Liquefied Natural Gas for Hawai‘i: Policy, Economic, and Technical Questions

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FACTS GLOBAL ENERGY

Liquefied Natural Gas for Hawaii: Policy, Economic, and Technical Questions

Evaluating liquefied natural gas for Hawaii and the corresponding policy, economical, and technical questions associated with potential imports.

20 December 2012

A Study by

FACTS Inc. (Part of FGE – FACTS Global Energy)

For

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List of Abbreviations

AAGR	average annual growth rate
b/d	barrels per day
bcf/d	billion cubic feet per day
bscf/d	billion standard cubic feet per day
BTU	British thermal unit
CCGT	combined cycle gas turbines
cf/d	cubic feet per day
cbm	cubic meters
DBEDT	Department of Business Economic Development and Tourism
EIA	Energy Information Administration
GW	gigawatts
GWh	gigawatt hours
HCEI	Hawaii Clean Energy Initiative
HDV	heavy-duty vehicle
HECO	Hawaiian Electric Company, Inc.
IEA	International Energy Agency
IPP	independent power producers
IRP	Integrated Resource Plan
kb/d	thousand barrels per day
km	kilometers
kt	thousand tonnes
ktoe	thousand tonnes of oil equivalent
ktpa	thousand tonnes per annum

kWh	kilowatt hours
LDV	light-duty vehicle
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSFO	low-sulfur fuel oil
MECO	Maui Electric Company, Inc.
MSFO	medium-sulfur fuel oil
mmb/d	million barrels per day
mmBtu	million British thermal units
mmscf/d	million standard cubic feet per day
mmt	million tonnes
mmtoe	million tonnes of oil equivalent
mmtoe/d	million tonnes of oil equivalent per day
mmtpa	million tonnes per annum
MW	megawatts
NGV	natural gas vehicle
scf	standard cubic feet
toe	tonnes of oil equivalent
tcf	trillion cubic feet
TWh	terawatt hours
USWC	United States West Coast

Disclosure and Acknowledgements

FGE has over 200 on-going retainer clients around the world, including government agencies, multinational oil and gas companies, independent refiners, traders, gas and power utilities, national oil companies, large financial institutions, and research institutions. Among its longest-standing clients are many government agencies, including the US Department of Energy and the US Energy Information Administration.

Founded in 1985 in Honolulu, the company's flagship office is in London, with major offices in Singapore, China, Japan, and Dubai, as well as satellite offices in Australia, Los Angeles, and New York. FGE has long been recognized as one of the world's leading consulting firms in oil and gas analysis.

The founder, Dr. Fereidun Fesharaki, is former President of the International Association for Energy Economics; a member of the Council on Foreign Relations; was appointed to the National Petroleum Council under both the Bush and the Obama administrations; and is a Senior Associate at the Center for Strategic and International Studies. He is also the sole expert on energy in CNN's GX-20 group of global experts.

In Hawaii, FGE clients include HECO, HAWAIIGAS, and DBEDT. The company has undertaken many previous studies on Hawaii's energy issues, including early studies of LNG potential in Hawaii. FGE undertook the present study with the intent of providing a fair and independent analysis with respect to the potential introduction of LNG into the State. Beyond payment for this study, FGE will receive no compensation whatsoever whether the State decides to import LNG or not, and no matter under what terms it is imported. The FGE team for this study was led by Mr. Shahriar Fesharaki who worked in conjunction with Dr. David Isaak, Dr. Nelly Mikhaiel, Mr. Chris Gascoyne, Dr. Kang Wu, and Ms. Alexis Aik. The project was supervised by Dr. Fereidun Fesharaki, Chairman of FGE.

During the course of completing this study, FGE conducted numerous interviews with contacts in Hawaii, on the mainland US, and in the Asia-Pacific region. There is a long list of individuals that we owe a debt of gratitude and would like to thank them for their assistance which proved invaluable. We would also like to thank John Cole at HNEI for his feedback and input into the study. In addition, special thanks go out to Shaun Davidson of Excelerate Energy L.L.C., Roland Fisher of Gasfin Development S.A., Michael Hansen of Hawaii Shippers Council, Tom Young and Joe Boivin of HAWAIIGAS, Ron Cox and Bob Isler at HECO, and Mark Glick and Tan Yan Chen of DBEDT. Overall, we trust that this study will yield useful insights as to the future prospects of LNG in the State of Hawaii.

Executive Summary

CHAPTER I: POTENTIAL DEMAND FOR LNG IN HAWAII

- FGE's baseline demand forecast results in 148 kb/d of oil demand in 2030, which would rise even higher to around 159 kb/d if we substitute fuel oil for power generation with diesel in 2017 to comply with new EPA regulations.

- Making adjustments with respect to the HCEI goals, however, results in some 50% reduction in fuel demand to some 76 kb/d, 41% of which would come from demand for jet fuel as there will be no readily available alternative.

- LNG can substitute for oil products in the power sector, the utility and non-utility gas sector, the transport sector (ground and marine), and the industrial sector (refining).

- Assuming a *successful achievement of HCEI goals*, Hawaii's total potential LNG demand ranges from approximately 1-2 mmtpa between 2015 and 2035. If *50% of HCEI goals* are met in 2030, then LNG demand could be as high as 2.5 mmt in 2030.

Figure 1: Maximum Potential LNG Demand in Hawaii; By Sector

	[kt]		Power	SNG and LPG	Ground Transportation	Marine Transportation	Other (refineries, etc)	Total
Full HCEI	2015							
		High	1,785	127	-	12	100	**2,023**
		Medium	1,446	103	-	6	75	**1,629**
		Low	1,135	79	-	2	50	**1,267**
	2020							
		High	1,533	130	21	25	100	**1,810**
		Medium	1,242	105	16	13	75	**1,451**
		Low	975	80	7	5	50	**1,117**
	2030							
		High	1,175	138	89	30	100	**1,533**
		Medium	952	111	71	15	75	**1,224**
		Low	747	83	30	6	50	**916**
	2035							
		High	1,165	143	194	33	100	**1,635**
		Medium	944	113	132	16	75	**1,281**
		Low	742	84	62	7	50	**945**
Half HCEI	2030							
		High	2,189	138	108	30	100	**2,566**
		Medium	1,773	111	90	15	75	**2,064**
		Low	1,393	83	30	6	50	**1,562**

- Although HCEI goals alone would change the size and pattern of demand in 2030 (a demand barrel with more than 70% middle distillates) such that it would not be compatible with a healthy Hawaii refining industry, the situation would be much worse for the refineries as we add another *25-30 kb/d demand cut* by introducing LNG into our energy system. Under the LNG scenarios explained earlier, 60-70% of the 45-50 kb/d demand for oil would be jet fuel, about 20% gasoline, and some minor portions of other products.

Figure 2: Hawaii Fuel Demand Under Different Scenarios; By Fuel

[kb/d]		Gasoline	Jet Fuel	Diesel	Fuel Oil	Others	Total
Fuel Demand	**2010**						
	Actual	28.1	24.7	18.7	33.7	10.1	**115**
	2030						
	Baseline	37.9	31.4	27.9	38.6	12.0	**148**
	Diesel Sub	37.9	31.4	67.5	9.9	12.0	**159**
	HCEI *	11.4	31.4	23.2	5.5	4.3	**76**
	High LNG	9.7	31.4	3.7	1.0	1.2	**47**
	Low LNG	11.0	31.4	4.1	1.0	3.3	**51**
Fuel Replaced	**2030**						
	High LNG	1.7	-	19.5	4.5	3.1	**29**
	Low LNG	0.4	-	19.1	4.5	1.0	**25**

* with diesel substitution effects included

CHAPTER II: POTENTIAL COSTS AND BENEFITS OF IMPORTING LNG

LNG SOURCING

- **LNG is not a grocery store.** The best long-term contracts will never be found by putting the process out to general bid or tender. LNG is not sold based on "sticker prices." Most LNG is "sold" before a project even begins construction. Anyone who does not procure supply before the project is committed will pay higher prices—unless they strike a special deal with someone who already is committed.

- Alaska, Australia, Canada, the US Gulf Coast (USGC), and the US West Coast (USWC) are the five sources treated in detail in this report.

- LNG from Alaska, Australia, and Canada is expected to be priced by indexation to international oil prices. LNG from the USGC and the USWC is expected to be indexed to US natural gas prices.

- **LNG can be supplied by plants not yet planned**. Although most of the focus in the press has been on export projects, there are many LNG facilities in the US devoted to US needs, and, as the American Natural Gas Highway project is completed, there will be many more. The capital costs per unit are generally less than the giant export projects, and some smaller companies would be willing to build a plant dedicated to Hawaii. But these potential suppliers will not be found by issuing an RFP.

DELIVERED COSTS TO HAWAII

- By their nature, forecasts are uncertain. For this reason, **major LNG imports should not be undertaken unless the expected savings are substantial.** Expected savings of, say, 10-15%, are probably not enough to warrant the large investments and long-term commitments required for bulk LNG imports; such savings could easily be wiped away by market fluctuations.

- Cost savings from LNG imports into Hawaii will clearly depend on where and how it is procured.

- Under a base case LNG demand forecast of 500 ktpa, it appears that conventional, benchmark, onshore terminals using **small, US-built, Jones Act compliant LNG carriers loading from the US West Coast can deliver LNG to Oahu 31-47% cheaper than oil through 2030.**

Figure 3: Savings in Delivered Energy Cost, LNG vs Low-Sulfur Diesel,* 2012 US$/mmBtu

	2015	2020	2025	2030
Alaska	na	na	8%	8%
Australia	-8%	3%	3%	4%
Canada	na	14%	15%	16%
US Gulf Coast	33%	35%	32%	31%
US West Coast	na	47%	44%	43%

** Because of new EPA policies, LS diesel is expected to be the main utility fuel in Hawaii before 2020. At present, on Oahu LS diesel and LS fuel oil are almost identical in cost per mmBtu.*

- **Savings relative to oil are very large when the LNG is sourced from the Lower 48** (with the US West Coast being the most attractive option). The savings are cut roughly in half if LNG is sourced from Canada. The savings shrink dramatically when sourced from Alaska or Australia.

- In all of these cases, some additional savings could be made if larger LNG carriers could be employed—at least up to the point where deliveries become so large that the cost of holding the inventory becomes prohibitive. The feasibility of using larger carriers depends both on engineering unknowns (e.g., Can the vessels be accommodated on Oahu?) and political unknowns (e.g., Can Hawaii get a Jones Act waiver?).

DIRECT SAVINGS IN THE POWER SECTOR

- LNG could provide **fuel savings in the Oahu power sector of 40-50% or more compared to oil.** It could also provide even larger savings compared to retrofitting existing power plants with "back-end" emissions controls.
- Even with the additional costs of interisland transportation, it appears that neighbor-island generation could also reap major savings from LNG. In an example steam plant of 40 MW, savings in power costs were 22-44%.

Figure 4: Electricity Fuel Cost Savings, LNG vs Oil (%)

	2015	2020	2025	2030
Existing Baseload	na	48%	45%	42%
Existing Peaking	na	45%	42%	39%

UNCONVENTIONAL DELIVERY OPTIONS

- The costs of "floating" solutions—offshore storage and regasification, or near-shore floating storage and regasification—appear to be similar to conventional, standard, import terminals. Not enough engineering and traffic study has been done to see which options are viable, and what the limits on their capacity might be. **It would be very unwise to settle on any single solution before more site-specific study has been undertaken.**
- The economics of other solutions appear to be generally similar, although there are many caveats (e.g., offshore delivery requiring two vessels is the most expensive option at 500,000 tpa, but the economics improve at one million tpa). **In general, floating and onshore solutions have comparable economics, and the differences are small compared to the issues of where and how the LNG is sourced.**
- Onshore and near-shore delivery solutions allow LNG to be supplied to neighbor islands and to non-utility uses (such as CNG cars or interisland

transport). Offshore delivery means that only the Oahu utilities will benefit from LNG imports.[1] The benefits are substantial, but it needs to be clear that choosing offshore gasification amounts to a policy decision.

CONCLUSIONS

- LNG has the potential to achieve huge savings for Hawaii energy consumers—but it is critical to obtain it from the right source on gas-indexed prices.
- If all LNG is regasified offshore, this will close off many options for the use of LNG in sectors such as transport—and will also restrict LNG to Oahu alone.
- There are potential sites and projects on the US West Coast, but these projects will not be developed and then go in search of a buyer. Getting the best deal for Hawaii will require a proactive approach.

CHAPTER III: OTHER RISKS AND IMPACTS OF IMPORTATION OF LNG INTO HAWAII

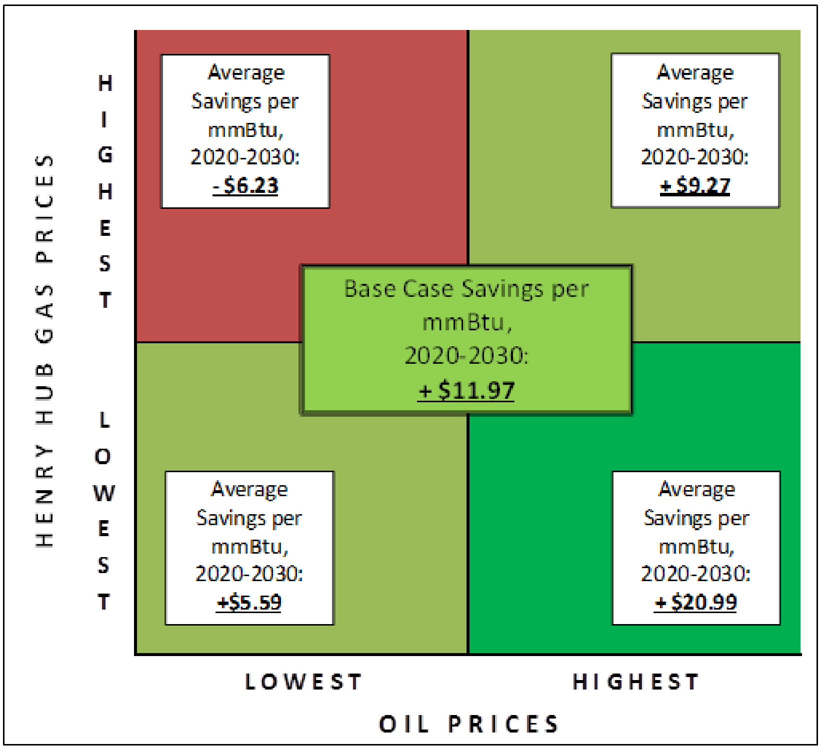
LNG AND HAWAII'S EXPOSURE TO THE OIL MARKET

- Hawaii is dependent on imports of low-sulfur crudes from the Asia-Pacific region. Since the Asia-Pacific region is itself the world's largest importer, crude oil there is more expensive than in major exporting regions. Thus, **Hawaii is dependent on the most expensive crudes from the most expensive region.**
- LNG can indeed help cushion Hawaii from movements in the oil market—if the LNG is sourced from a location where it is gas-indexed. At present it appears the only sources of gas-indexed LNG will be the US West Coast and the US Gulf Coast.
- To give an assessment of risk, we computed outcomes on delivered prices to Hawaii at US$70/b crude oil, US$144/b crude oil, the NPCC low gas price forecast, and the NPCC high gas price forecast. **As the chart below shows, at the highest gas price and lowest oil price, there could be losses rather than savings from using LNG. Yet it needs to be noted that this is one case out of**

[1] Technically it is *physically possible* to take gas from offshore regasification and compress it to make CNG, but the economic and thermodynamic benefit of producing CNG directly from LNG is lost. For that matter, it is also *physically possible* to take gas from offshore regasification and reliquefy it onshore, but the economics and logic would be questionable.

five. Turned around, the chart says that in four out of five cases, there will be major costs in continuing to use oil rather than LNG.

Figure 5: Savings and Losses Quad Chart



LNG AND REFINERY VIABILITY

- Hawaii's two refiners control most of the state's oil-import infrastructure, and control the entire supply infrastructure for low-sulfur fuel oil in the power sector. Since the facilities are privately owned and unregulated, there is no long-term obligation to supply, or to supply at any given price; if the refiners choose not to accept the best terms offered by the utility in a negotiation, they have the right to terminate supply. This is an additional instance of Hawaii's vulnerability to the oil market.

- Hawaii's refiners have had rocky economics for many years, and the issue of closure or sales has been revisited repeatedly. Chevron doesn't publish figures on performance of its individual refineries, but Tesoro does, and its Oahu refinery has the worst economics of any plant in its system.

- The Oahu refineries were technologically advanced when they were built, but they are now comparatively unsophisticated. The refineries are small by world standards, but, perversely, together they have too much capacity for Hawaiian demand today.

- The HCEI—if successful--will slash Hawaiian oil demand by 46% in 2030 from the baseline forecast. (This falls short of the oft-quoted goal of 70% because it seems possible that there will be no displacement of jet fuel.)
- LNG would also cut demand for refined products, but our scenarios show cuts of only 15-19% from the 2030 baseline.
- **LNG is certainly not good news for the refiners, but its impact is minor compared to the intended effects of the HCEI.**

LNG AND RENEWABLE ENERGY GOALS

- How will LNG affect the growth and development of renewables in Hawaii? The only way to answer this question sensibly is to compare LNG to what would be used in the absence of LNG—that is, oil products.
- Some people worry that LNG will be so cheap that it will challenge renewables. This is a strange kind of logic, since it in effect is an argument that the best thing for Hawaii renewables would be if the customers all paid the highest energy prices possible. If that is to be State policy, then LNG is a bad idea. Our analysis here assumes that State policy is to lower prices within the HCEI framework, not keep them high.
- The study considered LNG relative to oil in eight dimensions of HCEI goals. In all of the measures except one, LNG either tends to help or strongly helps achieve HCEI goals.
- The one measure where LNG is not helpful to HCEI goals is in fungibility with renewables. Capital equipment designed for gas (such as CNG cars) generally doesn't readily accommodate common renewable fuels. (This could of course change if biogas were to be developed on a large scale in Hawaii.)
- The one area where LNG may compete with renewables is in road transport. Unless great strides forward are made, it is doubtful that biofuels will be as cheap as LNG or CNG in vehicles. This may one area where the State faces a trade-off between maximizing the use of renewable energy and the lower consumer costs from LNG imports.

OTHER RISKS OF LNG

- The risk of political cut-off of LNG from any of the five sources we have studied is vanishingly small. There is always a risk of natural disasters—but this applies to all energy infrastructure.

- The bulk of Oahu's energy facilities are located in a swath that runs from Waiau to Kahe, all in low-lying areas with exposures to the south. Hurricanes or tsunamis could have a devastating effect. These disasters threaten not only a potential LNG terminal, but the refineries, tank farms, and power plants in the area.

- There is nothing that can be done to prevent natural disasters, but disaster-response plans can be developed to minimize the consequences. The worries over the possible closure of the Tesoro refinery make it clear that the State has no effective contingency plan for getting needed fuels onshore. An LNG terminal needs a contingency plan to handle disasters—but so do the refineries.

- The risk of losing an LNG tanker at sea needs to be considered. LNG tankers are not easy to come by on short notice, and LNG tankers or ATBs of a size needed to serve Hawaii are especially scarce. Above all, a "one-ship fleet" should be avoided, even if one larger ship would be adequate to serve Hawaii's import needs.

- We have assumed storage that can hold one month's supply of LNG at 500 ktpa. With a voyage distance of about a week from the US West Coast, this should make it possible to avoid drawing the tank dry even if a vessel is lost at a time when the tank is not near full. (We are not claiming that this is the optimum size, just a workable size for the purposes of our calculations. This should be studied as part of overall State contingency planning.)

- Luckily, in the power sector, LNG and diesel are readily swappable—if investments are made in dual-firing. Many Gas Turbines and CCGTs around the world already rely on diesel backup for units that rely on imported LNG. The power utilities already own huge volumes of fuel oil storage tanks. Converting a fraction of these to backup diesel could offer a large reserve with minor additional investment.

- Finally, many people believe that LNG tankers are "floating bombs," and that LNG is readily explosive. This is far from the truth. LNG needs to be handled with caution, like any energy-dense fuel, but experience and detailed simulations show that in event of an accident, there is little probability of an explosion. Experts tend to be made much more nervous by gasoline tanker trucks on the freeway than by LNG.

Chapter IV: HAWAII'S NATURAL GAS/LNG REGULATORY STRUCTURE, POLICIES, AND PRACTICES

- There is a wealth of regulatory experience on the US mainland regarding both natural gas and LNG imports, but Hawaii has comparatively little background in this area.

- An understanding of the regulatory regime applicable to a Hawaii LNG terminal is incomplete without an understanding of the structure and regulation of the natural gas business on the mainland, which features eleven LNG tanker discharge terminals. A series of reforms promulgated since the 1970s have opened the continental US market considerably, although it is still subject to great regulatory oversight. These liberalized market conditions on the mainland are in stark contrast to the isolated and small natural gas market in Hawaii—such as it is—which is characterized by a lack of upstream gas production/import facilities and a paucity of players competing for market share.

- Due to the intense level of LNG import terminal development on the mainland over the past decade, the regulatory regime governing US LNG import terminal siting, permitting, construction, and operation has achieved great clarity. FERC will have jurisdiction over an onshore Hawaii import terminal or an offshore facility located in State waters, whereas the Maritime Administration and the Coast Guard will vet applications for offshore capacity located in Federal waters. State and local bodies will have a voice in the licensing process, but this will ultimately be overseen by Washington, D.C.
    - The extent of the Hawaii's Public Utilities Commission's oversight of LNG terminal operations will be determined by the ownership structure and business model selected for a Hawaii import terminal. Opinions about the need for additional PUC manpower to accommodate the heavier workload are divided.

- HAWAIIGAS' proposal for an import facility in the State is the only project that has gained full public exposure so far, but they are by no means the only entity that has considered building an import terminal. There are pros and cons to the myriad of LNG ownership structures that are possible for an LNG import terminal in the State. Whatever the ownership structure and business model selected, cooperation between Hawaii end-users—whether as project sponsors or offtakers—is essential for the project to proceed, since economies of scale are a key component of LNG project success.

- Hawaii is in a very different situation from the mainland. Any LNG terminal in Hawaii would likely be the only terminal. Issues such as third-party access and requirement to supply are more crucial than on the mainland,

- There are many ways that an import facility might be structured. **The ownership details of such an import facility, or such facilities, might not be as important as whether or not it is a state-regulated entity.**

- As discussed in Chapter III, over the years, both HECO/HEI and HAWAIIGAS have had to negotiate their fuel supplies with the refiners. The refiners have a duopoly over most oil import infrastructure. The refiners are not regulated and their import infrastructure is privately owned. This meant the suppliers could refuse to supply unless the terms were satisfactory, and the buyers had no option other than to build their own import terminals—an impractical proposition. **The concept sometimes proposed that a private, unregulated supplier should build LNG import facilities, and provide the LNG, would perpetuate the problem the utilities have faced for decades.**

CONCLUDING REMARKS

- The potential of LNG to cut fuel costs in Hawaii is enormous, and need not conflict with the goals of the HCEI. Indeed, LNG could play an important role in allowing renewables to be accommodated in Hawaii's energy system.

- LNG-import infrastructure is expensive, involving at least hundreds of millions of dollars in capital investment. This one-time cost needs to be kept in perspective, however: Hawaii's current oil bill is estimated to be in excess of $6 billion **per year**.

- If LNG is introduced without careful consideration about sourcing, without further study of terminal siting options, and without good regulatory controls, however, many of the possible benefits might not be realized.
- The predicted savings achieved by importing LNG rely on the difference between gas prices in the Lower 48 and the price of oil on the international market. Since both of these are uncertain, small levels of savings could be wiped out by relatively small movements in oil or gas prices. For that reason, we believe that large-scale LNG imports for Hawaii should only be pursued if the expected percentage savings are quite substantial.

I. POTENTIAL DEMAND FOR LNG IN HAWAII

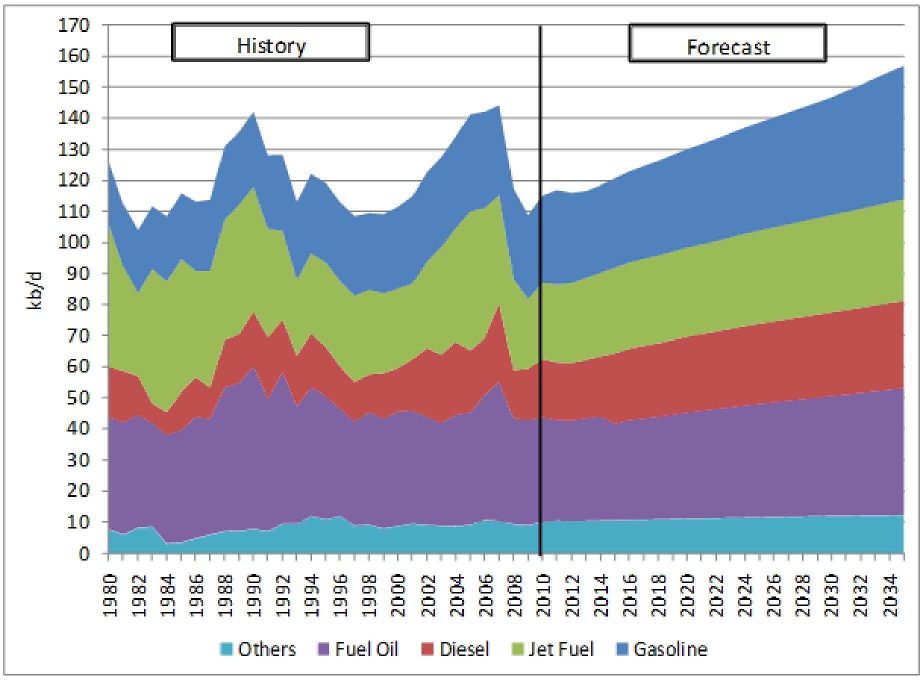
This section analyzes the potential demand for LNG in Hawaii, for different possible end-use applications of natural gas including but not limited to power generation, domestic use, and transportation.

1.1. Hawaii's Fuel Demand; History and Forecast

After peaking at 145 kb/d in 2007, the global economic slowdown pushed Hawaii's fuel demand back to almost 110 kb/d in 2009, a level that the State had last seen in 1999. Although demand has been recovering, 2011 figures reflected that of 2002, partly due to the slow economic recovery and partly due to the negative impacts of Japan's March-11 tsunami and earthquake on Hawaii's tourism.

Based on the latest forecasts[2] for the economic growth rate, the tourism growth rate (visitor arrivals), power demand growth rate, and petroleum products' prices in the next two decades, FGE has forecasted a baseline fuel demand before the Hawaii Clean Energy Initiative (HCEI) goals are met.

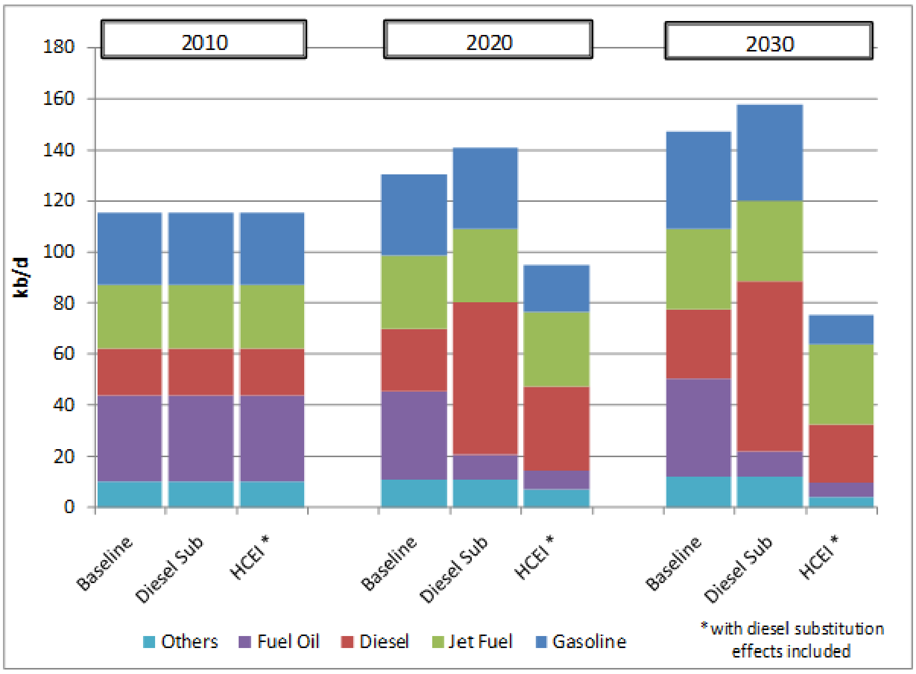
Figure 6: Fuel Demand; History and Forecast (Baseline; without HCEI goals)



[2] DBEDT Population and Economic Projections for the State of Hawaii to 2040 (March 2012); HECO IRP2013 Sales and Underlying Economic Forecast – Moved By Passion scenario (October 2012); and FGE Crude Oil and Petroleum Product Price Forecast.

The baseline is used to forecast the fuels in different sectors (especially the power and transportation sectors) after HCEI goals are met. The constraint on fuel oil use in the power sector after 2015 (to comply with the EPA's MACT standards) is also accounted for and the forecast substitutes fuel oil demand for power generation with diesel demand before applying the goals of HCEI, called the "diesel sub" scenario in the following discussions. Hence, the "HCEI" scenario includes the diesel substitution in it. The following figure shows the fuel demand in 2020 and 2030 under baseline, diesel sub, and HCEI scenarios.

Figure 7: Fuel Demand Projection Under Different Scenarios



1.2. Natural Gas for Power Generation

With data from EIA's Power Plant Operations Report[3], which presents monthly and annual data on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level, FGE has categorized the energy demand for the power sector in Hawaii by fuel and county.

As presented by the Figure below, fossil fuels (coal and oil) comprised more than 86% of input for power generation in 2011 across the State of Hawaii. Fuel oil alone (mostly LSFO) provided the State's power generators with more than half of the required energy, 90% of which is being burned for Oahu's power generation. The intermittent

[3] The table is generated based on the EIA-923 detailed data, presenting all energy consumption for Utility, Non-Utility, and Combined Heat & Power plants (http://www.eia.gov/electricity/data/eia923/).

renewable sources (99% wind and 1% solar[4]), however, accounted for only 3% of the energy input to the State's power generation in 2011.

Figure 8: 2011 Energy Demand for Power Generation by Source and County

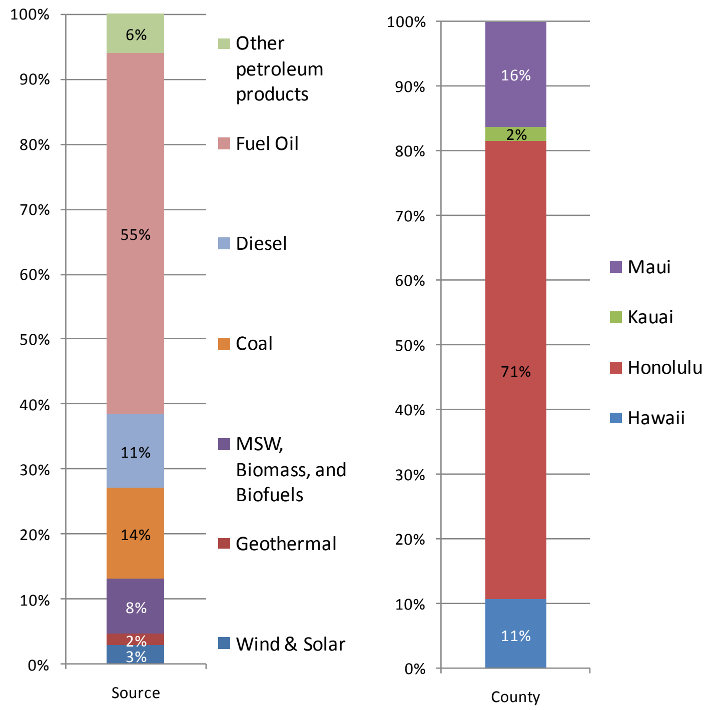
[mmBtu]	Honolulu	Hawaii	Maui	Kauai	State
Wind	575,248	1,541,420	1,195,344	-	3,312,012
Solar	-	-	17,743	17,172	34,915
Geothermal	-	2,175,743	-	-	2,175,743
Hydro	-	433,110	106,761	365,267	905,138
MSW	5,370,143	-	-	-	5,370,143
Biofuels	578,935	-	-	-	578,935
Biomass	-	-	3,634,503	-	3,634,503
RENEWABLES	**6,524,326**	**4,150,273**	**4,954,351**	**382,439**	**16,011,389**
COAL	**14,774,788**	**-**	**1,297,373**	**-**	**16,072,161**
Diesel	376,694	2,625,833	8,100,325	2,004,391	13,107,243
Fuel Oil	57,453,514	3,636,509	2,528,743	-	63,618,766
Waste Oil	1,948,665	1,850,404	59,333	69,832	3,928,234
Other	-	-	1,828,791	-	1,828,791
OffGas	902,133	-	-	-	902,133
Jetfuel	276,201	-	-	-	276,201
OIL	**60,957,207**	**8,112,746**	**12,517,192**	**2,074,223**	**83,661,368**
NON-RE	**75,731,995**	**8,112,746**	**13,814,565**	**2,074,223**	**99,733,529**
TOTAL	**82,256,321**	**12,263,019**	**18,768,916**	**2,456,662**	**115,744,918**

Source: EIA

In terms of geographical distribution, more than 70% of the energy for power generation is being used in the county of Honolulu (Figure 9).

[4] The solar numbers do not include roof-top PV.

Figure 9: Division of Power Sector's Energy Consumption by Source and County 2011



1.2.1. Existing Generating Capacity

Using the same resource, i.e. EIA's Power Plant Operations Report, FGE constructed a table of all existing fossil-fuel based generating capacities across the State (Figure 10). The list is comprehensive, including all utility, non-utility, CHP, and industrial power plants.

Figure 10: Fossil-fuel-based Power Generation Plants in Hawaii[5]

	Plant Name	Operator	Generation Technology	Capacity [MW]	Maximum Generation [MWh]	Actual Generation [MWh]	Utilization Rate [%]	Average Heat Rate [Btu/kWh]
HAWAII								
	Hamakua Energy Plant	Hamakua Energy Partners LP	CCGT	66.0	578,160	215,791	37.3%	8,610
	Kanoelehua	HELCO	IC	9.5	83,220	299	0.4%	12,013
	Kanoelehua	HELCO	GT	11.5	100,740	20	0.0%	28,200
	Keahole	HELCO	IC	7.5	65,700	3,107	4.7%	11,003
	Keahole	HELCO	GT	63.6	557,136	197,173	35.4%	12,185
	Puna	HELCO	ST	15.5	135,780	68,039	50.1%	14,733
	Puna	HELCO	GT	23.6	206,736	12,979	6.3%	12,058
	Shipman	HELCO	ST	15.0	131,400	4,719	3.6%	17,343
	W H Hill	HELCO	ST	37.1	324,996	195,390	60.1%	13,062
	Waimea	HELCO	IC	7.5	65,700	1,836	2.8%	11,355
HONOLULU								
	Honolulu	HECO	ST	113.0	989,880	95,534	10%	13,876
	Kahe	HECO	ST	559.0	4,896,840	2,996,653	61%	10,218
	Waiau	HECO	GT	102.0	893,520	8,810	1%	18,081
	Waiau	HECO	ST	397.0	3,477,720	1,014,460	29%	10,696
	Kalaeola Cogen Plant	Kalaeloa Partners LP	CCGT	214.0	1,874,640	1,445,668	77%	8,410
KAUAI								
	Kapaia Power Station	KIUC	GT	39.1	342,516	211,971	62%	8,669
	Port Allen	KIUC	CCGT	41.4	362,664	32,338	9%	15,539
	Port Allen	KIUC	IC	91.4	800,664	168,360	21%	9,284
MAUI								
	Hana Substation	MECO	IC	2.0	17,520	97	1%	10,990
	Kahului	MECO	ST	34.0	297,840	176,582	59%	14,321
	Maalaea	MECO	CCGT	133.2	1,166,832	636,642	55%	8,858
	Maalaea	MECO	IC	96.6	846,216	189,227	22%	10,116
	Miki Basin	MECO	IC	10.4	91,104	19,595	22%	10,249
	Palaau Power	MECO	GT	2.5	21,900	239	1%	18,435
	Palaau Power	MECO	IC	12.6	110,376	33,395	30%	9,942
Total Oil						7,728,924		
HONOLULU								
	AES Hawaii	AES Hawaii Inc	ST	203.0	1,778,280	1,382,098	78%	10,730
Total Coal						1,382,098		
Grand Total						9,111,022		10,169

Source: EIA

The average heat rate listed in the above table is calculated based on the total input energy to each plant in 2011 and the total power generation of each plant. Extraordinarily high heat rates of some plants is due to two reasons: either the plant is a combined heat and power plant (uses part of the energy input for the purpose of industrial heat or steam), or it is being operated as a spinning reserve unit most of the time.

1.2.2. Future Power Demand

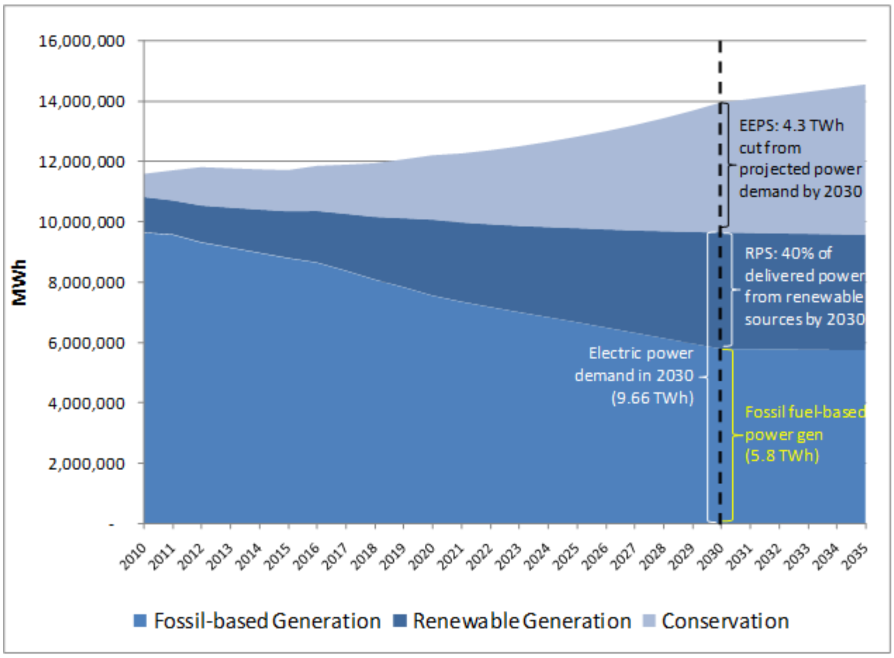
In the absence of HCEI goals, Hawaii's power demand is expected to rise at an average annual growth rate of 1.5%[6], reaching 15.7 TWh by 2030. After subtracting the 4.3 TWh efficiency goal, set by Hawaii's Energy Efficiency Portfolio Standard (EEPS), the

[5] The generation technology refers to the prime mover of the generation units, which includes:
ST: Steam Turbine, including geothermal;
IC: Internal Combustion (diesel, piston) Engine;
GT: Gas Turbine, also known as combustion turbine and includes jet engine design;
CCGT: Combined Cycle Gas Turbine.

[6] Based on HECO IRP2013 Underlying Economic Forecast – Moved By Passion scenario (October 2012)

actual power demand in 2030 drops to 9.6 TWh. Then, according to Hawaii's Renewable Portfolio Standard (RPS), 40% of the 2030 delivered power would be supplied by renewable sources, which results in 5.8 TWh of fossil fuel based generation.

Figure 11: Power Demand Forecast; After HCEI[7]



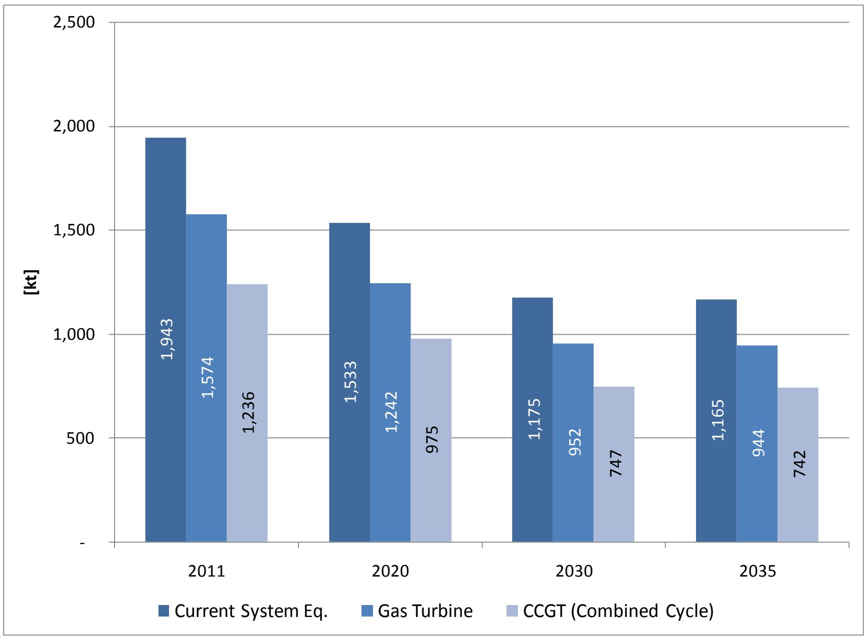
1.2.3. LNG Demand for Power Generation

1.2.3.1. Maximum Potential LNG Demand for a Full System Conversion

Under this scenario, FGE estimated the maximum potential LNG demand to convert all non-renewable power generation to gas-fired power generation. To this end, three scenarios are assumed: LNG demand at the current system-wide average heat rate (10,169 Btu/kWh, equivalent to 33.5% efficiency); LNG demand for state-wide conversion to gas-fired gas turbine (average heat rate of 8,421 Btu/kWh[8], equivalent to 40.5% efficiency); and LNG demand for state-wide conversion to gas-fired combined cycle gas turbine (average heat rate of 6,614 Btu/kWh[9], equivalent to 51.5% efficiency).

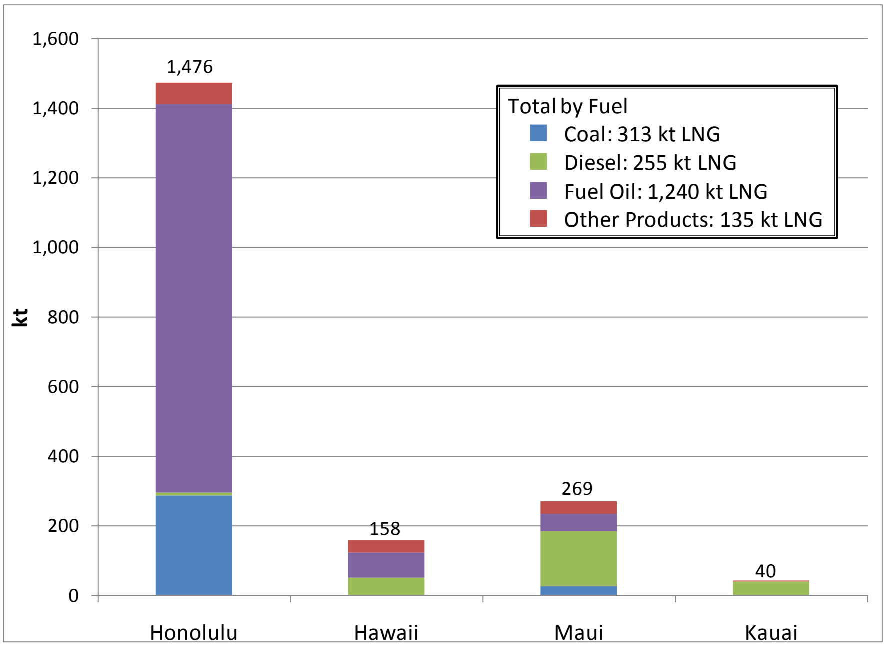
[7] For the purpose of extending our forecast to 2035, FGE assumes the 30% efficiency goal and 40% renewable energy goal would be maintained for the 5-year period beyond 2030.
[8] Assuming GE LM6000PF Sprint gas turbine's heat rate.
[9] Assuming GE LM6000PF Sprint gas turbine's heat rate in a 2X1 Combined Cycle setup with Evaporative Cooled Inlet

Figure 12: Maximum Potential LNG Demand For Power Generation; After HCEI



As shown in Figure 12, the LNG-equivalent of fossil fuels consumed in the existing generation system stands at 1,943 thousand tonnes per annum (ktpa) or 1.9 million tonnes per annum (mmtpa) of LNG in 2011. Increasing the generation efficiency by assuming a system-wide upgrade to gas turbines would cut it down to 1.6 mmtpa of LNG, and a further efficiency increase by going to a full CCGT system would require 1.2 mmtpa of LNG to generate all required non-renewable power in 2011. In 2030 a similar analysis would result in 1.2 mmtpa, 0.95 mmtpa, and 0.75 mmtpa of LNG demand at current efficiency levels, gas turbine, and CCGT systems. This would set the range of 0.7-1.2 mmtpa as the maximum potential demand for LNG for power generation in Hawaii by 2030 assuming HCEI goals are met. Assuming HCEI goals are not met, the scale of LNG demand for each of the above scenarios would increase, the extent of which depends on what portion of HCEI goals are met.

Figure 13: LNG Equivalent for Power Generation; By County and Fuel, 2011.



When breaking down the 2011 LNG-equivalent (of 1,943 ktpa) by fuel and county, as expected, the majority (64%) of it would replace the fuel oil consumption on Oahu. Oahu's non-renewable power generation would be equivalent to nearly 1.5 mmtpa of LNG demand, assuming its current average heat rate of 10,074 Btu/kWh (Figure 13). It is worth mentioning that the inclusion of the 214 MW KPLP combined cycle plant (average heat rate of 8,410 Btu/kWh) is the main reason for the relatively lower heat rate for the county of Honolulu compared to HECO system's average heat rate (10,511 Btu/kWh).

1.2.3.2. LNG Demand for Partial Conversion

Although the previous section provided a range for the maximum LNG demand for power generation, the following analysis estimates a more realistic size of LNG demand to supply the 2030 power demand after considering the HCEI goals.

To this end, FGE has made the following assumptions:

- All existing CCGT and gas turbine (GT) plants will be converted to LNG. Assuming the existing plants' roles (base load units versus peaking units) would also stay the same, the average heat rates for these plants are considered to stay the same (10,577 for GTs and 8,650 for CCGTs).
- Considering the uncertainty of coal being part of energy mix in 2030, the LNG demand analysis is done both with and without coal.

- After subtracting the existing CCGT/GT plants, coal plant, and HCEI goals, the remaining conventional power generation would determine the size of required gas turbine for a full gas-fired power generation.
- Although CCGTs have higher thermal efficiency, to address better load following (the peaking units) and higher "intermittent" or "intermittent" renewable resources (such as wind and solar), some of the remaining units are assumed to be GTs and the rest to be converted to CCGTs.
- In 2011, the ratio of peaking capacity to the total non-coal non-GT capacity stood at about 26%. Since the most efficient conversion setup would highly depend on the magnitude and type of renewable resources used in power generation, FGE assumed two scenarios for the ratio of new gas-fired units: 1) one-third GT, two-third CCGT; 2) one-half GT, one-half CCGT.[10]
- The capacity factor for peaking units (GT) and base units are assumed to be at higher levels of 25% and 75%, respectively, than the current utilization rates of 20% and 59% in the existing units.

Figure 14: 2030 LNG Demand For Power Generation; A Partial Conversion Analysis, without Coal

		2030 Power Demand MWh	Average Heat Rate btu/kwh	LNG mmbtu	LNG kt	Capacity Factor %	Average Capacity MW	Name-plate Capacity MW
Existing oil-based GTs		**2,761,631**						
GT		431,192	10,577	4,560,887	89	20%	49	242
CCGT		2,330,439	8,650	20,158,240	393	59%	266	455
Sum of Existing GTs and Coal		**2,761,631**						
2030 Non-renewable Demand		**5,799,864**						
Remining		**3,038,233**						
New gas-fired	**Scenario 1**							
GT	50%	1,519,116	8,421	10,047,436	196	25%	173	694
CCGT	50%	1,519,116	6,614	12,792,479	249	75%	173	231
Total					**927**		114	458
New gas-fired	**Scenario 2**							
GT	33%	1,002,617	8,421	8,443,036	165	25%	114	458
CCGT	64%	1,944,469	6,614	12,860,718	251	75%	222	296
Total					**897**			

The above assumptions (along with assuming no coal as part of 2030 energy mix for power generation) would result in 0.9-0.93 million tonnes of LNG demand to meet the conventional power demand after HCEI goals are met (Figure 14).

Although the scenarios above differ very little in terms of LNG demand, the main difference is in terms of reserve capacity availability. Scenario 1 requires 347 MW of

[10] The reason for the second scenario is to allow higher penetration of intermittent RE power generation in the system.

new gas-fired capacity on average. This much average capacity, however, translates into 694 MW of installed GT capacity and 231 MW of installed CCGT capacity (assuming 50% GT with 25% capacity factor and 50% CCGT with 75% capacity factor). Under these assumptions, 520 MW of new GT capacity would serve as reserve potential to compensate during renewable resource loss or peak load. Also, to add 231 MW of CCGT capacity, 154 MW of new gas turbine capacity could be added to 77 MW of existing steam units. Thus, Scenario 1 would require construction of 848 MW new gas turbine capacity.

On the other hand, Scenario 2, with 336 MW of additional gas-fired capacity on average, would require 458 MW of installed GT capacity and 296 MW of CCGT capacity (assuming on-third GT with 25% capacity factor and two-third CCGT with 75% capacity factor). Less GT to CCGT ratio assumed in this scenario obviously implies less reserve potential (343 MW as oppose to 520 MW). Scenario 2 would require construction of 655 MW of new gas turbine capacity (458 MW for new GT capacities and 197 MW gas turbine capacity to convert 99 MW of existing steam turbines to CCGTs).

The latter, despite the lower capital cost requirement for new GT installations, would be less preferred in the case of having higher fluctuating renewable resources such as wind and solar on the renewable portfolio in 2030 than more stable resources such as geothermal.

