Hawaii Energy Strategy Project 2: Fossil Energy Review

TASK III
GREENFIELD OPTIONS: PROSPECTS FOR LNG USE

Prepared for

State of Hawaii
Department of Business, Economic Development & Tourism,
Energy Division

by

The East-West Center
Program on Resources: Energy and Minerals

December 1993

Hawaii Energy Strategy Project 2, Fossil Energy Review

Task III. Greenfield Options: Liquefied Natural Gas

Authors:
Fereidun Fesharaki
David Fridley
Shiva Pezeshki
Kang Wu

Senior Editor:
Kennon Breazeale

Secretarial/Technical Support:
Sandra Dela Cruz
Suhaesih Rahmasari

December 1993

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Contents

Tables

Figures

Abbreviations, Acronyms, and Measures

AAGR	average annual growth rate in percentage terms
ADO	automotive diesel oil
AES	Applied Energy Services (Hawaii)
ANS	Alaska North Slope (crude oil)
API	degrees of API (American Petroleum Institute); API gravity.
ASEAN	Association of South East Asian Nations
bcf	billion cubic feet
b/d	barrels per day
boe	barrels of (crude) oil equivalent
Btu	British thermal unit
BTX	benzene, toluene, xylene; BTX raffinate: the material remaining after aromatics extraction
CAT REF	catalytic reformer
CDU	crude distillation unit
cf	cubic feet
cf/d	cubic feet per day
c.i.f.	cost, insurance, freight
CIS	Commonwealth of Independent States (former Soviet Union)
CNG	compressed natural gas
CPE	centrally planned economies
d	day
dwt	deadweight tons
EC	European Community
ETBE	ethyl tertiary butyl ether
FBC	fluidized bed combustors
FCC	fluid catalytic cracker
FGD	flue gas desulfurization
f.o.b.	free on board (f.o.b.t.: free on board and trimmed)
gPB/l	grams of lead (Pb) per liter
GSP	gross state product
GW	gigawatts (1,000,000 kilowatts)
HDC	hydrocracker
HGI	Hardgrove grindability index
HGO	heavy vacuum gasoil (also HVVGO)
HSFO	high-sulfur fuel oil
HVAC	heating, ventilating, and air-conditioning
HVVGO	heavy vacuum gasoil
IDO	industrial diesel oil
IEA	International Energy Agency (Paris)

IGCC	integrated gasification combined cycle
kg	kilogram (2.205 pounds)
km	kilometer (0.62 miles)
kW	kilowatt (1,000 watts)
kWh	kilowatt-hours
l	liter (1.057 U.S. quarts)
lb	pound
LCO	light cycle oil
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRG	liquefied refinery gas
LSFO	low-sulfur fuel oil
LSWR	low-sulfur waxy resid
LTVGO	light vacuum gasoil
m	thousand
mb	thousand barrels
mb/d	thousand barrels per day
MDO	marine diesel oil
MITI	Ministry of International Trade and Industry (Japan)
mm	million
mmb	million barrels
mmb/d	million barrels per day
mmcf/d	million cubic feet per day
mmt	million tons
mmtoe	million tons of oil equivalent
MON	motor octane number
MTBE	methyl tertiary butyl ether
MW	megawatts (= 1,000 kW)
NGL	natural gas liquids
OECD	Organisation for Economic Cooperation and Development
OPA 90	Oil Pollution Act of 1990 (U.S.)
OPEC	Organization of Petroleum Exporting Countries
OTEC	ocean thermal energy conversion
PADD-V	Petroleum Administration for Defense District V (Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington)
PCF	pulverized coal fired (power plant)
PCI	pulverized coal injection
PNG	Papua New Guinea
RCC	resid catalytic cracker
RDS	resid desulfurizer
resid	residual oil; also called heavy oil, bunker fuel, bottoms, etc.
RON	research octane number
RP ratio	reserves-to-production ratio
RVP	Reid vapor pressure

RVPBI	Reid vapor pressure blending index
t	ton (U.S. short ton)
tcf	trillion cubic feet
TEL	tetraethyl lead
TFI	transport fuels index (East-West Center)
toe	tons of oil equivalent
UAE	United Arab Emirates
VB	vacuum bottoms
VDU	vacuum distillation unit
VGO	vacuum gas oil
VR	vacuum resid
y	year

II. Liquefied Natural Gas

A. Prospects for LNG Use in Hawaii

1. Overview

An assessment of liquefied natural gas (LNG) use in Hawaii differs in many respects from one concerning other fossil fuels such as oil and coal. The production, transportation, and consumption of LNG form a relatively rigid chain that allows very little flexibility. At the production end, a liquefaction plant and port handling facilities have to be built. Marine transportation is provided by ships that are designed solely to carry LNG. At the consumption end, port handling facilities, a regasification plant, and a pipeline delivery system have to be built.

The construction costs of these facilities are extremely high, and all the components of the chain have to be built in such a way that the entire chain begins to function simultaneously. Once the gas is liquefied, it has to be maintained at extremely low temperatures. (Some gas inevitably boils off the LNG in transit, but it is recaptured and used as fuel for the specially designed ship.) Timely delivery is therefore a critical factor. Technically, LNG could be maintained in its liquid form for long periods, but the cost would be prohibitive. For practical purposes, LNG, unlike other fuels, cannot be left in storage.

Clearly, LNG offers little flexibility in terms of supply diversification, delivery schedules, price-sensitive short-term substitution, or storage. Unlike the other fossil fuels, moreover, LNG can only be used when a long-term, guaranteed market for a relatively large, fixed volume is arranged *in advance*. Without such a guarantee by customers willing and able to use the fuel over the life of a supply contract (usually 15 to 20 years), LNG projects are economically not viable.

In the Hawaiian market, the only viable candidate for LNG use is the island of Oahu. Unlike coal or oil, it is impractical to bring large cargos of LNG to Oahu and

transship partial cargos to the neighbor islands. The potential markets on the neighbor islands are too small to justify the capital expenditures needed to construct the specialized carriers, additional LNG regasification plants, and delivery infrastructure that would be required.

Given the integrated nature of LNG supply and consumption as outlined above, this section will begin with an overview of the Asia-Pacific LNG market, its major players, and the likely availability of LNG supplies in the region. The discussion will then examine the possibilities for the economic supply of LNG to Hawaii, the potential Hawaiian market, and the viability of an LNG project on Oahu.

2. The Asia-Pacific LNG Market

The Asia-Pacific region is the core of a trade boom in LNG. The boom has been fueled by growing environmental concerns that have encouraged fuel switching away from oil, coal and nuclear energy. World LNG trade could double or triple over the next 20 years. World LNG demand has grown at an average rate of 20 percent since 1970, and is projected to reach 130-150 million tons in 2010. (All data are recorded in metric tons.) In addition, many of the new producers of natural gas are located far from the markets of the Far East, which means that pipeline projects are either technically or economically not viable at the present time. Also, the concern for diversification of supply sources, and the fact that many of the current producing countries are reaching the limits of their export capacities, will ultimately lead the importing countries to the more distant producers of natural gas, where trade is possible only in the form of LNG. Political instability in many regions of the world, which has affected pipeline gas deliveries, has also made LNG more attractive and reliable. The introduction of the new combined-cycle gas turbines—which have thermal efficiencies equal to (if not higher than) boilers—also adds to the clean-fuel characteristic of natural gas, making it a more competitive fuel.

In the Asia-Pacific region, the strongest economies—Japan, Taiwan, and South Korea—are expected to have the highest growth rates in LNG demand. The soaring

demand will, however, surpass all current expansion projects and will create a shortfall in supplies by the year 2000. In order to meet this ever-increasing demand, grassroots projects will be necessary. At this point, it is essential to underline that the projected *demand* for LNG is *potential*; that is, the demand will materialize only if the supply is established. Demand is more volatile for natural gas than for oil, given the fact that gas can much more easily be replaced by other types of fuel. Current prices of natural gas and the extensive capital needed to finance LNG projects have discouraged many investors and thus led to the abandonment of numerous ventures. LNG grassroots projects are extremely costly and without the prospect of substantial price increases, developers are reluctant to push these projects forward. On the other hand, new environmental regulations and taxes in the consuming countries will indirectly subsidize the use of natural gas, by increasing the price of other (so-called "dirty") fossil fuels and thereby favoring LNG in world energy trade.

2.1. Demand for LNG in the Pacific Rim

As noted, the Asia-Pacific region will experience major growth in the demand for LNG in the twenty-first century. The import growth will take place mainly in Japan, Taiwan, and South Korea. Some new players, however, may soon emerge in this region.

Japan. In 1992 Japan accounted for almost 65 percent of all LNG imports in the world. Japanese demand is projected to reach about 70 million tons/year (mmt/y) by 2010. This growth is mainly fueled by increasing demand for electric power. At the same time, the addition of up to 15,000 megawatts (MW) of nuclear power capacity has been postponed or indefinitely delayed. A substantial increase has also been recorded in town gas use. In addition, the government fuel diversification policy has encouraged switching to natural gas and away from oil and coal. Japanese utility companies are the biggest buyers of LNG in the country. So far, Indonesia has been the major supplier (up to 22.9 mmt/y) of the Japanese market. This pattern is likely to change in the coming decades, because of Indonesia's decreasing supply availability and the emergence of major players in the Middle East, with Qatar as the most imminent.

South Korea. Recent environmental pressures have led to an ever-increasing interest in LNG in South Korea. Nearly 75 percent of LNG imports are used for power generation. Indonesia used to be the only supplier (about 2.7 mmt/y), but in 1992 LNG shipments from Malaysia began at Korea's Pyeong Taek import terminal. The demand for LNG is projected to reach 10 mmt/y by 2000, and Korea Gas Corporation has already signed a letter of intent to buy 2.4 mmt/y of LNG from Qatar's Ras Lafflan. The incremental supply is to come from other grassroots projects in the Middle East and Far East.

Taiwan. Taiwan is the third major growth center for LNG demand in Asia. Demand is projected to triple over the next 15 years. The share of LNG in Taiwan's power generation sector will increase from 4.1 percent in 1992 to nearly 23 percent by the turn of the century. During the same period, nuclear's share of the power market is expected to drop from 30 percent to 19 percent. The Chinese Petroleum Corporation (CPC), the state enterprise responsible for Taiwan's LNG imports, has expressed its intentions to further diversify the import sources of natural gas to the country. CPC's major concern is that Indonesia might not be able to keep up with Taiwan's growing demand, and it has therefore made efforts to conclude a memorandum of understanding with Malaysia's Petronas. CPC is expected to start imports of about 2.2 mmt/y of LNG from Malaysia in 1995. CPC has also signed a letter of intent for purchase of 2 mmt/y of LNG from Qatar's Ras Lafflan plant starting in 1998, although it seems likely that the project will be delayed until around the turn of the century. No price has yet been negotiated.

