



COLLEGE OF SOCIAL SCIENCES
HAWAII ENERGY POLICY FORUM
UNIVERSITY OF HAWAI'I AT MANOA

Final Report On

Evaluating Liquefied Natural Gas (LNG) Options for the State of Hawaii

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**Prepared for
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List of Abbreviations

AAGR	average annual growth rate
ANWR	Arctic National Wildlife Refuge
ANS	Alaska North Slope
b/d	barrels per day
bcf/d	billion cubic feet per day
bscf/d	billion standard cubic feet per day
BTU	British thermal unit
cf/d	cubic feet per day
cm ³	cubic meters
DBEDT	Department of Business Economic Development and Tourism
EIA	Energy Information Administration
GW	gigawatts
GWh	gigawatt hours
HECO	Hawaiian Electric Company, Inc.
IGCC	integrated gasification combined cycle
IEA	International Energy Agency
IPP	independent power producers
IRP	Integrated Resource Plan
kb/d	thousand barrels per day
km	kilometers
ktoe	thousand tonnes of oil equivalent
KWh	kilowatt hours
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSFO	low sulfur fuel oil
MECO	Maui Electric Company, Inc.
mmb/d	million barrels per day
MMBtu	million British thermal units
mmscf/d	million standard cubic feet per day
mmtoe	million tonnes of oil equivalent
mmtoe/d	million tonnes of oil equivalent per day
mtpa	million tonnes per annum
MW	megawatts
scf	standard cubic feet
toe	tonnes of oil equivalent
tcf	trillion cubic feet
tscf	trillion standard cubic feet
TWh	terawatt hours
USWC	United States West Coast

Introduction and Overview of Findings

The prospect of bringing liquefied natural gas (LNG) to Hawaii has been discussed at various times in the past, but it has been largely dismissed due to high costs. In recent years, however, the LNG market has undergone a dramatic transformation. Production costs have declined and the large number of new supply projects has transformed the LNG market into a buyer's market, where buyers have much more flexibility in contract terms and prices are significantly lower. Of course, a change of this magnitude is likely to be disruptive to the existing energy infrastructure, but LNG clearly deserves a close look as Hawaii considers its future energy strategy.

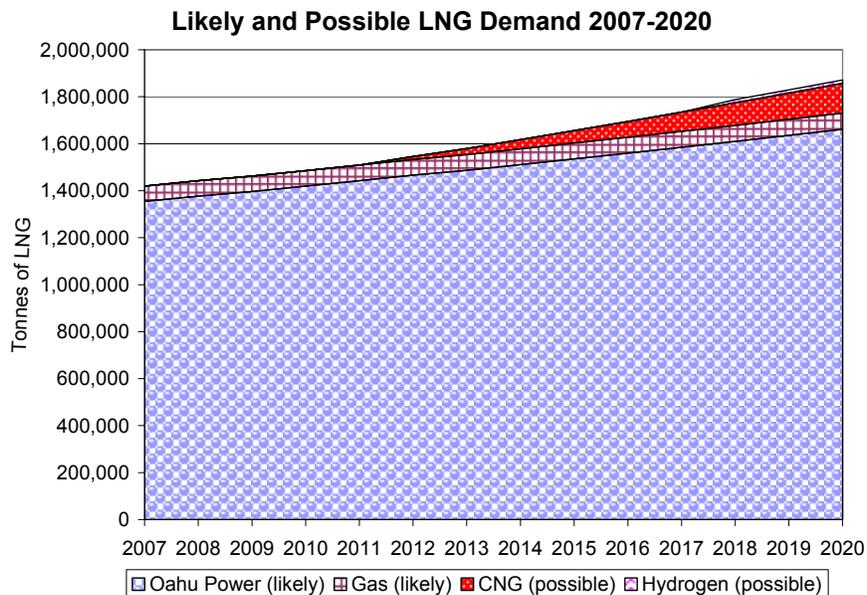
FACTS Inc. has been asked to provide an update on the state of the regional LNG market and to examine the advantages/disadvantages of bringing LNG to Hawaii in the context of recent market developments. This section provides a brief introduction to the LNG market and a general overview of the findings of this study.

LNG: Characteristics and Background

- LNG is natural gas that has been cooled to -256 °F, at which point it liquefies and occupies 1/600th the volume that it does in its gaseous state.
- LNG is not pressurized or flammable in its liquefied state.
- The first LNG trade in the Asia-Pacific region was between Alaska and Japan, beginning in 1969.
- The major suppliers in the Asia-Pacific region are Australia, Brunei, Indonesia, and Malaysia. Russia (Siberia) is expected to join this group in 2006-07.
- Approximately 2/3 of the 111 million tonnes per annum LNG market is in the Asia-Pacific region, but both the US and European markets are set to grow quickly over the coming decade.

LNG: Possible Hawaii Demand Scenarios

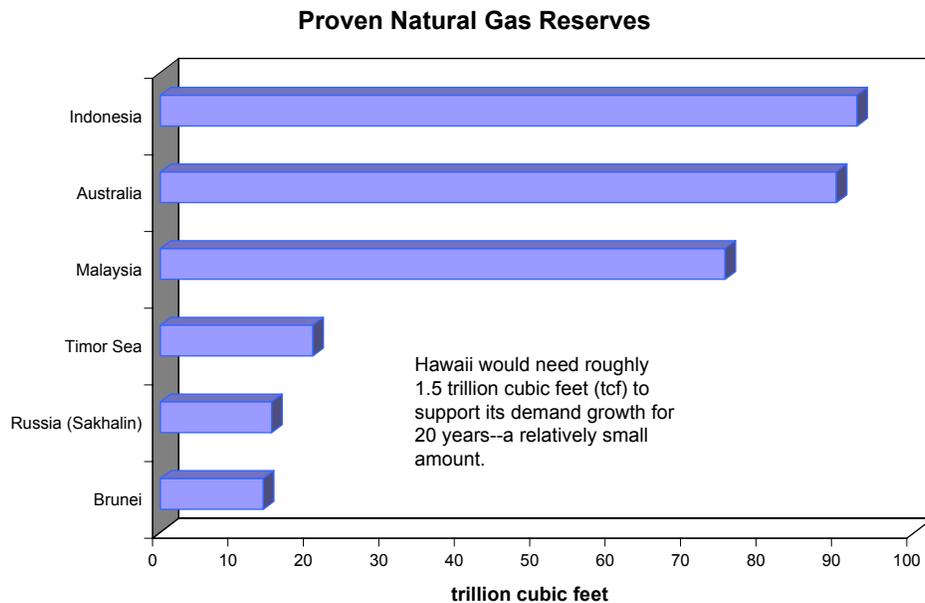
- As reflected in the figure below, power would likely dominate LNG use. According to our estimates, if all of the major oil fired power plants were to be converted to LNG, Hawaii would require approximately 1.35 million tonnes of LNG in 2007 (a hypothetical date for first imports) for use in power generation. This would grow to 1.54 million tonnes by 2015 and 1.66 million tonnes in 2020.
- In comparison to consumption in the power sector, the Oahu utility gas market is likely to be quite small (an estimated 65,019 tonnes in 2007). However, there is certainly a lot of room for growth as the price of utility gas may be reduced with LNG imports.
- Over time, there is the possibility that other uses may emerge, including compressed natural gas (CNG) for vehicles, neighbor island use, and reforming natural gas into hydrogen for fuel cells.



Source: Calculations based on information provided by DBEDT

- It should be noted that LNG supply is not a major concern, as there is a large amount of “stranded” gas in the Asia-Pacific region. If Hawaii chooses to sign a long-term contract, it is essentially claiming proven gas reserves for its own use

for 20-30 years, which is the typical time frame for a long-term contract. The figure below shows that Hawaii's reserve requirements (approximately 1.5 trillion cubic feet over the life of a 20-year contract) are relatively small when compared to the proven reserves of major potential suppliers.



Source: BP Statistics

Advantages of LNG for Hawaii

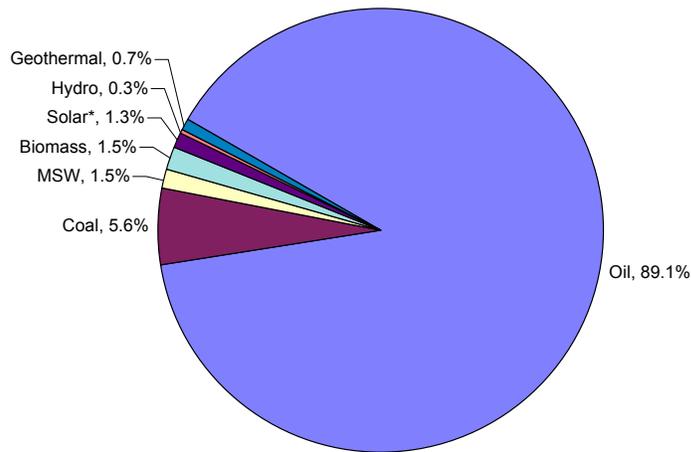
There are a number of clear advantages to pursuing the LNG option in Hawaii:

Energy Security

- As illustrated below, LNG offers the opportunity for substantial diversification away from oil within this decade. Currently, oil is the source of close to 90 percent of Hawaii's energy consumption.
- If Hawaii chooses to pursue the LNG option, it could reduce oil's share of the primary energy mix by approximately 20 percent within 4-7 years of a decision to move forward.
- LNG may be sourced from stable supply sources, such as Australia.

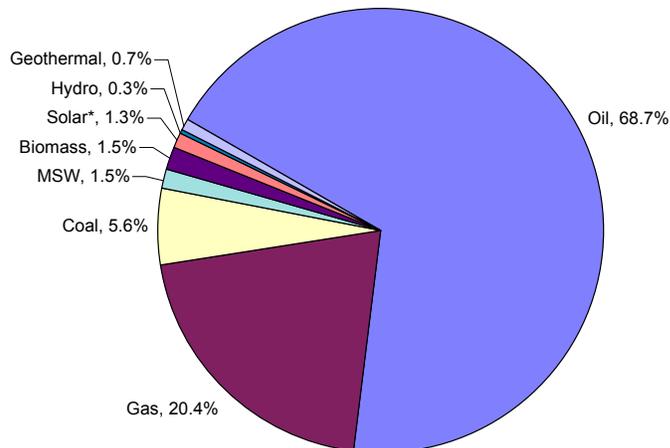
- If desired, Hawaii could sign a 20-30 year contract with a price formula of its choosing, in terms of the linkage to oil price (or other fuel). This would guarantee supply and likely reduce uncertainty over future price stability.
- HECO could retain the ability to consume fuel oil in the event of an LNG supply disruption, thereby further enhancing energy security.

State of Hawaii Primary Energy Fuel Mix: 2001



*Note: Solar includes wind and solar heated water.
Source: DBEDT estimate for 2001.

**Hypothetical State of Hawaii Primary Energy Fuel Mix w/LNG: 2001
(1.209 mtpa LNG)**

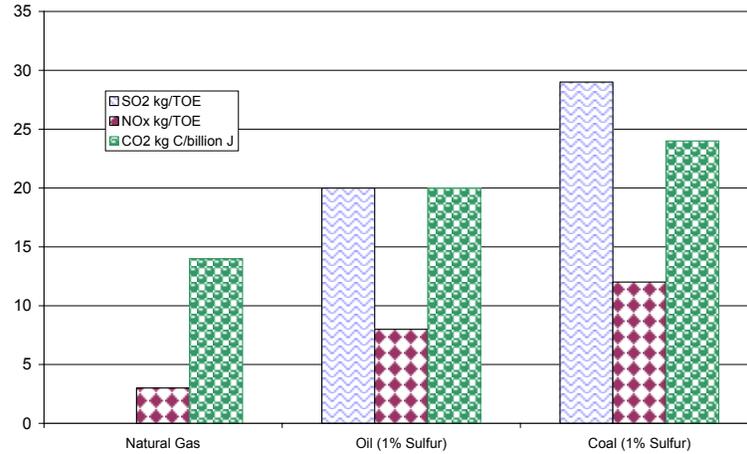


*Note: Solar includes wind and solar heated water.
Source: DBEDT estimate for 2001.

Environment

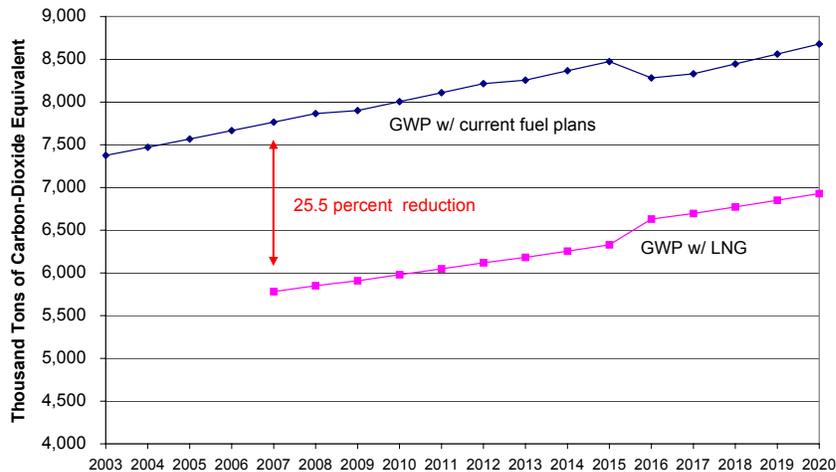
- Natural gas is a relatively clean-burning fuel. As illustrated by the estimates presented below, in terms of key pollutants, it is lower than fuel oil or coal.

A Comparison of Alternative Fuels in Power Generation



- Looking forward to 2020, using LNG instead of maintaining current fuel plans would reduce the global warming potential of Oahu power generation by approximately 25 percent, as shown in the following figure. It should be noted, however, that LNG production and transport consumes more energy than oil production and transport, so the true reduction is closer to 15 percent when the entire production chain is taken into account.

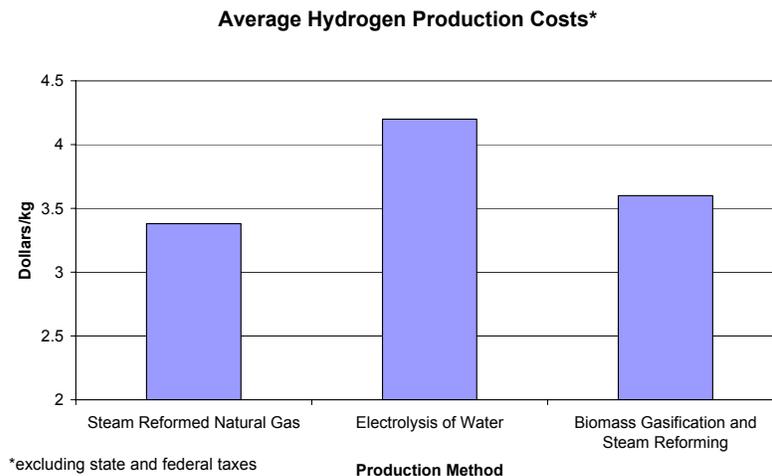
**Global Warming Potential of Oahu Power Generation
Current Fuel Plans vs. LNG in 2007**



Source: Calculations based on information provided by DBEDT

A Potential Bridge to a Hydrogen Economy?

- Hydrogen powered fuel cells are seen by many to be the technology that will allow us to move away from an oil based economy. The Federal Government has earmarked \$1.7 billion for the research and development of hydrogen fuel cell technology.
- Hawaii is arguably among the best sites in the US to explore this technology—electricity generated via geothermal, solar and wind power has long been viewed as the ideal, albeit currently expensive, emissions free means of producing hydrogen for fuel cells (via electrolysis of water).
- In spite of its promise, the high cost of producing hydrogen and developing a hydrogen infrastructure is a considerable roadblock along the path towards an emissions-free hydrogen economy. There is, however, a possible solution in bridging the gap towards a Hawaii hydrogen economy—LNG.
- LNG, or in its gaseous form, natural gas, is currently the least expensive feedstock for producing hydrogen. Although running fuel cells with hydrogen derived from natural gas is not emissions free, it is a very efficient and a low pollution interim solution, which could enable the development of a hydrogen infrastructure. Eventually the hope would be to move away from a dependence on natural gas and to produce hydrogen using electricity that is generated from renewable sources.

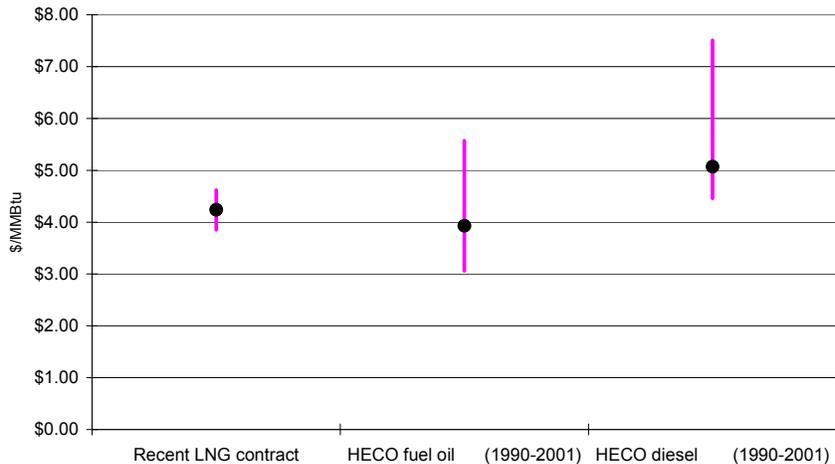


Source: U.S. Department of Energy

Competitive Price

- Currently the LNG market is a buyer's market. The capacity of potential projects outweighs likely demand, and thus suppliers are offering major concessions to secure buyers.
- Hawaii is an appealing market to a number of potential LNG suppliers. It is seen as stable and secure, and its location between the US West Coast and most potential supply sources would likely allow sellers to better optimize their supply operations, as the US West Coast market develops.
- Among the main disadvantages of Hawaii as an LNG market is that it is a relatively small market and it may be both expensive and difficult to establish a receiving terminal.
- The following figure illustrates the range of potential costs to supply LNG vs. other fuels. Recently, BP agreed to supply LNG to SK Power and POSCO Corporation of South Korea from the Tangguh field in Indonesia. This supply agreement is quite relevant to Hawaii as a price marker, because the LNG volume (1.1 million tonnes per annum) is very similar to Hawaii's anticipated LNG demand.
- Although the details of the agreement are confidential, it is widely believed (and reported) that the FOB price is approximately \$2.50/MMBtu at a \$20/bbl oil price. The formula is believed to have a price floor of \$2.15/MMBtu (at a \$15/bbl oil price) and a price ceiling of \$2.92/MMBtu (at a \$26/bbl oil price). Adding an estimated \$0.70/MMBtu for transportation from Tangguh to Hawaii and an estimated \$1.00/MMBtu for regasification, port costs, and other capital costs, yields an LNG price range of \$3.85-\$4.62/MMBtu, with an average price of \$4.24/MMBtu. This range is depicted in the figure under the category "Recent LNG contract."
- For comparison, the high/low range of prices and average price that HECO paid for fuel oil and diesel over the period 1990-2001 is also reflected in the figure.

Cost of LNG vs. Other Fuels (Hi/Low Range and Average)



- Given these estimates, it is clear that LNG has the potential to be competitive with fuel oil, and especially diesel. LNG has the added bonus that its price is certain to be less volatile, if a pricing formula similar to the BP and SK/POSCO agreement were to be adopted.
- Existing plans to cover future growth in electricity consumption call for a diesel fueled combined cycle power plant. LNG is obviously very competitive with diesel, so the price advantage of introducing LNG would likely grow over time.

Jobs Created During the Course of Construction and Operation

- Constructing an LNG terminal typically takes approximately 3 years. One source estimates that about \$100 million would be spent in local communities, but this obviously varies depending on the type of terminal that is selected. For example, if an offshore terminal is selected the number of jobs created would be less.
- At the peak of construction approximately 400 direct contract construction workers would be employed. If you include direct, indirect, and induced jobs (i.e., the employment multiplier—jobs created as a result of the initial job. For example, an employee at the LNG terminal could buy a new house, thereby creating construction jobs.), approximately 891 jobs could be created over the course of the construction period.

- An LNG terminal would have approximately 45 direct full-time employees once it is in operation. Because it is not an established industry in the State, it is not clear what the employment multiplier is for LNG, but if the employment multiplier for the power industry (3.10) and the job multiplier for the petroleum industry (4.63) are taken as guidelines, between 140 and 208 jobs would be created in the overall economy.¹

Disadvantages of Pursuing the LNG Option

The main disadvantage of LNG is that it would be disruptive to the existing energy infrastructure. In some ways, this is acceptable because one of the primary goals of the State is to diversify away from its existing dependence on oil. There could, however, be some negative consequences which must be weighed against the advantages.

Reduced Competition Associated with a Possible Refinery Closure

- Fuel oil comprises a large share of the production of both the Chevron and Tesoro refineries. The refineries could respond in a number of ways if a large portion of the fuel oil market is displaced by LNG, including changing their crude slate, upgrading to produce higher value products, and exporting to other markets, but there is certainly the possibility that one of the refineries would close.

Possible Job Losses Associated with a Refinery Closure

- If a refinery were to close due to the introduction of LNG, there would likely be some net job loss.
- As an example, we understand that the Chevron refinery employs approximately 180 direct full-time employees. In the event of a closure not all of these jobs would be lost as ports, tanks, and delivery would be maintained. If we assume that 110 direct full-time employees are terminated with a multiplier of 4.63, as discussed previously, the overall job loss would be 509 jobs.
- Taking into account the creation of jobs through the LNG terminal, the estimated net job loss would be between 301 and 369 jobs.

¹ Source: Eugene Tian, DBEDT

- It is important to note that jobs would likely be created if gas and electricity prices were to fall, due to the introduction of LNG. This could lead to increased consumer spending, and eventually new jobs.

Summary

- If Hawaii was developing its energy infrastructure from scratch, LNG would likely be the ideal fuel, especially given the available options. It would allow the State to limit its dependence on oil, it is clean burning, and it could serve as a useful ‘bridge’ fuel as the State looks to develop other technologies, such as fuel cells. On top of this, LNG is price competitive with alternative fuels.
- Of course, Hawaii is not developing its energy infrastructure from scratch. LNG would displace existing fuels, and as a result its introduction could be disruptive to the existing infrastructure, including the possible closure of a refinery.
- To conclude, because it is currently a buyer’s market, an array of LNG suppliers are anxious to sell LNG to Hawaii at very attractive terms. We suggest that Hawaii’s energy stakeholders take a close look at this opportunity.

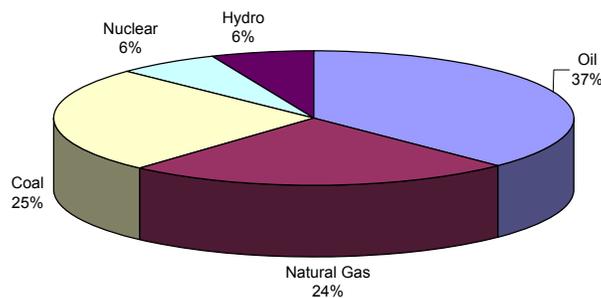
Chapter 1

Background and Market Familiarization¹

Natural Gas in the Primary Energy Mix

Historically, natural gas has been viewed by the energy industry as an “ugly duckling,” compared to its more versatile brother, oil. In fact, a number of oil producers simply treated natural gas as a byproduct and flared it, as the cost of processing the gas was greater than its value. Often the negative value of the gas was due to the long distance from demand centers, thereby making it uneconomic to transport via pipeline. Technological innovations, such as liquefied natural gas (LNG), have enabled producers to utilize these previously stranded gas fields, and have contributed to the rise in the international trade of this hydrocarbon. More recently, tightening environmental standards throughout the world have increased the popularity of natural gas, especially in the power sector.