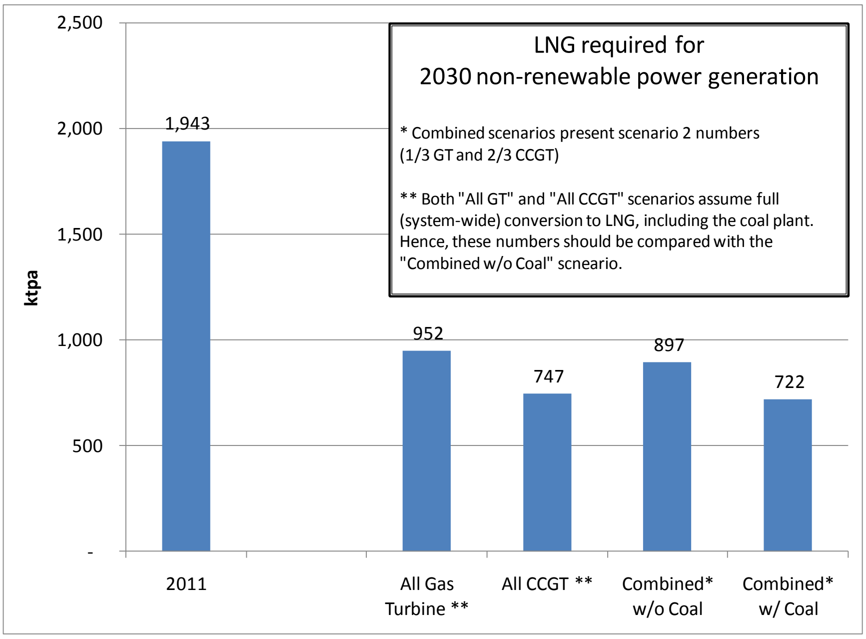
Comparing this result (0.9-0.93 mmt of LNG) with the range of demand from the previous section (0.75-0.95 mmt of LNG), implies that taking advantage of the existing generation structure for fuel switching planning would result in a more efficient use of LNG infrastructure to meet the power demand in the long run, while giving enough of fast response peaking GT units.

Figure 15: 2030 LNG Demand For Power Generation; A Partial Conversion Analysis, with Coal

		2030 Power Demand MWh	Average Heat Rate btu/kwh	LNG mmbtu	LNG kt	Capacity Factor %	Average Capacity MW	Name-plate Capacity MW
Existing oil-based GTs		**2,761,631**						
GT		431,192	10,577	4,560,887	89	20%	49	242
CCGT		2,330,439	8,650	20,158,240	393	59%	266	455
Coal		**1,382,098**				78%	158	203
Sum of Existing GTs and Coal		**4,143,729**						
2030 Non-renewable Demand		**5,799,864**						
Remining		**1,656,135**						
New gas-fired	**Scenario 1**							
GT	50%	828,067	8,421	6,973,155	136	25%	95	378
CCGT	50%	828,067	6,614	5,476,838	107	75%	95	126
Total					**724**			
New gas-fired	**Scenario 2**							
GT	33%	546,524	8,421	4,602,282	95	25%	62	250
CCGT	64%	1,059,926	6,614	7,010,352	145	75%	121	161
Total					**722**			

Although it is unlikely for the AES plant to keep renewing its contract with HECO to sell its coal-based generation for another 20 years, for the sake of completeness and taking into account the uncertainty, we did the above calculations assuming coal will be part of the energy mix for power generation in 2030. With the same set of assumption made above, the same analysis would result in 0.72 million tonnes of LNG demand to meet the conventional power demand after HCEI goals are met (Figure 15).

Figure 16: Power Sector's LNG Demand Under Different Scenarios



As explained previously, the above analysis is based on successful implementation of HCEI goals and any shortage would result in higher LNG demand.

1.2.4. State of Gas-Fired Power Generation Technology

In 2011, natural gas accounted for 25% of US power generation, second only to coal which accounted for 42%. Gas-fired power generation has grown by 5% per annum since 2000, the fastest amongst all fossil fuels, as advancements in electric efficiencies coupled with decreasing costs have made gas-fired power plants extremely popular among electric utilities. There are two types of gas-fired power plants, gas turbine (GT) plants and combined-cycle gas turbine (CCGT) plants. In general, gas turbines can burn not only natural gas but also crude oil, petroleum products such as diesel and fuel oil, and other liquid fuels. The process of each type of plant is outlined below along with some information on electrical efficiencies and costs.

1.2.4.1. Gas Turbine[11]

There is nothing terribly new or unusual about gas turbines. They use the same technology as jet engines, but they use it to turn a power generation unit rather than to push a plane through the sky.

The difference from a steam turbine is that in a combustion turbine the fuel is combusted and the hot combustion gases are sent through the turbine at high velocity and temperature, thereby generating electricity when the turbine blades spin.

Gas turbines consist of an air compressor and a gas turbine aligned on a single shaft connected to an electricity generator. Air is compressed by the compressor and used to fire natural gas in the combustion chamber of the gas turbine that drives both the compressor and electricity generator (Figure 17). The majority of the gross power output of the gas turbine is needed to compress air, while the remaining power drives the electricity generator.

The efficiency of combustion turbines is somewhat better than steam turbines (typically 30-34%), reaching up to around 42%. There are around a half-dozen combustion turbines operating as power generators in the islands (excluding CCGTs—see below).

These units are often called “Gas” turbines, because they are driven by hot gases. This gives many people the impression that they run only on natural gas as fuel. This is not at all the case. In principle, almost anything can be used as fuel. In practice, as

[11] Aka Combustion Turbines; Aka Jet Turbines; Aka Simple Cycle Gas Turbines [SCGT]; Aka Open Gas Cycle Turbines [OCGT].

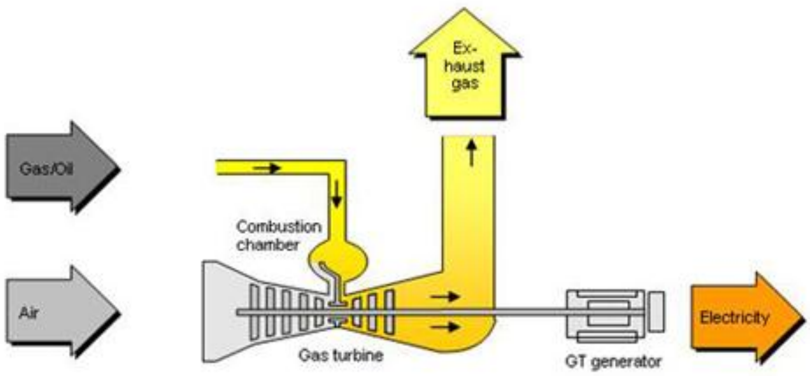
discussed below, lighter, cleaner fuels like natural gas are easier to use, but a considerable number of "Gas Turbines" are run on low-sulfur diesel.

Gas turbines are often the first choice for following quick shifts in power requirements. They can come up to full production far more rapidly than a steam turbine. They are also generally cheaper and fairly "modular." For this reason, they have become increasingly popular in rapidly developing economies in Asia, where they can be added as needed with lead times of 18-24 months…as opposed to the 3-5 years often required for major steam plants.

In the past, the strike against gas turbines was that they tended to use "expensive" fuels like natural gas and diesel. Today, with diesel prices below low-sulfur fuel oil, and US gas prices far below any oil products, it is a very different game.

These installations are often referred to as OCGTs or SGCTs to distinguish them from the more advanced CCGTs discussed below.

Figure 17: Gas Turbine



Source: Siemens

Capital costs will be discussed in Chapter 2 and the annual operating costs for GT and CCGT plants are the same at around 4% of the investment costs per year, though generation costs between the two plants vary greatly. As GT plants are operated for peak load service, the load factor is much lower than CCGT plants. In addition, fuel costs are higher as the efficiency of GT plants is about 2/3rd that of a CCGT.

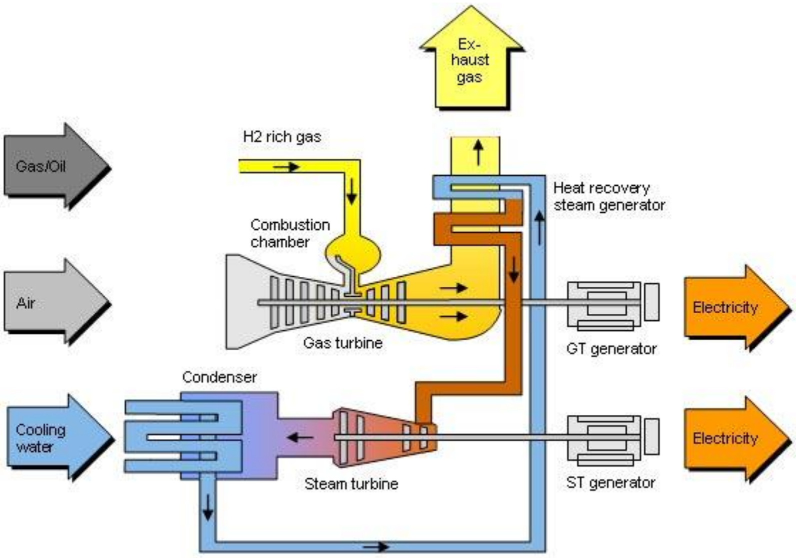
1.2.4.2. Combined Cycle Gas Turbine

CCGT is a mature technology that has become the workhorse for IPPs all over the world. These power plants are one of the most popular options for both intermediate and base load electricity generation.

It is common to hear people refer to CCGTs as if they are somehow complex and hugely technologically advanced. The engineering of the best CCGTs is in fact a marvel—but the concept of the CCGT is quite simple. And CCGTs are not some exotic, Star-Wars technology: Four of them have been operating commercially in Hawaii already for many years.

A CCGT combines Gas Turbines and conventional steam turbines. When a Gas Turbine runs, the combusted gas that come out the other side of the turbine are still terrifically hot, which means they still contain a huge amount of energy. The gases are so hot, in fact, that they can be sent to a Heat Recovery Steam Generator (HRSG), which is essentially a heat exchanger (typically a configuration of pipes often called a “harp”) that use the hot gases to turn water in the pipes to steam. The steam then turns a steam turbine. The waste heat from the Gas Turbine is enough to run another steam turbine “downstream” (Figure 18).

Figure 18: Combined Cycle Gas Turbine



Source: http://www.powergeneration.siemens.com/products-solutions-services/power-plant-soln/combined-cycle-power-plants/

This usually isn’t a 1-to-1 relationship; a 100 MW gas turbine doesn’t produce enough waste heat to run a 100 MW steam turbine. The usual relationship is about 2-to-1, or, in the industry jargon, 2 x 1: two-thirds of the generation comes from the gas turbines.

The Kauai Utility Island Co-op already runs a CCGT plant on diesel and naphtha, as does Hamakua Energy Partners. MECO’s Maalaea runs a CCGT based on diesel.

The largest CCGT in the islands, however, is the Kalaeloa Partners plant on Oahu. Kalaeloa is perhaps unique in the United States (possibly in the world) in running on LSFO. This is so unusual that in 2009 *Combined Cycle Journal* wrote a long article describing how this is possible. Many of the metals and salts in fuel oil are injurious to the equipment at high temperature, and heavy fuels like fuel oil generate large amounts of ash and soot that accumulate everywhere from the turbine blades to the HRSG. The unit must be shut down and cleaned once a day, and then undergoes a more extensive clean-out every week.

CCGTs naturally cost more than Gas Turbines, though not by much—typical CCGTs usually only cost 25% more per unit generating capacity than a similar Gas Turbine. Oddly, no one is quite sure how CCGT costs compare to traditional steam-turbine plants running on gas or oil products, because it has been many years since anyone built such a unit in the United States. (HECO's youngest steam turbine is more than 30 years old.)

CCGTs have a massive efficiency advantage over standalone steam turbines or Gas Turbines. Record thermal efficiencies for CCGTs have now touched 61%. For reference, compare to the 33% average efficiency of HECO's LSFO-fired steam turbines.

Most CCGTs will not be able to reach or sustain 61% efficiency, especially in Hawaii (power generation is less efficient in hot climates). However, Hawaii-specific calculations show that a 52% efficiency is attainable and sustainable.

It is easier to see what this means by using heat rates. HECO's island-wide Heat Rate for its LSFO plants is about 10,400 Btu/kWh. A CCGT at 52% efficiency has a Heat Rate of about 6,600 Btus/kWh. The CCGT uses 37% less energy to generate a kWh. This is a massive increase in energy efficiency.

Because CCGTs include a steam turbine, they do not come up to full power as rapidly as Gas Turbines, so they are not as adept at coping with changing power demands. But in recent years designers have made great strides in this area, and quick-start strategies have allowed new configurations to come up to full power in increasingly short periods of time.

The Figure below illustrates the key data and figures for GT and CCGT plants.

Figure 19: Key Data and Figures for Natural Gas based Power Technologies

Technical Performance	Typical current international values and ranges					
Energy input	Natural gas					
Output	Electricity					
Technologies	**GT**			**CCGT**		
Efficiency, %	35–42%			52–60%		
Construction time, months	Minimum 24; Typical 27; Maximum 30					
Technical lifetime, yr	30					
Load (capacity) factor, %	10–20			20–60		
Max. (plant) availability, %	92					
Typical (capacity) size, MWe	10–300			60–430		
Installed (existing) capacity, GWe	1168 (end of 2007)					
Average capacity aging	Differs from country to country. CCGT construction started end of 1980s.					
Environmental Impact						
CO2 and other GHG emissions, kg/MWh	480–575			340–400		
NOx, g/MWh	50			30		
Projections	**2010**		**2020**		**2030**	
Technology	GT	CCGT	GT	CCGT	GT	CCGT
Net Efficiency (LHV), %	35-42	52-60	≤ 45	≤ 64	≤ 45	≤ 64

Source: IEA energy Technology Systems Analysis Program

1.3. Natural Gas as a Substitute for SNG And LPG

1.3.1. Existing SNG and LPG Demand

HAWAIIGAS has been providing the county of Honolulu (only the southern part of Oahu) with SNG, sold as utility gas and produced at the SNG plant located near Campbell Industrial Park. Utility gas is distributed via an underground transmission system, primarily throughout Oahu's urban core, through nearly 1 thousand miles of underground pipeline, between Kapolei and Hawaii Kai carrying SNG directly from the plant to consumers.

SNG sales in Oahu comprises almost 85% of HAWAIIGAS's total utility gas sales, with state-wide utility propane (LPG) making up the balance of sales. This additional utility service is provided to other parts of Oahu and the neighbor islands by underground lines that supply gas to customers from a centrally located propane tank or holder.

In addition, HAWAIIGAS and other propane suppliers (wholesale and retail) serve all islands with propane (as a non-utility commodity). Non-utility gas customers choose their best option from competing businesses.

Another established non-utility LPG (propane) supplier is AmeriGas, doing business statewide as Oahu Gas Service, Maui Gas Service and AmeriGas Big Island. Oahu Gas Service is located at Campbell Industrial Park, where direct shipments of propane are received from the refinery. The propane is then distributed to its Oahu customers and shipped to Maui Gas Service and AmeriGas Big Island, where it is stored in tanks for distribution to customers.

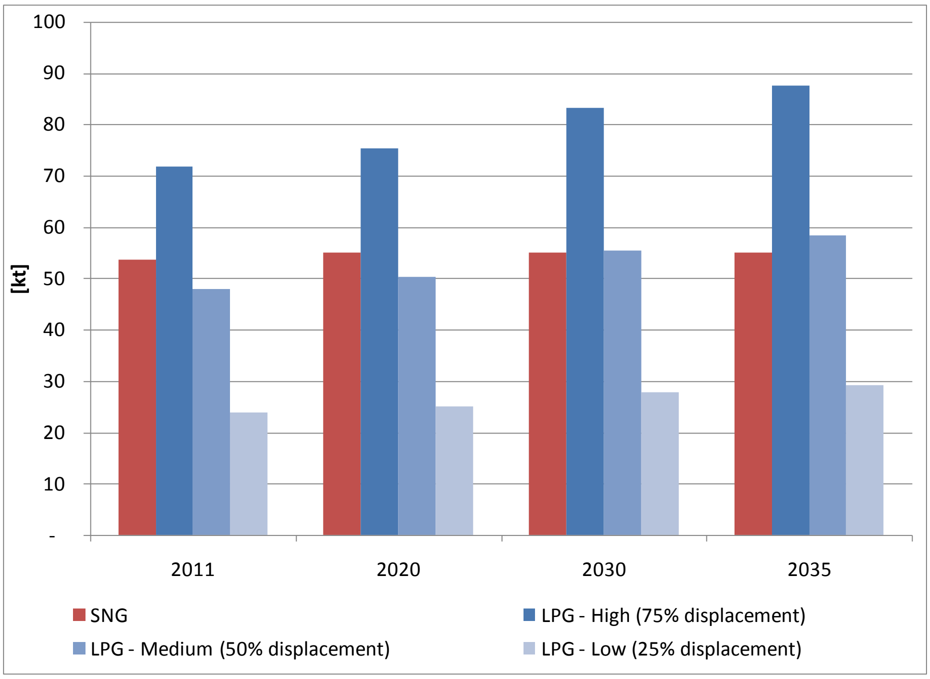
Existing demand for SNG has been fairly constant over the past few years at some 2.8 million mmBtus per annum, equivalent to 55 ktpa of LNG. LPG demand, however, has been increasing in recent years, going from 2.6 kb/d in 2009 to 3.5 kb/d in 2011. The additional supply has been imported from foreign sources as local supply is limited and the local refineries' crude run is determined by demand for major products such as gasoline, jet fuel, diesel and fuel oil.

1.3.2. LNG Demand for SNG and LPG

Almost all SNG demand is easily convertible to LNG, as no change is needed after LNG is regasified and injected into the pipeline distribution network which currently carries SNG produced at the SNG plant.

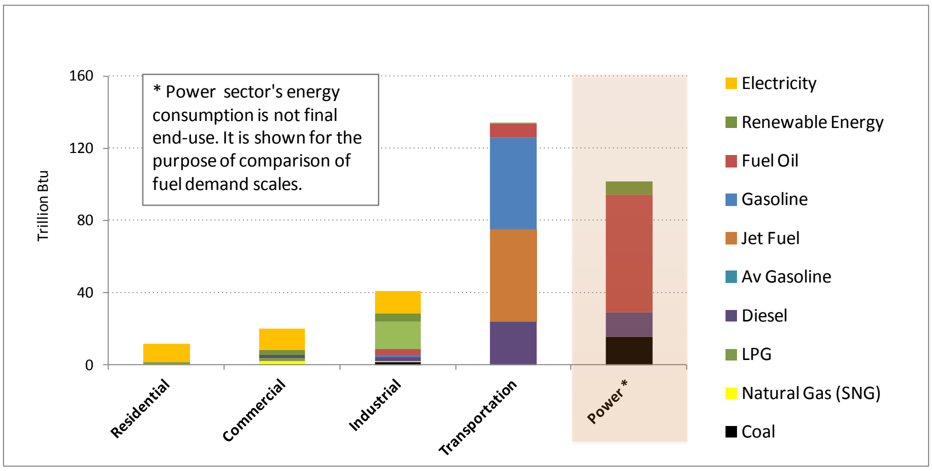
However, in the case of LPG it is not possible to convert all the demand into LNG, as some LPG applications (such as BBQ tanks, etc.) and customers (without large LPG storage or access to utility gas) cannot be easily converted and will continue to utilize LPG. Hence, the maximum potential LNG demand for SNG is calculated by assuming full conversion to natural gas, but the LPG conversion ratio could be anywhere between a low of 25% or a high of 75%. Using 100% for SNG and the three aforementioned scenarios for LPG conversion, LNG demand for SNG and LPG consumption would be somewhere between 83 to 138 ktpa in 2030. Under the same assumptions, potential LNG demand for SNG and LPG in 2011 would range between 72 to 120 ktpa, not materially different than the 2030 forecast.

Figure 20: LNG Demand For SNG and LPG



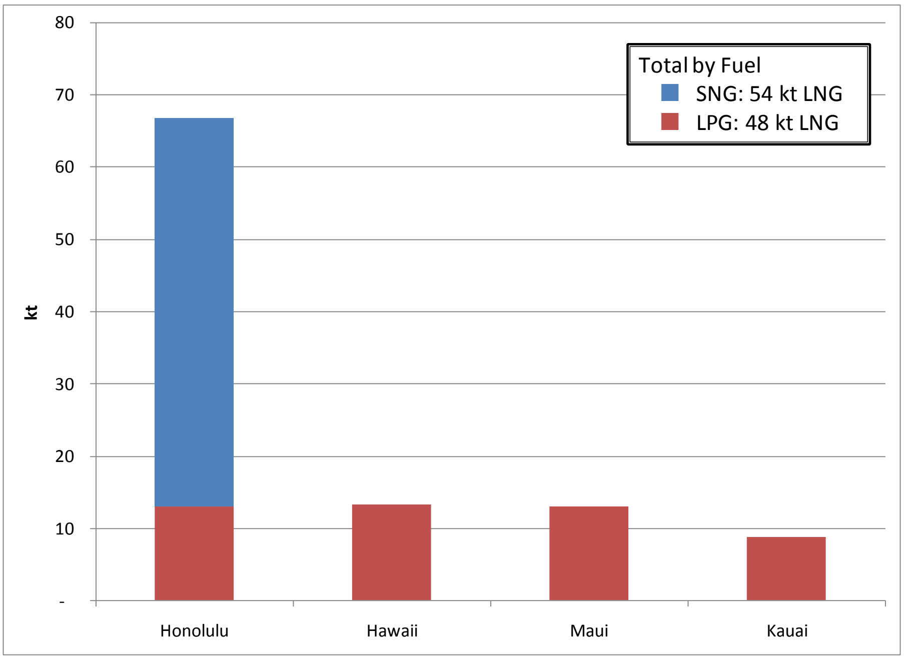
In our demand forecast, LPG demand is assumed to grow with a modest growth rate of 1% over the next two decades, reaching to 4.1 kb/d in 2030 from 3.5 kb/d in 2011. SNG demand, however, is assumed to remain constant at 2.9 million mmBtus. This assumption is made based on: 1) it has been constant over the past 6 years, 2) any growth would imply fuel switching of residential and commercial applications from electricity to gas, which would divert some of the estimated LNG demand for power. It is worth mentioning that although there will be differences between the amount of LNG required for 1 Btu of energy utility (hot water, cooking, etc) when using natural gas versus electricity in those applications, the scale of demand is so small that such a differential could be considered as estimation error (Figure 21).

Figure 21: Final Energy Consumption by Source and Sector; Hawaii, 2010.



Assuming a 50% LPG conversion rate as a medium scenario, the LNG demand equivalent for SNG and LPG would be 102 ktpa (Figure 22). As explained earlier, excluding Oahu's LNG demand for current utility SNG, the remaining 48 kt would be almost equally divided between counties except for Kauai where demand would be slightly smaller.

Figure 22: 2011 LNG Equivalent for Current SNG & LPG Demand (50% sub.)

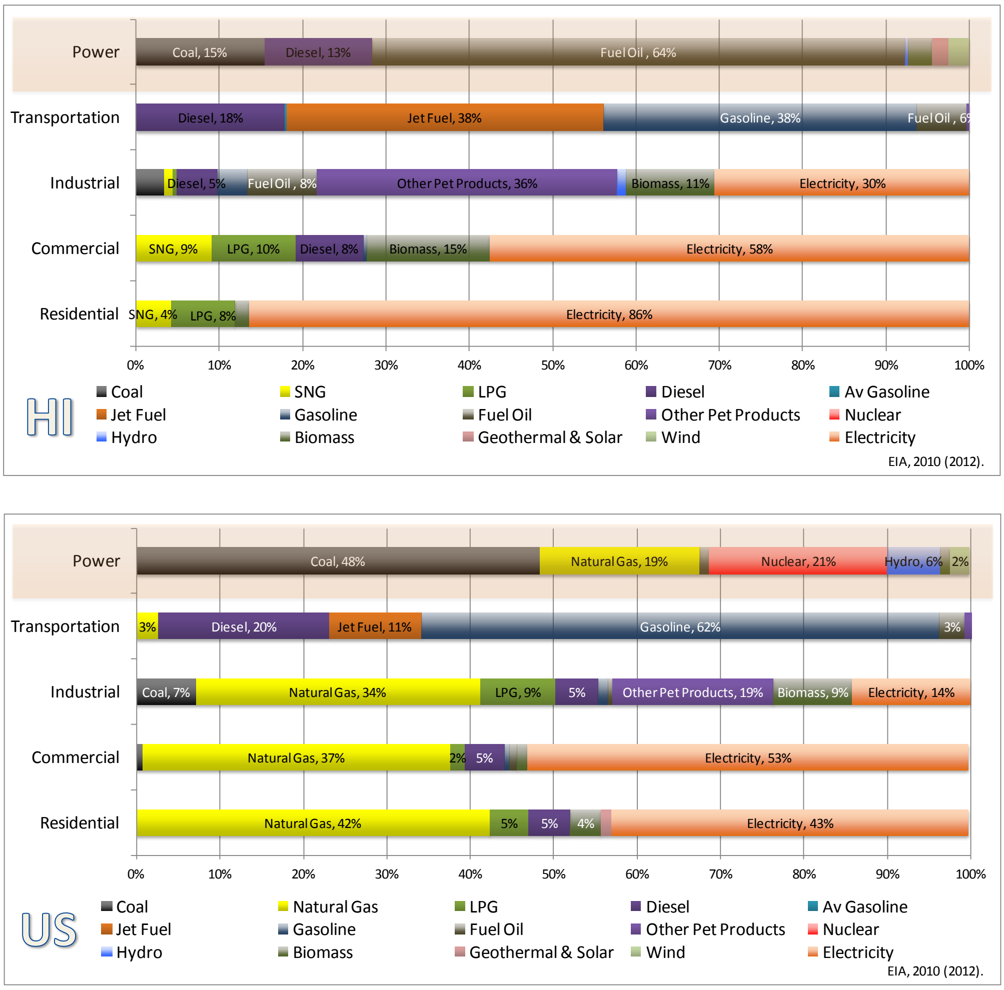


1.3.3. State of Technology for Natural Gas Use in Residential and Commercial Applications

SNG and LPG are mainly used by residential and commercial (RC) sectors in Hawaii, primarily for applications such as water heating, cooking (range and oven), and dryers, as opposed to the US mainland, where space heating is the main application of natural gas in these sectors. Hence, the scale of RC demand for natural gas in Hawaii is much smaller than what is observed on the mainland. Another reason to assume a much lower share for natural gas in RC energy portfolio in Hawaii is the more established LPG market for these sectors' energy demand compared with the rest of the nation (on average).

So, assuming observed 40% share of natural gas in the US RC energy demand as the maximum potential, the potential natural gas demand would be much less in RC sectors in Hawaii. In 2010, SNG comprised less than 5% and 10% of the residential and commercial energy demand, respectively.

Figure 23: Energy Consumption by Source and Sector; Hawaii vs. United States, 2010



Source: EIA

As explained in the previous section on LNG demand, the extent of fuel switching from electricity to natural gas in these sectors depends on not only the supply availability, but also on consumers' preferences and the associated savings potential. Another competing energy source in RC sectors is roof-top PV and solar water heaters. Hence, although it might be possible to estimate a range for potential penetration of natural gas in Hawaii's RC sector in a detailed study with consideration of its incentives and barriers and exact size of each of the above-mentioned applications (assuming availability at all end-use locations), there are many uncertainties as well as little importance of such a figure for the purpose of this study that it is not considered as part of the scope of this study.

1.3.3.1. Water Heating

Typical water heaters in the US are electric resistance or atmospheric natural gas tank water heaters. According to national statistics, based on residential and commercial energy surveys, households on the mainland use natural gas to heat water more than any other fuel source and about 40% use electricity.

Electric water heaters are generally more efficient than the gas water heaters. Based on the US DOE's energy conservation standard, electric water heaters' Energy Factor is 95%, while for the gas water heaters, depending on the type, it would either be 62% for the types with gas-storage or 82% for the instantaneous types with on demand gas (no pilot).[12] Although higher efficiency has turned the tank-less or instantaneous gas water heaters into a promising option for residential users, because they are usually very compact and generally wall-hung, it can be an expensive option to install in retrofit applications, requiring special ductwork and upsizing the gas lines.

It is important to note that the energy factor standard is defined as the amount of energy the appliance uses for a unit of utility/service that the appliance provides (for example a 1 degree increase in the temperature of a certain volume of water in this case), which is based on the end-use energy consumption. However, looking at it on a life-cycle basis and considering the 30% efficiency of power generation and transmission (that is, it takes about three times as much source energy to deliver a unit of electricity to the end-use), an electric water heater that appears to be 50% better than a gas water heater with storage tank and 10% better than the tank-less one actually uses much more energy than the average gas water heater.

In addition, considering the end-user and taking an economic point of view, the price differential between residential electric and utility gas rates could well offset the efficiency gain of choosing electric water heaters versus gas water heaters. As Hawai'i has the most expensive utility gas (SNG) and electricity, Oahu's residential customer had to pay \$55 per mmBtu of utility gas and \$100 per mmBtu of electricity in October 2012, which means a 45% savings potential for residential sector to switch from electricity to natural gas for certain applications, assuming the same application efficiency. Thus, unless electric water heaters (or any other end-use application) provide the consumers with more than 45% increased efficiency, using gas water heaters would be economically preferred for customers too, given the natural gas supply availability.

1.3.3.2. Cooking

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[12] Final Rule for Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters; Federal Register/Vol. 75, No. 73/April 16, 2010/ http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/htgp_finalrule_fedreg.pdf.

As explained in the water heating section, gas is generally preferred to electricity as a heating fuel on the US mainland, where natural gas is cheap and available in most places as opposed to most locations in the State of Hawaii.

However, given the low price of utility gas and relatively small share of cooking in RC energy demand, the choice of gas versus electric ranges and ovens has more to do with users' own preferences, assuming the availability of gas option. Many people prefer to cook with gas stoves due to better cooking control; however, it could introduce combustion products into the house that must be vented to the outside.

Electric ranges and electric ovens have higher Energy Factors than the gas burning ones (Max-tech EF is 70% for electric ranges and 40% for gas ranges; and it is 12% for electric ovens compared with 6% for gas ovens[13]). As discussed for water heaters, however, fuel preference would also depend on the supply-side (generation and transmission) efficiency and the retail price of electricity and natural gas.

1.3.3.3. Clothes Drying

Although electric clothes dryers would offer higher efficiency than the gas dryers, similar to the water heaters and cookers, the efficiency difference is much less here. According to the US Department of Energy, minimum required Efficiency Factor for gas clothes dryers is set at 2.67 lbs/kWh while the requirement for electric clothes dryers, depending in the voltage level and dryer's capacity, would range between 2.90 to 3.13 lbs/kWh[14].

1.4. Natural Gas for Ground Transportation

1.4.1. Existing Fuel Demand for Ground Transportation

According to the EIA, Hawaii's transportation sector consumed 49% of total end-use energy in 2010, ranking first in the country. California's transportation sector ranks 2nd with a 40% share of total end-use energy while the national average is 28%. Hawaii's

[13] Final Rule for Residential Dishwashers, Dehumidifiers, and Cooking Products, and Commercial Clothes Washers Standards; Federal Register/Vol. 74, No. 66/April 8, 2009; http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/74fr16040.pdf

[14] Final Rule for Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners; Federal Register/Vol. 76, No. 164/August 24, 2011/ http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/aham_2_final_rule_amending_dates_fr.pdf.

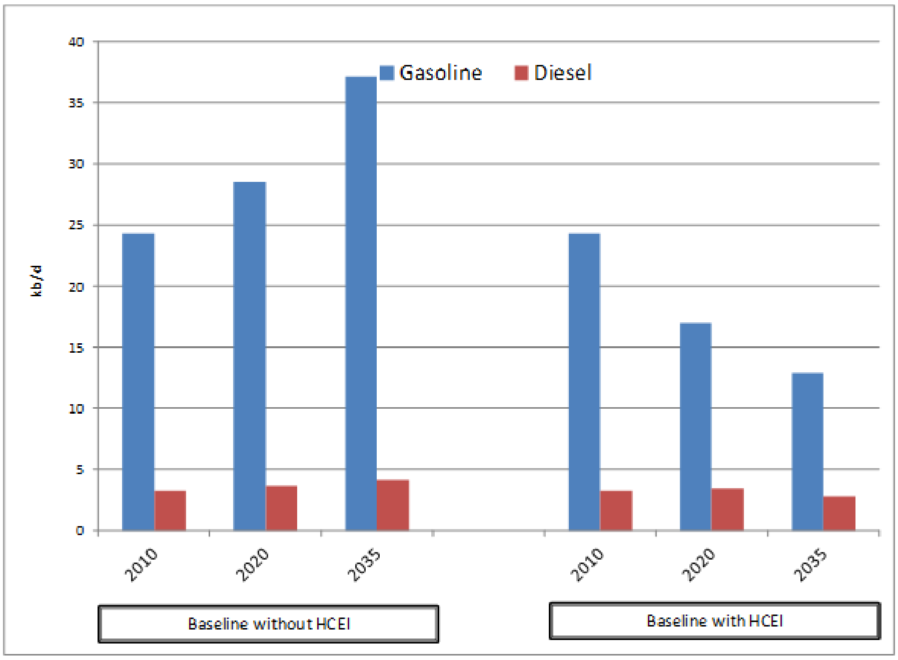
high share of transportation, however, is not due to having the least efficient vehicles and fleet, high vehicle per capita, or high vehicle miles traveled (VMT) per capita. It is specifically because of the large air and marine transportation demand components, particualry the former as jet fuel is a large part of Hawaii's demand barrel. In 2005, ground transportation accounted for 39%, marine transportation for 13%, and air transportation for 48% of total transportation fuel consumption in the State of Hawaii.

In 2011, ground transportation consumed more than 30 kb/d of liquid fuels, accounting for more than 25% of total fuel demand in the State. Such a large energy profile would make the ground transportation sector another potentially significant component of LNG demand besides the power sector. Gasoline consumption (including ethanol and other blending components) comprises about 90% of total ground transportation fuel, with the rest being diesel.

1.4.2. Future Fuel Demand for Ground Transportation

FGE developed a baseline forecast for transportation fuel demand without considering increased efficiency and renewable energy plans of HCEI; the baseline forecast up to 2035, models demand growth with respect to external factors such as expected population growth and forecasted fuel. The baseline is then used to calculate the fuel demand reduction due to expected increased vehicle efficiency and VMT reductions. Deducting the renewable fuel goals of HCEI from the remaining demand, FGE calculated the expected gasoline and diesel demand to generate the scenario called baseline with HCEI, shown in Figure 24.

Figure 24: Highway Fuel Consumption; Diesel and Gasoline



1.4.3. LNG Demand for NGVs

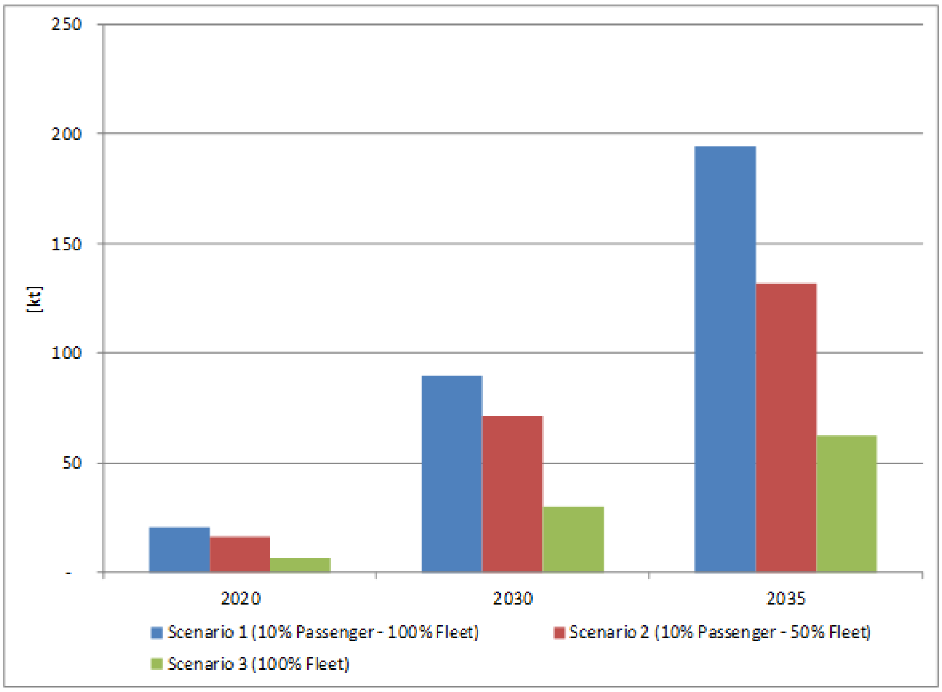
In 2010, there were about 250 thousand natural gas light-duty vehicles (LDVs), accounting for 0.11% of 225 million light-duty vehicles in total, out of which 80 thousand were passenger cars and the rest were light trucks. In its latest outlook, US DOE projects a minor increase in NGV share of total LDVs to 0.17% by 2030[15]. For heavy-duty vehicles (HDVs) however, due to the current national plans for extending LNG fueling networks[16] to serve the LNG trucking system in the US, the national outlook is much more optimistic.

To estimate the potential LNG demand for natural gas vehicles (NGVs), FGE assumed three scenarios: 1) 10% passenger vehicles (115 thousand) and 100% freight vehicles (40 thousand) conversion to NGVs; 2) 10% of passenger vehicles (115 thousand) and 50% of freight vehicles (20 thousand) conversion to NGVs; and 3) 50% of freight vehicles (20 thousand) only to convert to NGVs. In all the above scenarios, it is assumed that conversions start from 2016 and gradually reaches the threshold by 2035. Another implicit assumption made, according to historical data, is that total highway gasoline is consumed 96% by passenger vehicles and 4% by freight vehicles and highway diesel is divided by 28% by passenger vehicles and 72% by freight vehicles. The final assumption made for this section is to convert passenger vehicles to CNG vehicles and freight vehicles to use LNG.

Based on the above assumptions, potential LNG demand for ground transportation would range from 30-90 kt in 2030, increasing to 50-200 kt by 2035, depending on the scenario. The first scenario, as expected, accounts for the highest amount of LNG compared to the other two scenarios (Figure 25). A notable point in this analysis is the increasing LNG demand for transportation as higher conversion occurs; as opposed to decreasing LNG demand for power generation over time (due to increase in clean power—efficiency and renewable based power), which would provide an opportunity to shift LNG demand from the power sector to the transportation sector over time.

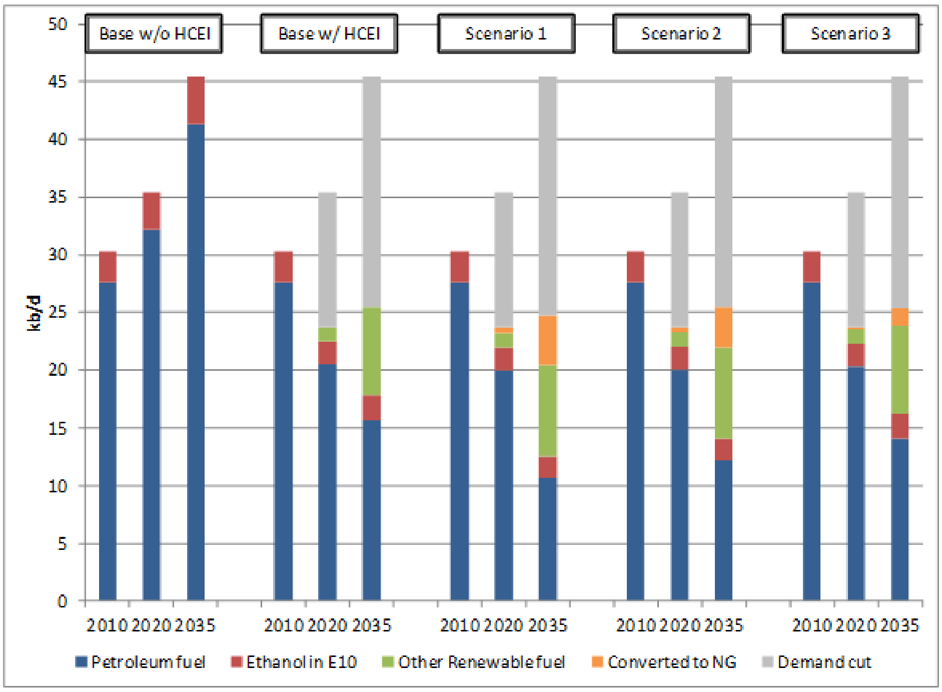
[15] AEO 2013 Early Release (Dec 2012) – Table 58. Available online at: http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm
[16] http://www.lngglobal.com/lng-for-fuel/first-stage-of-the-clean-energy-network-of-lng-fueling-stations-is-complete.html

Figure 25: LNG Demand Highway Fuel Consumption; Diesel and Gasoline



Another interesting point to note in this analysis is the reduction in gasoline demand in each of these scenarios. Scenario 1, with the highest NGV penetration in the transportation sector, would offset 4.3 kb/d of fuel demand (out of 15.7 kb/d, after HCEI; of which 12.9 kb/d is gasoline) by 2035. Scenario 3, however, with 50% of freight vehicles conversion to NGVs would only offset 1.5 kb/d of 2035 fuel demand (Figure 26).

Figure 26: Ground Transportation Fuel Demand; By Component



The last point to consider here is the conflicting nature of gasifying the ground transportation with HCEI clean fuels goal. As the figure above illustrates, under high natural gas penetration scenarios such as Scenario 1, the renewable fuel goal of 2030 would imply almost 50% of renewable fuel (ethanol and biodiesel) blending in petroleum fuels, which makes the already ambitious goal of 70% clean transportation even harder to achieve. On the other hand, however, if natural gas (which is considered as alternative fuel by US DOE) would be included in the clean fuel goal, then it can help achieve the goals of 70% clean transportation sector by 2030.

1.4.4. State of NGV Technology

The number of natural gas vehicles (NGVs) has grown in recent years due to the low price of natural gas in the United States as well as the environmental benefits compared to burning oil products. There are currently about 120,000 NGVs on US roads today and more than 15.2 million worldwide.[17] Transit buses account for about two-thirds of NGVs in the United States and waste collection and transfer vehicles, about 12%. In 2011, nearly 20% of all transit buses ran on compressed natural gas (CNG) or liquefied natural gas (LNG) and nearly 40% of all trash trucks purchased were powered by natural gas. If LNG comes to Hawaii it could make sense to convert transit buses, waste collection and transfer vehicles, airport shuttles and vehicles, and City and State vehicles to run on natural gas instead of petroleum products.

1.4.4.1. Technology

In its traditional gaseous form, natural gas occupies more volume than traditional liquid fuels, so it is either compressed or liquefied and used as a vehicle fuel to make it practical for transport use. CNG is the most common application for NGVs, but LNG use is becoming increasingly common. CNG has a high octane rating (>120) and is used in spark ignition engines for both light-duty and heavy-duty vehicle applications. Some vehicles operate exclusively on CNG and some can use both CNG and gasoline. CNG is stored onboard vehicles in cylinders at pressures of 3,000 to 3,600 pounds per square inch in tube-shaped cylinders that are attached to the rear, top or undercarriage of the vehicle. The cylinders meet very rigorous safety standards and are made of high-strength materials designed to withstand impact, puncture and fire. On a per gallon basis, CNG stored in the vehicle tank has about one-third less energy content than gasoline, which limits driving range when compared to a gasoline vehicle.

[17] www.ngvc.org

LNG is considerably denser and has greater energy content than CNG. Therefore, a larger quantity of LNG can be stored in the same tank volume. LNG requires only 30 percent of the space of CNG to store the same amount of energy. In order to keep the LNG cold, LNG is stored on-board vehicles in thermal storage tanks, akin to sophisticated thermos bottles. However, because storing a chilled liquid onboard a vehicle is complex, LNG is only used on heavy-duty trucks and buses.

1.4.4.2. Infrastructure

The most critical part of the infrastructure for NGVs is the fuelling stations. There are about 1,000 NGV fuelling stations in the US with the largest amount (238) located in California. At CNG fuelling stations the gas is typically taken from the local gas utility's line at low pressure, compressed on site and then stored in the vehicle's storage tanks at high pressure. The tank is filled in about the same time it takes to fuel a similar petroleum vehicle. With respect to LNG, the fuel is typically trucked to the station and stored onsite in special cryogenic storage tanks. To fuel vehicles, LNG is pumped into the vehicles much like other liquid fuels, but using much more sophisticated cryogenic fuelling equipment.

There also are LCNG fuelling stations that uses LNG to fuel both LNG and CNG vehicles. LNG vehicles are fuelled as described above; for CNG vehicles, the LNG is compressed as a liquid and then gasified. The high-pressure gas is then stored on the vehicle as with a CNG station. Since it takes less energy to compress a liquid than a gas, once the LNG is available, LCNG stations are less expensive to operate.[18]

One of the leaders in designing, building, operating, and maintaining natural gas fuelling stations is Clean Energy based in Seal Beach, California. The company has built over 150 fuelling stations nationwide and delivered nearly 800 million gallons of CNG and LNG to customers. In 2010, it acquired IMW Industries, Ltd., a leading supplier of compressed natural gas (CNG) equipment for vehicle fuelling, and world leader in natural gas compression technology.

1.5. Natural Gas for Marine Transportation

As mentioned earlier, marine transportation accounted for 13% of total transportation fuel demand in Hawaii in 2005. This demand however is mainly for long-distance overseas trips of large vessels between Hawaii and US mainland or other countries in

[18] www.ngvc.org

Asia or the Americas. Interisland marine transportation fuel consumption comprises only a small portion of it (14% in 2005).

Currently most interisland marine fuel is diesel. The interisland cargo trades are virtually all performed by tugs and barges, burning diesel in their high speed diesel engines. Some fuel oil, however, is used by the cruise ship, "Pride of America," operating interisland.

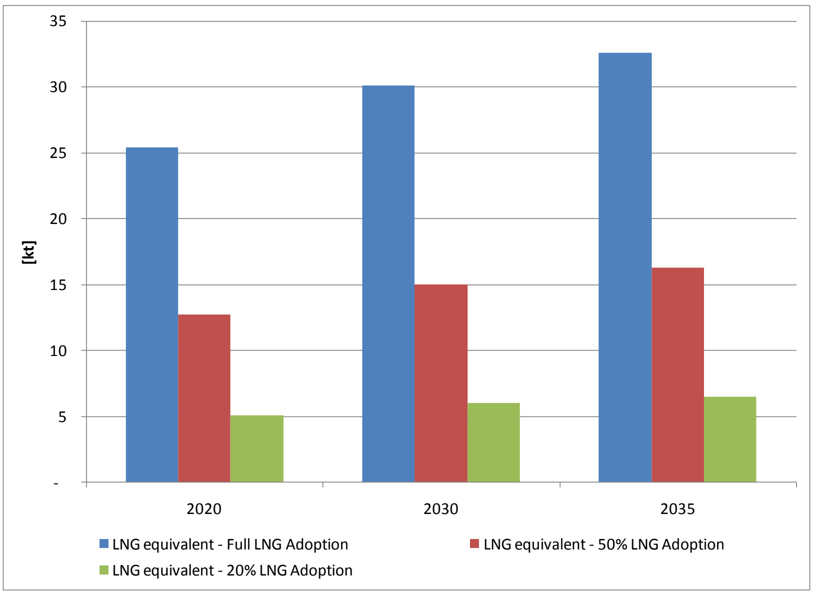
FGE estimated interisland diesel use to be around 0.5 kb/d in 2011, increasing to around 0.8 kb/d by 2035.

1.5.1. Potential LNG Demand for (Interisland) Marine Transportation

LNG is compatible with post-2015 IMO regulations, which none of the bunker fuel sold in Hawaii at present can manage. At present, there is no international bunkering system for LNG, so any demand for non-interisland shipping is speculative. Hence, this study only considers the interisland shipping to be converted from diesel to LNG.

To this end, FGE assumes three scenarios of high (100%), medium (50%), and low (20%) fuel conversion of interisland vessels. Unlike ground transportation and due to the limited number of stakeholders (a few vessel owners compared with thousands of vehicle owners), conversion assumes to start in 2015 and complete by 2016. Based on these three scenarios, potential LNG demand for interisland marine transportation would range between 7 ktpa and 33 ktpa by 2035.

Figure 27: LNG Demand for Interisland Marine Transportation



1.5.2. State of LNG Fueled Marine Vessels

1.5.2.1. Marine Fuel

The International Maritime Organization (IMO) is the United Nations agency charged with ensuring marine safety and the prevention of marine pollution by ships. Currently there is a global cap of 3.5% on the sulfur content of marine bunker fuel to limit emissions of sulfur dioxide, a harmful pollutant. From January 1, 2020, a global sulfur limit of 0.5% in marine bunker fuel oils is expected, though these may be pushed back to 2025 pending further investigation by the IMO into the global availability of low-sulfur bunker fuels. Since 2005 a number of Emission Control Areas (ECAs) have been implemented around the world where the sulfur content limit of marine bunker fuel is far more stringent. The current limit of 1% will be reduced to 0.1% by 2015. North America (including Hawaii) falls into an ECA and will have to abide by these new regulations by 2015.

Hawaii's interisland marine transport market has a couple of options. The easiest route is simply buying lower sulfur diesel that meets the new standards. However 0.1% sulfur diesel is not readily available in the market. Lower sulfur diesel at .05% is still used on the US West Coast in ship bunkers and locomotives, but it is a thin market as people have switched to what is called ultra low sulfur diesel (.0015%). While .05% diesel is available in Singapore it is quite a bit more expensive than what ships currently burn for fuel. Another potential option is to burn LNG if the fuel is readily available in the State.

1.5.2.2. Technology

There are currently 29 ships that run on LNG and another 12 on order. The bulk of these vessels are car/passenger ferries that operate in Norway. A critical aspect of the development of LNG as a fuel is the lack of an established bunkering infrastructure and supply chain network for delivering LNG as a marine fuel. Assuming that Hawaii brings in large enough volumes of LNG to supply the local marine fuel market for interisland transportation, the ships would have to convert their engines to run on LNG. There are currently three natural gas engine technologies used for large marine vessels: (1) spark-ignited lean-burn, (2) dual-fuel diesel pilot ignition with low-pressure gas injection, and (3) dual-fuel diesel pilot ignition with high-pressure gas injection. Spark-ignited engines operate exclusively on natural gas, while diesel pilot ignition engines can operate on a range of fuels, including natural gas, marine distillate, and marine residual fuels. Besides fuel flexibility, there are other trade-offs between the various technologies, including NOx and GHG emissions, efficiency, and sensitivity to natural gas quality.

According to the American Clean Skies Foundation, conversion of vessels to LNG operation is expensive—it can cost up to $7 million to convert a medium-sized tug to operate on natural gas and almost $11 million to convert a large car and passenger ferry. Approximately one-sixth of this cost relates to conversion of the vessel engines and the rest is for installation of LNG storage tanks and related safety systems and ship modifications. As the cost of conversion is so high, the most likely candidates are vessels that have a high utilization and annual fuel use relative to vessel size and engine power. The owner of the vessel would have to weigh their expected fuel costs for liquid petroleum fuel versus the delivered price of LNG fuel and the conversion cost to see if the economics work.

1.6. Other Potential Demand for Natural Gas

1.6.1. Potential LNG Demand for Industrial Use

In addition to the five LNG demand sectors discussed in sections 1.1 to 1.5, industrial fuel use in refineries and combined heat and power (CHP) plants could possibly be the areas where LNG can play a role.