Potential new buyers. China and India may emerge as new buyers of LNG early in the next century (see Figure 1). Although both countries have their own gas resources, considerations of sheer territorial size and geography may lead to LNG imports in certain industrial cities. There have also been indications that Thailand and Hong Kong may become LNG importers. Hong Kong will soon begin importing gas through a pipeline from China's Hainan Island (Yacheng 13-1 field), and Thailand is discussing gas imports from Indochina and Malaysia via pipeline. For Thailand and Hong Kong, pipeline gas import is likely to be a priority, whereas LNG will be a second option.

Figure 1. Asia-Pacific Projected LNG Demand, 1992-2010

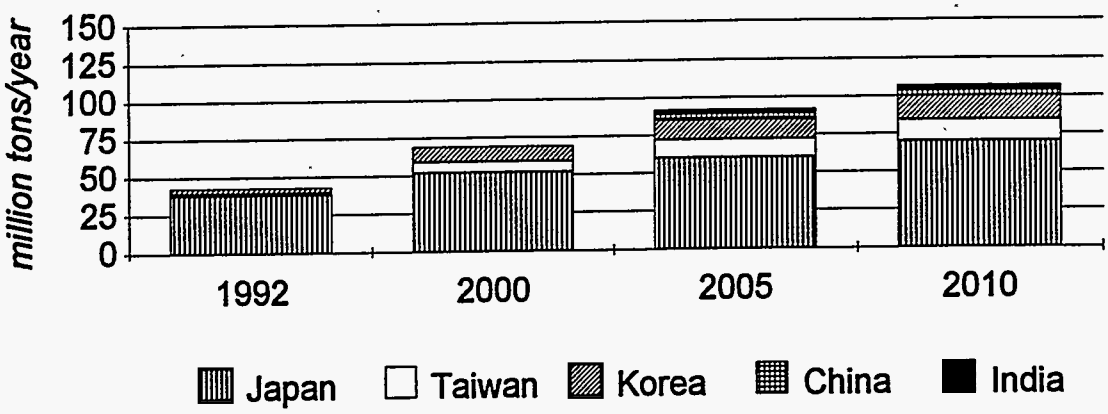
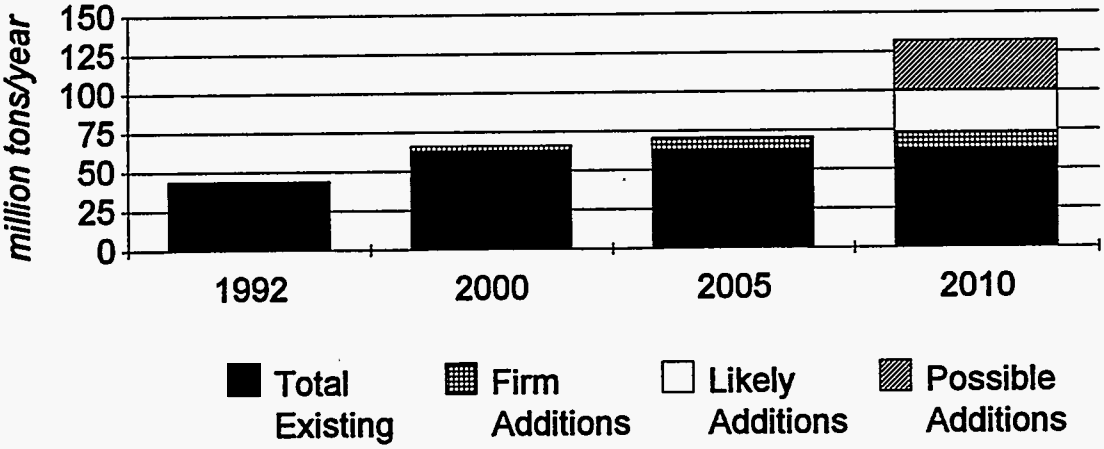


Figure 2. Asia-Pacific Projected LNG Supply, 1992-2010



2.2. Asia-Pacific LNG Suppliers

In 1992 the Pacific rim accounted for 73.4 percent of total world LNG trade, for almost 60 percent of the LNG transported, and for three-quarters of the LNG delivered in the world. Indonesia was the largest exporter. Algeria was in second position (24 percent of world exports), followed by Malaysia (12 percent), Brunei (9 percent), and Australia about (8 percent). The demand for LNG is expected to increase by roughly 50 percent over the next two decades. The demand growth in the Asia-Pacific region to the year 2000 will mainly be satisfied through expansions of existing supply sources in Australia, Malaysia, and Abu Dhabi, and by new projects in Qatar. Other new projects such as those in Oman, Russia's Sakhalin Island, and Indonesia are planned, but there is a big question as to whether their production will be onstream in time to meet the soaring demand. Figure 2 shows the supply situation in the Asia-Pacific region.

Indonesia. LNG exports from Indonesia stood at 22.9 million tons (mmt) in 1992, which represents about 57 percent of the country's total gas production. Six trains at Arun in northern Sumatra and five trains at Bontang in East Kalimantan supply almost half of the Japanese and all of the Korean and Taiwanese markets. Current contracts for Arun are due to end between 1999 and 2007, while the expiration date for Bontang contracts is between 1999 and 2009. In January 1994 a sixth train is due to come onstream at Bontang. The supplies from this train are destined for the Japanese market through 2013. The addition of a seventh train (with a capacity of 2.3 mmt/y) at Bontang has been discussed, following Total's successful nearby explorations in East Kalimantan. In the meantime, some of the commitments of Arun are expected to be switched to Bontang, given the fact that Arun reserves will start to decline soon after 2010.

Increasing demand in the Indonesian domestic market will mean that less and less gas will be available for export, unless substantial new reserves are discovered. The Exxon-operated Natuna Island project has been suspended for an indefinite period of time because of technical and financial problems. Natuna's gas has a carbon dioxide content of about 75 percent. Development costs for these reserves are estimated to reach US$30-40 billion. The project is therefore deemed uneconomical for the moment, although with shrinking supplies and skyrocketing demand by the year 2010, its

development is merely a matter of time. Regarded in 1992 as the project most likely to go ahead, the project seemed by mid 1993 to be dead forever. But then Pertamina announced that negotiations with Exxon may soon resume. We believe that the development of Natuna is unavoidable, and with improved prices, the projects will be rationalized in the next 2-3 years.

Malaysia. As the third biggest LNG exporter in the world, Malaysia has 7.5 mmt/y of capacity at its Bintulu plant in Sarawak, East Malaysia. It now expects to double its export capacity to 15.8 mmt/y by 1997. The expansion plan entails the construction of three additional trains at Bintulu at an estimated cost of US$1.6 billion. The giant gas fields recently discovered by Occidental and Nippon Oil in the South China Sea, off Sarawak, may lead to the construction of new LNG trains. If sufficient gas is proven, the new fields can either feed into Bintulu, or, alternatively, a new grassroots facility with an estimated capacity of 4 million tons can be constructed.

Petronas has also given a contract for the construction of five new LNG carriers, each with a capacity of 150,000 cubic meters, to French shipbuilders Chantiers de l'Atlantique. The first vessel is scheduled for delivery in mid 1994 and the last one in mid 1997. The new tankers are to handle growing deliveries to Japan.

Malaysia currently has contracts with Tokyo Gas, Kansai Electric Power, Osaka Gas, and Toho Gas. From 1996 Bintulu will supply a fifth Japanese utility—Tohoku Gas, which currently gets its 2.9 mmt/y of LNG from Indonesia. Many of Indonesia's Japanese buyers will switch to Malaysia for their LNG needs at the end of their contracts, because of the decreasing supply capacities of Indonesia.

Brunei. Brunei renewed its supply contract with a consortium of Japanese utilities in March 1993. According to the original contract, which was Asia's first LNG contract, Brunei's Coldgas delivered 5.1 mmt/y of LNG to three Japanese utilities: Tokyo Electric, Osaka Gas, and Tokyo Gas. The new contract calls for a 10-percent increase in the original volume, or a total delivery of 5.6 mmt/y of LNG through 2013. Brunei's total LNG capacity is 6.5 mmt/y. Only 5.6 mmt/y is firmly committed to Japan, and therefore nearly 1 mmt/y is available for spot trading.

Australia. LNG shipments from Australia's Northwest Shelf to Japan started at 2 mmt/y only about three years ago. Since then deliveries have more than doubled and reached a peak of 5.4 mmt/y in early 1993. The export volume from the Northwest shelf is expected to rise another 3 mmt/y by the end of the decade. The buyers from the Northwest Shelf are Tokyo Electric, Chubu Electric, Kansai Electric, Choguku Electric, Kyushu Electric, Tokyo Gas, Osaka Gas, and Toho Gas. Although Australia is currently exporting only to Japan, it intends to seek future market opportunities in Taiwan and South Korea.

The increase in export volumes until the end of the decade will most likely come from an extension of the Woodside Petroleum Ltd. group's fields and facilities in the Northwest Shelf. An eighth LNG tanker with a capacity of 125,000 cubic meters is under construction in order to handle the new deliveries from the Northwest Shelf. The carrier is scheduled for delivery in late 1994.

The next most viable LNG project in Australia is near the Gorgon fields, west of Barrow Island. These reserves are estimated to contain about 7-8 trillion cubic feet (tcf) of natural gas. It seems that a slight increase in the current prices of Australian LNG would make the project viable. The project is likely to go ahead earlier than some other grassroots projects. Two options have been considered for the development of these fields: a linkup with the Northwest Shelf project or an altogether separate grassroots facility. Some of Northwest Shelf partners would like to see the Gorgon field gas as a feed into their project in order to ensure a longer life for their gas availability. Gorgon partners (some of whom are also in the Northwest Shelf) are likely to want a separate development.

At the same time, Apache, Western Mining, Ampolex, and Bridge, following their recent gas discoveries of East Spar and Maitland (2-4 tcf) near Gorgon, could themselves become LNG export candidates if their costs were lower. It may also be possible to see a consolidation of both sets of reserves, through special arrangements between the two parties. In that case, the construction of a separate LNG facility may become more likely.

Abu Dhabi. In the second half of 1994, Abu Dhabi's Das Island LNG plant expansions are due to be completed and will thus boost production to nearly 5 mmt/y from the current 2.5 mmt/y. The new train will probably serve an extended contract with Tokyo Electric which may in turn assign part of its gas to Chubu Electric. This arrangement will take place in the event of Chubu having a temporary shortage of gas, since supplies from Qatar may become available later than the present schedule, which is 1997. The third train will liquefy 430 million cubic feet/day of gas, most of which will come from the Permian Khuff reserves in offshore Abu Al Bukhoosh field. The field, which is located on the border with Iran, is operated by Total.

Alaska. Japan's first supplier, Alaska, has been exporting about 1 mmt/y of LNG since 1969. The Kenai liquefaction terminal is owned 70 percent by Phillips Petroleum, also the operator for the North Cook Inlet field which supplies gas to the plant. The other 30 percent is owned by Marathon Oil, the operator of the second gas field, the Kenai field, which feeds the liquefaction plant.

