IV describes the methodology to estimate netbacks and presents the resulting netback values. It also provides the net present value of LNG projects based on different gas input price assumptions. Detailed cost schedules, volume build up, and net present values are included in Appendix 1.

B. Summary

Natural gas exports from developing countries as LNG grew rapidly from 112 BCF in 1970 to about 1.2 TCF in 1980. Over the next few years, trade in natural gas is expected to grow more slowly than in the 1970s. About 10 to 20 possible LNG projects in the developing countries are being reviewed at present. There is a potential market for these exports principally in Japan and Western Europe. However, given the state of world demand these projects will compete with each other. In the next decade, only a few projects in countries that have substantial gas reserves and the advantages of the presence of international oil companies, closeness to markets, and perceived political stability may be realized.

LNG projects require large proven reserves and take about a decade between the first indication of interest and their commissioning. The minimum reserves needed for an LNG project are about 3 trillion cubic feet (TCF); projects based on reserves of 4-5 TCF benefit from economies of scale. The certification of reserves dedicated to a project and production levels is a major issue. For example, one reason for the delay of the Cameroon project was related to the reserve certification process, which reduced previous estimates of proven reserves. LNG projects are highly capital intensive and require considerable up front investments; the study indicates that the investment required for liquefaction, shipping, and receiving and regasification for a 300 MMCFD project is estimated at about $1.4-1.7 billion depending on the level of existing infrastructure. The capital cost for a larger project of about 500 MMCFD is expected to be about $2.0-2.4 billion. This indicates substantial economies of scale.

The issues related to financing such large-scale projects are complex. Because of their high capital intensity and large amounts of loan financing and cash flow requirements, LNG projects are very sensitive to price variations. They therefore require long-term agreements on prices and escalation formulas as well as willingness of sellers and buyers to commit themselves to operations at high load factors over a long period of about 15 to 25 years. The relatively inflexible nature of LNG trade as well as the need for a strong, long-term relationship between exporters and importers makes LNG projects particularly sensitive to producers' and investors' perceptions of political, technical, and market risks.

All the cases considered in this study provide positive economic netbacks.1/ However, the netback values to LNG, ex-pipeline delivered at the liquefaction plant for the 11 cases, vary widely. There is a direct relationship between lower gas prices and lower netbacks. Except in Case VI, which uses a higher LNG price assumption as a sensitivity test, and Cases III, IV, V, and IX, which use different discount rates to measure sensitivity to the opportunity cost of capital, the netback values are between $2.23 and $3.40 per MCF. These netback values calculated at the point of gas delivery to the liquefaction plant would, based on experience in the countries reviewed, cover costs of finding, producing, and transporting gas to the liquefaction plant, as well as the respective rent to the exporting country for depleting an exhaustible resource and the profit of the companies involved in the project.

1/ The netback is estimated at three points: (i) entry into the liquefaction, plant (ex-pipeline), (ii) loading onto LNG carriers (ex-liquefaction, and (iii) delivery (ex-ship).

The netback varies only to a small extent as a result of the range of plant sizes studied here (300-500 MMCFD). However, with a liquefaction plant size below 300 MMCFD, large diseconomies of scale set in. The study also indicates that a relatively short distance LNG project, in which one liquefaction plant serves several receiving terminals, yields a netback value close to that from a long distance project serving only one terminal. The netback is very sensitive to the price of the gas delivered in the importing country. The netback to gas when the gas price is based on mid-1982 cif crude oil parity, in the sensitivity case (VI), is $4.46 per MCF compared to $3.09 in Case I when the price is based on 80% of crude oil prices.1/ Netback values are also affected by location and the level of infrastructure at the liquefaction site.

The netback to gas delivered at the liquefaction plant (ex-pipeline), estimated in the basic cases, excludes exploration, production and transmission costs. When the specific cost of gas exploration, production and transmission to the liquefaction plant is included, the netback to gas ex-well can be determined. A separate study of the marginal cost of natural gas in ten developing countries has been carried out and its results indicate a range of gas delivery costs. 2/ The sensitivity of LNG projects to the cost of gas was investigated, assuming that the cost of natural gas delivery to the liquefaction plant is $0.50 and $1.00 per MCF. The impact of higher gas input costs (into the liquefaction plant) on net present values and consequently netbacks is very significant. In Case I, for example, the net present value of the project falls from $2.90 billion to $1.97 billion when a natural gas delivery cost to the liquefaction plant of $1.0 per MCF is included.

The results of this study provide only a preliminary and general impression of the economic value of gas in LNG exports. Any specific project will have to be separately studied to allow for its specific economic, financial, and legal characteristics. In a particular case, the details of the quantity and quality of gas input to the liquefaction plant and actual infrastructure costs will affect the netback value ex-pipeline to the exporters. Also, different debt/equity ratios and tax systems can cause significant differences in overall project profitability. In any LNG pro-

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1/ Construction of these hypothetical projects is assumed to begin in 1982 and take 5 years. Operation begins in 1986 and continues for 20 years. Therefore, the recent oil price fall is not expected to change the netback values significantly since these values are based on long-term oil price projections which have not changed drastically from previous projections. Further, all the value-in-use studies are based on similar price projections and will therefore remain consistent and comparable.

2/ Estimates of these costs in several developing countries are provided in the "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications", Energy Department Paper No. 10, World Bank, 1983.

ject there are close links between financing arrangements, the costs of equipment which are often purchased from the gas importing country, and the contract price and conditions. As a result, it is often difficult to ascertain the exact economic costs of a particular project. The situations considered in this paper, however, provide general cost and benefit estimates which should assist countries in deciding whether a particular project is worth studying in detail.

II. THE EVOLUTION AND PROSPECTS OF LNG TRADE

A. Early Projects

International trade in LNG began with the trial shipments from Louisiana to Canvey Island in 1954. 1/ Its success led to the first commercial base load international LNG project in 1964 between Arzew, Algeria, and the UK for about 40 BCF per year over a 15 year contract period. This was followed by ventures between Algeria and France in 1965, and Alaska and Japan in 1969. Gas exports grew about tenfold between 1966 and 1980 because of the mutual benefits for exporters and importers of LNG. For exporting countries, flared gas in Abu Dhabi and Libya, or gas which was surplus to foreseen long-term domestic needs, could be exported as LNG to generate foreign exchange. LNG projects provide an important option for developing countries with relatively abundant unutilized natural gas reserves.

For importing countries before 1973, imported gas prices were cheap relative to alternative energy sources. Between 1973 and 1979 LNG prices remained competitive, though they were increasingly linked to the prices of petroleum products. In countries with a serious pollution problem, such as Japan, LNG also had a premium value as a clean fuel. Several European countries had gas pipeline networks (to distribute town gas produced from coal) which could be used to distribute natural gas. In some instances, LNG imports were needed to maintain the supply of gas to existing distribution networks, where not enough gas was available locally. For other importers, LNG provided an economic way of diversifying the sources and types of energy, to improve the overall security of supply. For both buyers and sellers, LNG became a proven means of supply which was technically reliable and safe and also offered the most economic means of bringing large volumes of gas to markets where delivery by pipeline was impractical.

B. The Development of LNG Trade

Much larger LNG projects were planned in the 1970s to exploit economies of scale in liquefaction and to meet increasing demand (Table 2). The first of this new generation of large scale projects was the Brunei exports to Japan in 1972. This contract provided for the supply of about 280 BCF per year over 20 years. World LNG trade increased from 112 BCF in 1970 to about 1.2 TCF in 1980. Trade in LNG grew more rapidly than the gas export market as a whole and increased its share from 7 percent to about 19 percent of total gas trade in 1982.

1/ The use of LNG for peak shaving began in the US in the early 1940s. The volumes involved were very small--less than 1 billion cubic meters in 1950 and 5 billion cubic meters in 1960.

Table 2

Operational LNG Export Projects and Projects Under Construction a/

Exporter	Importer	Contract Initial Delivery	Contract Term Years	Volume in MMCFD
Algeria b/	UK/British Gas	1964	15	110
Algeria	France/Gaz de France	1965	25	50
Alaska	Japan/Tokyo Gas/Tokyo Electric Power	1969	15	135
Libya	Italy/SNAM	1970	20	240
Libya	Spain/INAGAS	1970	15	110
Algeria	France/Gaz de France	1972	25	350
Brunei	Japan/Osaka Gas/Tokyo Electric Power	1972	20	745
Algeria	Spain/ENAGAS	1976	23	450
Abu Dhabi	Japan/Tokyo Electric Power	1977	20	355
Indonesia	Japan/Osaka Gas/Kansai	1977	20	440
Indonesia	Japan/Chibu and Kyushu Electric Power/Nippon Steel	1978	20	630
Algeria c/	USA/Distrigas	1978	20	120
Algeria d/	USA/El Paso	1978	20	1000
Algeria e/	USA/Distrigas	1981	20	450
Algeria	France/Gas de France	1982	20	530
Algeria f/	Belgium/Distrigaz	1982	20	500
Malaysia g/	Japan/Tokyo Gas	1983	20	870
Indonesia	Japan/Nagoya/Osaka/Himeji	1983	20	460
Indonesia	Japan/Niigata/Tokyo	1983	20	480

a/ Status as of March 1983; actual exports in 1982 were in some cases below the volumes indicated in this table.

b/ This project has been terminated.

c/ This project has supplied small quantities since 1971.

d/ Supplies from the El Paso project have been suspended since 1980.

e/ The Trunkline project started operating in 1983 but exports are below contracted volumes.

f/ Exports in 1982 were far below these volumes.

g/ Operation began in March 1983 at 400 MMCFD.