Figure 28: Fossil-fuel-based Industrial Power Generation

	Plant Name	Operator	Generation Technology	Capacity [MW]	Maximum Generation [MWh]	Actual Generation [MWh]	Utilization rate [%]	HeatRate [Btu/kWh]
HONOLULU								
	Chevron Refinery	Chevron Corp	GT	9.0	78,840	67,947	86.2%	25,592
	Tesoro Refinery	Tesoro Hawaii Corp	GT	20.0	175,200	114,337	65.3%	11,755
MAUI								
	HC&S Puunene Mill	Tesoro Hawaii Corp	ST	46.1	403,836	2,308	0.6%	29,297
Total						184,591		

Source: EIA

Hawaii's two refineries, Chevron and Tesoro, purchase their needed steam from the two neighbor power plants, AES Hawaii plant and Kalaeloa Partners Power plant. Hence their heat rates are not as high as typical CHP plants, such as Hawaiian Commercial & Sugar (HC&S) company's Puunene Mill (Figure 28).

Figure 29: Potential LNG demand for Industrial Power Generation

Plant Name	Power Generation Technology	HeatRate [Btu/kWh]	2011 Cogen Fuel Use [mmBtu]	LNG equivalent @ Current heat-rate [kt]	Non-offgas Refinery Fuel Use [mmBtu]	LNG equivalent @ Current heat-rate [kt]	LNG demand [kt]
HONOLULU							
Chevron Refinery	GT	25,592	1,738,928	34	-	-	34
Tesoro Refinery	GT	11,755	1,344,079	26	2,299,500	45	71
MAUI							
HC&S Puunene Mill	ST	29,297	67,603	1			1
Total			3,150,610	61	2,299,500	45	106

For the refining process energy use, Chevron gets a good deal from burning coke off their FCC catalyst. On top of this, they burn about 1.7 million mmBTU annually for their cogen plant (Figure 29). As about half of that is their refinery offgas, and there is no real reason to displace it, their realistic LNG demand is probably limited to about 17 ktpa.

Tesoro's situation, however, is different. Tesoro refinery has no catalyst coke, and most of their offgases go to their hydrogen plant. Their cogen plant burns about 1.4 million mmBTU per year (mostly "waste oil," but also small volumes of diesel and jet components), which is equivalent to about 26 ktpa of LNG (Figure 29). In addition, they burn varying amounts of bottoms within the refinery. Assuming around 1 kb/d of refining bottoms (2.3 million mmBtu), which could of course fluctuate substantially, would result in another 45 ktpa potential demand for LNG in their refinery. This would imply a 100 ktpa potential demand for refineries.

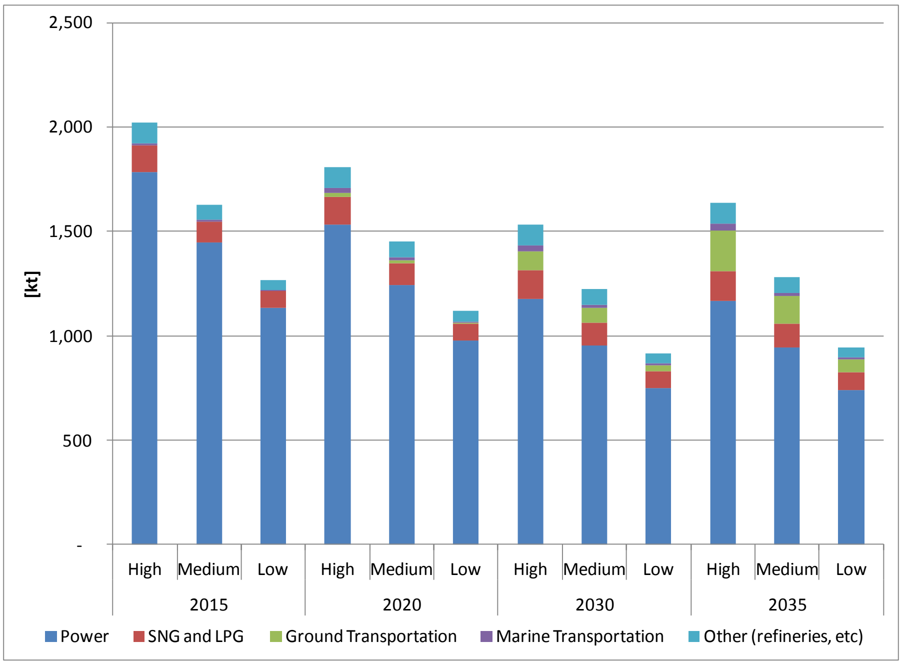
Meanwhile, with regard to the refineries' potential LNG demand, there are some complications that need to be considered. First, as mentioned earlier, both the refineries receive steam for IPPs. If that flow ceased, their demand would go up. On the other hand, however, both have cogen power plants which could drive their demand down if they shut down those plants. Finally, if the refineries keep operating in the longer term, at some point they would need to install substantial new hydrodesulfurization to meet the required specifications, which would raise their hydrogen demand—and LNG, upon availability, would be an obvious source. But that is incredibly speculative, and would be contingent on the refiners making major new investments in Hawaii.

There will be some other industrial demand for LNG as fuel for heat and steam generation (in addition to the HC&S mill listed in Figure 29), but the scale would be small enough to be considered as the estimation error.

1.7. Conclusions

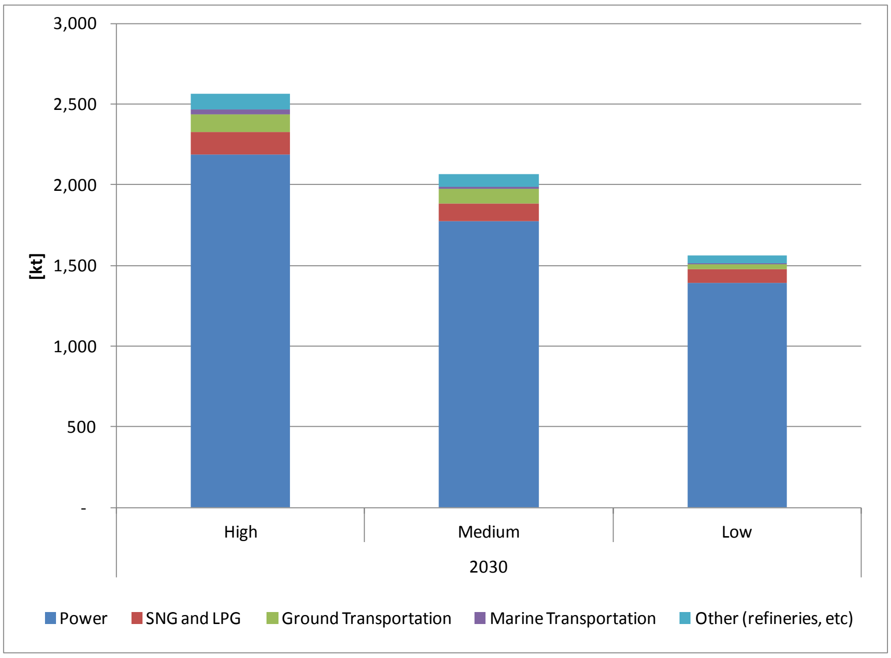
If Hawaii successfully achieves its HCEI goals, total potential LNG demand ranges from approximately 1-2 mmtpa between 2015 and 2035. (Figure 30). It is clear that the power sector is the main driver and that absolute demand within this sector is dependent on what type of technology is deployed. The potential introduction of NGV's to run on CNG or LNG makes the transport sector the second biggest potential natural gas market for the State (by 2035), followed by the SNG/LPG market and large industrial fuel use (mainly two refineries), and finally the interisland marine transport market. While not all of these sectors will switch to LNG, this exercise demonstrates the potential role that natural gas could play in Hawaii's energy mix over the coming decades.

Figure 30: Total Potential LNG Demand



As mentioned several times in this Chapter, the above summarized potential of LNG relies on the relatively strong assumption of meeting all HCEI goals. As a sensitivity analysis to our estimates we changed the energy efficiency and renewable energy assumption to half of what is set by HCEI, dubbed *Half-HCEI scenario*. As Figure 31 illustrates, such assumptions would imply additional LNG demand of 0.5-1 mmtpa in 2030, based on this scenario. LNG demand would increase to some 2.5 mmtpa (from 1.5 mmtpa under Full-HCEI) in the high penetration scenario and to some 1.5 mmtpa (from less than 1 mmtpa under full-HCEI) in the low penetration scenario.

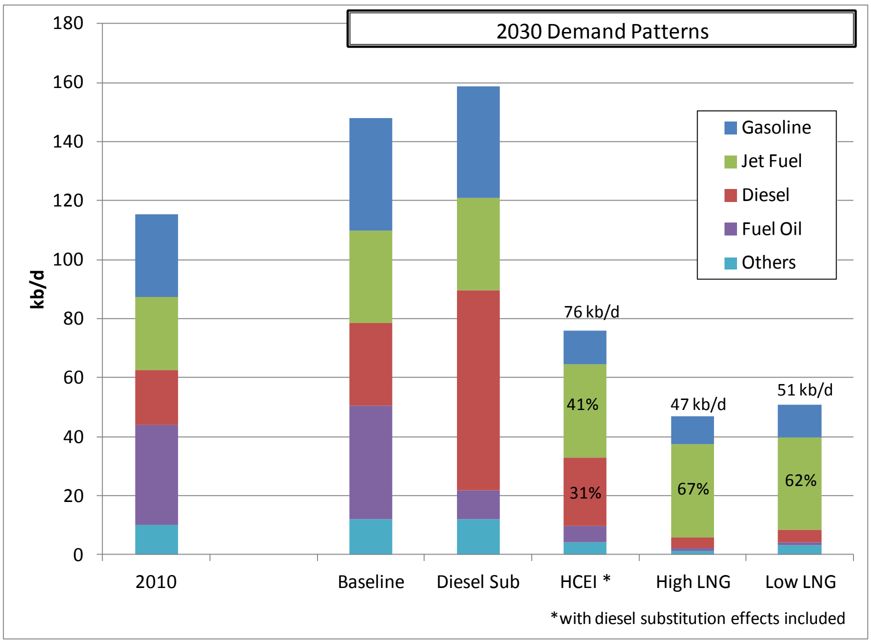
Figure 31: Total Potential LNG Demand



It is worth mentioning the implications of LNG's introduction on oil demand for Hawaii in 2030. A more complete analysis of similar implications on the refineries' viability is discussed in Chapter 3. Although LNG imports will substitute for some petroleum products demand, the major cut will happen primarily as a consequence of a successful HCEI implementation. Figure 32 presents the size and pattern of petroleum products demand in 2030 under various scenarios. In both high and low LNG scenarios we assume all power generation and all SNG supply will be substituted by LNG, but the difference is in the degree of LNG penetration in the (ground and marine) transportation market as well as other (LPG).

As Figure 32 clearly shows, the size and pattern of demand in 2030 under the HCEI goals (a demand barrel with more than 70% middle distillates) would not be compatible with a healthy Hawaii refining industry. The situation, however, would be much worse for the refineries if we add another 25-30 kb/d demand cut by introducing LNG in our energy portfolio, 20 kb/d of which is LNG substitution for diesel in the power sector. Under the LNG scenarios explained earlier, 60-70% of the 45-50 kb/d demand for oil would be jet fuel, about 20% gasoline, and some minor portions of other products.

Figure 32: 2030 Oil Product Demand Under Different Scenarios



II: POTENTIAL COSTS AND BENEFITS OF IMPORTING LNG

2.1. *Primary Fuel Cost Savings*

2.1.1. Oil Product Price Forecasts

Forecasts of oil prices are easy to come by. Dozens of firms and government agencies produce outlooks for key crudes, such as WTI, Brent, Dubai + Oman, or the JCC. Unfortunately, corresponding product prices are difficult to come by. Most detailed product price forecasts in particular markets are available only through specialist consulting firms. In addition, for the purposes of this study, we need long-term product price forecasts in Hawaii. We are not aware of any publically available sources for Hawaii product price projections.

FGE produces detailed price forecasts in a number of major markets, including the Singapore market. Most product trading in the Asia-Pacific region is based on the Singapore market. Furthermore, over recent decades, most HECO contracts for LSFO have been based on Singapore prices, or on prices in the neighboring Indonesian market. Even when markers from East Asia, such as Korean prices, have been employed, these prices themselves refer back to Singapore prices.

Furthermore, if Hawaii switches to low-sulfur diesel (a possibility discussed later in this report) as the main utility fuel, it is probable that the import price from Singapore will drive prices in Hawaii. (The US West Coast no longer produces significant volumes of low-sulfur diesel, as environmental regulations have forced a switch to ULSD, ultra-low sulfur diesel). In any case, Californian and Singaporean diesel prices are highly correlated across time.

For previous studies of supply options, FGE has developed a model that derives landed Hawaii prices for utility fuels from Singapore prices. In general, the prices derived are quite similar to Japanese import prices across time, which is not surprising, as Japanese import prices are driven by Singapore prices.

Figure 33: FGE Oil Product Price Forecasts

	Oahu LSFO $/bbl	Oahu LS Diesel $/bbl	Oahu LSFO $/mmBtu	Oahu LS Diesel $/mmBtu
2009	$ 60.28	$ 96.67	$ 9.72	$ 16.67
2010	$ 85.20	$ 97.11	$ 13.74	$ 16.74
2011	$ 122.00	$ 114.53	$ 19.68	$ 19.75
2012	$ 139.49	$ 128.33	$ 22.50	$ 22.13
2015	$ 136.91	$ 133.76	$ 22.08	$ 23.06
2020	$ 144.33	$ 146.56	$ 23.28	$ 25.27
2025	$ 141.87	$ 151.96	$ 22.88	$ 26.20
2030	$ 135.09	$ 153.25	$ 21.79	$ 26.42

note: 2009-2011 actual dollars of the day. 2012-2030 in projected 2012 real dollars.

(In looking at these prices, it is important to keep in mind that fuel oil contains more heat per barrel than diesel. The figures here have been converted at their contract rates of 6.2 mmBtu/bbl for LSFO and 5.8 mmBtu/bbl for diesel. As an example, take a look at the figures for 2011. LSFO is more expensive per barrel than diesel—$122/bbl vs $114.53/bbl. But fuel oil is slightly cheaper per mmBtu.)

The FGE oil forecast is considered quite conservative; many other groups are projecting much higher growth in oil prices. In real terms, our crude oil prices and diesel prices climb slowly but steadily through 2030. But our LSFO prices are relatively flat.

This trend reflects the fact that LSFO prices—which are usually below the price of crude—have been pushed up to high levels as a result of the Japanese Triple Disaster. Even after those pressures ease toward the end of the decade, LSFO will continue to rise somewhat as a result of increases in the underlying crude prices. Toward 2030 the prices move down slightly as a result of switches away from fuel oil around the region.

In general, FGE believes that increased oil prices of recent years have not yet worked their way through the world energy system. Considerably more conservation and fuel switching is coming, and high prices will continue to bring in new resources, such as Canadian (and eventually Venezuelan) oil sands. Exploitation of shale will also increase the volumes of liquid hydrocarbons—as well as producing even larger volumes of shale gas. Even though oil demand in countries such as China and India will continue to grow, it will be at a much lower rate than in the past, and at the same time US and European demand will tend to fall—especially because of continued growth in hybrid and plug-in vehicles, but also because of gas-for-oil substitution.

There are, of course, other opinions. The EIA at the US Department of Energy does publish detailed product price forecasts. Unfortunately, these are national aggregates rather than regional numbers, and some important assumptions must be made to try to adapt them to local Hawaii prices.

EIA does not forecast LSFO prices. It does, however, forecast fuel oil prices in the electric power sector, and today such fuel oil is overwhelmingly low sulfur. The prices in question, however, are mostly at utilities on the Eastern Seaboard, and tend to be considerably lower than Oahu prices. Although the differential fluctuates, since 2009, the average barrel of utility LSFO has cost $11.47/bbl more on Oahu than on the mainland. Applying this fixed differential to the EIA forecast produces a plausible version of an EIA forecast for Hawaii LSFO.

Diesel is less problematic. As in the case of LSFO, there is no regional diesel forecast, but there is a projection of the average for the power sector. There is no consistent pattern of differences between mainland and Hawaii diesel prices in recent years, but Hawaii utility diesel prices are pegged to Los Angeles spot prices plus a fixed premium. To apply the EIA numbers to produce a Hawaii forecast, we simply added this premium to the EIA forecast for utility diesel.

Figure 34: EIA-Derived Oil Product Price Forecast

	Oahu LSFO $/bbl	Oahu LS Diesel $/bbl	Oahu LSFO $/mmBtu	Oahu LS Diesel $/mmBtu
2009	$ 60.28	$ 96.67	$ 9.72	$ 16.67
2010	$ 85.20	$ 97.11	$ 13.74	$ 16.74
2011	$ 122.00	$ 114.53	$ 19.68	$ 19.75
2012	$ 139.49	$ 128.33	$ 22.50	$ 22.13
2015	$ 156.07	$ 140.07	$ 25.17	$ 24.15
2020	$ 164.77	$ 148.63	$ 26.58	$ 25.63
2025	$ 171.17	$ 155.71	$ 27.61	$ 26.85
2030	$ 172.12	$ 162.26	$ 27.76	$ 27.98

note: 2009-2011 actual dollars of the day. 2012-2030 in projected 2012 real dollars.

There are two major differences between the FGE forecast and that of EIA. First, and most obvious, the EIA forecast is considerably higher, and prices continue to climb strongly through 2030. The other notable divergence is that EIA sees LSFO (in prices per barrel) staying higher than diesel on an ongoing basis—though diesel surpasses LSFO in cost per mmBtu by 2030. We consider this an unlikely outcome. It is easy to switch from fuel oil to diesel in most fuel oil uses, while the opposite is generally not true; there are therefore pressures that work relatively quickly to bring diesel prices up to at least fuel oil levels.

Those who understand the structure of current power generation in Hawaii might note that high-sulfur diesel and MSFO/IFO fuel oils, used on the neighbor islands, are not included in these forecasts. This is not because the volumes are comparatively small, but instead because we doubt that these fuels will be burned by the end of the current decade. Although new EPA regulations do not forbid the burning of such fuels, they make it exceedingly difficult and expensive. By the end of the decade, it is quite likely that most of the neighbor island utilities will have switched to low-sulfur grades like those presently used on Oahu—or to some other energy source altogether. Therefore, the prices on other islands can be calculated from the Oahu prices plus the delivery costs from Oahu.

2.1.2. LNG Export Price Forecasts

At the outset, it is important to be clear about one point regarding LNG: It is not a supermarket. A buyer cannot wait for someone else to make the investments and then arrive and buy what is needed at a fair price. As mentioned before, LNG is a marriage, not a date. To get good terms, the buyer must enter "before the item goes on sale to the general public."

Most oil is not sold on the "spot market," which is the market for single cargoes or a few cargoes; and very little oil is actually sold or delivered on the futures market. But almost all the oil sold on longer contracts today is tied to spot prices or futures-market prices. In other words, a small proportion of the physical transactions in oil end up determining the prices for most of the ongoing contracts.

The LNG market is far from this point. There is indeed a spot market in LNG, but it is small, unpredictable, and has little influence on the contract market in LNG. LNG contracts reference other gas prices, or various oil prices. What they do not do, yet, is use the LNG spot market price.

In principle, a brave buyer could make all purchases from the LNG spot market. In practice, the spot market is still too thin to act as a main source of supply, or even to act as a reliable index.

A primary buyer of LNG will obtain supplies from the project itself—often by ownership or partnership, or, at the minimum, by signing a binding SPA while the project is still in development. In other words, most projects are "sold out" before they produce a drop of LNG.

Today, some of these primary buyers do not have a guaranteed home for the LNG they have contracted to buy. Instead, they are gambling that they will be able to resell their volumes for more than their contracted purchase prices. To date, this has almost always been the case: The primary buyers get the best prices, and the secondary buyers pay a premium.

All this is by way of saying that a buyer that wants the best price cannot simply wait for someone to develop a project and then offer an enticing price. The buyer who wants the best price needs to become part of the project development process.

Discussing Hawaii's options for importing LNG poses a rather curious problem: given Hawaii's geographical location, the logical possible sources of large-scale imports are projects that are not yet complete, or in some cases, are not even approved. Indeed, the most promising sources might be from projects that have not yet been announced.

It should be emphasized that the above caution does not apply to imports of ISO containers on cargo ships, such as HawaiiGas has proposed for their Phase I and II supply projects; such volumes can easily be sourced out of the US West Coast today. But when discussing imports of hundreds of thousands of tonnes of LNG per year, any of the likely sources are not yet in operation.

In terms of exportable gas resources, there are five potential sources within shipping reach of Hawaii: Australia, Alaska, British Columbia, the US West Coast, and the US Gulf Coast. Ironically, it is the most distant locations, Australia (5,840 nm) and the US Gulf Coast (6,100 nm via the Panama Canal) that have firm projects under development. The projects on the West Coast of North America, all 2,100-2,400 nm from Honolulu, are still unapproved and uncommitted.

The Australian and Canadian projects are aimed at the Asian market, and are clearly predicated on oil-linked prices. The Alaskan project is so expensive that it will have to sell at oil-linked prices…or not be built.

On the other hand, the driver behind most projects in the Lower 48 is "Henry Hub plus"—a premium over the price of pipeline gas.

The oil-linked and Henry Hub-linked projects all face different outlooks. Therefore, these will be dealt with in different sections.

2.1.2.1. *Oil-Linked FOB Prices*

These projects all have features in common. First, there are large "upstream" investments required to develop the gas reserves, process them into LNG feed, and deliver them by pipeline to the liquefaction plant. The Australian projects are in the remote and largely unpopulated North, and some of the gas reserves are offshore. The British Columbian projects are somewhat (though not entirely) less remote, but major new pipelines would have to be built to deliver Canadian gas from the interior provinces. In the case of Alaska, the gas pipeline will have to come all the way from the North Slope to the Kenai Peninsula Area—an 800-mile stretch across difficult, remote, and environmentally sensitive terrain.

Second, all require substantial development at the liquefaction plants. This is especially true in Australia, where harbors, power plants, and even housing need to be built. This is less true in British Columbia, but substantial development would have to occur. The Alaskan liquefaction project would be sited in Valdez, the present terminus of the Trans-Alaska oil pipeline, so there is already substantial local infrastructure, but the costs will not be minor.

Projects in the Lower 48 are very different. Most of the proposed export projects are at developed sites—sites that were originally developed or partially developed, as LNG import projects. Because of this, they tend not to be in remote areas, and tend to be close to existing gas pipeline systems. Local labor and infrastructure are already in place. In some cases, all that is lacking is a liquefaction plant.

Asian LNG formulas are the "classic" selling arrangements for LNG. In general, these contracts take the form of:

LNG Price (per mmBtu) = A x Crude Price ($/bbl) + B

where "B" is simply a constant. "A" is called the "slope," and is a percentage of the crude price. But since crude is priced in barrels, the slope also needs to convert to a price per mmBtu. This is usually achieved by adopting a nominal heat content for crude oil of 5.8 mmBtu/bbl (even though particular crudes may differ). Therefore, the price of crude in $/mmBtu is:

Crude Price (per mmBtu) = Crude Price ($/bbl) x (1/5.8)

The fraction 1/5.8 is 0.172, or 17.2%. Therefore—ignoring any constant C—if the slope were 17.2%, the price of LNG would be exactly the price of crude.

Of course, buyers do not want to pay crude prices for LNG; for many, the whole point of buying LNG is that it is cheaper than crude. Therefore the slope is usually well below 17.2%. When the market is weak, slopes may slide into the single digits. Recently, with a tight market in the wake of Fukushima, slopes for new contracts in Asia have generally been in the 14-15% range—meaning that the price (once again ignoring any constant) is 81-87% of the price of crude oil...in mmBtu.

Much LNG is sold for on a landed ("DES," delivered ex-ship—similar to what is usually called CIF) basis, as the LNG tankers are often part of the project. To keep things on a comparable footing across projects, however, in this study we are looking entirely at FOB prices. (It is doubtful whether most sellers would offer DES contracts to Hawaii in any case, as the deliveries would have to be on ships much smaller than the long-haul tankers owned by most large export projects.)

Indexation to crude is not inevitable, but in the case of the Australian and Canadian projects, various spokespeople have made it clear that oil-indexation is assumed in their calculation of the economics. Although Alaska has not made formal pronouncements on the topic, the prefeasibility study for the Alaska Gas Pipeline Authority (AGPA) assumed oil-indexations, and considered slopes higher than those seen today (up to 16%).

Of course, the question inevitably arises, which crude price? Since Indonesia is an exporter of both crude oil and LNG, it indexes its LNG to its own basket of crudes, the Indonesian Crude Price (ICP). In Europe, Brent crude is often included in formulas (as are oil products like fuel oil or diesel). But to avoid possible market manipulation, the crude price used in Asia is typically the Japanese Custom Cleared (JCC) price, which is the average price of crude delivered to Japan. Since Japan is such a large buyer, and imports from so many different sources, the JCC is a good estimate of the "world crude price."

Therefore, to forecast LNG prices for oil-linked contracts, it is necessary to forecast the JCC. FGE forecasts the JCC on an ongoing basis.

Unfortunately, EIA does not have a JCC forecast to accompany its US product price forecasts. The closest EIA comes to an external market forecast on an annual basis is the US crude import price—in effect, the "USCC price." This is generally lower than the JCC (partly because most Japanese imports travel greater distances), but the difference is not wide. Since 2003, the JCC price has been about 4.2% higher than the US average import price. This percentage has been applied to the EIA forecast of US average import prices to develop the series shown alongside the FGE forecast in the chart below.

Figure 35: Projected JCC Crude Prices (2012 $)

	FGE $/bbl	EIA $/bbl	FGE $/mmBtu*	EIA $/mmBtu*
2015	$ 106.73	$ 123.51	$ 18.40	$ 21.29
2020	$ 115.98	$ 125.43	$ 20.00	$ 21.63
2025	$ 120.68	$ 131.35	$ 20.81	$ 22.65
2030	$ 120.54	$ 137.10	$ 20.78	$ 23.64

*at nominal 5.8 mmBtu/bbl

2.1.2.2. *Australia*

By the end of this decade, Australia will surpass Qatar as the world's single-largest LNG export country. Today, Australia has only three operating LNG export projects that represent a combined nameplate capacity of ~25 mmtpa. However, Australia currently has seven LNG projects under construction, all of which are targeting startup around the middle to the end of this decade. These projects will add almost 62 mmtpa of nameplate export capacity to Australia's books, which exceeds Qatar's installed 77 mmtpa of liquefaction capacity by a fair margin. In addition, there is approximately 124 mmtpa of planned export capacity under development. Some of this capacity entails the expansion of existing facilities or plants currently under construction, and (assuming all the other criteria to ensure the successful execution of a brownfield LNG project are met) will therefore be easier and cheaper to implement than competing greenfield ventures. There is little doubt that Australia as an LNG export province faces challenges. These challenges have already affected the development of projects under construction and could contribute to the demise of less-competitive planned ventures. Nevertheless, FGE maintains that Australia will be this decade's dominant LNG producer.

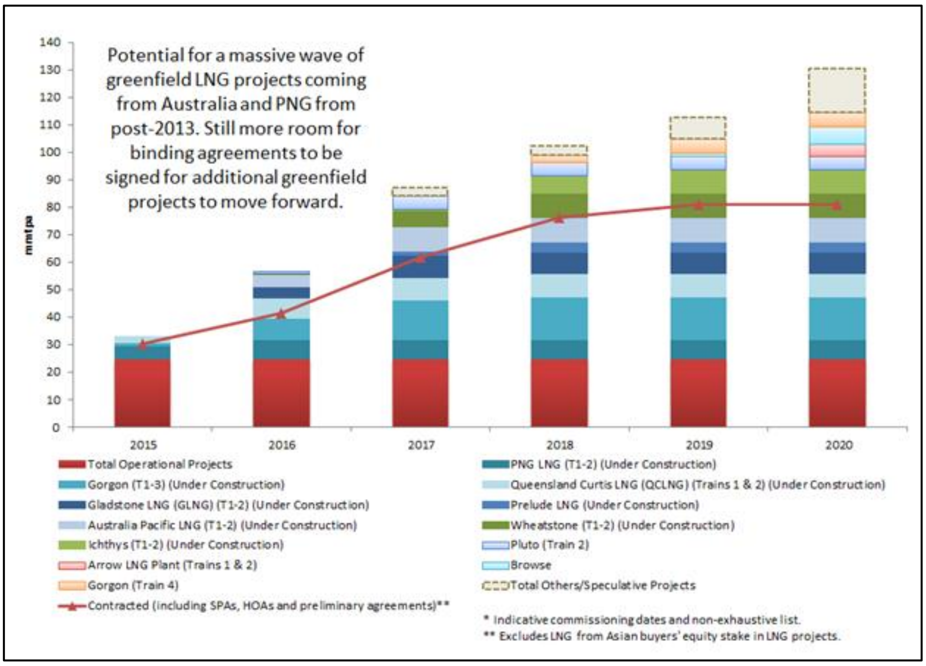
The vast majority of Australia's LNG export capacity is—and will continue to be—located in northern/northwestern Australia. This region of the country is known for its vast quantities of conventional gas resources. Existing Australian projects comprise of the Northwest Shelf venture in the state of Western Australia, which has been operating since 1989; the relatively nearby Pluto project, which began flowing in 2011, after about a year's delay; and the Darwin LNG project in the Northern Territory, which exported its first cargo in 2006. All these projects are fully committed to buyers East of Suez. In the case of NWS and to a lesser extent Pluto, recent long-term sales have been limited by access to feedgas. The region will host no less than four more projects within five years, for a total of around 37 mmtpa: Gorgon (15 mmtpa), Ichthys (8.4 mmtpa), Prelude (3.6 mmtpa), and Wheatstone (8.9 mmtpa). However, eastern

Australia will emerge as the nation's third LNG export hub around the middle of this decade. Several companies have sought to exploit the rich coal seam gas reserves of the northeast Australian state of Queensland, and to date, three projects are under construction. They are Australia Pacific LNG (9 mmtpa), Gladstone LNG (7.8 mmtpa), and Queensland Curtis LNG (8.5 mmtpa). These three projects, which represent a total of around 25 mmtpa of liquefaction capacity, are located quite close to each other and will largely operate out of the established Queensland port town of Gladstone.

All of Australia's existing projects, and most of the projects currently under construction, have been fully committed to other buyers. Given Australia's expensive operating environment, long-term SPAs with grade-A buyers for the lion's share of each project's capacity are especially crucial for reaching an affirmative final investment decision. Australia's coal seam gas-based projects have virtually no uncommitted capacity. APLNG, GLNG, and QCLNG are therefore not in a position to supply Hawaii with LNG unless expansions are sanctioned. This is somewhat unfortunate, as eastern Australia is closer to Hawaii in terms of shipping distance than northern/northwest Australia. By contrast, there is some uncontracted capacity at projects in northern/northwest Australia. For example, global LNG traders like Total and BP have access to volumes from the Ichthys and Gorgon projects respectively, whereas the Wheatstone project has some available supply. (Wheatstone's supply availability is attributable to a Korean company's fairly recent decision not to follow through with purchase plans from the project.)

There is also a string of planned LNG projects in various stages of development all over the country. Some of these projects entail the expansion of existing ventures or projects under construction. For example, Pluto, Gorgon, QCLNG, and Wheatstone all have fairly long-standing expansion plans. Then there are various greenfield projects sponsored by companies with highly variable LNG project experience and financial strength. Some of these projects are fairly advanced; others, distinctly less so. They range from the technically challenging and expensive Browse LNG venture in western Australia, which is seeking a 2019 startup date, to the coal seam gas-based LNG Newcastle venture in the eastern Australian state of New South Wales. Including expansions to existing projects, there are no less than 20 'planned' Australian LNG export initiatives in the works, for a total of some 124 mmtpa. There are no firm sales agreements underpinning any of these ventures.

Figure 36: Projected Australian LNG Exports vs Contracted Supply



It is, of course, exceedingly unlikely that all these projects will proceed: some projects lack feedgas or experienced developers; face technical/environmental challenges; or are excessively expensive to develop, to name but a few reasons. FGE believes Australia will export over 100 mmtpa of LNG by 2020. Costs are probably the biggest challenge for existing and future ventures. Australia has always been known as a high-cost LNG producing province, owing to factors such as a highly skilled and consequently well-remunerated workforce and a small national population that presents significant manpower constraints. Australia's high-cost environment has been exacerbated by the appreciation of the Australian dollar as well as the sheer number of mining and energy projects currently under construction simultaneously, all of which are fiercely competing for raw materials and skilled workers. As a result, capital costs for Australian LNG projects have increased dramatically and project completion schedules have slipped. The single-train Pluto project, for example, was expected to cost A$11.2 billion to develop but came in about a year late at A$14.9 billion. Estimates for cost over-runs at the A$43 billion Gorgon venture will be announced by the end of 2012, but speculation is already rife that the project has slipped behind schedule. Cost over-runs have also been reported at eastern Australian CSG projects: for example, QCLNG raised the capital cost estimate for its project by A$4.8 billion in early 2012. The project was sanctioned as recently as November 2010. It is logical to assume that any subsequent Australian projects that make an affirmative FID in the short to medium term will face similar challenges. Australia's high-cost environment also makes it all but inevitable that Australian LNG developers will insist on oil-indexed sales to ensure the desired rates of return on their investments. The upshot is, is that Australia will certainly have LNG available for purchase by Hawaii; the question is, whether Hawaii is willing to pay Australia's price.

2.1.2.3. *British Columbia*

Alaska is not the only far north Pacific Rim province with LNG export ambitions. A number of Canadian entities have also floated plans for LNG export capacity in the region. This capacity is based on the promising unconventional gas deposits of British Columbia and Alberta: namely, the Horn River, Cordova Embayment, Liard, Doig, and liquids-rich Montney tight gas/shale plays. There are no less than seven planned LNG export projects, but since only a few projects have provided details of desired send-out capacity, it is exceedingly likely that total planned capacity is much greater than the ~55 mmtpa outlined in the table below. Almost all these projects are sponsored by companies with not only significant upstream Canadian shale gas assets, but also (in some cases) companies with a well-established role in the LNG business. The strength of the various project sponsors will undoubtedly affect these projects' prospects for success. However, each project also faces common challenges: namely, the sheer remoteness of the shale plays; the potentially high break-even costs for producing the gas; a comparative lack of gas delivery infrastructure; and of course, high development costs.

Figure 37: Planned Canadian LNG Export Ventures

Project	Nameplate Capacity (mmtpa)	Sponsor	Sponsor's Start-Up Date	Status	Comments
Kitimat LNG	11	Apache, EOG, EnCana	Formerly 2017	Planned	Government export approval granted. Kitimat LNG no longer has a firm date for completing the export terminal. In theory, it could be ready 4½ years after a final investment decision is made. The company has stopped saying when it will make that decision.
BC LNG	1.8	Douglas Channel Energy Partners (DCEP)	2014	Planned	Government export approval granted.
LNG Canada	24	Shell, Korea Gas, Mitsubishi, and PetroChina	2019-2022	Planned	LNG export application lodged.
TBD	7.4	Progress Energy/Petronas	~2020	Planned	Setback resulting from Ottawa's October 2012 decision to block Petronas' C$5.17 billion (US$5.18 billion) bid for Progress after Industry Minister Christian Paradis said it was unlikely to bring a "net benefit" to the country.
Prince Rupert LNG	TBD	BG	2020	Planned	BG has signed a Project Development Agreement with Spectra Energy Corp for a new natural gas transportation system from northeast BC to Prince Rupert. The approximately 850-kilometer (525 mile), large diameter natural gas transportation system will begin in northeast B.C. and end at BG Group's potential LNG export facility in Prince Rupert. Capacity is 4.2 bcf/d.
Nexen/INPEX	TBD	TBD	TBD	Planned	No specific plans yet.
TBD	11	Imperial Oil (75%-owned by XOM) and XOM	TBD	Planned	Imperial, when combined with parent ExxonMobil Corp., has dibs on 340,000 hectares in the Horn River. There's also scope for more feedgas availability: Exxon Mobil Canada made in October 2012 a C$3.1 billion (US$3.15 billion) offer for gas-weighted Canadian junior Celtic Energy in seeming preparation for an LNG export bid, probably located around Kitimat.

The first project to emerge was the Kitimat LNG project near Bish Cove in British Columbia. Formerly licensed as an LNG import terminal, project sponsor Galveston LNG subsequently sold the project to companies with significant shale gas assets that hoped to capitalize on the twin attributes of existing LNG project engineering work for the site and evidence of a growing Asian appetite for LNG from new suppliers. Kitimat LNG was joined by six other companies in fairly short order. Today, Kitimat LNG remains the most advanced project in the development queue thanks to the completion of front end engineering and design work for the terminal and associated 463-kilometer pipeline, as well as at least a few years of sustained marketing efforts. The company has also received approval from the Canadian National Energy Board to export LNG produced at Kitimat. (Indeed, the National Energy Board's ready approval of LNG sales from Kitimat LNG and its much smaller and less-credible rival, BC LNG, suggests something of an advantage compared to the US, where the question of LNG exports to countries with which the US lacks a free trade agreement remains contentious.)

Although most of Canada's LNG export projects are based on what appear to be sound gas reserves and backed by experienced players, cost—and the consequently, the competition posed by developers in the US—remain significant barriers to entry. US shale gas production is much more advanced than Canada's, and—especially in regions with rich liquids deposits—generally has a lower break-even cost. Broadly speaking, there is also a need merely to expand gas processing and takeaway infrastructure in the US, whereas shale basins in Canada will require significant investments in new midstream infrastructure to monetize the gas. Moreover, several planned shale-based US LNG export projects will utilize existing LNG import infrastructure, thereby significantly reducing capital expenditure costs. By contrast, Canada must build western liquefaction plants from scratch. Finally, the US' willingness to sell LNG on a Henry Hub basis renders it very attractive to prospective buyers.

In order to circumvent the challenges of more costly upstream and liquefaction development costs, virtually all Canadian LNG export consortia have resolved to index LNG sales to crude oil. The need for oil indexation is all the greater considering the local AECO-C hub's historic discount to Henry Hub, rendering local hub-based pricing for Canadian shale gas production and LNG sales even more impractical. However, this approach has not been received kindly by prospective Asia Pacific LNG buyers. Given the significant disconnect between world oil prices and hub-indexed gas prices in North America and northwestern Europe, Far East LNG buyers are agitating for the inclusion of hub indexation on future LNG supply contracts, rather than 100% crude oil indexation. It seems that US LNG sellers' willingness to adopt Henry Hub indexation for LNG sales has helped stall marketing initiatives for more advanced Canadian players like Kitimat LNG. It remains to be seen whether Canadian LNG sellers can overcome these not-insignificant barriers to entry, and secure Asia Pacific LNG market shares after 2015 and into the early 2020s, as currently hoped.

2.1.2.4. *Alaska*

Alaska has long been an LNG exporter. The 1.5 million tpa Kenai LNG plant started operations in 1969, and continued to ship LNG to Japan until the plant was idled in November 2011 because of gas feedstock shortages and problems acquiring shipping contracts. The plant reopened in February 2012. However, its license to operate expires in 2013, and there is doubt whether there is enough gas to keep the plant running.

Kenai LNG is located on the Cook Inlet in southern Alaska, near the Cook Inlet oil and gas fields. The Cook Inlet fields are small and declining; almost all of Alaska's hydrocarbon reserves are on the North Slope, up on Alaska's Arctic shore.

The North Slope oil reserves were tapped in the 1970s with the completion of the Trans-Alaska Pipeline. Since that time, there has been mounting pressure to build an equivalent gas pipeline along the same general route. From the State's point of view, this would offer not only increased revenues, but would also supply cheap gas to cities all down the route (including Fairbanks). One of the major plans was to tie Alaskan gas into the Canadian (Alberta) pipeline system and deliver more gas to the Lower 48; other plans considered building a "Y" pipeline that ties into both Alberta and the existing Alaskan oil export center at Valdez. The price tag for such a line was tentatively set at US$41 billion.

With the gas glut in North America, the attraction of delivering gas to Alberta has waned. There are now proposals for a pipeline only to Valdez, the proposed site of a new LNG export facility; the preliminary costs for that are estimated at US$26 billion.

The Alaska Gasline Inducement Act (AGIA) of 2007 offers up to US$500 million in State seed money to pipeline developers. The contract and incentives were awarded to TransCanada, who has been joined by ExxonMobil. (There was also another pipeline proposed by ConocoPhillips and BP, but that proposal has been shelved.)

The major promoter of the LNG project is the Alaska Gasline Port Authority (AGPA). AGPA has applied to USDOE for export authority (see the section below on gas-linked projects for more on the issue of DOE export licenses).

The overall project, if it is built, will be staggeringly expensive. Costs of US$45-65 billion, in addition to the pipeline, are being quoted, bringing the anticipated price tag to US$71-91 billion. Many analysts are privately beginning to refer to the project as a US$100 billion proposition.

If the go-ahead were given today, it is generally estimated that the construction time would be at least ten years, so the earliest LNG would be available from the project would be 2022. Most analysts consider 2022 quite optimistic; a straw poll saw likely onstream dates of 2025 to post-2030.

If these costs are correct, the AGPA LNG project will require oil indexation—and probably a somewhat higher slope than Australian or Canadian projects presently on the books. For purposes of this study, we have assumed initial contract slopes of 15% in 2022, declining to more-typical levels of 14.85% by the middle of the 2020s.

From a practical point of view, Alaska is not a near-term prospect for LNG supplies to Hawaii. In the longer term, however, it might provide options for diversification of supply or spot cargoes.

2.1.2.5. *Price Forecast for Oil-Linked Supply Sources*

The chart below shows the derived FOB prices for oil-indexed suppliers based on our two JCC forecasts. Prices are shown starting with the earliest possible year of availability. Because the timing and slopes for the Australian and Canadian projects are the same, the FOB prices are close, although our slopes assume that Canada will be under somewhat more competitive pressure. Of course, the FOB costs are only one element in the price build-up for delivery to Hawaii.

Figure 38: Projected FOB LNG Prices for Oil-Linked Contacts (2012 US$/mmBtu)

	FGE JCC Prices			EIA JCC Prices		
	Alaska	Australia	Canada	Alaska	Australia	Canada
2015	na	$ 15.85	na	na	$ 18.34	na
2020	na	$ 16.01	$ 15.66	na	$ 17.31	$ 16.93
2025	$ 17.92	$ 16.65	$ 16.29	$ 19.51	$ 18.13	$ 17.73
2030	$ 17.90	$ 16.63	$ 16.27	$ 20.36	$ 18.92	$ 18.51

2.1.2.6. *Gas-Linked FOB Prices*

The US Natural Gas Act (which is based on legislation dating back to 1938) requires Department of Energy authorization for any import or export of natural gas from the United States. The language is quite broad, requiring that any allowed trade be deemed in the public interest. This effectively makes US international trade in natural gas a political decision.

However, the Energy Policy Act of 1992 amended the Natural Gas Act to specify that any exports of natural gas to countries with a US Free Trade Agreement (FTA) should be deemed to be in the public interest. In other words, for countries where the US has a Free Trade Agreement that extends to gas, the DOE must approve the exports, and the application for export is a rubber-stamp process.

The list of FTA countries is quirky: Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Singapore, and South Korea. (Costa Rica and Israel have FTAs with the US that do not apply to gas.) Many major US trade partners are conspicuously absent from the list; and some on the list are either existing LNG exporters (Australia, Oman and Peru) or have LNG export projects under development (Canada and Columbia). Others are small countries where LNG imports are either unlikely or are likely to be small in volume. The only major LNG importer on the FTA list is South Korea. Because of this, the non-FTA export license is prized by US LNG export project developers.

FTA export authorization is exceedingly easy to obtain, since sales to FTA nations are automatically deemed to be in the public interest. As such, applications to export LNG to FTA countries must be granted without modification or delay. However, non-FTA export authorization is much more difficult to come by. It is required by federal statute to separately review petitions for exports to non-FTA countries with which trade is not prohibited by US law or policy, and determine if they are consistent with the public interest. To date, DOE has rubber-stamped a number of applications for LNG exports to FTA countries, but has approved only one application for exports to non-FTA (the Cheniere LNG project at Sabine Pass). At least fifteen additional projects have applied, but no decision has been made by the DOE. A major report on the macroeconomic impacts of LNG exports was commissioned by the DOE and was released in early December 2012. The report was favorable towards the net economic benefit of LNG exports and is expected to play a role in policy making in the early part of 2013.

The decision is political in nature. President Barack Obama is believed to be receptive to the concept of US LNG exports, but it is generally considered likely he would support some constraints on the level of exports, at least until the impact of exports on US consumers is clarified. A victory for former Governor Mitt Romney, on the other hand, would probably have resulted in unfettered approval for all projects, with market conditions being the final arbiter.

If non-FTA approval is not forthcoming, this won't mean the end of US LNG projects, but it would put a tight cap on them.

Of course, no one in the US needs any sort of DOE approval to export LNG to Hawaii, as that is interstate trade. And, although a few years ago many would have scoffed at the idea of an LNG plant dedicated to serving Hawaii (or perhaps Hawaii and some FTA partners), small-to-midscale LNG is a growing business.

The LNG projects in the Lower 48 are not tied to the development of gas fields. This means that the promoters of the liquefaction projects do not need to achieve a return to the gas project. This is why so many of them have chosen to take an approach based on an independent gas price plus a fee. When someone signs a contract with such a project, they essentially lock in a guaranteed rate of return on the capital investment, irrespective of what happens to gas prices. These arrangements are called "tolling projects."

Most Lower 48 projects have no exposure to the financial results of gas production and pipelining. Their exposure is limited to investment in the liquefaction plant. The project investors can afford to sell at "Henry Hub + C" and still make solid, guaranteed profits.

This does not mean that project developers or their primary buyers will be willing to sell at "Henry Hub + C," or even at "Henry Hub + C + P," where P is a reasonable additional mark-up. The market being what it is, there is no real reason that someone in control of a needed volume of LNG should not sell it only for the highest price they can get.

The only constraint on this behavior is the possibility that the buyer could arrange for cheaper prices from another project—or launch a project of their own.

As mentioned above, Cheniere's Sabine Pass is the only project that has been approved for non-FTA exports. The project, which was sold out before construction began (as is commonly the case with LNG), was relatively frank about the terms of its pricing contract: the offtakers pay 115% of Henry Hub (the extra 15% accounts for the use of gas in the liquefaction process) plus a tolling fee of US$2.25-$3/mmBtu. But there has been some discussion of a very different formulation for its proposed Corpus Christi facility. This might reflect higher costs, but it also might reflect a new assessment of what the market will bear.

2.1.2.7. *Henry Hub Price Forecasts*

Projections of future gas prices in the US cover a wide range. Many oil and gas companies are now insisting that prices are likely to stick at US$4/mmBtu indefinitely. There are plenty of Henry Hub forecasts available, but some of these are generated by groups with their own agendas.

Fortunately, there are also published forecasts by public agencies. The EIA, of course, revises its Henry Hub forecast annually. Another carefully thought-through forecast is produced by the Northwest Power and Conservation Council (NPCC, formerly the Northwest Power Planning Council). The NPCC forecast, unlike EIA's, has Low, Medium, and High scenarios (and also has Medium-Low and Medium-High versions). These forecasts are shown in the figure below.

Figure 39: NPCC and EIA Henry Hub Forecasts (2012 US$/mmBtu)

	NPCC			EIA
	Low	Med	High	EIA
2012	$ 2.50	$ 2.70	$ 2.81	$ 3.58
2015	$ 3.85	$ 4.89	$ 6.03	$ 4.46
2020	$ 3.74	$ 5.82	$ 7.80	$ 4.76
2025	$ 3.64	$ 6.34	$ 8.94	$ 5.86
2030	$ 3.54	$ 7.07	$ 10.40	$ 6.54

The NPCC's Medium scenario is quite similar to EIA's outlook, although they have quite different opinions of 2012. NPCC's Low scenario is very similar to what many oil and gas companies are saying privately. NPCC's High forecast is one of the highest anywhere. Together these three forecasts cover the whole range of outcomes envisioned by almost any energy analysts.

Since the NPCC Medium forecast and the EIA forecast are so close by 2015 and beyond, we have adopted the EIA forecast as our Base Case for this study. The NPCC Low and High forecasts are employed as needed to bracket the results, but, to avoid "scenario blindness," the main text of the report concentrates on the Base Case.

2.1.2.8. *Liquefaction Costs in the Lower 48*

The cost of liquefaction projects is baffling. A look at the long-term, worldwide trend showed project costs falling steadily from around US$700/tpa in 1980 to a low of around US$300/tpa around 2003. Then the curve suddenly slants steeply upward: By 2010, typical costs were around US$375-575/tpa, and many new projects are being priced out at well over US$1,000/tpa; in the case of Australian projects and Alaska LNG, the costs are even higher.

Some of these are genuine cost increases that reflect factors such as a shortage of LNG engineering and skilled labor, higher steel prices, and more costly project financing after 2008. Some of it reflects the problems of megaprojects in remote locations, where basic infrastructure is not available.

The situation is quite different in the Lower 48, as the table below shows. At present, the most expensive project on the books is Cheniere's Corpus Christi plant, at nearly US$800/tpa; the cheapest is Excelerate's Phase II expansion, followed closely by Dominion Cove, both at around US$250/tpa.

Figure 40: Projected Capital Costs for US LNG Projects

	Cost, billion $	Capacity mmtpa	Cost, $/tpa	State	Project Type
Dominion Cove	$ 2.00	7.80	256	Maryland	Conversion
Excelerate II	$ 1.21	4.00	301	Texas	Floating
Freeport	$ 4.00	13.20	303	Texas	Conversion
Cameron	$ 6.00	12.00	500	Louisiana	Conversion
Excelerate I /1	$ 2.15	4.00	536	Texas	Floating
Jordan Cove /2	$ 5.00	9.00	556	Oregon	Greenfield
Sabine Pass /3	$ 5.60	9.00	622	Louisiana	Conversion
Golden Pass	$ 10.00	15.60	641	Texas	Conversion
OLNG /4	$ 6.30	9.60	656	Oregon	Greenfield
Boron	$ 0.08	0.11	708	California	Greenfield
Corpus Christi	$ 11.60	15.00	773	Texas	Greenfield

/1 Includes 27 mile gas pipeline
/2 Includes 223 mile gas pipeline
/3 First two trains only
/4 Includes 86 mile gas pipeline, bidirectional terminal, and peak-shaving.

The numbers need to be treated with some caution. Of all these projects, only the tiny Boron project in California (105,000 tpa) has actually been completed. Some might claim that this plant might be more expensive if it were completed today, but interviews with companies currently building small-to-medium LNG plants suggests that the costs have settled under US$700/tpa.

Sabine Pass will start construction in 2013; the other export projects are still on the drawing boards. There is ample opportunity for cost increases as the projects near construction.

To keep things in perspective, it should be noted that there are also more than 60 mid-sized liquefaction facilities in the US that have been operating for many years—in some cases, for decades. These are mostly "peak-shaving" facilities, designed to store gas for gas utilities, or for electric utilities burning gas for peaking purposes. The surplus of gas has made many of these plants less critical to utility gas supply. The capital costs of these plants are spread over so many years that they are not informative—but the number of existing liquefaction plants in the US should make it clear that this is not an untried or speculative technology.

There is no real risk that the prices shown in the previous table will rise to the stratospheric heights quoted in Australia and Alaska. All of the US projects listed will be receiving pipeline gas rather than investing in developing gas fields, though three of them will have to build sizeable spur lines to hook their projects into the gas grid.