There have also been discussions about a major new LNG export project from Alaska of up to 14 mmt/y. The gas would come from the Prudhoe Bay gas reserves via the trans-Alaskan pipeline to the Valdez liquefaction terminal. The partners are Arco, Exxon, and BP. However, for the time being, the producers at Prudhoe Bay are not pursuing any firm agreements to export gas. It is possible that the project will be reconsidered after the turn of the century. A decision to pursue further developments would very much depend on the price and the demand for LNG in the Pacific Rim.

Qatar. There are currently two important LNG projects in Qatar, both supplied by the North Field giant gas reserves (between 160-210 tcf). The first and more imminent project is Qatargas with a final capacity of about 6 mmt/y. The partners in this venture are state QGPC (70 percent), Mobil (10 percent), Total (10 percent), Mitsui (7.5 percent), and Marubeni (7.5 percent). The plans are for the construction of two trains, possibly three. Japan's Chubu Electric has already signed a contract for 4 mmt/y. However, no price has yet been agreed upon. The first two trains will come onstream most probably by the year 2000, which is slightly later than originally scheduled.

Ras Lafflan is the second LNG project currently under development in Qatar. The project seems to be equally a sure starter, although not before the turn of the century. The participants are Mobil with 30 percent of the shares and QGPC with 70 percent. Unlike Qatargas, Ras Lafflan has no firm contracts, but only letters of intent from South Korea, India, and Taiwan. It also has plans to market its gas in Taiwan and Japan. The construction of at least five trains is planned in the Ras Lafflan project, of which only one stands a firm chance of being completed before 2010. The production volume is projected to eventually reach 10 mmt/y.

Oman. Oman LNG, a project in which the government is the leading shareholder (51 percent), followed by Royal Dutch/Shell (34 percent), has started to gather momentum. The construction of the liquefaction plant at Bimmah, with a capacity of 5 mmt/y, is scheduled to begin in late 1996 and to come onstream toward the beginning of the next decade. Other participants in the project include Total with 6 percent, Mitsubishi and Mitsui with 3 percent each, Partex with 2 percent, and Itochu with 1 percent. The 7-percent shareholding of Japanese firms may indicate that Japan will be a major market. Oman's minimum 17 tcf of gas reserves located onshore represent a sure advantage: they are both cheaper and faster to develop.

Russian Far East. Huge gas reserves await development off Sakhalin Island. The feasibility study for two of the gas fields has already been completed by a consortium formed by Marathon (30 percent), Mitsui (20 percent), Royal Dutch/Shell (20 percent), McDermott (20 percent), and Mitsubishi (10 percent). The results of the study indicate that the development costs for the two fields of Piltun-Astokhskoye and Lunskoye, with joint reserves of about 7-14 tcf of gas and at least 700 million barrels of liquids, would reach $11.8 billion. The countries of the Pacific rim are an attractive market for this gas.

This project is, however, fraught with economic, technical, and political uncertainties. For the moment, the Russian government is insisting on linking the oil with the gas developments which, in this case, would shoot the development costs sky high. The main problem in this case is the construction of a transportation infrastructure for sending both oil and gas to the island's southern port of Korsakov, a distance of 580

miles. Such complexities make any major progress in the project unlikely in the near future.

Yemen. The megaproject backed by Exxon and Hunt for the production of 5 mmt/y of LNG, has so far been slow in moving up the queue. However, Yemen's substantial and relatively cheap onshore reserves make it an inevitable LNG source by the end of the first decade of the twenty-first century.

Papua New Guinea (PNG). There are currently two main areas of interest for LNG projects in PNG; one is onshore and the other offshore. The latter includes the Pandora gas field for which Mobil is the operator. There are great possibilities of gas finds in the future in this area, but so far, only about 5 tcf have been proven, which does not provide for an economically viable project in PNG's geographical context.

The onshore reserves of the Hides gas fields, operated by BP, seem to have more gas but not in a concentrated area. This makes it technically more difficult and financially more costly to pipe the gas down to the coast. A feasibility study carried out by BP in 1992 concluded that an LNG scheme based on the gas from the Highlands reserves was not viable for several reasons, amongst which are the lack of adequate proven reserves, high capital costs of liquefaction plant, facilities and pipeline, and finally, current low LNG prices.

Vietnam. Vietnam's geographical position and potentially large gas reserves could make it a possible LNG supplier to the countries of the Asia-Pacific, given the inevitable shortage in the coming decades. On the other hand, with the improving economic conditions, domestic gas demand might increase substantially and thus leave no surplus available for export. No serious studies have been undertaken so far. For the time being, there has been no real urge to find new sources. The situation could change with the surging demand in about 10 to 15 years.

2.3. LNG Price Issues

Nothing is more critical for the future LNG trade than the pricing. Currently the price of LNG delivered to Japan on a c.i.f. (cost, insurance, and freight) basis varies between $3.45 and $3.64 per million Btu. The low prices reflect the formula linking

LNG prices to crude oil (Figure 3). The weak crude oil prices and their uncertain future do not bode well for megaprojects such as LNG chains.

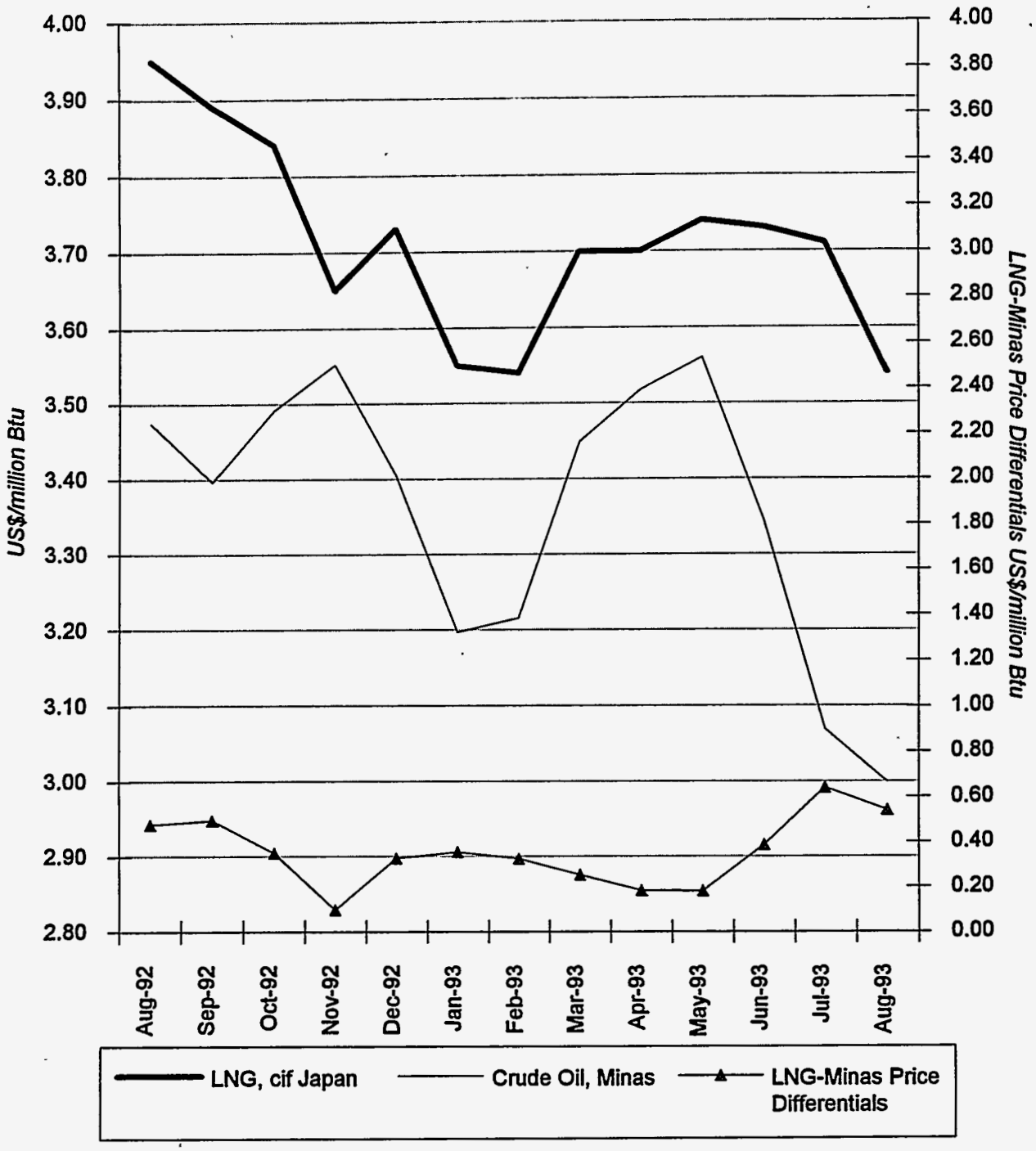
In the past few years, cost escalation for grassroots projects involving processing technologies have been large. The cost of building refineries, petrochemical plants and LNG facilities have risen by 50-100 percent. Remote areas, offshore facilities, and huge developments and infrastructure expansion have created a situation where it is *next to impossible* to expect grassroots facilities to be built at current prices. For the projects to go ahead, two things need to happen: consumers *must pay a higher price*, and the producer governments *must ease tax terms*. Alternatively, the price of oil *must rise*.

If crude oil prices rise to, say, $23-25 per barrel for Minas crude, many of the LNG projects become viable. Within CIF prices of $4.25 to $5.50, most projects discussed earlier would become viable. Without a crude oil price increase, other special arrangements would need to be made.

The governments in the producer countries have shown some flexibility in reducing the tax burden and providing a better environment for the foreign partners. The state oil and gas companies in Indonesia, Qatar, and Oman have been particularly helpful in providing incentives for their projects to go ahead. The companies have also employed the most advanced technologies to reduce costs. Still, cost reductions and government flexibility are less critical than the price issue.

Currently, the existing suppliers of LNG are able to get a reasonably good return on their LNG exports. As such, the LNG industry faces an irreconcilable duality. On the one hand, the existing projects are viable with CIF prices of, say, $3.50 per million Btu (mmBtu). On the other hand, no new grassroots projects could be built within the existing price levels. Among the existing projects, the Northwest Shelf has a rather marginal rate of return, having been designed for higher prices. Until the oil price collapse of 1986, the consumer had been used to paying in excess of $5/mmBtu, but lower oil prices resulted in lower LNG prices. Many consumers worry that if they pay the higher price for the new projects, they may be forced to pay the same high prices for the existing projects too. Also, the consumers—particularly those in Japan—are not yet ready to pay the higher prices. This points toward the major LNG industry dilemma:

Figure 3. LNG and Crude Oil Prices, 1992/93



there is a very large potential demand for LNG, but the potential supply is unlikely to come forth at the right time. *The result is that, as we get closer to the date when the consumer is counting on deliveries (which may not be available), the consumer's willingness to pay a higher price will increase.*

The new LNG projects will be available at price levels that differ from project to project. There are no clear details, nor is there a clear understanding of all cost elements. Our very rough judgment is that Qatargas and Ras Lafflan can work at prices in the range of $4 to $4.25 per mmBtu. Gorgon and the nearby East Spar and Maitland LNG facilities might become viable at $4.25 to $4.50 per mmBtu, while Sakhalin might need $4.75 per mmBtu and higher in order to become viable. At the higher end, Natuna might need more than $5 per mmBtu, and the price of exports from Alaska could be even higher.