In 1983, with the implementation of projects under construction, international LNG trade has virtually stopped growing. Some of the proposed projects in the 1970s, such as projects from Iran to the US and Japan, and from Algeria and Nigeria to the US and Europe, have not been carried out. Some of these have been cancelled, while others might be reactivated in their original or in a different form. Actual trade has remained at 1.2-1.3 TCF per year since 1980. This is generally attributed to the economic recession, widespread energy conservation, and a switch from energy-intensive industries to manufacturing of less energy-intensive products and services in developed countries. Over the next few years, LNG trade is expected to grow more slowly than in the 1970s. Except for the expansion in existing projects such as the Malaysian project, no other new projects have progressed to a stage where they can be implemented before 1986.

C. LNG Demand, Supply and Prospects

Developing countries are responsible for over 95 percent of LNG exports. In the next two decades they are likely to remain the major suppliers of LNG. The Middle East holds over 25 percent of total world proven reserves, with Iran holding over one half of this region's reserves. Within this region, only Abu Dhabi has an operating LNG project. In Africa, Algeria and Libya are already LNG exporters. In Latin America there are no current LNG projects. There are, however, pipeline exports from Mexico, which has the largest gas reserves in the region, to USA and from Bolivia to Argentina. There are large gas reserves in this region and there is a growing regional market; Bolivia and Brazil are studying a large pipeline project and the Mexican-USA trade is expected to grow. In Asia, Malaysia holds the largest gas reserves, and together with Indonesia and Brunei has operating LNG projects.

Most of the demand for LNG will continue to come from developed countries. A few developing countries may also begin LNG imports in the next decade. The three major consuming areas are the USA, Japan, and Western Europe. The USA is the world's largest consumer and is responsible for about 34% of world gas consumption. Though it is the largest producer of natural gas, there is great uncertainty about the effect of gas price deregulation on its domestic supply. It also imports gas from Canada and Mexico and, to a limited extent, Algeria. The USA is not expected to have an interest in additional LNG trade until the end of this decade, given the reserves within North America, the potential pipeline trade with Canada and Mexico, an absence of a policy towards LNG, and uncertainty about supply and demand. After 1990, the growth of LNG imports would depend on their prices; a rapid increase would require changes in the USA regulatory system and domestic gas pricing policy.

Japan has no significant gas reserves and accounts for 67 percent of world LNG imports. It is expected to remain the largest importer of LNG at least until the year 2000. Its dense urban concentrations require very tight pollution control, which puts a premium value on the clean burning characteristics of gas. Japan currently imports LNG from Alaska, Abu Dhabi, Brunei, Indonesia, and Malaysia. The major users of LNG in Japan will remain power utilities, which currently account for 75 percent of total gas use, followed by industrial and residential users. The expected overcapacity in nuclear plants, together with the slow growth rate of electricity demand, could seriously reduce the derived demand for LNG.

Western Europe has about 5 percent of total world reserves and already imports LNG and pipeline gas from North Africa and the USSR. Between 1979 and 1982, total European gas consumption dropped by about 6 percent, mainly due to a fall in power and industrial consumption. Western Europe's gas production is expected to peak this decade. Its decline, together with rising consumption levels as the economic recovery proceeds, is expected to increase the reliance on imported gas. A major concern is to improve the security of energy supplies through diversifying sources of supply.

Over the next few years, natural gas exports are expected to grow more slowly than the 1970s. Some of the possible LNG projects presented in Table 3 are being reviewed at present. There are, however, complex political, commercial, and economic problems to be resolved in the case of each possible project. There is a potential market for these exports principally in Japan and in Western Europe, but given the state of world demand, these projects will compete with each other and only a few may be realized. In the next decade gas trade will involve only about 15 countries that have large gas reserves and the advantages of the presence of international oil companies, acceptable financing, pricing, and fiscal arrangements, closeness to markets and perceived political stability. Regional trade is one prospective area of growth. Bolivian exports to Argentina, which the World Bank has assisted, and Mexican exports to the US, are examples which may be followed by the Bolivia-Brazil, and Bangladesh-India pipelines presently being studied.

Table 3

Possible Base-Load LNG Projects a/

Exporter	Importer	Contract Term Years	Daily Volume in MMCFD
Australia	Japan	20	850
Bangladesh	Japan/Europe	-	310
Cameroon	Europe	20	420
Canada	Japan	20	400
Canada	USA	20	260
Gulf of Guinea	Europe	-	500
Indonesia	Korea	20	210
Indonesia	Japan	-	220
Nigeria	Europe	20	500
Qatar	Japan/Europe	20	870
Thailand	Japan	-	250
Trinidad & Tobago	USA	20	600
USSR	Japan	20	400

a/ Some of these projects have already been studied (e.g. Nigeria) while others are at an initial stage of study (e.g. Thailand).

D. Pricing

One of the most important determinants of supply and demand for LNG over the next two decades, is the price of LNG in the consuming countries relative to competing fuel prices. Gas pipeline and LNG export projects are extremely sensitive to price variations because of their capital intensive nature and the large amount of loan financing involved. LNG pricing has always been complicated because of the secrecy demanded by buyers and sellers as to the contract details and escalation clauses. Prices in many cases reflect political as well as economic considerations. Over the years, the bases for pricing LNG have changed from the cost of service to simple and then complex escalation clauses and to indexing based on the cost of alternative energy in the market. The history of LNG pricing provisions and changes in these provisions has shown that it is difficult to determine a pricing mechanism that will endure throughout a twenty year LNG contract. Consequently, most contracts have provisions to reopen price negotiations at specified intervals.

Table 4

LNG Prices a/

Contract	Imported Gas Price b/ ($/MCF)
Algeria - Belgium	5.90
Algeria - France	5.70
Brunei - Japan	5.76
Indonesia - Japan	5.66
Malaysia - Japan	5.84
Alaska - Japan	5.73
Abu Dhabi - Japan	6.04

a/ CIF regasified prices for natural gas delivered into the domestic transmission pipeline of the importing country as of February 1983; these prices are expected to fall since gas price formulas are linked to oil prices.

b/ Prices assume that 1 cubic foot is equivalent to 1000 BTU.

The main problem in determining a fixed pricing provision is that the prices of alternatives to LNG in the market place change over time both from the perspective of the buyer and the seller. It is therefore impossible to determine with certainty what will constitute an acceptable LNG price in the future. A review of some recent LNG pricing agreements in Table 4 provides an indication of current prices. LNG prices are far above pipeline gas exports. The agreed gas price for the recent Trans-Mediterranean pipeline project between Algeria and Italy was $4.41 MCF. The price of Soviet pipeline gas imports is estimated at close to about \$4.50/MCF. Due to the fall in oil prices gas prices are also expected to have fallen. LNG projects in some cases may compete with gas pipeline projects and future LNG prices relative to the price of pipeline gas will be a major determinant of the share of LNG in total gas exports.

The controversy on linking LNG prices to fob or cif prices of crude oil, fuel oil or other petroleum product prices continues. 1/ This study has simplified the complex pricing structures by adopting two distinct pricing assumptions that provide lower and upper boundaries. These prices are expressed in constant 1982 US dollars. They are escalated according to projections of future crude oil prices made in mid-1982. The lower limit has been set according to 80 percent of crude oil prices. The upper limit to LNG prices is set by crude oil prices.

1/ While exporters have argued for fob crude oil parity, present contracts, with Japan for example, are based on cif parity.