Moreover, of the eleven projects for which we have data, almost half of them (five) are conversions of existing LNG import terminals. (Sabine Pass itself is one of these.) The average cost for conversion projects is US$465/tpa—but Sabine Pass has now settled on US$622/tpa, which suggests that some of the other projects may be a bit over optimistic.

Greenfield projects, which require construction of port facilities, power plants, storage, and in some cases long feedstock pipelines, are naturally more expensive. The average cost of these projects is calculated at US$673/tpa; again, this may prove over optimistic.

The Excelerate LNG project is a two-phase proposal for an offshore LNG plant. The first phase is the most expensive, as the second phase can piggyback on much of the infrastructure built for Phase I. Excelerate is a specialist in offshore LNG storage and regasification, with several operating projects around the world. However, this is their first venture into LNG production. They are firm believers in the offshore option, partly because of flexibility in siting, and partly because of timing: construction time for offshore LNG is estimated to be 44 months. The costs are presently estimated at around US$419/tpa, which is far less expensive than any other greenfield project. Even if these costs are quite over optimistic, there is room for them to double without exceeding estimated costs for the Corpus Christi greenfield plant by much.

2.1.2.9. *Liquefaction Charges for the Lower 48*

A simple but flexible FGE cash flow model was used to determine real (2012$) levelized liquefaction costs. Inflation was assumed to be 2% per annum, interest on loans to be 10% per annum, and the required IRR on equity was set at 15%. The Debt:Equity ratio used was 70:30, and interest was capitalized until project start-up, with full repayment eight years after start-up. Operating costs were taken at US$0.85/mmBtu. Any cashflow shortages were also capitalized and rolled to the next period.

Given the uncertainties surrounding capital costs, we adopted three investment levels: US$700/tpa, US$1,000/tpa, and US$1,300/tpa. This not only accommodates any over optimism on the part of projects in the previous table, but also allows for the possibility that a dedicated plant might be designed to supply Hawaii, in which case the economies of scale suggest per-unit capital costs might be considerably higher.

The levelized costs per mmBtu corresponding to the three investment levels round off to US$2.70, US$3.50, and US$4.30, respectively. As a "reasonability check," the US$700/tpa figure of US$2.70/mmBtu can be compared to the contracts signed by Sabine Pass; with a capital cost of US$622/mmBtu, Sabine Pass signed initial contracts with fees of US$2.25/mmBtu, and signed its last contracts at US$3/mmBtu.

As another reference point, a study commissioned for the hugely expensive Alaska Gasline LNG project puts the liquefaction cost of the project at about US$4/mmBtu. If the Alaskan project is ever built, it may take the prize for the most expensive project ever, but it is not because of the capital costs of liquefaction.

2.1.2.10. *LNG Costs FOB Lower 48 Versus JCC-Linked Prices*

With liquefaction cost ranges, we can now assess FOB prices in the Lower 48 under the various scenarios of Henry Hub prices and capital costs, compared to projected Pacific Rim prices based on JCC. The results are shown in the table below.

Figure 41: LNG FOB Prices in the Base Cases (US$/mmBtu)

FGE Oil Prices

	2015	2020	2025	2030
Alaska	na	na	$ 17.92	$ 17.90
Australia	$ 15.85	$ 16.01	$ 16.65	$ 16.63
Canada	na	$ 15.66	$ 16.29	$ 16.27
US Gulf Coast	$ 8.63	$ 8.98	$ 10.23	$ 11.02
US West Coast	na	$ 8.98	$ 10.23	$ 11.02

EIA-Derived Oil Prices

	2015	2020	2025	2030
Alaska	na	na	$ 19.51	$ 20.36
Australia	$ 18.34	$ 17.31	$ 18.13	$ 18.92
Canada	na	$ 16.93	$ 17.73	$ 18.51
US Gulf Coast	$ 8.63	$ 8.98	$ 10.23	$ 11.02
US West Coast	na	$ 8.98	$ 10.23	$ 11.02

Since the EIA oil-price forecast is higher than FGE's, the JCC-linked prices in Alaska, Australia, and Canada rise until by 2030, the projected EIA-based LNG price is about US$2.25-2.50/mmBtu higher than the FGE prices.

Even more striking, though, is the gap between the oil-based prices in Alaska, Australia, and Canada, and the gas-linked prices in the US Gulf and the US West Coast. The oil-linked FOB prices are from about 50-85% higher than the FOB prices in the Lower 48. This is a massive difference.

What does all this mean? Simply put, in most cases US LNG from the Lower 48 is likely to have a huge cost advantage over JCC-linked prices around the Pacific Rim. Even in the worst-case scenario (discussed later), with sharp increases in US gas prices, LNG sold FOB from the US West or Gulf Coasts will still have a string cost advantage over oil-based prices.

In the coming months, more will be known about LNG availability from the Lower 48. Once DOE's policy on LNG exports is clear, there will probably be many opportunities to negotiate supply contracts.

Yet we must repeat: The LNG business is not a supermarket. LNG buyers who get decent prices strike their deals before the projects are finalized; they do not wander the aisles looking at price tags.

In the case of Hawaii, volumes might be sourced from projects built for other purposes (such as local supply or peak-shaving); or the solutions may include purpose-built plants dedicated to supplying Hawaii. Although initially it might seem improbable that anyone would build a project to meet such a relatively small annual demand, smaller scale has its advantages. Deep draft harbors are not needed, and the footprint of the project would be far smaller than the 6-15 mmtpa export projects around the region. Indeed, small floating LNG plants, scaled down from projects like that proposed by Excelerate, are a real possibility.

Would someone invest the money to build such a project? The answer is certainly yes, and the number of possible sponsors is much larger than the number of companies that can develop major LNG export projects. The Boron LNG project in California was built by Clean Fuels Energy, a small California company, and the price tag was US$75 million. Compare that to the US$10 billion ExxonMobil is planning to spend on the Golden Pass project. There are many companies that can raise millions, but the list of companies that can raise billions is much shorter.

A US exporter to Hawaii is not an exporter at all, but is engaging in interstate trade. DOE approval is not needed, and the political issues around the exports are less contentious. For example, in Oregon, opponents of the LNG projects ask why new pipelines should be built, and virgin coastlines cleared, to support megaprojects shipping American energy to Asia. None of those objections would apply to a more modest project destined for Hawaii.

Whether supply is to be obtained from one of the new export projects, or repurposed existing facilities, or from a new, purpose-built project for Hawaii, a good price will require a proactive approach. In principle, the most promising sourcing options would be from the US West Coast. But even if the FOB sourcing were to be solved, there are still the issues of transport to Hawaii, and bringing the gas onshore.

2.1.3. LNG Transportation Costs to Hawaii

As discussed earlier, LNG projects traditionally move the liquefied gas between an export harbor and an import terminal via LNG tankers. Recently, however, the fastest-growing segment of the LNG trade has been the delivery of LNG via a tanker to an FSU (floating storage unit) or FSRU (floating storage and regasification unit), which allows LNG receiving terminals to be placed in service much more rapidly. In addition, new types of Articulated Tug and Barge (ATB) vessels are in advanced engineering design and expected to be active within a few years. Each of these modes of transport will be addressed in turn, but first the issue of the Jones Act must be examined.

2.1.3.1. *The Jones Act*

Any discussion of seaborne transport to Hawaii must begin by discussing the problem in context of the Jones Act. As most Hawaii residents know, the Jones Act requires any trade between two US ports to be carried on US-built, US-flagged vessels, and the crew must be three-quarters comprised of US merchant seamen.

It is often said that LNG movements between US ports is not possible because there are no US-built LNG carriers and no US shipyards capable of building them. This is something of an oversimplification. As the table below shows, there are still 13 US-built LNG carriers actively trading. (Two other US-built carriers have been scrapped, and one has been converted to a floating oil storage.) All of these carriers are now under non-US flags (most of them flags of convenience), but in principle these could be purchased and reflagged and used for US-to-US service.

Figure 42: US-Built LNG Carriers

Ship Name	Flag	DWT	Year
Galeomma	Singapore	63,460	1978
LNG Abuja	Bahamas	68,600	1980
LNG Aquarius	Indonesia	63,600	1977
LNG Aries	Marshall Islands	63,600	1977
LNG Capricorn	Marshall Islands	63,600	1978
LNG Delta	UK	63,460	1978
LNG Edo	Bahamas	68,600	1980
LNG Gemini	Marshall Islands	63,600	1978
LNG Leo	Marshall Islands	63,600	1978
LNG Libra	Marshall Islands	63,600	1979
LNG Taurus	Marshall Islands	63,600	1979
LNG Virgo	Marshall Islands	63,600	1979
Matthew	Norway	63,460	1979

This is not a likely solution for Hawaii, unfortunately, because of the size of the vessels. The deadweight tonnage (DWT) of these ships is probably too large to match Hawaii's import needs. The DWT of a ship is the weight of cargo and ship's stores it can bear. At 90% cargo loading, each LNG cargo from the ships listed above would deliver roughly 57,000 tonnes of LNG, and, for reasons of security of supply, at least two vessels would have to be engaged. From Alaska or the US West Coast, this would amount to deliveries of about 2.2 million tonnes of LNG annually, and even from the US Gulf Coast or Australia this hypothetical pair of ships would deliver nearly 1 million tonnes per year. The former is more volume than Hawaii is likely to need, and even the latter is certainly far more than could be accommodated in the near term. There are uncertainties about harborage for offloading ships of this size. The concept is not impossible—especially if the ships travel only partially laden—but it does raise many questions. (See the section on FSU/FSRU Options below for further discussion of this issue.)

No LNG carrier has been built in a US shipyard since 1980, and the consensus is that the necessary infrastructure and skills no longer exist. Therefore, the argument that no new US-built LNG carriers are a possibility at first seems irrefutable.

There is, however, an exception to this argument. The US Coast Guard has ruled that LNG barges, where the LNG containment vessels are not an integral part of the hull, are compliant with the Jones Act even if the containment vessels are manufactured outside the US. Such vessels have already been designed, and it appears likely that some will soon be built. As will be discussed below, such barges are a realistic option for delivering LNG to Hawaii without requiring any Jones Act waivers.

There is one final question raised by the Jones Act, and this relates to floating storage. It is not clear whether an FSU or FSRU would be classified as a "ship" under the Jones Act. There are specific rules for determining this under ship classifications, and local regulations may also apply.

Of course, it could be argued that an FSU/FSRU is not in fact *transporting* cargo or passengers between two US ports, but instead is storing and offloading cargo. In effect, such a vessel might be considered a part of a port facility rather than a means of transportation. It is difficult to predict how the Coast Guard or the courts would rule in such a case. This adds yet another unknown to the problem of a Hawaii LNG chain.

2.1.3.2. *Tanker Delivery Costs*

There are approximately 370 LNG tankers presently in service around the world, but only 7% of them are under 125,000 cubic meters (cbm, around 63,000 DWT). Based on the available fleet statistics, there are less than ten LNG tankers of less than 35,000 cbm—the size likely to be most useful for deliveries to Hawaii.

This situation may be changing, however. Although the trend has been toward larger and large ships, small "multi-gas" (LNG, ethylene, and LPG) carriers have been built at a size of around 7,500 cbm. There is a recognized need for transport of small LNG cargoes, and many solutions are on the drawing board (especially in East Asia and the Mediterranean)—but many in the industry seem to be looking to Articulated Tug and Barge systems (see below) as the solution for small LNG deliveries.

Chances are that LNG tankers to serve Hawaii would have to be built from scratch. As mentioned previously, this means that such ships will not comply with the Jones Act. In terms of our analysis, this means that without Jones Act waivers, these ships would be restricted to foreign imports. In the following, therefore, it must be kept in mind that transport costs from Alaska, the US West Coast, and the US Gulf Coast, all assume Jones Act waivers.

FGE's Shipping Rate Calculation Model was used to estimate delivery costs from the five candidate regions. All were calculated on the basis of 25,000 cbm tankers at estimated current charter rates. Charter rates of course fluctuate with time. In today's relatively tight LNG shipping market, charter rates for the smaller vessel classes appear to cover the costs of newbuilding.

The results of the analysis are shown in the figure below. The shipping costs from Australia and the US Gulf Coast are more than double the costs from the West Coast of North America—an unsurprising result, since the distances are more than twice as far.

Figure 43: LNG Tanker Shipping Costs

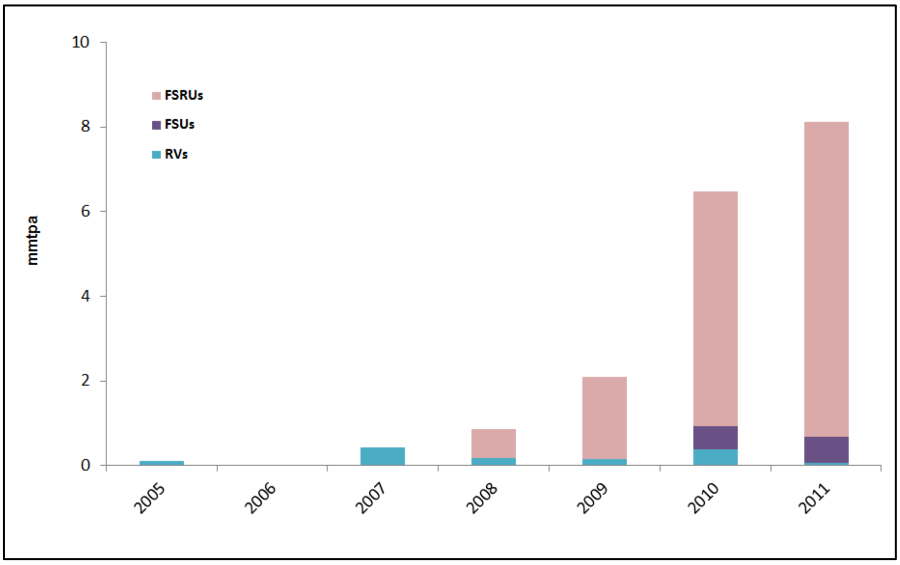
	Alaska* Valdez	Australia NW Shelf	Canada Kitimat	US West* Astoria	US Gulf** Sabine Pass
Distance, nm	2,462	5,840	2,350	2,246	6,100
Cost, $/mmBtu	$ 1.92	$ 4.03	$ 1.85	$ 1.78	$ 4.41

*requires Jones Act waiver
**requires Jones Act waiver; includes Panama Canal tolls

2.1.3.3. *FSU/FSRU Options*

Floating storage and regasification has many attractions. It avoids many siting problems; in most cases it appears to be substantially cheaper. One of the biggest reasons for adoption of floating import facilities, however, is timing; for sites with no LNG import infrastructure, adopting floating infrastructure can offer import capabilities in as little as a year, as compared to 3-5 years for conventional import terminals. As the figure below shows, the growth in floating import infrastructure (including dedicated regasification vessels, RVs) has been dramatic.

Figure 44: Worldwide Floating Import Infrastructure (mmtpa)



Floating infrastructure takes many forms. In some cases, the storage and/or regasification vessel is permanently moored at an onshore jetty; in others, offshore jetties are constructed and the gas or LNG is brought on by undersea pipeline. In a few cases, the storage vessel may be moored to the seafloor itself, well offshore.

Mooring offshore raises many issues. Obviously longer pipeline runs are needed, which may make offshore regasification a necessity, as long cryogenic pipelines are expensive—and largely untested. A bigger problem, especially for ships not moored to offshore jetties, is wave height. Ship-to-ship LNG transfer is a practical proposition, but wave heights and crest-to-crest distances make many people skeptical whether such a system would be reliable in the Hawaii environment.

Gasfin, an established LNG shipping company in the EU, has performed a preliminary analysis of supplying Oahu with LNG from Kitimat, British Columbia (for Jones Act compliance). The plan would feature two purpose-built 25,000 cbm LNG carriers and a 60,000 cbm FSRU. Gasfin estimates that the total delivery cost for this would be US$4/mmBtu—plus or minus 25% (in other words, US$3-5/mmBtu).

What Gasfin could not determine—and what cannot be determined without a major study—is whether there are suitable sites for mooring an FSRU and tying it into the onshore gas grid. It is also not clear if these less-conventional options would offer cost savings over standard onshore infrastructure.

Excelerate Energy has used an approach called a Submerged Turret Loading (STL) Buoy that is locked into the hull of the FSRU and connects to the undersea pipeline. Such a system was in operation for many years 116 miles offshore of Louisiana. As the company is proud to point out, it was the only import terminal to continue operating during Hurricane Katrina.

Excelerate also provides more conventional dockside ship-based regasification terminaling solutions called "GasPorts". Under this configuration, an FSRU moors at a jetty equipped with an articulated, high-pressure gas-offloading arm that sends gas from the FSRU to the nearby gas grid. The LNG is regasified aboard the FSRU itself. Excelerate has installed the system in two locations in Argentina, as well as single facilities in Kuwait and the United Kingdom.

Excelerate was kind enough to run preliminary estimates for delivery of LNG from our key destinations to Hawaii, using both their STL approach and their GasPort approach. Costs vary between about US$2/mmBtu up to over US$6/mmBtu. The higher costs apply to the STL option. Costs for the shore-jetty GasPort option range from US$2/mmBtu up to about US$4.50/mmBtu.

As mentioned earlier, there are questions about how effective the STL approach, which would site the facility well-offshore, would be in Hawaii under certain sea conditions.

There are a large number of uncertainties about the GasPort approach as well. There is no doubt that the concept is technically feasible and practical in many situations. The uncertainties come from the logistics and site selections in Hawaii for a large vessel to be moored directly to shore jetties. There are not that many sheltered shorefront sites on Oahu that could be sacrificed on a permanent basis. Excelerate has examined a possible permanent berth near the Waiau power plant at the tip of the East Loch of Pearl Harbor. It is not clear whether ship traffic restrictions would allow the desired deliveries, and the channel leading to the proposed mooring site and the mooring site itself might have to be dredged. It is a comparatively high distance from the main industrial district around Barber's Point (and from the Kahe power plant). In addition, it is close to a heavily populated area, with all the issues that population density entails.

Offshore storage and gasification along the model of the STL Buoy system may in fact be a poor idea for Hawaii, irrespective of delivery economics. Once the LNG gas re-assumes a gaseous form, many options become impractical. Yes, gas onshore on Oahu can feed power plants and existing HawaiiGas SNG customers, but it eliminates many of the other possible usages of LNG, such as road transport and marine bunkering. LNG may also be the best way to deliver gas for CNG filling stations.

Most important of all, however, offshore gasification seems to rule out moving LNG to the neighbor islands, making gas an Oahu-only proposition. There may be some sort of offshore option—such as an FSU moored directly to a jetty—that could avoid these limitations—but there is little real difference between LNG storage tied directly to shore and standard onshore storage.

This is an important point for all parties to understand: Choosing offshore gasification would be a major policy decision with far-reaching consequences.

This should not be confused with an approach like Excelerate's GasPort model, however. LNG can be offloaded to shore from a permanently moored vessel, and can also be offloaded on LNG barges or ISO containers. In fact, Argentina's Escobar GasPort, which was commissioned in June 2011, is being expanded into a "hub-and-spoke" site where the FSRU will offload LNG directly onto LNG barges and tanker trucks (as well as moving regasified LNG into pipelines).

Whether Excelerate's GasPort option would be practical given the siting issues on Oahu cannot be determined without detailed study; and given the possible needs to restrict vessel size or traffic, and for investment in harbors and dredging, it is not clear that it would enjoy economic advantages over an onshore terminal. Nonetheless, it is technically feasible and does not eliminate the option of bringing LNG onshore or moving it to the neighbor islands.

2.1.3.4. *Articulated Tug and Barge Options*

Articulated Tug and Barge (ATB) systems have been around for many years, and are widely employed in cargo and oil-product trades. Unlike traditional tug and barge systems, ATBs do not tow the barge, but instead lock into it from behind and push it from behind—as if the tugboat were a detachable engine. ATBs are used widely in coastal trade, but over the past two decades they have emerged as "blue water" ships, certified to withstand open ocean voyages.

Figure 45: The Brandywine: An Oil-Products ATB (courtesy Argent Marine)

ATBs are generally not as fast as traditional tankers, and they are more limited in what the Navy calls "endurance"—the distance that can be travelled without replenishing fuel and other ship stores. (It might seem as if an ATB carrying fuel would not have a problem in this regard, but so far the Coast Guard has ruled that the fuel for the tug needs to be located on the tug rather than on the barge.) An ATB can cross distances such as the US West Coast to Hawaii, but shipbuilders begin to blanch when distances much further are discussed. ATBs are therefore not at present a reasonable possibility for LNG imports from the US Gulf Coast or Australia.

ATBs do have some significant advantages, however. They are cheaper to operate; among other savings, they can operate with smaller crews. They are flexible; they do not need as much draft as a traditional tanker, and they can easily enter river systems and relatively shallow ports. They also have some special advantages of their own, such as “Drop and Swap,” where the tug drops off a full barge and picks up “the empty” to return for refueling. In such a system, the barge becomes a storage unit rather than merely a means of transport.

There are some other possible advantages specific to the United States. ATBs are generally cheaper to build than tankers of equivalent size. In the case of the US, the higher cost of US shipyards is more-or-less offset by the fact the ATB is a somewhat cheaper design. The result is that an American-built LNG ATB is expected to cost about the same as a foreign-built tanker of comparable size.

In addition, there are special federal loan guarantees for projects built in US shipyards, and there are often concessionary loans available from various sources.

To date, no LNG ATB has been built, but it is expected that there will be several on the water before 2015. The build time is also expected to be short (24-30 months), and the barge and tug can be built in entirely different shipyards.

A 30,000 cbm ATB LNG vessel is expected to cost about US$120 million. If we assume concessionary financing (6% interest, 10-year loan term, 70:30 Debt:Equity) and an IRR on equity of 15%, then the levelized return on capital investment need only be US$0.93-1.01/mmBtu. The operating costs, with a US crew on a small vessel, are not negligible however. Our estimate include insurance, taxes, maritime union wages and benefits, ship stores, fuel, and other detailed elements. As the table below shows, this raises the cost considerably.

Figure 46: Calculated Cost of LNG Delivery to Hawaii on 30,000 cbm ATB

	Alaska Valdez	Australia NW Shelf	Canada Kitimat	US West Astoria	US Gulf Sabine Pass
Distance, nm	2,462	5,840	2,350	2,246	6,100
Cost, $/mmBtu	$ 1.89	na*	$ 1.82	$ 1.74	na*

*Voyage exceeds ship endurance range.

Even with a hefty operating cost added in, however, the ATB costs are essentially the same as non-US tanker rates. In other words, in this analysis, the Jones Act has no real cost to the Hawaii consumer…as long as the LNG is sourced from Western North America.

2.1.4. LNG Import Terminal and Onshore Costs

If there is anything that is site-specific in terms of cost, it is an import terminal. A conventional LNG import terminal includes LNG storage, regasification facilities, short-run import pipelines, and variable-run pipelines to supply the gas to the main distribution network. Most of these costs can be estimated from other projects or engineering estimates. What is powerfully site-specific is the cost of the harbor facilities.

Harbor facilities include docking/mooring piers or jetties, discharge buoys connected to cryogenic pipelines, and a deep enough access channel to allow the vessel to arrive at the dock. If most of the harborage and docking already exists, it costs comparatively little to add LNG facilities. If, as is more often the case, there is water access to an existing port but new piers and moorage must be built, the cost is much greater; and if, as sometimes happens, new channels and mooring sites must be created by dredging and other geoengineering on top of other costs, the price can go very high indeed. Naturally, most onshore LNG terminals are sited at locations where natural conditions provide good harbor access, but not all projects have this luxury.

Ignoring the harbor problem for a moment, the biggest single onshore cost is usually the LNG storage tankage. Tankage enjoys strong economics of scale up to the maximum size (many of the mainland import terminals have several max-sized tanks). Smaller tanks cost more per tonne or gallon. (Storage is usually denominated in volume terms.) LNG in Hawaii would likely require 15-25 million gallons of storage—about one-third to one-half of the typical tank size at major import facilities.

Smaller tanks of this size are sometimes built. Tankage similar to the Boron plant in California has been estimated by the plant owner at US$5 per gallon. In addition, in May of 2012, DEPA of Greece released at tender for a 25 million gallon storage facility to be built for an estimated US$150 million. The DEPA project is at an existing site, and does not include elements other than storage; this gives a cost of just under US$6/gallon.

If we take 500 ktpa as the reference point, and assume a month storage capacity (around 25 million gallons), the cost at US$6/gallon comes to US$145 million (very similar to the DEPA project numbers). Based on past assessments done by FGE, we estimate that other onshore infrastructure, including piping, controls, buildings, and regasification, amount to about US$50 million.

The harborage is, of course, the great uncertainty. In the past, based on interviews, we have used a range of US$55-100 million for constructing a marine berth. Other recent estimates suggest a range of US$50-75 million. To ensure that we are being conservative, we selected an estimate of US$80 million, which gives total onshore investments of US$275 million.

Assuming that the investments are made by a utility, the required return is not assumed to be as high as that required by other investors in the LNG chain. We have calculated the required charge per mmBtu to give a pre-tax IRR on equity of 10%. Annual operating costs are taken at 6% of the total capital investment (a typical rate in the industry). At these levels, the onshore charges amount to US$2.38/mmBtu over a 20-year project life.

We also considered scenarios where onshore costs went as low as US$200 million (with smaller storage and somewhat cheaper marine berth costs) and as high as US$315 million (with considerably higher harborage costs). These assumptions can push the charge per mmBtu up or down somewhat, but they do not have a substantial effect on the overall analysis; other uncertainties are as large or larger.

2.1.5. Delivered Cost Build-Ups

There are only four major elements in the delivered cost build-up from sources with oil-linked pricing. The biggest, of course, is the FOB price, which tracks back to the projected JCC oil price.

The next is the costs of transport. This is not, however, merely the base charter rate discussed previously. After 2015, Hawaii will be an IMO ECA zone, and all fuels will have to be very low in sulfur. In our view, this means that LNG tankers or ATBs will all begin to burn LNG as their bunker fuel (some do already, and some burn a mixture of LNG and oil). Thus, we have taken the fuel component of the base transport cost and grown it by the increase in the price of LNG at the source. In general, this tends to increase real transport costs across time.

In addition, we have calculated the “boil-off” and added it to the transport cost (at the price of the FOB LNG loaded). This could be debated. Some ships (usually very large ones) recapture the boil-off and reliquefy it. Others route it to the ship engines. ATBs may not be able to do the latter; so far, rulings by the Coast Guard suggest that even ATBs burning LNG as their sole bunkers will not be able to route boil-off to their engines, but will need separate LNG fuel tanks. In any case, this is a small item; even in roundtrip from Australia, only 5% of the cargo will boil off.

Onshore costs are self-explanatory, but we have added the additional cost of gas burned off in regasification. This is estimated at 2%, and priced at the delivered, onshore cost. Ways of using "coolth" to add heat, the LNG could lower this cost, but, as before, the effect on the overall analysis is small.

The following figure gives the delivered costs of oil-linked LNG regasified on Oahu, based on the FGE oil-price forecast. The FOB price is a significant discount from international oil prices, but by the time delivery is included the advantage narrows.

Figure 47: Oil-Linked Price Build-Up Based on FGE Oil Prices

Alaska Delivery Build-Up, 2012 US$/mmBtu (FGE Prices)

	2015	2020	2025	2030
FOB Price	na	na	**$ 17.92**	**$ 17.90**
+ Transport & Boil-off	na	na	$ 2.37	$ 2.36
+ Onshore Costs	na	na	$ 2.38	$ 2.38
+ Regas Loss	na	na	$ 0.45	$ 0.45
= Delivered Cost	na	na	**$ 23.12**	**$ 23.10**

Australia Delivery Build-Up, 2012 US$/mmBtu (FGE Prices)

	2015	2020	2025	2030
FOB Price	**$ 15.85**	**$ 16.01**	**$ 16.65**	**$ 16.63**
+ Transport & Boil-off	**$ 4.82**	$ 4.85	$ 4.94	$ 4.94
+ Onshore Costs	**$ 2.38**	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	**$ 0.46**	$ 0.46	$ 0.48	$ 0.48
= Delivered Cost	**$ 23.51**	**$ 23.70**	**$ 24.46**	**$ 24.43**

Canada Delivery Build-Up, 2012 US$/mmBtu (FGE Prices)

	2015	2020	2025	2030
FOB Price	na	**$ 15.66**	**$ 16.29**	**$ 16.27**
+ Transport & Boil-off	na	$ 2.20	$ 2.24	$ 2.24
+ Onshore Costs	na	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	na	$ 0.40	$ 0.42	$ 0.42
= Delivered Cost	na	**$ 20.24**	**$ 20.91**	**$ 20.89**

The next figure provides the same build-up based on EIA-derived prices. As might be expected, the prices are even higher, averaging about US$2.40-2.75/mmBtu above US prices.

Figure 48: Oil-Linked Price Build-Up Based on EIA-derived Oil Prices

Alaska Delivery Build-Up, 2012 US$/mmBtu (EIA Prices)

	2015	2020	2025	2030
FOB Price	**na**	**na**	**$ 19.51**	**$ 20.36**
+ Transport & Boil-off	na	na	$ 2.36	$ 2.41
+ Onshore Costs	na	na	$ 2.38	$ 2.38
+ Regas Loss	na	na	$ 0.48	$ 0.50
= Delivered Cost	**na**	**na**	**$ 24.73**	**$ 25.65**

Australia Delivery Build-Up, 2012 US$/mmBtu (EIA Prices)

	2015	2020	2025	2030
FOB Price	**$ 18.34**	**$ 17.31**	**$ 18.13**	**$ 18.92**
+ Transport & Boil-off	$ 4.95	$ 4.81	$ 4.92	$ 5.03
+ Onshore Costs	$ 2.38	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	$ 0.51	$ 0.49	$ 0.51	$ 0.53
= Delivered Cost	**$ 26.18**	**$ 24.98**	**$ 25.93**	**$ 26.85**

Canada Delivery Build-Up, 2012 US$/mmBtu (EIA Prices)

	2015	2020	2025	2030
FOB Price	**na**	**$ 16.93**	**$ 17.73**	**$ 18.51**
+ Transport & Boil-off	na	$ 2.19	$ 2.23	$ 2.28
+ Onshore Costs	na	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	na	$ 0.43	$ 0.45	$ 0.46
= Delivered Cost	**na**	**$ 21.93**	**$ 22.79**	**$ 23.63**

Build-ups sourced from the Lower 48 follow a very different pattern, as they are driven by gas prices. The prevailing gas price, taken as Henry Hub, is increased by 15%. The liquefaction fee is then added on (at a presumed US$1,000/tpa) to arrive at the FOB price.

The transport charge is taken from tanker rate calculations (plus fuel escalation and boil-off), but, as shown before, the costs are essentially the same if an ATB is employed for cargoes from the US West Coast. (The US Gulf Coast is probably too distant to employ ATBs.) In addition, the voyage from the US Gulf Coast must pass through Panama both laden on the initial leg and in ballast on the return; these costs were calculated on the gross registered tonnage under the existing system of tolls. It should be kept in mind that the USGC-Oahu trip probably requires Jones Act exemptions.

The figure below tells a very different story from the oil-linked prices examined above. Even in 2030, after significant increases in gas prices, LNG from the US Gulf Coast can be landed in Hawaii for under US$20/mmBtu.

Figure 49: Gas-Linked Price Build-Up from the Lower 48

USGC Delivery Build-Up, 2012 US$/mmBtu (Tanker Delivery)

	2015	2020	2025	2030
EIA Henry Hub	$ 4.46	$ 4.76	$ 5.86	$ 6.54
x 115%	$ 5.13	$ 5.48	$ 6.73	$ 7.52
+ Liquefaction, $1,000/tpa	$ 3.50	$ 3.50	$ 3.50	$ 3.50
= FOB Price	**$ 8.63**	**$ 8.98**	**$ 10.23**	**$ 11.02**
+ Transport & Boil-off	$ 4.86	$ 4.94	$ 5.25	$ 5.44
+ Onshore Costs	$ 2.38	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	$ 0.32	$ 0.33	$ 0.36	$ 0.38
= Delivered Cost	**$ 16.19**	**$ 16.63**	**$ 18.22**	**$ 19.22**

USWC Delivery Build-Up, 2012 $/mmBtu (Tanker Delivery)

	2015*	2020	2025	2030
EIA Henry Hub	$ 4.46	$ 4.76	$ 5.86	$ 6.54
x 115%	$ 5.13	$ 5.48	$ 6.73	$ 7.52
+ Liquefaction, $1,000/tpa	$ 3.50	$ 3.50	$ 3.50	$ 3.50
= FOB Price	**$ 8.63**	**$ 8.98**	**$ 10.23**	**$ 11.02**
+ Transport & Boil-off	$ 1.96	$ 1.99	$ 2.11	$ 2.18
+ Onshore Costs	$ 2.38	$ 2.38	$ 2.38	$ 2.38
+ Regas Loss	$ 0.26	$ 0.27	$ 0.29	$ 0.31
= Delivered Cost	**$ 13.23**	**$ 13.62**	**$ 15.01**	**$ 15.89**

*Notional; no major export capacity in 2015

Even more impressive, of course, are the prices from the US West Coast, which are far lower than LNG landed in Hawaii from any other source, rising from a little over US$13/mmBtu in 2015 to well under US$16/mmBtu in 2030.

2.1.6. Primary Savings Estimates

The question for Hawaii, of course, is not about the absolute delivered price of LNG, but rather how LNG compares to the fuels it could displace—especially oil products. Once again, we have to look at both the FGE and EIA-derived oil-price forecasts; these affect not only the oil-linked prices of LNG from Alaska, Australia, and Canada, but also the onshore costs of LSFO and LS diesel in Hawaii. This is done for the FGE oil forecast in the figure below.

Figure 50: Primary Savings (Losses) of LNG Imports Compared to FGE LSFO and Diesel

Delivery Build-Up, 2012 US$/mmBtu (FGE Oil Prices)

	2015	2020	2025	2030
Alaska	na	na	$ 23.12	$ 23.10
Australia	$ 23.51	$ 23.70	$ 24.46	$ 24.43
Canada	na	$ 20.24	$ 20.91	$ 20.89
US Gulf Coast	$ 16.19	$ 16.63	$ 18.22	$ 19.22
US West Coast	na	$ 13.62	$ 15.01	$ 15.89
Hawaii LSFO	$ 22.08	$ 23.28	$ 22.88	$ 21.79
Hawaii LS Diesel	$ 22.99	$ 25.17	$ 26.07	$ 26.25
DELIVERED TO HAWAII: LSFO - LNG				
Alaska	na	na	$ (0.24)	$ (1.31)
Australia	$ (1.43)	$ (0.42)	$ (1.58)	$ (2.64)
Canada	na	$ 3.04	$ 1.97	$ 0.90
US Gulf Coast	$ 5.90	$ 6.65	$ 4.66	$ 2.57
US West Coast	na	$ 9.66	$ 7.87	$ 5.90
DELIVERED TO HAWAII: LS Diesel - LNG				
Alaska	na	na	$ 2.95	$ 3.15
Australia	$ (0.52)	$ 1.48	$ 1.61	$ 1.81
Canada	na	$ 4.94	$ 5.15	$ 5.36
US Gulf Coast	$ 6.80	$ 8.55	$ 7.85	$ 7.03
US West Coast	na	$ 11.56	$ 11.05	$ 10.36
PERCENT SAVINGS DELIVERED TO HAWAII: LSFO - LNG				
Alaska	na	na	-1%	-6%
Australia	-6%	-2%	-7%	-12%
Canada	na	13%	9%	4%
US Gulf Coast	27%	29%	20%	12%
US West Coast	na	42%	34%	27%
PERCENT SAVINGS DELIVERED TO HAWAII: LS Diesel - LNG				
Alaska	na	na	11%	12%
Australia	-2%	6%	6%	7%
Canada	na	20%	20%	20%
US Gulf Coast	30%	34%	30%	27%
US West Coast	na	46%	42%	39%

It should be emphasized that the FGE oil-price forecast is considered "conservative" by many; our forecasting models do not see a continued climb in LSFO prices—after all, much of the current price situation is explained by Fukushima—and the overall forecast does not see oil prices in general growing very rapidly. Therefore, LNG prices here are being compared to prices that some would consider to be on the low side.

Under this scenario, LNG imports from Alaska and Australia do not save money compared to LSFO, but lose it. Imports from Canada do show some minor savings.

The situation is not as grim for the oil-linked LNG exporters when compared to LS diesel, but the margin between LNG and diesel is thin for Alaska and Australia. Canadian imports save around US$5/mmBtu, a savings of 20% compared to diesel.

US$5/mmBtu corresponds to US$29/barrel for diesel; diesel prices would have to fall US$29/bbl from the forecast to eliminate this advantage.

LNG imports from the Lower 48 offer much greater savings. Even though the US Gulf Coast is quite distant, the percentage savings are quite large. USGC LNG compared to LSFO enjoys large percentage savings in the 2015-2020 period, but this advantage begins to decline as LSFO prices weaken slightly and US gas prices rise.

The US Gulf performs much better in comparison with diesel, and this may be the more important contrast; as discussed in the section on electricity prices below, LSFO may be driven out of the power sector by the cost of environmental controls well before 2020.

But what stands out in the figure is the major cost advantages of LNG sourced from the US West Coast. The savings compared to LSFO range from 27-42%; compared to diesel, LNG saves 39-46%. These potential savings are so large that there is a comfortable cushion between the LNG prices and the oil prices; oil prices could drop considerably and LNG would still offer substantial savings.

Naturally, the same general pattern prevails when EIA-linked oil prices are considered, as shown in the figure below. While there are losses only in the case of near-term Australian prices (because of high LNG demand in East Asia), the savings are still much smaller for LNG sourced from the three oil-linked exporters.

Because EIA foresees continued strengthening of the market for LSFO in the power sector, the percentage savings are much the same against both LSFO and diesel. The advantages of LNG sourced from the Lower 48 are even more pronounced.

Figure 51: Primary Savings (Losses) of LNG Imports Compared to EIA LSFO and Diesel

Delivery Build-Up, 2012 US$/mmBtu (EIA Oil Prices)

	2015	2020	2025	2030
Alaska	na	na	$ 24.73	$ 25.65
Australia	$ 26.18	$ 24.98	$ 25.93	$ 26.85
Canada	na	$ 21.93	$ 22.79	$ 23.63
US Gulf Coast	$ 16.19	$ 16.63	$ 18.22	$ 19.22
US West Coast	na	$ 13.62	$ 15.01	$ 15.89
Hawaii LSFO	$ 25.17	$ 26.58	$ 27.61	$ 27.76
Hawaii LS Diesel	$ 24.15	$ 25.63	$ 26.85	$ 27.98

DELIVERED TO HAWAII: LSFO - LNG

	2015	2020	2025	2030
Alaska	na	na	$ 2.88	$ 2.11
Australia	$ (1.01)	$ 1.59	$ 1.68	$ 0.91
Canada	na	$ 4.65	$ 4.82	$ 4.13
US Gulf Coast	$ 8.99	$ 9.95	$ 9.39	$ 8.54
US West Coast	na	$ 12.96	$ 12.59	$ 11.87

DELIVERED TO HAWAII: LS Diesel - LNG

	2015	2020	2025	2030
Alaska	na	na	$ 2.11	$ 2.32
Australia	$ (2.03)	$ 0.64	$ 0.91	$ 1.12
Canada	na	$ 3.70	$ 4.05	$ 4.35
US Gulf Coast	$ 7.96	$ 9.00	$ 8.62	$ 8.75
US West Coast	na	$ 12.01	$ 11.83	$ 12.08

DELIVERED TO HAWAII: LSFO - LNG

	2015	2020	2025	2030
Alaska	na	na	10%	8%
Australia	-4%	6%	6%	3%
Canada	na	17%	17%	15%
US Gulf Coast	36%	37%	34%	31%
US West Coast	na	49%	46%	43%

DELIVERED TO HAWAII: LS Diesel - LNG

	2015	2020	2025	2030
Alaska	na	na	8%	8%
Australia	-8%	3%	3%	4%
Canada	na	14%	15%	16%
US Gulf Coast	33%	35%	32%	31%
US West Coast	na	47%	44%	43%

The tables above apply only to our Base Case scenarios. It is possible to generate innumerable other scenarios; the Best Case and Worst Case scenarios are discussed in the examination of benefits and risks in the next chapter.

As mentioned earlier, Excelerate has provided preliminary estimates of costs for delivery of LNG to Hawaii, via both their GasPort (near-shore) and Gateway (offshore) options, assuming a USGC origin. In both options, Excelerate's plans are for 138,000 cubic meter vessels (as opposed to the 25,000-30,000 cubic meter vessels assumed in our base case for deliveries from the USWC, Canada, or Alaska).

In the case of the Gateway option, where ship-to-ship transfer of LNG may not be possible, the option is to deliver on a pair of alternating FSRUs. This either takes two

STL buoys, or results in an interruption of up to 12-24 hours while one vessel disengages from the buoy and is replaced by the second.

For their cost estimates, Excelerate assumed Jones Act waivers. (As discussed previously, there is some chance that a pair of US-built tankers could be repurchased and reflagged to comply with the Jones Act, but this is highly speculative, and would involve relying entirely on ships more than 30 years old.)

How does this compare in terms of delivered cost to our cost build-ups given here? Unfortunately this involves some degree of apples and oranges comparison, since our base cost is from the USWC on small (and, the case of ATBs, US-flagged) ships, while Excelerate's are based on large ships traveling from the US Gulf Coast.

Excelerate provided their estimates on the basis of annual demands on the order of 500 ktpa (the same used as our base case) and at 1,000 ktpa. Naturally, the latter has much better economics—but it is also representative of Hawaii's demand in later stages of introducing LNG.

In the figure below, the 500 ktpa option compares Excelerate's USGC delivered cost (which include transport, harborage and regasification, but are broken out in their estimates) with the base case derived previously from the USWC. These are all simply detailed estimates rather than the results of detailed engineering studies at specific sites. What is interesting is that they are all in the same basic range. True, Excelerate's lowest cost saves US$0.61/mmBtu over our Base Case, and their highest cost is US$1.38/mmBtu more expensive than our Base Case, but readers should be cautioned against reading too much into such numbers. To make decisions about which course to pursue based on estimates rather than site studies is inadvisable.

The 1,000 ktpa option attempts to compare apples to apples. To produce this comparison, we scaled up the onshore storage capacity to the size of the Excelerate storage (which is approximately 21 days at this higher level of consumption), and amortized it (and the associated harbor and regas facilities) over the large annual throughput. To this was added an upper and lower transport cost derived from the FGE LNG Shipping Model.

A number of things are worth noting. As might be expected, there are substantial economies of scale. Indeed, in the past most LNG analysts insisted that 1,000 ktpa was the minimum economic size for an LNG plant. In the case of the Excelerate numbers, the assumed costs are cut precisely in half. In the case of the FGE onshore analysis, the costs fall by 28-45%, but we have made more detailed assumptions in our calculations.

Figure 52: Delivery Comparison, Base Case vs. Excelerate (US$/mmBtu)

500 ktpa	Low	High
GasPort (near-shore) from USGC, 138 k cub m	$ 4.03	$ 4.42
Gateway (offshore) from USGC, 138 k cub m	$ 4.38	$ 6.02
Onshore (base case) from USWC, 25-30 k cub m (2020)	$ 4.64	$ 4.64
1,000 ktpa		
GasPort (near-shore) from USGC, 138 k cub m	$ 2.02	$ 2.21
Gateway (offshore) from USGC, 138 k cub m	$ 2.19	$ 3.01
Onshore from USGC, 138 k cub m	$ 2.53	$ 3.35

What this analysis does not attempt to determine is how the economics might improve for USWC sourcing if larger ships, with Jones Act waivers, were used from the USWC. It is probable that the economics would improve, but this requires altogether too much speculation, since it is not clear in this case whether or not a 138,000 cubic meter vessel could be accommodated at either end of the voyage.

At the scale of 500 ktpa, Jones Act compliant delivery to an onshore terminal from the USWC appears to be similar to Jones Act waiver deliveries to near-shore or offshore options from the USGC.

At this level of analysis, the estimated costs are all quite similar. Excelerate has noted that this is commonly the case, and that the main advantage of offshore or near-shore installations, is not necessarily cost, but rather speed of installation—and often more flexibility in siting. What needs to be thoroughly understood is that without detailed examination of harbor, land-use, and siting issues, it is not established that any of the options are actually possible. At the risk of repeating the point, choosing between these options on the basis of preliminary price estimates would be unwise.

In light of the above, optimists may wish to keep in mind the idea that our baseline costs might be as much as US$2/mmBtu overpriced compared to expected costs when and if Hawaii's demands for LNG reach a million tonnes per annum or more. Realists may wish to argue that everything always seems to cost more when built than on paper.

To further complicate matters, not only are there uncertainties about whether these options are feasible, *it is not clear that they are all feasible at the same scales.* Even if all three options are feasible in physical and regulatory terms, there may be upper limits to how much storage or throughput capacity can be accommodated under each option. This is one more reason why we stress that decisions should not be made on an a priori basis, but only after the options have been adequately characterized.

It is possible to be a little more definitive about LNG sourcing. Despite the long-standing connections between the 49th and the 50th States, Alaska appears to be a poor match for meeting Hawaii's needs for LNG. Even the proponents of the project do not believe it can be in production before 2022, and most observers think 2025 or 2030 is more likely. All of the analyses done in the prefeasibility studies assume the LNG will be exported on an oil-linked basis, assuming rather high slopes; and high prices will be needed if the current capital cost estimates are correct.

There has been some speculation that Australia may find itself awash in LNG, and that this might result in lower prices to compete with looming exports from the US. While the exports from the US will in fact challenge Australian margins, there is unlikely to be a large surplus of capacity in the near future in Australia. Yes, their plans are ambitious, and much of the planned capacity has not yet lined up buyers. But it is unreasonable to suppose that tens of billions per project will be invested prior to finding customers willing to sign contracts at the high prices needed. The oil-linked LNG market may well soften on into the next decade—in fact, an erosion of slopes is already included in our analysis—but it would be a bad strategy to bank on cheap Australian LNG that may never materialize.

Canada may offer more possibilities than Alaska. Not only are the projected capital costs lower; the Canadian projects will also be drawing gas from a lengthy connection to the North American gas hubs. This may put some downward pressure on prices, but there is presently no plan to price LNG on a tolling basis tied to AECO C spot prices (the Canadian equivalent of Henry Hub). Canadian producers can afford to cut prices more than the Australians or Alaskans, but the present plans are focused on selling into East Asia on oil-linked prices—not on competing with LNG exporters in the Lower 48.

The US Gulf Coast is more competitive as a potential LNG supplier than might have been expected. The transport costs are still quite large; the Jones Act remains an issue; and if Panama Canal tolls are revised upwards significantly, it will hurt the economics. Still, the US Gulf Coast is the second-best option for LNG supply for Hawaii, and if we assume Jones Act waivers, moderation by Panama, and the ability to deliver to Oahu on 138,000 cubic meter vessels, then pricing from the US Gulf Coast is probably comparable to the US West Coast.

The US West Coast is hands-down the ideal source for LNG exports to Hawaii. If ATBs are used for transport, the Jones Act is not an issue, and the distances are short. Gas is readily available through the existing pipeline system, which draws on Canadian gas sources as well a US sources. (Oregon LNG often points out that all of their gas supplies will be imported from Canada.) In fact, Pacific Northwest gas prices are generally lower than Henry Hub.

The two major export projects planned on the US West Coast are both in Oregon, and continue to face stiff environmental opposition. While the possibility of sourcing LNG from these projects should not be ignored, Hawaii does not need megaprojects to meet its needs. Smaller-scale projects, nearer to the size used for peak-shaving or vehicle-fuel supply, are easier to site and build. The US West Coast offers the best economics, and should be the first option investigated for sourcing LNG for Hawaii.

In the following analyses of the economics of LNG onshore, we will base our calculations on deliveries from the US West Coast. Equivalent economics are presented in the Appendix for supplies from the US Gulf Coast.

We do not feel that under the current outlook that calculations sourced from oil-indexed suppliers are warranted. The projected savings from these sources—when there are savings at all—are in most cases small enough that the uncertainties in projections could easily erase them. Unless circumstances change dramatically, we would advise against sourcing LNG from oil-linked exporters.

Our cost build-up here has assumed an onshore facility served either by small tankers or by ATBs. As mentioned in the transport section, there are other options, such as the use of larger tankers to serve a "near-shore" LNG terminal, such as the one Excelerate advocates. Based on very preliminary estimates from Excelerate, it appears that the delivery costs are quite similar for the near-shore floating installation and an onshore facilty. Excelerate noted in that this is commonly the case, and that the main advantage of near-shore installations, such as their GasPort option, is not cost, but rather speed of installation—and often more flexibility in siting.

2.1.7. Imports via ISO Containers

HawaiiGas has applied to FERC for approval of "Phase I" imports of LNG from the mainland to provide backup fuel for their SNG system. If approved, this will constitute the first imports of LNG into Hawaii.

The application proposes to import LNG in so-called "ISO containers," often referred to simply as "ISOs." ISO stands (somewhat confusingly) for the International Organization for Standardization, which sets voluntary standards on thousands of matters ranging from software programming procedures to food safety. The LNG containers referred to here are ISO intermodal cryogenic liquids containers of the larger size.

They are referred to as intermodal because they are approved for transport, loading, and offloading on trucks, ship, or rail, and for transfers between those modes. They are essentially long tubes—in effect, giant thermos bottles—that can be used to transport LNG, ethane, ethylene, or other liquefied gases. They are already widely used to move LNG from small liquefaction plants to LNG/CNG fuelling stations; on the West Coast, they are the main modes of LNG delivery to the ports of Oakland, Los Angeles, and Long Beach.

Although a 40-foot ISO can hold nearly 12,000 gallons of LNG, if they are to be transported by road then they are generally limited to 8,600 gallons because of damage to the roadbed at higher weights.

Although HawaiiGas has not made formal application for Phase II, the plan is to expand the imports of LNG via ISOs to serve their SNG network and other customers.

ISO containers of this type cost US$180-220,000 per unit, and can hold LNG with no evaporation for 75-85 days. Of course, to get LNG into the distribution system will take regasifiers (which are available in portable units), and ideally many of the ISOs would unload into a small cryogenic storage unit. Discussions with HawaiiGas suggest that additional onshore facilities could cost up to US$9 million.

If we assume 50 ISO units at US$200,000 per unit, making 12 round trips per year between California and Hawaii, and add US$9 million for central facilities, then at a 10% IRR, the capital cost works out to US$6.76/mmBtu.

Shipping an ISO from California and back can cost US$6,000 per unit, but lower costs can be negotiated for ongoing handling of multiple units. On the other hand, depending on where the LNG is sourced, trucking to the loading port and returning empty containers can add US$1-2,000 to that cost. After consulting with sources on the mainland, we estimate a delivery cost per unit of US$7,500 per trip—which, for a load of 8,600 gallons per ISO, amounts to a shipping cost of US$10.83/mmBtu. Together with the levelized capital costs, this means that the total shipping to Oahu, including onshore costs at both ends, amounts to US$17.59/mmBtu.