The consumers of LNG in Asia must make a clear judgment that they must pay more or there *will not* be enough LNG. The high price is possible through three mechanisms:

(a) assess a premium over the oil prices formula by deeming a crude price;

(b) assess a price based on alternative fuels, such as coal; or

(c) assess a price based on gas-to-gas competition or LNG spot prices.

We do not believe that option c is viable in the Asia-Pacific region. Option b can result in an LNG price range of at least $5/mmBtu, given the more efficient uses of gas for power generation and the smaller size of plants, compared with coal-fired plants. Ultimately however, the practical way to build a price formula is to assess a premium by deeming a crude price in the range of $23-25 per barrel. There is a certain precedence here (through the informal agreements on the deemed price of Minas in 1986 after the oil price collapse), and this could easily be achieved if the consumer so desires.

We strongly believe that high LNG prices are unavoidable and are only a matter of time. By 1995 consumers will realize that, by their own inaction, they will be facing an uncertain supply of gas. The concern bordering on panic will result in willingness to pay the higher price. Gradually, most if not all the stalled projects will begin to move

forward. Still, the gas *will not arrive on time* as expected by consumers. This will result in higher oil consumption for several years until gas supplies become available.

2.4. Ranking of the New LNG Projects

Currently, there are about 90 mmt/y worth of projects being debated in the Far East. Most of these include expansions to existing facilities. Before 2005 the only pure grassroots projects will be Qatargas and Oman. Most of the other ventures after 2005 are grassroots projects, the future of which is obscured by technical, financial, or political instability.

The expansion plans in Australia's Northwest Shelf, Malaysia's Bintulu, Indonesia's Badak, and Abu Dhabi seem to be pretty solid and well on their way.

The Qatargas LNG project is solid with firm contracts and sure to come onstream by the end of this decade, although it will not reach its full capacity until 2005.

The other Qatari project, Ras Lafflan, has also a very good chance of coming onstream by 2005. The project has very good prospects, but no firm buyers at this point in time. South Korea, Taiwan, and India have so far only signed letters of intent to purchase LNG from Ras Lafflan, but no final commitments have been made. The second phase of this project, Ras Lafflan II, will not be completed before 2010.

Oman's LNG project seems to be also very solid. It has the geographic advantage over Qatar of having onshore reserves. Its shareholders include Shell, which has significant experience in this field. We therefore believe that this project is likely to go ahead and start operations by 2005.

Among the likely supply additions, Australia's Gorgon project is next on the list. With large gas reserves and strong partners, the project is expected to progress rapidly and become operational early in the next century.

After all the skepticism about the future prospects of the Natuna LNG project, discussions among the partners is expected to resume shortly. It finally appears that the project is not dead after all, as many had presumed. High costs of development seem to be the major obstacle in this venture. However, the concern over the gas shortage in a few years is starting to become more apparent among the buyers of the Pacific rim.

Therefore, we believe that the Natuna LNG will finally become available, but probably not before 2010.

There seems to be quite a lot of interest in the Sakhalin LNG project from several major buyers. The geographic location of Sakhalin Island makes its gas particularly attractive to the markets of the Far East. It is likely, therefore, despite all the technical and political complications, that the project will go ahead and will become operational by 2005.

The projects in Alaska and Papua New Guinea are based on reserves in extremely challenging environments and will not go ahead unless a reasonable price for LNG is achieved. The LNG from these sources will become available, if at all, no earlier than the end of the next decade. As for the project in Malaysia based on gas reserves discovered by Oxy Nippon Oil (which could be either a grassroots project or just an addition to the facilities in Bintulu), developments will depend on new gas finds in the region.

Finally, the Yemen LNG project, with its significant gas reserves, could be completed by 2010, if the demand arises. So far, the developments have been very slow, but the possibility of suddenly rapid progress is not excluded. In that case, the project could be completed just in time to meet the large demand in 2010.

3. LNG Balance in the Region

Table 1 shows the LNG balance situation in the Asia-Pacific region from 2000 to the year 2010. We can see from the table that, under almost any scenario, a shortage in LNG supplies is inevitable by the end of this decade. The first scenario assumes that there will be no new additions to the existing supplies (Figure 4). We can appreciate in this case that the shortage will become acute by the middle of the next decade and would reach about 36 mmt/y by the year 2010.

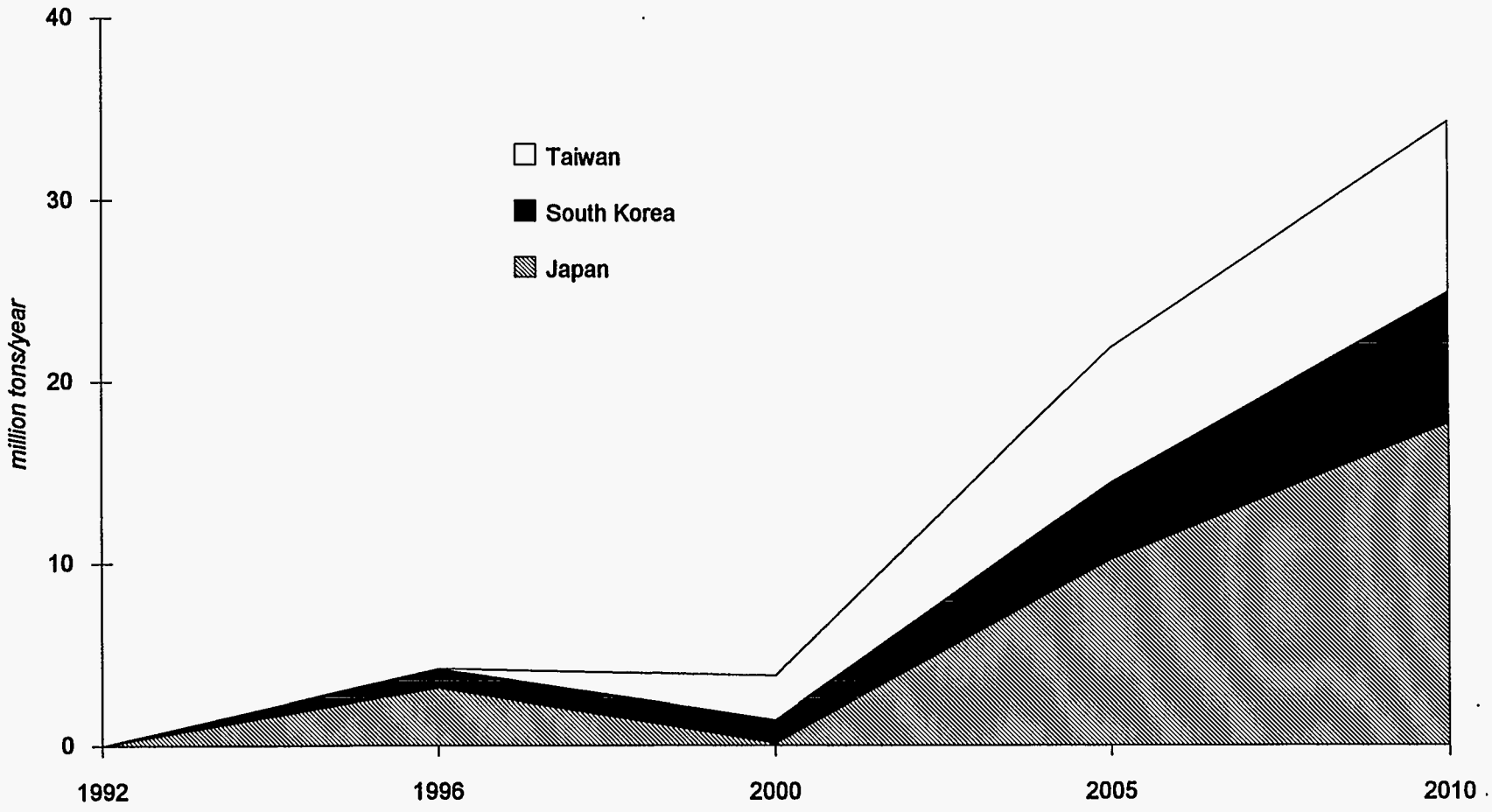
The likely scenario in Table 1 assumes that there would be only an addition of firm projects—in this case only the two LNG projects in Qatar—before 2010. Here, the shortage would be slightly less severe, at least until 2005.

Table 1. Asia-Pacific LNG Supply/Demand Balance, 2000-2010

	Supply/Demand Balance (million tons/year)		
Category of Project	2000	2005	2010
Existing projects	-5.9	-21.3	-36.3
Existing and firm projects	-1.9	-12.8	-25.3
Existing, firm, and likely projects	-1.9	-3.8	1.7
Balance of all projects	-1.9	-10.8	26.7

Note: The balance of all projects includes possible and potential projects and possible new demand (China and India).

Figure 4: Projected LNG Contract Shortfall , 1992-2010



The third possibility is that not only the firm projects in Qatar would be completed, but also some of the other more likely undertakings, such as those in Australia (Gorgon), Oman, Sakhalin, and Indonesia (Natuna) would come to fruition. Under this scenario, a small shortage would still be felt at the beginning of the next century. However, by 2010 when the megaproject in the Natuna Sea is completed, there would even be a modest surplus of capacity.

Under the last scenario, in which all the other possible but complex projects discussed above would also be completed, Table 1 still shows a deficit in the LNG balance of the region before 2010. This deficit is cause on the one hand by the fact that besides the addition in supplies, two new important players would join the ranks of the LNG buyers in the Asia-Pacific region. China and India, with an aggregate demand of about 4-10 mmt/y, would significantly influence the availability of LNG in the region from the beginning of the next century. On the other hand, the supplies from other major projects, such as those in Alaska and Yemen, if they materialize at all, would not arrive before 2010.

In a final analysis, we may say that the awareness about the lack of sufficient LNG supply sources in the region among the prospective buyers will eventually induce them into investing in the more capital-intensive projects. However, by that time it will be too late to avoid the shortages at the beginning of the next century. Grassroots projects will take no less than seven years to complete. Thus, as noted earlier, oil will have to replace the gas supplies, until such time that the new projects are operational, i.e., near the end of the first decade of the twenty-first century.

B. Scope for LNG Use in Hawaii and Market Displacement Issues

The question of supply is only half the equation concerning LNG use in Hawaii. With no current facilities or market for LNG, and only a small market for gas altogether, LNG must be considered as a substitute fuel for the state. This section addresses the question of the scope of LNG use, based on the possible substitute uses to which it can be put.