III. STRUCTURE OF LNG PROJECTS

Each phase of an LNG system is described below. Capital and operating cost schedules associated with each of the eleven simulations, starting from the decision to construct until the first availability of the project after 5 years and continuing for 20 years of operation, are included in Appendix I. 1/ Costs are presented in 1982 constant US dollars and exclude all taxes and financial charges. An LNG export project consists of four distinct but interrelated phases:

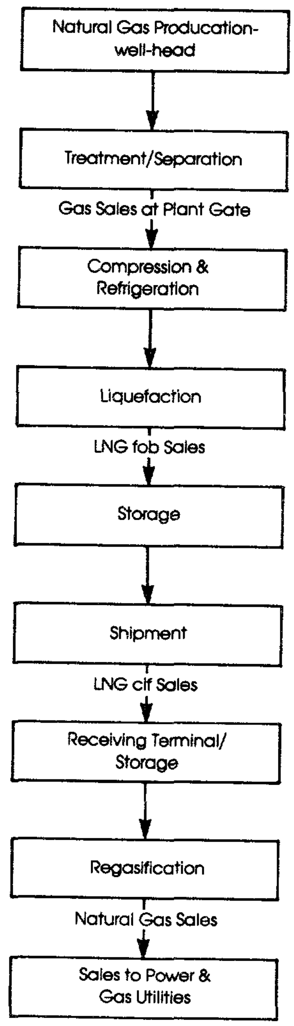
- gas production, treatment, and transport to the liquefaction plant;
- liquefaction, storage and ship loading;
- shipping LNG in special cryogenic tankers to the reception terminal; and
- receiving terminal, unloading, LNG storage, and regasification.

Although these activities are generally conducted by separate entities, an LNG project requires a high degree of interdependence and interaction between suppliers and customers (Figure 1). Each phase of an LNG project is part of an integrated system stretching from the gas well to the ultimate consumer. If any one element in the chain is not ready in time or fails for any reason, the whole project may be in jeopardy.

The project must also operate at a high load factor and over a contract period of about 15 to 25 years in order to justify the enormous investments required. Neither the supplier nor the customers can easily turn elsewhere for outlets or alternative supplies of LNG of the magnitude involved. Unlike oil trade, opportunities for the spot cargo trading of baseload LNG for conventional uses are small. There is, however, a greater opportunity for spot cargo trading for peakshaving purposes.

1/ The 20 years include four years for building up capacity.

AN LNG EXPORT SCHEME



A. Gas Production and Transmission

The production phase of an LNG project is basically no different from a pipeline gas venture for export or domestic uses. An LNG project is however, more sensitive to possible variations in the gas quality and quantity over the life of a project since the liquefaction plant must be fully loaded at all times. The threshold volume of recoverable reserves is important because the gas liquefaction costs are greatly influenced by the size of a project.

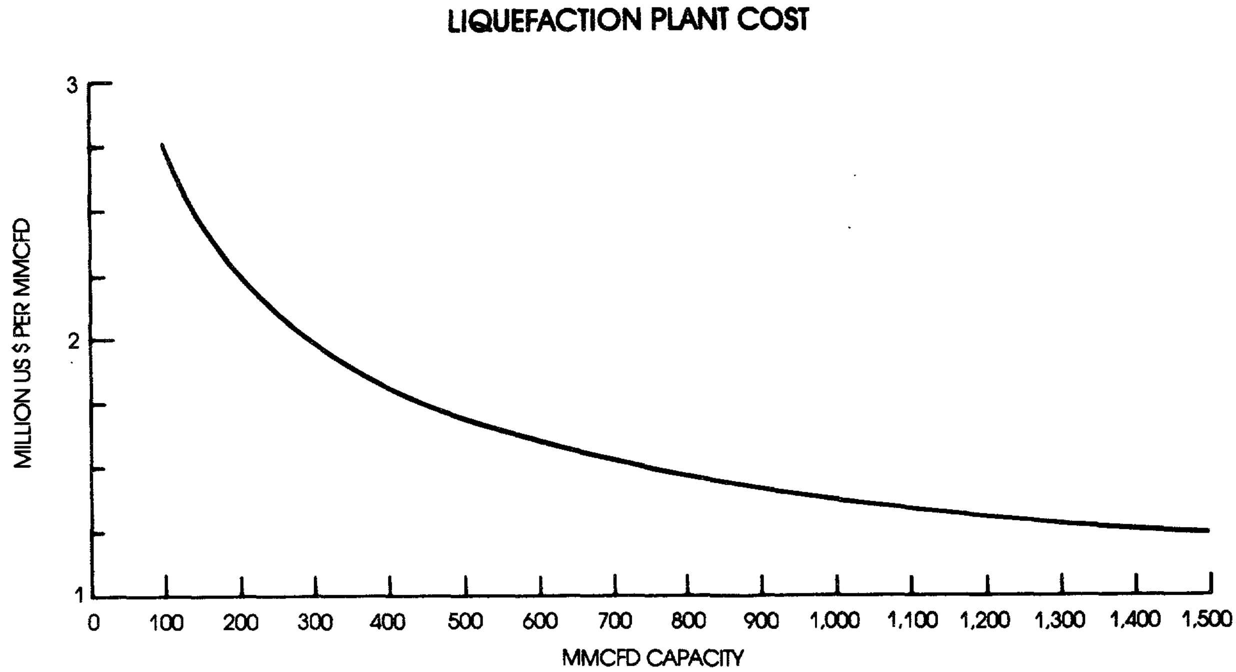
Export volumes tend to be large and the reserves dedicated to an export scheme should be sufficient to sustain production for the contract period, i.e. 15-25 years, with about 30 percent safety margin, particularly if part of the supply comes from associated gas. LNG projects require very reliable estimates of reserves and production. Reserves of about 3 TCF provide a sufficient threshold for LNG projects with an approximate capacity of 300 MMCFD; projects based on recoverable reserves of 4-5 TCF benefit from economies of scale. This is due to the replication of liquefaction costs and lumpy and indivisible infrastructure costs.

The gas that enters the liquefaction plant is treated and free of most impurities. If the gas contains a high percentage of carbon dioxide, hydrogen sulfide, nitrogen, and metal particles which can disrupt the production process, it would require additional investment in pretreatment equipment that reduces the netback to the well-head. The gross thermal content of the gas for purposes of this analysis is assumed to be 1000 Btu/scf. This is a very lean gas stream. In practice a higher or lower calorific value can significantly affect the costs and benefits of the project. 1/

B. Liquefaction

The process of liquefaction requires cooling methane to about negative 161°C at atmospheric pressure to reduce its volume to 1/600th of gaseous methane. Each process train or liquefaction unit generally involves further purification and dehydration of the incoming gas followed by compression, refrigeration and liquefaction. The liquefaction plant is often the most expensive link in the LNG chain. For example, a 500 MMCFD liquefaction plant is estimated to cost a minimum of $800 million excluding interest during construction at a developed site. The most costly items within the plant are the liquefaction trains, and steam and power generating facilities, each contributing 25 percent or more to the total cost.

1/ A rich gas with a high content of heavy hydrocarbons can be marketed in two ways. First, the heavy gases could be extracted, fractionated and transported by LPG carriers. This could increase the net present value of the project cash flow and also the netback. Second the heavier gases could be liquefied with the methane and transported to the importing country together. For some buyers this gas will have a premium value. Mixing of rich and lean gas may cause problems for other end users and require adjustment of burners.



The 500 MMCFD plant size was chosen as a relatively standard size liquefaction plant. The possibility of scaling down the liquefaction plant was investigated. The results indicate that for a plant size below 300 MMCFD, costs begin to rise quite rapidly as indicated in Figure 2. There are significant economies of scale in the construction and operating costs of liquefaction plants. Capital and operating costs of the liquefaction plant are crucially dependent on the availability of local infrastructure and personnel. Building facilities such as deep water ports, roads, and housing as well as training unskilled labor and the expenses of skilled expertise may add more than 100 percent to the cost of construction. Storage, marine and loading costs following liquefaction increase costs by another $200 million for a 500 MMCFD plant and by $165 million for the 300 MMCFD plant, as indicated in Table 5. Operating costs are about 5 percent of capital costs and include maintenance and labor costs as well as internal consumption of 8-12 percent of the gas input.

Table 5

Liquefaction Plant Cost Breakdown a/
(in millions of US$)

	500 MMCFD	300 MMCFD
Liquefaction Section	290	170
Utilities and Auxilliaries	330	230
Site Preparation and Building	35	30
Storage	90	70
Marine and Loading	110	95
Total	855	595

a/ Total capital cost figures may differ slightly from figures in the report due to rounding; all capital and operating costs for each case are provided in Appendix I.

C. Transportation

The current standard for new tanker designs is 130,000 cubic meters. This standard has evolved as a compromise between significant economies of scale and the need for LNG carriers to be able to enter European, Japanese, and American ports. 1/ The capital cost of the two major tanker designs, the membrane and spherical types, depends on the shipyard but a price of $150 million for a 130,000 cubic meter tanker is often quoted for both designs. 2/ However, in order to maintain their economic competitiveness, some LNG shipyards may offer discounts that reduce this cost.

The operating costs cover fuel and harbor fees as well as maintenance, insurance and wages and are sensitive to distance. For a typical route of about 5000 nautical miles one way, chosen in this study as a case which corresponds approximately to a North African-European project, operating costs constitute 7-8 percent of capital costs. The study assumes zero boil-off since current tanker design has reduced the maximum boil-off

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1/ An additional factor in the design of modern tankers is safety regulations; the US Coast Guard regulations set global standards.