Figure 1-1
World Primary Energy Consumption, 2002



Source: BP Statistical Review of World Energy, 2003

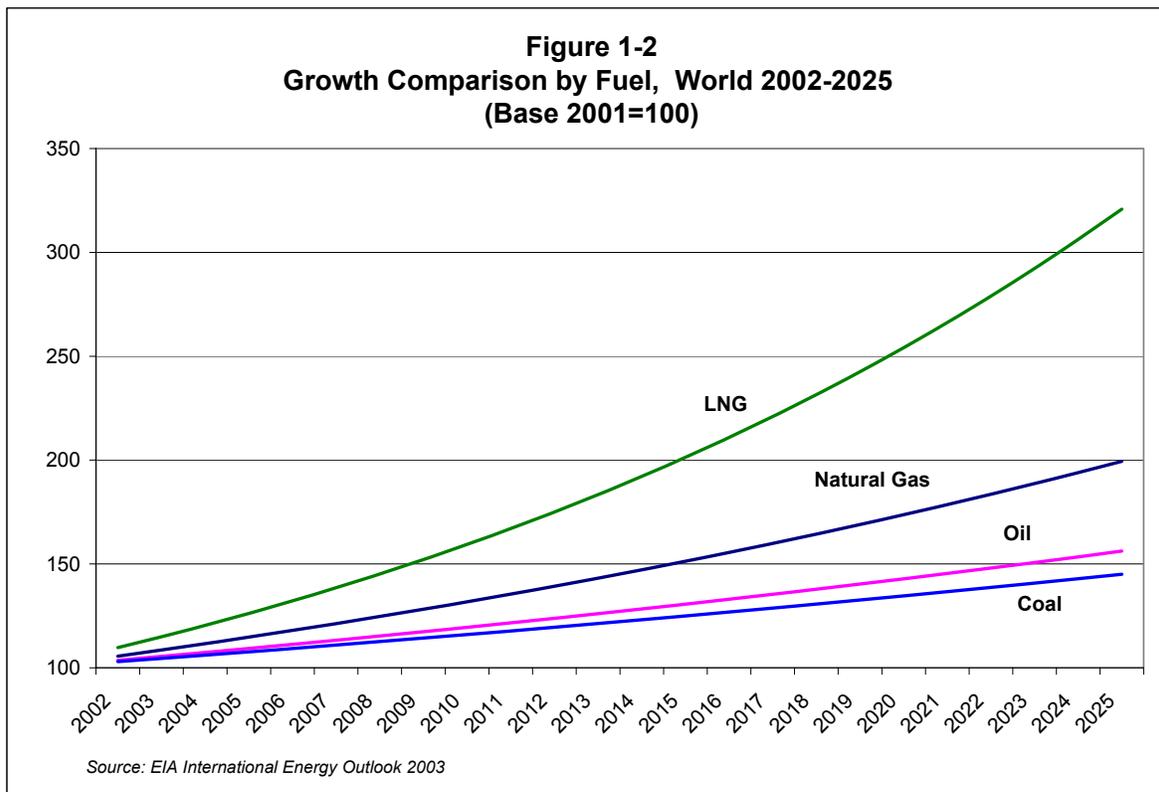
In 1970, worldwide natural gas consumption was 36 trillion cubic feet (tcf), or about 17 percent of primary energy consumption (PEC). By 2002, natural gas consumption had jumped to 91 tcf, accounting for 24 percent of PEC (see Figure 1-1). Pipeline gas accounted for 94 percent of

¹ This chapter draws on FACTS database and sources; BP Statistical Review of World Energy 2003; Energy Information Administration International Energy Outlook 2003; US Geological Survey World Petroleum Assessment 2000.

natural gas supply in 2002, whereas LNG accounted for 6 percent, making it a relatively small force in overall supply. However, LNG is expected to play a much larger role in the natural gas market, as a number of new and expansion projects are coming online in the next decade, as discussed in subsequent sections.

Why Natural Gas?

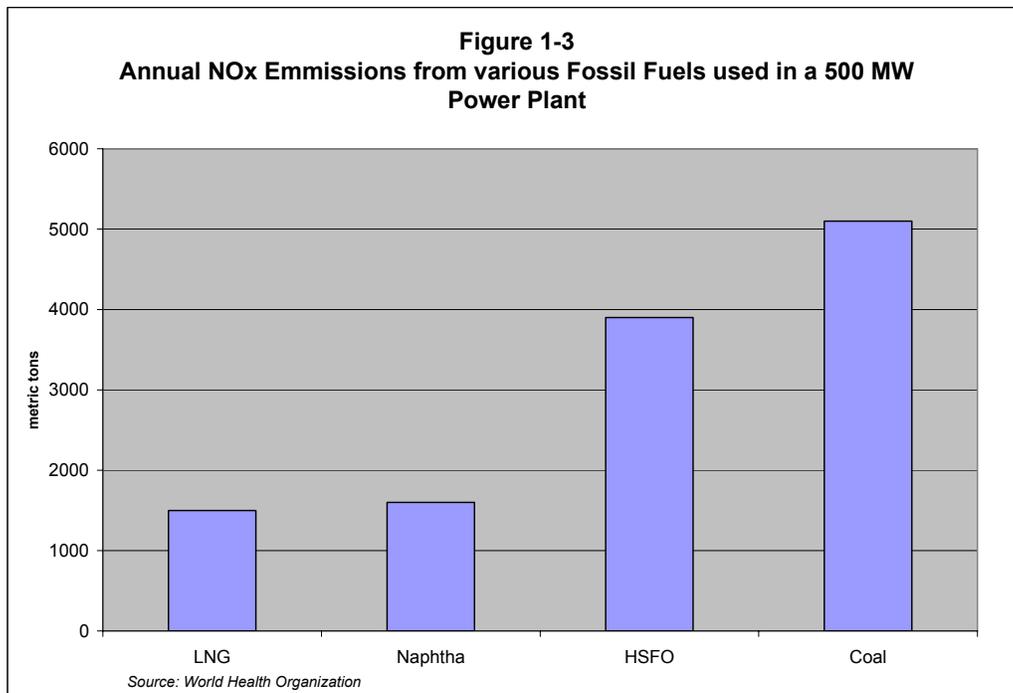
For a number of reasons, natural gas use has increased substantially in recent decades and this trend is forecast to continue, if not accelerate, in the near future (see Figure 1-2).



First of all, liquefied natural gas (LNG) is allowing gas to penetrate markets that were in the past inaccessible because of distance barriers. Developments in both liquefaction facilities and LNG tankers over the past thirty years have led to declining unit costs, thereby increasing the competitiveness of LNG versus other fossil fuels, such as oil and coal. Secondly, governments are looking to reduce their dependence on Middle East oil imports and diversify their national energy supply mix, and natural gas often allows them to do this. This is particularly relevant to Hawaii, as we are dependent on oil for approximately 90 percent of our PEC, making the State

very susceptible to turmoil in the world oil markets. A strike in Nigeria or a war in the Middle East has a direct effect on the price we pay for gasoline, power and other goods and services. Diversifying our energy sources could help alleviate some of these price fluctuations. Finally, in the power sector, higher efficiencies and lower investment and operating costs have made natural gas a popular alternative to other fuels, despite its higher fuel cost when compared to coal. This, coupled with the environmental benefits of burning natural gas, makes it an attractive fuel.

As mentioned above, one of the main drivers of natural gas and LNG consumption is environmental benefits, especially in the power sector. According to a study done by the World Health Organization, LNG (or natural gas) emits the least amount of NO_x when compared to other fossil fuels commonly used in power generation (see Figure 1-3). LNG also emits less SO_x, particulate matter, and CO₂.

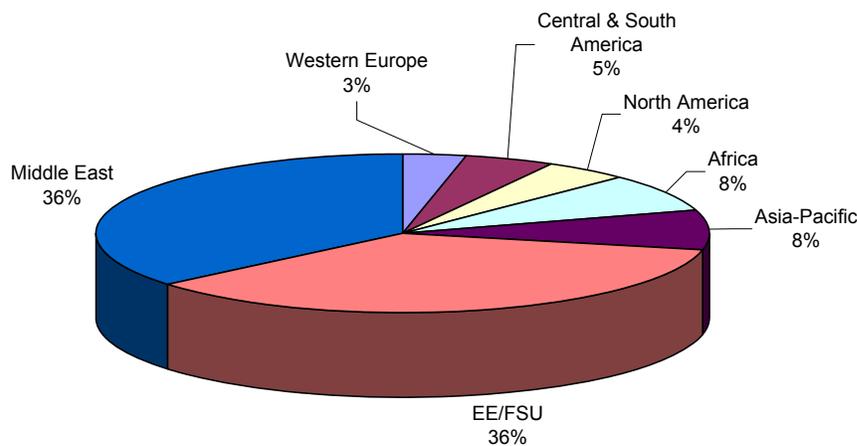


Gas Reserves

Since the mid-1970s, world natural gas reserves have generally increased every year. As of January 1, 2003, proven world natural gas reserves were 5,501 tcf as reported by the *Oil & Gas Journal*. Worldwide, the reserves-to-production ratio (RP ratio) is estimated at 62 years, with

higher RP ratios in regions with substantial reserves and low consumption, such as Africa and the Middle East. Please note that these are proven reserves and do not count possible and potential reserves which would significantly increase the reserve figures.² Figure 1-4 illustrates the regional distribution of worldwide natural gas reserves.

Figure 1-4
World Gas Reserves by Region as of January 1, 2003

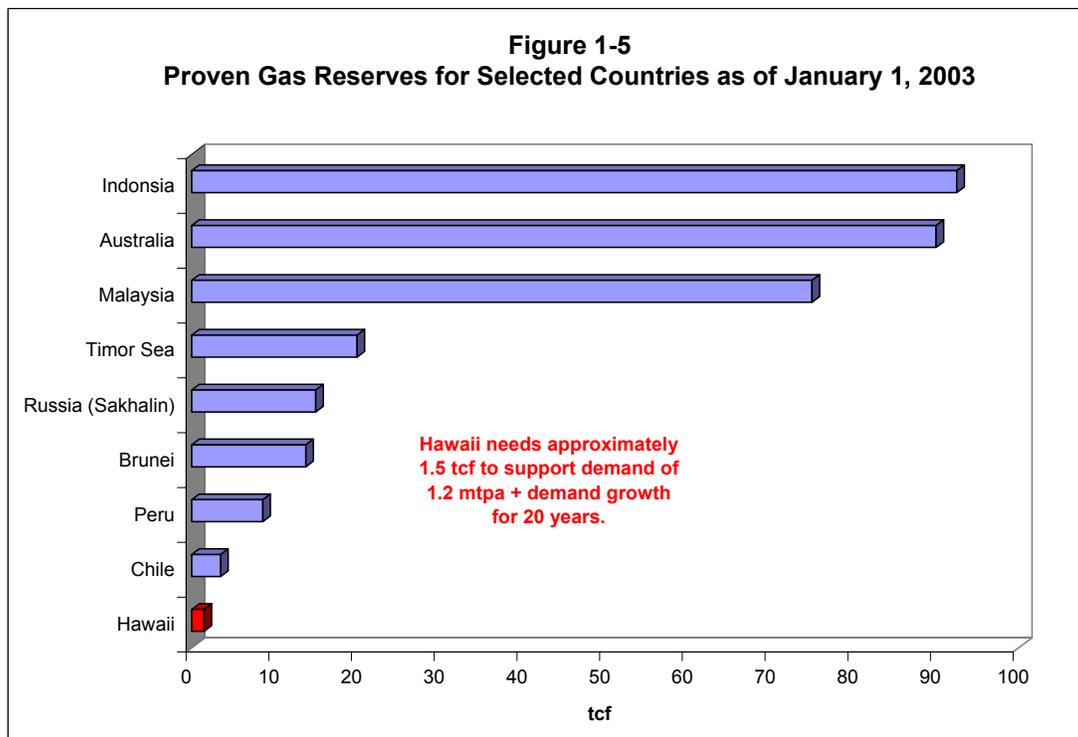


The Middle East and Former Soviet Union (FSU) along with Eastern Europe (EE) dominate world gas reserves with a 72 percent share. The Asia-Pacific region is a substantial consumer, yet holds only 8 percent of proven gas reserves and these reserves are spread out across the region, hence the popularity of LNG. In North America the situation is somewhat precarious, with depleting reserves (4% of the world total) and the largest consumption in the world. Traditionally United States' gas consumption has been served by domestic production, along with substantial piped imports via Canada, thereby negating the need for the more expensive LNG. However, with the production of North American suppliers stagnating, prices have increased from the historical range of \$2-3/MMBtu to the \$4-6/MMBtu range that we have seen

² The US Geological Survey in their report *World Petroleum Assessment 2000*, states that the mean estimate for undiscovered gas reserves is approximately 4,900 tcf, about double current proven reserves.

over the last two years. This has influenced the re-emergence of LNG on the domestic gas scene, as LNG is seen as economically viable at US gas prices of \$3.50/MMBtu and higher.

A key question in the context of this study is: if Hawaii were to source LNG from the Asia-Pacific region, would there be enough gas available for export considering the region has only 8 percent of the world's gas reserves? The answer is a resounding yes. Gas demand in Asia is strong and reserves are comparatively limited on a worldwide scale, yet they are still substantial, especially when looking to export to a small market such as Hawaii. Figure 1-5 looks at likely possible suppliers of LNG to the State and compares proven reserves with Hawaii's potential demand of approximately 1.2 million tonnes per annum (mtpa).³ The figure clearly shows that there are ample reserves available among the possible candidates in Asia (also Peru and Chile) and that exporters should have no problem supplying the gas from their specific projects. The more important factor on assessing the potential of LNG imports into Hawaii rests with the price, not supply availability. This will be addressed in detail in Chapter 5.



³ See Hawaii Hydrocarbon Outlook, January 2003.

World LNG Trade

In 2002, the Asia-Pacific region accounted for approximately 69 percent of world LNG trade, or 77.1 million tonnes (see Figure 1-6). This was down slightly from 2001, when the region had a 71 percent market share, although both scenarios underpin the significance of Asia with regards to worldwide LNG trade. The high proportion of LNG trade in the Asia-Pacific region can be attributed to the distance between demand centers, such as Japan and South Korea, and sources of supply in Southeast Asia and the Middle East. By 2015 LNG demand in the region is expected to reach 141 million tonnes. Given its location in the middle of the Pacific, it is obviously important that Hawaii understand the likely direction of the Asia-Pacific market as it considers future LNG options.

Figure 1-6
World LNG Trade, 2002

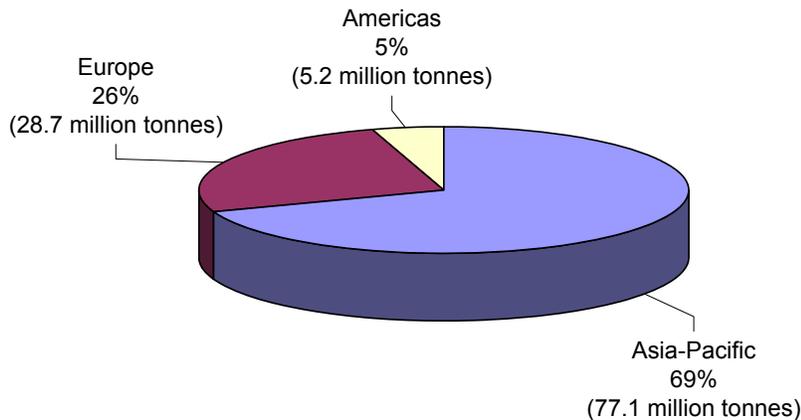


Figure 1-6 illustrates that Europe accounted for about 26 percent of world LNG trade in 2002, with the major consumers being France and Spain. Nine LNG terminals have been built throughout Europe, mostly in Southern Europe, in an effort to diversify away from pipeline imports from Algeria and Russia. European demand is forecast to remain strong, potentially doubling by 2010.

The Americas (US and Puerto Rico) accounted for the remaining 5 percent of LNG demand in 2002. Of this, 4.7 million tonnes were consumed in the US, while the remaining 0.5 million tonnes were consumed in Puerto Rico. Recently, the US market has been a hot topic in the energy industry, with even Alan Greenspan making a pitch for increased imports into the US because of declining natural gas production in North America. LNG is seen by many as an alternative to dwindling domestic gas supplies and this has led to an enormous amount of proposed receiving terminals to service the giant gas market. The press has reported at least 20 new proposed terminals targeting the US market on top of the existing 4 terminals that have recently been reopened or expanded. By 2025 LNG will potentially supply 10-15 percent of US gas demand, compared to about 1 percent currently.

Although Hawaii's potential LNG demand is relatively small, increased gas demand in the US (particularly the USWC), as well as in Asia, puts Hawaii in a unique position as it is well placed between the two regional demand centers. Multiple suppliers in Southeast Asia and Australia have signed Memorandum of Understandings (MOUs) with potential receiving terminals on the USWC and in Baja, California. Having Hawaii as a supply option may also allow potential suppliers to better optimize shipping, thereby lowering costs. There is also the possibility of Hawaii acting as a midway point between the two regions and receiving LNG either on the way to the USWC or during the backhaul.

Key Players

As stated above, LNG demand is poised to increase drastically during the next couple of decades. The industry has responded with a plethora of projects, some expansion projects and some new, or "Greenfield," projects. Currently there are 12 LNG exporters in the world, with 8 supplying the Asia-Pacific market (see Table 1-1). Of these eight suppliers, three are found in the Middle East, four in Asia-Pacific, and one in the US (Alaska). Currently, Indonesia has the largest amount of liquefaction capacity at 29.4 million tons per annum (mtpa) followed by Malaysia, Qatar, Australia, etc.

Table 1-1
Liquefaction Plant Capacity for Asia-Pacific Market (mtpa)

Asia-Pacific		Middle East	
<u>Operating</u>		<u>Operating</u>	
Alaska (Kenai)	1.4	Abu Dhabi	5.7
Australia (NWS)	7.5	Oman	6.6
Brunei	7.2	Qatargas	8.3
Indonesia (Bontang)	22.6	RasGas	6.6
Indonesia (Arun)	6.8	RasGas II (Train 3)	4.7
Malaysia Satu	7.6		
Malaysia Dua	7.8		
Malaysia Tiga Train 1	3.4		
Malaysia Tiga Train 2	3.4		
Sub-total	67.7	Sub-total	31.9
<u>Under Construction</u>		<u>Under Construction*</u>	
Australia NWS Train 4	4.2	Oman Train 3	3.3
Australia (Darwin)	3.5	Qatargas Debottleneck	1.2
Sakhalin II	9.6	RasGas II (Train 4)	4.7
		RasGas II (Train 5)	4.7
Sub-total	17.3	Sub-total	13.9
<u>Under Consideration</u>		<u>Under Consideration*</u>	
Australia (NWS) T5	4.2	Iran	14.4
Australia (Gorgon)	10.0	Qatargas II (Train 4,5)	15.6
Australia (Sunrise)	5.3	Qatargas III (Train 6)	7.8
Bolivia	7.0	RasGas II (Train 6,7)	15.6
Brunei Train 6	4.0	Yemen	6.0
Indonesia (Bontang) T9	3.5		
Indonesia (Tangguh)	8.0		
Indonesia (Donggi)	7.0		
Peru	4.0		
Sub-total	53.0	Sub-total	59.4
Total	138.0	Total	105.2

*Middle East projects under construction & consideration are expected to target primarily Europe and the US.

Table 1-1 illustrates the enormous amount of production capacity expected to come online in the next decade. In the Asia-Pacific region 85.0 mtpa will be operating by 2010 (currently operating + under construction) with the majority of the projects targeting the Asia-Pacific market. Indonesia, Malaysia, Australia and Sakhalin (Russia) have all expressed interest in supplying the USWC markets, thereby making them likely potential suppliers to Hawaii.

It should be noted that although a substantial amount of capacity is coming online in the Middle East (especially in Qatar and Iran, which share the largest gas field in the world), the primary target of this added capacity is Europe and the Gulf/East Coast of the US. As a consequence, the Middle East is not particularly relevant as a potential supplier from Hawaii's perspective. In general, Middle Eastern suppliers have shifted their focus away from their traditional markets in Asia and towards Europe and the Gulf/East Coast of the US because of strong future demand growth in these regions.

Before proceeding with a more detailed examination of the challenges of bringing LNG to Hawaii, as presented in the following sections, it should be pointed out that LNG would likely be delivered to Hawaii under one of three scenarios. (1) A supplier in Asia, or even Latin America, would deliver LNG cargoes from a single supply source that are solely destined for Hawaii (this is the traditional model). (2) A supplier in Asia/Latin America would deliver LNG cargoes from multiple supply sources to Hawaii (this is the new trend, as it optimizes shipping). (3) A supplier from Asia would deliver to the USWC and drop off some cargo along the way or as backhaul. Each of these scenarios is plausible, according to the companies we have spoken to with equity in LNG projects in Asia and Latin America. However, 1 and 2 are viewed as the most likely scenarios.

Chapter 2

Outlook for Small LNG Markets¹

Why Small-Scale Markets?

In terms of the global LNG market, Hawaii’s projected demand of about 1.3 million tonnes per annum (mtpa) would be considered relatively small, at less than 1 percent of world demand. In the past, LNG projects were typically developed with major markets—such as Japan and Korea—in mind. The idea was that either a single buyer or a small group of “anchor” buyers would take the full volumes. Small individual markets, such as Hawaii, were largely ignored. Recently, however, market conditions have changed and Hawaii is receiving a lot of attention among suppliers as a potential LNG consumer. This section examines the prospects for the development of relatively small LNG markets, such as Hawaii.

The rush to build new, larger, LNG projects to monetize gas fields and capture economies of scale has led some suppliers to search for multiple buyers for a single output, a shift away from the traditional strategy of dedicating a single train to a major anchor buyer. This, along with flat demand in some traditional markets such as Japan, is causing prospective suppliers to consider all opportunities to develop new markets in what has become a buyer’s market. Often these new opportunities are in areas where gas demand is strong but markets are small, such as in the Dominican Republic and Puerto Rico. Other small markets which have been considered in the past include the Philippines, Sri Lanka, New Zealand, and Singapore. In some cases the initial development is targeted at the power sector, with the terminal and power plant developed jointly in order to streamline costs. Although these models may not fit the Hawaii model exactly, it is worth taking a quick look at successful projects with a similar demand structure.

A Small-Scale Project in Puerto Rico

Building a new regasification terminal entails a host of critical factors such as choosing an appropriate site, ensuring a close and readily available local market, obtaining the necessary

¹ This chapter draws primarily on FACTS database and conversations with various contacts.

permits, reassuring the public in terms of safety and environmental issues, and securing favorable financing. Often the most effective way to ensure a regasification terminal makes it through the planning process is to link it to an existing or new power plant and/or other useful energy application. Eco-Electrica, the developer of the Penuelas terminal in Puerto Rico took the aforementioned points into consideration before beginning construction on a terminal that was successfully completed in 2000.