The scope for the introduction and utilization of liquefied natural gas in Hawaii is limited by the potential areas of fuel substitution and by possible new uses within the energy system of the state, and in particular, the island of Oahu. LNG is used in direct combustion, which puts it into competition with the combustion uses fuel oil, diesel fuel, gasoline, coal, liquefied petroleum gas (LPG), synthetic natural gas, and bagasse. Table 2 lists the demand for these fuels on Oahu in 1992, in both heat-content terms and in tons of LNG equivalent, converted on a Btu basis. Assuming full substitution of all these fuels (except for bunker use of fuel oil), total LNG equivalent demand would be 2.63 million tons. With the exclusion of the unlikely and the more costly fuel substitutions, demand would still reach 1.76 million tons. The latter volume most likely represents the theoretical maximum market for LNG use in the state.

1. Supply Substitution

Propane and synthetic natural gas (SNG) and their uses are discussed in the second volume of this East-West Center study. LNG can substitute for propane and SNG in most of their current uses, in both the utility and the non-utility sectors. However, the maximum volume that can be substituted by LNG will probably be slightly lower than the cumulative consumption volume of the two fuels. The difference is because of the fact that it would be either impossible or uneconomical to substitute LNG for certain uses of bottled propane. Total consumption volume of SNG and propane for 1992 stood at 181,186 tons of LNG equivalent.

GASCO's utility SNG is produced from low-octane light hydrocarbons that are by-products of the local refineries. These light hydrocarbons are already in surplus in Hawaii, and the excess supply is exported. If replaced by LNG, any surplus low-octane light hydrocarbons will have to be shipped out of the state and sold as petrochemical feedstock. The existing reticulation of the SNG pipeline can be used for LNG transport and supply, but the capacity falls far short of what would be required.

The market of utility propane, or propane-air, is rather small compared to the SNG market, accounting for 14.4 percent of the total utility gas market. The total amount of utility propane sold in 1992 was 492 billion Btu, or 10.1 thousand tons of

Table 2. Scope for LNG Substitution in Hawaii

Fuel	1992 Consumption (Total)		1992 Consumption (Likely Substitution)	
	(billion Btu)	(tons of LNG equivalent)	(billion Btu)	(tons of LNG equivalent)
Propane	5,363.0	111,016	4,429.0	91,682
SNG	2,930.0	60,652	2,930.0	60,652
Gasoline	28,807,1	596,395	5,120.8	106,000
Fuel Oil	71,059.7	1,470,955	52,682.6	1,090,548
Diesel	118.9	2,461	118.9	2,461
Coal	15,840.0	327,892	15,840.0	327,892
Bagasse	2,627.0	54,380	2,627.0	54,380
Total	**127,238.5**	**2,633,872**	**85,184.1**	**1,763,154**

Note: The data for diesel represent the estimated diesel consumption on Oahu for power generation.

LNG equivalent. Of the total utility propane sales, Oahu accounted for only 33 percent, the Island of Hawaii accounted for 48 percent, Maui 17 percent, and Kauai and Molokai together for 2 percent (GASCO data). While LPG consumers on Oahu may switch to LNG provided that the current pipeline system is used for natural gas (regasified LNG), LNG cannot be a substitute for the propane supplied to the neighbor islands.

The non-utility propane market in Hawaii is much larger than the utility propane market. In 1992 the non-utility propane distributed by GASCO, the Oahu-Maui Gas and Aloha Gas amounted to 2.7 trillion Btu (56 thousand tons of LNG equivalent). Should this amount of propane be replaced by LNG, the current pipeline system would have to be expanded, and any excess propane would have to be shipped to the U.S. Mainland or Asia for sale.

2. Fuel Substitution

Fuel oil, diesel, coal, and bagasse are the chief fuels used for power generation in Hawaii. A total of about 90 trillion Btu of these fuels was used for electric power generation in 1992. It would be possible to substitute most of the fuel oil (HECO's consumption) and all of the coal (Applied Energy Systems's consumption) with LNG, which would require up to 1.4 million tons of LNG equivalent. In order to use LNG for power generation, however, the current power plants that use fuel oil would have to be replaced by LNG combined-cycle plants. The replacement costs could be very high. In addition, the extra fuel oil produced by the local refineries will have to be exported. Finally, the Applied Energy Systems coal plant is a very modern facility, and it is doubtful that economics would warrant closing it in favor of LNG.

According to *The State of Hawaii Data Book 1992* (DBEDT, March 1993), a total of 2.6 trillion Btu of bagasse was consumed in 1992 for the production of electricity on Oahu. The decline of the sugar industry—the source of the bagasse fuel—calls into question the long-term availability of this fuel and the electric power generated therefrom; similarly, since sales of bagasse-based electric power contribute significantly to the economic viability of the sugar companies, substitution of bagasse by imported fuels would further reduce income sources for the companies and raise their costs. The recent

announcement of the closing of Oahu Sugar in two years reinforces doubts about the long-term viability of the industry on Oahu, though it may be that alternate sources of biomass will be developed (see HES Project 3).

3. Alternative Uses

Natural gas can be used as fuel in automobiles, usually in the form of compressed natural gas (CNG), provided that the automobiles are retooled and installed with bifuel engine conversion kits (i.e., so that the engine can use gasoline or natural gas or both). In 1991 there were roughly 400,000 vehicles using CNG in Italy, the United States, and New Zealand.[1]

The disadvantages of using CNG for automobiles are as follows:

(1) The heavy, bulky pressurized tank, which takes up a considerable portion of the trunk space in automobiles. While a full 55-gallon diesel saddle tank weighs 580 lbs, a 55-gallon fuel equivalent LNG tank weighs 630 lbs, and a 55-gallon equivalent CNG tank weighs in excess of 2,600 lbs.

(2) The dependence on a network of public CNG filling stations. If CNG were to become the fuel for a significant proportion of the automobiles in a region, CNG filling stations would have to be connected to an in-place natural gas distribution network. Should such a network not exist, then CNG use would probably only be economically attractive for fleets of buses and trucks, which could be refueled at one central station.

(3) The limited range of mobility. A tankful of CNG provides a driving range of only 150-200 miles, whereas a 20-gallon tank of gasoline is good for 400 miles or more.

(4) High cost of car retrofitting. The cost of retrofitting to burn CNG can run over $1,000 per car.

Some applications use LNG directly in vehicles, though this technology is not widespread. Most of the research on direct uses of LNG for transport have focused on

---

[1] Marvin H. Muenzler and James F. Houle, *LNG Development in the Asia/Pacific Region*, Asian Development Bank, October 1991.

large vehicles such as buses, trucks, trains, and boats. These are demonstration projects only, not commercial applications. However, LNG as a transport fuel may rightly be considered a "greenfield technology" and is therefore noted here.

If LNG could be used directly for automobiles, some of the disadvantages of CNG could be overcome:

(1) An LNG tank is less bulky than a CNG tank, since LNG is about 3.5 times as dense as CNG. A tank size similar to a gasoline tank may be practical and easy to accommodate without taking up trunk space.

(2) An LNG tank weighs far less than a CNG tank. The LNG will not be under pressure, and thus the tank wall would be thinner—most likely stainless steel or aluminum cryogenic tank designs.

(3) If the LNG receiving facilities are in place, LNG tank trucks could supply filling stations, similar to the situation with gasoline tankers. There would be no reliance upon an in-place natural gas distribution network as would be required for a CNG network.

If direct uses of LNG become commercially feasible, it may not be necessary to convert LNG into CNG for automobiles in Hawaii. However, the costs of replacing the gasoline-burning engines with bifuel engines and of installing new LNG stations will still be high, and it would be costly to build the fleet of LNG tank trucks. Moreover, the extreme low temperature at which LNG must be maintained in order to remain a liquid, together with the high risk of explosion, are major obstacles for using LNG as a transport fuel. In the near term, if LNG were deemed feasible for Hawaii, its use as a transport fuel would most likely be via CNG. Nevertheless, in the twenty-plus-year time frame required for LNG contracts, significant breakthroughs could occur in direct transport uses of LNG.

4. Refinery Imports and Trade Issues

For Hawaii's refiners, the impact of LNG use in the state would be tremendous. Given the minimum LNG use that would make such a project justifiable, and given the

limited size of the Hawaiian energy market, the overall pattern of energy use in the state would have to change. Consequently, the state's refiners would be faced with the problem of excess production of refined products that would no longer be needed in the local market. One solution would be to downsize their refining capacities, in order to reduce excess production of unneeded products. An alternative would be to market the extra products, including gasoline and fuel oil, in Asia. If the supply imbalance became extreme, there could be a point where it was simply uneconomical to refine in Hawaii, and the state would then rely on imports for all of its needs (notably jet fuel).

C. Economics of an LNG Project in Hawaii

1. Scale of an LNG Project

By nature, the construction of an LNG project is very complex and requires extensive capital investment, large markets, and long-term commitment from both sellers and buyers. At present, almost all of the world's LNG trade is carried out on a contract basis, and the duration of these contracts is typically 20 years or longer.

Among the numerous factors that influence the construction of LNG projects around the world, economies of scale is one of the most important. The minimum scale for economic justification of an LNG project is different for suppliers and buyers. For potential LNG suppliers, a bare minimum of 3 trillion cubic feet (tcf) of recoverable gas reserves is considered necessary to start an LNG project. The LNG project should be located very close to a site—or directly on a site—that has such an amount of reserves.[2] Most project developers consider the presence of 5 tcf of recoverable reserves to be a level at which an LNG project is economically worthwhile, assuming other geographical considerations are favorable. For instance, the initial gas reserves for Indonesia's Arun and Bontang LNG projects were estimated at 13.1 and 18 tcf, respectively. Proven reserves for Malaysia's Bintulu were estimated at 20 tcf and Brunei's 11.3 tcf. Gas reserves for Abu Dhabi and Australia's Northeast Shelf are also significantly higher than

[2] For a discussion of this problem, see "The Case for and against LNG Exports from PNG", *Asian Oil and Gas*, May 1993.

10 tcf.[3] In terms of LNG produced, a minimum of 1 train and an ideal of 2 trains and above are required for starting the projects. Annually, there are 1-2 million tons of LNG produced per train, and each train can operate independently from the other in the same project.

LNG can be transported overseas only by specialized tankers. Currently there are 65 LNG vessels operating worldwide. Forty-four of these are in the 125,000 cubic meters (m^3) class; 10 are between 50,000 and 87,600 m^3, and 11 are under 50,000 m^3. The smallest LNG tanker has a cargo volume of 25,500 m^3, was built in 1965 and has been used for LNG trade between Algeria and Spain. The specialized, cryogenic, double-hulled LNG tankers are built only in the United States, Japan, and Europe, and worldwide there are only eight shipbuilding yards that construct such vessels. There is no real secondhand market for LNG carriers. The estimated new building prices have soared to $270-290 million for a 125,000 m^3 vessel, from $120 million at the end of 1986.[4] Construction costs are expected to continue rising for some time, owing to the high demand for new carriers and the limited number of shipyards equipped to build LNG carriers.

As mentioned earlier, the cost of building LNG facilities is extremely high. Therefore extensive initial investment is needed in order to create an LNG chain. The LNG chain has three components:

(1) the liquefaction plant;

(2) the tankers; and

(3) the receiving terminal.