2/ There are more than 60 LNG tankers in the world. The membrane design had an early lead but recently the spherical design seems to have taken over due to its higher flexibility in quantities carried and the ease of inspection of the spherical tank.

of gas en route to 0.11 percent or less per day.1/ Improved insulation of new carriers and the installation of a small reliquefaction system also reduce boil-off.

The number of LNG tankers depends on the distance between ports, speed, tank filling rates, expected downtime, desired safety margin,and other system characteristics and the overall volume of LNG transported. The hypothetical projects simulated here were designed to allow for these factors and require 5 vessels in Cases I-VI, 3 vessels in Cases VII-IX, and 1 vessel in Cases X-XI.

D. Receiving/Regasification Terminal

The receiving terminal and regasification plant is the simplest and least expensive phase of the LNG chain. It consists of a harbor with facilities for off-loading tankers, LNG storage, regasification, and distribution of gas. The docking facilities typically cost at least $120 million and do not vary much with the size of the terminal. The port and storage facilities may represent over half of the total costs of the receiving and regasification terminal.

Table 6

Receiving Terminal Cost Breakdown
(in millions of US$)

	500 MMCFD	300 MMCFD	Multiple a/ Destination
Regasification	125	75	90
Utilities and Auxiliaries	90	55	70
Site Preparation and Building	20	15	60
Storage	100	80	240
Marine and Loading	130	120	370
Total	465	345	830

a/ These figures include regasification plants/receiving terminals at all three destinations.

1/ The boil-off is the gas vaporised by heat leakage into the LNG tank. In conventional LNG carriers, the LNG boil-off is used to supply a portion of their fuel needs.

There are two principal processes for regasification. In large installations, sea water is used to raise the LNG temperature. For small and peak shaving plants, gas burners are used. 1/ A regasification facility, using sea water vaporization that matches the 500 MMCFD liquefaction plant and the 130,000 cubic meter LNG carrier size, will cost about $450 million. Annual operating costs include mainly maintenance costs, and wages, and represent about 3 percent of total capital costs.

1/ The capital cost of the gas vaporization process is only half that of using sea water, but this difference tends to be offset by the cost of the gas used in the gas burners.

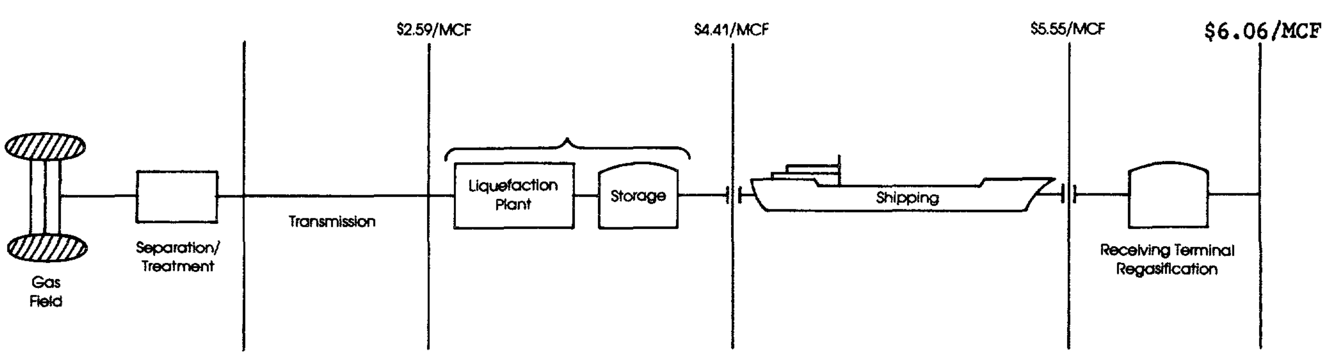
IV. NATURAL GAS NETBACKS

A. Methodology

This part of the paper discusses the calculation of values of natural gas delivered to the liquefaction plant, tankers, and the regasification plant, taking as given the price of gas delivered to the importing country's grid. The netback is estimated based on three sets of information: volume of production (V), capital cost (I), and operating costs (O), and the price of gas (P) at the delivery point. For this purpose, the present value of all economic capital and operating costs in constant prices is calculated excluding all financial and fiscal cost components (e.g. interest, depreciation, taxes and subsidies). Capital and operating costs are then deducted from the present value of the total revenue (also in constant prices). The resulting present value of net benefits is divided by the discounted volume of gas transferred at each keypoint of the project to estimate the netback to natural gas.

The actual volume of gas transferred at each key point is limited by the size of dedicated recoverable reserves, liquefaction plant, and the number of LNG carriers. The capacity build-up period from the date of commissioning the liquefaction plant to its reaching full capacity is four years. The capital and operating cost schedule, volume of gas, and prices used in all simulations undertaken in this study, starting with the decision to construct the liquefaction plant until first availability of the product and the conclusion of the twentieth year of operation, are included in Appendix I. Cost data are based on the data collected from several LNG companies. This cost information has been cross-checked and updated through ongoing contact with LNG- related firms.

Figure 3
UNIT NETBACK VALUES FOR A TYPICAL LNG SCHEME — CASE II



As an example of a netback calculation, in one of the simulations based on scenario A (Case II) presented in Figure 3, the value of gas at the point of entry into the importing country's main transmission line (ex-vaporization) is determined by the delivered price and quantity of gas over the 20 years of the project's operation. This is estimated by dividing the present value of the sum of revenues from the sale of regasified gas (PV_1 is the revenue from gas sales) which is \$5.2 billion (Appendix I) by the present value of the volume of regasified LNG delivered to the pipeline As indicated in Figure 3 the value of gas at the point of entry into the importing country's transmission pipeline is \$6.06/MCF.

The netback ex-ship is estimated by deducting the present value of the capital and operating costs for the receiving terminal, storage, and regasification facilities which is \$433 million (as indicated in Appendix I), from the present value of the total revenue from the sale of gas (\$5.2 billion) and dividing by the present value of the gas volume delivered into the main transmission pipeline of the importing country. This results in a netback value of \$5.55/MCF ex-ship at the delivery point into the receiving terminal. Algebraically,

$$N_{ex\text{-}ship} = \frac{\sum_{i=0}^{20} [(PV_1)/(1 + r)^i] - \sum_{i=-5}^{20} [(C_1 + O_1)/(1 + r)^i]}{\sum_{i=0}^{20} [V_1/(1 + r)^i]}$$

where P is the price of natural gas delivered into the importing country's pipeline, V_1 is the volume of gas delivered each year, C_1 and O_1 are respectively capital and operating costs related to regasification, storage and the receiving terminal, and r is the discount rate.

The netback ex-liquifaction is estimated similarly by deducting the present value of all receiving, storage, and regasification ($C_1 + O_1$) plus shipping capital and operating costs which is \$1.4 billion from the present value of total revenues from the sale of gas and dividing by the present value of the gas volume transferred into the ship. Algebraically,

$$N_{ex\text{-}liquefaction} = \frac{\sum_{i=0}^{20} [(PV_1)/(1 + r)^i] - \sum_{i=-5}^{20} [(C_2 + O_2)/(1 + r)^i]}{\sum_{i=0}^{20} [V_2/(1 + r)^i]}$$

where (PV_1) is the total revenue from gas sales, ($C_2 + O_2$) is equal to ($C_1 + O_1$) plus the capital and operating cost of shipping and V_2 is the volume of gas transferred into the ship. 1/

The netback at the point of entry into the liquefaction plant (ex-pipeline) is estimated by deducting ($C_2 + O_2$) plus the liquefaction and storage capital and operating costs which is $2.8 billion from the present value of the revenues from the sale of gas and dividing by the discounted volumes of gas delivered to the liquefaction plant (V_3). Algebraically,

$$N_{ex\text{-}pipeline} = \frac{\sum_{i=0}^{20} [(PV_1)/(1 + r)^i] - \sum_{i=-5}^{20} [(C_3 + O_3)/(1 + r)^i]}{\sum_{i=0}^{20} [V_3/(1 + r)^i]}$$

where ($C_3 + O_3$) is equal to ($C_2 + O_2$) plus the liquefaction and storage capital and operating costs. The netback at this point as illustrated in Figure 3 is $2.59/MCF.

B. Netback

The results of netback calculations are presented in Tables 7a, 7b, and 7c. The netback calculations start from the assumed value of the regasified product supplied at the perimeter of the regasification facility where the gas enters the transmission system in the importing country. The netback at each stage is expressed by deducting the cost of each phase down to the gas delivered to the liquefaction plant. For example scenario A represents the standard medium-sized liquefaction plant that serves one receiving terminal 5000 nautical miles away with 5 LNG tankers. In one of the simulations (Case I) the net present value of the regasified LNG is $6.06/MCF as delivered into the receiving country's pipeline. This is the present value of the price of gas over the project period (Figure 3). The cost of regasifying the LNG is $0.51/MCF; shipping costs are $1.14/MCF. This leads to a netback for LNG loaded onto the ship of $4.41/MCF. 2/ Deducting the liquefaction cost of $1.32 yields a netback value of $3.09 per MCF for the gas delivered to the liquefaction plant. Table 7a provides the netback values for Case I and Cases II-VI which test for sensitivity to the level of infrastructure, discount rates, and the price of gas in the importing country.