The \$650 million terminal in Penuelas, Puerto Rico involved the construction of a LNG receiving terminal, a combined cycle cogeneration plant, and a desalination unit (2 million gallons/day). This quite substantial project was unique in that it was the first financed project that combined an LNG terminal and a new power plant. The power plant is 507 MW and consumes 93 mmscf/d sourced from nearby Trinidad. The terminal has one 160,000 m³ storage tank (about 70,000 tonnes—just over one tanker’s capacity) and the terminal and storage facility are reported to have cost around \$200 million. Current contracted volumes are 0.55 mtpa. As the Puerto Rican market is competing with supplies destined for the US, the price is linked to Henry Hub, the gas price marker in the US.²

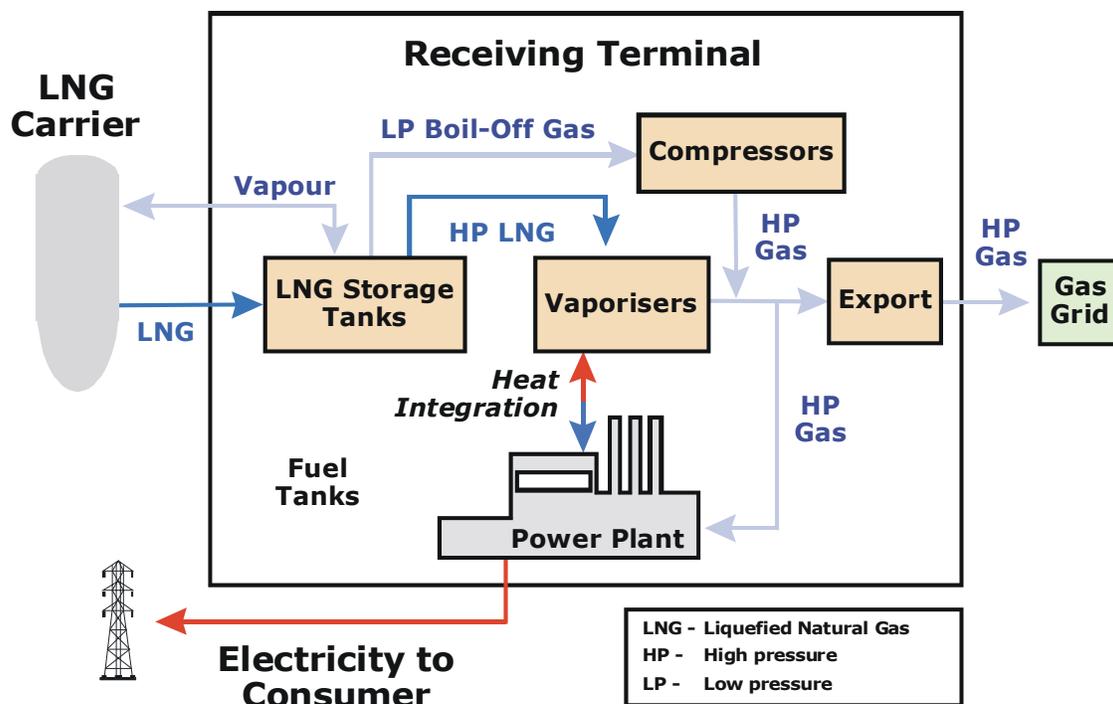
A Small Scale Project in the Dominican Republic

In 2002 AES finished work on an integrated \$400 million LNG terminal that included an import terminal, regasification facility, pipeline, and a 300 MW combined cycle power plant, located outside of Santa Domingo in the Dominican Republic. For reference, a diagram of this integrated power plant is included as Figure 2-1. The capacity of the receiving terminal is 2 mtpa and contracted volumes are currently 0.6 mtpa. The gas will be going to the newly constructed combined cycle power plant and also to a converted 210 MW oil-fired power plant (Hawaii’s situation is likely to parallel this model—converting existing oil-fired capacity and building new combined cycle power plants to satisfy future demand growth). The cost to convert the fuel-oil power plant to gas is reported to have been \$1.5 million.

² Henry Hub is a physical point in Louisiana where 17 gas pipelines intersect, thereby creating a competitive reference point for market prices. This will be explained in more detail in Chapter 5, LNG Pricing.

Figure 2-1

Integrated Power Plant and Receiving Terminal—Dominican Republic



Source: Andy Flower, Pacific Gas Insiders 2002

Implications for Hawaii

There are both similarities and differences when comparing the aforementioned receiving terminals with a possible terminal in Hawaii. The similarities center on the challenges of supplying a small-scale market, addressing the need to diversify fuel sources (both islands were extremely dependent on oil, as is Hawaii), and protect the local environment—all at a reasonable cost.

Among the major differences between these projects and Hawaii is that in the case of the Dominican Republic, and especially Puerto Rico, a suitable harbor was available that needed only minor modifications, thereby decreasing overall construction costs. In the case of Hawaii the only harbor that is available is Barber’s Point, and the port would require substantial modifications to accommodate a large LNG tanker. In particular, the harbor would need to be dredged at least another 4 feet, to 42 feet, to allow LNG tankers of 135,000 m³ (a typical size) to

offload. One way to avoid dredging the harbor would be to bring in smaller size LNG tankers, a definite possibility according to the LNG suppliers that FACTS has had discussions with (older tankers of approximately 90,000 m³ may be available in 2009 as the Alaska-Japan LNG contract ends). In this context, it should also be noted that in contrast to Hawaii, the projects in Puerto Rico and the Dominican Republic are very close to their supplier, Trinidad. Thus these projects are able to save on transportation costs, which helped make LNG cost competitive.

The experience in the Caribbean shows that costs can be brought down to a level which makes small scale import terminals economically feasible. The Puerto Rican terminal alone (including the import terminal and storage facility) is reported to have cost approximately \$200 million, which puts it roughly in line with the cost that potential suppliers have put forward for Hawaii, with the potential cost of dredging in Hawaii being the key variable which could raise costs substantially. Hawaii is also likely to convert existing oil-fired power plants to gas, as has been done in the Dominican Republic. Overall, it is important to note that Hawaii is not moving into uncharted territory as it considers converting to LNG. Other island economies have already proceeded down this path and shown that it is a viable option.

Chapter 3

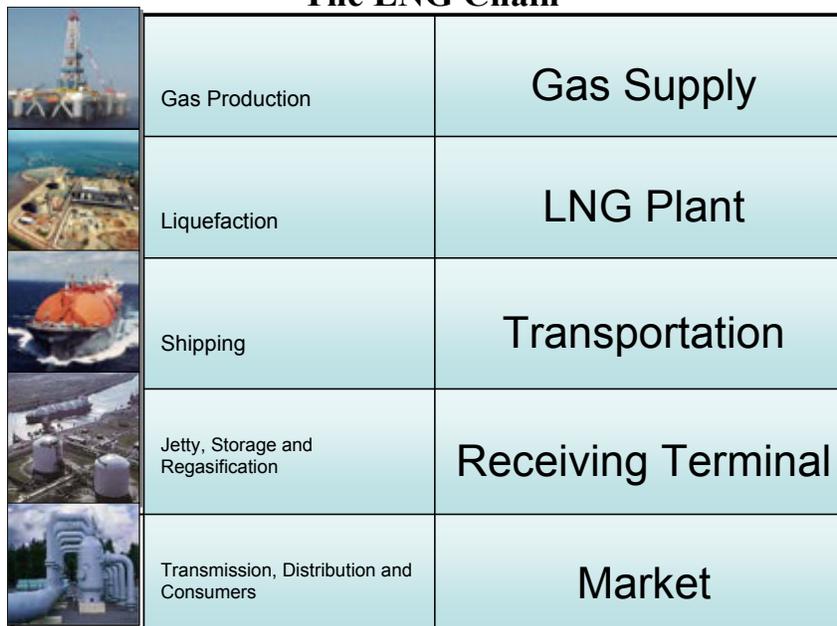
Overview of LNG Technology¹

This section of the study provides an overview of the technology that is employed along the LNG chain. While the final stages of the LNG chain are of primary interest to Hawaii, there have been a number of technological developments that have triggered cost savings and have also opened up new possibilities for consumers.

The LNG Chain

The main links in the LNG supply chain are gas supply, the LNG plant, transportation, regasification, and finally, consumption of the gas (see Figure 3-1). The first step is obviously to produce the gas. A decision is made as to whether the gas should be piped to a market, injected into nearby oil fields to enhance production, converted to liquids such as oil products or methanol (still quite uncommon), or finally, converted to LNG.

Figure 3-1
The LNG Chain



Photos: BG

¹ This chapter draws on FACTS database and sources, the text Liquefied Natural Gas: Developing and Financing International Energy Projects, by Gerald B. Greenwald, “Applying New Technology to Lower Overall LNG Costs,” by John Stone, Gastech 2000 Conference, and Drewry LNG Market Review 2002.

Once the decision is made to export LNG, the gas is sent to a liquefaction plant (often referred to as a liquefaction train) where natural gas is converted from its gaseous state into a liquid, which is 1/600th the volume, and it is stored. The liquid gas is then transported via LNG tanker to the receiving terminal where it is then piped to a nearby storage tank(s). When it is needed, the liquid gas is piped from the storage tanks to the regasification facility where it is heated to return it to its gaseous form. It is then piped into a distribution network and/or a power plant.

Key Technologies in the LNG Chain

Exploration and production costs have been decreasing due to technologies, such as 3-D seismic imaging and improved subsea facilities. 3-D seismic imaging first gained popularity in the mid 1960s as this tool helped create accurate pictures of areas that held reservoirs, thereby allowing greater precision in drilling and lowering overall production costs. Additional advances in seismic imaging such as 4-D seismic imaging have allowed further analysis of hydrocarbon reservoirs by creating moving pictures that show how reservoirs have changed during production and how it will likely change in the future. In addition, well designs such as the “Big Bore” design pioneered by ExxonMobil increases flow rates and reduces well counts for upstream production facilities, contributing to lower overall project costs.

Liquefaction is essentially the same process as that used in domestic refrigerators, except on a much larger scale. The process entails compressing a refrigerant gas (propane, ethane, or methane) and releasing it through a valve which reduces the temperature. This refrigerant gas is then used to cool the feed gas until it eventually reaches -256 degrees Fahrenheit, at which point methane, the main component of natural gas, liquefies. The first commercial liquefaction process is known as the Cascade Process designed by Phillips in the 1960s for a liquefaction plant in Kenai, Alaska. Another popular liquefaction process is the Mixed Component Refrigerant Process (MCR), developed by Air Products and Chemicals Inc. It has been used in most of the plants built in the last 25 years. Both of these liquefaction technologies are in use today, with individual suppliers tailoring the designs to fit their specific needs.

It should be noted that as the excitement over the prospects for future growth in LNG demand has grown, new technology is under development. For example, ExxonMobil’s promising

PLNG (pressurized LNG) steel pipe, which weighs less than grades in use today but is 20-50 percent stronger, allows higher pressure to be applied to the refrigerant gases and enables the gas to be liquefied at a temperature of -150 degrees Fahrenheit, instead of the traditional -261 degrees. PLNG could significantly reduce liquefaction expenses because the plant is only about half the size of a traditional liquefaction facility and the process is simpler and uses less energy.

There are two main ship designs in use today in the **transportation** of LNG, namely the Kvaerner-Moss and the Membrane designs. The Kvaerner-Moss ships contain the LNG in distinctive self-supporting spherical tanks (illustrated in Figure 3-1). The tanks are welded into the hull of the ship at their equatorial rim, with the upper half of the sphere protruding above the deck. The Membrane ships are similar to the Kvaerner-Moss model except that the tanks are built into the structure of each ship's hull and are not visible from the outside. In 2002, out of an existing fleet of 143 vessels, about 52 percent were Kvaerner-Moss designs, 44 percent Membrane designs, and the remaining four percent were other designs. The price of both types of ships has decreased substantially over the last decade due to increased competition amongst Asian and European shipyards. Currently an LNG tanker cost approximately \$150-160 million for a 140,000 m³ vessel. In comparing the two ships there is no significant difference in costs for comparable sized ships and no major differences in operability. However, Membrane ships have one major advantage in that their cool-down time is less, enabling these tankers to spend less time in port.

It should be noted that new super-sized LNG tankers are being planned in an effort to capture economies of scale where large trades exist. For example, Qatar has announced plans to build 200,000 m³ vessels to service future trades with the UK and US. These super-sized tankers face constraints which will limit their widespread use (they are likely to be impractical for Hawaii) such as draft restrictions in ports, Port Authority rules, the strength of the jetty, and storage capacity at receiving terminals. No receiving terminal currently in operation or under construction can receive ships greater than 160,000 m³, so it is clear that these ships will be targeting new large-scale terminals being built in the UK and the US.

The main facilities at a **receiving terminal** include a jetty to berth and unload ships, storage tanks, regasification facilities or vaporizers, and a connection to a pipeline grid or power plant. There are numerous types of storage tanks in use throughout the world, ranging from single containment, to double containment, to full containment. The tanks are generally constructed of nickel steel to withstand the extremely low temperature of LNG. Full containment tanks offer the maximum protection against failure, which allows tanks to be placed much closer together, but costs are substantially increased. If land space is not an issue, it makes economic sense to spread single containment tanks throughout the site. In the case of Hawaii, adequate land space is an issue and thus the more expensive full containment tanks would almost certainly be required.

There are a variety of different vaporizers currently in use, with the two most popular being the Open Rack LNG Vaporizer (ORV) and the Submerged Combustion Vaporizer. Essentially, the vaporizers heat the liquid gas and convert it back to its gaseous state. Vaporizers would represent a relatively small portion of the overall cost of a potential receiving terminal in Hawaii, at an estimated cost of between \$10-30 million.

An LNG receiving terminal is a substantial construction project which is sometimes viewed as an eyesore, and opposed, by local residents. Opposition has been particularly strong in the United States, especially on the West Coast. The industry has responded to their concerns by introducing the concept of on-board regasification terminals and off-shore receiving terminals. *El Paso's Energy Bridge* ship is a revolutionary system that aims to allow LNG carriers to regasify LNG on the ship and pump the gas ashore through dedicated offshore buoys. This technology adds roughly \$30 million to the cost of a ship. The major disadvantage of such a system in the context of Hawaii is that the offtake would need to be used directly, as there is no suitable natural gas storage mechanism in the State.² With Hawaii's small market it is unlikely that these ships will be able to unload a full cargo very quickly, unlike major demand centers on the Gulf/East Coast. This would obviously add to costs, as an expensive tanker would sit idle, and consequently it is unlikely that this is a practical option for Hawaii.

² In the continental US natural gas is sometimes stored in underground salt caverns.

Developing an offshore terminal is a possibility that has been discussed among potential suppliers of LNG to Hawaii. Numerous offshore receiving terminals have been proposed for the Gulf Coast and West Coast of the continental United States. While no offshore receiving terminals are currently in operation, ChevronTexaco's Port Pelican is currently in the process of obtaining the necessary permits to construct a \$600 million facility with a capacity of 7-10 mtpa off the coast of Louisiana. The advantages of an offshore receiving terminal in Hawaii would include the reduction of NIMBY (not in my backyard) concerns, no dredging of the harbor at Barber's Point and avoidance of further congestion in shipping lanes. Disadvantages include a challenging operating environment and higher capital expenditures (it is estimated that the cost is roughly double that of a land based facility) and possible issues with strong currents and large surf. However, it should be noted that offshore concrete structures that contain storage facilities do exist in the petroleum industry and have been proven successful in challenging operating environments such as the North Sea.

Trends in Costs

Improved technology and larger liquefaction facilities have substantially reduced the unit cost of LNG over the last twenty years. Table 3-1 indicates the current range of costs at various stages for a new LNG venture. The figures are based on data released by various organizations and should be taken as a broad guide. In comparing the high and low case for all stages, costs range from a low of \$1.25 to a high of \$4.95/MMBtu. Of course, a project is unlikely to be at the high or low end of these estimates at all stages. For example, Hawaii is likely to be near the high end in cost for its regasification terminal, but if it receives gas from the Asia-Pacific region rather than the Middle East its transport cost will be much lower than \$1.40/MMBtu.

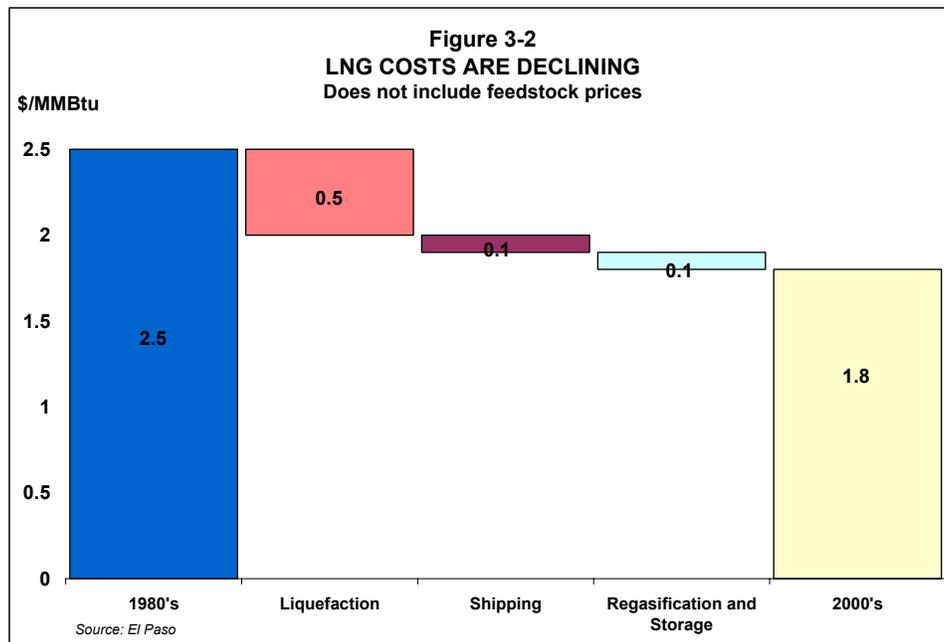
Overall, costs obviously vary substantially depending on the size of the liquefaction train, the distance to the market, and the challenges in establishing a regasification terminal at the end market. Because Hawaii is a relatively small market and its regasification terminal would probably be relatively expensive on a unit basis, Hawaii would likely fall somewhere between the average and high cost category—in the range of \$3.50-4.50/MMBtu—and final prices would reflect this.

Table 3-1
Indicative New LNG Project Costs (US\$/MMBtu)

	Low	Average	High
Gas at liquefaction plant producer/exporter	0.25	0.75	1.25
Liquefaction costs infrastructure, local factors	0.50	1.00	1.50
Transportation cost (distance/size of ships employed)	0.20	0.80	1.40
Regasification cost and storage	0.30	0.40	0.80
Total	1.25	2.95	4.95

Source: Drewry LNG Market Review and discussions with potential suppliers

As mentioned earlier, the unit cost of LNG has come down substantially in recent years. The largest cost savings have come in liquefaction trains, as illustrated by Figure 3-2, which shows where the cost savings have come when comparing a typical project in the 1980s to today. New technologies and larger trains have enabled suppliers to reduce liquefaction costs from a high of nearly \$600/tonne of capacity to about \$200/tonne of capacity for a Greenfield project. The unit cost of transport and regasification terminals has also declined, although not by as much as liquefaction trains.



LNG for the Neighbor Islands

Most of the discussions of the possibility of bringing LNG to Hawaii focus on the Oahu market, but it is certainly technically feasible to bring LNG to the neighbor islands as well. Delivering LNG to the neighbor islands would certainly offer unique challenges as the markets are obviously substantially smaller than Oahu and it would not make economic sense to build full-scale receiving terminals on all of the outer islands. However, there is the possibility of using barges to carry LNG from Oahu to various destinations, as is done in Japan, albeit at a high cost.

Another possibility, as mentioned by one supplier, is to place trucks that carry LNG on to barges and send them to the neighbor islands. The trucks would simply drive off the ships and drop off their cargo at select destinations. Of course, the receiver of the LNG would have to have the necessary vaporizers to transform the liquid back into gas. There are existing utility systems on the neighbor islands that currently use LPG for cooking and water heating and it is likely that the gas could be placed into these existing systems.

Chapter 4

LNG Contracts¹

This section of the study provides an overview of the main terms of an LNG contract. Of course, Hawaii could develop a contract structure that fits its individual needs and priorities, but this is the general framework that most contracts follow. The important thing to remember is that developing an LNG contract is analogous to developing a relationship. Both sides need to signal steadily deepening levels of commitment for things to move forward and investment to progress.

In general it is clear that LNG markets are moving away from rigid long-term contracts and toward terms that more closely fit the needs of the buyers. This trend is likely to continue for the near to medium term, as buyers will likely have the upper hand in the marketplace.

Main Terms in a Typical LNG Contract

A typical LNG contract, or a Sales and Purchase Agreement (SPA), is a definitive contract between a seller and buyer for the sale and purchase of a quantity of LNG for delivery during a specified period at a specified price. Prior to finalizing the full details of an SPA, a letter of intent (LOI), memorandum of understanding (MOU), or heads of agreement (HOA) is typically signed, which is used as a broad outline to develop the terms for the sale and purchase of LNG. Although LOIs, MOUs, or HOAs outline the broad principles of the agreement, they do not include details of certain aspects, including the pricing mechanism. In most LOIs, MOUs, or HOAs there is likely to be a provision for either the sellers or the buyers to withdraw if an agreement cannot be reached on the details of the SPA.

¹ This chapter draws on FACTS database and sources, ExxonMobil Gas Marketing Company, *LNG A Glossary of Terms* (Petroleum Economist, April 2001), Gerald B. Greenwald, *Liquefied Natural Gas: Developing and Financing International Energy Projects* (Kluwer Law International, 1998), and Andy Flower, *The Fundamentals of LNG*, LNG Short-Term Trading, (August 2003)

LNG contracts/SPAs define details and clauses covering specific issues such as those listed below:

- Duration
- Volume
- Take-or-pay flexibility
- FOB versus CIF/ex-ship
- Price
- Force majeure
- Other relevant procedures

Duration

Traditionally, long-term sales agreements are necessitated by project economics to guarantee revenues to remunerate large capital investments. Therefore, most of the existing long-term contracts are for periods of at least 20 years. Buyers did not have a problem in accepting long-term contracts in the 1960s/1970s, since they needed to finance investment in terminals, power plants, and distribution systems.

In recent contracts, however, some buyers—especially Japanese buyers—are asking for a mixture of long-term, medium-term and shorter-term contracts, as uncertainty over demand prospects due to stagnant economic growth and market liberalization have made it very difficult for some buyers to commit to long-term contracts without greater flexibility. Sellers are reluctant to move away from long-term contracts, but they are starting to make concessions in this area to win new contracts or to ensure contract extensions. It should be noted that new buyers in developing markets (including China and India) are an exception to the trend toward shorter contracts, as they tend to want long-term (20 years) contracts so they can arrange financing for terminals and power plants.

Volume

In most SPAs there is a “build-up” period before buyers take the annual contracted volumes. Some buyers need a slower build-up period to meet market growth. For sellers, rapid build-up is important, as build-up volumes provide the early cash flow to remunerate investment.

A contract also provides the buyer with “upward flexibility and “downward quantity tolerance.” Upward flexibility provides the buyer with the right to receive additional volumes that the seller has the ability to supply. Downward quantity tolerance, meanwhile, is the volume the buyer can elect “not to take” without triggering a take-or-pay obligation. While typically the quantity tolerance on older contracts is quite narrow, some of the newer contracts and extensions have adopted wider quantity tolerances.

Take-or-Pay and Destination Clauses

A take-or-pay clause in a contract requires a minimum quantity of LNG to be paid for, whether or not delivery is accepted by the buyer. The take-or-pay clause provides sellers with a secure stream of revenue, as it ensures that the buyer does not fail to take its contractually required quantities. The take-or-pay level is typically at least 90 percent of the contracted quantity in most existing contracts, but some sellers are softening take-or-pay terms in recent contracts.

Older projects have been able to creatively relax take-or-pay levels by transferring portions of renewed contracts to a short-term basis, which effectively reduces take-or-pay commitments. Similarly, some expansion projects have offered a mixture of long-term and short-term volumes to create greater offtake flexibility. Examples of recent contracts with relaxed take-or-pay levels include Malaysia LNG (MLNG) Satu with Tokyo Gas and Tokyo Electric Power Co. (TEPCO), and MLNG Tiga with a Japanese buyers’ consortium (contract details to be discussed later in this chapter). However, take-or-pay terms for new or “Greenfield” projects—with the exception of internally funded projects—will likely remain high as it is often necessary to finance a new project.

Most existing contracts limit the buyer’s ability to transfer cargoes to other buyers. Under destinations clauses, some contracts even limit the buyer’s ability to take cargoes to alternate

terminals owned by the buyer. Buyers are already requesting more flexible destination clauses and contracts like ConocoPhillips' Bayu-Undan agreement with Tokyo Gas and TEPCO—where the seller gets a share from certain redirected/retraded cargoes—which will likely increase in the future, as discussed later in this chapter.

FOB versus CIF/ex-ship

In a FOB contract the buyer lifts the LNG from the liquefaction plant and is responsible for transporting the LNG to the receiving terminal. The buyer is responsible for the shipping, either owning the LNG ships or chartering them from a shipowner. Under an FOB contract the seller typically requires an assurance that the shipping protocols provide a safe and reliable offtake of the LNG to prevent a disruption in the contract.