The following section will examine each component of the LNG chain, the investment required, and the cost incurred per mmBtu of LNG.

For the purposes of this cost analysis, the East-West Center has developed a model in which the delivered cost of LNG can be calculated, given a range of input variables.

---

[3] Muenzler and Houle, *op. cit.*

[4] "World LNG Trade to Sour to 2010 if Prices, Funds Line Up," *Oil & Gas Journal*, June 28, 1993.

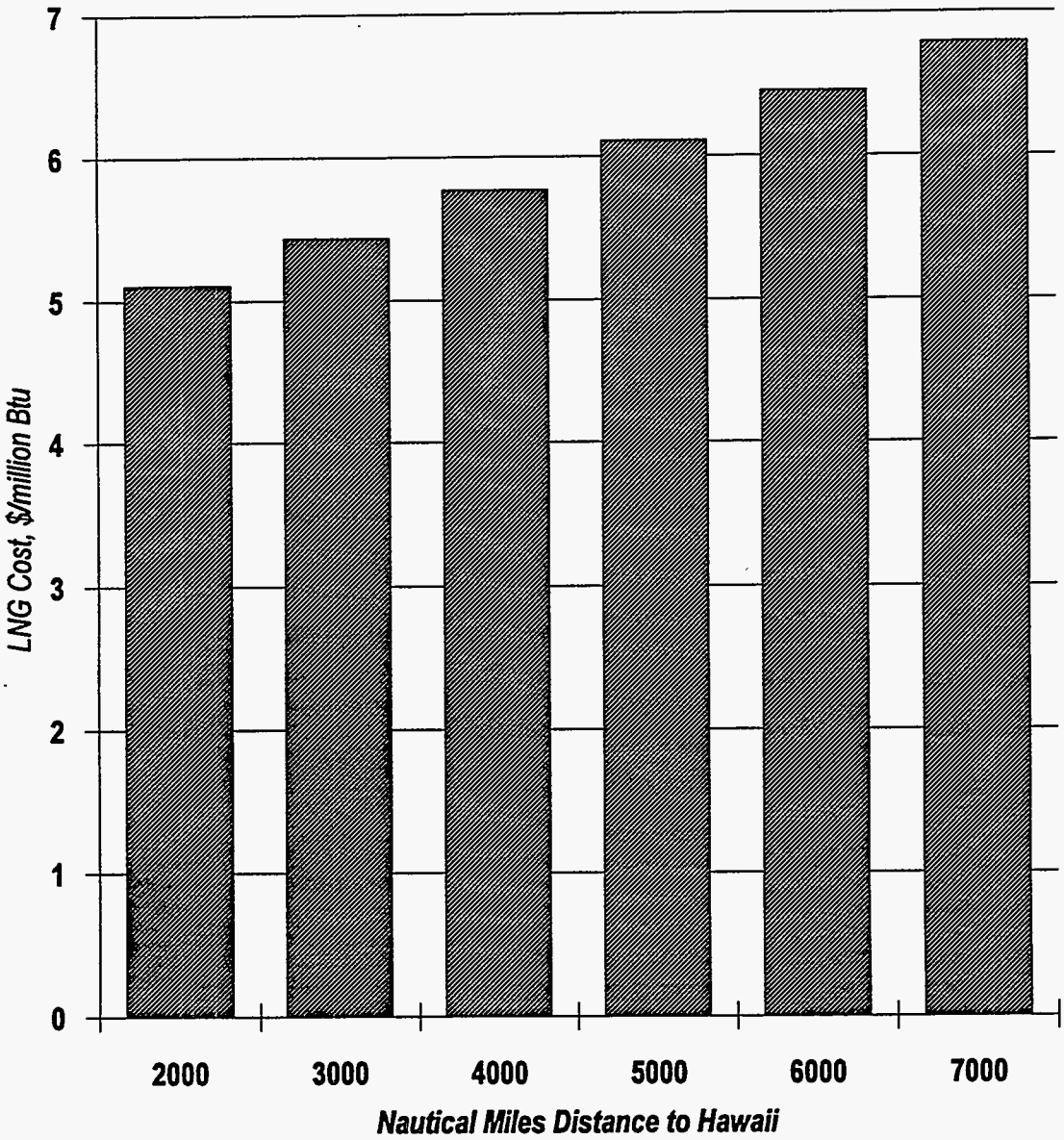
With this model, it is possible to compute the delivered cost of LNG to different destinations from different sources. The variants in the model include the shipping distance from the LNG plants, the price of natural gas at different plant gates, the LNG plant capital costs, the regasification plant capital costs, and the land cost in different locations. Each of these factors influences the delivered cost of LNG.

In the context of Hawaii, two figures are provided to illustrate how the delivered cost of LNG can change as a function of different variants. Figure 5 shows that, all other factors being constant, the delivered cost of LNG to Hawaii increases substantially with the distance of the LNG source. Clearly, factors besides distance also affect the delivered cost. For example, Figure 6 takes the distance as a constant (Qatar in this figure). The delivered cost of LNG to Hawaii increases as a function of the price of natural gas at the LNG liquefaction plant. Here, even if the price of natural gas is zero, the delivered cost of LNG to Hawaii would still be about $5/mmBtu.

In the model, it is possible to vary essentially any input variable. However, in order to carry out a cost analysis for LNG imports to Hawaii, certain general assumptions have to be made. In this analysis, the assumptions are as follows:

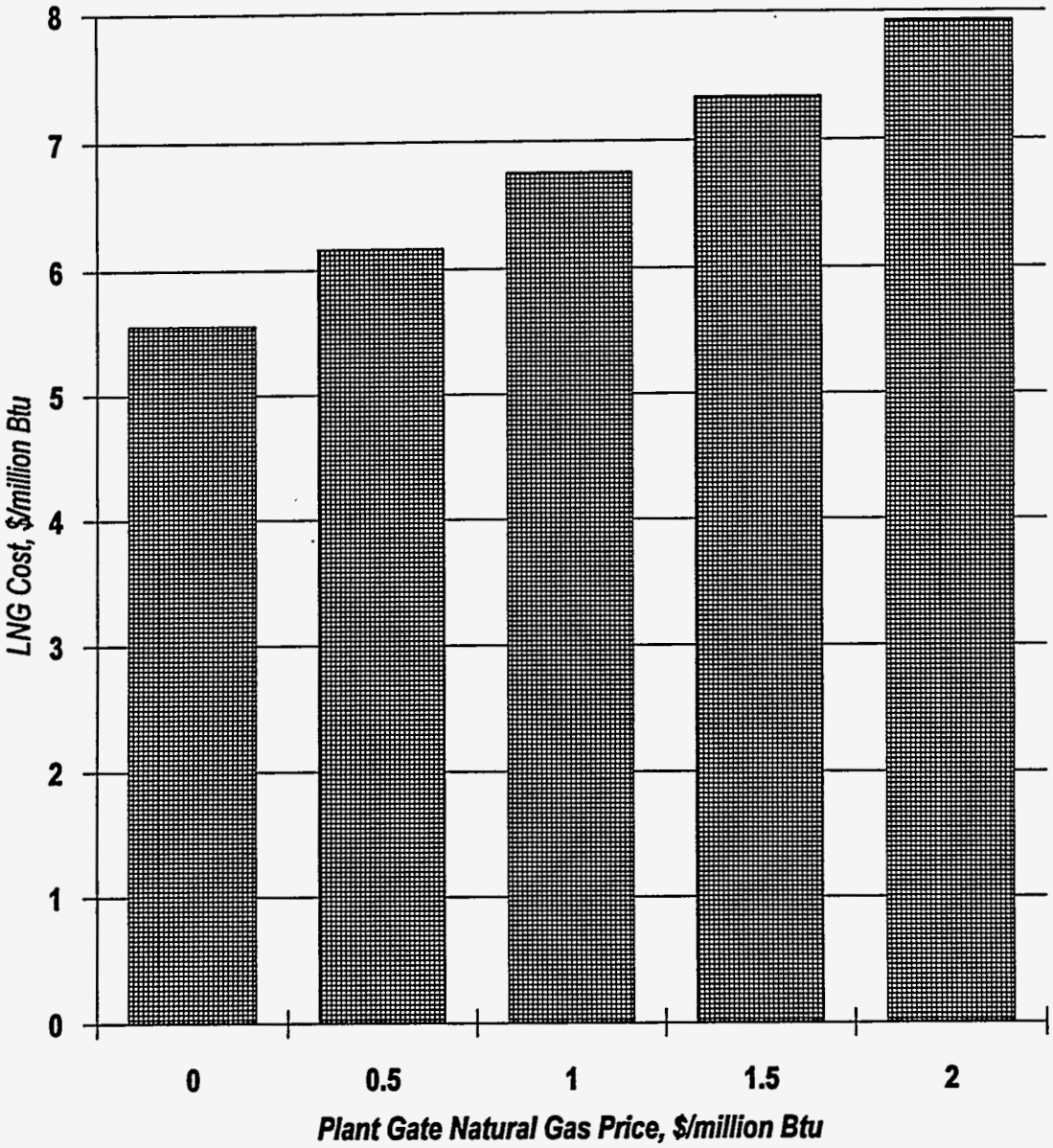
- It is important to underline that all the LNG currently available is under contract. This implies that there is no actual surplus of LNG in the international market. The volume of LNG produced is almost equivalent to the volume contracted by importers. Thus, there is no spot market for LNG at the present time. With tightening supplies in the Asia-Pacific region, we assume that the LNG supply to Hawaii would come from a new LNG source in the Middle East.
- The design send-out flow rate of the natural gas would be 300 million cubic feet per day (mmcf/d).
- Annual delivery to Hawaii would be about 2.1 mmt/y.
- The calorific value of the imported LNG would be 1,050 Btu per cubic foot.
- All values are expressed in constant 1993 U. S. dollars.

Figure 5. Delivered LNG Cost to Hawaii as a Function of Shipping Distance



Note: Assumes a plant gate natural gas price of $1.50/million Btu

Figure 6. Delivered LNG Cost to Hawaii as a Function of Plant Gate Natural Gas Price



Note: Assumes LNG plant is in Qatar

- We also make the assumption that the price of gas at plant gate would be $1.15/mmBtu.
- The contract period for the import of LNG to Hawaii would be 20 years.

Liquefaction plant. Bearing in mind the limited volume of gas needed to supply Hawaii, it would be unrealistic to assume that a separate plant could be built for this purpose, especially in the Middle East. Therefore, we will assume that the Hawaiian purchases of small volumes are the output of a liquefaction train, part of a much larger plant with a capacity of 1,200 mmcf/d. This will also mean that all the common facilities in the plant are shared among several buyers.

The estimated investment cost for a 1,200 mmcf/d capacity liquefaction plant, including port facility and storage, is $3.2 billion. The investment cost shared by Hawaiian suppliers can be calculated as a portion of the total cost for the large plant. For 300 mmcf/d of capacity, their share will be approximately one-third of the total cost.