1/ It is assumed that there is no boil-off and that the volume of gas transferred to the ship is equal to the volume of gas delivered to the transmission pipeline of the importing country ($V_1 = V_2$).

2/ The detailed cost figures and calculations are provided in Appendix I.

Table 7a
Unit Netback Values for Scenario A
($/MCF)

Value Reference Point	I	II	III	IV	V	VI
Regasified	6.06	6.06	6.24	6.12	5.99	7.57
LNG ex-ship	5.55	5.55	5.89	5.69	5.41	7.06
LNG loaded	4.41	4.41	4.95	4.64	4.18	5.93
Gas ex-pipeline a/	3.09	2.59	3.83	3.40	2.75	4.46

a/ Gas at the entry point of the liquefaction plant.

With less infrastructure, as in Case II, infrastructure costs increase and the netback ex-pipeline falls to $2.59/MCF. The sensitivity to discount rates was measured in cases III, IV, and V. The netback value of gas supplied to the liquefaction plant varies from a low of $2.75 with a 12 percent discount rate to a high of $3.83 per MCF with a 5 percent discount rate. The netback values are most sensitive, however, to the pricing policy. If gas is valued in the importing country according to its calorific parity with crude oil (Case VI), the netback ex-pipeline increases from $3.09 to $4.46 per MCF.

The second scenario is centered on a liquefaction plant of 300 MMCFD, to examine the diseconomies of scale. Due to the different production schedule, the present value of the gas stream entering the gas grid in the importing country in Case VII for example, is somewhat lower than in Case I, at $5.98/MCF. Working back through the LNG chain, $0.65/MCF is netted out in the regasification plant which is 27 percent more than in Case I. Shipping costs are similar since LNG carriers are used with roughly equal efficiency in both cases. Unit liquefaction costs rise to $1.38 per MCF, although the expected diseconomies of scale are moderated by a shorter construction period and a faster build-up of production. There is only a relatively small difference between the netbacks in Cases I and VII. Diseconomies of scale in liquefaction plants start at plant sizes less than 300 MMCFD as indicated by Figure 2. The unit netback into the liquefaction plant is $2.85 per MCF. Limited infrastructure, and therefore higher capital costs at the liquefaction plant site, reduce the ex-pipeline netback to $2.31 per MCF. The netback is also sensitive to the discount rate as demonstrated in Case IX.

Table 7b

Unit Netback Values for Scenario B
($/MCF)

Value Reference Point	VII	VIII	IX
Regasified	5.98	5.98	6.17
LNG ex-ship	5.33	5.33	5.68
LNG loaded	4.23	4.23	4.77
Gas ex-pipeline a/	2.85	2.31	3.59

a/ Gas at the entry point of the liquefaction plant.

The third scenario illustrates the economics of a small-scale multi-destination LNG system where LNG is carried over a short distance of about 1000 nautical miles to several small markets. The major difference from the other basic cases is that regasification costs are higher. For the regasification phase, even after substituting gas-fired vaporization, which is more appropriate to smaller systems, the cost is close to three times the vaporization costs in Case I. In the transportation phase, the short hauls in Case X bring down the fuel cost dramatically. Since the cost per day in harbor is far below the operating cost at sea, the overall effect is a transportation cost about one-third that of Case I. The unit netback ex-pipeline in this case is $2.77/MCF compared to $3.09/MCF in Case I. In Case XI, sensitivity to a limited level of infrastructure is tested;, the netback value ex-pipeline falls to $2.23 per MCF.

Table 7c

Unit Netback Values for Scenario C
($/MCF)

Value Reference Point	X	XI
Regasified	5.98	5.98
LNG ex-ship	4.51	4.51
LNG loaded	4.14	4.14
Gas ex-pipeline a/	2.77	2.23

a/ Gas at the entry point of the liquefaction plant.

In all the cases presented in Tables 7a, 7b, and 7c, the netbacks are positive. With current soft world oil prices LNG prices are also under pressure. The lower price assumptions in all cases except case VI, however, provides a conservative view of prices over the long run. With LNG prices at 80% of crude oil prices, netbacks are likely to vary between \$2.23 and \$3.40 per MCF. 1/ If crude oil prices rise the Case VI price assumption will be applicable and netbacks will increase.

C. Net Present Value of Projects

The net present value of the project used in the derivation of the netbacks in Tables 7a, 7b and 7c excludes the cost of gas production and transmission. The netback ex-well can be estimated by including the cost of gas. Hence, the net present values of projects were estimated to examine their sensitivity to gas costs.

Table 8

Project Net Present Values with Different Gas Cost Assumptions
(in millions of US\$)

Case	I	II	III	IV	V	VI	VII	VIII	IX	X	XI
Gas Costs a/											
\$0.00/MCF	2,908	2,434	6,581	4,032	2,087	4,204	1,760	1,427	3,941	1,708	1,374
\$0.50/MCF	2,438	1,934	5,723	3,439	1,707	3,733	1,452	1,119	3,393	1,399	1,066
\$1.00/MCF	1,967	1,493	4,865	2,847	1,328	3,263	1,144	810	2,845	1,091	758

a/ Cost of gas delivered to the liquefaction plant.

As indicated in Table 8, the net present values of LNG projects and, consequently, netbacks are very sensitive to the cost of gas delivered at the liquefaction plant. The netbacks estimated at the liquefaction entry point have to cover the cost of finding, producing and transporting natural gas to the plant. The net present value of projects ex-pipeline is therefore higher than the net present value ex-well. Once the gas production and transmission costs are included the net present values fall significantly as demonstrated in Table 8.

Opportunities for LNG exports are expected to be limited in the 1980s. Therefore, the LNG export market should be very competitive and only a few developing countries are expected to benefit from the LNG option. Projects based on relatively low cost natural gas supplies and

1/The cases considered in this study are assumed to begin in 1982 with a construction period of 5 years, followed by 20 years of operating life.

higher net present values and netbacks will provide higher returns to the exporting country and companies. However, as already mentioned, the decision on each potential project will depend on a variety of project-specific economic, financial, technical, political, and legal factors.

APPENDIX I

L N G E C O N O M I E S
Case I

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Present value of payments (10^6 US$)	5,183																								
Unit netback ex vaporization (US$/MMBtu)	6.06																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	5,183																								
Operating cost excl. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)	0	0	94	281	94	0	0	0																	
Present value of net cash flow (10^6 US$)	4,750																								
Volume of LNG receipts (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex ship (US$/MMBtu)	5.55																								
THE LNG CARRIERS :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	4,750																								
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)	0	0	75	225	225	225	0	0																	
Present value of net cash flow (10^6 US$)	3,776																								
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)	4.41																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	3,776																								
Operating cost excl. gas (10^6 US$)						13	23	36	38	38	80	38	38	38	38	80	38	38	38	38	80	38	38	38	38
Capital outlay (10^6 US$)	0	59	219	312	203	51	0	0																	
Present value of net cash flow (10^6 US$)	2,908																								
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)	3.09																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Project total operating cost (10^6 US$)						55	85	127	134	135	178	137	138	140	141	184	143	144	146	147	190	150	151	153	154
Project total capital outlays (10^6 US$)	0	59	388	818	521	276	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	-59	-388	-818	-521	-38	431	713	777	796	773	835	856	877	898	877	942	964	988	1,012	994	1,062	1,089	1,116	1,144
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
c) 1.00 (US$)	0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Net present value of project @ a) (10^6 US$)	2,908																								
Net present value of project @ b) (10^6 US$)	2,438																								
Net present value of project @ c) (10^6 US$)	1,967																								

LNG ECONOMIES
Case II

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)	5,183					292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Unit netback ex vaporization (US$/MMBtu)	6.06																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	5,183																								
Operating cost excl. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)	0	0	94	281	94	0	0	0																	
Present value of net cash flow (10^6 US$)	4,750																								
Volume of LNG receipts (bcf`						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex ship (US$/MMBtu)	5.55																								
THE LNG CARRIERS :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	4,750																								
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)	0	0	75	225	225	225	0	0																	
Present value of net cash flow (10^6 US$)	3,776																								
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)	4.41																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	3,776																								
Operating cost excl. gas (10^6 US$)						21	35	56	59	59	124	59	59	59	59	124	59	59	59	59	124	59	59	59	59
Capital outlay (10^6 US$)	0	91	339	483	313	78	0	0																	
Present value of net cash flow (10^6 US$)	2,434																								
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)	2.59																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Project total operating gost (10^6 US$)						62	97	147	155	156	222	158	159	160	161	228	164	165	166	168	234	170	172	173	175
Project total capital outlays (10^6 US$)	0	91	508	989	632	303	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	-91	-508	-989	-632	-73	418	693	756	775	729	814	835	856	877	833	921	943	967	991	951	1,042	1,068	1,095	1,124
Feedstock cost a) 0 00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b 0.50 (US$)	0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
c) 1.00 (US$)	0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Net present value of project @ a) (10^6 US$)	2,434																								
Net present value of project @ b) (10^6 US$)	1,934																								
Net present value of project @ c) (10^6 US$)	1,493																								