In the best of all possible worlds, the FOB price of LNG would be the US West Coast FOB price for liquefaction established in the previous section. That is probably too low for LNG sourced from small producers in urban areas, but is given as the “Low FOB” price in the figure below. Based on pricing in Southern California, it appears likely that small, ISO-based purchases will probably cost about US$2.50/mmBtu above the estimated liquefaction plant cost. This is given as the “High FOB” estimate below.

Figure 53: Delivered Cost of LNG from ISO Containers (US$/mmBtu)

	2015	2020	2025	2030
Low FOB	$ 8.63	$ 8.98	$ 10.23	$ 11.02
Low Delivered Cost	$ 26.22	$ 26.57	$ 27.82	$ 28.61
High FOB	$ 11.13	$ 11.48	$ 12.73	$ 13.52
High Delivered Cost	$ 28.72	$ 29.07	$ 30.32	$ 31.11

The delivered costs are quite high—although what is surprising is that they are not that far above EIA's projections for oil prices in Hawaii from 2020 onward. In the Low Delivered Cost case, the LNG cost is within US$1/mmBtu of diesel and LSFO prices in 2020; in the High Delivered Cost case, this rises to US$2.50-3.50/mmBtu above oil.

It should be understood, however, that HawaiiGas is not attempting to deliver LNG in ISOs to compete with Oahu oil products. These LNG imports are intended to compete primarily with their existing SNG (synthetic natural gas). Today, gas in Hawaii is manufactured from refined products and, as might be expected, comes with a hefty price tag; recent prices have run about US$41/mmBtu. Therefore, even in the High Delivered Cost case, LNG brought in by ISOs can provide gas much more cheaply than current costs.

Of course, if LNG is brought onshore in bulk from tankers or ATBs, then ISOs will immediately become obsolete as a means of bringing LNG to Oahu. This does not mean, however, that ISOs would have no further role to play in the market. ISOs are a natural way of delivering LNG from centralized storage to end-users. As mentioned earlier, they are already used for LNG/CNG fuelling stations on the mainland, and this use is expected to expand rapidly. They are also an easy way of providing LNG bunkering at ports, and could provide gas to large users in areas where gas pipelines currently do not exist.

But from a statewide point of view, the most important long-term use of ISOs may be to provide LNG to the neighbor islands. So far in this chapter, the focus has been on LNG delivery to Oahu. But what about the other islands? Will small LNG import terminals be built? If so, how will they be served—by ATBs dropping partial loads? The costs and logistics are daunting to consider, especially when the Oahu facility is considered to have poor economies of scale.

But deliveries in ISOs from central storage on Oahu is a very realistic proposition. At an average interisland shipping cost of US$900 per voyage, the delivery cost amounts to about US$1.30/mmBtu. If the ISO spends two weeks before being returned for refill, then the total cost including the capital charges amounts to only US$1.55/mmBtu—a 10-12% mark-up from the cost of LNG on Oahu.

2.2. *Electricity Rate Savings from LNG*

2.2.1. Existing Power Plants

The figure below shows a list of the fossil-fueled power plants on Oahu (excluding cogeneration within the refineries). Nearly 80% of the capacity is owned by HECO. Of the HECO capacity, in turn, slightly more than 80% are steam turbines designed for LSFO.

One of the striking features of the overall HECO system is its age. All of the HECO steam turbines are more than 30 years old, and many are more than 50 years old (two units at Waiau are more than 60 years old). In an industry where the useful life of a plant is generally taken as 30 years, it is something of a tribute to HECO's management and maintenance of its system that it continues to produce power with a high degree of reliability.

As an aside, it should be noted that the Campbell Industrial Park gas turbine and the Kahe #3 steam turbine have been run on biofuels in varying proportions. They are included here for the sake of completeness, but they are arguably not "fossil-fueled plants" any longer.

The two fossil-fueled IPPs, Kalaeloa Partners and AES Coal, are more advanced designs than the power plants in the HECO system—a large CCGT in the former case, and a fluidized-bed coal plant in the latter. But even these "modern" plants are more than 20 years old.

Figure 54: List of Oahu Fossil-Fueled Plants

Site	Owner	#	Fuel	Tech	Role	Min MW	MW	Year	Age
Honolulu	HECO	8	LSFO	Steam	Base	24	56	1954	58
Honolulu	HECO	9	LSFO	Steam	Base	24	57	1957	55
						48	**113**		**56**
Waiau	HECO	3	LSFO	Steam	Intermed	24	49	1947	65
Waiau	HECO	4	LSFO	Steam	Intermed	24	49	1950	62
Waiau	HECO	5	LSFO	Steam	Intermed	24	57	1959	53
Waiau	HECO	6	LSFO	Steam	Intermed	24	58	1961	51
Waiau	HECO	7	LSFO	Steam	Base	35	92	1966	46
Waiau	HECO	8	LSFO	Steam	Base	35	92	1968	44
						166	**397**		**52**
Kahe	HECO	1	LSFO	Steam	Base	30	92	1963	49
Kahe	HECO	2	LSFO	Steam	Base	30	90	1964	48
Kahe	HECO	3	LSFO	Steam	Base	30	92	1970	42
Kahe	HECO	4	LSFO	Steam	Base	30	93	1972	40
Kahe	HECO	5	LSFO	Steam	Base	55	142	1974	38
Kahe	HECO	6	LSFO	Steam	Base	45	142	1981	31
						220	**651**		**40**
Waiau	HECO	9	Diesel	G Turbine	Peaking	15	52	1973	39
Waiau	HECO	10	Diesel	G Turbine	Peaking	15	50	1973	39
						30	**102**		**39**
CIP	HECO	1	Diesel/BioD	G Turbine	Peaking	**32**	**110**	**2009**	**3**
CEIP	HECO	1-3	Diesel	Int Comb.	Local	*n.a.*	5	*n.a.*	*n.a.*
Ewa Nui	HECO	1-6	Diesel	Int Comb.	Local	*n.a.*	10	*n.a.*	*n.a.*
Helemano	HECO	1-3	Diesel	Int Comb.	Local	*n.a.*	5	*n.a.*	*n.a.*
Iwilei	HECO	1-3	Diesel	Int Comb.	Local	*n.a.*	5	*n.a.*	*n.a.*
Kalaeloa	HECO	1-3	Diesel	Int Comb.	Local	*n.a.*	5	*n.a.*	*n.a.*
							29		
Kalaeloa	KPLP	1	LSFO	GT-CCGT	Base	24	82	1989	23
Kalaeloa	KPLP	2	LSFO	GT-CCGT	Base	24	82	1991	21
Kalaeloa	KPLP	3	LSFO	ST-CCGT	Base	21	50	1991	21
						68	**214**		**22**
Barbers Pt	AES		Coal/Oth Solid	Circ Bed	Base	**76**	**180**	**1990**	**22**

Note: excludes cogen units in refineries.
Source: EIA/HECO

At a lower level of resolution—collapsing all similar types of units at one site into unified plants—it is possible to get a bird's eye view of fossil-fueled power generation in Hawaii in 2011, as shown below.

Baseload power plants are usually assumed to operate at 70-90% of their theoretical maximum output. (100% is impossible because of maintenance.) One of the somewhat surprising features of the figure is the realization that no facilities other than the AES coal plant and the Kalaeloa CCGT operate in this range. Even "baseload" steam turbine plants (Hill, Puna, Kahe, and Kahalui) operate at only 50-65% of capacity. (The CCGTs at Kapaia and Maalaea also operate in this range.) Some steam turbines (Honolulu is the obvious example) are operating as peaking plants, being kept "spinning" a large percentage of the time so as to be ready for peak following.

Figure 55: Hawaii Fossil-Fueled Plants and Characteristics by County

HAWAII			Capacity [MW]	Max. Output [MWh]	Actual (2011) [MWh]	Utilization [%]	HeatRate [Btu/kWh]
Hamakua	Hamakua Energy	CCGT	66	578,160	215,791	37.3%	8,610
Kanoelehua	HELCO	IC	9.5	83,220	299	0.4%	12,013
Kanoelehua	HELCO	GT	11.5	100,740	20	0.0%	28,200
Keahole	HELCO	IC	7.5	65,700	3,107	4.7%	11,003
Keahole	HELCO	GT	63.6	557,136	197,173	35.4%	12,185
Puna	HELCO	ST	15.5	135,780	68,039	50.1%	14,733
Puna	HELCO	GT	23.6	206,736	12,979	6.3%	12,058
Shipman	HELCO	ST	15	131,400	4,719	3.6%	17,343
W H Hill	HELCO	ST	37.1	324,996	195,390	60.1%	13,062
Waimea	HELCO	IC	7.5	65,700	1,836	2.8%	11,355
HONOLULU*							
Honolulu	HECO	Steam	113	989,880	95,534	10%	13,876
Kahe	HECO	Steam	559	4,896,840	2,996,653	61%	10,218
Waiau	HECO	GT	102	893,520	8,810	1%	18,081
Waiau	HECO	Steam	397	3,477,720	1,014,460	29%	10,696
Kalaeola	Kalaeola Partners	CCGT	214	1,874,640	1,445,668	77%	8,410
KAUAI							
Kapaia	KIUC	GT	39.1	342,516	211,971	62%	8,669
Port Allen CCGT	KIUC	CCGT	41.4	362,664	32,338	9%	15,539
Port Allen IC	KIUC	IC	91.4	800,664	168,360	21%	9,284
MAUI							
Hana Substation	MECO	IC	2	17,520	97	1%	10,990
Kahului	MECO	ST	34	297,840	176,582	59%	14,321
Maalaea CCGT	MECO	CCGT	133.2	1,166,832	636,642	55%	8,858
Maalaea IC	MECO	IC	96.6	846,216	189,227	22%	10,116
Miki Basin	MECO	IC	10.4	91,104	19,595	22%	10,249
Palaau Power	MECO	GT	2.5	21,900	239	1%	18,435
Palaau Power	MECO	IC	12.6	110,376	33,395	30%	9,942
Puunene Mill	HI Com & Sugar	ST	46.1	403,836	2,308	1%	29,297
Total Oil					**7,731,232**		
HONOLULU							
AES Hawaii	AES	ST	203	1,778,280	1,382,098	78%	10,730
Total Coal					**1,382,098**		
Grand Total					**9,113,330**		

*excludes CIP and Kahe 3, fired or co-fired with biofuels

Source: EIA/HECO

Load-following is inherently energy inefficient. Looking in the previous figure, it is clear that there is a strong inverse correlation between heat rate and utilization—that is, the less a unit is used, the more energy it consumes per kWh generated. Starting and shutting down a unit consumes extra fuel, and keeping it spinning (or "hot") to respond to demand fluctuations uses extra energy. This is a good part of why the Honolulu station, which runs at 10% utilization, uses 36% more energy to produce a kWh than the Kahe station (which runs at 61% utilization).

It should be clearly understood that we are not saying any of these plants are being managed in an inefficient fashion. The point is that running thermal power plants in a varying fashion uses more energy. It is also inefficient in terms of capital costs. It is very simple to see that if a plant generates power only 10% of the time, that the capital cost for that power will be nine times higher than for a plant that runs 90% of the time.

To put it in more concrete terms, if a baseload plant running at 90% utilization must recover 2 cents per kWh to pay back the original investment, then that same plant running at 10% will have to recover 18 cents per kWh.

Many newer CCGT and GT plants are designed for better, faster, and more-efficient load-following. Great strides have been made in this area in the last decade. Nonetheless, it is always less energy-efficient to follow a fluctuating demand; and, regardless of energy efficiency, if a plant only runs a small percentage of the time, its capital cost per kWh generated will soar.

The effect of renewables on conventional power demand cannot be predicted at this point, because at present we have no good guess as to the composition of renewable power supplies in coming years. Yes, we have a Renewable Portfolio Standard (RPS) that specifies that 40% of generation by 2030 will be from renewables—but at present it is unclear whether these will be mostly intermittent renewables (such as wind and solar) or baseload, dispatchable sources (such as geothermal, OTEC, or biofuels). If intermittent sources play a large role, then the average utilization of the State's generating capacity will tend to decrease even further. In addition, installing new generating capacity, with better load-following capabilities, will probably be required.

There are two important points to be made here. First, much of the existing power generation capacity in Hawaii is probably due for replacement. It has been exceedingly well maintained and skillfully managed—or it would not still be working. But it should be recognized that in most environments some of this capacity would have been retired and replaced.

(It should be added that it is rather difficult to assess the cost of replacing existing oil-burning steam turbines with similar equipment; it has been many years since such a plant has been built in the US. Even in areas in the US where oil is still burned as a power source, new installations have generally been diesel-fired GTs or CCGTs.)

Second, expanded use of solar and wind in the power sector may require replacement of generating capacity with more sophisticated and responsive equipment. (The alternative, would be to run existing equipment in an increasingly less energy-efficient fashion.) This is in effect a consequence of the HCEI, which may raise the cost of conventional power generation.

Therefore, in the analysis that follows, the costs of new generating capacity in the form of GTs and CCGTs are attributed to the switch away from LSFO. Yet some of this new capacity might be required by replacement needs, and some by the load-following demands of the HCEI and RPS. Therefore, attributing all of these costs to the deployment of LNG is not quite correct and slightly underestimates the economics of LNG in power.

2.2.2. Economics of LNG in Existing Power Plants

All things held equal, lighter fuels tend to be more efficiently combusted than heavier fuels, but the differences in any given use are only a fraction of a percent. Therefore, even though gas is a fraction of a percent more efficient than diesel, and an even larger fraction of a percent more efficient than fuel oil, it is more straightforward to compare them using the same heat rates for the same end-uses. The cost of fuel at the existing heat rate determines the fuel cost per kWh. To this must be added the other direct cost, the levelized capital investment required to perform the burner conversion.

2.2.2.1. *Direct Costs: Burner Conversions*

Burner conversions are such small capital investments in the scheme of things that it is hard to get data on the cost of conversion. Furthermore, such conversions are rather site-specific, and different designs and vintages require different approaches.

To complicate matters, many plant conversions to gas do not replace oil products with gas, but instead introduce dual-firing. In this way, existing oil tanks and pipelines can act as backup fuel in the event of an emergency. Duel firing with diesel backup has been the approach adopted by Puerto Rico in their recent LNG-import venture, and it is hard to resist noting the analogy between Puerto Rico and Hawaii: islands separated from sources of supply, and visited by hurricanes and the other vagaries of seaborne trade.

According to technology vendors we have consulted, the cost of dual-firing on new units is typically around US$500,000 per unit; this increases to nearly US$1 million per unit on retrofits. Thus, for a plant like Kahe, with its six units, conversion might cost about US$6 million. (The range of cost estimates is very large; some retrofits apparently run as low as US$140,000 per unit.) If we assume a utilization rate of 60%, then the charge for retrofitting to dual-firing is less than 0.02 cents per kWh.

For smaller plants with low utilization factors, the retrofit costs can be much higher on a per-kWh basis. If we consider a 50 MW single-unit plant running at only 20% utilization, the cost can increase by a factor of 10…to over 0.1 cents/kWh. In other words, even at very high retrofitting costs relative to the size of a plant, when the costs are spread out over electricity rates, they are still only a tiny variation in the cost to the consumer.

We will include these costs in our analysis, but it should be recognized that they have no important effect on the results.

2.2.2.2. *Indirect Costs: Gas Delivery*

The means of gas delivery for power plants on Oahu will be by pipeline. On the neighbor islands, it is more likely to be by means of ISOs.

In the early 2000s, gas pipelines on the mainland typically cost US$30,000-US$100,000 per inch-mile. The inch-mile is not a common unit, but it refers to the diameter of the line in inches and the miles covered by the line. In other words, if it is a five-inch diameter line stretching three miles, and the cost is US$75,000 per inch-mile, then the construction cost would be US$75,000 x 5 inches x 3 miles = US$1.125 million.

Costs have jumped sharply in the recent past, partly because of increases in the cost of steel, and partly because there is so much pipeline building underway on the mainland. Typical prices are now around US$188,000 per inch-mile. Recent studies in mainland North America have found costs from US$90,000 per inch-mile to US$300,000 per inch-mile. The latter figure is from Pennsylvania, and it attributed to high land values and high population densities in the area concerned.

It has been some time since a major gas trunkline was built on Oahu, but we find it doubtful that it will be much cheaper than in urban Pennsylvania, and it could well be more expensive.

There is nothing more site-specific than a pipeline, however. In addition to the uncertainty of the cost per inch-mile, we are faced with a situation where we are unsure of where the LNG terminal will be, how far the pipeline must run to reach it, and what the annual power output of the generating plant will be as the HCEI comes into play.

Fortunately, as with burner conversions, the costs of pipelines are a small factor in the total cost of power (although they are admittedly much higher than in the case of burners). To give a realistic assessment, we have to deal in ranges.

Our assumption here is that gas will be landed somewhere in the vicinity of the Barber's Point industrial district, stretching from Kalaeloa Harbor to the West Loch of Pearl Harbor. This region can reach most of Oahu's power plants with a pipeline run of one to ten miles.

A large plant will require a 10-inch diameter pipeline. Smaller plants could be supplied with smaller pipes. The figure below shows ranges that seem to encompass most of the major arrangements that could be contrived for major Oahu power stations: a large plant with high utilization, and a much smaller plant with much lower utilization, both of them located anywhere from one to ten miles away from the LNG terminal. The figure also covers costs of up to US$500,000 per inch-mile—far higher than reported in any source we have encountered to date.

Figure 56: Levelized Cost of Pipeline Charges, cents per kWh

600 MW, 60% utilization, 10-inch				
	Miles			
k$/in-mi	1	3	5	10
200	0.01	0.02	0.04	0.07
300	0.01	0.03	0.06	0.11
400	0.01	0.04	0.07	0.15
500	0.02	0.06	0.09	0.19

100 MW, 10% utilization, 5-inch				
	Miles			
k$/in-mi	1	3	5	10
200	0.13	0.40	0.67	1.34
300	0.20	0.60	1.01	2.01
400	0.27	0.80	1.34	2.68
500	0.34	1.01	1.68	3.35

For a large plant (Kahe is the only plant of this size), the costs per kWh are negligible.

For a smaller plant with very low power output, the costs are more significant. In the worst case examined, they exceed 3 cents per kWh. But it needs to be recognized that the costs per kWh for low-utilization peaking stations are already sky-high, not just in Hawaii, but everywhere. It is the fact that these costs are averaged into a large rate base that makes them relatively imperceptible.

To put this in perspective: if we have two plants as described above, both 5 miles from the LNG terminal, and assume the worst (US$500,000 per inch-mile), then we will have a pipeline charge of 0.09 cents per kWh for power from the first station, and 1.68 cents per kWh from the second. But when the cost is averaged into the rates, the overall increase is only about 0.14 cents per kWh. Overall, the effect of pipeline costs is relatively small, although they may be large for any one power plant.

In general, if the projected savings from a measure—such as introducing LNG as a power generation fuel—are so small that they can be significantly cut by costs of this magnitude, then the proposal should be approached with considerable skepticism.

There is another type of delivery to be considered apart from pipelines, of course, and that is delivery via ISO containers to power plants on the neighbor islands. This is significantly more expensive than major pipeline deliveries, but interisland pipelines are not a realistic option. At an estimated US$1.55/mmBtu delivery via ISO, the cost is not necessarily much higher than some scenarios that can be developed for pipeline delivery to peaking plants on Oahu.

Serving neighbor-island power plants with ISOs would require a large number of containers: a 40 MW power plant running at around 60% utilization would demand 7-11 ISO-loads per day. In the longer term, some form of dedicated storage and possibly specialized barge delivery might prove to have better logistics and costs, but this is purely hypothetical. What is clear is that, once LNG is delivered onshore to Oahu, ISOs are an immediate option for bringing LNG to the power sector on other islands.

2.2.2.3. *Rate Impacts of LNG in Existing Power Stations*

Both LSFO and diesel are used in power generation in Hawaii at present, although diesel on Oahu is restricted to some relatively small plants. The reason they are both considered in this section, however, is because new environmental standards may force LSFO to be replaced by diesel even in large steam turbines. This topic is examined in more detail in Section 2.3, but the basic economics are laid out here.

The calculations considered in this discussion assume sourcing from the US West Coast. Similar calculations based on US Gulf Coast sourcing are provided in the Appendices.

The figure below shows the costs of power from LNG, LSFO, and low-sulfur diesel in a large baseload plant. The assumptions are a 600 MW plant running at 60% utilization; a 5-mile pipeline at US$400,000 per inch-mile; six units in the plant, all retrofitted at a cost of US$1 million per unit; and a plant heat rate of 10,220 mmBtu per kWh.

Spread over so many kWh per year, the cost of the pipeline and retrofits are minor, and the results primarily reflect fuel-to-fuel competition. As might be expected from the landed costs presented previously, the savings are quite large—in fact, they are just slightly lower than the primary savings.

The percent savings decline over time as gas prices rise in the EIA Henry Hub forecast, but they are quite large whether FGE or EIA oil prices are used.

Figure 57: Savings from LNG in Existing Equipment—Oahu Baseload Plant

USWC LNG Base Case	2015	2020	2025	2030
LNG, $/mmBtu	na	$ 13.62	$ 15.01	$ 15.89
Fuel Cost, c/kWh	na	13.92	15.34	16.24
Retrofit, c/kWh	na	0.02	0.02	0.02
Pipeline, c/kWh	na	0.07	0.07	0.07
LNG Power, c/Kwh	na	14.01	15.44	16.33
FGE Oil Prices				
LSFO, $/mmBtu	$ 22.08	$ 23.28	$ 22.88	$ 21.79
LSFO Power, c/kWh	22.57	23.79	23.39	22.27
LS Diesel, $/mmBtu	$ 22.99	$ 25.17	$ 26.07	$ 26.25
LS Diesel Power, c/kWh	23.50	25.73	26.64	26.83
Savings				
LNG vs LSFO, c/kWh	na	9.78	7.95	5.93
LNG vs Diesel, c/kWh	na	11.72	11.20	10.49
LNG vs LSFO, %	na	41%	34%	27%
LNG vs Diesel, %	na	46%	42%	39%
EIA Oil Prices				
LSFO, $/mmBtu	$ 25.17	$ 26.58	$ 27.61	$ 27.76
LSFO Power, c/kWh	25.73	27.16	28.22	28.37
LS Diesel, $/mmBtu	$ 24.15	$ 25.63	$ 26.85	$ 27.98
LS Diesel Power, c/kWh	24.68	26.19	27.44	28.59
Savings				
LNG vs LSFO, c/kWh	na	13.15	12.78	12.04
LNG vs Diesel, c/kWh	na	12.18	12.00	12.26
LNG vs LSFO, %	na	48%	45%	42%
LNG vs Diesel, %	na	47%	44%	43%

It is instructive to examine a case where the plant is not so large and the utilization is not so high. This has the effect of increasing the retrofitting and pipeline costs per kWh, and offers another benchmark.

This case is provided in the figure below. It assumes a 100 MW plant with two units, running in peaking mode (10% utilization). The heat rate is taken at 13,900 Btu/kWh. As in the previous case, it assumes a 5-mile pipeline run at US$400,000 per inch-mile.

The results tell an important story. The plant in this case produces only about 3% as much electricity per year as the baseload plant considered above. With fewer kWh to spread the retrofitting and pipeline costs across, the additional costs per kWh are 17 times higher—but the charge still amounts to only 1.35 cents/kWh.

On the other hand, as is typical of steam plants used for peaking, the heat rate is considerably higher. This results in higher fuel costs per kWh for both the LNG and the oil products. Because of this, the LNG savings are even higher in cents/kWh than in the baseload case. (The percentage savings fall somewhat, however, as these are a percentage of the oil costs, and the oil costs per kWh are much higher in this case.)

Figure 58: Savings from LNG in Existing Equipment—Oahu Steam Peaking Plant

USWC LNG Base Case	2015	2020	2025	2030
LNG, $/mmBtu	na	$ 13.62	$ 15.01	$ 15.89
Fuel Cost, c/kWh	na	18.93	20.87	22.09
Retrofit, c/kWh	na	0.21	0.21	0.21
Pipeline, c/kWh	na	1.34	1.34	1.34
LNG Power, c/kWh	na	20.48	22.42	23.64
FGE Oil Prices				
LSFO, $/mmBtu	$ 22.08	$ 23.28	$ 22.88	$ 21.79
LSFO Power, c/kWh	30.69	32.36	31.81	30.29
LS Diesel, $/mmBtu	$ 22.99	$ 25.17	$ 26.07	$ 26.25
LS Diesel Power, c/kWh	31.96	34.99	36.23	36.49
Savings				
LNG vs LSFO, c/kWh	na	11.88	9.39	6.65
LNG vs Diesel, c/kWh	na	14.51	13.81	12.84
LNG vs LSFO, %	na	37%	30%	22%
LNG vs Diesel, %	na	41%	38%	35%
EIA Oil Prices				
LSFO, $/mmBtu	$ 25.17	$ 26.58	$ 27.61	$ 27.76
LSFO Power, c/kWh	34.99	36.94	38.38	38.59
LS Diesel, $/mmBtu	$ 24.15	$ 25.63	$ 26.85	$ 27.98
LS Diesel Power, c/kWh	33.57	35.62	37.32	38.89
Savings				
LNG vs LSFO, c/kWh	na	16.46	15.96	14.95
LNG vs Diesel, c/kWh	na	15.14	14.89	15.24
LNG vs LSFO, %	na	45%	42%	39%
LNG vs Diesel, %	na	43%	40%	39%

The present study cannot begin to assess the costs of all the conversion options for all the power plants in the islands, but it is worth examining the economics of neighbor-island power plants supplied via ISOs.

There is no such thing as a typical neighbor-island power plant, as they vary widely in size, fuel source, and generating technology. To keep somewhat consistent with our approach for the Oahu plants, we have selected a busload steam turbine plant. Its assumed characteristics are 40 MW, 60% utilization, a heat rate of 13,050 Btu/kWh, and a retrofitting cost of US$1 million for a single unit. There is no pipeline cost, but there is a charge of US$1.55/mmBtu for delivery on ISO containers. The cost of oil-product delivery from Oahu is taken as US$3 per barrel.

Figure 59: Savings of Small Neighbor-Island Steam Plant Supplied via ISO

USWC LNG Base Case	2015	2020	2025	2030
LNG, $/mmBtu	na	$ 13.62	$ 15.01	$ 15.89
Transport, $/mmBtu	na	$ 1.55	$ 1.55	$ 1.55
Fuel Cost, c/kWh	na	19.79	21.62	22.76
Retrofit, c/kWh	na	0.05	0.05	0.05
LNG Power, c/kWh	na	19.84	21.66	22.81
FGE Oil Prices				
LSFO, $/mmBtu	$ 22.56	$ 23.76	$ 23.36	$ 22.27
LSFO Power, c/kWh	29.44	31.01	30.49	29.06
LS Diesel, $/mmBtu	$ 23.04	$ 25.23	$ 26.12	$ 26.30
LS Diesel Power, c/kWh	30.07	32.92	34.09	34.32
Savings				
LNG vs LSFO, c/kWh	na	11.17	8.83	6.25
LNG vs Diesel, c/kWh	na	13.08	12.42	11.52
LNG vs LSFO, %	na	36%	29%	22%
LNG vs Diesel, %	na	40%	36%	34%
EIA Oil Prices				
LSFO, $/mmBtu	$ 25.65	$ 27.06	$ 28.09	$ 28.24
LSFO Power, c/kWh	33.48	35.31	36.66	36.86
LS Diesel, $/mmBtu	$ 24.20	$ 25.68	$ 26.90	$ 28.03
LS Diesel Power, c/kWh	31.58	33.51	35.10	36.58
Savings				
LNG vs LSFO, c/kWh	na	15.47	14.99	14.05
LNG vs Diesel, c/kWh	na	13.67	13.44	13.77
LNG vs LSFO, %	na	44%	41%	38%
LNG vs Diesel, %	na	41%	38%	38%

Given the hefty delivery charge, the savings are surprisingly large—from a minimum of 22% up to 44% savings over oil products. Of course, as mentioned, ISOs cannot logically supply all of the needs of all the neighbor-island power plants; it would involve too many deliveries of too many containers. But ISOs are generally considered to be the most expensive way of delivering LNG, so they provide a useful benchmark for the cost benefits available.

(*n.b*. Although the neighbor-island utilities do not presently burn LSFO or low-sulfur diesel, coming federal regulations in 2016-17 will either require that they upgrade to these cleaner grades of fuel, or add expensive emission controls. Therefore, these are in fact a logical base of comparison beginning in the latter half of this decade.)

2.2.3. Economics of LNG in New or Hybrid Power Plants

The previous section reviewed the cost savings likely from replacing oil products with LNG in existing equipment. Gas, however, is considered the ideal fuel for more advanced, more efficient power plant technologies, such as SCGTs and CCGTs. As discussed elsewhere, LSFO can be used in CCGTs, and is, at Kalaeloa Partners, but it results in greatly increased maintenance work. Low-sulfur diesel, on the other hand, can be and often is used as fuel in CCGTs.

CCGTs unquestionably use less fuel to generate power—and emissions drop in line with the fuel savings. The question is whether the energy savings outweigh the capital costs.

As explained earlier, a CCGT is simply one or more gas turbines feeding their waste heat to a steam turbine. This of course raises the option of converting an existing steam turbine to a CCGT by adding gas turbines and a heat exchanger—what we refer to as a hybrid plant, or "upstreaming." While simple in concept, this can become quite complex in practice, since the design operating temperatures between the new and old units must be matched to achieve maximum efficiency. We will examine the economics of this option as well, although it is not clear that it could easily be applied to any given steam turbine.

2.2.3.1. *Location, Location, Location*

The cost of land varies so widely that it is usually excluded from preliminary cost analyses. Detailed cost estimation can only be done when a site is selected and front-end engineering design (FEED) is completed. Obviously neither site selection nor engineering can be undertaken within the scope of this study, so all of the cost estimates exclude land costs.

We would be remiss, however, if we did not raise the topic of plant location. The existing power infrastructure is laid out to feed the existing transmission system, and any new power plants needs to tie in to that system; the cost and environmental impact of building new long-distance transmission lines could be huge.

In addition, the overall demand for power from existing fossil-fueled power plants is in decline, so if new plants are built, they will be displacing existing units. This suggests that, all other things held equal, the best and cheapest location for new generating capacity is near existing power stations—or, if feasible, on the sites occupied by existing power stations. This could minimize land costs as well as the costs of tying in to the existing power grid.

2.2.3.2. *Cost of New Generating Capacity*

It is a given that construction projects tend to cost more in Hawaii, for a variety of reasons. EIA periodically assesses the probable cost of building new power facilities in all of the US states (and at multiple locations in the larger states). The latest "base" cost for Advanced Combustion Turbines, and Advanced Combined Cycle plants are shown in the table below, along with the capital costs they estimate for Hawaii. Yes, it is more expensive in Hawaii: 73% more expensive in the case of the Gas Turbine and 49% more expensive in the case of a CCGT.

Figure 60: EIA Capital Cost Estimates, 2010

	Gas Turbine		CCGT	
	Base Cost	Hawaii	Base Cost	Hawaii
Capital Cost, $/kW	$ 665	$ 1,149	$ 1,005	$ 1,497
Fixed O&M, per kW-y	$ 6.70		$ 14.62	
Variable O&M, per MWh	$ 9.87		$ 3.11	

Source: EIA, Nov. 2010
Updated Capital Cost Estimates for Electricity Generating Plants

One of the problems with EIA's numbers, however, is that they are for plants that are quite large relative to Hawaii's market. The reference capacity for the GT above is 210 MW, while the CCGT uses a 400 MW unit as a basis.

Since the EIA's numbers were published in 2010, and based on analysis done somewhat earlier, one might suspect that these costs had increased with inflation in the interim. It is more likely the opposite, however, as turbine efficiencies keep climbing and costs in general are tending to decrease somewhat.

GE is a leading technology vendor for GT and CCGT licenses and equipment, and they were kind enough to provide us with analyses of smaller CCGTs. They conducted their analysis using GT-Pro, a widely used engineering software package that takes account of ambient climatic conditions as well as differences in labor and materials costs. They provided us with cost and efficiency analyses at plants ranging in size from 113 MW to 241 MW. The 113 MW (net) plant—the one we feel is most appropriate for the analysis on Oahu—costs out at US$1,331/kW (with US$6.10/MWh Variable O&M cost).

HECO also provided estimates (via Black & Veatch) of CCGT costs from a previous analysis submitted as part of their IRP. Their numbers are quite different—about US$3,500/kW—but they are for a fundamentally different kind of system. The GE analysis looked at a 113 MW "2x1" (two gas turbines and one steam turbine) system; HECO analyzed a much smaller 58 MW (net) plant in a 1x1 configuration. The "Direct Costs" reported by HECO are about US$1,000/kW cheaper, and are therefore more in line with what might be expected for a much smaller unit.

The difficulty in applying the above HECO estimates to the question posed in this study—what are the likely savings?—is that this unit studied by HECO is intended to fulfill different duties than existing units and give the company more flexibility in load-following. The capital cost required is thus a consequence of system design rather than the use of LNG. The only way to compare apples to apples in this situation is to ask what the savings from LNG would be in the same plant (or an equivalent plant) using another fuel—in this case, presumably diesel. To put it another way, a plant fitting this description may well be needed for load-following, but it would be needed irrespective of whether or not LNG is ever introduced to the islands.

There is also an inherent problem in comparing costs between an existing facility and a newbuilt plant in a market where demand is contracting. If a newbuild is *replacing* existing capacity, then the capital costs can be attributed to the newbuild. But the non-fuel operating and maintenance costs of the new capacity ought to be offset by reductions in non-fuel operating and maintenance costs in capacity that will be closed. For example, it is quite probable that the staffing for the new plant will be drawn from other plants that will be closed. Other operating costs will also be eliminated, or transferred to the new facility. When capacity is replaced, O&M costs for the system might increase somewhat, decrease somewhat, or stay roughly the same; but it does not make sense to assume that capacity can be replaced without a decrease in the operating cost of the older capacity.

2.2.3.3. *New Baseload CCGTs*

Oahu already has a CCGT—Kalaeloa Partners—and, unsurprisingly, it runs at by far the highest utilization rate (77%) of any oil-fired facility in the State. Kalaeloa's heat rate in 2011 clocked in at 8,410 Btu/kWh, as opposed to the average 10,440 of the rest of the oil plants on Oahu. (It might be higher if the maintenance requirements from burning LSFO were not so demanding.) Kalaeloa is being run as a baseload plant because, with the exception of the AES coal plant, it is the cheapest source of fossil-fueled power.

There is still room for the introduction of more baseload and intermediate capacity on Oahu—but the elbow room may narrow as more renewables are introduced. (Or it may not. As we have stressed many times in this report, the kinds of renewables in the energy mix make a massive difference to the kind of conventional capacity that matches best.)

We calculated the results for a new, 113 MW CCGT running natural gas versus natural gas in conventional equipment. The assumptions are a 3-mile, 5-inch pipeline at US$400,000 per inch-mile, and capital costs of US$1,331/kW, with a 10% IRR on investment. The CCGT costs are capital costs and fixed O&M alone (since, as discussed above, the net change in variable system O&M might be positive or negative as capacity is being replaced).

If the plant does no better on heat rate than the Kalaeoloa plant, then moving to a CCGT offers no net savings compared to burning gas in an existing facility. On the other hand, if it runs at heat rates of about 7,400 Btu/kWh, then it saves an additional 10%. Moving to CCGTs as existing equipment needs to be replaced is probably warranted, and moving to CCGTs and other advanced technology as required for load-following is a necessity. Lest it get lost in the details, however, let us emphasize that the bulk of savings possible in the power sector are from the replacing oil with LNG, not from moving to more advanced power-generation technologies.

2.2.3.4. *The "Hybrid" Option*

A CCGT is nothing more than a conventional steam turbine fed with the waste heat of one or more gas turbines. The idea is thermodynamically simple, but it took decades to make it practical. But GTs (mostly for peaking power) and CCGTs are now the technology of choice for gas or oil-fired power in most of the world. (The biggest exceptions are Iraq and Saudi Arabia, where steam turbines have been built recently to burn crude directly from the oil fields.)

Hawaii, and Oahu in particular, has a huge capacity of oil-fired steam turbines (although these are largely gone from the rest of the US). Because of this, it is tempting to consider the possibility of adding gas turbines upstream of the steam turbine. The problem is quite site-specific. The location of the gas turbines and the placement of the heat recovery steam generator are an issue, and the match between the heat requirements of the steam turbine and the new gas turbines can result in efficiency losses.

Oahu also poses two specific problems. First, the steam turbines tend to be quite old. Second, the size of the steam turbines is generally inversely related to their age: the oldest turbines are 50-60 MW, and the newer turbines are 90-140 MW. This would not pose a problem in a service area with large and growing conventional power demand, but it poses a serious problem on Oahu. The typical configuration of a CCGT is "2x1," meaning that a steam turbine of 1 MW is accompanied by 2 MW of GT capacity upstream. This means that older units, of 50-60 MW, might transform into a CCGT of 150-180 MW. The newer units of 90-140 MW, however, would become CCGTs of 180-420 MW, which is almost certainly more than the system can absorb.

Based on estimates from industry sources, however, the capital cost savings from building around existing steam plants could amount to 25-45% of the investment costs—but this is very dependent on the site, existing design, and layout. Since we are discussing units that are already decades old, the practicality of this can be questioned.

On the other hand, tens of millions of dollars are involved in the investment, so the possibility of "hybridizing" at an existing site should be carefully examined before committing to greenfield solutions.

Assuming a reduction in capital costs of 35% and heat rates of 7,400-8,400, this could save 4-14% as compared to gas under steam boilers. As before, it is important to keep in mind that the main driver of savings is the introduction of cheaper LNG as a fuel. The effects of generation technologies onshore are important, but they are also incremental. It is the sourcing of the LNG that has by far the most impact.

2.2.3.5. *Diesel vs. LNG in Load-Following*

Both diesel and natural gas are often used in both GTs and CCGTs. Indeed, diesel is sometimes used as the backup fuel in GTs and CCGTs where gas is the main fuel.

Standalone steam turbines are the least efficient means of generating power from oil products, but they are the dominant technology on Oahu. With the HCEI and RPS coming into increasing force in coming years, other, more responsive generation technologies may be required (depending, once again, on the mix of renewable technologies). There seems to be a general expectation that the renewables will be intermittent and non-dispatchable (e.g., mostly wind and solar)…although this is not a foregone conclusion.

If the renewables entering the system are intermittent and non-dispatchable, then complementary conventional generating facilities will have to be increasingly load-following.

The nature of load-following plants is that they are responsive to demand fluctuations, but they do not generate power a high percentage of the time. Their capital cost per kWh is often astronomical compared to baseload plants, but they are a critical part of any modern power system. If such new systems must be added to the grid—at costs per kWh well above baseload costs—then the question becomes what the comparable fuel costs might be. On Oahu, the only realistic options are diesel and natural gas (via LNG).

Therefore, to do the comparison, all that is needed is the average heat rate, and, for the gas, the pipeline cost per kWh; the capital cost of the plant is the same for either fuel. The example considered below assumes a 5-inch pipeline and a 3-mile run at US$400,000 per inch-mile. It uses a 60 MW plant running at 10% utilization, with a heat rate of 7,660 Btu per kWh. The savings are substantial.

Figure 61: LNG vs. Diesel in CCGT Peaking Plant, 3-mile Pipeline

USWC LNG Base Case	2015	2020	2025	2030
LNG, $/mmBtu	na	$ 13.62	$ 15.01	$ 15.89
Fuel Cost, c/kWh	na	10.43	11.50	12.17
Pipeline, c/kWh	na	1.34	1.34	1.34
Total Fuel Cost, c/kWh	na	11.77	12.84	13.51
Savings, FGE Oil Prices				
Diesel Fuel Cost, c/kWh	na	19.28	19.97	20.11
LNG Savings, c/kWh	na	7.51	7.13	6.59
LNG Savings, %	na	39%	36%	33%
Savings, EIA Oil Prices				
Diesel Fuel Cost, c/kWh	na	19.63	20.56	21.43
LNG Savings, c/kWh	na	7.86	7.72	7.91
LNG Savings, %	na	40%	38%	37%

Because the unit produces relatively few kWh per year, the pipeline costs per kWh are substantial. It is worth asking how the result would change if the same plant required a longer run. The results of a 10-mile pipeline delivery are shown in the figure below. The longer run definitely cuts into the savings compared to diesel, but gas still provides savings of around 20%—even with a 4.5 cent/kWh pipeline charge. (A 10-mile run to a baseload plant would be far more economical; the case below is really a worst-case scenario).

Figure 62: LNG vs. Diesel in CCGT Peaking Plant, 10-mile Pipeline

USWC LNG Base Case	2015	2020	2025	2030
LNG, $/mmBtu	$ -	$ 13.62	$ 15.01	$ 15.89
Fuel Cost, c/kWh	$ -	10.43	11.50	12.17
Pipeline, c/kWh	$ -	4.47	4.47	4.47
Total Fuel Cost, c/kWh	$ -	14.90	15.97	16.64
Savings, FGE Oil Prices				
Diesel Fuel Cost, c/kWh	na	19.28	19.97	20.11
LNG Savings, c/kWh	na	4.38	4.00	3.46
LNG Savings, %	na	23%	20%	17%
Savings, EIA Oil Prices				
Diesel Fuel Cost, c/kWh	na	19.63	20.56	21.43
LNG Savings, c/kWh	na	4.73	4.59	4.79
LNG Savings, %	na	24%	22%	22%

2.3. *Fuel Conversion and New EPA Emissions Controls*

New EPA regulations coming into play in the 2016-2017 period will affect allowable emissions from Oahu's steam turbine plants. The power industry has faced decades of increasingly tight standards on common pollutants such as sulfur, but the new regulations not only address sulfur, but also a host of various particulates. The regulations, known as MATS (Mercury and Air Toxics Standards) and MACT (Maximum Achievable Control Technology), were directed mainly at less-advanced coal plants, but the ash content of LSFO is high enough that it cannot comply with the new standards without adding major “back-end controls” to every unit.

The capital costs of compliance are estimated by HECO to amount to US$583 million for the six units at Kahe, and US$361 million for the four steam units at Waiau—a total investment of nearly a billion dollars. Ironically, the investment would be required to keep burning fuel oil at a time when both HECO and the State are attempting to move away from oil.

If the costs of these new controls are amortized over 20 years, and if the output of Kahe and Waiau remain constant at recent levels, then the control systems would add about 2.3 cents per kWh to Kahe’s power cost, and 4.2 cents to Waiau’s power cost. But this assumes that both plants will continue to burn fuel oil for the next twenty years, and that both will continue to run at existing utilization rates. In actual practice, a 20-year commitment to fuel oil at both plants seems improbable given HECO’s goals in renewables; and there is a good chance that utilization rates will decline even if all the capacity remains online. In other words, 2.3 and 4.2 cents per kWh is a conservative estimate of the extra cost to the consumer—it would probably be more.

An alternative to adding back-end controls is to burn low-sulfur diesel instead. As discussed in Chapter 3, this could pose serious problems for the refining sector, which would have a shortage of diesel and a surplus of LSFO. Nonetheless, low-sulfur diesel does meet all of the new emissions standards without having to add expensive new scrubbers and baghouses.

The figure below compares all three options for the Waiau plant. Because its annual output is lower, Waiau’s control costs are much higher than Kahe’s. The LNG delivery costs are also higher (this assumes a retrofit cost of US$1 mm per unit, and an 8-inch pipeline over a five-mile run).

Diesel can indeed save money compared to LSFO plus controls. The results point out the differences between the FGE and EIA oil forecasts, however; there is a comfortable savings margin between diesel and the LSFO option in EIA’s outlook, but in FGE’s view the savings narrow steadily and become quite slim.

We have already seen that LNG, even if burned in a conventional steam turbine plant, can offer major savings over LSFO. When the extra cost of controls is added in, the savings expand even more, generally toward savings of 50% or more.

Figure 63: Waiau Power Plant: LSFO with Back-end Controls vs. Diesel vs. LNG

FGE OIL PRICES	2017	2018	2019	2020	2025
LSFO, US$/mmBtu	$ 22.55	$ 22.79	$ 23.03	$ 23.28	$ 22.88
Fuel Cost, c/kWh	24.1	24.4	24.6	24.9	24.5
Controls--current util, c/kWh	4.2	4.2	4.2	4.2	4.2
LSFO Option, c/kWh	28.3	28.6	28.8	29.1	28.7
LS Diesel, US$/mmBtu	$ 23.84	$ 24.28	$ 24.72	$ 25.17	$ 26.07
Diesel Option, c/kWh	25.5	26.0	26.5	26.9	27.9
Diesel Savings, c/kWh*	2.8	2.6	2.4	2.2	0.8
Diesel Savings, %*	10%	9%	8%	7%	3%
LNG, US$/mmBtu	$ 13.38	$ 13.46	$ 13.54	$ 13.62	$ 15.01
Fuel Cost, c/kWh	14.3	14.4	14.5	14.6	16.1
Pipeline & Retrofit, c/kWh	0.2	0.2	0.2	0.2	0.2
LNG Option, c/kWh	14.6	14.6	14.7	14.8	16.3
LNG Savings, c/kWh*	13.8	13.9	14.1	14.3	12.4
LNG Savings, %*	49%	49%	49%	49%	43%

EIA OIL PRICES	2017	2018	2019	2020	2025
LSFO, US$/mmBtu	$ 25.92	$ 26.10	$ 26.33	$ 26.58	$ 27.61
Fuel Cost, c/kWh	27.7	27.9	28.2	28.4	29.5
Controls--current util, c/kWh	4.2	4.2	4.2	4.2	4.2
LSFO Option, c/kWh	31.9	32.1	32.4	32.6	33.7
LS Diesel, US$/mmBtu	$ 24.95	$ 25.13	$ 25.32	$ 25.63	$ 26.85
Diesel Option, c/kWh	26.7	26.9	27.1	27.4	28.7
Diesel Savings, c/kWh*	5.2	5.2	5.3	5.2	5.0
Diesel Savings, %*	16%	16%	16%	16%	15%
LNG, US$/mmBtu	$ 13.38	$ 13.46	$ 13.54	$ 13.62	$ 15.01
Fuel Cost, c/kWh	14.3	14.4	14.5	14.6	16.1
Pipeline & Retrofit, c/kWh	0.2	0.2	0.2	0.2	0.2
LNG Option, c/kWh	14.6	14.6	14.7	14.8	16.3
LNG Savings, c/kWh*	17.4	17.5	17.6	17.8	17.4
LNG Savings, %*	54%	54%	55%	55%	52%

**Compared to LSFO plus back-end controls*

Kahe presents a somewhat different picture. With the same per-unit retrofit costs, and a five-mile, 10-inch pipeline, the major difference is in the output of the plant: Kahe is not only larger, but has much higher utilization than Waiau.

As the figure below shows, the savings from LNG are still large, but the savings from diesel substitution are more questionable. In the FGE forecast, the savings from diesel eventually go negative.

Figure 64: Kahe Power Plant: LSFO with Back-end Controls vs. Diesel vs. LNG

FGE OIL PRICES	2017	2018	2019	2020	2025
LSFO, US$/mmBtu	$ 22.55	$ 22.79	$ 23.03	$ 23.28	$ 22.88
Fuel Cost, c/kWh	23.0	23.3	23.5	23.8	23.4
Controls--current util, c/kWh	2.3	2.3	2.3	2.3	2.3
LSFO Option, c/kWh	25.3	25.6	25.8	26.1	25.7
LS Diesel, US$/mmBtu	$ 23.84	$ 24.28	$ 24.72	$ 25.17	$ 26.07
Diesel Option, c/kWh	24.4	24.8	25.3	25.7	26.6
Diesel Savings, c/kWh*	1.0	0.8	0.6	0.3	(1.0)
Diesel Savings, %*	4%	3%	2%	1%	-4%
LNG, US$/mmBtu	$ 13.38	$ 13.46	$ 13.54	$ 13.62	$ 15.01
Fuel Cost, c/kWh	13.7	13.8	13.8	13.9	15.3
Pipeline & Retrofit, c/kWh	0.1	0.1	0.1	0.1	0.1
LNG Option, c/kWh	13.8	13.9	13.9	14.0	15.4
LNG Savings, c/kWh*	11.6	11.7	11.9	12.1	10.2
LNG Savings, %*	46%	46%	46%	46%	40%

EIA OIL PRICES	2017	2018	2019	2020	2025
LSFO, US$/mmBtu	$ 25.92	$ 26.10	$ 26.33	$ 26.58	$ 27.61
Fuel Cost, c/kWh	26.5	26.7	26.9	27.2	28.2
Controls--current util, c/kWh	2.3	2.3	2.3	2.3	2.3
LSFO Option, c/kWh	28.8	29.0	29.2	29.4	30.5
LS Diesel, US$/mmBtu	$ 24.95	$ 25.13	$ 25.32	$ 25.63	$ 26.85
Diesel Option, c/kWh	25.5	25.7	25.9	26.2	27.4
Diesel Savings, c/kWh*	3.3	3.3	3.3	3.3	3.1
Diesel Savings, %*	11%	11%	11%	11%	10%
LNG, US$/mmBtu	$ 13.38	$ 13.46	$ 13.54	$ 13.62	$ 15.01
Fuel Cost, c/kWh	13.7	13.8	13.8	13.9	15.3
Pipeline & Retrofit, c/kWh	0.1	0.1	0.1	0.1	0.1
LNG Option, c/kWh	13.8	13.9	13.9	14.0	15.4
LNG Savings, c/kWh*	15.0	15.1	15.3	15.4	15.1
LNG Savings, %*	52%	52%	52%	52%	49%

**Compared to LSFO plus back-end controls*

The annual savings (based on 2020) for LNG in these two plants is US$500-650 million annually when compared with the option of burning LSFO with back-end controls added.

By way of comparison, the annual savings from diesel are US$30-150 million annually—and run a very real risk of going negative in the longer term.

Unfortunately, the chances of delivering LNG economically before the MATS and MACT regulations are enforced are quite low.

For reasons that should be obvious from the foregoing, one of the plans under discussion is to switch from LSFO to diesel rather than installing back-end controls. A switch to diesel might also be applied to fuel-oil-fired power plants on the neighbor islands (who are also subject to new EPA regulations). This would obviously slash the market for fuel oil and increase diesel demand dramatically, requiring exports of fuel oil and imports of diesel. Moreover, if a refiner was to cease operation in the same timeframe—which could easily happen—the diesel import requirements would soar even higher; the utilities are not the only diesel users in the State. In a previous analysis we have done of this situation, we saw scenarios where as many as six cargoes per month of diesel imports might be required.

The problem is not one of diesel supply—there are ample volumes available for import—but of physical logistics. There are presently limited facilities for diesel imports (and the refiners' pipelines are licensed for only small volumes). Importing large volumes of diesel would pose serious challenges—though they are not insurmountable. But switching away from fuel oil to diesel and then from diesel to LNG over the period of a few years would be very disruptive for a refining industry that is already in poor economic health.