Under a CIF contract, the seller is responsible for transportation and insures the cargo on behalf of the buyer. The buyer takes ownership of the LNG either as the LNG is loaded onto the vessel or during the voyage to the receiving terminal. Payment is made at the time ownership transfers. Under an ex-ship contract, which is more common than CIF, ownership of the LNG transfers to the buyer, as the LNG is unloaded at the receiving terminal and payment is due at that time.

In both FOB and CIF/ex-ship deals, the contract must delineate shipping related issues, including the obligation of a responsible party to provide sufficient LNG tankers to lift the contracted volume and relevant operating procedures.

Price

LNG pricing formulas are discussed in detail in Chapter 5. In this context it should be noted that in addition to the base-price formula the contract states procedures for price renegotiation under “a sudden change of circumstances.” Also, some buyers have a “side agreement” under their long-term contracts (namely the Japanese buyers) which allows for regular price reviews, usually every 4-5 years.

Force Majeure

In essence force majeure is a clause that, under special circumstances, allows a party to be released of certain obligations that are specified in a contract. Force majeure is defined as, “Any circumstance which is beyond the reasonable control of the party effected and prevents or hinders due performance of obligations under the contract and which can not overcome by due diligence.” It should be noted that force majeure is rarely invoked.

The contract provides details of the force majeure events such as acts of war, labour disputes, damage to facilities (which are not due to negligence), and failure of a third party to perform under a contract.

If LNG cannot be delivered or received due to force majeure, such cargoes will operate either as a reduction to the basic contract quantity to be taken by the buyer during a relevant period, or as an exception to the buyer’s take-or-pay obligation for the period. Usually, the buyer restores the undelivered quantities in a subsequent period. The contract provisions normally require the parties to try to schedule the delivery of restoration cargoes before the end of the contract term.

Other Relevant Procedures

In addition to these main terms discussed above, the contract includes other relevant procedures and details, such as quality of LNG, measurement and testing of LNG when it is loaded or discharged, invoicing and payment, and the applicable law.

Changing LNG Contract Structure

Although the structure of Asia LNG contracts has remained relatively unchanged since the first contract was negotiated for Japanese buyers in 1960, the overall landscape of the LNG market has been shifting towards a buyers’ market.

Traditionally, long-term sales agreements were necessitated by project economics, since heavy capital investments were incurred in the early stages. Most of the existing long-term contracts for the Japanese buyers—the world’s largest LNG buyer—are for at least 20 years.

In recent contracts, however, buyers are asking for shorter-term sales, greater flexibility, reduced take-or-pay provisions, and lower prices. Japanese buyers have become notably assertive in renewing and signing new contracts as the country's prolonged economic recession and uncertainty over demand prospects have made it very difficult to commit themselves to contracts without flexibility.

China's Guangdong LNG contract with the Northwest Shelf (NWS) consortium took full advantage of the Japanese buyers' initiatives, and also pushed to change several of the previously orthodox Asian LNG contract clauses. Unlike the Japanese—who need more flexibility—the Chinese focused on establishing a pricing formula that minimizes price volatility over the long term. China also secured a gas price that is markedly lower than existing contracts.

As a result of these changes, some buyers now want both shorter-term contracts and rates approaching the Guangdong price (details to be discussed in Chapter 5: Pricing). This trend can be observed in the Korea Gas Co.'s (KOGAS) recent negotiations for medium-term contracts with Australia's NWS and MLNG Tiga, which have substantial seasonal offtake flexibility (details to be discussed later in this chapter). This is an extremely important concession, considering Korea consumes about 70 percent of its LNG during the October-March period.

“Orthodox” Contracts vs. “New-Style” Contracts

The “orthodox” Asian LNG contracts of the past have typically been for a long term and on an ex-ship basis, with a price formula that generally has approximately an 85 percent linkage to the price of crude oil. The crude oil price marker is generally JCC (Japan Custom Cleared or Japan Crude Cocktail), with the exception of the existing Indonesian contracts with Japanese buyers, which is priced off of ICP (Indonesian Crude Price). Selected components of the “orthodox” contracts are listed below:

- Prevalence of CIF/ex-ship contracts
- 20 years or greater contract durations

- 90 percent or greater take-or-pay
- Strict destination clauses
- Minimal seasonal offtake flexibility
- Formula pricing with an approximately 85 percent crude oil linkage

More recently, the trend towards market deregulation and weak demand growth forecasts (particularly in Japan) have created market uncertainty, which has driven the need for a combination of long-term and short-term/spot contracts. This trend is expected to continue, as many current LNG exporters have amortized their investments and are thus released from the requirement to have inflexible 15-25 year contracts which were imposed by lenders.

Many of the “new contracts” are signed on an FOB basis, which give buyers more control over cargoes and the potential to manage variations in demand. Buyers are able to trade LNG during low demand periods if their contracts give them a resell option.

It should be noted that Japanese buyers increasingly favor FOB contracts. TEPCO—Japan’s largest LNG importer which accounts for over 33 percent of the country’s total imports—will start using some of its own vessels for transportation, allowing the buyer more control over shipping. The first vessel began operations in October 2003 and the second vessel will be operational in 2006. Other Japanese buyers are preparing themselves for FOB contracts as well. By 2006, Osaka Gas will have 3 operational vessels and Tokyo Gas will probably have 4 vessels.

Approximately 87 percent of the newly signed contracts after 1995 are estimated to be based on FOB, compared with approximately 14 percent of such contracts prior to 1995.

Details of the selected “new-style” contracts—which are changing LNG marketing strategies and setting innovative precedents—are discussed below.

MLNG Satu to Japan: Under a contract renewal (supplies began in April 2003), MLNG Satu gave TEPCO and Tokyo Gas significant flexibility as compared to the previous 20-year contract on an ex-ship basis. The renewed contract has a combination of long-term (15 years with provision for a 5-year extension) and short-term (4-year base) volumes as shown in Table 4-1. The two Japanese buyers will use their own vessels to deliver part of the volumes on an FOB

basis. The renewed contract includes a regular price review every four years and is believed to have a different price for each category (long-term, short-term, ex-ship, and FOB).

Table 4-1 MLNG Satu to TEPCO and Tokyo Gas

TEPCO	New (beginning 04-2003)		Previous (ending 03-2003)
	Long-Term (15 years)*	Short-Term (4-year-base)**	Term (20 years)
Ex-Ship	3.2 mtpa	0.4 mtpa	4.8 mtpa
FOB	0.9 mtpa	0.3 mtpa	
Total	4.1 mtpa	0.7 mtpa	
Grand Total	4.8 mtpa maximum		4.8 mtpa maximum

Tokyo Gas	New (beginning 04-2003)		Previous (ending 03-2003)
	Long-Term (15 years)*	Short-Term (4-year-base)**	Term (20 years)
Ex-Ship	1.7 mtpa	0.3 mtpa	2.6 mtpa
FOB	0.4 mtpa	0.2 mtpa	
Total	2.1 mtpa	0.5 mtpa	
Grand Total	2.6 mtpa maximum		2.6 mtpa maximum

**With provision for a 5-year extension. **Review after every 4 years.*

MLNG Tiga to Japan: In the face of strong competition in Asian LNG markets, MLNG Tiga departed from their traditional contract structure to secure buyers. In February 2002, Osaka Gas, Toho Gas, and Tokyo Gas signed an SPA with MLNG Tiga that contained a mixture of long-term and short-term volumes for a maximum offtake of 1.6 mtpa for 20 years from 2004 (see Table 4-2). Under the agreement, 680,000 tpa (ex-ship) will be delivered under take-or-pay conditions over 20 years. In addition, the buyers' consortium takes 480,000 tpa (FOB) under a renewable one-year contract and has the option of taking another 440,000 tpa during the contract period (20 years). The optional quantities (of up to 440,000 tpa) depend upon both the buyers' needs and the sellers' availability.

Table 4-2 MLNG Tiga to Japan Gas Consortium

Japan Gas Consortium	MLNG Tiga (04-2004)	
	Long-Term (20 years)	Short-Term (1-year-base)*
Ex-Ship	0.68 mtpa	0.48 mtpa
FOB		
Sub Total	1.16 mtpa	
Optional Volume	0.44 mtpa	
Grand Total	1.6 mtpa maximum	

**Renewable for up to 20 years.*

Bayu-Undan to Japan: ConocoPhillips has an established relationship with Japanese buyers through its Alaska Kenai project, which many believe gave both sides room to more easily negotiate a flexible contract for the new Bayu-Undan project. TEPCO and Tokyo Gas are also participating in the Bayu-Undan project, in which they hold a 10.1 percent share. The two Japanese utilities will receive a maximum of 3 mtpa (2 mtpa for TEPCO and 1 mtpa for Tokyo Gas) on a FOB basis for 17 years starting in 2006.

The contract includes a price formula which has a lower crude oil price linkage and a portion of it has a fixed price. The contract also permits sales within Japan without informing the supplier, however, sales outside of Japan require the seller's permission and a 50/50 split on any additional revenue. TEPCO and Tokyo Gas will use their own vessels for transportation, thereby enabling them to resell their LNG.

NWS and MLNG Tiga to Korea: In their recent supply agreements, both NWS and MLNG Tiga have given seasonal offtake flexibility to KOGAS in order to satisfy Korea's increasing seasonal shortfalls. KOGAS is contracted to buy 500,000 tpa (ex-ship) from the NWS project for seven years, starting in late 2003. One hundred percent of the contracted volume will be supplied in Korea's winter season (generally understood to be October-March). KOGAS's contract with MLNG Tiga allows it to buy 1.5 mtpa (with the option to buy an additional 500,000 tpa) on an ex-ship basis for 7 years, beginning in May 2003. Eighty percent of the contracted volumes will be supplied in the winter months (October-March) to meet the seasonal increase in demand and the remaining 20 percent in the summer.

NWS to China Guangdong: The Chinese focused their negotiation efforts on the pricing formula while keeping an "orthodox" contract duration of 25 years. The contract allowed the Chinese to achieve a lower overall price as well as reduced price volatility through a more limited crude oil price linkage. The Chinese contracted to buy 3.3 mtpa of LNG from NWS beginning in late 2006 (there is a build-up period). The LNG will be supplied on an ex-ship basis initially, and then transferred to an FOB basis once the Chinese have constructed their own LNG vessels.

Anticipated Trends in Contract Terms Through 2010/2015 Which Could Impact Hawaii

Overall, we expect the recent trends discussed above to continue. LNG contracts will move toward an FOB basis through 2010/2015, as this gives buyers more control over their cargoes. Destination clauses will continue to be relaxed, creating opportunities for arbitrage and a more robust spot market. In addition, more long-term and short-term contract combinations, along with optional volumes, will create greater offtake flexibility. Take-or-pay levels are expected to remain relatively high for financing new projects, but internally financed projects may be more flexible.

Given that Hawaii's potential LNG demand is forecast to be relatively steady, without a sharp seasonal fluctuation in demand, some of the typical concerns—especially seasonal offtake flexibility—may not apply to the State. This could work to the State's advantage if it chooses to secure an LNG contract in the future.

Chapter 5

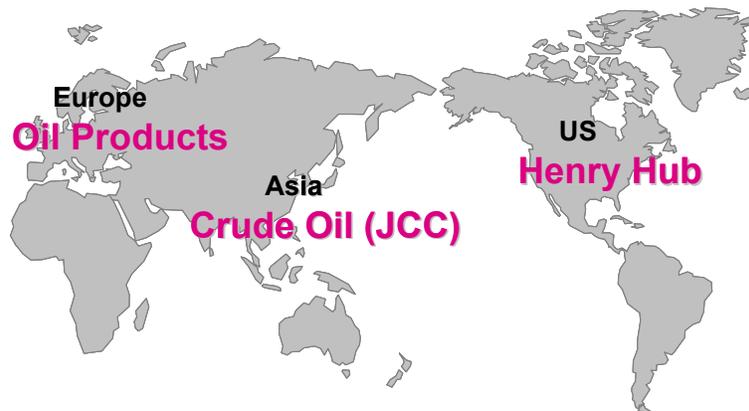
LNG Pricing¹

Regional LNG Prices

If Hawaii is to import LNG among the many decisions that will have to be made is how to price the LNG. Hawaii is located between two major markets that have very different pricing mechanisms and the State may wish to adopt one of these mechanisms or it may wish to adopt an entirely new system. Whatever the decision, it will have long term implications for the State in terms of price level and volatility. This chapter presents an overview of likely options for the State. Please keep in mind that this list is not meant to be exhaustive, but is a good outline of the options that may be considered.

Natural gas is not yet a globally traded commodity so prices can vary substantially from region to region. Currently Europe, Asia, and the U.S. each have their own unique pricing mechanism (see Figure 5-1). For example, in Europe pipeline gas prices are set to compete with oil products, namely gasoil and fuel oil. LNG has to be competitive with pipeline gas, and therefore is generally priced on a similar basis.

Figure 5-1
LNG Pricing by Region



¹ This chapter draws on FACTS database and sources, BP Statistical Review 2003, World Gas Intelligence (various issues), the Korean Energy Review, as well as presentation material provided by Andy Flower @ *Pacific Gas Insiders*, December 2002.

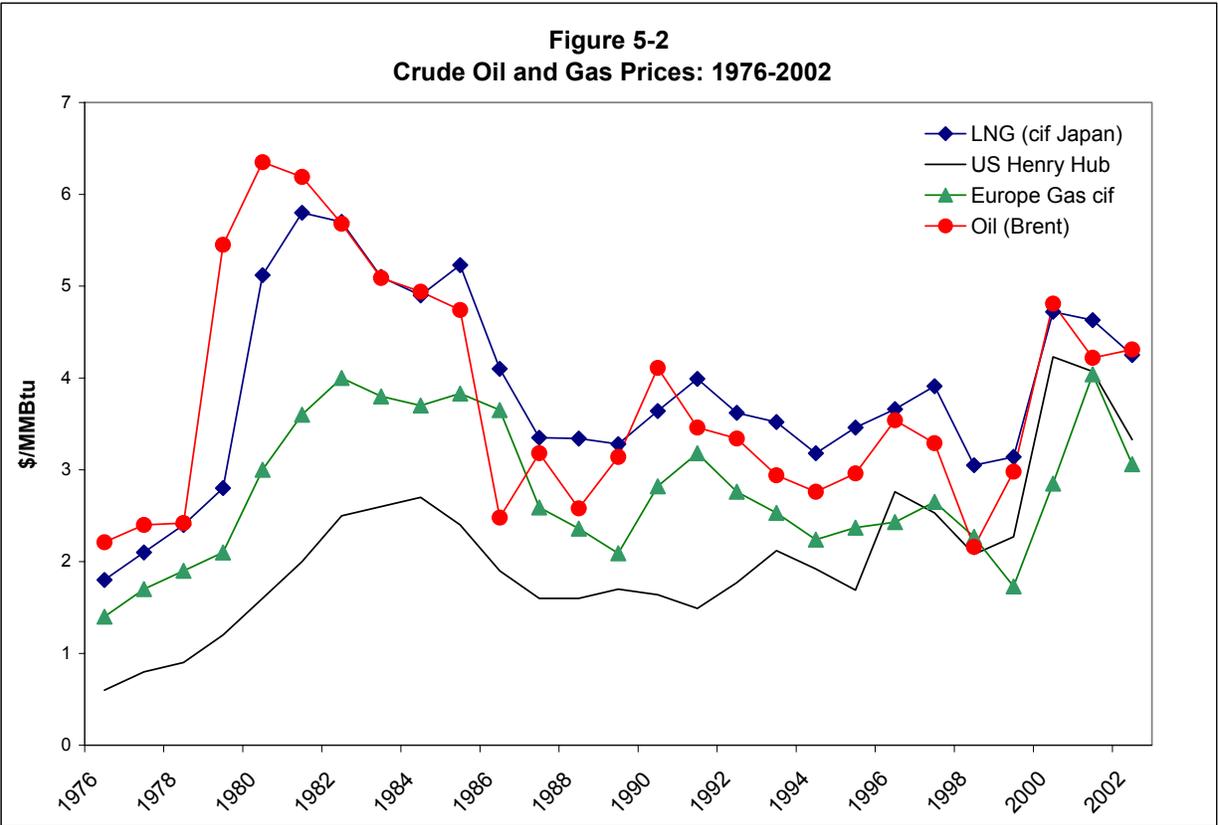
In the U.S. a competitive gas market is firmly ensconced and prices are generally linked to the market price at Henry Hub which, is a physical point in Louisiana where 17 gas pipelines intersect, thereby creating a competitive reference point. The price of gas at various points in the continental U.S. is derived from differentials (+/-) from Henry Hub. The differentials are based on demand patterns and distance of end-users. LNG sales into the U.S, whether they are spot sales or long-term trades, are linked to Henry Hub prices because LNG is competing with pipeline gas.

It is interesting to note that high volumes at Henry Hub allows for a transparent market which has enabled a futures market to develop on the NYMEX. This futures market allows sellers and buyers to hedge their sales and purchases, thereby guaranteeing future prices.

In the past, price volatility and low prices in comparison to the other major gas markets deterred LNG suppliers from targeting the U.S. market. However, recent prices of \$4-6/MMBtu and a projected decline in domestic production and pipeline imports from Canada have added to the appeal of bringing LNG into the U.S.

In Asia LNG prices are generally based off of crude oil, specifically the Japan Custom Cleared (JCC) Crude price. JCC is the average price of crudes imported into Japan every month and is published every ten days. Because of the linkage between crude prices and LNG, the price of LNG goes up or down with the price of JCC. The extent to which the two prices are linked has changed in recent contracts, which will be explored further in subsequent sections.

Figure 5-2 illustrates crude and gas prices from 1976-2002. It shows that Europe and the U.S. have typically had lower gas prices than Asia because of competition from gas pipelines (until recently). In the U.S. gas is produced domestically and is also imported from Canada and Mexico. In Europe gas is piped from Algeria, the Netherlands, the North Sea, and Russia.



We can also see from the figure that the price of LNG in Asia is roughly in line with the price of crude oil, demonstrating the relationship between the two. In the early years LNG was generally priced at a discount to crude oil and now it is generally priced at a slight premium to crude. The evolution of pricing in the Asian LNG market will be discussed in the following section.

Evolution of LNG Prices in Asia

Table 5-1 discusses the evolution of LNG prices in Asia. In 1969 the first cargoes were shipped from Kenai, Alaska to Japan at a fixed price of \$0.52/MMBtu. This is a substantial premium to crude oil as crude’s price averaged \$0.33/MMBtu in equivalent terms.² Then in 1973 the Arab-Israeli war led to the 1973-74 Arab Oil Embargo and a rapid increase in oil prices. Prices skyrocketed from an average of \$2.83/b in 1973 to \$10.41/b in 1974, or \$1.90/MMBtu. The

² In order to compare various fuels one has to calculate a heating value which is measured in millions of British Thermal Units (MMBtu). In the case of crude oil, each barrel contains approximately 5.48/MMBtu. This enables us to compare heating values of hydrocarbons such as oil and natural gas which have different physical and chemical compositions.

LNG suppliers wanted to capture the benefits of the higher oil prices and the Japanese accommodated their request and agreed to a crude oil linkage.

Table 5-1 Evolution of LNG Pricing in Asia		
1969	Start of Asian LNG trade (Alaska to Japan)	Fixed pricing -\$0.52/MMBtu
1973-74	First oil crisis (High oil prices) (\$10.41/b or \$1.90/MMBtu)	Changed to crude oil index to capture higher oil price
1986	Oil price crash	Provisional pricing Introduction of S-curve
Late 90s	Market changes, supply to new markets	New price indices and mechanisms emerging

The basic formula and crude oil linkage remained the same until 1986 when prices crashed because of OPEC’s decision to abandon the use of Official Government Selling Prices (OGSP) and to allow prices to be set by supply and demand in world oil markets. The oil price crash in 1986 put the suppliers in a bind and they again asked for the help and cooperation of the Japanese. The Japanese accommodated once again and agreed to an “S-Curve” based pricing formula. As depicted in detail in the next section, the S-Curve retained a crude oil linkage but reduced the volatility implicit in the old formula.

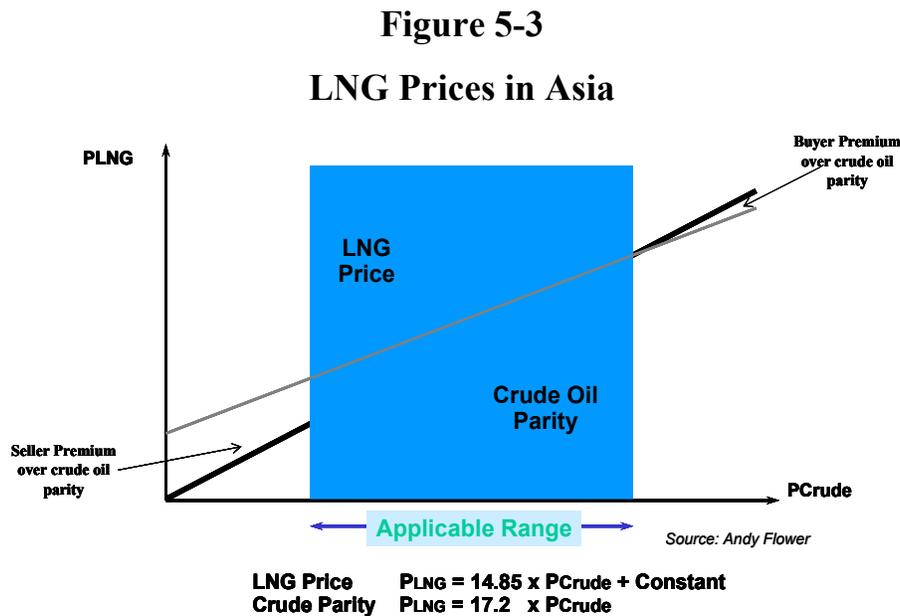
In recent years we have witnessed discussions of new pricing indices. Some have suggested linking a portion of the LNG price to inflation, some have advocated a return to fixed prices. Others have pushed for a linkage to coal prices as it is a major competing fuel in many markets. We have also seen floor and a ceiling prices emerge in some contracts. These are definitely interesting times in what many consider a buyers market and the pressure is clearly on the sellers to come up with innovative and economic pricing schemes.

Current LNG Price Formula in Asia

As discussed earlier, the current Asian LNG price formula revolves around a crude oil linkage. The traditional formula breaks down in the following manner: $P_{LNG} = A \times P_{Crude\ Oil} + B$. The variables are defined below:

- P_{LNG} = price of LNG in cents/MMBtu
- A = slope of line (shows crude linkage)
- $P_{Crude\ Oil}$ = price of crude oil in \$/bbl
- B = a constant in cents/MMBtu

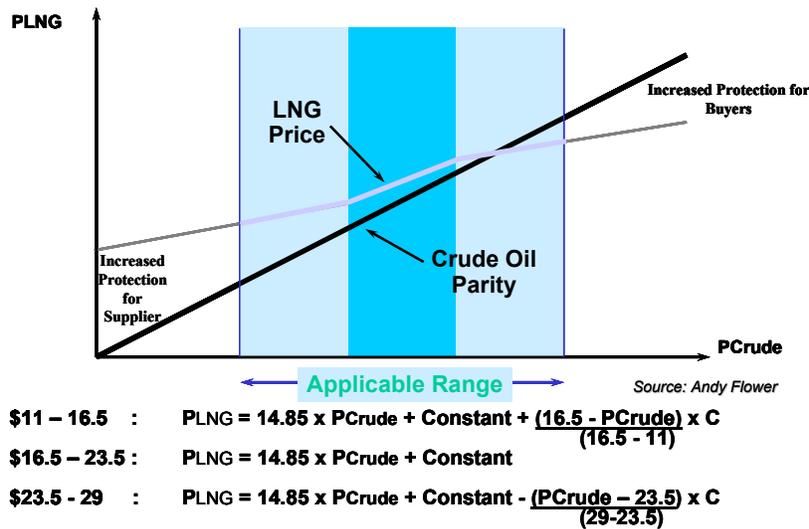
Most LNG sold in Asia uses this formula, where $A=14.85$ and $B=70-90$ cents. The slope is critical because it shows the linkage between LNG prices and crude oil prices. A slope of 14.85 has an 85 percent crude oil linkage, meaning that if the price of crude increases by 10 percent, the price of LNG will increase by 8.5 percent.³ In the past the slope generally remained the same for all Asian LNG contracts and the point of negotiation usually focused on the constant. Figure 5-3 below outlines the concept of the formula and illustrates how suppliers are able to achieve a premium over crude oil parity at low oil prices and how the buyers are able to achieve a premium at higher oil prices.