L N G E C O N O M I E S
Case III

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Present value of payments (10^6 US$)		9,738																							
Unit netback ex vaporization (US$/MMBtu)		6.24																							
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		9,738																							
Operating cost excl. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)		0	0	94	281	94	0	0	0																
Present value of net cash flow (10^6 US$)		9,190																							
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)		5.89																							
THE LNG CARRIERS:																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		9,190																							
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)		0	0	75	225	225	225	0	0																
Present value of net cash flow (10^6 US$)		7,733																							
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)		4.95																							
THE LIQUEFACTION PLANT:																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		7,733																							
Operating cost exc. gas (10^6 US$)						13	23	36	38	38	80	38	38	38	38	80	38	38	38	38	80	38	38	38	38
Capital outlay (10^6 US$)		0	59	219	312	203	51	0	0																
Present value of net cash flow (10^6 US$)		6,581																							
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)		3.83																							
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Project total operating cost (10^6 US$)						55	85	127	134	135	178	137	138	140	141	184	143	144	146	147	190	150	151	153	154
Project total capital outlays (10^6 US$)		0	59	388	818	521	276	0	0																
Project cash flow ex pipeline (10^6 US$)		0	-59	-388	-818	-521	-38	431	713	777	796	773	835	856	877	898	877	942	964	988	1,012	994	1,062	1,089	1,1161,144
Feedstock cost a) 0.00 (US$)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	00
b) 0.50 (US$)		0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	9191
c) 1.00 (US$)		0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183183
Net present value of project @ a) (10^6 US$)		6,581																							
Net present value of project @ b) (10^6 US$)		5,723																							
Net present value of project @ c) (10^6 US$)		4,865																							

L N G   E C O N O M I E S
Case IV

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Present value of payments (10^6 US$)		6,598																							
Unit netback ex vaporization (US$/MMBtu)		6.12																							
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		6,598																							
Operating cost exckl,. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)		0	0	94	281	94	0	0	0																
Present value of net cash flow (10^6 US$)		6,125																							
Volume of LNG receipts (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex ship (US$/MMBtu)		5.69																							
THE LNG CARRIERS :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		6,125																							
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)		0	0	75	225	225	225	0	0																
Present value of net cash flow (10^6 US$)		4,995																							
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)		4.64																							
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)		4,995																							
Operating cost excl. gas (10^6 US$)						13	23	36	38	38	80	38	38	38	38	80	38	38	38	38	80	38	38	38	38
Capital outlay (10^6 US$)		0	59	219	312	203	51																		
		0	0																						
Present value of net cash flow (10^6 US$)		4,032																							
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)		3.40																							
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Project total operating cost (10^6 US$)						55	85	127	134	135	178	137	138	140	141	184	143	144	146	147	190	150	151	153	154
Project total capital outlays (10^6 US$)	0	59	388	818	521	276	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	-59	-388	-818	-521	-38	431	713	777	796	773	835	856	877	898	877	942	964	988	1,012	994	1,062	1,089	1,116	1,144
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
c) 1.00 (US$)	0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Net present value of project @ a) (10^6 US$)	4,032																								
Net present value of project @ b) (10^6 US$)	3,439																								
Net present value of project @ c) (10^6 US$)	2,847																								

LNG ECONOMIES
Case V

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Present value of payments (10^6 US$)	4,127																								
Unit netback ex vaporization (US$/MMBtu)	5.99																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	4,127																								
Operating cost excl. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)	0	0	94	281	94	0	0	0																	
Present value of net cash flow (10^6 US$)	3,726																								
Volume of LNG receipts (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex ship (USE/MMBtu)	5.41																								
THE LNG CARRIERS :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	3,726																								
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)	0	0	75	225	225	225	0	0																	
Present value of net cash flow (10^6 US$)	2,877																								
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)	4.18																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	2,877																								
Operating cost excl. gas (10^6 US$)						13	23	36	38	38	80	38	38	38	38	80	38	38	38	38	80	38	38	38	38
Capital outlay (10^6 US$)	0	59	219	312	203	51	0	0																	
Present value of net cash flow (10^6 US$)	2,087																								
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)	2.75																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						292	515	840	911	931	951	973	994	1,017	1,039	1,061	1,085	1,108	1,133	1,159	1,185	1,212	1,240	1,268	1,298
Project total operating cost (10^6 US$)						55	85	127	134	135	178	137	138	140	141	184	143	144	146	147	190	150	151	153	154
Project total capital outlays (10^6 US$)	0	59	388	818	521	276	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	-59	-388	-818	-521	-38	431	713	777	796	773	835	856	877	898	877	942	964	988	1,012	994	1,062	1,089	1,116	1,144
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
c) 1.00 (US$)	0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Net present value of project @ a) (10^6 US$)	2,087																								
Net present value of project @ b) (10^6 US$)	1,707																								
Net present value of project @ c) (10^6 US$)	1,328																								

L N G   E C O N O M I E S
Case VI

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MBtu)						6.29	6.47	6.66	6.86	7.01	7.17	7.33	7.49	7.66	7.82	7.99	8.17	8.35	8.54	8.73	8.93	9.13	9.34	9.56	9.78
Delivered to distribution grid (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Payment by pipeline (10^6 US$)						365	644	1,050	1,139	1,163	1,189	1,216	1,243	1,271	1,298	1,326	1,356	1,386	1,417	1,448	1,481	1,515	1,550	1,586	1,623
Present value of payments (10^6 US$)	6,480																								
Unit netback ex vaporization (US$/MMBtu)	7.57																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	6,480																								
Operating cost excl. gas (10^6 US$)						14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Capital outlay (10^6 US$)	0	0	94	281	94	0	0	0																	
Present value of net cash flow (10^6 US$)	6,046																								
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)	7.06																								
THE LNG CARRIERS:																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	6,046																								
Operating cost excl. gas (10^6 US$)						27	48	77	82	83	84	85	86	88	89	90	91	92	94	95	96	98	99	101	102
Capital outlay (10^6 US$)	0	0	75	225	225	225	0	0																	
Present value of net cash flow (10^6 US$)	5,072																								
Volume of LNG loaded (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Unit netback ex liquefaction (US$/MMBtu)	5.93																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						58	100	158	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Present value of revenues (10^6 US$)	5,072																								
Operating cost excl. gas (10^6 US$)						13	23	36	38	38	80	38	38	38	38	80	38	38	38	38	80	38	38	38	38
Capital outlay (10^6 US$)	0	59	219	312	203	51	0	0																	
Present value of net cash fkow (10^6 US$)	4,204																								
Volume of gas input (bcf)						64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Unit netback ex pipeline (US$/MMBtu)	4.46																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						365	644	1,050	1,139	1,163	1,189	1,216	1,243	1,271	1,298	1,326	1,356	1,386	1,417	1,448	1,481	1,515	1,550	1,586	1,623
Project total operating cost (10^6 US$)						55	85	127	134	135	178	137	138	140	141	184	143	144	146	147	190	150	151	153	154
Project total capital outlays (10^6 US$)	0	59	388	818	521	276	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	-59	-388	-818	-521	35	560	923	1,004	1,028	1,011	1,078	1,104	1,131	1,157	1,142	1,213	1,241	1,271	1,301	1,291	1,365	1,398	1,433	1,469
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	32	55	87	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
c) 1.00 (US$)	0	0	0	0	0	64	110	173	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Net present value of project @ a) (10^6 US$)	4,204																								
Net present value of project @ b) (10^6 US$)	3,733																								
Net present value of project @ c) (10^6 US$)	3,263																								