The EPA can (and does) grant waivers. We understand they generally do not comment on waivers unless an application is made. Historically they are reluctant to grant waivers where the argument is economic hardship or increased prices. On the other hand, based on conversations with those knowledgeable about environmental affairs, we believe there is a good chance that they would be receptive to granting waivers when the reason for delay is to put in place infrastructure that will result in a major improvement in the environment. This would be even more probable if the proposal came from the State and the Hawaii Congressional Delegation rather than from affected utilities alone. This seems like an option that should be explored if Hawaii decides to proceed with LNG imports.

LNG is the cleanest of all fossil fuels. It is possible to imagine a future when low-sulfur diesel is no longer acceptable without control systems, but LNG is the standard by which other fossil fuels are judged. Between the HCEI and a plan to replace oil with LNG, the State could make a very good case to the EPA for granting a waiver. This would avoid the "diesel dislocation" that otherwise seems probable.

2.4. *Possible Vehicular Uses of LNG/CNG*

There is considerable confusion about LNG and CNG fueling stations. The topic deserves a little explanation.

Most CNG-only stations have their own compressors and tanks, and receive their fuel from natural gas pipelines. In fact, there are home versions of these compressors that allow the owners of CNG vehicles to refuel their vehicles from their residential gas pipeline connections.

But some CNG-only stations produce all of their fuel from LNG delivered by truck-mounted ISO containers. This most often is done because of some kind of infrastructure limitations. For example, the Santa Cruz (CA) Municipal Transportation Department's CNG station does not have access to gas pipelines. Such stations have LNG storage tanks, but do not dispense LNG; all of their LNG is evaporated into CNG. These are often referred to as "LCNG" (LNG-to-CNG) stations; but "LCNG" is also sometimes used to refer to stations that dispense CNG from LNG and also offer LNG directly.

Most LNG-only stations receive their LNG via ISO containers carried on trucks (but there is a move toward developing large LNG fueling stations that would have their own liquefaction plants onsite).

There are an increasing number of stations where the LNG supplies both the LNG and, after partial regasification, supplies CNG to a separate set of pumps. These are sometimes called L-CNG or L/CNG stations.

So, if a station has no LNG storage, it can only be a CNG station. But if there is an LNG storage tank, it could be LNG-only, CNG-only, or LCNG.

In the Hawaii context, this means that LNG fueling would have to be based on truck deliveries of ISO containers. On the other hand, CNG could be supplied via LNG delivery on ISO containers, or, in areas where pipeline gas is available, could be supplied by compressors at the station.

As mentioned earlier, LNG is a practical fuel only for heavy-use vehicles. Not only is installing LNG tanks and engines expensive, the ideal vehicle for LNG is one where the natural tendency of LNG to boil-off is countered by heavy use. If a vehicle is used for only a few hours a day, then LNG is a poor choice.

For this reason, the most likely fuel for passenger vehicles is CNG. Heavy-duty vehicles can use either CNG or LNG, although LNG is usually preferred when it is available.

2.4.1. CNG in Passenger Vehicles

Some of the complexities which dog analysis of gas in road transport on the mainland are not an issue in Hawaii. Mainland stations dealing with LNG need to do careful tradeoffs between onsite liquefaction and trucking in LNG from liquefaction plants. In the case of Hawaii—assuming that the LNG is not all regasified!—this choice need not be examined, since it has already been liquefied by the export source. In addition, the matter of range between fueling stations is not a limitation. Growth in the use of natural gas vehicles on the mainland has always been held back by the lack of a nationwide refueling network. On islands, it would be easy to ensure that no one could get beyond the reach of the supply network (even on the Big Island).

Calculating the cost of adding CNG to a station is highly speculative, since there are many factors (including space constraints) that affect the price. Some sources estimate the incremental cost of CNG at an existing site as US$500-700,000 per station—but half of the cost is typically the gas compressors. If the gas is delivered as LNG, the cost is probably closer to US$250-350,000 per station. Assuming that construction averages 50% more in Hawaii for such specialized work, this suggests a cost of US$375-525,000 per station.

Although sales volumes vary widely between stations, a typical Hawaii station may have a throughput of 1.5 million gallons per year. If CNG captures 25% of this throughput in energy terms, that amounts to a CNG throughput of about 375,000 GGE per year. (GGE is gallons of gasoline equivalent, taken at 114,000 Btu per GGE. It is important to note that for transport applications, lower heating values (LHVs) are typically used. LNG is taken at a LHV of 71,700 Btu/gallon.)

If the construction cost is amortized over 10 years at 15%, then the cost per GGE is 20-28 cents. Adding 30% additional operating cost increases the cost to 26-36 cents per GGE. LNG delivery via ISO is estimated at US$500 per trip, which amounts to 9 cents per GGE, giving a delivered cost of 35-46 cents per GGE (amounting to US$4.37-5.65 per mmBtu, for an average of US$5.01 per mmBtu).

Using the 2020 landed LNG price on Oahu, this means an LNG price at the station of US$18.50/mmBtu. This amounts to US$2.11/GGE. To this must be added a retail margin, assumed to be 8%, giving a pretax price of US$2.28/GGE.

Assuming that taxes will be applied per GGE at current rates for gasoline, this adds about 52 cents per GGE, plus 4% sales tax, resulting in a final pump price of US$2.91/GGE.

How does this compare to other options? Once again this requires a great number of assumptions. FGE's price forecast sees gasoline at about US$4.90/gallon in 2020. The electricity price is a large question mark. In principle, LNG could bring power prices down, but renewables might increase them; for purposes of this exercise, we assume 35 cents/kWh. The figure below shows the implications of these assumptions.

Figure 65: Fuel Savings Against Conventional Gasoline Cars

	Chevy Volt	Honda Civic		
	Electric	Gasoline	Hybrid	CNG
Fuel, unit	kWh	gallons	gallons	GGE
Fuel use per 100 miles	36	3.1	2.3	3.2
Fuel Cost, $ per unit	$ 0.35	$ 4.90	$ 4.90	$ 3.16
Fuel Cost per 100 miles	$ 12.60	$ 15.31	$ 11.14	$ 10.18
Fuel Savings vs Gasoline	18%	0%	27%	34%
Car Price (2012) MRSP	$ 39,145	$ 15,755	$ 24,050	$ 26,155

Performance details from USDOE FuelEconomy.gov

Although electric cars are widely assumed to have a large advantage over other options—an idea reinforced by free recharging stations at various locations—if electric cars are fueled at something like Hawaii power prices, they are not necessarily the best option. Off-peak pricing for charging might be able to improve this outlook, as might direct charging from photovoltaics.

The Honda Civic is used in this comparison because it is the only car that is manufactured with three different fuelling options; unfortunately, there is no electric version as yet.

Depending on the miles driven, the total ownership and fueling costs per mile could tell a very different story. On the other hand, the 2012 MSRP for cars may tell us very little about the relative prices and performance of cars by the end of the decade. Electric cars and CNG cars in particular are still in their early stages of development, and it is expected that prices may fall considerably as the market for such vehicles expands.

CNG (via LNG delivery) shows the best performance in terms of fuel costs in this analysis. Nonetheless, this is a simplified examination of the problem, based on broad estimates rather than detailed construction costing. This is a topic that deserves closer examination, but the numbers we have derived here point to the possibility of large savings from the use of CNG. The savings from CNG should also apply to light-duty fleet vehicles.

2.4.2. Gas Fuels in Heavy-Duty Vehicles

Only a few years ago, LNG or CNG heavy-duty vehicles cost up to US$100,000 more than their diesel counterparts. These costs have fallen rapidly, and may fall further. CNG and LNG trucks are comparable in price; according to Freightliner, the premium for LNG vehicles is US$37-42,000, while the premium for CNG is US$40-45,000.

For a heavy-duty fleet vehicle in Hawaii, the choice between LNG and CNG is largely one of the desired time before returning to base to refuel. There is also some concern that LNG-fueled vehicles may require more maintenance (although there is not yet enough evidence to decide). It would require detailed study to decide between LNG and CNG for a given use.

Fortunately, in the case of Hawaii, the product will be delivered onshore as LNG (unless a decision is made to undertake offshore regasification, in which case there will be no LNG). This means that central fueling stations in Hawaii could easily be based on LNG, CNG, or a combination.

To get a sense of the likely economics, consider a heavy-duty, Class 8 vehicle. Assume that it operates 8 hours per day, 300 days per year, with an average speed of 25 mph and an average diesel consumption of 4.25 miles per gallon. (The miles per gallon assumption is the midpoint estimate for heavy Class 8 vehicles from Oak Ridge National Labs.) This results in an annual consumption of a little more than 14,000 gallons per year.

The delivery and station cost for the CNG option provide a good estimate for a central fueling station as well. One difference between diesel and gasoline apart from volatility, however, is that diesel contains more energy per gallon than gasoline—typically 129,500 Btu/gal versus 114,000 Btu/gal. Therefore, a DGE (diesel gallon equivalent) of gas is about 14% more energy than a GGE.

If we assume US$40,000 as the average cost premium of a CNG or LNG fuelled truck, then with amortization over 10 years at 15%, the economics in 2020 are those shown in the figure below.

Figure 66: Natural Gas Fuel Savings in Heavy Fleet Vehicles

CONVENTIONAL OPTION		
Diesel, gal/y		14,000
Diesel cost/gal	$	5.48
Diesel cost/y	$	76,720

LNG/CNG OPTION		
DGE gal/year		14,000
DGE cost/gal	$	3.51
DGE cost/y	$	49,168
Amortization/y	$	7,970
Total Cost/y	$	57,139
Savings	$	19,581
% Savings		26%

Even with a hefty annual charge to retire the extra cost of the gas vehicle, the potential savings are quite large—about a quarter less than the standard diesel option.

As with CNG in passenger cars, the option appears promising, but requires detailed, site-related studies to provide more precise costs.

2.5. *Marine Use of LNG*

Marine use of LNG is relatively new, but it is spreading rapidly in the Baltic, and plans are being laid for systems of bunkering that cover all of Europe. There is also a great deal of planning afoot in the US—not only because of the low prices of US gas, but also because of the IMO regulations mentioned in the previous chapter.

There is not a great deal of experience with conversion of marine vessels to LNG, but there are marine engine manufacturers with engines for sale, and some groups (notably the American Clean Skies Foundation) have studied the retrofitting issue.

For the ~4,000 horsepower (hp) tugs often used in interisland navigation, installation of a new LNG powered engine is projected to cost about US$1.6 million. The most expensive element in the conversion is the LNG storage tank; eight days of fuel storage is estimated to cost about US$4.5 million, bringing the total to around US$6.1 million for the full conversion. (In principle, CNG can also be used, and CNG tanks can be less expensive, but they take up far more space. They are probably not practical on a tugboat.)

Although more permanent storage might be built, the cheapest and most easily implemented way of fueling would be directly from a truck-mounted ISO container at the dock. For purposes of this analysis we have assumed that fueling would cost US$1/mmBtu, but it could be cheaper or more expensive depending on what alterations need to be made dockside.

One major difference between marine fuels and road fuels is the comparative lack of taxes. Marine diesel pays no road use taxes, and is subject only a 2 cent per gallon state tax (as well as sales tax). Presumably the same rules will apply to LNG.

Using 2020 as a benchmark once again, the figure below gives the estimated economics of conversion of a 4,000 hp tugboat to LNG. Once again, amortization at 15% over ten years is assumed.

Figure 67: Estimated Economics of Tugboat Conversion to LNG

CONVENTIONAL OPTION	
Diesel, gal/y	564,000
Diesel cost/gal	$ 4.96
Diesel cost/y	$ 2,797,440

LNG CONVERSION	
DGE gal/year	564,000
DGE cost/gal	$ 2.23
DGE cost/y	$ 1,258,808
Amortization/y	$ 1,215,438
Total Cost/y	$ 2,474,246
Savings	$ 323,194
% Savings	12%

Conversion to LNG appears to offer significant savings, but it needs to be stressed that these numbers are very hypothetical. We expect a flurry of conversions in Europe and the US by the middle of the decade, so the real costs of conversion and retrofitting should be understood before LNG fuelling becomes an option in Hawaii.

2.6. *Other Implications and Uses of LNG*

2.6.1. SNG and Propane Substitution

The multiple steps taken to derive the delivered price of LNG on Oahu, and then carry that through to the economics of power generation, make it clear that assessing the economic viability of LNG in Hawaii in general is a complex matter.

There is an exception to that rule, however. To be blunt, substituting LNG for utility SNG or propane is a "no-brainer." Petroleum products in Hawaii are expensive, and manufacturing gas from them makes it even more expensive. As HAWAIIGAS has understood for some time, even importing LNG in ISO containers is cheaper than existing utility SNG and propane: the savings even via high-cost ISOs is typically 30% or more.

As shown in the figure below, if LNG is delivered in bulk to an onshore terminal, the savings in gas supply costs could be as high as two-thirds. If gas prices decline substantially, gas usage would probably expand, and this fact would be a good thing: in heat-based end-uses such as cooking or clothes drying, gas has a powerful efficiency advantage over burning fossil fuels to generate electricity to then generate heat.

Figure 68: Savings from LNG Displacement of SNG (US$/mmBtu and %)

	2015	2020	2025	2030
SNG Price	$ 40.09	$ 42.49	$ 43.76	$ 43.72
ISO delivered Cost	$ 27.47	$ 27.82	$ 29.07	$ 29.86
Savings	$ 12.62	$ 14.67	$ 14.68	$ 13.85
% Savings	31%	35%	34%	32%
LNG Bulk Cost		$ 13.62	$ 15.01	$ 15.89
Savings		$ 28.87	$ 28.74	$ 27.83
% Savings		68%	66%	64%

Even if, for whatever reasons, Hawaii decides not to undertake large-scale imports of LNG, smaller-scale imports via ISOs are still competitive and should be encouraged.

2.6.2. Use of Coolth

Given the great pains that are taken to liquefy gas and keep it insulated to prevent warming, it is somewhat ironic that in the majority of the world's LNG import terminals some of the delivered gas is burned to regasify the LNG.

The amount consumed in regasification is not large, but it is a waste of energy. Furthermore, thermodynamically speaking, any time there is a large temperature difference between two points, that temperature gradient is a source of energy. LNG is so cold that it has a huge temperature gradient with respect to normal air temperature.

Harnessing the "cold energy" or "coolth" not only provides a source of energy, but also slashes the use of energy for regasification. Although only a fraction of the world's import terminals harness coolth, cold energy projects at LNG import terminals in Japan have been in operation for decades. Japan of course faces high energy prices and relies on imports for most energy supplies…but the same could be said of Hawaii.

The figure below shows some of the existing applications of cold energy. Japan has long been the leader (as befits the world's largest LNG importer), but more countries are beginning to study the issue, including Italy and the UK.

Figure 69: Applications of Coolth at LNG Import Terminals

Application	Country	Scale
Power Generation	Japan	21 MW
Liquefying Nitrogen, Oxygen, Argon	Japan	
Refrigeration/Cold Storage	Japan, Korea	
Cooling Gas Turbine Air	India, Japan, Spain	
Dry Ice	Japan	3.3 t/y
Cryogenic Pulverization of Plastics/Wastes	Japan	7,000 t/y

Source: Ng, Gordon Kar-Wai, 2006
Recovery and Utilization of Cold Energy of Liquefied Natural Gas

One of the most important and simple uses is in refrigeration for agricultural products; the Japanese have used it for freezing food, including fish. There are also a number of studies and demonstrations of cold energy desalination.

Obviously exploiting coolth is not a top priority in the early stages of establishing LNG in Hawaii, but it certainly deserves a wide-ranging, open-minded examination—possibly by engineering faculty and students at the university. It is an opportunity to take a wasted energy resource and match it with a need in the Hawaii economy.

2.6.3. Decoupling from Asia Pacific Oil Markets

It is apparent from the analysis done of the power sector in the foregoing pages that if LNG is sourced from the Lower 48, its price has very little connection with the price of oil. To the extent that LNG displaces oil, it also breaks the State's ties to oil price movements.

Barring major breakthroughs in technology, a considerable degree of energy-price dependence on oil will continue through the near future. There are two reasons for this. One is that even with the most aggressive substitution campaign possible, Hawaii will still be oil-dependent. With a concerted effort, oil can be driven entirely out of the power sector; and major inroads can be made in some forms of transportation. But even under the most stringent scenario, Hawaii will remain critically dependent on large volumes of jet fuel—and probably more than that.

The second reason is that substitution, whether the source of the substitutes is renewables or LNG, will take time. To some extent, the ultimate pace is set by the HCEI and RPS. A smart LNG strategy has to look forward toward 2030 and see how much oil the HCEI will leave—and plan for that level rather than building infrastructure to substitute for oil demand in, say, 2020-2025. So through the middle of the next decade, there will still be "excess" oil in the system waiting for the HCEI to substitute it away.

To put it another way, if Hawaii's LNG strategy gears up to build the infrastructure for maximum oil substitution in the near term, then it will have too much LNG deliverability in the long term.

Not only are the HCEI and RPS pacesetters for the entire process, but uncertainties about the mix of renewables continues to create further uncertainties in the kinds of fossil-fuel facilities that will be needed—especially in the power sector. Substitution cannot move ahead efficiently if the shape and variability of the future load curve remain so uncertain.

2.7. *Conclusions*

The import of LNG into Hawaii could dramatically cut energy costs and reduce reliance on oil. There is no inherent conflict with the goals of the HCEI as long as the imports are scaled to take account of the HCEI and RPS milestones. Indeed, gas in the power sector may help to accommodate renewables by making it easier and cheaper to follow fluctuating loads.

There is a critical distinction to be made between bringing LNG to a central port and bringing gas alone onshore to Oahu. Offshore regasification without a terminal dealing in LNG can provide substantial savings, but those savings will be limited to Oahu utility customers. An LNG terminal, on the other hand, can allow LNG to be moved to the neighbor islands and also supplied to additional sectors such as transportation.

One thing must be emphasized, any savings from LNG are critically dependent on the terms of how the LNG is sourced. Unlike oil, LNG is not a world market. It is entirely possible to arrange deals that would result in little or no savings, or might even be more expensive than oil imports.

In oil, it is possible to get the best deal by simply announcing a tender, but oil is a fully developed, highly liquid market, with huge uncommitted volumes and futures markets for hedging risks. LNG is still highly channelized, with the vast majority of the volume traded tied up in long-term supply arrangements, often at widely differing prices.

In LNG, the best long-term prices are achieved by striking deals before projects are actually built (or by building them). To take the case of Cheniere's Sabine Pass export terminal on the US Gulf Coast, the LNG production was already long sold out before construction began. True, those buyers may be willing to resell some of their volumes—but it will be at "market" prices (if there is such a thing in LNG) rather than the low prices at which they can acquire it.

Importing LNG on a large scale to Hawaii is a major undertaking, involving large investments and affecting other basic energy infrastructure and energy companies. Although we have done our best to assess the likely savings, these depend on oil prices and gas prices, and no one can predict those with any certainty. What this means is that LNG imports should not be sought because of *some* savings. The expected percentage savings should be large—large enough that they ca not be wiped away by comparatively minor changes in the markets.

The economics of imports from LNG suppliers on an oil-linked pricing basis are marginal or even negative. Imports from the US West Coast, and even the US Gulf Coast, are far more promising, but an importer cannot simply get a great deal by tendering or buying "off the shelf." To get the best deal will require innovation and flexibility, and may even require investment in projects.

The planned US export projects—which, apart from Cheniere, may or may not be built—are not the only possible source of LNG from the Lower 48. There is an LNG building boom underway on the mainland, largely to fuel vehicles. And these intermediate-sized LNG plants have better economics than the mega-scale export projects. There are companies willing to build gas-indexed projects on the US West Coast, and there are sites where they can be built. But no one is going to build such a project and then see if a market develops—they will only be built if they are approached with a long-term offtake agreement. A proactive approach is needed.

III. Other Risks and Impacts of Importation of LNG into Hawaii

3.1. *LNG and Oil Price Vulnerability*

3.1.1. Hawaii's Exposure to the Oil Market

"Energy security" was the catchphrase of the 1980s, but most governments did little to achieve it. At the time, the emphasis was on security of physical supply; after the disruptions of the two oil crises of the 1970s, memories of lines at gasoline stations had the public worried that physical cutoffs loomed in the future.

It is worth noting, however, that there was never a true physical shortage in 1973/74 or 1979/80; supplies were always adequate to support normal levels of consumption. Hoarding, or holding back stocks in anticipation of possible shortages, created a perceived supply crisis where none existed.

Today, shortfalls in physical supply are even less of an issue than in the 1970s and 1980s. The world trading network, once almost entirely in the hands of the oil majors, has become a more diverse and sophisticated. Although a natural disaster could cut off supply to certain areas because of damage to supply infrastructure (as happened in certain areas after Hurricane Katrina), the risk of a cutoff of oil from political disruptions is now rather remote. In the modern trading market, oil and refined products are always available…at a price.

The price increases in 2008 and 2010-2012 show that the world oil market is still subject to rapid movements in price. Most analysts feel that the overall price increases in the market will probably be sustained by decreased supply from exporting countries and growing demand in developing importers such as China and India. This does not mean that prices will never fall—it is the nature of the market to fluctuate. But few experts believe that prices will return to 2006 levels of around US$60/bbl; many feel, based on the cost of new supplies coming onstream, that US$80/bbl is a floor.

Except for a few OPEC nations, where oil prices are kept low and constant, everyone is exposed to fluctuations in the price of oil on the international market. (And even OPEC countries with low domestic prices are not immune; while their consumers may be sheltered from the market, their treasuries are affected by every move in the world price.) What distinguishes Hawaii from most locations is the degree of exposure.

In 2010, about 86% of Hawaii's energy came from oil, as compared to 38% for the US mainland. Even more dramatic is the difference in reliance on oil in the power sector. The figures for 2010 show that 74-78% of Hawaii's fuel for electricity is from oil, while on the mainland, oil's role in power has now virtually disappeared, accounting for only 0.8% of fuel in the power sector. Mainland consumers are exposed to oil-price fluctuations at the gas station, but changes in oil prices do not affect their electricity bills.

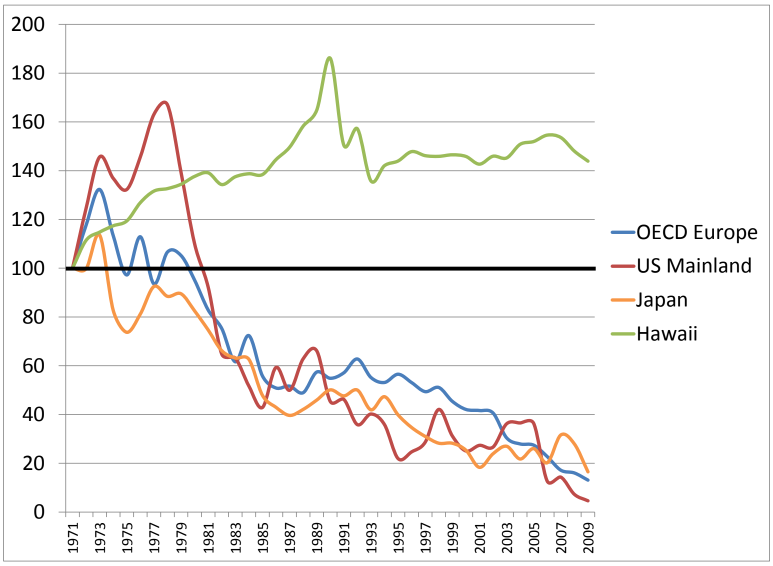
Moreover, the gap in average fuel prices for the power sector, whether oil or other fuels, is now huge. At the end of 2011, the fuel cost of Californian electricity was less than US$5/mmBtu, while the fuel component on Oahu was more than US$21/mmBtu. (This is not strictly a fair comparison, since many of California's generation sources are wind, hydro, or nuclear, where the fuel is either free or a negligible element. On the other hand, it is true that even if these sources have higher capital costs than oil, they are not subject to fluctuation with the world fossil-fuel market.)

Hawaii's exposure to the market is not just an issue in comparison to the mainland US. Consider Japan, which, although larger, shares some important characteristics with Hawaii—an island state reliant on imports for virtually all of its supplies of fossil fuels. In 1980, Japan relied on oil for 51% of its power generation. By 2010, this had fallen to only 9%. The Fukushima disaster has increased Japanese reliance on oil in power, but even so, today's oil burning in the power sector is still below the level seen in 2008.

Japan is not an isolated example. Oil use in power was never large in Europe, amounting to 19% in 1980, but it has recently been driven below 2%. Large developing countries like China and India have always relied primarily on their coal reserves rather than oil for power generation. Even Singapore, a small island state with a massive oil refining industry, took steps in the early 1990s to build subsea pipeline to import gas from Malaysia and Indonesia; although Singapore is probably the most important fuel oil exporter in Asia, 80% of its power is generated by pipeline gas, and plans are underway to begin imports of LNG.

The figure below puts things into perspective. Hawaii fuel oil use in the power sector grew rapidly in the mid-1980s until the advent of the AES coal plant drove it down. Since then it has been roughly constant—but the trends are out of sync with other major regions of the world. Although not shown on the figure, China's fuel oil demand in power boomed as the Chinese economy surged in the 1970s; on the same scale of 1971 = 100, in 1980, China's demand reached 400—but today it is 45. Despite astonishing economic growth, China's oil demand in power is now less than half of what it was in 1971.

Figure 70: Utility Fuel Oil Use (1971 = 100)



Hawaii may not be the most exposed state or country in its level of exposure to the oil market, but it is clearly a leading candidate for the title. The implications for consumers can be seen from the simple example shown below. (This example is simplified, as it includes only the effects of fuel oil prices.) At recent prices, almost three-quarters of any increase in the price of oil feeds straight through into higher prices for electricity customers on Oahu. (The results are similar on other islands.) Thus, no matter what cost-saving measures or business-efficiency practices a Hawaii utility adopts, the savings are negligible compared to the cost of oil.

Figure 71: Estimated Role of Oil in Oahu Power Costs

OAHU LSFO and Power Costs, June 2012		
	Fuel Oil Price, $/bbl	$ 147.50
÷	Heat, mmBtu/bbl	6.27
=	Cost, $/mmBtu	$ 23.52
÷	Btu/mmBtu	1,000,000
x	Heat Rate, (Btu/kWh)	10,422
=	Fuel Cost, $/kWh	$ 0.25
	Oahu $/kWh	$ 0.34
	Fuel Component	72%

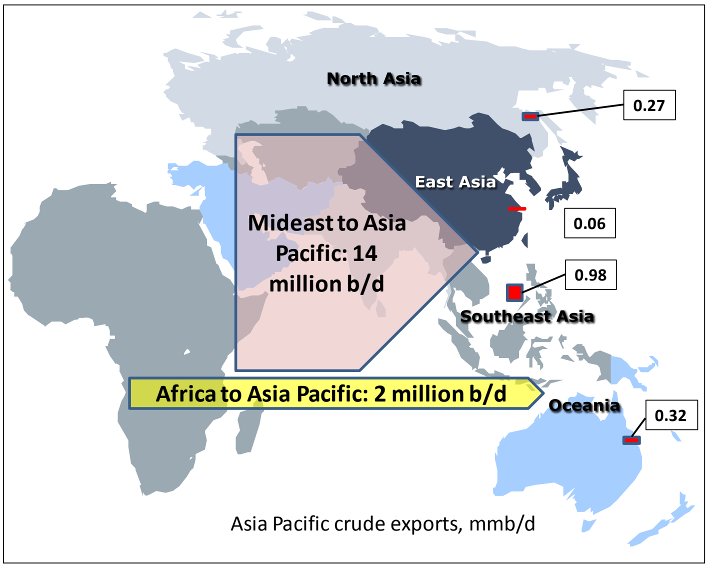
The section on refinery viability will discuss more refinery technology, including desulfurization, but for purposes of this discussion it should be noted here that almost all low-sulfur fuel oil is produced from low-sulfur crudes. With proper equipment, low-sulfur gasoline or diesel can be produced from high-sulfur crudes, but desulfurization of fuel oil is extraordinarily expensive; typical units cost US$1 billon, and the operating costs are extremely high.

Low-sulfur crudes are relatively uncommon. Main producing centers of low-sulfur crude are in West Africa, the North Sea, some areas in the Central US, and a few Asia Pacific countries: Australia, Brunei, China, Indonesia, Malaysia, and Vietnam. The majority of US West Coast, Canadian, and Latin American crudes are very high in sulfur.

When California was a major user of low-sulfur fuel oil in the 1970s, it imported large volumes from Southeast Asia, because those are the only major suppliers accessible from the US West Coast. After California drove fuel oil out of its power system, the refineries quickly made investments to handle increased volumes of very heavy, high-sulfur crudes.

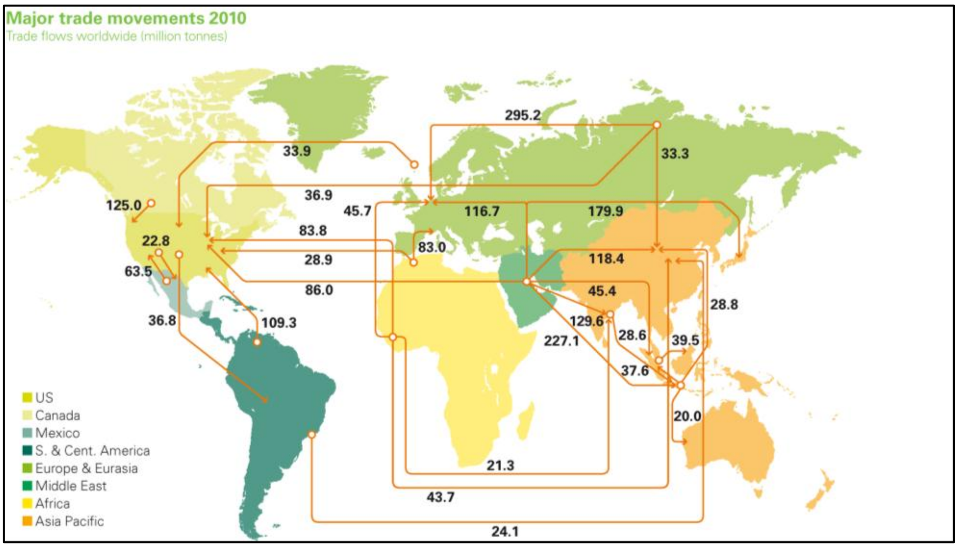
Meanwhile, Asia-Pacific countries have begun consuming the bulk of their own low-sulfur crude output. Today, only about 1 million b/d of Asia Pacific crude is exported—mostly to other Asian countries. About two-thirds of the region's low-sulfur crude demand is imported from Africa, mostly West and North Africa, a long-haul voyage. (From Lagos, Nigeria's oil port, to Singapore is a voyage of over 9,000 miles; to Tokyo, a voyage of 12,500 miles.) This makes the delivered cost of these low-sulfur crudes in Asia quite high, and naturally drives up the prices of the smaller volume of Asia Pacific low-sulfur crudes. Yet this is the market from which Hawaii must select most of its crudes; the West Coast of the Americas is notorious for the high-sulfur levels in its crudes.

Figure 72: Main Oil Exports to Asia, and Asia Pacific Crude Exports, 2010



In terms of world oil trade, Hawaii is "at the end of the pipeline." Relatively little crude oil flows from the Americas to Asia, and today relatively little oil flows from Asia to the Americas. Although cross-Pacific trade in manufactured goods is enormous, cross-Pacific trade in crude oil is negligible. Indeed, as the figure below shows, the authoritative BP Statistical Review of World Energy does not list any major trans-Pacific oil flows in either direction.

Figure 73: Major International Oil Flows, 2010



Source: BP

At one time, Hawaii was an integral part of the US West Coast oil market. Refiners in California and Washington supplied any shortages in the Hawaii market, and in the days when low-sulfur fuel oil was an important power sector fuel in California, Hawaii refiners successfully won supply contracts to California utilities. Refiners in California, Hawaii, and Washington all competed for crude imports, especially imports from Alaska, Ecuador, Indonesia, and Malaysia. Californian prices could be used as indexes in supply contracts in Hawaii.

This has changed dramatically. In 2010, Hawaii imported 83% of its crude from the Asia-Pacific region (the remainder came from Saudi Arabia plus a single cargo from Argentina). The US West Coast, on the other hand, took only 6% of its crude imports from the Asia-Pacific region. Even more telling, only 2.5% of US West Coast crude runs to refineries came from the Asia-Pacific region (against 83% in Hawaii). The biggest source of US West Coast crudes is the US West Coast (including Alaska)—crudes that Hawaii can no longer run because they are too high in sulfur for Hawaii refiners.

The result has been an increasing disconnect between the mainland oil market and that of Hawaii. The biggest problem area is low-sulfur fuel oil. There is no longer a market in low-sulfur fuel oil on the US West Coast: no price quotes and no significant volumes available. (The fuel oil from low-sulfur crudes imported to the US West Coast today is generally cracked into lighter products; very little ever appears on the market as fuel oil.) At the same time, specification changes have eliminated US West Coast markets in high-sulfur diesel (used by neighbor-island utilities), and even low-sulfur diesel; Platt's recently stopped reporting low-sulfur diesel prices in California and Washington because the market has become too "thin." The reference price on the US West Coast today is ultralow-sulfur diesel, or CARB (California Air Resources Board) diesel. Even gasolines have very different specifications—CARB gasoline must meet a number of constraints that do not apply to gasoline in Hawaii.

The market for low-sulfur fuel oil in Asia is large in volume (although most of it is consumed in the country where it is made and therefore is not traded), but it is a small product relative to Asian consumption. Japan and Korea are the only consistent importers, and, prior to the Fukushima Triple Disaster, their imports of fuel oil were well under 100,000 b/d. That admittedly is close to Hawaii's total consumption of oil, but it amounts to less than one-half of one percent of oil demand in the Asia-Pacific region.

After the Triple Disaster, Japanese and Korean imports of low-sulfur fuel oil more than doubled. This had a powerful effect on the price of low-sulfur fuel oil on the market (and in Hawaii), but that price change did not affect Asian consumers very strongly, as even after the imports more than doubling, the trade in low-sulfur fuel oil still amounts to only a little over one-half of one percent of oil consumption in the region.

By way of contrast, in Hawaii, low-sulfur fuel oil—which is linked by contract to Asian prices—accounts for about a quarter of total oil demand, and about two-thirds of all oil demand in the power sector. Therefore, even though East Asia has seen similar increases in low-sulfur fuel oil prices, those prices have little effect on the Asian consumer because they are only a small element of oil demand or electricity prices. Those same prices drive Hawaii prices, however, and the effect on Hawaii consumers is very large indeed.

To summarize, the US West Coast (excluding Hawaii) oil market is tied to prices of high-sulfur, North American crudes. Low-sulfur fuel oil, high-sulfur diesel, and even low-sulfur diesel, have all but vanished from the market.

In Hawaii, the refiners look to Asia as the main source of crude oil, and import no crude from the US at all. The main oil products in Hawaii have specifications that match those in use in Asian countries, not on the US West Coast. Hawaii refiners are forced to bid against Asian refiners for shrinking volumes of Asian low-sulfur crudes; and, although there are still large volumes of low-sulfur crudes available from West and North Africa, the transport costs to Hawaii are prohibitive.

Hawaii is therefore unique among US states in its exposure to the Asian market; but it is far different from Asian countries in the degree of its reliance on oil. A physical supply cutoff is no longer a real risk. Today, Asian oil buyers exercise a long reach, and traders can always procure crude cargoes…at a price. But what might be a minor bump in the overall Asian picture—such as the Triple Disaster—can be magnified into a major pricing problem in Hawaii. There is no sign that this risk will be lowered as long as Hawaii remains so dependent on oil.

3.1.2. LNG and Oil-Shock Vulnerability

The pressing question is whether introducing LNG can moderate or ameliorate Hawaii's exposure to oil price shocks. Overall, the answer, as shown in earlier chapters, is clearly "yes"—but there are many caveats.

Even with widespread adoption of renewables and LNG, Hawaii will remain critically reliant on jet fuel. Although considerable work is aimed at aviation biofuels, development is still in the early stages. Boeing has sponsored some serious research into using LNG as an aviation fuel, and it appears promising, but such aircrafts are not envisioned as being commercialized before 2040.

The biggest caveat, however, regards the sourcing of the LNG. As Chapter II discusses, for at least the rest of this decade, and possibly beyond, the price of LNG outside the United States is likely to remain tied to oil prices. If LNG is sourced on an oil-linked contract, then obviously it will move with the oil market (although depending on the contract, the price may not rise quite as high as the oil price).

In most cases, however, LNG imports into Hawaii will probably only be attractive if they are linked to Henry Hub or some other US domestic gas market. At present, there is little question that US natural gas prices are delinked from oil prices. There are two schools of thought about the future. Most of the energy companies seem to believe that the linkage is permanently broken; many of them are talking about gas prices staying flat in real terms for as much as twenty years. Other groups—including FGE and EIA—see a gradual tightening of the US gas market, with a small degree of influence of oil on gas prices being reestablished as new forms of interfuel competition come into play.

The question in terms of policymaking is not whether US gas will remain entirely delinked from oil, but whether the price of gas delivered to Hawaii will be lower than corresponding oil prices. Even though most analysts are projecting continued high oil prices on average, oil prices will continue to be volatile. It is easy to imagine scenarios where, at least for a time, oil prices will drop below the delivered cost of LNG. (It is also easy to imagine scenarios where this will never happen.)

There is no certainty in the oil market—or, indeed, in any aspect of the future economy—so there will always be risks. Hawaii has already decided that one way to minimize risks is to move away from imported fossil fuels through a combination of conservation and renewable energy. Until fossil fuels are eliminated entirely, choices will have to be made between the possible sources.

Low-sulfur fuel oil seems like a bad bet on a number of grounds. It is a less-than-ideal fuel for high-efficiency power generation technologies such as CCGT. Its availability in the region is expected to dwindle because low-sulfur crudes are scarce, and low-sulfur fuel oil from such crudes is the feedstock of choice for new cracking units in Asia.

But the most telling argument against LSFO is the problem of compliance with environmental standards. Large investments in scrubbers and baghouses would commit the State to long-term use of oil in power—and for those investments to ever be amortized at a reasonable cost per kWh, use of oil in power would have to remain relatively high. It is illogical to make massive investments in something which is being actively phased out by state policy.

Low-sulfur diesel—even ultralow-sulfur diesel—is not as low in emissions as natural gas. Nonetheless, it can comply with many advanced emissions standards, and it can be run as an excellent fuel for CCGTs, thereby offering major cuts in fossil energy demand in the power sector—and offering load-following capabilities. Indeed, in some places that import LNG, low-sulfur diesel is the standard back-up fuel, and the two are used somewhat interchangeably.

Is there a chance that low-sulfur diesel prices will go below US gas prices? That is exceedingly improbable. But there is some chance that diesel prices might go below the cost of LNG delivered to Hawaii. This had led a few people to speculate that the optimum arrangement might be dual-fired LNG/diesel capacity, with the State choosing to import one or the other based on current market prices.

Initially this seems like an attractive proposition, but closer examination reveals two major problems. First, if large investments are made in infrastructure to import LNG, those costs will have to be amortized over large volumes spread across many years. If LNG volumes were to fluctuate substantially based on the diesel-LNG price spread, the cost recovery would either become very difficult, or the per-unit infrastructure charges would take a huge leap every time LNG imports were cut sharply.

The second problem is one inherent in the nature of an LNG supply train. True, there is a small spot market in LNG that allows for short-term and even single-cargo purchases—although this is not yet a feature of the US market. But in general, the best prices require long-term commitments and contracts right down the supply chain, from the LNG producer through the shipping and down to the local terminal. Some adjustments can be made to volumes across time, but, at least in today's world, LNG cannot be turned on and off like a spigot.

This does not argue against dual-fired LNG/diesel capacity, which may have an important role as an energy back-up strategy, but it does mean that playing the market between the two fuels as a way of hedging against LNG cost increases is probably not a realistic option.

A critic of LNG in Hawaii recently asked "How can we be sure the price of LNG won't go too high?" One is tempted to answer that no one can be sure of such things, but in fact there are at least two mechanisms by which one could, in principle, levelize LNG prices.

As mentioned earlier, most liquefaction contracts in the US are run on a tolling basis, and it is up to the buyer of the LNG to procure the gas feedstock. Normally this would be done simply by purchasing from the national gas grid at Henry Hub plus (usually taken as Henry Hub plus 15%). But a producer of gas is free to feed gas into the system near their producing field and arrange to swap it for gas delivered elsewhere (possibly with a small adjustment charge depending on the location of source and destination).

This is one reason that many potential buyers of LNG in the US are busily investing in gas fields; by "farming in" to existing gas projects, they can secure reserves that then can act as a hedge against future price increases. In principle, buying gas reserves could allow a buyer of LNG to keep the feedstock cost flat for years or even decades.

Of course, like all insurance, such a strategy would cost money. Today, with gas prices at around US$3/mmBtu, there have been purchases of assets that suggest gas reserves can be bought for less than US$2/mmBtu. This means that the purchase price of a 20-year reserve of gas could be bought for about US$40 per annual mmBtu. If an internal rate of return of 10% was required, then this would translate out to a levelized cost of US$5.70/mmBtu across 20 years.

The upfront investment required would be substantial. For a market like Hawaii's, where demand might be in the range of 500 ktpa, the upfront cost would be on the order of US$1 billion. (That is a huge sum—but consider that Hawaii's oil import bill presently is US$4-5 billion *per year*.)

As might be imagined, there is a way of procuring long-term levelized gas contracts from producers in exchange for an upfront payment—thereby eliminating the problem of taking equity positions and being involved in the gas-production industry. Such contracts are known as Volume Production Payments (VPPs). A VPP guarantees a certain total amount of gas to be delivered over a certain number of years. Most VPPs run 5-10 years, but at least one has been signed for a period as long as 15 years. Recent VPPs have been based on levelized gas prices that amount to US$4.50-US$5.15/mmBtu in upfront costs. That is about twice the purchase price of reserves, but similar to the levelized costs (including return on investment) of purchasing reserves.

In other words, there are ways of coming close to locking in LNG prices. Much like the case with home mortgages, the security of a fixed-rate, long-term mortgage costs more at any given point in time that a shorter-term, adjustable rate mortgage. Security and predictability cost money, because someone else is being paid to assume some of the risk.

While it might be possible to use contracts or purchases to lock in LNG prices with a reasonable degree of certainty, there is no way to assure that there is no circumstance under which the price of oil cannot dip below the delivered price of LNG. Like all major economic decisions, deciding between LNG and oil requires the weighing of data, opinions, and various intangibles.

Perhaps a better question than "How can we be sure the price of LNG won't go too high?" is "How can we be sure the price of oil won't fall?" A benefit of LNG sourced on a Henry Hub-linked basis is that it is decoupled from oil prices; but because it is decoupled from oil prices, there is also a chance that oil prices might fall while gas prices stay constant. In that case, Hawaii could end up paying more for LNG than it would have paid for oil.

On a short-term basis this is not a problem, markets fluctuate. But moving to LNG imports (and, it should be noted, adopting the HCEI) are decisions that close off other paths.

Some have recently speculated that growing oil production in the US and Iraq, coupled with falling oil demand in the US, could put strong downward pressure on oil prices, pushing them down in to the range of US$80-90 per barrel. OPEC in particular is concerned about the prospect, and has been exploring plans to prevent the drop.

What would that mean for Hawaii LNG? To determine this, we examined a case where the JCC falls to US$85 per barrel and remains there, and all of the corresponding product prices were reduced by the same percentage decline. At the same time, the gas price in the US is assumed to continue climbing at the EIA's forecast rate.

The results are shown in the figure below. (Because we are assuming a flat US$85/bbl JCC price, there is no point in presenting a separate EIA case, as they would be quite similar.)

Figure 74: Oil Price Drop Analysis

Delivery Build-Up, 2012 US$/mmBtu (FGE @ $85 JCC)

	2015	2020	2025	2030
Alaska	na	na	$ 17.51	$ 17.51
Australia	$ 20.06	$ 18.99	$ 18.99	$ 18.99
Canada	na	$ 15.91	$ 15.91	$ 15.91
US Gulf Coast	$ 16.19	$ 16.63	$ 18.22	$ 19.22
US West Coast	na	$ 13.62	$ 15.01	$ 15.89
Hawaii LSFO	$ 17.54	$ 18.49	$ 18.18	$ 17.31
Hawaii LS Diesel	$ 18.26	$ 20.00	$ 20.71	$ 20.85

DELIVERED TO HAWAII: LSFO - LNG

	2015	2020	2025	2030
Alaska	na	na	$ 0.67	$ (0.20)
Australia	$ (2.51)	$ (0.49)	$ (0.81)	$ (1.68)
Canada	na	$ 2.58	$ 2.26	$ 1.40
US Gulf Coast	$ 1.36	$ 1.87	$ (0.04)	$ (1.91)
US West Coast	na	$ 4.88	$ 3.16	$ 1.42

DELIVERED TO HAWAII: LS Diesel - LNG

	2015	2020	2025	2030
Alaska	na	na	$ 3.20	$ 3.34
Australia	$ (1.79)	$ 1.01	$ 1.72	$ 1.87
Canada	na	$ 4.08	$ 4.79	$ 4.94
US Gulf Coast	$ 2.08	$ 3.37	$ 2.49	$ 1.63
US West Coast	na	$ 6.38	$ 5.69	$ 4.96

PERCENT SAVINGS DELIVERED TO HAWAII: LSFO - LNG

	2015	2020	2025	2030
Alaska	na	na	4%	-1%
Australia	-14%	-3%	-4%	-10%
Canada	na	14%	12%	8%
US Gulf Coast	8%	10%	0%	-11%
US West Coast	na	26%	17%	8%

PERCENT SAVINGS DELIVERED TO HAWAII: LS Diesel - LNG

	2015	2020	2025	2030
Alaska	na	na	15%	16%
Australia	-10%	5%	8%	9%
Canada	na	20%	23%	24%
US Gulf Coast	11%	17%	12%	8%
US West Coast	na	32%	27%	24%

There are two things to note here. First, and most important, LNG from the US West Coast still maintains substantial savings, even with a fall in oil prices. Imports from the US Gulf Coast gradually drift into negative territory relative to LSFO in the late years—but, as we have seen in the previous chapter, burning LSFO in Hawaii after 2016 would entail nearly a billion dollars in new environmental controls.

The second point is that the economics of imports from oil-linked sources (Alaska, Australia, and Canada) improve somewhat. Indeed, Canada becomes a more attractive source than the US Gulf Coast. This is to be expected: when oil prices fall, oil-linked LNG prices follow them down, while gas-linked prices do not budge.

The above case is a fairly challenging proposition: a big drop in the price of oil, and the price of natural gas continuing to rise at a rate that virtually no one expects. (We are using the EIA 2012 forecast as our Base Case. The EIA's preliminary release of their 2013 Henry Hub forecast shows that, despite the expected freeing of exports, their predicted gas price in 2030 is now more than US$1/mmBtu lower than last year's projection.)

Of course, it is always possible to find a worse case. What if the price of oil goes to US$20/bbl and stays there, and the price of natural gas skyrockets? It is not impossible—although we are unable to find a reputable public forecast that is looking at US$20/bbl oil. In fact, we are unable to find a serious oil-price forecast that goes below US$80/bbl, and, although many sources are now seeing a softening of the oil price in the middle of this decade, there do not seem to be any who assume that US$80/bbl oil will remain that low in the long term. (IEA's new WEO 2012 forecast has a scenario called "450" where worldwide policies dramatically cut the demand for oil; this scenario shows the price of oil gradually declining to a floor of US$100/bbl in 2030, while their "Current Policies" scenario shows the price of crude at US$145/bbl in 2030.)

It is impossible to answer every "what-if" that might be posed. If the underlying question is whether importing LNG will result in savings under every imaginable condition, the answer is "no." We can give a sense of the range of possible outcomes, but these involve some sets of assumptions we consider quite improbable taken together.

Let's start by looking at the supply costs for LNG. On the low price side, assume the NPCC Low Henry Hub forecast. Add on the US$700/tpa liquefaction costs, and take the lowest delivery costs to Oahu (Excelerate's US$2.02/mmBtu).

On the high side, assume the NPCC High Henry Hub forecast. Use US$1,300/tpa liquefaction costs, and use the Excelerate US$6.02/mmBtu delivery costs.

Our current thinking suggests that there is a fairly solid floor at around US$70/bbl for crude oil. This is the upper end of costs for oil-oriented hydrofracking in the US. Unlike conventional oil production, where most of the costs are in exploration and initial development—and are therefore already spent by the time production begins—hydrofracking requires constant new drilling and development. Put another way, in conventional oil, the upfront costs are large, but the operating costs are relatively small. In hydrofracking, which is the source of virtually all of the growth in US oil output, the upfront costs are relatively small, but the operating costs are large. That means that if prices fall below the floor, oil supply quickly begins to fall…and prices should rise.

Of course, Hawaii does not burn crude oil. For purposes of this exercise, let us use diesel costs, with diesel pegged at the crude price plus 20% (a typical relationship). Let's use the US$70/bbl crude floor—a 35% drop from recent JCC crude prices. To keep things symmetrical, let's also examine a 35% increase in crude prices, to around US$144/bbl (and a 20% premium of diesel above crude).

The following figure may seem complex, but it is presented in an attempt to forestall "what-if" questions about prices. The math is simple arithmetic and can easily be adapted to any crude-price or gas-price assumptions that might be postulated. The cases in the figure show the full range of what we consider reasonable, and actually extend well outside the range of anything we consider likely for prolonged periods.

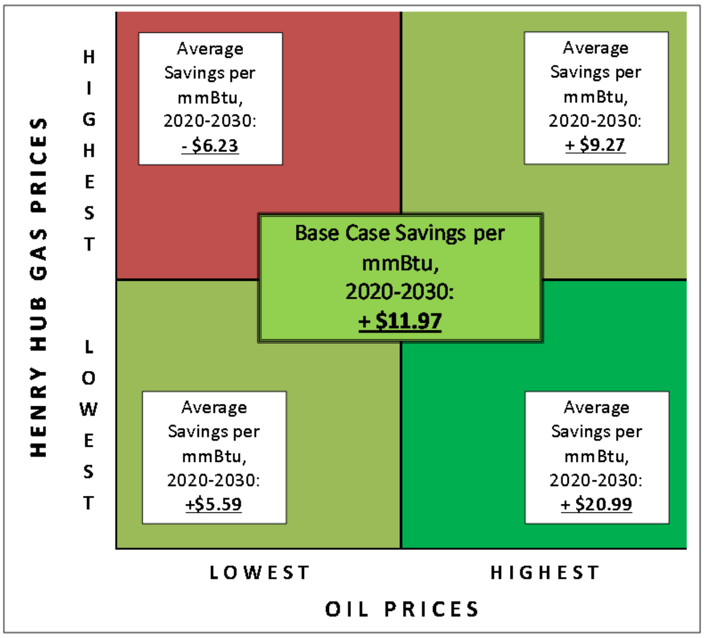
Figure 75: Best, Worst, and Base Cases (US$/mmBtu)

BEST	Henry Hub	115% H Hub	+Lique-faction	+Delivery & Regas	=Delivered Price	Diesel @ $70/b Crude	Savings (Loss) @$70/b	Diesel @ $144/b Crude	Savings (Loss) @$144/b
2020	$ 3.74	$ 4.31	$ 2.70	$ 2.02	$ 9.03	$ 14.50	$ 5.47	$ 29.90	$ 20.87
2025	$ 3.64	$ 4.19	$ 2.70	$ 2.02	$ 8.91	$ 14.50	$ 5.59	$ 29.90	$ 20.99
2030	$ 3.54	$ 4.07	$ 2.70	$ 2.02	$ 8.79	$ 14.50	$ 5.71	$ 29.90	$ 21.11
WORST									
2020	$ 7.80	$ 8.97	$ 4.30	$ 6.02	$ 19.29	$ 14.50	$ (4.79)	$ 29.90	$ 10.61
2025	$ 8.94	$ 10.29	$ 4.30	$ 6.02	$ 20.61	$ 14.50	$ (6.11)	$ 29.90	$ 9.29
2030	$ 10.40	$ 11.96	$ 4.30	$ 6.02	$ 22.28	$ 14.50	$ (7.78)	$ 29.90	$ 7.62
BASE									
2020	$ 4.76	$ 5.48	$ 3.50	$ 4.64	$ 13.62	$ 14.50	$ 0.88	$ 29.90	$ 16.28
2025	$ 5.86	$ 6.73	$ 3.50	$ 4.78	$ 15.01	$ 14.50	$ (0.51)	$ 29.90	$ 14.89
2030	$ 6.54	$ 7.52	$ 3.50	$ 4.87	$ 15.89	$ 14.50	$ (1.39)	$ 29.90	$ 14.01

As the figure shows, in the Worst Case, of high gas prices against prolonged low oil prices, the losses from importing LNG rather than burning oil are significant. Even in the Base Case, using the EIA 2012 Henry Hub forecast, a US$70/bbl price poses significant threats, with losses gradually increasing. (Although, as mentioned previously in this report, small deviations up or down should not be over interpreted.)