³ The 85 percent crude oil linkage is calculated by dividing 14.85 by 17.2.

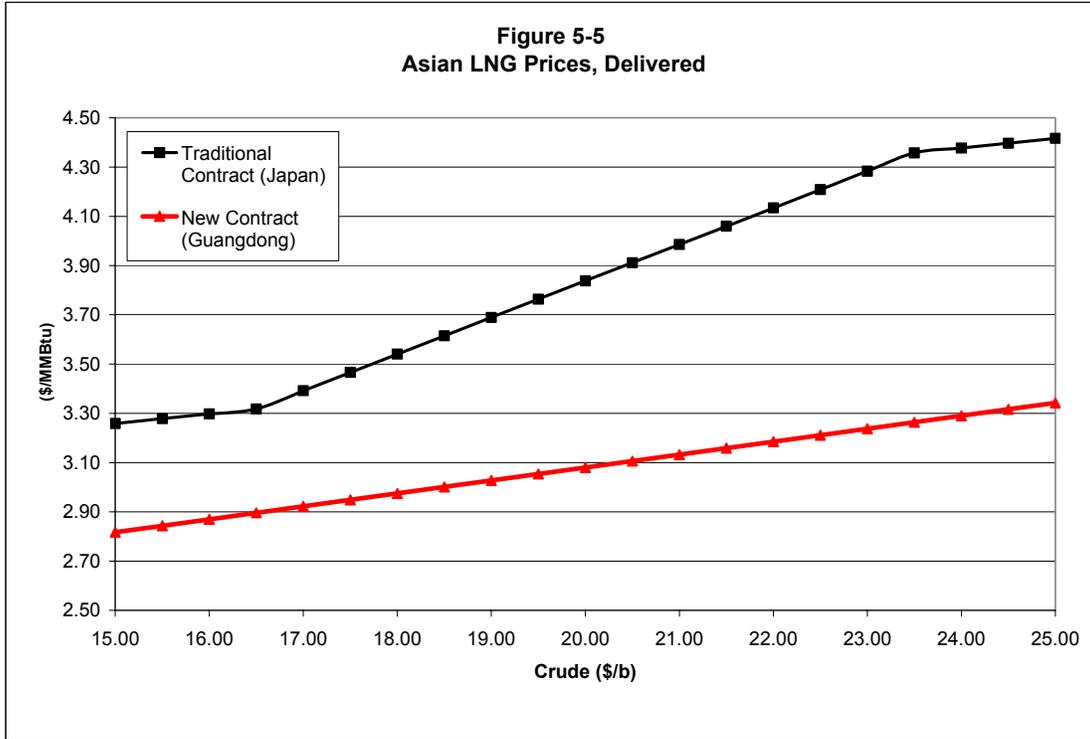
The price formula above was used by Japanese buyers until 1986 when the S-curve was introduced. The S-curve reduced fluctuations in LNG prices and allowed for an even bigger premium for sellers, at oil prices between \$11-16.50, and increased protection for buyers at oil prices ranging from \$23.50-\$29.00 (see Figure 5-4). Currently, only Japan uses the S-Curve while Korea and Taiwan have signed contracts using the traditional pricing formula illustrated in Figure 5-3.

Figure 5-4
S-Curve Price Formula



Recent Trends in LNG Pricing in Asia

Recently, fierce competition among suppliers to secure markets has led to dramatic changes in the traditional Asian LNG pricing formula. With their groundbreaking tender for the Guangdong LNG terminal, the Chinese buyers were able to achieve not only a lower overall LNG price from Australia, but also more price stability through a lower crude oil linkage of 30 percent (see Figure 5-5). The deal had serious implications for suppliers as it signaled a shift in power from the sellers to the buyers.



Future LNG Pricing in Asia

The price of LNG in Asia has in the past evolved with current market conditions and this trend is expected to continue in the future. The emergence of new buyers such as India with different requirements could impact prices. In India coal is a major source of energy and there has been talk of linking the future price of LNG in the country to coal. We have also seen buyers invite bids from potential suppliers instead of directly negotiating with the sellers, thereby creating more competition among suppliers. Finally, power deregulation in certain countries such as Japan has put pressure on existing buyers (TEPCO, Kansai Electric, etc.) to reduce prices to their customers.

There are numerous possible outcomes of new LNG contracts in Asia that include but are not limited to the following: lower prices for increased volumes, lower crude oil linkages and lower overall prices, linkage to coal in countries such as India, a possible return to fixed prices to alleviate uncertainty because of price volatility, indexing a portion of the price to inflation, and a tradeoff between flexibility and lower price. The final point on flexibility is especially crucial to markets such as Korea, where 70 percent of the demand occurs between October and March.

How to Price LNG in Hawaii

This chapter has discussed how LNG is priced throughout the world, and specifically how LNG prices have evolved in the Asia-Pacific region. In the context of Hawaii there are numerous options available and the goal of this section is not to recommend a specific pricing mechanism, but rather to layout the possible options. The general goal of most pricing systems is to protect the buyer and seller from volatility, and also to minimize the incentive for default on the part of either side.

Table 5-2 summarizes potential LNG pricing options for Hawaii, and the pros and cons of each strategy. We have identified eight potential pricing mechanisms ranging from the traditional Asian price formula to a combination of a Henry Hub, LSFO, and fixed prices.

Table 5-2 Potential LNG Pricing Options For Hawaii		
Pricing Options	Pros	Cons
1) <i>Traditional Asian Formula</i> 85% linked to crude, 15% fixed	Established pricing mechanism that suppliers are comfortable with	Fuel price still closely linked to oil market
2) <i>Asian Price Formula w/S-Curve</i>	Reduces volatility and increased protection for buyers at high oil prices	While not as closely linked to oil prices as option #1, fuel prices are still subject to oil price volatility
3) <i>Chinese LNG Price Formula</i> 30% linked to crude, 70% fixed	Even less price volatility as 70% is fixed	Some oil price volatility
4) <i>100% fixed price</i>	No volatility and can accurately budget fuel costs	Can't capture benefits of lower oil prices
5) <i>Linkage to oil but not JCC</i> e.g. Could link to LSFO price in Singapore	Linkage to LSFO fuel price is a concept that HECO is familiar with and LSFO prices tend to vary less than oil prices	Uncommon in Asia and US mainland; LSFO prices are correlated with oil prices
6) <i>100% linkage to Henry Hub Prices</i>	LNG prices linked to a transparent marker that consumers could easily follow	Prices fluctuate daily and Hawaii would be exposed to market conditions of U.S. mainland
7) <i>Price floor and a price ceiling</i> e.g. Recent contract in India	Limits volatility and gives the buyer a range of what the price will be	Can't capture benefits of lower oil prices
8) <i>Combo of Henry Hub, LSFO, fixed prices</i> e.g. Price is 1/3 linked to Henry Hub, 1/3 to LSFO, and 1/3 is fixed	Spreads risk through diversification of price markers	May be confusing to consumers

Option #1 focuses on adopting the traditional Asian formula (see Figure 5-3), which is an 85 percent linkage to crude, while the remaining 15 percent of the price is fixed. Among the benefits of this formula is that it is an established pricing mechanism that suppliers have experience with, and perhaps more importantly, are comfortable with. One of the negative aspects of the formula is that the fuel price is still closely linked to the oil market and therefore it

would not reduce the State's exposure to the volatility of oil prices—which is one of the main reasons to introduce LNG in the first place.

Option #2 is to implement the Asian price formula with an S-curve, as illustrated in Figure 5-4. As stated earlier, the S-curve reduces price volatility and allows for increased protection for buyers at high oil prices. However, the S-curve formula is still obviously linked to oil prices, albeit to a lesser degree than Option #1.

Option #3 is to adopt the Chinese LNG price formula, which has a 30 percent linkage to crude, while the remaining 70 percent of the price is fixed. This formula provides substantially reduced price volatility as a large percentage of the price is fixed. Also, it is unlikely that small-scale buyers of LNG would be able to negotiate such favorable terms as the Chinese, due to the suppliers' willingness to be flexible on price in order to be a first mover in the lucrative Chinese market.

Option #4 revolves around setting a fixed price for LNG deliveries into the State. A fixed price eliminates volatility and allows buyers to accurately budget their fuel costs. The negative consequence of a fixed price is that it does not provide a mechanism for buyers to capture the benefits of lower oil prices.

Option #5 proposes linking the price of LNG in Hawaii with LSFO in Singapore as this is what is currently burned in the majority of HECO's power plants. Linking the price to LSFO is a concept that HECO is familiar with and also the price of LSFO tends to vary less than crude prices, thereby offering a bit more price stability. However, the price of LNG will still be subject to swings in the oil market.

Option #6 focuses on linking the price of LNG to Henry Hub prices as is the case in the continental United States. The benefit of a Henry Hub linkage is that LNG prices are linked to a transparent marker that consumers could easily follow and understand. Of course the delivered fuel price would include transportation charges plus the terminal cost plus the buyer's margin. Once these prices are broken down the consumer could check daily on the internet and verify the

price of Henry Hub plus the additional charges to see their daily fuel costs. The main drawback of this pricing mechanism is that not only do prices fluctuate daily but more importantly consumers in the State would be exposed to the market conditions of the US mainland. Therefore, a rupture in a pipeline or a cold winter in the Northeast would cause a spike in prices and would hurt consumers in the State because of issues that are beyond their immediate control.

Option #7 explores the possibility of implementing a price floor and a ceiling. This was done recently in India with the contract signed by Petronet with Qatar. A price floor and ceiling limits volatility in fuel price and also gives the buyer a range of what the price will be. As is the case with a fixed price, this option could potentially not allow the consumer to capture the benefits of low oil prices if the floor is higher than the current price of oil.

Option #8 proposes a pricing mechanism that combines the Henry Hub price with the Singapore LSFO price and a fixed price. In Table 5-2 we have an example of equal weight distributed among all three options although in theory any combination could be used, depending on the needs and perceptions of the buyer. The benefit of this pricing mechanism is that risk is spread through the diversification of various price markers. The main drawback of this combined pricing option is that it may be confusing to customers who want to know how their fuel costs are calculated.

It is important to note that while the eight options presented above just about covers the array of possible pricing alternatives, it is obviously not an exhaustive list. Sellers have recently signaled a willingness to accommodate variations on traditional pricing options. The option that should be pursued depends on one's perception as to the future direction of related markets, risk tolerance, and the direction of government policy. FACTS cannot comment on the risk tolerance of relevant stakeholders and future government priorities. However, we do feel that it is unlikely that the price of oil will drop below \$18/b for a sustained duration in the future. As a consequence, securing a low crude oil linkage with a price floor and ceiling would appear to fit the state's need for low price volatility as well as helping to ensure relatively low gas prices in the event of high oil prices.

Chapter 6

Short-Term Trading¹

While short-term trades are quite common in other energy markets, such as oil, the LNG market has long been characterized by rigid long-term contracts. This is changing, however, and this chapter examines the evolution of short-term trading, which is a growing phenomenon in global LNG markets.

If Hawaii pursues the LNG option it is unlikely to have a substantial need for short-term cargoes, because it has relatively small seasonal swings in demand and its future demand growth is relatively stable and predictable. However, the growth of short-term trading is important to Hawaii for two reasons: (1) It would provide Hawaii an opportunity to cover a potential supply disruption, thereby enhancing energy security; (2) North America's proposed West Coast terminal projects could open up new trading opportunities, and due to its location, Hawaii presents an interesting opportunity for a supplier to capture synergies between Asia, Hawaii, and the West Coast.

The Development of Short-Term LNG Trading

Short-term LNG trading is generally defined as “sales of a single cargo or multiple cargoes that are not traded under the terms of a long-term contract.” It includes:

- Additional cargoes traded between buyers who have a long-term contract in order to meet seasonal variations in demand or additional requirements
- Cargo swaps between buyers or between sellers
- Cargo swaps over time, called a “time swap” (i.e., buyer A receives a cargo today and returns the same volume to buyer B in the future)
- Sellers selling cargoes into high priced markets to take advantage of price differentials (arbitrage)

Prior to 1990, there were very few short-term trades. Short-term trading was still limited to intra-regional trade in the early 1990s, but in recent years it has become more common to see trades across regional boundaries.

Because most existing US terminals operate on a (relatively) open access basis, the US generally provides a market of last resort for producers with surplus LNG. In addition, the recent high gas prices encouraged sellers to move more cargoes to the US.

In the Asia-Pacific region, short-term trading is primarily used by buyers to manage variations in demand. For example, in South Korea, where winter demand is over three times summer demand, the short-term market is used regularly to manage seasonal swings in demand. During the winter of 2002/2003 South Korea utilized the short-term market to purchase 43 cargoes (normally one cargo contains about 60,000 tonnes—43 cargoes is roughly double Hawaii's projected annual demand) due to an extremely cold winter.

Over the past few years there has also been increased cargo swapping between Asian buyers. The primary reasons are Indonesia's declaration of force majeure on its export commitments from the Arun LNG complex and Japan's nuclear power crisis, which started in August 2002.

In the first case, during March-July 2001 Indonesia's Arun LNG exports were disrupted due to the escalating activity of the Free Aceh Movement (an armed separatist movement), which led to fear for the safety of the workforce in North Aceh (details to be discussed in Chapter 8: Security of Supply Issues). Japanese term buyers (Tohoku Electric Power and Tokyo Electric Power) and South Korea's KOGAS were affected by the supply disruptions and were forced to look for spot/swap supplies to cover the shortfall.

¹ This chapter draws on FACTS database, conversations with industry contacts and sources; Andy Flower, *2nd Pacific Gas Insiders 2002*, LNG Short-Term Trading (December 2002); Andy Flower, *The Fundamentals of LNG*, LNG Short-Term Trading, (August 2003)

More recently, Japan's nuclear power plant problems contributed to a sharp increase in short-term trades. Since August 2002 TEPCO's LNG-fired power plants have been used for *base-load* electricity supply because the bulk of TEPCO's 17 nuclear reactors were closed for safety re-inspections. As a consequence, TEPCO, Japan's largest electric utility, has been using short-term trades to satisfy increased requirements for LNG. Over the first half of 2003, TEPCO used 39 percent more LNG than the previous year. Total consumption was 9.6 million tonnes for January-June 2003, compared with 6.9 million tonnes for the same period in 2002. Most long-term suppliers increased their sales volumes to TEPCO this year, and at the same time, Chubu Electric Power and Kansai Electric Power have been using short-term trades to help TEPCO overcome its supply shortfall.

Future Prospects

Currently, the structure of the LNG market is placing limits on the proportion of LNG which can be traded on a short-term basis. In the near term a major constraint is a shortage of uncommitted LNG vessels. In 2002, 127 out of 136 LNG vessels were committed to specified long-term contracts. In addition, destination clauses in contracts are restricting the buyer's ability to sell LNG.

Such limitations will be overcome and short-term trading will likely increase in the future. About one-third of LNG vessels currently on order (approximately 55 vessels) are not dedicated to a specific project or a specific trade route. As discussed in Chapter 4, destination clauses will likely be eased into new contracts, giving more flexibility to the buyers to resell LNG.

By 2010, short-term cargoes could represent 15-20 percent of world LNG trade, compared with approximately eight percent in 2002. Short-term trading will likely grow most rapidly in the Atlantic Basin, where distances are comparatively short and buyers and sellers will continue to look for arbitrage opportunities between the US and European markets to manage risk and increase profitability.

However, short-term trading will also increase in the Asia-Pacific markets. South Korea continues to require short-term cargoes in winter to meet seasonal demand swings, and the

opening of new markets (e.g., India and China) could increase the scope of cargo swaps. Contractually, the proportion of FOB deals is increasing, which will provide buyers more opportunities to trade LNG amongst themselves. In particular, as discussed in Chapter 4, Australia's Bayu-Undan contract already gives buyers (TEPCO and Tokyo Gas) more scope to trade cargoes to other buyers in Japan and elsewhere.

Chapter 7

Environmental and Safety Concerns¹

Introduction

Of course, we all have an interest in maintaining our State's pristine surroundings. The environment has added importance in Hawaii because it is the bread and butter of our economy, as it draws tourists from around the world. As a consequence, it is critical to examine the impact that LNG could have on our environment in terms of emissions and possible spills. Obviously, safety concerns are important as well. Each of these issues is discussed in turn in this chapter.

Overall, we believe it is fair to say that in comparison to other fuels LNG has numerous advantages. Compared to other hydrocarbon fuels it is environmentally friendly and has an excellent safety record—LNG is not explosive, toxic or carcinogenic. *A key point is that LNG is not pressurized and it dissipates quickly and thus the risk of explosion is very low, especially when compared to some fuels already in use in Hawaii, such as LPG.*

Environmental Concerns

Emissions

Liquefied natural gas (LNG) consists almost entirely of methane, and it is the cleanest burning of all fossil fuels. The main byproducts of combustion of natural gas are carbon dioxide and water vapor. At the other end of the spectrum, coal and fuel oil both emit relatively high quantities of pollutants, including nitrogen oxides (NO_x) and sulfur dioxides (SO₂). Combustion of these fuels may also release particulate matter into the environment. The following table outlines the varying levels of emissions from natural gas, coal and oil. Natural gas emits the lowest levels of carbon dioxide and negligible amounts of SO₂, particulates and mercury.

¹ This chapter draws on FACTS database and sources, The Energy Information Administration (EIA), DBEDT's *Hawaii Energy Strategy 2000*, <http://www.ferc.gov/>, www.elpaso.com, www.nfpa.org, and www.shell-usgp.com.

Table 7-1 Emission Levels from Combustion of Various Fossil Fuels (pounds per billion BTU of energy input)			
Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	1	1,122	2,591
Particulates	7	84	2,744
Mercury	0	0.007	0.016
Source: EIA			

Spills

It is well known that an oil spill can have catastrophic consequences, both environmental and economic. After the Exxon Valdez incident in 1989, the State funded a study to determine the potential damage to the economy if an oil spill were to occur in Hawaiian waters. The study found that, in addition to the environmental damage, the monetary loss could be staggering. Cleanup costs were estimated at \$210 to \$305 million, and if oil washed onto Oahu's shores it could translate into a 32 percent reduction in tourism, or a \$3.06 billion loss in tourism revenue.

Whether spilled in water or on land, when LNG is released into the atmosphere it begins to evaporate, causing a visible vapor cloud. The likelihood of this vapor cloud igniting is very slim, as LNG vapor is lighter than air, which causes it to dissipate rapidly (as discussed later in this chapter). Hawaii's trade winds would accelerate dissipation, acting as a natural safety measure. Unlike oil, a LNG spill leaves no residue and thus there is no environmental cleanup.

LNG Safety Issues/Concerns

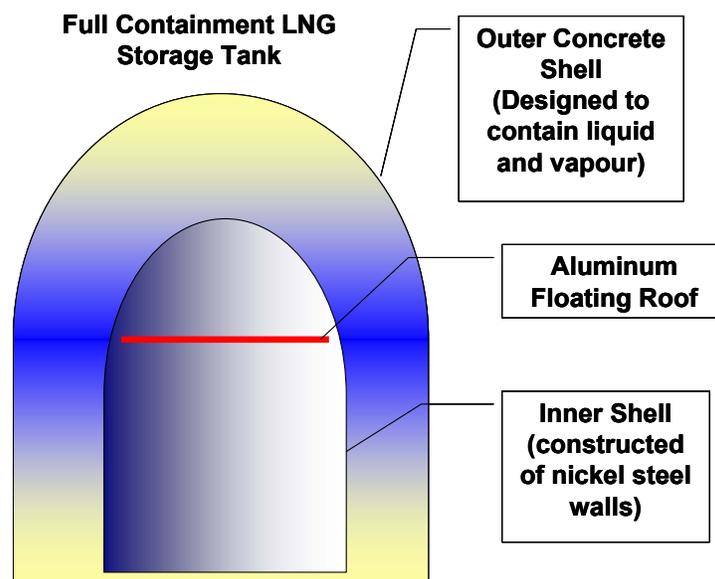
LNG has been transported in ocean-going vessels for about 40 years, making more than 35,000 voyages without a significant incident involving loss of cargo in port or at sea. In addition, LNG regasification and storage facilities have operated safely in populated cities in Asia, Europe, and the United States for decades. Although it was long ago, it should be noted that a major accident occurred in 1944 before tanks were designed for the cold temperatures of LNG. A tank in Cleveland, Ohio ruptured and spilled the uncontained liquid into storm drains, followed by a large deadly fire. Tanks have since been redesigned to prevent a reoccurrence of this incident and there has been no other LNG tank failure since 1944.

Safety Features in LNG Storage

Because they are often in populated areas, LNG storage tanks, which come in three primary designs, are among the most critical components of the LNG chain when it comes to ensuring safety.

- The least expensive storage tank is the ‘single containment’ tank, which consists of an inner nickel steel wall and roof to contain the liquid and vapor. An outer carbon steel wall surrounds this tank to provide insulation, however this second wall is not designed to contain LNG liquid or vapor.
- Another option is a ‘double containment’ tank, which consists of an inner nickel steel wall and roof. Outside of this is another barrier made of concrete, which is designed to contain LNG liquid, but it is not designed to contain LNG vapor. Release of vapor must be vented and sprayed with either water or foam to control the risk of fire.
- Based on conversations with industry contacts, it is the general consensus that the State would utilize ‘full containment’ storage. Full containment provides the maximum protection against LNG leakage. It consists of an inner nickel steel tank with an aluminum floating roof. This is surrounded by an outer tank made of concrete, designed to contain both LNG liquid and vapor.

Figure 7-1



Safety Features in LNG Transportation and Receiving Terminals

LNG tankers are designed with an array of safety features. These double-hull ships transport LNG at atmospheric pressure at temperatures of -256° F (LNG's saturation point). The cargo containment utilizes several layers of protection to ensure that there is no leakage. The first layer consists of a primary liquid barrier followed by a layer of insulation; on top of this is a second liquid barrier with another layer of insulation. Each of these insulation layers are monitored for any signs of leakage, with equipment sensitive enough to locate a pin-head size leak.

An LNG tanker features an extensive instrumental package that safely shuts down the system if it starts to operate outside of predetermined parameters. Ships are also equipped with radar and positioning systems that alert the crew to other traffic and hazards around the ship. At onshore receiving terminals, safety features include methane detectors, ultraviolet or infrared fire detectors, closed circuit TV, offsite monitoring, training requirements for personnel, and restricted access to terminal property.

Space Requirements

It is our understanding that there are no definitive regulations in terms of space requirements for LNG facilities. Space requirements at individual facilities are determined on a case-by-case basis by federal and local agencies.

Risk of Fire/Explosion

Contrary to popular belief, LNG itself does not explode or burn because it is not under pressure and it does not contain oxygen. In the case of an accidental release natural gas is only flammable within a narrow gas to air ratio. If the fuel concentration is lower than 5 percent it cannot burn because of insufficient fuel, and if the fuel concentration is higher than 15 percent it cannot burn because there is insufficient oxygen. Overall, for LNG to burn it must be released, vaporized, mixed with air at a ratio of 5-15 percent, and it must come in contact with an ignition source.

Although portions of an LNG vapor cloud are flammable under the right gas to air ratio, the flame speed of an unconfined cloud is slow and it will not explode. In contrast, LPG has a higher risk because it is stored under pressure and it is heavier than air so it does not dissipate as

quickly. Fuel oil is toxic and if it spills, especially on water, the environmental impact can be very severe (see Table 7-2).