L N G   E C O N O M I E S

Case VII

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Payment by pipeline (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Present value of net cash flow (10^6 US$)	3,300																								
Unit netback ex vaporization (US$/MMBtu)	5.98																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Present value of revenues (10^6 US$)	3,300																								
Operating cost excl. gas (10^6 US$)						10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Capital outlay (10^6 US$)	0	0	68	203	68	0	0	0																	
Present value of net cash flow (10^6 US$)	2,987																								
Volume of LNG receipts (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex ship (US$/MMBtu)	5.33																								
THE LNG CARRIERS :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,987																								
Operating cost excl. gas (10^6 US$)						35	45	48	49	50	51	51	52	53	53	54	55	55	56	57	58	59	59	60	61
Capital outlay (10^6 US$)	0	0	0	225	225	0	0	0																	
Present value of net cash flow (10^6 US$)	2,372																								
Volume of LNG loaded (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex liquefaction (US$/MMBtu)	4.23																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,372																								
Operating cost excl. gas (10^6 US$)						20	25	27	27	27	56	27	27	27	27	56	27	27	27	27	56	27	27	27	27
Capital outlay (10^6 US$)	0	0	118	295	177	0	0	0																	
Present value of net cash flow (10^6 US$)	1,760																								
Volume of LNG loaded (bcf)						82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Unit netback ex liquefaction (US$/MMBtu)	2.85																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Project total operating cost (10^6 US$)						65	81	85	86	87	117	88	89	89	90	120	91	92	93	94	124	95	96	97	98
Project total capital outlays (10^6 US$)	0	0	186	723	470	0	0	0																	
Project total cash flow ex pipeline (10^6 US$)	0	0	-186	-723	-470	305	402	438	452	464	446	487	499	512	524	507	550	563	577	591	577	621	637	653	670
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	41	52	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
c) 1.00 (US$)	0	0	0	0	0	82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Net present value of project @ a) (10^6 US$)	1,760																								
Net present value of project @ b) (10^6 US$)	1,452																								
Net present value of project @ c) (10^6 US$)	1,144																								

LNG ECONOMIES
Case VIII

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Payment by pipeline (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Present value of payments (10^6 US$)	3,300																								
Unit netback ex vaporization (US$/MMBtu)	5.98																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Present value of revenues (10^6 US$)	3,300																								
Operating cost excl. gas (10^6 US$)						10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Capital outlay (10^6 US$)	0	0	68	203	68	0	0	0																	
Present value of net cash flow (10^6 US$)	2,987																								
Volume of LNG receipts (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex ship (US$/MMBtu)	5.33																								
THE LNG CARRIERS :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,987																								
Operating cost excl. gas (10^6 US$)						35	45	48	49	50	51	51	52	53	53	54	55	55	56	57	58	59	59	60	60
Capital outlay (10^6 US$)	0	0	0	225	225	0	0	0																	
Present value of net cash flow (10^6 US$)	2,372																								
Volume of gas input (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex liquefaction (US$/MMBtu)	4.23																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,372																								
Operating cost excl. gas (10^6 US$)						31	39	41	41	41	87	41	41	41	41	87	41	41	41	41	87	41	41	41	41
Capital outlay (10^6 US$)	0	0	182	455	273	0	0	0																	
Present value of net cash flow (10^6 US$)	1,427																								
Volume of gas input (bcf)						82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Unit netback ex pipeline (US$/MMBtu)	2.31																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Project total operating cost (10^6 US$)						76	94	100	100	101	147	102	103	104	104	151	106	107	107	108	154	110	111	111	112
Project total capital outlays (10^6 US$)	0	0	250	884	566	0	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	0	-250	-884	-566	294	388	423	438	449	415	473	485	497	510	477	535	549	563	577	546	607	622	638	655
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	41	52	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
c) 1.00 (US$)	0	0	0	0	0	82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Net present value of project @ a) (10^6 US$)	1,427																								
Net present value of project @ b) (10^6 US$)	1,119																								
Net present value of project @ c) (10^6 US$)	810																								

L N G   E C O N O M I E S
Case IX

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Payment by pipeline (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Present value of payments (10^6 US$)	6,063																								
Unit netback ex vaporization (US$/MMBtu)	6.17																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Present value of revenues (10^6 US$)	6,063																								
Operating cost excl. gas (10^6 US$)						10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Capital outlay (10^6 US$)	0	0	68	203	68	0	0	0																	
Present value of net cash flow (10^6 US$)	5,666																								
Volume of LNG receipts (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex ship (US$/MMBtu)	5.68																								
THE LNG CARRIERS :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	5,666																								
Operating cost excl. gas (10^6 US$)						35	45	48	49	50	51	51	52	53	53	54	55	55	56	57	58	59	59	60	61
Capital outlay (10^6 US$)	0	0	0	225	225	0	0	0																	
Present value of net cash flow (10^6 US$)	4,758																								
Volume of LNG loaded (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex liquefaction (US$/MMBtu)	4.77																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	4,758																								
Operating cost excl. gas (10^6 US$)						20	25	27	27	27	56	27	27	27	27	56	27	27	27	27	56	27	27	27	27
Capital outlay (10^6 US$)	0	0	118	295	177	0	0	0																	
Present value of net cash flow (10^6 US$)	3,941																								
Volume of gas input (bcf)						82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Unit netback ex pipeline (US$/MMBtu)	3.59																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Project total operating cost (10^6 US$)						65	81	85	86	87	117	88	89	89	90	120	91	92	93	94	124	95	96	97	98
Project total capital outlays (10^6 US$)	0	0	186	723	470	0	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	0	-186	-723	-470	305	402	438	452	464	446	487	499	512	524	507	550	563	577	591	577	621	637	653	670
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	41	52	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
c) 1.00 (US$)	0	0	0	0	0	82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Net present value of project @ a) (10^6 US$)	3,941																								
Net present value of project @ b) (10^6 US$)	3,393																								
Net present value of project @ c) (10^6 US$)	2,845																								

L N G   E C O N O M I E S
Case X

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (BCF)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Payment by pipeline (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Present value of payments (10^6 US$)	3,300																								
Unit netback ex vaporization (US$/MMBtu)	5.98																								
THE RE-GASIFICATION FACILITY :																									
Deliveries (bcf)						74	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Present value of revenues (10^6 US$)	3,300																								
Operating cost excl. gas (10^6 US$)						25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Capital outlay (10^6 US$)	0	0	167	500	167	0	0	0																	
Present value of net cash flow (10^6 US$)	2,528																								
Volume of LNG receipts (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex ship (US$/MMBtu)	4.51																								
THE LNG CARRIERS :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,528																								
Operating cost excl. gas (10^6 US$)						13	16	'7	17	17	18	18	18	18	18	18	19	19	19	19	19	19	20	20	20
Capital outlay (10^6 US$)	0	0	0	75	75	0	0	0																	
Present value of net cash flow (10^6 US$)	2,320																								
Volume of LNG loaded (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unit netback ex liquefaction (US$/MMBtu)	4.14																								
THE LIQUEFACTION PLANT :																									
Deliveries (bcf)						75	95	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Present value of revenues (10^6 US$)	2,320																								
Operating cost excl. gas (10^6 US$)						20	25	27	27	27	56	27	27	27	27	56	27	27	27	27	56	27	27	27	27
Capital outlay (10^6 US$)	0	0	118	295	177	0	0	0																	
Present value of net cash flow (10^6 US$)	1,708																								
Volume of gas input (bcf)						82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Unit netback ex pipeline (US$/MMBtu)	2.77																								
FIGURES FOR THE ENTIRE PROJECT :																									
Project value of revenues at regasification terminal (10^6 US$)						370	482	523	538	550	562	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Project total operating cost (10^6 US$)						57	66	69	69	69	99	69	69	70	70	99	70	70	70	71	100	71	71	71	72
Project total capital outlays (10^6 US$	0	0	285	870	418	0	0	0																	
Project cash flow ex pipeline (10^6 US$)	0	0	-285	-870	-418	312	416	454	470	481	464	506	518	531	544	528	571	585	599	614	600	646	662	678	696
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	41	52	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
c) 1.00 (US$)	0	0	0	0	0	82	104	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Net present value of project @ a) (10^6 US$)	1,708																								
Net present value of project @ b) (10^6 US$)	1,399																								
Net present value of project @ c) (10^6 US$)	1,091																								