In most of the scenarios, however, the savings are significant. Perhaps the best way to give an overview of the results is with a standard Quad chart, with Henry Hub and JCC crude prices on the axes. This is shown in the figure below, which shows the extremes of the high and low prices for each fuel, and show them relative to the Base Case savings in the previous chapter. (This is the delivered, all-in, onshore savings per million Btu.)

Figure 76: Quad Chart of Savings and Losses at Extreme Prices



Is there a downside risk? Certainly. With the highest Henry Hub gas prices and the lowest oil prices considered, the extra costs to Hawaii could be considerable. But that is one extreme out of four—or five, if the Base Case is counted. Any major infrastructure decision is a gamble. Deciding not to change is also a gamble. The chart above cannot provide certainty, but it can give a good overview of how the landscape looks at this point in time.

3.2. *LNG and Refinery Viability*

3.2.1. Refining Basics

Refining is one of the most complex aspects of energy analysis. A satisfactory discussion of the topic would make a substantial report on its own—and would be out of place in the present study. Nonetheless, some details of the industry are needed to understand the challenges the Hawaii refiners face.

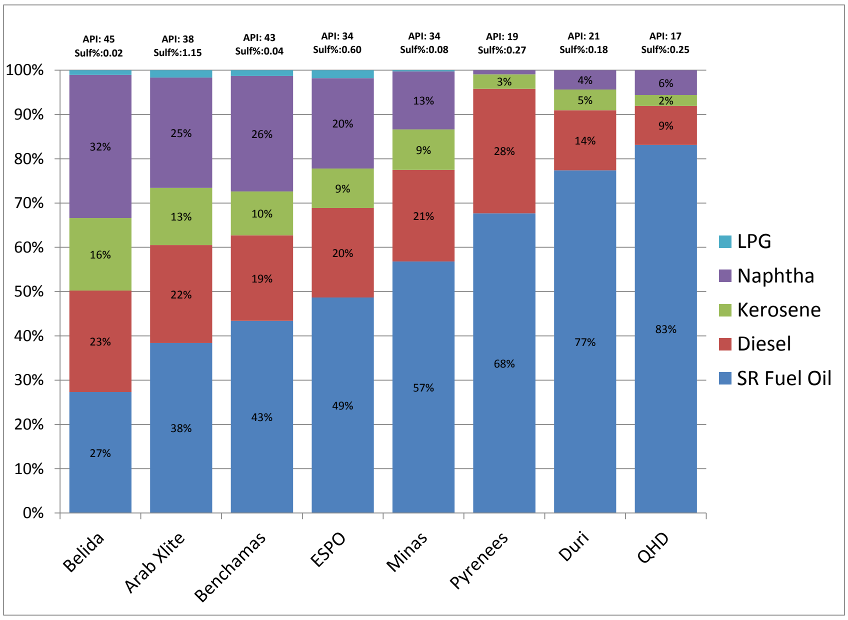
Although the news media talk about "the price of crude oil," crude oils have many different characteristics—and these characteristics strongly affect the price. The most important characteristics are API gravity and sulfur content.

API gravity—measured in degrees API, and often just called "the API of the crude"—is a measure of the density of the oil, but it is "upside-down." The less dense the crude oil, the higher the API. A very heavy crude oil might be 10 API. A very light crude might be 50 API. Most crude oils are in the range of 30 to 40 API.

Refined products have specific density ranges as well. Lighter products boil at lower temperatures. Gasoline is a light product, and boils or evaporates easily. Fuel oil is a heavy product, and is usually that part of the crude oil that still does not boil at 650 ^{o}F. Jet fuel and diesel are somewhere in between (and are often called "middle distillates"). Very heavy (fuel oil, asphalt) products tend to be worth less than products such as gasoline, jet fuel, and diesel.

The most basic refining process is crude distillation, which splits the crude oil into different boiling ranges. The figure below—which compares crudes that are often imported into Hawaii for refining—shows how much difference this can make. (The cut called "naphtha" in the figure is the material from which gasoline is made.)

Figure 77: Distillation Yields of Crudes Imported to Hawaii



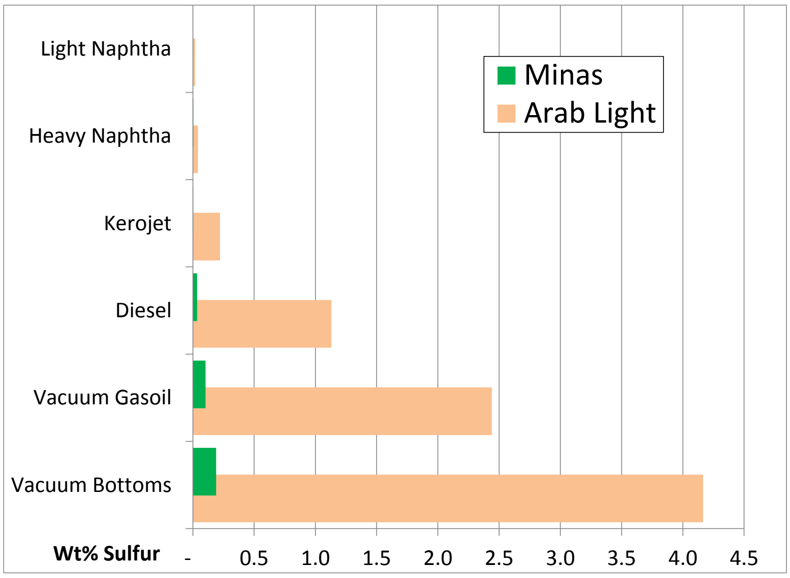
Some crudes imported to Hawaii yield less than 30% fuel oil; some are more than 80% fuel oil. All else held equal, lighter crudes—with less fuel oil—are more expensive.

All else is not held equal. As mentioned above, crude oils also differ in sulfur content. Sulfur is the main pollutant from oil; when sulfur is burned, it forms sulfur dioxide (the compound responsible for the smell of rotten eggs), and, when it encounters water in the atmosphere it forms "acid rain." Crude oils are often 1-3% sulfur by weight. Some crudes, however, have almost no sulfur.

Crudes with less than 0.5% sulfur by weight are called "sweet" crudes; crudes with more sulfur are called "sour" crudes. All else held equal, sweet crudes are more expensive than sour crudes.

To complicate matters, sulfur is not evenly distributed in the crude oil. The light cuts, like naphtha (the gasoline cuts) contain very little of the sulfur; the vacuum gasoil and vacuum bottoms (fuel oil cuts) have sulfur contents much higher than the crude. The figure below shows the distribution of sulfur in two well-known crude oils with similar API gravity: Arab Light (Saudi Arabia, 1.8% sulfur), and Minas (Indonesia, 0.08% sulfur).

Figure 78: Sulfur Distribution in Two 33/34 API Crude Oils



As a point of reference, on Oahu the maximum sulfur content of fuel oil is 0.5%. Minas achieves this easily, but Arab Light—the crude with the largest production on the planet—does not even come close.

Thus, the most expensive crudes tend to be light, sweet crudes; the cheapest tend to be heavy, sour crudes.

Refinery technology has been developed to solve some of these constraints. Fuel oil, which consists of long, heavy molecules, can be "cracked" into lighter products such as gasoline and diesel. High-sulfur products can be hydrodesulfurized to remove most of the sulfur. Both of these processes, however, use considerable energy, and are hugely expensive. Some of the new refineries planned for Iraq—which produces heavy, sour crudes—are projected to cost US$4-7 billion for a single refinery.

From a refiner's point of view, the ideal economic outlook is to have:

1) A large cracking capacity, to turn cheap heavy crudes into valuable gasoline, diesel, and jet, while minimizing fuel oil output;
2) A large desulfurization capacity, to turn cheap sour crudes into products that meet environmental standards;
3) A large refinery size overall, to lower the fixed costs (wages, overhead) per barrel of crude processed;
4) A large local market that is short of products, so that supplies of most products require imports (so the marginal supply must pay for transport costs, thereby keeping local prices higher).

3.2.2. The Hawaii Refining Situation

One of the first things that need to be noted about Hawaii's refining situation is that the two refineries dominate the state's oil-import infrastructure. This issue has come up again and again over the years, especially in the context of fuel-oil supply. HECO does not have terminals capable of handling large-volume imports; therefore supply must come through contracts with the refiners. The utility is unable to put supply contracts out for bid with any certainty of being able to receive the contracted volumes—since any imports of fuel oil would have to pass through the refiners' infrastructure.

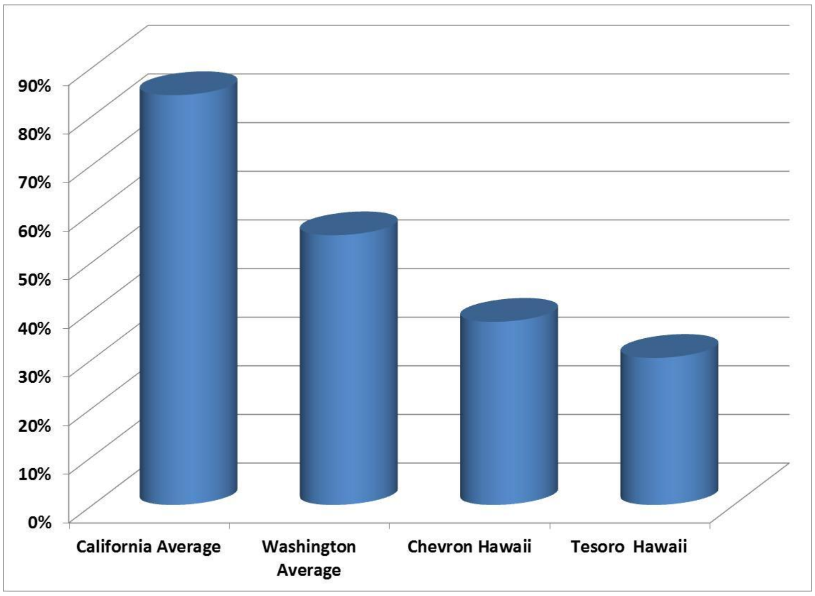
Although HECO's contracts with the refiners must be approved by the PUC, the refineries and their import infrastructure are privately owned and are not subject to regulation. In effect, if the terms of a supply contract do not meet the refiners' expectations, they are free to decline to supply. HECO's only options are either 1) build their own import terminal and go to the market for supply (an expensive option for ratepayers, if allowed), or 2) come to terms with the refiners.

This, then, is another kind of vulnerability. Not only is the state reliant on the most expensive forms of imported oil, but it also has to receive the bulk of its oil supply through two privately owned refineries/terminals. (The problem is especially accentuated in the case of low-sulfur fuel oil; there are terminals for the import of jet fuel, as well as small volumes of diesel and gasoline, that are not owned by the refiners, but no such facilities for large-scale fuel-oil imports for the power plants.) In low-sulfur fuel oil at least, the situation has so far led to only two sellers offering fuel oil in the market

The two Hawaii refineries are different from one another in many ways, but they face very similar problems—irrespective of the role of LNG in the State's future energy balance.

The figure below shows FGE's "Uplift Index"—a measure of cracking capacity plus some other upgrading technologies as a fraction of crude capacity—for the two Hawaii refiners compared to US West Coast averages. Clearly, the two Hawaii refineries lag behind Washington state, and have almost no uplift compared to California.

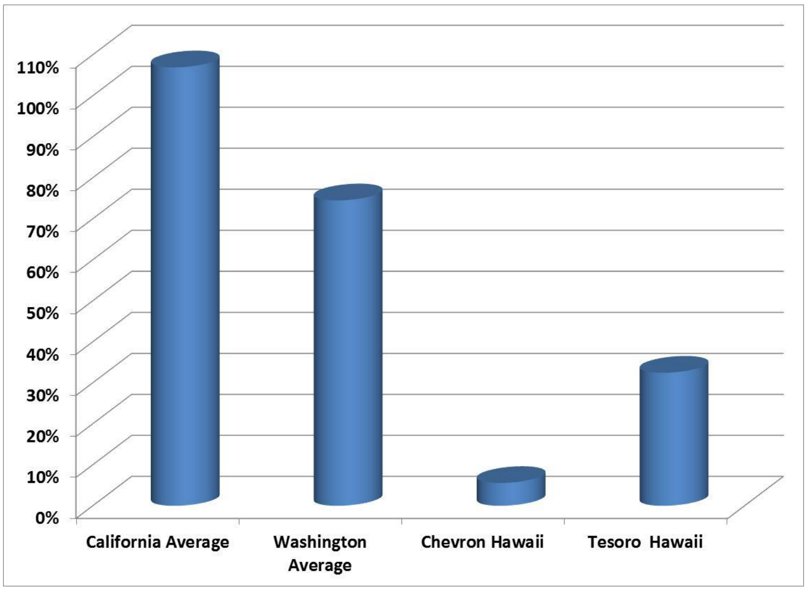
Figure 79: Uplift Indices



In other words, the Hawaii refiners can do comparatively little to process heavy crudes into lighter products.

The picture is even worse in terms of hydrodesulfurization. California and Washington refiners can take very sour, high-sulfur crudes, and turn them into refined products that can meet some of the most stringent environmental standards anywhere in the world. Tesoro, by comparison, can do little to clean up its crude inputs, and Chevron can do virtually nothing.

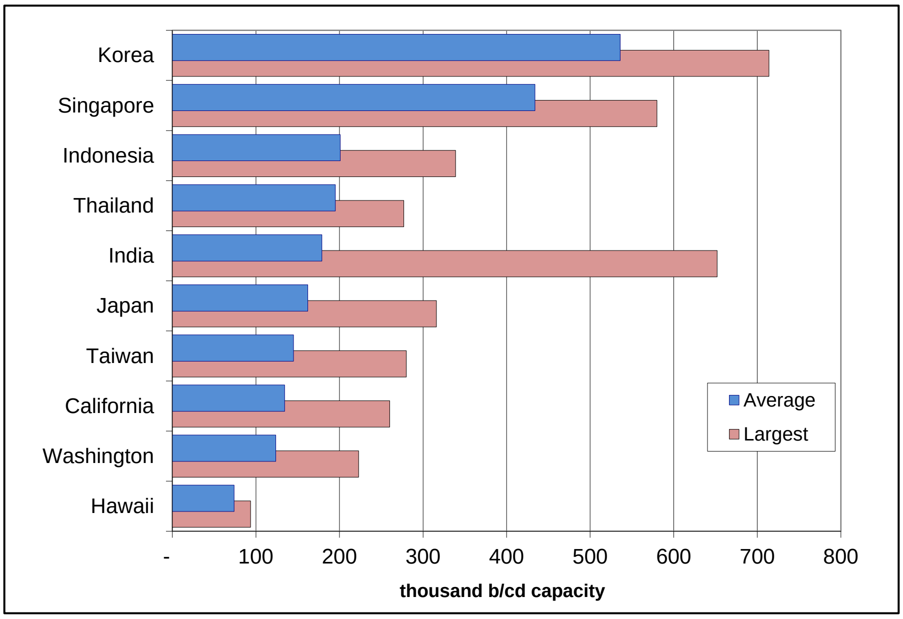
Figure 80: Desulfurization (HDT + HDC) Capacity Relative to Crude Distillation



It is critical to understand these points. Because Hawaii's refineries have little cracking capacity, most of their output pattern is determined by the type of crude they buy. Because they have little desulfurization, they cannot make saleable products unless they buy sweet crudes. A typical Californian refiner can buy some of the cheapest, nastiest crudes in the world and turn them into some of the cleanest, highest-quality refined products in the world. Hawaii refiners cannot do likewise; because of the lack of cracking and desulfurization, the refiners have to import scarce low-sulfur crudes in a region where such crudes are rare and sell at a premium.

Hawaii refiners also score poorly on the third element of economic outlook. By world standards, they are small, and have very high overheads compared to their crude runs. The staff and overhead are very similar between a 50 kb/d refinery and a 250 kb/d refinery—so the cost per barrel for the 50 kb/d is five times higher.

Figure 81: Refinery Capacities for Selected Asia Pacific Locations



Unsurprisingly, Hawaii is at the bottom of the heap in terms of refinery size. True, California and Washington also lag far behind the gargantuan refineries now operating in Asia; but the California and Washington refineries are far more sophisticated in terms of cracking and desulfurization. Hawaii refineries are small and also lacking in advanced equipment.

Finally, there is the fourth profitability issue—the capacity relative to demand. Hawaii oil product demand statistics are far from perfect. State statistics and federal statistics often disagree; sales and demand for some products are not reported because of confidentiality issues (with only two refiners it is often possible to calculate proprietary information from totals, so many numbers are suppressed); material moves in and out of the Free Trade Zone without being recorded in the State statistics; not all military consumption and movements are included; and the refiners themselves report different kinds of information from one another in their K-10s and annual reports. All oil product balances in Hawaii should be regarded only as estimates.

The numbers shown in the figure below are based on a variety of sources, including numbers from DBEDT, EIA, HECO, K-10 filings, and conversations with industry personnel.

Figure 82: Estimated Hawaii Oil Product Balance for 2010 (kb/d)

	OUTPUT			DEMAND*	OUTPUT-DEMAND
	Chevron	Tesoro	TOTAL	Hawaii	
LPG	1.1	1.0	**2.1**	3.3	(1.2)
Gasoline	14.3	15.0	**29.3**	28.1	1.2
Jet	8.0	15.0	**23.0**	24.7	(1.7)
Diesel	9.0	12.0	**21.0**	19.1	1.9
LSFO	8.4	14.5	**22.9**	28.2	(5.3)
HSFO	1.2	9.4	**10.6**	7.6	3.0
Others	5.0	2.9	**7.9**	6.9	1.0
TOTAL	**47.0**	**69.8**	**116.8**	**117.8**	**(1.0)**

*Including liquids burned in the refinery. Some apparent exports may be international bunkers.

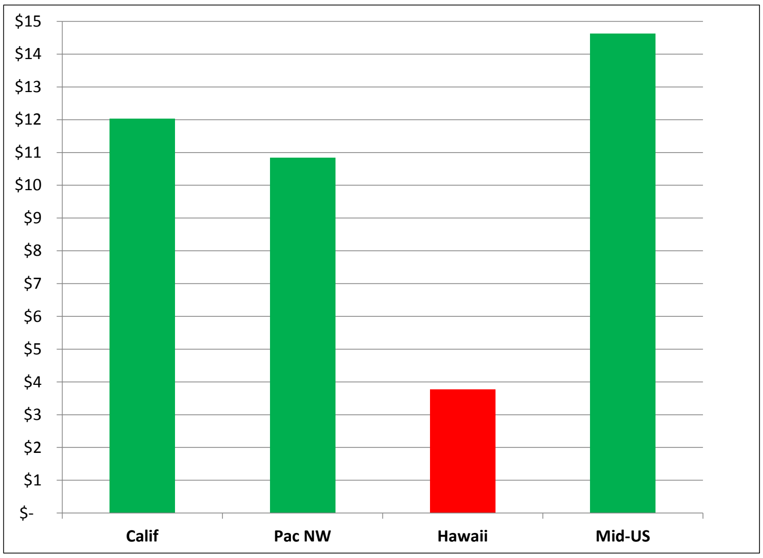
While these numbers are by no means definitive, they are indicative of the general dynamics of the Hawaii oil market. Hawaii is reasonably well-balanced in the middle distillates (diesel and jet), and sometimes runs a little short depending on circumstances; Hawaii both imports and exports jet fuel, and in some years with high tourism the net imports are quite high.

A critical element, however, is the total demand shown in the figure. Demand in 2010 was somewhere around 110 kb/d. Refining capacity is close to 150 kb/d. There is too much refining capacity for the size of the market.

Hawaii's refining industry thus scores low in every aspect of competitiveness. It does not have enough cracking capacity; it does not have enough desulfurization capacity; it is undersized in terms of today's market. But, perversely, although it is undersized relative to refineries elsewhere, it has too much capacity for Hawaii's demand.

Chevron does not publish refinery-by-refinery margins in its K-10 reports, but Tesoro does. Below are the results for 2010.

Figure 83: Tesoro Gross Refining Margins by Region, 2010



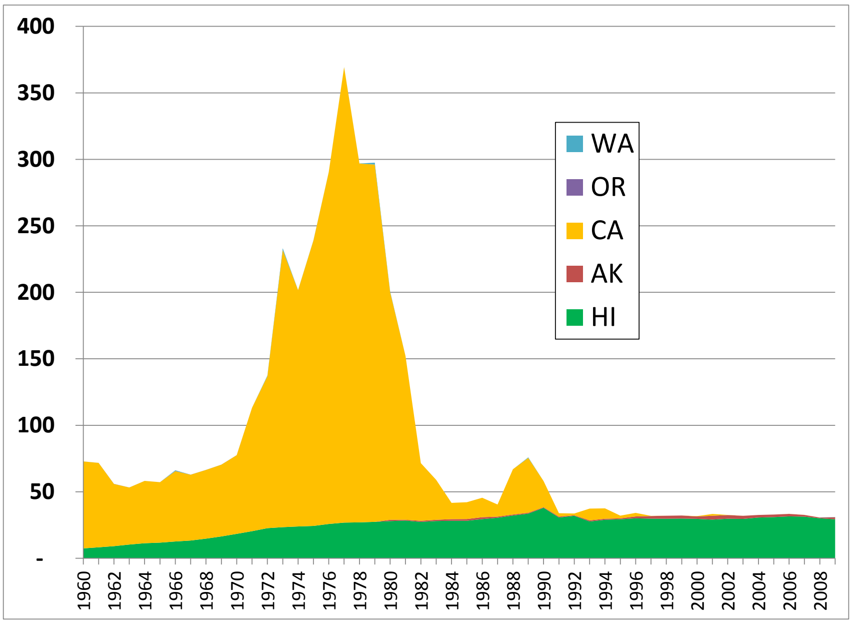
Source: Tesoro

The present situation is not the fault of the refiners. The State of Hawaii encouraged the expansion of refining capacity from the 1970s onward, and, beginning in the late 1980s, also introduced policies such as the "gas cap," which assumed the refiners were making excess profits out of Hawaii sales. (Even today, we encounter people in Hawaii who cite claims that half of Chevron's total earnings, or profits, or revenues, came from their Oahu refinery. Since Chevron's revenues are two or three times Hawaii's Gross Domestic Product, any of these beliefs are not only preposterous, but mathematically impossible.)

The refiners decided years ago not to spend more capital on their Hawaii refineries as they would probably never be able to break even on any future investments; and, as the figure above shows, spending money elsewhere would offer better returns.

In addition, Hawaii—for whatever reasons—has remained addicted to oil in the power sector. As the figure below shows, California moved rapidly into low-sulfur oil as a power source…and then just as quickly moved away. In 1977, Hawaii accounted for about 7% of oil consumed in the power sector on the US West Coast. By 2009, Hawaii accounted for 75% of all oil consumed in the power sector on the US West Coast. Over the period, California's oil demand in power dropped from almost 350,000 b/d to about 8,000 b/d. Over the same period, Hawaii's demand continued to grow.

Figure 84: US West Coast Oil Demand in the Power Sector (kb/d)

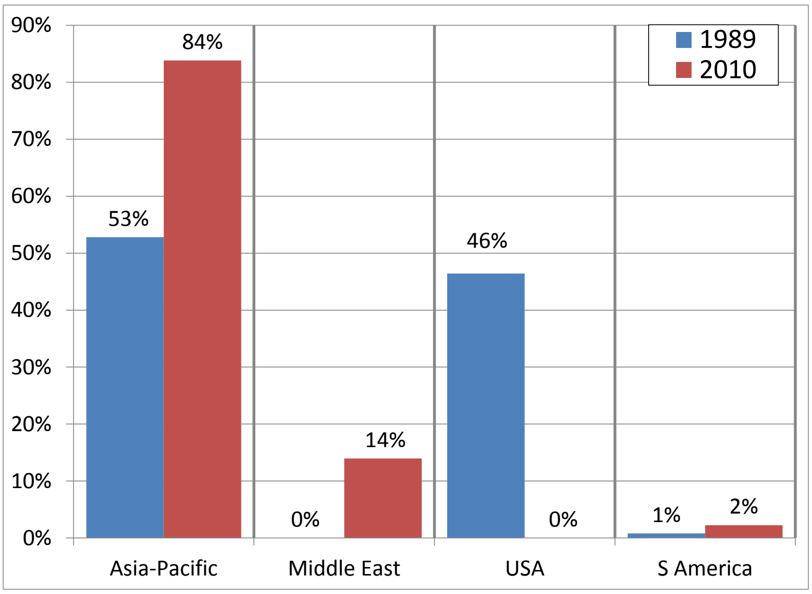


Source: EIA

With a continuing market for fuel oil, there was little incentive for the refiners to invest in cracking. Furthermore, given the overcapacity in total refining, additional cracking capacity would have resulted in excess supplies of gasoline and diesel.

Although the demand for fuel oil in power has been relatively steady over the years, changes in environmental regulations have moved Oahu utility fuel onto a low-sulfur basis. In the 1970s and 1980s, Hawaii refiners could import substantial amounts of high-sulfur and medium-sulfur crudes, including US West Coast crudes such as Alaskan North Slope. Today, Hawaii refiners cannot use such crudes because the sulfur content is far too high; the only imports of US crudes into Hawaii recently has been an occasional trickle of Cook Inlet crude (a small production low-sulfur Alaskan crude). The result is that Hawaii refiners must import sweet crudes, which are increasingly scarce (and expensive) in the Pacific Basin.

Figure 85: Sources of Hawaii Crude Imports, 1989 and 2010



Source: EIA

3.2.3. Impending Changes and Refinery Viability

It is reasonable to ask what effect the use of LNG might have on the economics of Hawaii's refining, but this question needs to be framed in the broader context of Hawaii's energy policy.

The goal of the HCEI from the outset has been to slash oil demand by 70 percent. Although specific standards have been agreed upon only in the power sector, the overall goal has always been to drive oil dependence to very low levels. The most recent report of the HCEI examines the feasibility of reaching the 70% goal in other sectors, including road transport.

Driving oil demand to low levels is by its very nature incompatible with healthy refinery economics. Irrespective of LNG imports, if the HCEI is successful in reaching its goals, the viability of Hawaii refiners will be endangered, and one or both are likely to cease operation.

To continue to operate, Hawaii refineries would have to become major exporters of refined products. The only growth market accessible to Hawaii refiners is Asia, but Hawaii is at a significant geographical disadvantage. If a Hawaii refiner produces an excess of low-sulfur fuel oil, it could easily be sold into Japan or Korea, but it would have to be sold at the prevailing prices in those markets. That means that in general the Hawaii refiner will have to pay for the transport to that market without being able to pass on the transport costs to the buyer. This could be different, of course, if the

Hawaii refiners were the marginal supplier to the region, but the chances of Asian prices being set by Hawaii delivery costs are slim indeed.

Thus, a Hawaii refiner's net earnings tend to drop with every barrel of exports. The cutbacks in LSFO demand implied in the HCEI by 2020 will reduce the refiners' net earnings by millions—and probably tens of millions—of dollars per year.

The refiners can respond to some extent by choosing lighter crudes, and producing somewhat less fuel oil, but light sweet crudes are expensive. Furthermore, if the cuts in demand range across the rest of the demand barrel, the Hawaii refiners will have little choice but to reduce their crude runs—which of course raises the average cost per barrel of refining.

In addition, the problem is not so simple as the total amount of oil demand. As discussed elsewhere, one possible means of meeting new environmental standards is to burn diesel instead of LSFO. This slashes LSFO demand—but the volumes of diesel required exceed what the refiners can produce. This then creates a situation where the refiners will have to import diesel on the one hand while exporting LSFO on the other.

LNG will make the problems faced by the refiners even worse, especially in utility fuels; the whole point of importing LNG as a power-sector fuel would be to substitute for oil that has not been pushed out by renewables.

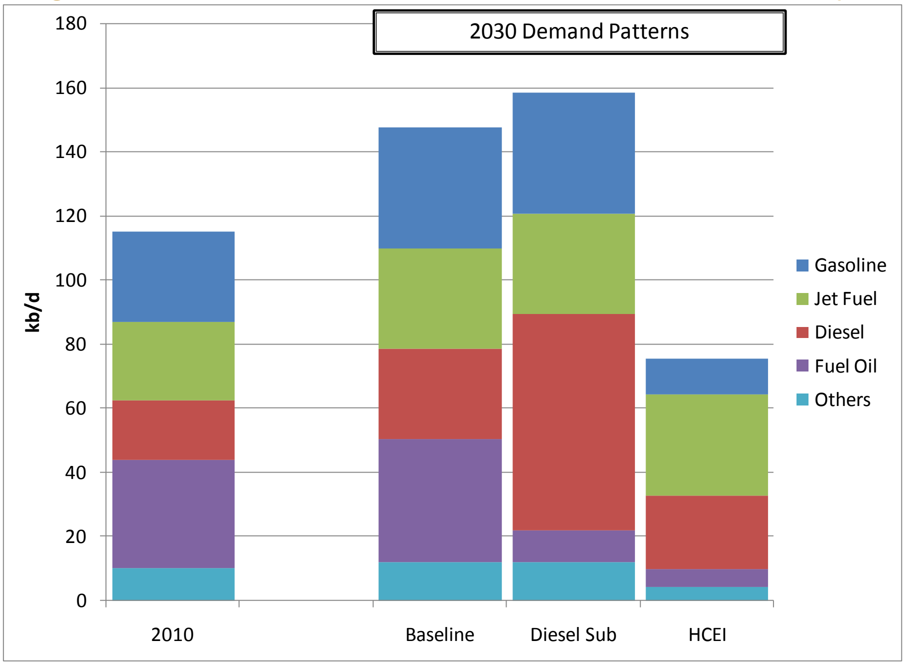
With or without LNG, the high prices plus existing State policies means that Hawaii refiners face a rapidly declining market for their products. There is already surplus refining capacity sitting idle; if there were money to be made from product exports, it is certain that the refiners would be running that capacity and accumulating the profits.

The unfortunate truth is that the surplus of capacity is only going to grow. LNG will deepen the problems faced by the refiners…but the 70% reduction in demand they face by 2030 is a consequence of the HCEI.

Consider the chart below. This looks at three scenarios—the baseline (our best approximation of what the HCEI originally expected to happen by 2030 without the initiative; the diesel substitution scenario, which is what would happen to baseline demand if the bulk of LSFO demand (excluding Kalaeloa) were switched to diesel for environmental compliance; and the HCEI goals, with 70% reduction (excepting jet fuel) from the baseline, as well as diesel substitution for LSFO.

The baseline scenario could have resulted in a more profitable refinery sector in Hawaii, with higher rates of utilization. But neither of the other two scenarios offer a good environment for refiners. Although, the diesel substitution scenario offered considerable growth—higher than the baseline in volume terms, since diesel has a lower heat content per barrel than fuel oil—the demand pattern would be impossible for a refiner to meet.

Figure 86: 2030 Oil Product Demand Under Three Scenarios (kb/d)



The diesel substitution scenario has demand for fuel oil dropping from about 29% of demand in 2010 to a mere 6% of demand in 2030, while demand for middle distillates (jet fuel and diesel) jumps from 38% to 62%. It would be impossible for the Hawaii refineries, in their present configuration, to meet this sort of demand pattern. (In fact, it would be difficult for any refinery anywhere to meet this pattern. With sufficient cracking capacity, the fuel oil output could be cut to a small percentage, but it is difficult to crack that much fuel oil without producing a surplus of gasoline or naphtha.)

Of course, no one foresaw that new federal regulations might drive LSFO out of the power sector, and force conversion to low-sulfur diesel. And, of course, the conversion of LSFO to low-sulfur diesel is not the only option; if the State remained committed to continued reliance on oil and an expansion of oil demand, then an expensive system of scrubbers and particulate controls could be installed. But paying for such controls only makes sense if large volumes of LSFO are to be consumed for decades to come.

In any case, the State has adopted measures to drive oil demand downward. The actual goals of the HCEI were 70% across-the-board reductions in demand for non-renewable energy (excepting jet fuel, for which there is no present substitute). Although the HCEI never presented an explicit calculation of what this would do to oil product demand, the result, if all goals were met, would look something very much like the last bar in the previous figure.

The HCEI goals outside the power sector are quite likely too ambitious to be met (especially in road transport). But the end-point toward which State policy has been directed is that shown in the figure—a sharp cut in the demand for oil products from today (much less from the projected 2030 numbers), and a demand barrel that is a whopping 72% middle distillates.

Oil demand in 2030 under the HCEI goals would be a little above 75 kb/d, as compared to a refining capacity of 147 kb/d. This implies a utilization rate of 51% for the refineries—if they were capable of meeting the demand pattern (which they are not). It needs to be recognized that a policy of driving oil consumption out of the Hawaii market is incompatible with a healthy Hawaii refining industry.

There might be room for one refinery in Hawaii under these circumstances, but not for two. Furthermore, unless massive investments were made, the remaining refinery would end up with substantial exports of fuel oil and gasoline/naphtha, and would still be quite short of jet fuel and diesel, necessitating large imports of middle distillates.

Imports of LNG will cut oil demand faster than the HCEI would alone. But critical problems for the refiners arise in 2016-2017, probably well ahead of any major LNG imports. These are the years where new federal environmental standards come into play (see previous chapter). If the decision is made to switch to diesel, at least on an interim basis, the bulk of demand for LSFO will suddenly switch to diesel. Even if the refiners adopt a different crude slate, they will still face an excess of fuel oil and a shortage of diesel. Unless they earn a very good margin on their diesel imports, there is little question that this will hurt refinery profitability.

3.2.4. Implications of Increased Product Imports

Because of the Japanese "Triple Disaster," LSFO is in short supply in the Pacific Basin. This is not the case with other finished products, however, and the outlook for supply growth in the region is very strong. Many new Asian refineries will be coming onstream in the middle of the decade, and most of them are designed to have exportable surpluses. Indeed, many analysts are concerned that there will be a glut of products on the Asia-Pacific market. Gasoline, jet fuel, diesel, and high-sulfur fuel oil are all likely to increase in export volumes available. The sole exception to this pattern of increased availability is LSFO, which is likely to be used increasingly as cracker feed.

In addition, gasoline and diesel demand are on a downward trend in the US. This is occurring against a background of increasing production of light crudes in the central part of the country, resulting in higher gasoline and diesel yields per barrel of crude refined. The surprising result is that the US is now a major, and growing, exporter of gasoline (especially to Latin America).

In such a market, it should be easy to procure needed product imports. In addition, any longer-term price impacts should be relatively minor. After all, the refiners have insisted for years that the prices at which they sell products are comparable to import parity prices. The Gas Cap legislation was based on the belief that imported products would actually be cheaper than the local prices from the refiners. (For the record, FGE never believed that this was the case. Our best calculations suggested that local prices and import parity prices were always quite close.) In addition, Hawaii is already a major importer of oil products; large volumes of jet fuel are often brought in from around the region.

This sanguine view, however, is about the longer term. *In the short term, there are significant risks of disruptions and consequent price problems.* The problem is one of infrastructure and uncertainties about infrastructure ownership.

The bulk of the oil-import infrastructure in the State is in the hands of the refiners. There are smaller import terminals in Honolulu Harbor, along with some tankage. The power companies own substantial product tankage (but not any overseas import facilities). Aloha also has its own gasoline and diesel terminal.

The two refiners have ample tankage to handle the State's needs, although much of that tankage is presently designated for storage of fuel oil and crude oil. If a major shift in demand patterns occurs while demand is still relatively high, tankage would have to be cleaned and shifted from one product to another—but unless the new demands were for high-volatility products (such as gasoline) or ultraclean products (such as jet fuel), this should be easy to accomplish.

The offshore problems may be more challenging. Since they were designed for crude oil, the refiners' import lines are not permitted for high volumes of product imports. To operate primarily as product lines, they would require re-permitting and possibly some modifications. In addition, products generally travel on smaller vessels than crude does, and there would probably be a large initial increase in ship traffic.

Hawaii's demand is small in the context of the Pacific Basin. Nonetheless, current shipping logistics and supply arrangements are not prepared for large movements of clean products to the middle of the Pacific. Ships may have to be relocated or repurposed, and an exporter will have to take Hawaii's demand into account.

If the refiners take steps to adapt their systems to large-scale imports, then a switchover to increased product imports should be relatively easy to handle. If they so choose, they could gradually shut down their refining facilities and convert their sites to import terminals. This has become a rather common practice on the mainland—so common that it is even referred to in shorthand as an "RTT" (Refinery-to-Terminal conversion).

Since the refiners control most of the import infrastructure, however, such rapid changeovers can only be accomplished if the refiners cooperate. Unlike the US mainland, where there are many "tolling" storage companies who take volumes from paying customers, there is little third-party import and tankage available in Hawaii.

In 2030, it is possible to imagine all product import needs being met by the facilities of just one of the two refiners. At present demand levels, however, it would be a breathtaking juggling act for one refiner to manage large product import volumes while continuing to operate. The problems are not down the road in 2030, but looming in the middle of the present decade when the environmental regulations change.

The near term is fraught with uncertainty for the refiners as well as the State. The State has limited control over what the refiners choose to do with their facilities. The refiners have no control over policy or the future composition of demand, and have to prepare for future supply needs by guesswork. Short of a major move by the State—such as establishing a new open–access import terminal, or arranging access to import facilities at one of the refineries—the uncertainties will continue, and the best that can be achieved is an ongoing dialogue.

The biggest near-term disruption is the possibility of a major switch to diesel to substitute for fuel oil. If a decision is made to begin imports of LNG for the power sector, the State may have an option to avert this disruption. Although the EPA has been reluctant to grant waivers or delays from the new regulations, a number of people we have spoken with believe that if the State approached the EPA with a proposal to delay the regulations until LNG became available, it might well be granted.

This change could allow the refineries to continue operating for a few more years without confronting a large shortage of diesel and a large surplus of fuel oil. Logistics and operations would continue on very much the same basis as in the past.

To summarize, the long-terms risks of relying on product imports are small. But there are significant risks of logistical disruptions and price consequences between now and the end of the decade. The nearer-term problems are the result of environmental regulations and the consumption trend established by the HCEI. By the end of the decade, or early in the next decade, if LNG becomes a major factor in the power sector, it will significantly increase the problems faced by the refiners.

3.3. *LNG and Renewable Energy Goals*

One question that is occasionally raised about LNG is whether it will be so cheap that it will discourage the use of renewables. When examined closely, this is a disturbing concept: it is essentially an argument that the best way to encourage renewables is by keeping energy prices high.

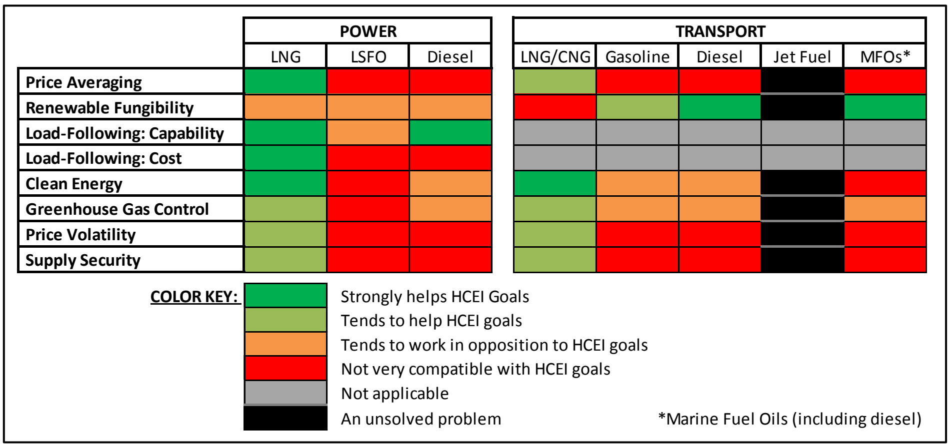
While high energy prices do indeed make renewables more competitive, it seems odd to advocate a policy of keeping Hawaii's energy prices as high as possible. It is hard to imagine many citizens of Hawaii endorsing such an idea.

Any discussion of LNG and renewable energy goals must consider LNG in the context of the existing fossil fuel system, which is dominated by oil. In the following, we consider the effects of oil products and LNG on achieving the HCEI goals—but we have deliberately excluded high prices as something that is to be desired.

It also needs to be recognized that not all of the HCEI goals may be achievable. In particular, a recent study for NREL concluded that even under an extreme scenario, the goal of 70% reduction in conventional road transportation energy by 2030 was not possible—at least not without converting large areas of land to biofuels plantations.

The figure below shows the various fossil fuels and indicates how they assist or hinder renewable energy. Although some of the issues are more closely related to lowering environmental impact rather than expanding renewables *per se*, we were guided in choosing the issues by recalling that the HCEI stands for the Hawaii *Clean* Energy Initiative. We have therefore assumed that lowering emissions of pollutants and greenhouse gases are also goals.

Figure 87: Fossil Fuel Effects on Clean Energy Goals



The long stack of black boxes under jet fuel may not persist forever. Biofuelled jets have been flown many times now, and both IATA and large companies like Boeing are encouraging innovation in this area. There are barriers to development, however—the first of which is that safe and replicable international standards must be agreed upon, and commercial levels of production must be attained. Biojet will probably begin to play a significant role in the market after 2020.

In addition, some of the most advanced designs for aircraft at Boeing are looking to use LNG in new-concept jets. Although most projections show such jets as entering the market around 2030 or later, there is speculation that low US gas prices may speed development.

Price Averaging. Price averaging refers to the idea that by lowering the average price of the combination of conventional fuels plus renewables, higher-priced renewables can be better accommodated in the system. For example, cheaper conventional fuels in the power sector can help hold down overall electricity costs, even if renewables cost more than conventional power.

On that score, LNG can make a major contribution; as seen in the previous chapter, the use of LNG can dramatically lower the cost of electricity. Oil products, which are expensive, have the opposite effect.

Price averaging in the transport sector is not so clear cut. Once again, the oil products are high priced and therefore do not assist in keeping overall costs down. LNG cuts the average cost of transport fuels, so offers an overall benefit—but it is a benefit that is unevenly distributed across customers.

A driver who buys a CNG car benefits directly in terms of lower costs, but that does not lower the cost for someone who drives, say, a biofuelled car. Indeed, in this particular example, LNG and renewables are in competition. But when CNG or LNG are used in public transit vehicles, sanitation trucks, or fleet vehicles, they do spread their price-averaging benefits widely across the community.

Renewable Fungibility. This describes the extent to which renewables can readily replace a given conventional fuel in existing equipment (with only limited modifications).

It is possible to quarrel with our evaluations substitutability in the power sector. Advocates of LNG will point to biomethane; supporters of LSFO will point to palm oil, and diesel fans will point to biodiesel. Yes, these are all technically feasible fuels, but for the foreseeable future they are expected to be quite expensive. (Biomethane from landfills is being used on the mainland, and even being charged into the pipeline system, but the costs to clean it up make it very high-priced when used in this fashion. Future technological innovation may make biomethane from crop wastes or other green waste an economical source; biofuel research has been and is still focused primarily on liquid fuels.)

In other words, there are many reasons to build a gas-fired or diesel-fired peaking turbine, but providing a future outlet for renewable fuels is not one of them.

Gas in road transport does not offer much room for substitution by renewables. Once again, creating biomethane, cleaning it, and compressing or liquefying it is technically possible. But, it seems uneconomic—especially compared to LNG, which is already clean and highly compressed to the maximum extent possible.

Direct use of 100% biofuels in existing or modified car engines is possible with conversion kits, but the efficiency, cost, and reliability of the systems vary. Biodiesel (if it meets ASTM D5761 standards) can be used directly in diesel engines.

Another compatibility of liquid fuels is that biofuels can be blended with them in a variety of proportions. Indeed, Hawaii already has a mandatory blending standard of 10% ethanol in gasoline. (Going to significantly higher percentages can require some engine modifications and special additives.) The Bus already utilizes substantial volumes of B20 (biodiesel in a 20% blend).

In general, oil-fueled road transport vehicles are no barrier to adoption of biofuels. The only real barrier is cost and availability. If biofuels were economically competitive, they would be widely used. This can be seen in the case of Brazil, where ethanol use soars when ethanol prices are low and gasoline prices are high for prolonged periods. (When the prices reverse for long periods, of course, ethanol use drops.)

Load-Following, 1: Capability. Load-following is explained in the Power section of the Background materials. Load-following power generation is critical to integration of fluctuating renewables into the power grid.

LNG (once regasified) is readily adaptable to load-following in gas turbines and CCGTs, and is the most common solution to peaking and load-following on the mainland. Diesel is roughly equally capable in this regard. Therefore, either of these fuels offers a perfect match with fluctuating renewables.

LSFO is best burned in steam turbines. Steam turbines are capable of some degree of load-following, but it is a poor technology for the purpose.

Load-Following, 2: Cost. While LNG and diesel are both almost equally good at load-following (gas is a tiny bit more efficient and requires less maintenance), as seen in the previous chapter, LNG has a powerful cost advantage over diesel in this application, saving 33-40% in terms of the final electricity fuel cost.

Clean Energy. LNG is the cleanest of the fossil fuels. Effectively all of the contaminants (such as sulfur) are removed prior to liquefaction, and combustion is highly efficient, resulting in no ash—and an 83% reduction in nitrogen oxides compared to oil.

LSFO is a clean fuel compared to high-sulfur fuel oil, but it still contains significant amounts of sulfur; in Hawaii, the burning of LSFO emits tens of millions of pounds of sulfur dioxide into the atmosphere each year. LSFO also has significant metals content, and produces significant amounts of particulates.

Low-sulfur diesel in power generation is much cleaner than LSFO, but it still emits some sulfur dioxide and particulates.

As in the power sector, LNG in transportation is extremely clean. Oil-based road transport fuels are some of the cleanest oil products, but they are still not clean compared to LNG.

At present, marine bunkers (both marine diesel and fuel oils) are among the dirtiest fuels burned in Hawaii. This will change in 2015 when IMO ECA regulations come into effect in US waters. Even though this will slash the sulfur content of marine bunker fuels to 0.1% sulfur, that is still a far higher sulfur level than is allowed in road transport; oil-based shipping bunkers will still be relatively dirty in terms of emissions.

Greenhouse Gas Control. Greenhouse gases are not, strictly speaking, pollutants. Life on earth would be impossible without carbon dioxide. But rising levels of carbon dioxide in the atmosphere is believed to be the main culprit in global climate change.

All fossil fuels emit carbon dioxide. On a per-Btu basis, coal is the worst offender, followed by fuel oil, followed by diesel.

LNG (or, more generally, natural gas) has the lowest per-Btu output of carbon dioxide of any fossil fuel. That does not mean there are no emissions; the emissions of carbon dioxide are only 33% lower than the emissions from fuel oil. (On the other hand, if gas is burned in a baseload CCGT, its per-kWh output of carbon dioxide is 62% lower than that of LSFO burned in a steam turbine.)

In principle, renewables do not emit carbon dioxide on a net basis; although biofuels do emit carbon dioxide when burned, the production of more biofuels absorbs the same amount of carbon dioxide as was emitted.

LNG is not a zero-CO_2 fuel. It is simply the lowest CO_2 fossil fuel.

Price Volatility. Imported oil is notorious for its price volatility, and one reason offered for the use of renewables is that it is expected that most of them would be supplied from local sources. (This logic does not hold if biofuels, such as crude palm oil, are sourced from Malaysia or other tropical nations.)

If LNG is sourced from the US, it is expected to not only be cheaper than oil, but far more stable in price.

Energy Security. Imported fuels cannot compete with locally produced energy in terms of security of supply. At present, however, virtually all of Hawaii's oil is imported from foreign countries.

The economics of LNG strongly favor importing from sources in the United States. While this is less secure than local energy, it is hard to imagine a more secure source of energy imports.

Summary. LNG is generally in alignment with the goals of the HCEI. It is clean, and can reduce price volatility and increase energy security. It can help renewables through price-averaging and load-following. Once the State's path forward in terms of the mix of renewables is clarified, the extent to which LNG can help will become clearer.

There is an area of potential competition between LNG and renewables in road transport. Renewables cannot be readily blended into CNG or LNG in the way biofuels can be blended into gasoline or diesel.

In general, LNG and CNG in transport are expected to be considerably cheaper than gasoline or diesel; and, at present, it appears that gasoline and diesel are likely to be cheaper than their biofuel counterparts.

This presents the State with an important policy decision. If CNG and LNG become widespread in transport, they could cut oil dependency and save Hawaii significant amounts of money at the pump. At the same time, however, CNG and LNG are liable to outcompete biofuels in transport as well as gasoline and diesel. In fact, the less oil is used in transport, the more limited blending opportunities for biofuels become.

It may make sense to displace imports of foreign oil with local biofuels even if there is a price premium to be paid; this is a political judgment. The question is whether it makes sense to pay potentially large premiums for local biofuels to displace imports of cheap LNG from the US mainland. (The proposition becomes even more questionable if the biofuels themselves are imported from foreign sources.)

3.4. *Other Risks of LNG*

The biggest risk of reliance on LNG imports is the chance of natural disaster. The problems in energy supply following Hurricanes Katrina and Sandy make it clear that major supply disruptions can result—and supply problems are simpler to solve on the mainland, where oil can be trucked or shipped in from many neighboring sources, and electricity can be wheeled through interconnected power grids. For Oahu, Hurricanes Iwa and Iniki were near-misses, but it would be unwise to plan on continued good luck.

It does not make sense to have multiple LNG import terminals to lower risk—especially since there are no logical places to site them that are far apart. This is not a problem unique to LNG: the two Oahu refineries are relatively close to one another. Indeed, the bulk of the State's energy facilities in terms of total volume are located in a swath that runs from Waiau to Kahe, all in low-lying areas with exposures to the south.