Table 7-2 Comparison of Various Liquid Fuels			
Properties	Fuel Oil	Liquefied Petroleum Gas (LPG)	LNG
Is it a carcinogen?	Yes	No	No
Is it toxic?	Yes	No	No
Can it form a vapor cloud?	No	Yes	Yes
Is it stored under pressure?	No	Yes	No
What happens if there is a spill?	Fuel oil will evaporate and form a potentially flammable pool.	LPG will evaporate and will form a vapor cloud. The vapor cloud could be flammable under the right gas to air ratio	LNG will evaporate and will form a vapor cloud. The vapor cloud could be flammable under the right gas to air ratio
Does a spill require a significant environmental clean up?	Yes	No	No

LNG Regulatory Framework in the U.S.

Regulatory approval for an LNG infrastructure in the U.S. is a rigorous and detailed process that involves numerous local, state, and federal regulatory agencies, such as, but not limited to the Federal Energy Regulatory Commission (FERC), the Department of Transportation, and the U.S. Coast Guard. The process can be time consuming as numerous agencies are involved. Currently, FERC is trying to speed up the approval process as supply of natural gas is expected to be tight

in the coming years. Once the permit approvals are in place it takes at least three years to build a receiving terminal depending on the necessary modifications to the current infrastructure.

If Hawaii were to build an onshore LNG receiving terminal the following federal agencies would be involved in the regulatory process:

- Federal Energy Regulatory Commission (FERC)
- Department of Energy (DOE)
- Department of Transportation (DOT)
- U.S. Coast Guard (USCG)
- U.S. Environmental Protection Agency (EPA)
- U.S. Army Corps of Engineers
- U.S. Department of Labor Occupational Safety & Health Administration (OSHA)
- U.S. Fish and Wildlife Service
- U.S. Minerals and Management Service

Various State and local agencies would also be involved, including (but certainly not limited to) the Honolulu Fire Department (HFD), the Honolulu Police Department (HPD), Department of Land and Natural Resources (DLNR), and the Public Utilities Commission (PUC).

If the State instead chooses to build an offshore receiving terminal, the following federal agencies would be involved in the regulatory process:

- National Oceanic and Atmospheric Administration (NOAA)
- Department of Energy (DOE)
- Department of Transportation (DOT)
- U.S. Coast Guard (USCG)
- U.S. Army Corps of Engineers
- U.S. Fish and Wildlife Service

Four federal regulatory agencies have specific regulatory roles directed by statutes, specifically the Department of Energy, FERC, the Department of Transportation, and the U.S. Coast Guard.

The Department of Energy authorizes all LNG imports via Section 3 of the Natural Gas Act. **FERC** is responsible for permitting LNG import terminals that are not covered under the Deepwater Port Act. FERC duties include overseeing the siting, construction, and operation of the terminals under its jurisdiction. **The Department of Transportation** is responsible for issuing permits to offshore LNG terminals in federal waters and also for ensuring the safe operation of LNG facilities. The USCG and Maritime Administration jointly process the license applications, and DOT issues the license. Lastly, the **U.S. Coast Guard** is responsible for assuring the safety of marine operations at all LNG terminals and aboard all LNG tankers in the U.S.

Federal guidelines for the design, construction, and operation of LNG facilities are as follows:

- **49 CFR PART 193:** *Liquefied Natural Gas (LNG) Facilities - Federal Safety Standards-* This portion of the Code of Federal Regulation (CFR) establishes and enforces standards pertaining to siting requirements, design, construction, equipment, operations, maintenance, personnel, qualifications and training, fire protection, and security.
- **33 CFR Part 127:** *Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas-* This federal regulation governs import and export LNG facilities or other waterfront facilities handling LNG. Specifically, the scope of this standard is from the unloading arms to the first valve outside of the LNG tank.
- **NFPA 59A:** *Standard for the Production, Storage, and Handling of Liquefied Natural Gas-* This is an industry consensus standard, issued by the National Fire Protection Association (NFPA). 59A was first adopted in 1967 and covers general LNG plant considerations, process systems, stationary LNG storage containers, vaporization facilities, piping systems and components, instrumentation and electric services, transfer of natural gas and refrigerants, fire protection, safety, and security. Also covered are requirements for vehicle fueling for industrial and commercial facilities using American Society of Mechanical Engineers (ASME) containers. This standard includes the tank

requirements for LNG facilities that ensure their ability to withstand natural events such as earthquakes, floods, and high winds.

- **NFPA:** *Standard for Liquefied Natural Gas Vehicular Fuel Systems*- This standard covers vehicular fuel systems, LNG fueling facilities, installation requirements for ASME tanks, fire protection, safety and security for systems onboard vehicles and for infrastructures storing 70,000 gallons of LNG or less.

LNG in Hawaii?

Will LNG make its way to Hawaii's shores? We believe if the decision were based solely on LNG's safety record and emissions, the answer would likely be "Yes." Overall, LNG is a clean fossil fuel with a relatively benign impact to the environment that has achieved an excellent safety record over the past 30 years.

Chapter 8

Security of Supply Issues¹

Among the major reasons that Hawaii may want to consider the LNG option is that it would enable diversification away from oil, thereby promoting energy security. Of course, if LNG supplies are at risk, the benefits of diversifying to LNG would be muted. This chapter explores the issue of security of LNG supply, including past disruptions and the potential for future disruptions.

History of Supply Disruptions

While LNG supplies have proven to be extremely reliable, in recent years there have been two major LNG supply disruptions, one at Indonesia's Arun in 2001 and the other at Malaysia's MLNG Tiga this year. Both Japanese and Korean buyers were affected by these sudden supply disruptions, and were forced to look for spot supplies to cover the shortfall.

The Arun Disruption: As mentioned briefly in Chapter 6, over the period of March-July 2001 ExxonMobil (the field operator) halted Arun gas production in North Aceh, Indonesia. This was due to the escalating activity of the Free Aceh Movement (an armed separatist movement), which led to fears for the safety of its workforce in North Aceh. The suspension of natural gas from the Arun field led to a sharp reduction in production from the Arun LNG facility. As a result, Arun LNG exports in 2001 dropped to 2.8 mtpa, down from 6.7 mtpa in 2000. Under existing contracts, Japanese buyers (Tohoku Electric Power and TEPCO) and South Korea's KOGAS were to receive 5.8 mtpa and they were forced to look for spot/swap supplies to cover the shortfall. The supply volumes lost from Arun were covered by other sources, such as Indonesia's Bontang and Malaysia's MLNG facilities.

¹ This chapter draws on FACTS database and conversations with industry contacts.

The MLNG Disruption: In August 2003 Malaysia’s newest LNG project, MLNG Tiga declared force majeure on its LNG export commitments. MLNG Tiga—a two-train 6.8 mtpa project—had just started operation of its first train in May 2003 when it was hit by a fire. The second train, which started operation in November 2003, delivered almost all of the contracted volumes—the damaged train was back in operation in March 2004. Japanese buyers (TEPCO, Tohoku Electric Power, and Japan Petroleum Exploration Co.) and South Korea’s KOGAS are the contracted buyers of MNLG Tiga.

How Have Concerns Been Addressed?

While it is a rare occurrence, when suppliers declare force majeure the buyers are responsible for finding alternative supplies to make up for the potential shortage. In practice, however, suppliers try to do what they can to find replacement cargoes for their buyers. MLNG Tiga, for example, attempted to arrange for replacement cargoes through Australia, Indonesia, and Brunei.

In general when buyers have to find replacement volumes they often have to pay significantly higher prices, because such prompt purchases often face difficulty in not only finding spot LNG, but also in finding uncommitted LNG vessels. Most LNG vessels are committed to a specified long-term contract (see Chapter 6: Short-Term Trading).

It should be noted that a swap agreement of LNG cargoes among buyers is also a possible way to deal with a supply disruption. For example, Chubu Electric Power has agreed to a “seasonal swap” of LNG cargoes with KOGAS. Chubu Electric Power—its demand, which is related to electricity generation, reaches its peak in the summer—took rights to one 60,000 tonne cargo that KOGAS is slated to buy next summer from Indonesia in exchange for the same volume of LNG going to KOGAS this winter from Chubu’s suppliers.

The lesson from this is that in preparation for any emergency situation, it is important for buyers to maintain a relationship with other buyers as well as their suppliers. In the past, Japanese buyers have formed consortium to buy a large volume of LNG on a long-term basis, and this consortium has played an important role in helping to limit supply disruptions. For example,

five electric utilities and three gas utilities have been jointly buying 7.33 mtpa (ex-ship) from Australia's Northwest Shelf (NWS) Trains 1-3 on a 20-year contract (1989-2009). In 2003, the NWS supplier agreed to allocate a portion of the LNG that was contracted for other consortium members to TEPCO, because TEPCO urgently needed to increase LNG-burning for power generation due to a series of shutdowns of its nuclear power plants.

It is critical to emphasize that the recent supply disruptions were very unusual and shocked the industry. The disruptions could have longer-term implications that will be reflected in future contracts. Some LNG buyers are considering including a "deliver-or-pay" clause in future contracts to match the "take-or-pay" obligations they face. In addition, some Japanese buyers (including Kansai Electric Power, Chubu Electric Power, and Osaka Gas) are considering requiring a "dual supply source" concept for future Indonesian LNG contracts before they agree to take a large volume. Under this requirement, LNG from Indonesia's Tangguh project will be supplied to Japan if Indonesia cannot supply LNG from its Bontang project, and vice versa.

Supply Sources

In evaluating the potential suppliers to the Hawaii LNG market there are several key points to be made in terms of security of supply:

Australia has been a reliable exporter of LNG since the late 1980s. Its gas fields are large (e.g., Greater Gorgon area reserves are equal to 47 tcf—1.5 tcf is enough to supply Hawaii for 20 years) and it has both expansion and greenfield projects in the works. The country is democratic and seen as very stable, allowing it to more easily obtain financing for future projects.

Malaysia, meanwhile, had maintained a pristine record as a supplier until the recent force majeure at MLNG Tiga. With the departure of the Prime Minister Dr. Mahathir Mohamed, who is well known for his heavy-handed but effective leadership, there is a chance that the corruption and cronyism that has plagued some other exporting countries could appear in Malaysia. In addition, Malaysia's local gas reserves are being depleted, forcing MLNG to look elsewhere for expansion opportunities, including Egypt LNG and Iran LNG.

Indonesia currently has the most liquefaction capacity in the world. However, recurring political unrest and the supply disruption in Arun has somewhat diminished Indonesia's reputation as a reliable supplier.

While Southeast Asian suppliers will continue to lead the Asia-Pacific market in the near future, there are a couple of wildcards with the potential to have a substantial impact on the East of Suez markets—Russia and Qatar. **Russia's** proposed two-train 9.6 mtpa liquefaction facility at Sakhalin is ideally located to serve Asian markets. Already heads of agreement have been signed with TEPCO, Tokyo Gas, and Tohoku Electric for a total of 2.3 mtpa beginning in 2007, and more sales contracts will follow. Other potential markets include Korea, Taiwan, China and Hawaii, and the US West Coast. There has been some turmoil in the Russian energy markets as the head of major oil and gas producer Yukos has been arrested, and there is some question as to who will dominate the country's energy scene in the future.

Looking forward, it is also likely that the Middle East will continue to flex its muscles and capture a substantial portion of the East of Suez markets (the Middle East is not a likely supplier to Hawaii, but it deserves mention because it is a major player). **Qatar**, with its low production costs and huge reserves, looks well positioned for the future. Not only does Qatar have the largest gas field in the world (shared with Iran), it also has established relationships with importers in Korea and Japan, thereby giving it a competitive advantage compared to other Middle Eastern suppliers. Although Middle East suppliers are perceived to be risky, the increased presence of US troops in Qatar will give the tiny Emirate an aura of stability and protection, further increasing its reputation as a reliable exporter. Qatar's current focus is the European market (especially Spain and Italy, and possibly the UK) and the US.

Possible Options for Ensuring Security of Supply

With the exception of two recent events, LNG supplies have been very reliable. The lessons that can be gleaned from the recent disruptions are: (1) It is important to have relationships with an array of buyers and sellers, or at the very least to be aware of the possibilities for short-term

trading in the event of a supply disruption. (2) Short-term cargoes can be procured in the event of a supply disruption, albeit sometimes at a higher price.

It is important remember that host governments play a significant role in determining the long-term security of any LNG project. It is worth noting that, with the exception of Alaska's Kenai project and Australia's NWS project, state-owned companies are involved in all of the existing LNG projects. In evaluating a potential supplier it is critical that the host government fully supports the project (new or existing). Australia is an excellent supply candidate because the government has generally been supportive of current and potential projects. Other countries, such as Indonesia, may be perceived as higher risk. However, in the case of Indonesia this perception may be somewhat inaccurate. With a large productive capacity and multiple supply projects it may have the flexibility to cover supply disruptions.

As a final note, although no contracts of this kind have been signed yet, the market seems more open to the idea of a "deliver-or-pay" clause in a contract. This may help mitigate the financial risk associated with force majeure and put pressure on suppliers to assure that volumes are delivered as promised, even if they have to secure spot volumes themselves and deliver them to buyers.

Chapter 9

LNG: A Bridge to a Hawaii Hydrogen Economy?¹

Introduction

As political entities worldwide have begun to realize the growing negative impact of carbon emissions on the earth, the potential for a dramatic policy response has risen. The Kyoto Protocol—an initiative calling for a shift towards reduced emissions—has triggered policy makers worldwide to take notice. While the United States has refused to sign the Kyoto Protocol, it has earmarked 1.7 billion dollars for the research and development of hydrogen fuel cell technology. Part of this research will explore the feasibility of developing a hydrogen infrastructure, an idea that has yet to become a reality anywhere in the world. Hawaii is no stranger to this type of research, and it is arguably among the best sites in the U.S. to explore this technology—electricity generated via geothermal, solar and wind power has long been viewed as the most ideal emissions free means of producing hydrogen fuel for fuel cells.

In spite of its promise, the high cost of producing hydrogen and developing a hydrogen infrastructure is a considerable roadblock along the path towards an emissions-free hydrogen economy. There is, however, a possible solution in bridging the gap towards a Hawaii hydrogen economy—liquefied natural gas (LNG). Natural gas is currently the least expensive feedstock for producing hydrogen. Although running fuel cells with hydrogen derived from natural gas is not an emissions free solution, it is a very efficient and low pollution interim solution which could enable the development of a hydrogen infrastructure. Eventually the hope would be to move away from a dependence on natural gas and to produce hydrogen using electricity that is generated from renewable sources.

In this chapter we discuss the technology of hydrogen fuel cells and the feedstocks being used to produce hydrogen fuel. We also examine the cost and distribution issues associated with this technology.

¹ This chapter draws on FACTS database and sources; Energy Information Administration (EIA), California Fuel Cell Partnership, and the U.S. Department of Energy.

Comparison of Feedstocks for Hydrogen Fuel Production

Although it is the most abundant element in the universe, hydrogen does not exist in a free state and must be extracted from feedstocks. In this section we will briefly discuss the advantage and disadvantages of the most popular feedstocks being used to produce hydrogen fuel.

Electrolysis of Water

Electrolysis of water is the ideal means of producing hydrogen fuel as it is pollution free, and it is the long-term goal of most proponents of fuel cell development. By running an electric current through water, the hydrogen and oxygen molecules are split apart.

- ◆ **Pros:** This method of hydrogen production is the most common next to steam reformation of natural gas and it is widely understood. Using this method, hydrogen production could be emissions free if a renewable energy source such as, solar, geothermal or wind is used to produce the electric current.
- ◆ **Cons:** Electrolysis of water requires a great deal of electricity and it is the most energy intensive of all the hydrogen production methods—current production costs would equate to a gasoline cost of anywhere from \$3-4 per gallon. If carbon-based fuels are used to produce the electricity for this process, greenhouse emissions will be quite high.

Biomass

Hydrogen can be extracted from biomass—a term used to describe organic wastes, forestry products, or agriculture byproducts. By utilizing the process of steam reformation, biomass is a relatively clean means of producing hydrogen fuel.

- ◆ **Pros:** Using biomass as a feedstock produces less greenhouse emissions than hydrocarbon alternatives.
- ◆ **Cons:** Hydrogen fuel production requires large amounts of biomass. In Hawaii the limitation of land size would likely be among the biggest barriers to this feedstock. Localized pollution (e.g., land, water) could also be an issue.

Methanol

Methanol has gained a great deal of popularity as a fuel cell fuel option because of its high energy density.

- ◆ **Pros:** Because of its liquid form it can be easily stored within a vehicle without the added costs of expensive storage tanks that hydrogen fuel requires.
- ◆ **Cons:** Methanol is a more expensive feedstock than natural gas, with estimated costs of \$11/GJ versus \$4-5/GJ for natural gas. Methanol also produces higher levels of greenhouse emissions.

Gasoline

Gasoline can also be reformed to produce hydrogen and several auto manufacturers are researching the use of an onboard vehicle reformer which would extract hydrogen for the fuel cell.

- ◆ **Pros:** The existing gasoline infrastructure is perhaps the biggest incentive to utilize gasoline as a feedstock for hydrogen fuel production.
- ◆ **Cons:** When used as a fuel cell feedstock, gasoline produces similar greenhouse emissions to methanol fuel cells. In addition, hybrid vehicles like the Toyota Prius are able to produce similar gas mileage at a much lower cost.

Natural Gas

Natural gas is comprised of approximately 90 percent methane, which carries one carbon atom to 4 hydrogen atoms. Natural gas is odorless and colorless and extremely flammable, yet when ignited, gives off very little greenhouse emissions. Because of this, natural gas is becoming increasingly popular, especially in countries with strict environmental regulations such as Japan.

- ◆ **Pros:** Natural gas, when steam reformed, is the most cost competitive feedstock for hydrogen production. In Hawaii's case using natural gas (LNG) is somewhat favorable due to its diversity of supply from numerous Asia Pacific countries, as opposed to relying on Middle East crude.
- ◆ **Cons:** Natural gas is a hydrocarbon and produces greenhouse emissions, albeit, at lower levels than gasoline or methanol.

We believe that natural gas presents the strongest case to being used as a feedstock for hydrogen production in Hawaii. Its relatively low costs and emissions hold it a step above the other feedstocks.

Emissions

The combination of greenhouse gases and air pollution has long been a side effect of using crude for our energy needs. Greenhouse gases are thought to be the contributing factor in global warming—the effect of carbon emissions rising to the upper atmosphere trapping heat which would otherwise escape into space. Combustion of fossil fuels is also thought to lead to air pollution, such as smog and acid rain.

In Hawaii, we may never see the smoggy haze of Los Angeles, due to the sweeping effects of our trade winds. However, we may eventually feel the long term effects on global warming. As such, the use of environmentally friendly fuels is becoming an urgent matter.

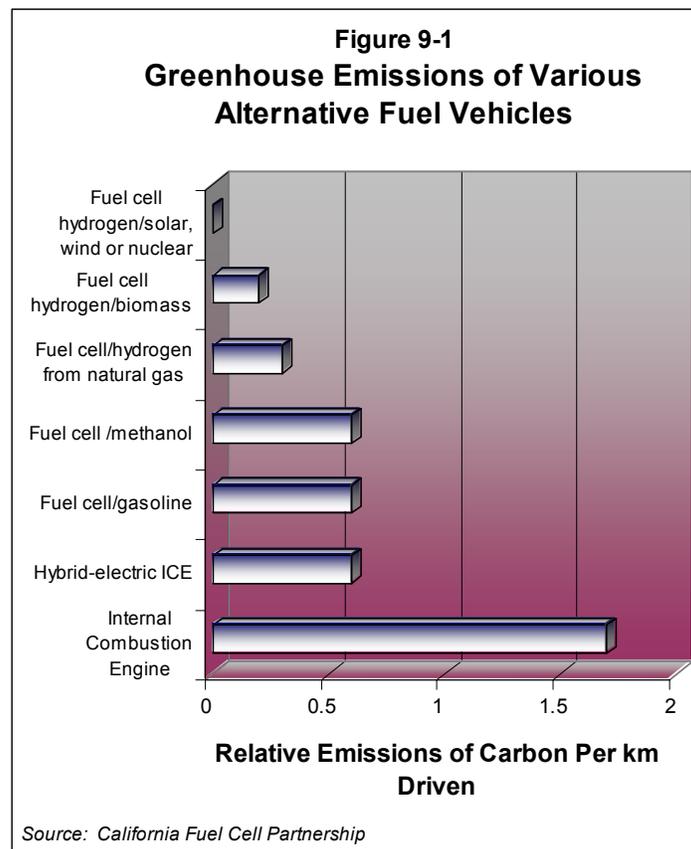
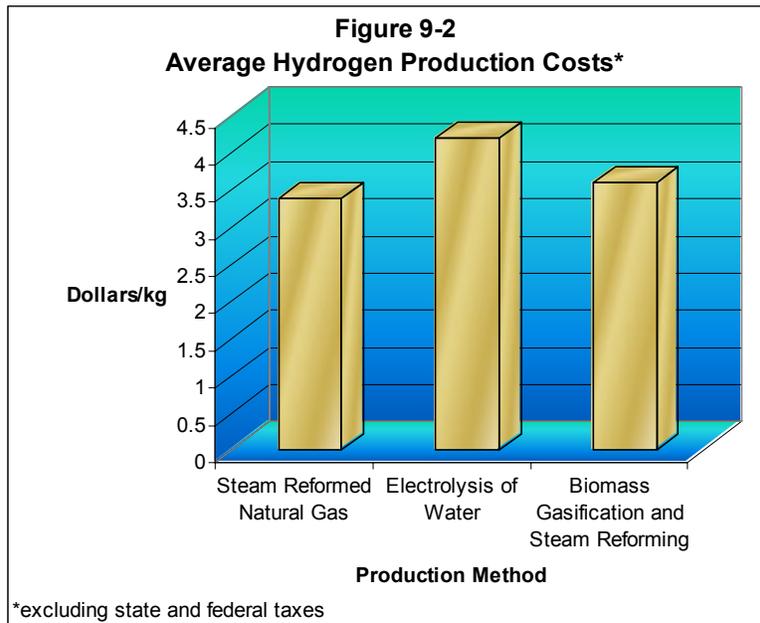


Figure 9-1 indicates that the ideal solution in terms of emissions would be to use renewable energy to produce zero emission hydrogen fuel. However, as mentioned earlier, at present this technology is not cost effective. While natural gas produces greenhouse gasses, it produces nearly half the emissions of methanol, gasoline, and hybrid vehicles.

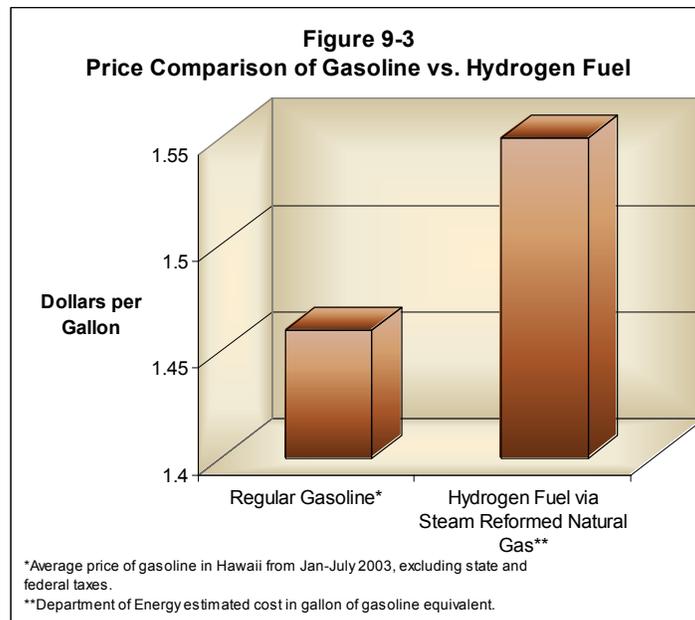
Costs Associated with Natural Gas as a Hydrogen Fuel Feedstock

Along with the advantage of relatively low greenhouse emissions, as mentioned above, natural gas is also a clear winner in terms of hydrogen fuel production costs. At present, steam reformation of natural gas is the most economical means of producing hydrogen fuel. Of the five feedstocks mentioned earlier, biomass, electrolysis of water, and steam reformed natural gas are the most ideal candidates for hydrogen production in terms of greenhouse emissions. As shown in the figure below, of these three, natural gas is the cheapest feedstock to produce hydrogen fuel, however biomass runs a close second.