Operating costs amount to $81 million/year for a 1,200 mmcf/d liquefaction facility. Again, Hawaiian purchasers will assume a proportional share of the total operating costs.

Taking into account the above figures and the assumptions specified at the outset, the total liquefaction cost of around $1.45/mmBtu can be estimated at the plant. This will be valid for any volume of gas processed, including the small volume purchased by Hawaii.

Marine transport. The distance between Hawaii and Qatar, one of the major Middle Eastern ports, is 8,620 nautical miles (15,965 kilometers). With an average speed of 18.5 knots, to ensure a volume of 2.1 mmt/y, six tankers with a capacity of 120,000 cubic meters (m^3) each will be needed.

The current cost of a 120,000 m^3 ship is about $260 million, and therefore a total investment of $1.56 billion for six carriers will be required. The annual operating costs for a 120,000 m^3 tanker is estimated at $0.54/mmBtu. With the above investment and operating costs, the unit transport costs for the Hawaiian supplies will amount to $2.66/mmBtu.

LNG terminal. We can break down the investment costs for the LNG terminal into four categories: marine installations, storage, regasification facilities, and utilities.

The marine installations for a 300 mmcf/d volume is estimated at $160 million, including jetty, one berth, and unloading facilities.

The investment costs for storage are estimated at $198 million for a capacity of 163,000 m^3. This capacity is designed to allow unloading of the large tankers, to provide a buffer between unloadings, and to cope with possible delays in ship arrival schedules because of poor weather or navigational conditions. This investment cost has been estimated for above-ground storage facilities. Underground storage requires a much higher investment.

The regasification facilities would demand an investment of $182 million. The send-out pressure is assumed to be 1,000 pounds per square inch (psi).

The utilities category comprises pipes, cables, electric stations, and other safety facilities. The total cost is estimated at $136 million.

The total land cost for LNG receiving facilities on Oahu is estimated to be about $29 million for a minimum of 190 acres of land. (Land use is discussed in the following section.)

The annual operating costs for the volume of 300 mmcf/d would be about $33 million. Taking the above costs into account, the total investment required for the receiving terminal reaches $624 million. At this rate, the unit cost at the LNG terminal is estimated to be $1.28/mmBtu.

From the calculations above, the unit cost of delivered gas to Hawaii works out at a minimum of $6.89/mmBtu.

Table 3 shows the estimated cost of LNG delivered to Hawaii from different sources. As can be seen from the table, the delivered LNG cost to Hawaii would range from $6.83 (Indonesia) to $7.71 (Australia) per million Btu—significantly higher than the price of low-sulfur fuel oil (LSFO), which currently averages $2.67/mmBtu. The right-hand column provides a comparison in terms of dollars per barrel. Comparing LSFO with LNG on a Btu basis, this column indicates how much higher the price of LSFO would be per barrel if it were priced on a basis competitive with the estimated LNG delivered prices to Hawaii. It should be borne in mind that this comparison is solely on a price basis, and the potential efficiency gains have not been taken into consideration.

Table 3. Estimated Delivered Cost of LNG for Hawaii

	LNG Cost $/million Btu	Indicative Price in $/barrel of Low Sulfur Fuel Oil*
Scenario I:**		
From Qatar	6.89	43.41
Scenario II:		
From Indonesia (Natuna)	6.83	43.03
Scenario III:		
From the Russian Far East	7.30	45.99
Scenario IV:		
From Australia (Gorgon)	7.71	48.57
Average 1993 Low Sulfur Fuel Oil Price*		
$/barrel		**16.85**
$/million Btu		**2.67**

* Conversion factors of 6.3 million BTU for a barrel of Low Sulfur Fuel Oil is used. No correction for efficiency gains has been made.

** Scenarios take into account escalated cost at points of production and regasification.

*** Based on Singapore spot LSWR price of the first quarter of 1993.

Since LSFO is currently used in Hawaii as a fuel for power generation, the state's consumers would have to pay a much higher price to use LNG instead. Whether or not the environmental and fuel diversification advantages gained through switching to LNG is worth the price is debatable.

2. Land Use and Siting Issues in Hawaii

The choice of the site of LNG receiving facilities is determined by a variety of factors such as natural, social, and economic conditions, land, port space, and economic returns. Certain minimum conditions have to be fulfilled for an LNG project, and other conditions would be desirable, as shown in the following outline:

Minimum conditions:

a. Size of receiving facilities: depends on demand for LNG (in Hawaii, the minimum plant size for LNG demand of 2.1 mmt/y).

b. Size of land use: depends on the amount of LNG received. In the case of Hawaii, the minimum feasible size would be 2.1 mmt/y. For this size facility, the land requirement would be close to 190 acres, plus about 800 acres of water space.

c. Height of the site: 1 meter above the peak wave.

d. Geological conditions: the site should be away from any earthquake zone.

e. Weather conditions: for at least 300 days of a year, visible distance of LNG tanker should be 2.3 miles or greater, and wind speed should be 12 meters/second (27 miles/hour) or less.

f. Ocean conditions: for at least 300 days of the year, the tidal range should be 3.3 feet or less, the horizontal surface current should be 2 knots or less, and the vertical surface current should be 1.5 knots or less.

g. Space: any property in the area within 0.6 mile around the unloading arm should belong to the LNG plant, and a surrounding zone of about 160 feet wide should be left empty as a cushioned area.

Desirable conditions:

a. Land use: land meant for an LNG receiving plant should be away from residential areas, in order to facilitate the purchase or lease of the land and to be safer to the population as well.
b. Environmental impact: the siting should be away from populated areas, commercial ports, and fishing zones, in order to reduce the possibilities of disputes and pollution.
c. Transportation: the site should not be too far away from a major city, so that it is not too difficult to meet the required demand level that would justify LNG plant construction.

All these factors suggest that the leeward, rather than the windward, side of the island of Oahu should be considered, if an LNG site is to be chosen. On the southern leeward side, the coastal area from Hawaii Kai to Pearl Harbor would meet some of the above conditions. The only truly appropriate area appears to be the Waianae coast near Barbers Point. Some of the characteristics that favor this particular site include stable surface winds, a low tidal range (maximum of 3 feet), and surface currents of under 0.5 knots nearby. However, the land requirements for the construction of an LNG receiving terminal may present a big challenge.

The land requirements of LNG receiving facilities vary, depending on the size of the regasification plant. Taiwan started the construction of its 1.5 mmt/y LNG receiving terminal in 1985, and imported its first cargo of LNG in 1990. Taiwan's 1.5 mmt/y LNG receiving terminal required a total of 75 hectares (184 acres)[5] of land and 300 hectares (735 acres) of water area in the harbor. While Taiwan reclaimed the needed land area by using the dredged materials from the basin, land reclamation may not be feasible for the island of Oahu.

The total land area on the island of Oahu is about 380,000 acres. The Ewa coast near Barbers Point would be the most appropriate site for potential LNG facilities on

[5] 1 hectare = 10,000 m^2 = 0.01 km^2; 1 acre = 4,074 m^2 = 0.0041 km^2; 1 hectare = 2.45 acres.

Oahu. The total land area in Ewa is 23,264 acres.[6] The total amount of coastal land that would be suitable for an LNG facility, however, is probably on the order of 10,000 acres. Approximately one-third of the total Ewa area is used by the U.S. Navy as air stations. The two local refineries, owned by BHPPA (Hawaii) and Chevron, the newly-built 180 MW coal-powered electric plant (owned by Applied Energy Systems), and the City and County of Honolulu's H-Power plant are all located near Barbers Point. In order to construct a 2.1 mmt/y LNG plant in Ewa, a large enough land area (at least 190 acres) and a vast water area (about 800 acres) must be available for the terminal and harbor. Barbers Point is the only appropriate site for an LNG facility on Oahu, and conflicts with other industrial establishments in the area will be unavoidable.

3. Infrastructure Issues in Hawaii

After regasification, the natural gas must be transported through a pipeline system to the end-users. On Oahu, GASCO's synthetic natural gas (SNG) producing capacity is 15 trillion Btu/y, equivalent to 41 mmcf/d of natural gas or 310.5 thousand tons of LNG per year. According to GASCO, the actual amount of SNG that it supplied in 1992 was 2.9 trillion Btu, equivalent to 8 mmcf/d of natural gas and 60.7 thousand tons of LNG per year. For a 1.5 mmt/y LNG plant, the volume of gas transported by pipeline would be 25 times the current volume of SNG and nearly five times the current SNG producing capacity. This means that an entirely new pipeline system would have to be set up to handle the incoming LNG.

D. LNG Safety Issues

In considering the possible utilization of LNG in Hawaii, careful deliberation must be given to safety issues. This section reviews the main issues concerned, although it is by no means an exhaustive study.

---

[6] *The State of Hawaii Data Book 1992*, DBEDT, March 1993, p. 28.

1. Explosion Risks

Contrary to what many people believe, LNG will not completely burn upon exposure to the atmosphere; nor will it immediately vaporize. This is because of the extreme coldness of LNG and the vast amount of heat required to vaporize it. This factor may have contributed to the fact that, so far, no major explosions have occurred aboard LNG tankers.

An accident that occurred during the Iran-Iraq war may provide a recent example of the risks of explosion on a carrier. An LPG tanker was hit by a missile in the Arabian Gulf, but surprisingly little damage resulted. While this was not an LNG tanker, it may serve as an illustration of the likely extent of damage when shipping refrigerated cargos.

The LPG carrier was loaded with 12,000 tons of liquid butane at minus 23° F. and 6,300 tons of liquid propane at minus 108° F. Both cargos were marginally above atmospheric pressure. The vessel was struck by three air-to-ground, armor-piercing Maverick missiles. One of the missiles caused a rupture about 6 feet long and 6 feet wide in the top of a butane tank. After an initial torchlike flame and radiation caused some heat damage, the pressure of the tank was fully released, and a small fire burned as butane boiled off and was burned. No explosion occurred and no large vapor cloud formed. The fire was put out with water, and the ship was towed to Dubai, where its cargo was transferred. There was no loss of life and no serious injury. Furthermore, only 1,200 tons of butane were lost. While this was not an LNG carrier, the relatively fortunate end result alleviated the fears of many observers.

Storage of LNG on land also carries a high risk of explosion. It is important to note that once regasified, the risks are the same as in handling natural gas. The last major LNG accident in the United States was actually related to storage of LNG on land and happened in 1944 in Cleveland.[7] The accident occurred in the liquefaction, storage, and regasification (peak shaving) plant of the East Ohio Gas Company, the first peak shaving plant built in this country. The cause of the accident was the collapse of a 4,200 m^3 LNG tank. As a result of fires and explosions, 130 people lost their lives and 225 others

[7] U.S. Congress, *Liquefied Energy Gases Safety*, 1978.

were seriously injured. Had the spillage not occurred at a time of day when children were at school and when most people were at work, the casualties might have been much higher. Another mitigating factor was the fact that the wind was blowing away from congested areas, otherwise damage could have been horrifyingly greater. The huge danger potential in this instance, however, is in large part a function of the siting of the LNG; this will be discussed in more detail below.