L N G   E C O N O M I E S
Case XI

YEAR	-5	-4	-3	-2	-1	0	1	2	3	4	5
Delivered price (US$/MMBtu)						5.03	5.18	5.33	5.49	5.61	5.73
Delivered to distribution grid (bcf)						74	93	98	98	98	98
Payment by pipeline (10^6 US$)						370	482	523	538	550	562
Present value of payments (10^6 US$)	3,300										
Unit netback ex vaporization (US$/MMBtu)	5.98										
THE RE-GASIFICATION FACILITY :											
Deliveries (bcf)					74	93	98	98	98	98	98
Present value of revenues (10^6 US$)	3,300										
Operating cost excl. gas (10^6 US$)					25	25	25	25	25	25	25
Capital outlay (10^6 US$)	0	0	167	500	167	0	0	0			
Present value of net cash flow (10^6 US$)	2,528										
Volume of LNG receipts (bcf)						75	95	100	100	100	100
Unit netback ex ship (US$/MMBtu)	4.51										
THE LNG CARRIERS :											
Deliveries (bcf)						75	95	100	100	100	100
Present value of revenues (10^6 US$)	2,528										
Operating cost excl. gas (10^6 US$)						13	16	17	17	17	18
Capital outlay (10^6 US$)	0	0	0	75	75	0	0	0			
Present value of net cash flow (10^6 US$)	2,320										
Volume of LNG loaded (bcf)						75	95	100	100	100	100
Unit netback ex liquefaction (US$/MMBtu)	4.14										
THE LIQUEFACTION PLANT :											
Deliveries (bcf)						75	95	100	100	100	100
Present value of revenues (10^6 US$)	2,320										
Operating cost excl. gas (10^6 US$)						31	39	41	41	41	87
Capital outlay (10^6 US$)	0	0	182	455	273	0	0	0			
Present value of net cash flow (10^6 US$)	1,374										
Volume of Gas input (bcf)						82	104	110	110	110	110
Unit netback ex pipeline (US$/MMBtu)	2.23										
FIGURS FOR THE ENTIRE PROJECT:											
Project value of revenues at regasification terminal (10^6 US$)						370	482	523	538	550	562
Project total operating cost (10^6 US$)						68	80	83	83	83	129
Project total capital outlays (10^6 US$)	0	0	349	1,030	515	0	0	0			
Project cash flow ex pipeline (10^6 US$)	0	0	-349	-1,030	-515	302	402	440	455	467	433
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	0	0	0	0	0	41	52	55	55	55	55
c) 1.00 (US$)	0	0	0	0	0	82	104	110	110	110	110
Net present value of project @ a) (10^6 US$)	1,374										
Net present value of project @ b) (10^6 US$)	1,066										
Net present value of project @ c) (10^6 US$)	758										

YEAR	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Delivered price (US$/MMBtu)	5.86	5.99	6.13	6.26	6.40	6.54	6.68	6.83	6.98	7.14	7.31	7.47	7.65	7.83
Delivered to distribution grid (bcf)	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Payment by pipeline (10^6 US$)	575	588	601	614	627	641	655	670	685	700	716	733	750	768
THE RE-GASIFICATION FACILITY :														
Deliveries (bcf)	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Operating cost excl. gas (10^6 US$)	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Volume of LNG receipts (bcf)	100	100	100	100	100	100	100	100	100	100	100	100	100	100
THE LNG CARRIERS :														
Deliveries (bcf)	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Operating cost excl. gas (10^6 US$)	18	18	18	18	18	19	19	19	19	19	19	20	20	20
Volume of LNG loaded (bcf)	100	100	100	100	100	100	100	100	100	100	100	100	100	100
THE LIQUEFACTION PLANT :														
Deliveries (bcf)	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Operating cost excl. gas (10^6 US$)	41	41	41	41	87	41	41	41	41	87	41	41	41	41
Volume of Gas input (bcf)	110	110	110	110	110	110	110	110	110	110	110	110	110	110
FIGURS FOR THE ENTIRE PROJECT:														
Project value of revenues at regasification terminal (10^6 US$)	575	588	601	614	627	641	655	670	685	700	716	733	750	768
Project total operating cost (10^6 US$)	84	84	84	84	130	85	85	85	85	131	85	86	86	86
Project cash flow ex pipeline (10^6 US$)	491	504	517	530	497	557	571	585	600	570	631	647	664	682
Feedstock cost a) 0.00 (US$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) 0.50 (US$)	55	55	55	55	55	55	55	55	55	55	55	55	55	55
c) 1.00 (US$)	110	110	110	110	110	110	110	110	110	110	110	110	110	110

ENERGY DEPARTMENT PAPER SERIES

EGY PAPER No. 1 — Energy Pricing in Developing Countries: A Review of the Literature by DeAnne Julius (World Bank) and Meta Systems (Consultants). September 1981. 121 pages, includes classified bibliography.

Reviews literature on the theory of exhaustible resources and on sectoral, national and international models for energy demand. Emphasis on project selection criteria and on pricing policy as a tool of energy demand management.

EGY PAPER No. 2 — Proceedings of the South-East Asian Workshop on Energy Policy and Management edited by Michael Radnor and Atul Wad (Northwestern University). September 1981. 252 pages.

Contains the edited version of the lectures and discussions presented at the South-East Asian Workshop on Energy Policy and Management held in Daedeok, South Korea, October 27-November 1, 1980.

Topics that are addressed include: the overall problem of energy policy and its relationship to economic development; the management of energy demand and related data; the role and value of models in energy planning, and the use of energy balances. Transport and rural sectors are also discussed in terms of their relationship to energy planning.

EGY PAPER No. 3 — Energy Pricing in Developing Countries: Lessons from the Egypt Study by DeAnne Julius (World Bank). December 1981. 14 pages.

Study on the effects of energy price change in a developing country. Provides insight into the mechanisms through which energy prices affect other prices in the economy and, therefore, the incomes of rich and poor consumers, profitability of key industries, the balance of payments, and the government budget.

EGY PAPER No. 4 — Alternative Fuels for Use in Internal Combustion Engines by G.D.C., Inc. (Consultant). November 1981. 179 pages, includes appendices.

Presents several alternative fuels used as replacement for conventional (gasoline and diesel) fuels in internal combustion engines. These alternatives, including LPG, natural gas, alcohol and producer gas, are derivable from natural resources that exist in so many developing countries. Also provides up-to-date information on the newest alternative fuel option currently available and those that are being developed and tested.

EGY PAPER No. 5 Bangladesh: Rural and Renewable Energy Issues and Prospects by Fernando R. Manibog (World Bank). April 1982. 64 pages, includes bibliography.

Analyzes subsector issues and recommends courses of action for energy project possibilities; identifies renewable energy projects which could create a positive impact in the short to medium term.

EGY PAPER No. 6 Energy Efficiency: Optimization of Electric Power Distribution System Losses by Mohan Munasinghe (World Bank) and Walter Scott (Consultant). July 1982. 145 pages, includes appendices.

Discusses the reasons for high existing levels of power distribution losses in developing countries. Identifies areas within a power system where loss optimization would be most effective. Shows that reducing losses is often more cost effective than building more generation capacity.

EGY PAPER No. 7 Guidelines for the Presentation of Energy Data in Bank Report October 1982 - 13 pages (incl. 4 Annexes). Masood Ahmed (World Bank).

The growing importance of energy issues in national economic management has led to increased coverage of the energy sector in many types of reports. However, there is still no clear, consistent and standardized format for presenting energy sector information. This paper reviews the problem and proposes guidelines for policymakers and operational staff who deal with energy issues. The paper is divided into three parts: part one sets out the basic framework for presenting aggregated energy data -- "the national energy balance"; part two deals with the use of appropriate units and conversion factors to construct such a balance from raw demand and supply data for the various fuels; and part three briefly discusses special problems posed by: (i) differences in end use efficiency of various fuels; (ii) the inclusion of wood and other noncommercial energy sources; and (iii) the conversion of primary electricity into its fossil fuel equivalent.

EGY PAPER No. 8 — External Financing for Energy in the Developing Countries by Althea Duersten (World Bank). June 1983. 66 pages, includes appendices.

Provides an overview of energy financing in the developing countries. Identifies energy investment requirements and past financing patterns. Discusses the historic roles of multilateral and bilateral assistance programs in helping to mobilize financing, particularly for low income oil importers and in providing economic and sector advice. Examines the role of official export credit, and discusses lending by private financial institutions which has been the predominant source of financing for energy projects in the middle and higher income developing countries.

EGY PAPER No. 9 — Guideline for Diesel Generating Plant Specification and Bid Evaluation by C.I. Power Services Inc. (Consultant). December 1982. 210 pages, includes appendices.

Explains the characteristics and comparative advantages and disadvantages of large low speed two-stroke diesel engines intended for electric generating plant service, and develops a bid evaluation procedure to permit comparing of bids for both types.

EGY PAPER No. 10 — Marginal Cost of Natural Gas in Developing Countries: Concepts and Application by Afsaneh Mashayekhi (World Bank) July 1983. 21 pages, includes appendices.

Defines the concept of marginal cost and average incremental cost. Uses the detailed supply, demand and investment data to apply this concept to estimate the average incremental cost of natural gas supply to major markets in ten developing countries. Demonstrates that the cost of natural gas delivery to the city-gate in many developing countries is far below the cost of competing fuels.

EGY PAPER NO. 11 — Power System Load Management Technologies by Resource Dynamics Corp. (Consultant), June 1983, 132 pages, includes appendices.

Techniques referred to as load management have begun to play an important role in shaping the patterns of electricity consumption in industrialized countries. Along with pricing, a variety of hardware is used to control loads directly and save on eneregy and peak capacity. This study reviews the state-of-the-art of these so called "hard" techniques, provides data on cost and manufacturers of this equipment and identifies controllable loads in developing countries.