However, it must be noted that hydrogen produced via natural gas reformation is relatively high, even when compared to Hawaii's high cost of gasoline. The figure below gives a comparison of hydrogen produced via steam reformed natural gas to Hawaii's average cost of gasoline from January to July 2003 (excluding state and federal taxes). The price of the natural gas feedstock is

based on DOE's 19-year national average industrial rate of \$5.34 per thousand scf. As you can see the gasoline equivalent per gallon of hydrogen is nearly 10 cents higher.



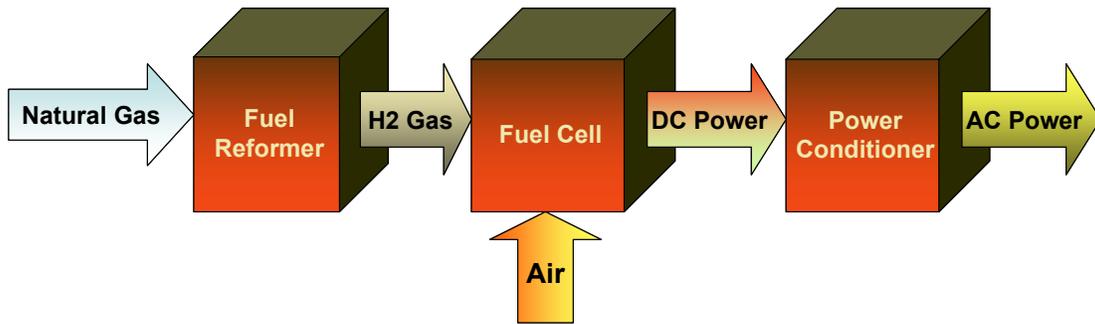
Hydrogen Fuel Cells

As we discussed earlier natural gas could be the stepping stone towards a hydrogen economy—but what exactly is a hydrogen economy? Imagine a world where all of our energy needs are supplied by a clean infinite energy source—hydrogen. Hydrogen fuel can be used to power fuel cells which in turn, can be used to run our homes, transportation and industry.

Fuel Cell

A fuel cell is a direct energy conversion system with no moving parts. Fuel cells are much like batteries with the exception that they consume fuel to maintain a chemical reaction that produces electricity. In simplest terms a feedstock—natural gas—is fed into a reformer, which extracts the carbon atoms from the natural gas leaving hydrogen enriched gas. The hydrogen gas is then fed to the fuel cell where it mixes with oxygen to begin a chemical reaction that produces DC power. The DC current is sent to a power conditioner which converts the current into AC current.

Figure 9-4 Natural Gas Fuel Cell



Fuel Cell Applications

Fuel cells are an extremely flexible power source and researchers have found many uses for them. They are perhaps most recognizable in transportation use, where the efficiency and reduced emissions these alternative power sources offer has sparked a race among automobile and fuel cell manufacturers to be the first to commercially mass produce fuel cell vehicles.

Transportation

Honda, Toyota, and Ford are a few of the auto manufacturers currently researching the use of fuel cells in vehicles. Honda has released several of its fuel cell vehicles in Japan and California on a trial basis. These fuel cell cars have a driving range of 220 miles and have achieved the U.S. Environmental Protection Agency's lowest vehicle emission rating.

Stationary Use

Stationary fuel cells are also gaining ground and are being implemented worldwide. Testament to this came in the recent installation of a 250 kilowatt fuel cell at the Sheraton Parsippany Hotel in Parsippany, N.J. The fuel cell runs on natural gas and supplies nearly 25 percent of the hotels electricity and heating.

Distribution Issues

Hawaii will require substantial infrastructure changes to accommodate natural gas (discussed further in Chapter 10) and additional capital investments would be required to further upgrade the infrastructure towards hydrogen fuel production and distribution.

There are several key questions that must be answered before the dream of a hydrogen infrastructure can be realized, as current research and development has not settled on several key issues related to fuel cells:

- ◆ Direct hydrogen fueling versus onboard reforming: Researchers are debating whether to store pure hydrogen directly on the vehicle/stationary fuel cell or use small onboard fuel reformers to process hydrocarbons such as gasoline or natural gas.
- ◆ The above issue will have a direct impact on how we distribute hydrogen fuel or a feedstock for hydrogen fuel production. There are two options to consider: 1) Central distribution of hydrogen from a large scale natural gas reformer (or another fuel source), which could produce large amounts of hydrogen, with either pipelines or ground transport to distribute the hydrogen fuel. 2) Small on-site reforming stations, where natural gas (or another fuel source) is either piped or transported to the stations to be reformed on-site into hydrogen fuel.
- ◆ Storage of hydrogen fuel is yet another dilemma that must be resolved. Hydrogen does not store as easily as gasoline and requires specialized containment, which is quite costly.

Centralized Hydrogen Production

Large scale hydrogen production plants range in hydrogen output from 25 to 100 mmscf/d. This translates into enough hydrogen to fuel approximately 220,000 to 900,000 hydrogen fuel cell vehicles, driven 11,000 miles per year. Capital costs for a 20 mmscf/d steam reformer are about \$200/kW of H₂ output, whereas the cost for a 200 mmscf/d steam reformer is estimated at \$80/kW of H₂. A plant of this size, in theory, could easily accommodate the vehicles in the City and County of Honolulu (In 2002, there were 643,810 registered passenger vehicles).

It should be noted that this cost does not take into account the distribution of hydrogen. The table below lists the estimated capital costs of hydrogen pipelines compared to natural gas pipelines.

Table 9-1		
Estimated Cost of Natural Gas Pipeline vs. Hydrogen Pipeline		
Diameter of Pipeline (inch)	Natural Gas Pipeline (\$/mile)	Hydrogen Pipeline (\$/mile)
3	200,000	400,000
9	500,000	900,000
12	600,000	1,000,000
14	800,000	1,400,000

Source: Department of Energy

Decentralized Hydrogen Production

Small refueling stations, which include a natural gas reformer, fuel storage and pumps, are quite cost competitive and would be ideal if Hawaii implements a distribution network for natural gas (we believe this is the likely scenario). A study by Direct Technologies found that a station capable of fueling 183 fuel cell vehicles a day would have an initial capital cost of \$253,000 and produce hydrogen fuel at \$1.55/gallon of gasoline equivalent (state and federal taxes excluded).

The Department of Energy estimates a station that could fuel 1,400 vehicles a day would have an initial cost of \$1.1 million. However, the cost of hydrogen would drop significantly, to \$.87/gallon of gasoline equivalent.

To put this into perspective, according to the Energy Information Agency (EIA) Hawaii is reported to have 361 gasoline service stations operating statewide in 2002. If we assume that Hawaii upgrades a quarter of the stations the capital costs would be nearly \$23,000,000 using the Direct Technologies estimated cost for a hydrogen fueling station.

Storage

The problems associated with hydrogen storage have retarded efforts to produce affordable fuel cells. Hydrogen is a rather complex fuel to confine and researchers face a variety of technical barriers. It is difficult to say which technology will emerge as the frontrunner, as each have their own advantages and disadvantages.

Gaseous Hydrogen: One gram of gaseous hydrogen occupies about 11 liters (or 2.9 gallons) of space at atmospheric pressure, which means that hydrogen must be heavily compressed in order to store sufficient amounts of energy. Current storage tanks range anywhere from 10,000-20,000

pounds per square inch (PSI). Due to the high pressures, these tanks have raised concerns of safety, and as such the tanks must be heavily reinforced and are quite heavy.

Liquid Hydrogen: Liquid hydrogen is ideal for transportation applications as it has a high energy to mass ratio which is three times that of gasoline. Unfortunately, the process of liquefaction involves lowering gaseous hydrogen to extremely cold temperatures (-235°C), and during the liquefaction process up to 40% of the energy content may be lost. Liquefied hydrogen must also be stored in a specially insulated tank to maintain its liquid form.

Metal Hydrides: This method of hydrogen storage is perhaps the safest. Through a chemical reaction hydrogen is bonded with metals or alloys. By applying significant amounts of heat to the hydrides 300-350°C, the hydrogen is released from its bonds. This technology is not an ideal means for transportation purposes as the weight and size of the hydrides are a burden on vehicles.

The Reality of a Hawaii Hydrogen Economy

The future outlook of a Hawaii hydrogen economy is somewhat cloudy. To look on the bright side, hydrogen fuel cells appear to have the backing of governments worldwide. Industries are also investing considerable funds into research and development of fuel cells.

- ◆ There are several Hawaii based projects underway to explore the viability of hydrogen fuel cells. In April of 2003 the Hawaii Fuel Cell Test Facility—a joint research initiative between the Hawaii Natural Energy Institute, the Hawaiian Electric Company and UTC fuel cells (a leading manufacturer of fuel cells)—opened its doors. The facility is exploring the feasibility of establishing a commercially viable fuel cell for transportation.

However, the cost of this technology is a considerable drag on development, as fuel cells remain extremely expensive due to the high costs associated with hydrogen fuel production and the materials used in fuel cells. Current costs of fuel cell vehicles range anywhere from 2 to 4 million dollars each. Stationary fuel cells are also expensive and range in costs anywhere from \$3,000-\$5,000 per kW. The price of fuel cells will have to drop to levels reflected in the table below, in order to become commercially viable.

Table 9-2	
Estimated Price for Commercial Viability of Fuel Cells	
Application	Price Point for Commercial Viability
Transportation	\$35-50 per kW
Distributed Residential	\$300-500 per kW
Distributed Commercial	\$1,200-3,000 per kW
Stationary Grid Connected	\$1,000-1,500 per kW
Portable/Micro	\$5,000-10,000 per kW

We believe that if Hawaii chooses to move further in the direction of a hydrogen-based economy, LNG could play a key role in the interim stages. A natural gas infrastructure will help to soften the blow on further capital investments towards hydrogen fuel production, and costs will eventually drop once fuel cells enter mass production.

Chapter 10

Cost of LNG: Can it Compete in Hawaii?¹

Introduction

While concerns about the project site, environmental impacts, security of supply, safety, etc., are all important, the most basic, and perhaps the most critical question that must be answered is: Can LNG compete with existing fuels? Although the marketers of LNG are somewhat hesitant to discuss prices in detail at such an early stage, their interest in the Hawaii market certainly signals that they believe LNG can be competitive. In addition, estimates of the costs involved in the LNG projects that would likely serve the Hawaii market indicate that LNG is likely to be a competitive source of energy. This chapter takes a look at the competitive position of LNG in Hawaii relative to other fuels.

Advantages and Disadvantages of Hawaii as an LNG Market

Before delving into numerical estimates, it may be productive to think of the advantages and disadvantages of Hawaii as a LNG market relative to other potential buyers. To the extent that Hawaii is an appealing market to sellers, it will be able to secure a lower price for LNG.

Hawaii has several clear advantages over alternative markets. First, although the regulatory details surrounding LNG have not been established, Hawaii has a well developed legal structure and a very dependable major buyer in HECO. It is also unlikely to see large-scale deregulation and other potential turmoil which threatens some market players in Asia. This is of the utmost importance in the LNG market, which requires large capital investments and typically looks for long term contracts to ensure that these costs can be recouped. A number of promising LNG markets, such as India, are suffering from the fact that buyers are seen as unreliable.

¹ This chapter draws upon presentations by several LNG marketers, information from various LNG focused seminars and conferences, and conversations with individuals involved in the gas and power industry.

A second advantage of Hawaii is that its potential demand is relatively stable, and does not see the dramatic seasonal swings seen in a country like South Korea, where gas consumption spikes in the winter. This limits the need for storage and allows producers to more fully utilize their capacity throughout the year.

A final major advantage of Hawaii is the emergence of the U.S. West Coast and Mexico as a promising LNG market. Because Hawaii is located along the route from Asia to these markets, potential synergies exist that were not in existence even a few years ago. The fact that energy companies are looking to more creatively utilize their LNG shipping capacity also increases the interest in Hawaii as a potential market. In the past, most LNG tankers were dedicated to a specific route, but this looks to be changing in the future, as discussed in Chapter 6.

From the point of view of LNG providers, there are two major disadvantages to the Hawaii market. The first disadvantage is the size of the market. The Hawaii market is relatively small when compared to the huge existing markets in Japan and Korea, and the enormous potential markets of China, India, and the U.S. mainland. However, a number of projects of Hawaii's size or smaller have come to fruition in recent years (e.g., in Puerto Rico and the Dominican Republic), and Hawaii is likely to exceed the 1 million tonnes per annum that allows economies of scale to kick in.

The second major concern about Hawaii is the site for the regasification terminal. This is also a concern on the U.S. mainland, where permitting is extremely difficult, but Hawaii presents an added challenge in that the likely location (the harbor at Barber's Point), would likely require substantial modification, as discussed later in this chapter. Alternatives, such as offshore regasification, would add considerably to the cost.

To summarize, although there are some disadvantages to the Hawaii market, in our conversations with LNG providers they were quite interested in the opportunity to sign what they see to be a very secure long-term contract that could provide a stable, albeit small, supply outlet for a new or expansion LNG project. Should Hawaii seek to pursue LNG, it should certainly be aware of its position in the marketplace and seek out sellers that will value its unique attributes.

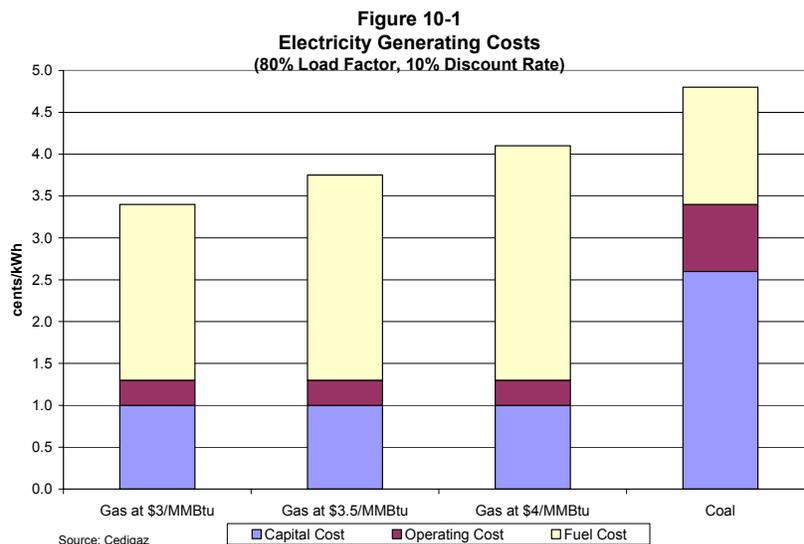
Necessary Infrastructure and Estimated Cost

In terms of infrastructure, by far the most challenging, and expensive, aspect of establishing LNG in Hawaii would be the regasification terminal. Regasification in itself would be relatively inexpensive (\$20-30 million), but the cost of building LNG storage is substantial (\$40-70 million). While the estimated expense varies widely, the most expensive part of the project would be to prepare Barbers Point Harbor to handle LNG tankers. Currently, the mouth of the harbor is too narrow, the basin is too small, and the depth is not adequate. The estimated expense of expanding the harbor has so far varied widely, from \$30 million to over \$100 million.

Other expenses worth noting would include two gas pipelines totaling approximately 17 miles in length to feed the existing boiler units at Kahe, Waiiau, and Kalaeloa (note that it is likely that Honolulu plant would continue to use low sulfur fuel oil and we understand that the Waiiau peaking units would likely not be modified to use gas). Each of the boiler units would be retrofitted to use either gas or fuel oil at a cost of approximately \$3-5 million each. (Total cost of approximately \$36-60 million).

Competitive Position of LNG under Alternative Price Scenarios

The two fuels that are obvious competitors to LNG in the power sector in Hawaii in the near term are coal and fuel oil, both of which are currently in use (in the longer term renewables could play an expanded role).



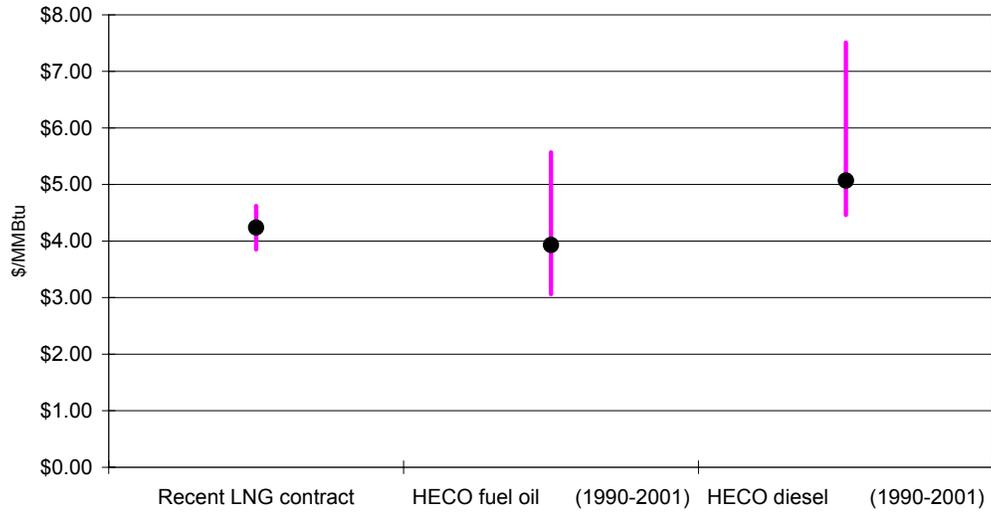
For new capacity, gas is very competitive with coal at a wide range of gas prices, as depicted in Figure 10-1. Overall, the obvious advantage of coal versus natural gas is that the fuel cost is much lower (typically \$1.50-2.00/MMBtu). However this is generally outweighed by the fact that the capital cost of a coal plant is much higher and the construction time is longer.

Turning the focus to fuel oil, if LNG is introduced in Hawaii, HECO would retrofit its existing steam boilers that are currently fired by low sulfur fuel oil. In addition, in the future, HECO plans to add a combined-cycle plant fueled by diesel. If LNG is available, this plant would be gas-fired instead of diesel-fired. In both cases, although there are some minor differences in terms of efficiencies and maintenance costs, it is appropriate to compare the cost-competitiveness of the fuels on a \$/MMBtu basis.

The cost of natural gas relative to fuel oil and diesel would obviously depend on the LNG price formula that is adopted and how it relates to oil. Because LNG is currently not imported to Hawaii, we must rely on recent LNG supply agreements as a guideline of the “market price.”

Recently, BP agreed to supply LNG to SK Power and POSCO Corporation of South Korea from the Tangguh field in Indonesia. This supply agreement is quite relevant to Hawaii as a price marker, because the volume (1.1 million tonnes per annum) is very similar to Hawaii’s anticipated LNG demand. Although the details of the agreement are confidential, it is widely believed (and reported) that the FOB price is approximately \$2.50/MMBtu at a \$20/bbl oil price. The formula is believed to have a price floor of \$2.15/MMBtu (at a \$15/bbl oil price) and a price ceiling of \$2.92/MMBtu (at a \$26/bbl oil price). Adding an estimated \$0.70/MMBtu for transportation to Hawaii and an estimated \$1.00/MMBtu for regasification, port costs, and other capital costs (this would be considered to be a high estimate by most observers in the LNG industry, but it is anticipated that the cost of port modifications will be quite high in Hawaii) yields an LNG price range of \$3.85-\$4.62/MMBtu, with an average price of \$4.24/MMBtu. This range is depicted in Figure 10-2 under the category “Recent LNG contract.” For comparison, the high/low range of prices and average price that HECO paid for fuel oil and diesel over the period 1990-2001 is also reflected in Figure 10-2.

Figure 10-2
Cost of LNG vs. Other Fuels
(Hi/Low Range and Average)



Source: HECO and DBEDT

Given these estimates it is clear that LNG has the potential to be competitive with fuel oil, and especially diesel. LNG has the added bonus that its price is certain to be less volatile if a pricing formula similar to the BP and SK/POSCO agreement were to be adopted.

Chapter 11

Demand Scenarios for LNG in Hawaii¹

Introduction

If Hawaii chooses to pursue the LNG option there are several main areas where it would, and could possibly, be consumed. Initially LNG would likely replace almost all of the fuel oil used on Oahu in power generation, as well as the synthetic natural gas that is used in the utility gas network, also on Oahu. Over time, LNG use would grow as demand grows in both of these systems, and there is also the possibility of other uses emerging, such as compressed natural gas for vehicles, neighbor island use, and reforming the natural gas into hydrogen for fuel cells. In this chapter, we briefly examine the consumption possibilities in each of these areas, a summary of which is provided in a table at the end of the chapter.

Power Generation

When we first examined the LNG option in the *Hawaii Hydrocarbon Outlook* we examined a number of scenarios, including importing relatively small quantities of LNG, but after extensive conversations with industry contacts it appears that the most likely scenario is that LNG would replace almost all of the fuel oil that is used for power generation on Oahu. As indicated in Table 11-1, LNG would be consumed in all of the units at Kahe, six of the units at Waiiau (two combustion turbine peaking units would continue to consume diesel, at least initially). The two units in downtown Honolulu, which are used only when electricity demand is at its highest, would likely continue to use fuel oil. Because usage at the downtown units is so limited, it would not be worth the cost of converting these units to consume natural gas. In all, approximately 97 percent of the fuel oil that HECO currently uses in power generation on the island of Oahu would be converted to LNG.

¹ This chapter draws upon conversations with industry participants; input from DBEDT; the *Hawaii Hydrocarbon Outlook*, January 2003, which was prepared by FACTS Inc. for the Hawaii Energy Forum; and *Hawaii Energy Strategy 2000*.

Table 11-1 HECO-Owned Generators (Existing HECO-Owned)		
Unit	Unit Type & Fuel*	Capacity (MW)
Honolulu 8	OFS-LSFO	56
Honolulu 9	OFS-LSFO	57
Waiau 3	OFS-LSFO	49
Waiau 4	OFS-LSFO	49
Waiau 5	OFS-LSFO	57
Waiau 6	OFS-LSFO	58
Waiau 7	OFS-LSFO	92
Waiau 8	OFS-LSFO	92
Waiau 9	CT-Diesel	52
Waiau 10	CT-Diesel	50
Kahe 1	OFS-LSFO	92
Kahe 2	OFS-LSFO	90
Kahe 3	OFS-LSFO	92
Kahe 4	OFS-LSFO	93
Kahe 5	OFS-LSFO	142
Kahe 6	OFS-LSFO	142
Total Capacity		1,263
*OFS-LSFO: oil-fired steam - low sulfur fuel oil (residual)		
CT-Diesel: combustion turbine - diesel		

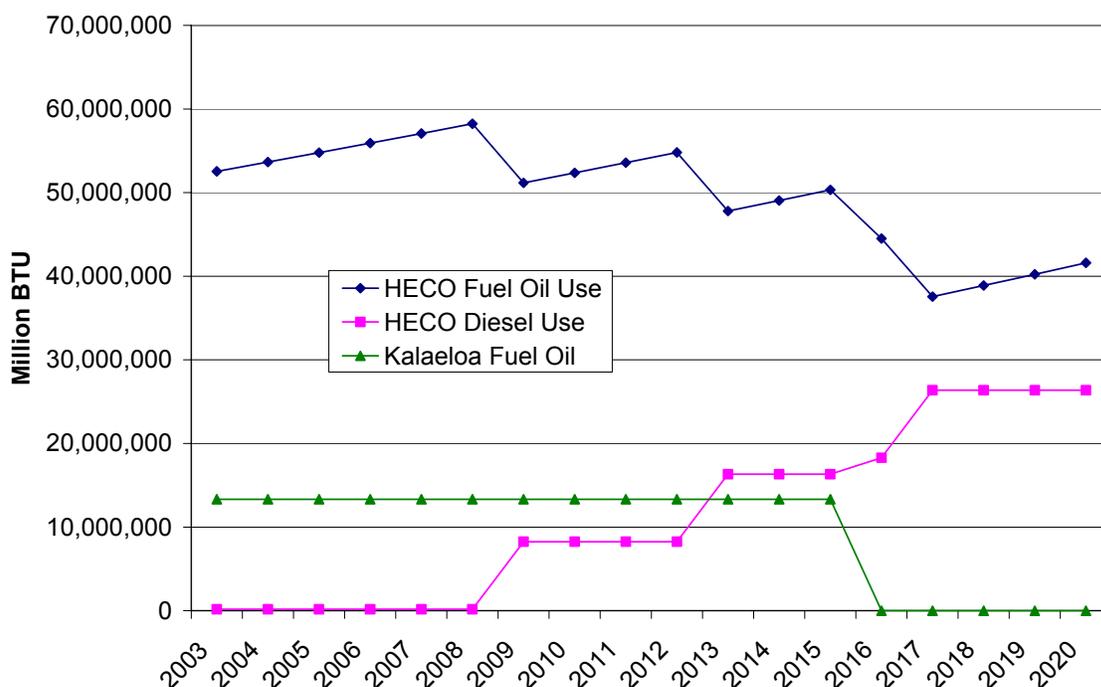
Source: HECO and DBEDT

HECO also has a power purchase agreement with independent power producer Kalaeloa Partners, which has a 180 MW dual-train combined cycle unit that is fueled by fuel oil provided by Tesoro. It should be noted that this fuel oil is “washed” for use in the combustion turbines. Also, as part of the supply contract, Tesoro receives steam heat from Kalaeloa Partners. While the fuel supply agreement and the units themselves would obviously have to be modified, the Kalaeloa units could certainly be fueled by LNG.