2. Ship Accidents

Over the years there have been few LNG carrier accidents. This is a point of vital importance to anyone considering the use of LNG in Hawaii, since even the remotest possibility of accident could have serious consequences for the population and for the unique plant and marine life in the state. Statistics show that, among the accidents that have occurred, most have been caused by steering problems arising from mechanical or electrical failures. None have resulted in any loss of life or injury, and less than half have incurred any financial loss through repair. As Table 4 shows, only one involved a fire or explosion and resulted in $66,000 of damage.

While no serious collision has ever taken place, a major LNG spillage at sea could result in a major fire. Considering a typical tanker contains 125,000 cubic meters of LNG in five tanks, Tables 5 and 6 illustrate the effects of a fire resulting in the spillage of just one of the five tanks.

The study cited indicates that the fire is not prolonged and that no explosion occurs that would cause great damage to the ship or anything close by. Once again, if a large amount of LNG is spilled into the sea, the intense cold of the LNG and the huge amount of heat needed to vaporize such a quantity causes the formation of some light floating ice and a vapor cloud.

Further vaporization occurs as the LNG spreads out and the heavy vapor cloud and liquid methane drift downwind. This mix of methane and air is initially too thick to be combustible, but it will eventually reach a concentration within combustible limits as the methane dissipates. However, firefighting techniques have been developed using dry

Table 4. LNG Carrier Safety Record, 1982-89

Date	Name of Vessel	Incident	Cause	Cost of Repairs ($US)	Location	Deaths	Injuries
10/19/82	Lake Charles	Grounding	Adverse Current	0	U.S. Gulf Coast	None	None
12/20/82	Louisiana	Auxiliary Generator	Mechanical	0	Open Seas	None	None
3/23/84	LNG Gemini	Collision Crossing	Failed to Comply	0	Not Designated	None	None
3/16/84	LNG Aquarius	Explosion-Cargo Fire	Open Flame	66,070	Open Seas	None	None
4/12/86	LNG Virgo	Steering Failure	Electrical	0	North Pacific	None	None
12/6/86	LNG Aries	Steering Failure	Mechanical	1,000	Open Seas	None	None
12/12/86	LNGAries	Steering Failure	Mechanical	1,000	Open Seas	None	None
2/4/87	LNGVirgo	Material Filure	Food/Cond.system	1,000	Open Seas	None	None
5/7/87	LNG Aquarius	Steering Failure	Electrical	0	Open Seas	None	None
12/24/87	LNG Capricorn	Steering Failure	Electrical	0	Open Seas	None	None
10/25/87	LNG Leo	Weather Damage	Adverse Condition	10,000	Open Seas	None	None
12/11/88	LNG Aquarius	Boiler Failure	Electrical	5,000	Pacific Ocean	None	None
11/10/88	LNG Aries	Steering Failure	Electrical	2,000	Pacific Ocean	None	None
4/1/88	LNG Taurus	Steering Failure	Stress	0	Pacific Ocean	None	None
8/23/89	LNG Taurus	Cooling System	Mechanical	0	Pacific Ocean	None	None
7/18/89	LNG Libra	Material Failure	Not Designated	0	Pacific Ocean	None	None

Source: US Coast Guard

Table 5. Fire Sizes and Duration

Size (m3)	Duration of Spill (sec)	Maximum Fire Diameter (m)	Fire Height (m)	Duration of Fire (sec)
25,000	Instantaneous	760	863	218
25,000	180	525	667	180
25,000	600	290	442	600
10,000	Instantaneous	495	641	173
10,000	180	330	483	180
10,000	600	185	323	600
1,000	Instantaneous	210	353	98
1,000	180	105	218	180

Source: "A Review of the feasibility of Methods for Reducing LNG Tanker Fire Hazards", D.S. Allan et. al.

Table 6. Thermal Radiation and Vapor Cloud Hazards for Different Spill Sizes and Durations

Spill Size *(m3)*	Duration of Spill *(min.)*	Distance of Harmful Themal Radiation from Pool Fire *(m*)*	Maximum Travel of Vapor Cloud *(km**)*	Maximum Half-Width of Vapor Cloud *(m)*
25,000	Instantaneous	2,100	20	700
	10	900	10	300
	30	550	3-2	150
10,000	Instantaneous	1,500	14	500
	10	600	7-5	200
	30	350	2-7	100
1,000	Instantaneous	660	5	200
	10	190	2-8	70
	30	120	1-4	35

* Distance from center of spill to a point receiving a radiation of 5 kW/m2.

** Maximum travel distance of unignited flammable vapor cloud assuming flammable limit is 5% methane in air, atmospheric stability class F.

Source: "A Review of the Feasibility of Methods for Reducing LNG Tanker Fire Hazards", D.S. Allan, et. al.

chemicals or foam as well as water deluge systems, in order to speed up the dispersion of the methane and thus take the concentration of methane in the air to a level below that of combustion. Tests in the United States show that this is the most effective means of tackling LNG fires.

LNG tankers have, for some time, been constructed with a double hull in order to make them safer. (Normally such a costly change would have been undertaken only in response to a serious accident, but this precaution was taken from the start even though no serious accidents have yet occurred.) Only double-hulled vessels may carry LNG, and only eight shipbuilding yards in the world are capable of building such vessels. These yards are now under a great deal of pressure and are working at capacity, since new regulations under the Oil Pollution Act of 1990 now require double hulls for oil tankers as well.

3. Siting

With reference to the Cleveland accident of 1944, probably the most important factor for residents of Hawaii is the location of an LNG reception point on the island. The Cleveland accident illustrated the potential consequences of an LNG spillage in an urban area and gives some insight into the danger of a major LNG accident.

The siting of any large-scale energy facility is a difficult decision, and LNG is no exception to that rule. Many points have to be considered including economic and safety issues, which often conflict with each other. Improved safety and environmental acceptance of a terminal will almost certainly be achieved by siting offshore. However, this will nearly always cost more, in some instances raising the cost by hundreds of percent.

Should onshore siting be chosen, an outline presented at GASTECH 88 noted some factors that could merit special consideration in fire protection analyses:[8]

---

[8] B. M. Lee, "Fire Protection Systems for LNG/LPG Process and Storage Facilities: The Essential Features," in the Proceedings of GASTECH 88, The Thirteenth International LNG/LPG Conference and Exhibition, Kuala Lumpur, Malaysia, 1988.

Inground storage vessels

- Non-impinging gas fires at venting devices or localized spill fire.
- LNG spill and/or low pressure gas fire in vaporizer pump area on roof.
- Complete involvement of tank.

Aboveground storage vessels

- Non-impinging gas fires at venting devices or localized spill fire.
- LNG spill and/or low pressure gas fire in bunded vaporizer pump area.
- Partial or complete spill fire within bunded area.

Processing area

- LNG spills from high pressure liquid pumping equipment.
- High-pressure impinging gas fires.
- Lubrication oil and/or gas fires in compressors; LNG spills from low-pressure process equipment.

It is also worth considering that distance and density of population are not the only criteria in the choice of site. Factors such as availability of firefighting equipment, closeness to distribution lines, and ease of access must be considered.

Special thought must be given to potential degradation of residential areas and to wildlife habitat because of increased industrial activity. Also to be considered are external factors that may cause or exacerbate accidents, such as adverse weather and the nearby airport.

In the case of Oahu, the sea conditions are very important. Because of the lightness of their cargos, LNG tankers are more buoyant than oil tankers. This means that strong winds or high waves could potentially cause the vessel to capsize. Taking this important factor into account, the North Shore and entire windward coastline of Oahu generally would be unsuitable for reception of LNG tankers, because of the seasonally high surf and the southwesterly flow of the trade winds, which in the event of an accident would move the LNG vapor onto the shore and into populated areas. In any case, docking

bays would still require breakwaters in order to further calm the sea, so that landing could take place safely.

4. Other Areas of Concern

Air pollution is much less of a concern in the case of LNG than it is for other fossil fuels. LNG combustion, unlike that of coal and oil products, emits little if any sulfur dioxide; and with proper siting of major consumers, nitrogen oxide releases would be quickly dissipated by Hawaii's tradewinds. Although all fossil fuels emit greenhouse gases from their combustion, unit emissions from natural gas are the lowest; this is offset, though only slightly, by direct emissions of methane (through leaks, for example), which is longer-lived than carbon dioxide and more effective at trapping infrared radiation. Methane is therefore a more potent greenhouse gas.

The generally cleaner nature of LNG/natural gas use at the point of combustion belies the overall environmental and safety impacts of constructing an LNG project. These environmental concerns have been the main motivator behind the switchings from the traditional fossil fuels (oil and coal) to natural gas. It is necessary to underline that Hawaii has no problems of air pollution. The issues of explosions, accidents, siting, and pollution with respect to environmental protection and human safety are critical to a thorough study of the potential of LNG use. These impacts need to be quantified and analyzed in context of the small, densely populated area of Oahu, which would provide the only logical market for the fuel.

E. Conclusions

This brief survey has focused on the prospects for LNG use in Hawaii. It is far from a complete technical assessment or an actual engineering/feasibility study. Such an effort would be very costly and should be pursued only if there is very powerful motivation for developing an LNG industry in Hawaii. The economics alone cannot justify LNG's introduction. The debate may continue as to whether fuel diversification and environmental reasons can outweigh the higher costs.

Several points stand out in this chapter. First, LNG is not a spot commodity. It cannot be purchased and used on a casual, short-term basis. As the Director of the East-West Center's Program on Resources is fond of saying, "Buying oil is like dating; buying LNG is like a marriage." Switching over to LNG in Hawaii would require a massive, long-term commitment and substantial investments in the LNG train and the local infrastructure.

Second, LNG supplies are growing very tight in the Asia-Pacific region. The price of LNG is bound to rise. Looking at the per-unit LNG prices now paid by major consumers such as Japan is not a good indication of the prices Hawaii would pay.

Third, some of the environmental benefits of LNG (that make it a prized fuel in Asia) are not entirely relevant in Hawaii. Hawaii's air quality is generally excellent, so switching to LNG in the electric power sector is not as critical as it is in areas with severe air pollution problems.

Fourth, the air quality benefits may be more than counterbalanced by the environmental hazards connected with large-scale coastal zone construction, and by the safety hazards of LNG carriers, regasification facilities, pipelines, and perhaps even LNG tank trucks and vehicles.

Fifth, LNG is not suitable for all energy uses, and is likely to be entirely unsuitable for neighbor island energy needs. Power sector and large-scale industrial uses appear most likely to be able to use LNG, followed by expansion of residential and commercial uses as pipeline networks are expanded. Transport uses initially may be possible in the form of CNG. Direct use of LNG in vehicles is still only an experimental/demonstration project level. Theoretically, it is possible to use LNG as a jet fuel, but this use is highly speculative. The safety risks may be extreme. Therefore, LNG would shift the pattern of demand, but is not cure-all for Hawaii's energy future.