Figure 11-1 projects future fuel oil and diesel use by HECO and Kalaeloa Partners. The assumption is that Kalaeloa Partner’s fuel oil use remains constant until 2016, when its contract expires. It is also assumed that HECO dispatches the units with the lowest heat rate first. Currently, HECO’s preferred plan calls for the addition of a 107 MW simple cycle diesel-fired combustion turbine to be added in 2009 as the first of three units to be included in a 318 MW

diesel fired 2-on-1 combined cycle unit. Phases 2 (107 MW) and 3 (104 MW) of the combined cycle unit would be installed in 2013 and 2016, respectively. In addition, another 107 MW simple cycle diesel-fired combustion turbine is to be added in 2017. In general, even if Hawaii does not pursue LNG, there will clearly be a move away from fuel oil as a fuel source in power generation in the future.

**Figure 11-1
Estimated Fuel Use Under Current HECO Plans**



Source: HECO and DBEDT

If these units were to be converted to be fueled by LNG, Hawaii would require approximately 1.35 million tonnes of LNG for power generation in 2007, increasing to 1.54 million tonnes by 2015. Current plans call for the addition of another coal-fired plant in 2016, once the HECO contract with Kalaeloa partners expires. If a coal plant is in fact built, some LNG consumption would be displaced by coal. However, because natural gas has environmental advantages over coal and the LNG infrastructure would already be in place, we speculate that Hawaii would likely build additional gas-fired capacity if the LNG option is pursued, and LNG consumption would grow to approximately 1.66 million tonnes in 2020.

Utility Gas

In comparison to the power sector, the amount of LNG that would be required by the utility gas sector would be very small, at least in the initial stages. It is our understanding that the infrastructure upgrades required to convert the existing infrastructure to accommodate regasified LNG would be minimal. Currently, synthetic natural gas is manufactured by the Gas Company from light ends (relatively light petroleum products) provided by the Tesoro refinery. The synthetic natural gas accounts for 94 percent of all utility gas consumed on Oahu, with LPG accounting for the balance. Most of the utility gas is consumed in the Downtown-Waikiki corridor.

Currently, gas is very expensive in Hawaii, with prices 3 to 4 times what is typically seen on the U.S. mainland. As a consequence, we believe that there is a lot of room for growth in the utility gas market with the introduction of LNG—which should bring cheaper gas. Because we believe that gas prices would likely fall by more than electricity prices with the introduction of LNG, the competitive position of gas would likely be enhanced. There would likely be an increase in gas demand for commercial water heating and gas-fired air conditioning. In addition, this could improve the economics of Combined Heat and Power Systems (CHP) and expansion of the utility gas network, both of which would boost demand.

At current levels, utility gas consumption would only be the equivalent of approximately 60,074 tonnes of LNG, which is only the size of about one cargo of LNG. The Gas Company's current base-case forecast of utility gas demand anticipates that demand will grow by only 0.43 percent annually between 2000-2020, to 68,792 tonnes in 2020. Even the high case projects growth of less than one percent (0.81 percent), to 75,832 in 2020. To illustrate the possible impact of lower prices and increased interfuel substitution, if demand were to grow by 2 percent per annum after the (hypothetical) introduction of LNG in 2007, demand would reach 85,420 tonnes by 2020.

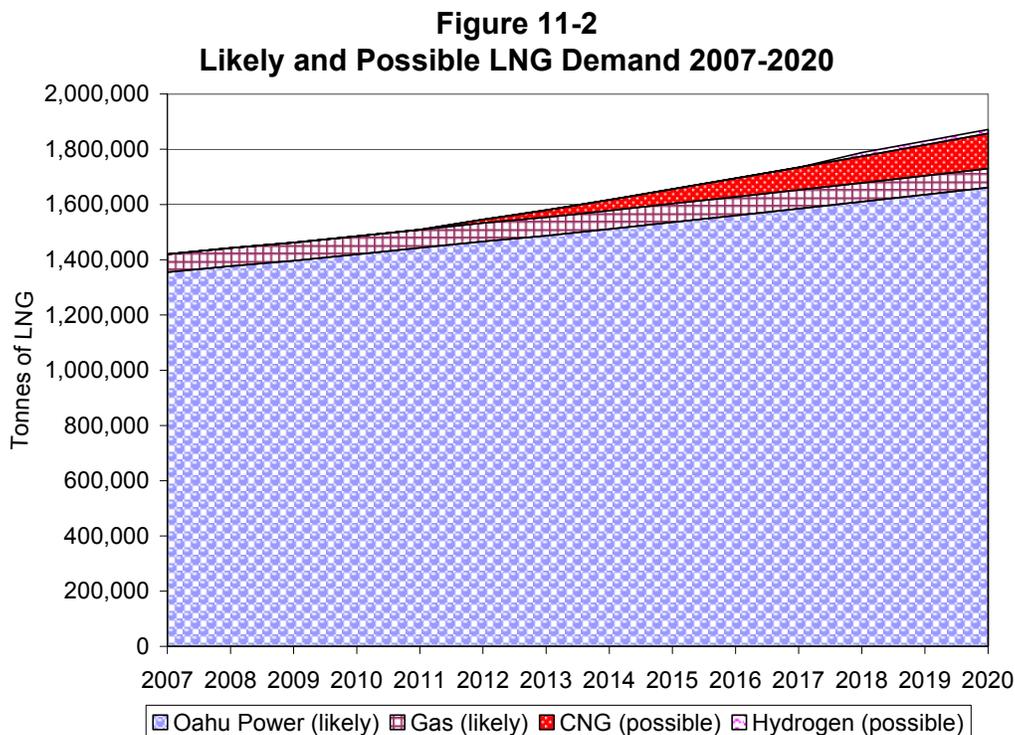
Other Uses

Other possible uses for LNG include: (1) encouraging the use of compressed natural gas (CNG)—first in fleet vehicles, and then in private vehicles; (2) the development of fuel cells, where natural gas serves as a relatively inexpensive source of hydrogen in the early stages of

development (as discussed in Chapter 9); (3) barging LNG to the neighbor islands for use in power generation. It is important to note that while each of these options is technically feasible, their economic viability is currently questionable.

Projected Demand

Given the discussion presented above, we project LNG demand over the period 2007-2020. Of course, this assumes that Hawaii begins receiving LNG in 2007, which may be optimistic. However, for the purposes of this analysis, establishing the exact year that shipments are initiated is not critical.



To begin, we assume that Oahu power consumption grows at an average annual rate of approximately 1.5 percent. This is approximately the same rate that is projected by HECO, and it is predicated on the assumption that gas will be used to satisfy future power demand. We follow the Gas Company in projecting that utility gas demand will grow at an average annual rate of 0.43 percent through 2020, although we feel that more rapid growth is certainly plausible if the introduction of LNG corresponds with lower gas prices. These growth projections could be considered quite conservative, and thus it is very realistic that Hawaii LNG demand in the

power and utility gas sectors would be approximately 1.42 million tonnes in 2007, growing to approximately 1.73 million tonnes in 2020.

In terms of the other possible uses of LNG discussed above, we choose a rather optimistic scenario where the use of CNG vehicles is encouraged. In 2012 CNG vehicles replace one percent of gasoline and diesel usage, and the share of CNG vehicles increases by one percent each year, such that CNG accounts for 9 percent of transport fuel in 2020. In addition we optimistically assume that a fuel cell pilot project will be underway by 2018 and this will replace one percent of the transport fuels. We feel that the cost of barging LNG to the neighbor islands is likely to be prohibitive, so we do not include this scenario in our final demand projections, which are depicted in Figure 11-2.

Chapter 12

Possible Disruptions to the Existing Energy Infrastructure: Implications for Energy Security and the Hawaii Economy¹

Introduction

Among the most pressing questions to address in examining the opportunity for LNG in Hawaii is, what will happen to the refineries? The State encouraged the development of a second refinery in 1972, to encourage competition and enhance energy security, and the prospect of losing a refinery is an understandable cause for concern. In a report entitled *Hawaii Hydrocarbon Outlook*, FACTS Inc. evaluated how alternative fuel substitution scenarios might impact refining margins, showing that LNG would have a substantial negative impact on profitability. More recently, Stillwater Associates released a detailed analysis of refining in the State, and while it is not a focus of their analysis, they did point out that LNG would threaten the viability of the refineries. Unfortunately, each of these analyses is somewhat static, in that they do not incorporate the wide array of responses that are available to the refineries if the LNG option is pursued. The fact is that this important question is impossible to answer with certainty, as the viability of each refinery depends on how the other responds, future market conditions on the U.S. West Coast and Asia, and the investment climate in the State.

In this chapter we build upon our previous assessment of how LNG might impact refinery profitability/viability, discuss how refineries might respond to the introduction of LNG, and examine how the introduction of LNG and/or the shutdown of a refinery could impact the energy market and the economy in general. As the interest in LNG has grown, many of those who have an interest in the issue, located both inside and outside of the State, have shared their opinions and we try to include their ideas here.

¹ This chapter draws upon conversations with industry participants; the *Hawaii Hydrocarbon Outlook*, January 2003, which was prepared by FACTS Inc. for the Hawaii Energy Forum; the *Study of Fuel Prices and Legislative Initiatives for the State of Hawaii*, August 2003, which was prepared by Stillwater Associates for DBEDT; and the Hawaii Energy Strategy Project 2, Task IV: *Scenario Development and Analysis*, December 1993, which was prepared by the East-West Center Program on Resources for DBEDT.

How Might LNG Impact Refinery Profitability/Viability?

In many ways Hawaii’s refineries might be considered to be dinosaurs—on the mainland, small refineries that produce large quantities of fuel oil have either been shutdown or upgraded. The survival of Hawaii’s refineries in their present form depends upon the fact that the Hawaii market is relatively isolated and power generation is heavily dependent on oil, which is becoming increasingly uncommon in most parts of the world.

As pointed to in the *Hawaii Hydrocarbon Outlook*, the introduction of LNG as a fuel source for power generation would likely have a substantial negative impact on refinery profitability. Fuel oil, which currently commands relatively high prices in the local market, would likely have to be exported to Asia. The fact that fuel oil would likely be sold at a much lower price, as well as the added costs incurred for transport, leads to much lower revenue for a substantial portion (approximately 27%) of Hawaii refiner’s production.

Table 12-1 Hawaii Petroleum Product Balance, 2001 (barrels/day)					
Fuel	Imports	Exports	Production	Consumption	
Propane*	577	0	3,547	4,124	
Naphtha	0	4,932	10,432	5,500	
Motor Gasoline	1,553	335	25,829	27,047	
Aviation Gasoline	0	0	99	99	
Jet Fuel/Kerosene	7,365	0	37,365	44,729	
Diesel	169	0	18,991	19,161	
Residual Fuel Oil	2,618	0	35,962	38,580	
>1% sulfur**	0	0	12,800	12,800	
<=1% sulfur	2,618	0	23,162	25,780	
Other	430	1,433	2,098	1,096	
Total	12,712	6,700	134,323	140,335	
*Includes SNG, **Includes Asphalt					
Source: DBEDT and industry contacts.					

As indicated in Table 12-1, which shows estimates of the State’s petroleum product balance in 2001, and Table 12-2, which presents a hypothetical example of the impact of LNG imports (also based on the 2001 product balances), exports of petroleum products increase to almost 32 kb/d (versus less than 7 kb/d without LNG) and local consumption of petroleum would drop to under

113 kb/d.² Under this scenario gross refining margins are projected to decline by 27 percent, which, depending on cost assumptions, could threaten the long-term viability of the refineries in their present form.³

Table 12-2 Hypothetical Hawaii Petroleum Product Balance w/LNG (barrels/day)					
Fuel	Imports	Exports	Production	Consumption	
Propane*		577	1,907	3,547	2,217
Naphtha		0	4,932	10,432	5,500
Motor Gasoline	1,553		335	25,829	27,047
Aviation Gasoline	0		0	99	99
Jet Fuel/Kerosene	7,365		0	37,365	44,729
Diesel	169		0	18,991	19,161
Residual Fuel Oil	0	23,162		35,962	12,800
>1% sulfur**	0	0		12,800	12,800
<=1% sulfur	0	23,162		23,162	0
Other	430		1,433	2,098	1,096
Total	10,094	31,769		134,323	112,648

*Includes SNG, **Includes Asphalt

In a recent in-depth examination of the refining situation in Hawaii, consultant Stillwater Associates came to a similar conclusion in terms of the impact of LNG on Hawaii's refineries. Stillwater Associates finds that when LNG is substituted for LSFO, the Chevron refinery's profits fall to zero and the Tesoro refinery operates at a loss.

How Might Refineries Respond to LNG?

The weakness of the analyses discussed above is that they are static, worst-case scenarios, where the refiners do not alter their behavior in response to LNG. In reality refiners have a wide array of options available to them aside from simply exporting excess fuel oil, which could be pursued either alone or in conjunction. These include, upgrading to reduce fuel oil output and increase the output of other products, importing crudes that yield less fuel oil, reducing crude runs, and shutting down.

² Clearly, overall petroleum product consumption is likely to be higher at the end of the decade when LNG is likely to be introduced, but the 2001 consumption estimates serve as a useful reference for this hypothetical example.

³ Please see the *Hawaii Hydrocarbon Outlook*, January 2003, which was prepared for the Hawaii Energy Forum for an in-depth discussion.

Given additional resources, it would be possible to set up a detailed liner programming model similar to that used in the Hawaii Energy Strategy Project 2, Task IV: *Scenario Development and Analysis*, which was prepared by the East-West Center Program on Resources for DBEDT in 1993. This type of analysis would allow for more flexibility in terms of crude use and possible upgrades in trying to project possible refinery responses. Unfortunately, this type of analysis goes beyond the scope of this report, and regardless, it is still lacking in terms of the options it allows.

In our conversations with industry contacts, possible responses to the introduction of LNG included upgrading the Hawaii refineries in such a way that they can serve niche markets that arise on the U.S. West Coast. Other options that have been discussed include a joint venture among the refineries (if allowed), seeking government subsidies in the form of investment tax credits, encouraging the State to takeover and regulate the refineries, etc. Most of these options are unlikely, but they are all possibilities. To complicate matters, the actions of each of the Hawaii refineries certainly impact the decision-making of the other, but the refiners have to make plans in isolation. In addition, in our conversations we noted that refiners are also somewhat hesitant to commit to upgrades in a market that is perceived as relatively stagnant and anti-refinery (e.g., lawsuits and gasoline price caps).

To summarize, our analysis in the *Hawaii Hydrocarbon Outlook* and the report done by Stillwater Associates clearly indicate that the profits of the refineries will suffer if LNG displaces low sulfur fuel oil in power generation. Whether one or both refineries will shutdown depends on a multitude of variables, such that even the industry players that are intimately involved are not certain what will happen. Given this uncertainty, perhaps it is best to operate under the assumption that a refinery would close if the LNG option is pursued, and evaluate how this would impact the State's energy and economic landscape.

Impact of a Refinery Shutdown

While we feel it is possible that a refinery could shutdown if Hawaii pursues LNG, it is unlikely that both would shutdown, as the advantage of being the only player in the market is bound to be appealing. It is difficult to speculate which, if any, refinery might shutdown, but the Chevron

refinery is smaller, older, less sophisticated, and less oriented toward producing jet fuel, so a case could be made that it would be more likely to shutdown. However, under the scenarios examined by Stillwater Associates, the Tesoro refinery suffers larger losses due to the introduction of LNG, so it is conceivable that it would close its doors.

Table 12-3 provides a rough estimate of the product slate of Hawaii’s refineries. In contrast to other states, the Hawaii market is roughly in balance, with jet fuel, and to some extent fuel oil, as the only fuels that are imported in large quantities.

Table 12-3 Estimated Product Slate (barrels/day)			
Fuel	Chevron	Tesoro	Total
Propane*	1,773	1,773	3,547
Naphtha	4,815	5,617	10,432
Motor Gasoline	12,915	12,915	25,829
Aviation Gasoline	49	49	99
Jet Fuel/Kerosene	12,455	24,910	37,365
Diesel	4,998	13,994	18,991
Residual Fuel Oil	13,607	22,355	35,962
>1% sulfur**	4,843	7,957	12,800
<=1% sulfur	8,764	14,398	23,162
Other	1,049	1,049	2,098
Total	51,661	82,662	134,323
*Includes SNG, **Includes Asphalt			
Source: DBEDT and industry contacts.			

Tables 12-4 and 12-5 show how the situation might change with the introduction of LNG and a refinery closure. In each case, we subtracted the estimated production of the respective refinery from total production, and examined how this might affect imports and exports, given the same level of consumption. Typically, Hawaii’s refineries operate at about 85 to 90 percent of capacity and each has some degree of flexibility to adjust the product slate to match market conditions, so this is a rough approximation. We should also note that it is unlikely that the State would import naphtha, which is currently used for power generation on the neighbor islands, so we have reduced consumption in the case where this possibility was indicated (i.e., a closure of the Tesoro refinery).

Table 12-4 Hawaii Petroleum Product Balance w/ LNG and Chevron Refinery Closure (barrels/day)					
Fuel	Imports	Exports	Production	Consumption	
Propane	444	0	1,773	2,217	
Naphtha	0	117	5,617	5,500	
Motor Gasoline	14,132	0	12,915	27,047	
Aviation Gasoline	49	0	49	99	
Jet Fuel/Kerosene	19,820	0	24,910	44,729	
Diesel	5,167	0	13,994	19,161	
Residual Fuel Oil	4,843	14,398	22,355	12,800	
>1% sulfur*	4,843	0	7,957	12,800	
<=1% sulfur	0	14,398	14,398	0	
Other	47	0	1,049	1,096	
Total	44,502	14,515	82,662	112,648	
*Includes Asphalt					

The Tesoro refinery has a larger capacity, and is oriented toward producing middle distillates, including jet fuel and diesel, so if it were to close, overall imports and especially imports of these products would increase.

Table 12-5 Hawaii Petroleum Product Balance, w/ LNG and Tesoro Refinery Closure (barrels/day)					
Fuel	Imports	Exports	Production	Consumption	
Propane	444	0	1,773	2,217	
Naphtha	0	0	4,815	4,815	
Motor Gasoline	14,132	0	12,915	27,047	
Aviation Gasoline	49	0	49	99	
Jet Fuel/Kerosene	32,275	0	12,455	44,729	
Diesel	14,163	0	4,998	19,161	
Residual Fuel Oil	7,957	8,764	13,607	12,800	
>1% sulfur*	7,957	0	4,843	12,800	
<=1% sulfur	0	8,764	8,764	0	
Other	47	0	1,049	1,096	
Total	69,066	8,764	51,661	111,963	
*Includes Asphalt					

If a Hawaii refinery were to shutdown, there are a number of potential drawbacks that should be considered, some of which have more merit than others. First, consider energy security. Importing LNG would serve to diversify Hawaii's energy base, reduce oil use, and could help limit energy price volatility. However, if this leads to the closure of a refinery, the State would have to import larger quantities of refined petroleum products. Although it is true that these

products are produced from oil, and thus overall oil use does not change with one or two refineries in operation, the State would require a variety of products, which may not be as widely traded as crude oil. In terms of energy security, diversifying through LNG is likely to be advantageous, but this caveat should be kept in mind.

A second concern is that there would be less competition in the marketplace. While this is a valid concern, it is not necessarily true. According to the Stillwater Associates report, jet fuel is the only major fuel in Hawaii that is essentially priced at import parity prices. All of the other fuels are generally priced above import parity prices. If other fuels, such as gasoline, were to be imported in large quantities (as is jet fuel), it is certainly possible that prices could drop to import parity.

A final concern that should be addressed is that an imported cargo might not satisfy Hawaii's specification requirements. This could be problematic, since locating alternative cargoes and remedying this problem would involve added time and expense, and in an extreme case, could lead to product shortages. The level of concern in this area obviously varies by fuel, as some fuels, like gasoline, have relatively strict specification requirements in the Hawaii market, and other products, such as jet fuel, are fairly standard internationally, or have relatively straightforward specifications, such as fuel oil. In any event, under this scenario it would be important that Hawaii establish reliable sources of supply. There are certainly a number of markets that import large quantities of petroleum products that regularly satisfy specification requirements, so Hawaii could certainly accomplish this, but it is a point that should be raised.

In summary, it is not clear that introducing LNG into the Hawaii energy mix would lead to the shutdown of a refinery, as there are a number of options available to each of the refiners, including upgrading, modifying their crude slate, and modifying their production strategy to take advantage of synergies with U.S. West Coast or Asian refineries. However, it is certainly a possibility that a refinery would close, which raises some concerns, though they are hardly insurmountable, as discussed above.

Economic Impact

Transforming the State's energy system through the introduction of LNG would certainly have an impact on the Hawaii economy. On the positive side, in the short-term a number of jobs would be created during the construction of an LNG terminal and in the long term, employees would be required to operate and maintain the terminal.

Constructing an LNG terminal typically takes approximately 3 years. One source estimates that about \$100 million would be spent in local communities, but this obviously varies depending on the type of terminal that is selected. For example, if an offshore terminal is selected the number of jobs created would likely be less. At the peak of construction approximately 400 direct contract construction workers would be employed. If you include direct, indirect, and induced jobs (i.e., the employment multiplier—jobs created as a result of the initial job. For example, an employee at an LNG terminal could buy a new house, thereby creating construction jobs.) approximately 891 jobs could be created over the course of the construction period.

When it is complete, an LNG terminal would require approximately 45 direct full-time employees. Because it is not an established industry in the State, it is not clear what the employment multiplier is for LNG, but if the employment multiplier for the power industry (3.10) and the job multiplier for the petroleum industry (4.63) are taken as guidelines, between 140 and 208 jobs would be created in the overall economy.⁴

It is critical to note that this is a narrow analysis and the full impact of LNG on the economy could be much larger, albeit difficult to discern, without more concrete information as to the final price of LNG. For example, if the introduction of LNG were to lower the price of electricity and utility gas, this would likely spur the overall economy and lead to the creation of jobs. Conversely, if LNG were to be introduced at a high price it could act as a drag on the economy. The key point in terms of minimizing possible negative impacts on the overall economy is to ensure that LNG is competitive with existing fuels, which we believe it can be, as discussed in Chapter 10.

⁴ Source: Eugene Tian, DBEDT

A final point to consider is that if a refinery were to close due to the introduction of LNG, there may be some net job loss in the energy sector. As an example, we understand that the Chevron refinery employs approximately 180 direct full-time employees. In the event of a closure, not all of these jobs would be lost as ports, tanks, and delivery would be maintained. If we assume that 110 direct full-time employees are terminated with a multiplier of 4.63, as discussed previously, the overall job loss would be 509 jobs. Taking into account the job creation through the LNG terminal, the estimated net job loss in the energy sector would be between 301 and 369 jobs.