This is not just a problem for LNG, but for oil for the whole State, and for power for Oahu. After the Tesoro Hawaii refinery announced it would be sold off (or possibly closed), there was a minor panic about oil product supplies in the event of a closure. Insofar as we were able to determine, there is no state-level emergency plan for handling import logistics in the event of a refinery being decommissioned. The real risk is not that a company will close down a refinery and stop supplies—there would be time to prepare, and world-class companies like Tesoro and Chevron simply do not behave like that. But what if one or both refineries were shut down by a natural disaster?

Compared to refineries, LNG import terminals are simple and relatively robust. Still, the State needs to develop a contingency plan for supply in event of a natural disaster. But the plan should also address how to manage oil product supply in event of a refinery closure, or the closure of both refineries—whether caused by a disaster, or simply by commercial decisions. The State's import infrastructure, even though it is presently mostly privately owned, is a matter of critical public interest.

The one area in which LNG poses some special concerns is in transportation. As we pointed out in the previous chapter, although in principle a single standard-sized LNG tanker could meet most of Hawaii's needs (at least in the near term), having a fleet consisting of one ship would be courting disaster. Oil tankers, and oil-product tankers, are so common that in event of an emergency a replacement tanker can always be found, but the market in LNG tankers is far thinner. Although it may be somewhat more expensive, more, smaller ships with more frequent deliveries is a much more secure option than putting all one's eggs in a single tanker.

Many sources of LNG are in potentially politically unstable areas: the Middle East, North Africa, and parts of Southeast Asia. The five possible sources examined in this report—Alaska, Australia, Canada, the US Gulf Coast, and the US West Coast—are all politically stable, and there is no risk of political cutoffs from the source.

There is also little risk of political problems *en route*, with the exception of supplies from the US Gulf Coast, which have to cross through the Panama Canal. While it seems improbable that Panama would choose to shut down its main source of revenue, there is precedent—the Suez Canal has been closed three times.

In our calculations, we have assumed that about one month of LNG storage would be on hand—although the amount stored would vary depending on demand levels, and the amount actually held in tankage. Whether this is adequate depends to a great degree on the supply source: Alaska, Canada, and the US West Coast are all roughly a week's voyage away.

Under any scenario, the biggest consumer of LNG will be the power sector. This is fortunate in terms of security, as it is easy to provide backup for power sector uses of gas. Pipeline gas, or CNG in cars and trucks, or LNG in trucks or marine transport, are not readily substituted by other fuels.

In the power sector, gas can be easily substituted in almost any end-use by diesel. Low-sulfur diesel, like gas, can be run in steam turbines, gas turbines, or CCGTs. Although most of the Hawaii power generators do not have enough diesel tankage to supply significant backup, they do have enough fuel oil tankage and pipeline capacity which could be converted.

This is not a hypothetical proposal; diesel backup is becoming standard, and Puerto Rico (which shares a number of parallels with Hawaii) uses diesel as the backup system for its LNG imports in case of supply interruptions by hurricanes or other problems. Paying a little extra for dual-firing capability seems like money well spent.

How much diesel should be held? This is a matter that ought to be considered in the context of a larger emergency-management plan, but if the revisit rate from LNG carriers is frequent, the stock levels might be no more than a week or two.

The final issue regarding risk is physical safety. It is common to hear that LNG tankers are “floating bombs,” or that LNG storage tanks can hold “energy equivalent to a nuclear bomb.” Given that gas is potentially explosive, this seems like a valid concern.

This is largely an issue of novelty. We all know that an open gas leak is dangerous. Would not an LNG tanker or storage tank be even more dangerous?

In the real world, no. True, LNG contains large amounts of energy in a small volume—but not nearly as much as oil does. A gallon of LNG contains only about half as much energy as a gallon of fuel oil; it contains about two-thirds as much energy as a gallon of gasoline. Furthermore, gas is explosive in only a narrow range of gas-oxygen combinations. A slow gas leak in an enclosed space provides plenty of time at every methane-oxygen ratio, and is therefore quite dangerous. As many government-sponsored studies have shown, a sudden release of LNG is unlikely to result in an explosion, because the time spent in the critical methane-oxygen ratio is quite short.

Gasoline, on the other hand, is quite dangerous. It spreads out as a liquid, evaporates readily, but does not entirely evaporate for a long time. It is ignitable and explosive for a long time after a spill, which is uncommon in oil products. You can put out a cigarette in a cupful of diesel oil, and, contrary to *Die Hard II*, jet fuel burns well, but it is exceedingly hard to get it to explode. Fuel oil has the highest energy density of the common oil products, but it actually requires some effort to get it burning. The most dangerous hydrocarbon product is probably the one most people deal with every day: gasoline. But most informed energy analysts would far prefer to take a ride on an LNG tanker than ride in the passenger seat of a gasoline tanker truck on the way to a service station.

Finally, the environmental impact of an LNG spill would have a comparatively small footprint. If the *Exxon Valdez* had been an LNG carrier, it would have resulted in some frozen fish, but there would not have been oil-soaked birds and otters; there would not have been tar washing up on the beaches for months.

This is not to say there are no physical risks to LNG. Combustible materials are hazardous, and there are no energy sources that have zero environmental impact. Safety and environmental standards need to be codified and rigidly enforced. But the belief that there is some extraordinary safety risk with LNG that is higher than oil products is patently untrue.

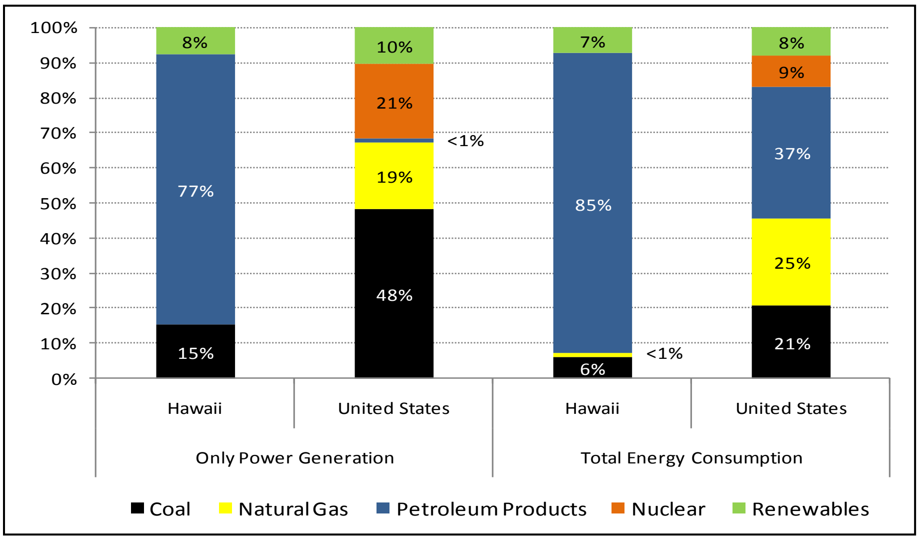
IV: Hawaii's Natural Gas/LNG Regulatory Structure, Policies, and Practices

The primary purpose of this section is twofold. First, FGE will summarize the current salient federal and state economic regulatory practices governing all components of the US natural gas value chain: LNG import terminals, interstate pipelines, gas storage, infrastructure, and local distribution companies (LDCs). This section will highlight the prevailing ownership structures of these value chain components and identify the structural and regulatory safeguards in place to ensure open, non-discriminatory access to critical gas infrastructure supply chain. Second, FGE will assess Hawaii's current regulatory structure, policies, and practices as they would relate to potential State LNG to burner-tip gas infrastructure supply chain development and operations. By comparing and contrasting the regulatory practices that govern the natural gas business on the mainland with Hawaii's, it is possible to identify any gaps, issues, or challenges that may arise from efforts to establish an LNG import terminal in the State.

4.1. *Natural Gas in the US: A Primer*

On average, natural gas accounts for about 26% of the US' current primary energy mix. It is superseded only by petroleum (crude oil, petroleum products, and natural gas liquids), and exceeds the shares of coal, renewable energy sources, and nuclear energy. Natural gas is increasingly the fuel of choice in power generation and industrial applications, but given oil's dominance in the transportation sector, gas' share of the nation's primary energy consumption (PEC) pales relative to oil. Nevertheless, gas' relatively high share of the US energy mix is in stark contrast to Hawaii, which is overwhelmingly reliant on oil.

Figure 88: US Primary Energy Mix and Power Generation Portfolio Relative to Hawaii (2010)



Source: EIA

The US as a whole accounts for about one-quarter of global natural gas production and consumption. Unlike most gas-consuming regions in the world, the US is largely self-sufficient: total dry gas production exceeded 63 bcf/d in 2011, whereas consumption surpassed 66.7 bcf/d. The power generation (31%) and industrial (28%) sectors account for the lion's share of US gas demand. Almost 40% of the nation's installed power generation capacity is fuelled by natural gas, thereby underscoring the demand growth potential represented by the power sector. The gap between US production and demand is traditionally met by imports via pipeline (mainly from Canada) and liquefied natural gas, namely the former. Net US natural gas imports topped 5.3 bcf/d in 2011.

Natural gas has been used in commercial applications in the US since the 19th century. As a result, sophisticated production, transportation, distribution, marketing, regulatory, and even financial frameworks have evolved to create the US natural gas business that we know today. With over 272 trillion cubic feet (tcf) of proved[19] dry gas reserves as of 2009, more than 515 natural gas processing plants, and over 305,000 miles of transportation infrastructure in place, it is fair to surmise that the US natural gas business is extremely large and somewhat intimidating to entities that have either no experience with natural gas outside their 'home' markets abroad and/or are used to heavily regulated or controlled market conditions. However, a solid understanding

[19] Also known as 1P reserves. Based on extensive analysis of geological and engineering data, proved reserves can be estimated with a high degree of confidence to be commercially recoverable from a given date forward, from well-established or known reservoirs and under current economic conditions.

of the mainland gas market's evolution and composition renders the task of understanding and possibly interacting with mainland US companies a more manageable task.

4.2. *US Federal and State Natural Gas Regulatory Regime*

The regulatory and commercial structure of the US gas industry has changed dramatically over the last two or three decades. The gas business has evolved from a system built on long-term take-or-pay contracts to a commodity market that is built on short-term physical transactions. In addition to a physical gas market comprising of upstream production, transportation pipelines, storage, LNG terminals, and distribution networks, a financial gas market has evolved to provide the requisite market transparency and financial instruments to mitigate the attendant price risks.

In contrast to the oil sector, in which some companies are active in all segments, it is more common for companies in the natural gas sector to concentrate on two or three segments (e.g., production/gathering, or transmission and storage). Natural gas is supplied and traded by private-sector companies in the US—unlike almost all other major energy producing or consuming countries in the developed world, the US has never had a state-owned petroleum company with monopoly powers over the natural gas business. The private sector companies active in the US natural gas sector—namely, the upstream and some parts of the midstream components of the value chain like interstate and intrastate pipeline transportation—are privately or publicly owned and range in size from entrepreneurial partnerships to very large organizations. However, some parts of the midstream and downstream components of the value chain like gas storage and especially local distribution are typically conducted by private entities subject to public utility regulation at the federal or State level, or by municipal utility districts.

4.2.1. Historic US Gas Regulatory Regime and its Evolution

Until the mid-1980s, the US natural gas business was relatively straightforward. It was characterized by limited flexibility and little diversity regarding sale and purchase transactions. Exploration and production companies explored for and drilled for natural gas, generally selling their product at the wellhead to pipeline transportation companies at federally regulated prices. Transportation companies transported their purchased volumes to customers comprising of natural gas utility local distribution companies and some large-scale industrial users. The latter distributed and sold gas to end-users, such as residential and commercial customers, as well as power plants and some industrial customers (Figure 89).

Figure 89: Former Commercial Structure of the US Gas Business

Source: Natural Gas Supply Association

The price received by producers for gas sold to pipeline transportation companies was federally regulated, as laid out in the Supreme Court's so-called Phillips Decision of 1954. Pipeline cost-of-service and rates of return were likewise federally regulated, as specified in the Natural Gas Act of 1938. Further down the value chain, state regulators monitored the price at which LDCs sold their gas to consumers, both in terms of the LDCs' purchased gas costs and their costs of service.

This somewhat static and tightly-controlled industry structure proved to have adverse effects for US natural gas players, from the wellhead to the burner tip. Regulated wellhead prices and assured monopolies for pipelines and LDCs provided little impetus for new technology development or service improvements. Producers also had little incentive to search for new reserves. Although sales prices to interstate pipeline gas companies were set by federal regulators at a low price, the finding and development costs for establishing new reserves were variable and unpredictable. Producers therefore saw little reason to explore for new reserves whose finding costs could exceed the sales price. This environment of low natural gas prices, indifferent interest by upstream gas producers, and surging oil prices in the 1970s created something of a 'perfect storm' for the US natural gas industry. The result was a surge in demand for natural gas that US producers were essentially constrained from meeting.

It is important to note that the federal government only regulated producer wellhead prices for natural gas destined for the *interstate* market. Natural gas sales within the *intrastate* market were relatively free of regulation. Consequently, economic incentives did not exist for producers to ship their gas across state lines, because producers could sell their gas at much higher prices to intrastate bidders. In 1965, a third of the nation's proved reserves were earmarked for intrastate consumers; by 1975, almost half of the proved reserves were committed to intrastate consumers.

Pipeline gas companies were blamed for the gas shortages of the 1970s, since they were charged with ensuring gas supplies to downstream consumers. This accounts for pipeline utility companies' decision to augment their supply portfolios with LNG. Four LNG receiving terminals on the mainland—Everett (Massachusetts), Cove Point (Maryland), Elba Island (Georgia), and Lake Charles (Louisiana) were developed between the 1970s and early 1980s by federally regulated pipeline gas companies. Distrigas of Massachusetts built Everett near downtown Boston; Columbia Gas partnered with the Consolidated Natural Gas Company to build Cove Point and help serve the Mid-Atlantic market; Southern Natural Gas sponsored Elba Island near Savannah; and the Trunkline Natural Gas Company sponsored the Lake Charles terminal near the township of Lake Charles itself. However, this proved to be an "infrastructure solution to a market problem," as the construction and startup of these terminals coincided with the passage of gas industry reforms enacted from the early 1970s to the late 1980s and beyond. These reforms radically affected the commercial gas mechanisms governing the US gas industry. It was market reform rather than LNG that ended the natural gas supply crunch of the 1970s. These reforms focused on unbundling pipeline gas sales from transportation functions:

- 1972: The Federal Energy Regulatory Commission's (FERC) Order 319 allowed open gas transmission to all high-priority customers.
- 1984: FERC Order 380 empowered pipelines' LDC customers to ignore their take-or-pay provisions with pipeline companies. However, this Order did not affect the back-to-back take-or-pay provisions in pipelines SPAs with producers.
- 1985-1989: FERC Orders 436, 500, and 528 established basic open access parameters for gas transportation pipelines, banning unduly discriminatory behavior by pipeline companies seeking to protect their SPAs and allowing LDCs to convert (usually over five years) their take-or-pay gas purchase contracts with pipelines into firm transportation contracts for corresponding volumes of gas.
- 1992: FERC Order 636 completed the open access process by forbidding most pipeline gas merchant activities, requiring that fixed transportation costs be recovered in monthly demand charges, and providing a framework for pipeline capacity release and acquisition by third-party bidders.
- 2005: The Energy Policy Act of 2005 conferred on FERC new authority and prescribed a number of specific tasks related to natural gas or natural gas markets for action by FERC.

Through these and other orders, gas pipeline services in the US were restructured to mandate the provision of open access. The promulgation of these rules coincided with the growth of the spot gas market in the 1980s and early 1990s. In response to the nascent spot gas trade, most pipeline companies re-negotiated, re-structured, reformed, and eventually terminated their SPAs with upstream gas suppliers. By the mid-1980s, rising wellhead prices enabled the market to transform from a state of gas shortage to a state of surplus. As a result, intense gas-on-gas competition—the hallmark of today's gas market in the US—evolved. Competition emerged and grew across all facets of the value chain, among pipelines, upstream producers, marketers, and end-users.

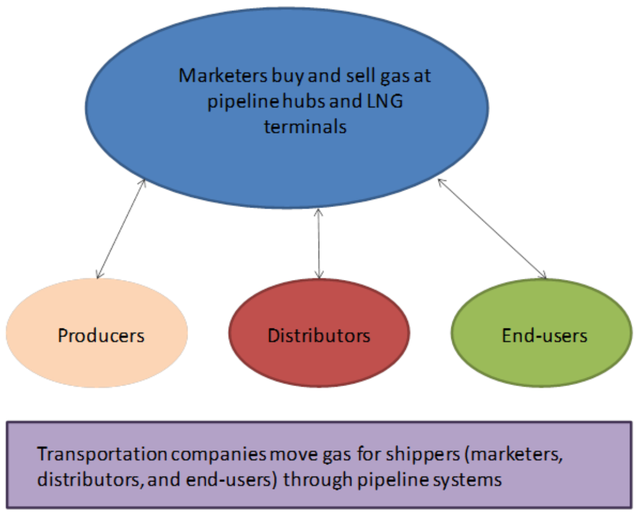
- **Upstream.** Wellhead prices are no longer regulated, so the price of natural gas is dependent on supply and demand interactions. Today, there over 6,300 producers of natural gas in the United States. These companies range from large integrated producers with global operations and interests in various components of the petroleum business, to small one or two person operations that may only have partial interest in a single stripper (marginal) well.
- **Midstream (processing, transportation, and storage).** The number of different companies own US gas processing capacity, interstate or intrastate pipeline transportation assets, and/or storage assets are in the three-figure range. However, ownership does not translate to automatic control over capacity. Multiple regulatory safeguards are in place to protect consumers and other competing gas industry players against a single company wielding excessive market power.
- **Distribution**. There are over 1,000 natural gas distribution companies in the US. While many of these companies maintain monopoly status over their distribution region, many states offer consumers options with respect to sourcing gas.
- **Marketers.** Unlike upstream producers, pipeline utility companies, and end-users, natural gas marketers are a relatively new addition to the US business. They have emerged as a central commercial feature of today's US gas market. The status of the natural gas marketing segment of the industry is constantly changing, as companies enter and exit from the industry quite frequently. These entities buy and sell gas, arrange pipeline transportation capacity, and provide financial services to players across the value chain, thereby lending liquidity to markets.
    - The top-10 US gas marketing companies include a mix of multinational integrated energy companies, former European monopoly utility companies, foreign national petroleum companies, and financial institutions: BP, EDF Trading, Gazprom, JP Morgan, and Macquarie, to

name but a few. These marketing companies, together with gas utilities, power generation companies, and industrial end-users buy natural gas from suppliers that include producers and other marketing firms. While gas marketing companies with upstream producing assets may act as merchants for in-house production, this will be mingled with gas purchases via other avenues.

As a result of these regulatory changes, the actual ownership pathway of gas is very different compared to that depicted in Figure 89. Interactions between the multiple owners of components in the natural gas value chain are much greater, and occur at different levels—very different to the 'straight-line' process of yesteryear. Figure 90 shows the commercial structure of the US gas business after unbundling. Of course, the actual ownership pathway of gas illustrated by the figure may be significantly more complicated because either the marketer or the distributor (i.e., the LDC), neither of whom are end-users, may sell directly to the end-user or to other marketers or LDCs.

Figure 90: Simplified Commercial Structure of US Natural Gas Industry After Unbundling

Source: Natural Gas Supply Association



The resulting mix of gas supply contracts are dominated by short-term and spot gas contracts, with a small share of the market reliant on long-term SPAs. Likewise, gas transportation agreements for pipeline capacity are relatively short-term in nature, with the notable exception of contracts that underpin new pipeline or storage capacity construction or major capacity additions. Because of the profusion of short-term arrangements, most natural gas purchase contracts and transportation agreements are standardized.

Gas buyers and sellers typically agree on a price at a given US gas trading hub where title transfer is to occur. For example, a seller might agree to sell 10,000 mmBtu daily over 31-days in October to a buyer. The applicable price throughout that month will be agreed by the buyer and seller during the closing days of the previous month. This is known as the "bid week." Of course, the two parties might simply agree to pay the published price of gas at the specific US gas trading hub (these prices always appear in publications by Platts, the Energy Intelligence Group, or similar), or a daily price throughout the month that will change with screen prices on the New York Mercantile Exchange.

The trading of natural gas is largely market-driven. However, rules are in place to ensure that the market is operated fairly. FERC has also implemented 'anti-manipulation' rules that prohibit fraudulent or deceptive practices and omissions or misstatements of material facts, in connection with purchases or sales of natural gas or transportation services subject to FERC jurisdiction. The Commodities Futures Trading Commission (CFTC) regulates natural gas futures to prevent similar abusive trade practices.

4.2.1.1. *Conclusion*

The US gas business is no longer a tightly bundled and controlled entity. A series of reforms promulgated since the 1970s have opened the market considerably. A huge milestone was reached in the mid-1980s, when FERC initiated the restructuring of interstate pipelines from merchant sellers and transporters of natural gas into transportation only businesses. This process was completed in the 1990s. As a result, today's US gas market is characterized by its wide range of players that are involved in only one or two components of the natural gas value chain: upstream producers generally do not own pipelines; pipeline companies are generally not engaged in the upstream; distributors may contract for interstate pipeline capacity without owning the pipeline or any upstream production; and so on. However, producers and pipeline transportation companies can and do participate in the natural gas marketing business, along with a string of other entities, like banks and other financial institutions. This general lack of market overlap has contributed in no small part to the much-vaunted liquidity of today's US gas market.

Despite these extensive gas market liberalization and re-structuring measures, the US gas market remains subjected to great regulatory oversight. FERC regulates US gas pipeline rates as well as the availability of new pipeline capacity, whereas individual States oversee gas distribution utility rates and expansions (see following sections).

Regulatory oversight also includes a 'referee' function in which regulators resolve conflicts and disputes among regulated entities and associated market participants such as customers, shippers, gas marketers, and upstream producers.

4.3. *Present-Day US Gas Industry Regulatory Regime*

4.3.1. Regulatory Agencies: The Main Players

The physical gas market is overseen by multiple federal and state-level agencies. The key federal agency for gas industry players throughout almost all the value chain is the Federal Energy Regulatory Commission (FERC). This federal agency obtains its authority and directives in the regulation of the natural gas industry from a number of laws. These include the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, the Outer Continental Shelf Lands Act, the Natural Gas Wellhead Decontrol Act of 1989, the Energy Policy Act of 1992 and the Energy Policy Act of 2005.

FERC is designed to be independent from influence from the executive or legislative branches of government, or industry participants, including the energy companies over which it has oversight. FERC is composed of five commissioners, who are nominated by the US President and confirmed by the Senate. Each commissioner serves a five-year term, and one commissioner's term is up every year. FERC's regulatory authority extends over the interstate transportation of natural gas, the import/export of natural gas via pipelines or LNG import terminals, and certain environmental and accounting matters.

The Natural Gas Act prohibits the import or export of natural gas to or from the US without obtaining the prior approval of the Department of Energy (DOE). The DOE offers two types of import and export authorizations: long-term authorization and 'blanket' (short-term) authorization. Long-term authorization must be sought by a party wishing to import or export natural gas pursuant to a signed gas purchase and sale contract that has a term longer than two years. The applicant must submit to the DOE: an application, a copy of the gas purchase and sale contract identifying the seller of the gas and the markets in which the gas will be sold, and the terms of the contract. Multiple federal agencies, such as the State Department (DOS) and the Defense Department (DOD) will weigh in on the matter, given the relationship between US energy exports/imports and national security interests. As a result, these deliberations take place at the highest government level: DOE, DOS, and DOD are, after all, all cabinet-level agencies whose respective secretaries are chosen by the President subject to Senate confirmation.

The Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the Department's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. This too is a highly political federal regulatory agency: the Administrator is the Agency's chief executive, appointed by the President and confirmed by the Senate. The OPS devises regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Since 1986, the entire pipeline safety program has been funded by a user fee assessed on a per-mile basis on each pipeline operator OPS regulates.

Federal authorities are not the only entities with a voice in the regulation of the US natural gas industry. Multiple state and local entities also participate in the licensing of gas infrastructure: pipelines, gas storage facilities, and especially LNG terminals. State public utilities commissions also have jurisdiction over retail pricing, consumer protection, and natural gas facility construction and environmental issues not covered by FERC or DOT.

4.3.2. LNG Terminals

There are almost a dozen LNG receiving terminals serving the mainland US and Puerto Rican gas markets (Figure 91). All currently operating US LNG facilities are ultimately owned by US or foreign private companies. Ownership structures vary from project to project and may include direct ownership by a single entity, joint ventures among two or more parties, or many other possible structures. Thanks to the passage of the Energy Policy Act of 2005, LNG terminal owners are no longer compelled to offer third parties non-discriminatory access to capacity, and can charge market-based rates for terminal service. As a result, the variety of business model options employed by US LNG import terminal developers on the mainland is great.

Figure 91: Operating Onshore US LNG Import Terminals

Note: Of all the terminals on this map, all were built as baseload LNG receiving terminals. The Kenai terminal is a baseload LNG export facility and has operated since the late 1960s.

Source: FERC

Map does not illustrate two shipboard regasification-based LNG terminals located offshore Massachusetts.

An LNG import terminal is defined as a facility involved in the business of receiving LNG from a foreign country, or a facility that receives LNG transported in interstate commerce by waterborne vessel. FERC has lead jurisdiction over the siting, construction, and operation of greenfield and brownfield US LNG import terminals and their associated pipelines. FERC's jurisdiction, which is laid out in Section 3 of the Natural Gas Act and confirmed in the Energy Policy Act of 2005, applies to onshore receiving terminals or offshore facilities located in state waters. Offshore receiving terminals located in federal waters are regulated by the Coast Guard and the Maritime Administration according to the Deepwater Port Act of 1974 (DWPA), as amended by the Maritime Transportation Security Act of 2002.

US LNG import terminal regulation has changed significantly over the past 10 years. For many years, LNG terminals were subjected to regulated third-party access regimes, where owners were required to offer terminaling service on a non-discriminatory basis. FERC's open-access policy became applicable to LNG import terminals as a natural consequence of Cove Point, Elba Island, and Lake Charles' development. These facilities were sponsored by interstate pipeline companies, albeit prior to adoption of FERC's open-access regime. During development of each of these projects, applications for construction authorization were filed with FERC's predecessor, the

Federal Power Commission, stating that these facilities would be employed in the interstate transportation of natural gas. As a result, these LNG import terminals came to be regulated in the same manner as interstate pipelines. When FERC adopted its open-access policies, through Orders 436, 500, and 636, these LNG import terminals fell within the scope of such policies by virtue of their status as interstate transportation facilities. Thus, the LNG import terminal was viewed as the beginning link of the interstate transportation supply chain.[20]

Each LNG terminal owner was compelled by FERC to hold an open season, or a form of auction, for throughput rights at the facility, with capacity awarded to the highest bidder. This also applied to the LNG terminal's connecting pipeline. The tariffs for firm or interruptible bundled LNG tanker discharge, storage, regasification, and sendout service were submitted by the terminal owner to FERC for approval. These rates provided the terminal owner with a modest but guaranteed rate of return on their investment. However, the fairly rapid passage of gas market liberalization legislation during the 1970s, 1980s, and 1990s remedied the very gas shortages that these four receiving terminals were built to address, thereby rendering most of them somewhat redundant. Consequently, two terminals—Cove Point and Elba Island—were mothballed for several years, whereas Everett and Lake Charles operated at low rates of utilization during the 1980s and 1990s.

The picture changed abruptly, however, as the new millennium dawned owing to perceptions of a looming gas supply deficit. Cove Point and Elba Island were reactivated in the early 2000s and their capacity auctioned to the highest bidders. Expansions were also sanctioned at both facilities. Meanwhile, a fresh open season for capacity at Lake Charles was fully subscribed by a single buyer in 2001, and no less than two expansions built. Only Everett, which was built in the early 1970s and therefore exempt from subsequent third-party access regulations, continued operating as a proprietary access facility, even after the terminal's acquisition by French conglomerate Suez (now GDF SUEZ) in the early 2000s. By and large, each terminal's capacity was secured by integrated energy companies with significant interests throughout the LNG value chain, from production to shipping to downstream US gas marketing. US LNG terminals were viewed as a reliable outlet for these companies'

[20] The Everett terminal has a different history. When Distrigas of Massachusetts lodged its application to construct the Everett facility, the company postulated that its proposed LNG import terminal would not be engaged in interstate commerce but would instead be engaged in foreign commerce as the last link in the LNG supply chain. The upshot was that when FERC adopted its policy of open-access, Everett was not subjected to these requirements.

global LNG portfolios, given the sheer size of the US gas market and the then-imagined prospects for demand growth. BP, Shell, and Statoil secured capacity at Cove Point; BG and Shell purchased throughput rights at Elba Island; and BG had sole rights at Lake Charles.

Given the US' perceived demand growth for LNG, numerous receiving terminals were proposed throughout the country in the early 2000s, from the East Coast to the Gulf Coast to the US Pacific Coast. These terminals were sponsored by a diverse range of companies, from integrated global petroleum companies with significant LNG industry experience; foreign former monopoly gas and power utility companies faced with liberalization legislation at home and seeking to make up for "lost" market share by expanding overseas; merchant energy companies; and terminal development companies with no LNG industry experience that viewed LNG facility development as a lucrative business opportunity. Evidence of public opposition to onshore terminal development, especially on the east and west coasts of the country, also encouraged the sponsorship of offshore terminal proposals.

The existence of multiple terminal proposals gave rise to widespread complaints by project sponsors that traditional, so-called FERC "heavy-handed" regulation of LNG terminals was discouraging the development of needed new LNG projects and supplies. Integrated LNG players like Shell and BP argued that developers of integrated international LNG supply projects need assured market access, which would be impossible if these players were forced to auction capacity at their facilities to third parties. The same points were made by US LNG developers unaffiliated with major LNG producers/shippers. For example, Sempra—which eventually went on to sponsor the Energia Costa Azul terminal in northwest Mexico and the Cameron LNG terminal on the US Gulf Coast—maintained that mandated open access at regulated rates of return would impede the development of the LNG industry and that FERC should decline to require LNG receipt terminals to charge cost-based rates for their services. According to Sempra, LNG should be viewed as simply another gas supply option and that gas-on-gas competition in the delivery market could be counted on to assure that price and discrimination problems were kept in check.

These arguments applied to the rapidly-growing plethora of planned offshore as well as onshore US LNG terminals. Stakeholder's concerns were fully addressed in 2002. First, regulatory certainty was provided for the licensing and operation of offshore LNG import terminals via the Deepwater Port Act. This Act was amended by the Maritime Transportation Security Act of 2002 to cover the regulation of oil *and* natural gas import facilities in federal waters. The Act, which was introduced for debate in July

2001 and signed into law by the President in November 2002, established a licensing system for the ownership, construction, operation, and decommissioning of offshore US LNG terminals. The Coast Guard and the Maritime Administration were charged with vetting applications for offshore receiving terminals, although governors of so-called Adjacent States possessed veto power over a proposed facility. The developers of offshore LNG import terminals were also granted the right of proprietary access to their facilities. In other words, at no time were owners obliged to offer non-discriminatory third-party access at a regulated rate of return. This was partly because of the-then considerable technical and financial risk borne by developers; it was believed that the recovery of fixed LNG terminaling costs could be accomplished only through the sales of LNG at competitive (market) prices.

FERC also assuaged onshore LNG terminal developers' regulatory and commercial concerns in late 2002. The Commission announced that henceforth, it would confine its review of LNG terminal proposals to their safety, security, and environmental aspects. The announcement was part and parcel of Cameron LNG's FERC approval (known as the "Hackberry Decision"; Hackberry was the name of the terminal's nominated site). In addition to noting the argument that investors in a "full-supply-chain" LNG project require assured access to terminal capacity, the Commission determined that LNG would be treated merely as another supply option for the US market and concluded that, like competing gas supplies, LNG should not be subject to price regulation nor to the requirement to offer open access service. The Hackberry decision effectively made onshore US import terminal proposals competitive with proposed offshore LNG facilities, which (as stated above) do not have to operate on a common carrier basis or provide access to third parties. The Commission accordingly granted Sempra the authority to implement rates, terms, and conditions or services as mutually-agreed upon by the parties to Cameron LNG's import transactions and specifically held that Cameron LNG was not required to offer open access service or to maintain a tariff and rate schedule for its terminaling service. However, open access requirements do still apply to pipelines transporting regasified LNG from LNG terminals in the US.[21]

[21] By and large, LNG terminal tailgate pipelines have the same ownership structure as the LNG terminal itself. The outcome of open seasons for capacity on these pipelines reflected throughput arrangements at the corresponding terminal. It would, after all, be pointless for an uninvolved company to waste time and money on participating in an open season for pipeline capacity at the tailgate of the terminal when said company lacks terminal access rights.

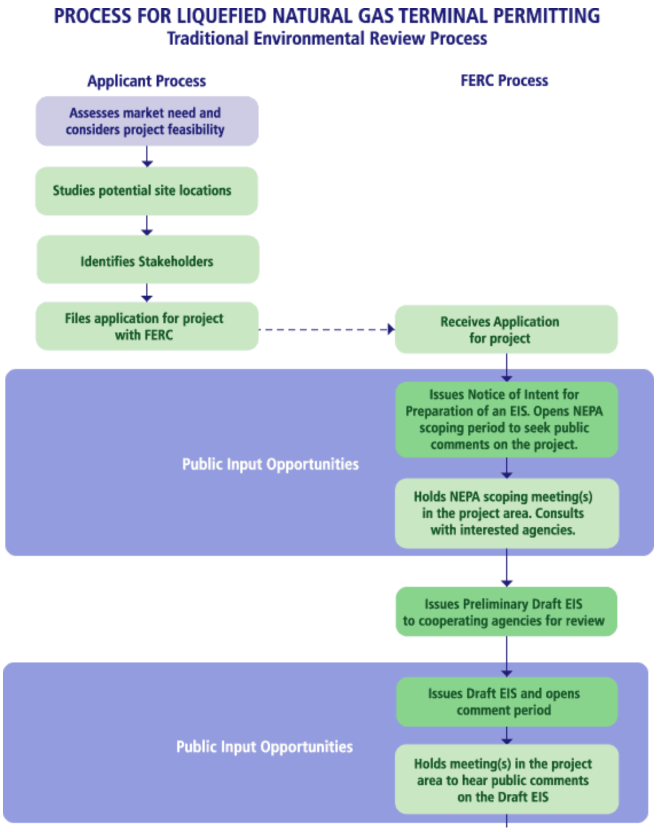
The Hackberry decision was codified when President George W. Bush signed the 2005 Energy Policy Act into law. Although there had been no opposition to the new policy by the participants in Hackberry, it was nevertheless subject to change by a subsequent Commission. Further, the decision raised the possibility, particularly when applied to imports of gas that did not enter the interstate grid, that individual states would be able to rely on the FERC's diminished role to block import terminals of which they did approve. Issues were raised in other cases, moreover, regarding whether the Commission's authority over an import terminal was as broad as the agency assumed. These issues were resolved, at least for the time being, in the Energy Policy Act of 2005:

- Congress amended Section 3 of the Natural Gas Act to confer on the FERC "exclusive authority" over applications for "the siting, construction, expansion or operation of an LNG terminal."
    - The term "LNG terminal" was also specifically defined.
- The statute also ensured that there could be no change in FERC's 2002 decision not to regulate the rates or terms and conditions of service on which LNG projects would be undertaken, at least until January 1, 2015.
    - Effective January 1, 2015, FERC has discretion whether or not it will apply the Hackberry dispensation to new terminal and expansion applications.
- If a project sponsor does elect to offer open access service, the Energy Policy Act of 2005 stipulates that FERC cannot authorize a project that results in existing customers subsidizing expansion capacity; the degradation of service to existing customers; or undue discrimination against existing customers that contravenes their terms or conditions of service at the facility.

The Energy Policy Act of 2005 also charged FERC, as the body with exclusive jurisdiction over the licensing of LNG import infrastructure, to establish a timetable for all the federal, state, and local authorizations needed to complete the regulatory process. Although FERC has oversight, state and local permits are also required to license the facility—for example, the applicant must obtain from the state water quality certificates, dredge and fill permits, and the crucial Coastal Zone Management clearance, where the planned terminal must be deemed consistent with the state's Coastal Zone Management Act objectives. All federal, state, and local agencies must cooperate and comply with the FERC-established deadlines. If a federal or state administrative agency does not comply with the FERC-established deadline, then there is recourse for the terminal applicant under a separate section of the NGA.

The FERC filing process for Section 3 authorization can take up to 18 months for an onshore facility (Figure 92). (The so-called "pre-filing" process can reduce the timeline. Under this system, the stakeholder can file the various regulatory documents and obtain FERC feedback before initiating the formal process, thereby reducing the amount of back-and-forth between the stakeholder and regulatory overseers. (About 80% of the applicants employ the pre-filing process, according to FERC.) Prior to any FERC decision regarding an LNG application, an extensive Environmental Assessment (EA) or an Environmental Impact Statement (EIS) is prepared to fulfil the requirements of the National Environmental Policy Act (NEPA). The purpose of the document is to inform the public and the permitting agencies about the potential adverse and/or beneficial environmental and safety impacts of proposed projects and their alternatives.

Figure 92: FERC LNG Terminal Licensing Process



Source: FERC

Thanks partly to the regulatory clarity provided by federal agencies and the Legislative/Executive arms of the federal government, no less than seven new LNG terminals were built during the first decade of the new millennium (Figure 93; one of these terminals, Excelerate Energy's offshore Gulf Gateway venture, was decommissioned just a few years after commencing operation due to a lack of utilization).

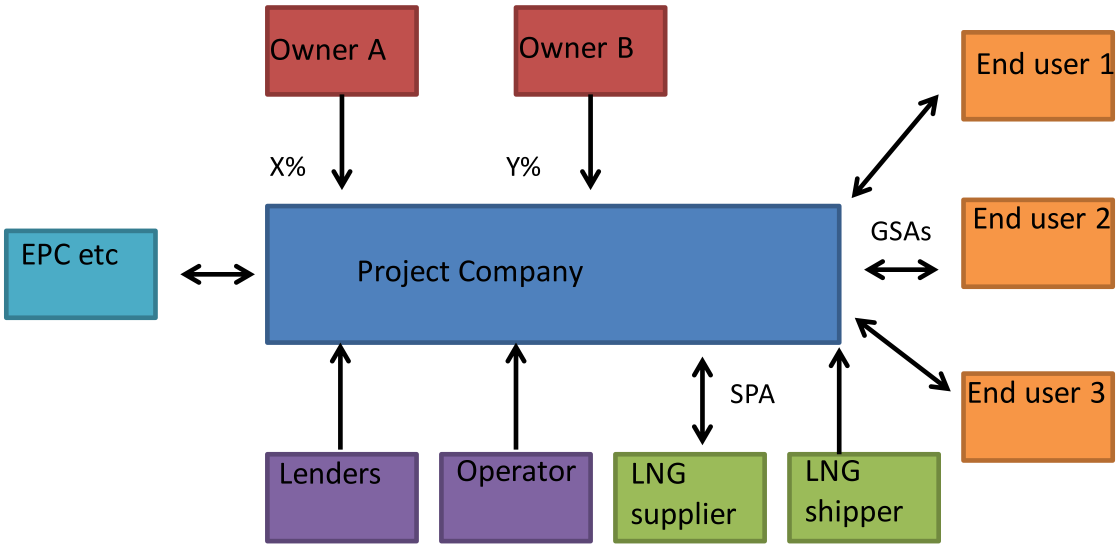
Figure 93: US LNG Import Terminals as of Late 2012

Terminal	Location	Sendout Capacity (bcf/d)	Owner	Capacity Holders
Cove Point	Maryland	1.8	Dominion	BP, Shell, Statoil
Everett	Massachusetts	1.035	GDF SUEZ	GDF SUEZ
Elba Island	Georgia	1.6	Southern LNG	BG, Shell
Lake Charles	Louisiana	2.1	Southern Union	BG
Northeast Gateway	Offshore Masachusetts	0.8	Excelerate Energy	Excelerate Energy
Neptune LNG	Offshore Masachusetts	0.4	GDF SUEZ	GDF SUEZ
Freeport LNG	Texas	1.5	Freeport LNG Development	ConocoPhillips, Dow, Mitsubishi
Sabine Pass LNG	Louisiana	4	Cheniere	Chevron, Total, Cheniere
Cameron LNG	Louisiana	1.8	Sempra	ENI (partial)
Golden Pass LNG	Texas	2	ExxonMobil, Qatar Petroleum, ConocoPhillips	ExxonMobil, Qatar Petroleum, ConocoPhillips
LNG Clean Energy Terminal	Mississippi	1.5	El Paso, Crest Investments, Sonangol	Consortium comprising Sonagás, Chevron, BP, Total and ENI, plus ENI (solo)

List excludes Excelerate Energy's Gulf Gateway terminal offshore Louisiana, which was recently decommissioned owing to low utilization

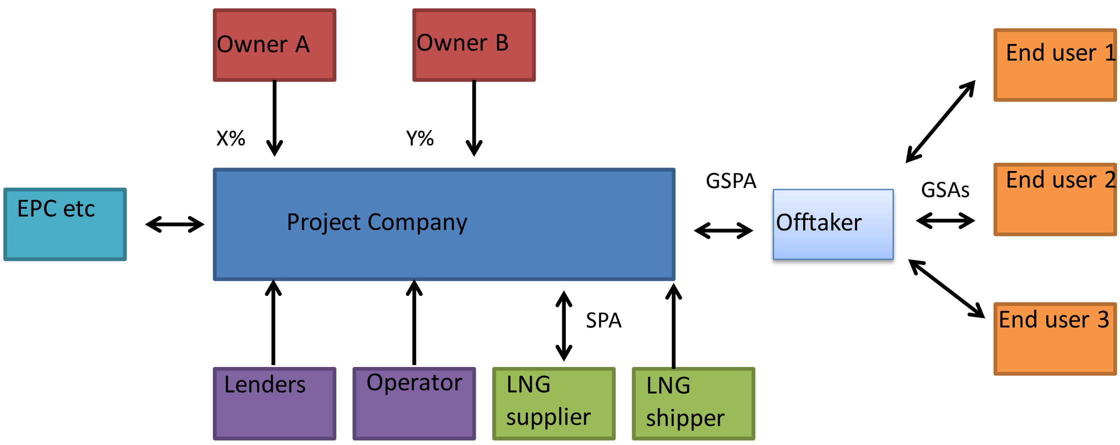
As a result of changes to US LNG regulatory regimes, the choice of business models open to import terminal developers opened considerably. An *integrated LNG chain* business model, as its name suggests, might be employed if a company or consortium of companies wish to secure a guaranteed outlet for a specified liquefaction project. Under this structure, the company established to develop, build, own, and operate the project would be responsible for purchasing LNG (perhaps from its own portfolio of LNG supplies or a specific LNG supply venture), possibly transporting LNG to the terminal, receiving/storing/regasifying it, transporting regasified LNG to downstream markets, and selling the volumes to end users. Under this structure, the project company would enjoy exclusive access to its throughput capacity and enter into gas sale and purchase agreements (GSPAs) directly with the end-users of gas (Figure 94).

Figure 94: Integrated LNG Import Terminal Business Model



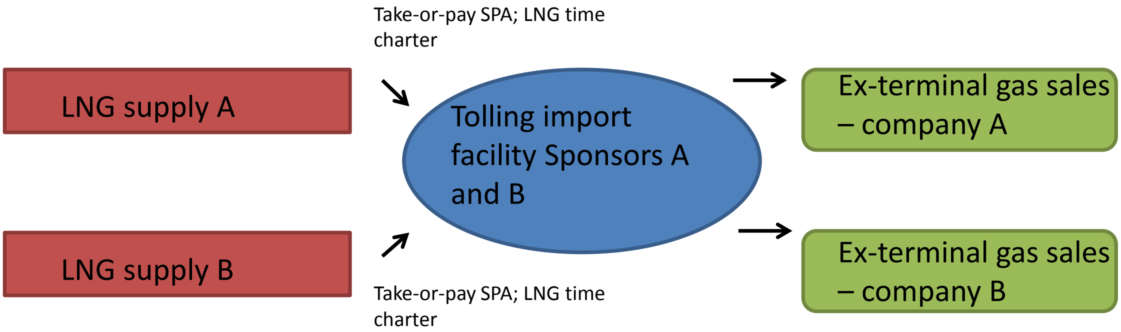
A *modified integrated project structure* would entail the creation of a dedicated terminal company to purchase LNG, transport it to the terminal, store/regasify it, and the sale of regasified LNG to one or more entities (intermediate offtakers) at the tailgate of the terminal. The terminal owners would maintain exclusive access to throughput capacity. Thereafter, the intermediate offtaker(s) would be responsible for marketing and selling the regasified LNG to end-users. In such a scenario, the intermediate offtaker(s) act as demand aggregator(s) and the Project Company is relieved of the responsibility of marketing regasified LNG to end-users (Figure 95).

Figure 95: Modified Integrated Project Structure



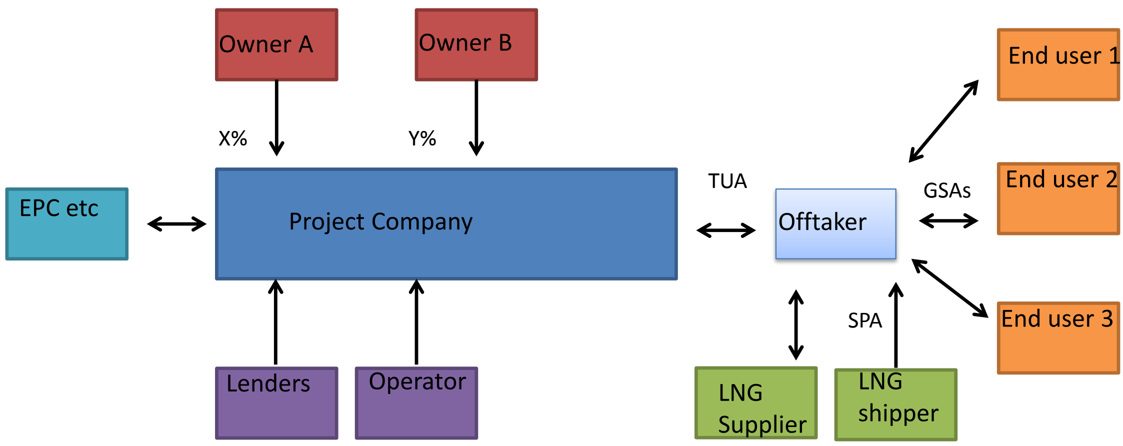
A *tolling* business model, on the other hand, guarantees the terminal's owner(s) access to a quantity of LNG terminalling services commensurate with its ownership of the facility; in other words, whatever a given entity discharges into the terminal, it will receive at the terminal's tailgate. Under this structure, the Project Company would only be responsible for providing regasification services and would charge a 'tolling fee' to through-putters for rendering these services (Figure 96).

Figure 96: Tolling LNG Import Terminal Business Model



A *core gas customer* model, or *merchant model*, would most likely be employed by an LNG terminal development company. The developer might lack access to LNG supplies or have little to no LNG industry experience, but is willing for various reasons to develop a terminal for the use of others. In this case, the development company could enter into exclusive negotiations with interested parties for the sale of terminalling services, or issue a tender for receiving terminal capacity. The interested parties or winning tender participants would then sign a terminal use agreement (TUA) with the terminal company and assume full responsibility for procuring LNG delivered to the terminal. The Project Company would receive, store, and regasify LNG on behalf of the tenant for an agreed-upon fee specified in the TUA. The tenant would then assume responsibility for marketing the regasified LNG and concluding GSAs with end-users (Figure 97).

Figure 97: Core Gas Customer Business Model

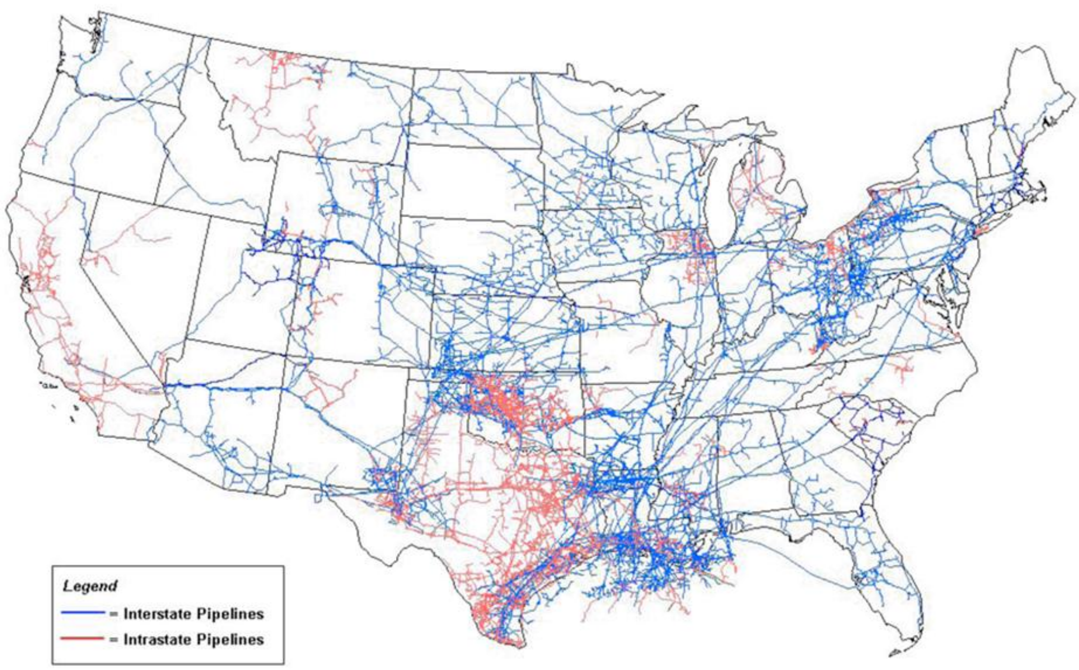


By and large, business structure selection is driven mainly by the depth and breadth of the sponsor(s) involvement in other components of the LNG value chain, especially their access to LNG supplies and downstream natural gas marketing position. In all cases, the terms and conditions governing the provision of terminalling service as well as the rates levied by the terminal owner will be specified in a so-called terminal use agreement. The business model selected by a Hawaii LNG terminal developer will have a significant bearing on the level of regulation by state and (possibly) federal authorities (see Section 4.4 below).

4.3.3. Interstate Pipelines

As their name implies, interstate pipelines in the US literally carry gas from one state to another—that is, the trunkline physically crosses a state line or lines. US interstate pipelines are illustrated in blue in Figure 98. The interstate system is a crucial artery for the transportation of gas from major producing regions to local natural gas utilities and sometimes directly to large users of natural gas. There are numerous interstate pipeline gas companies operating in the lower-48 states, such as Columbia Gas Transmission, Florida Gas Transmission, Kinder Morgan Interstate Gas Transmission, Southern Natural Gas, the Tennessee Gas Pipeline Company, and the Texas Eastern Transmission Pipeline Company. Interstate pipeline companies do not produce gas; their primary role is to arrange for the movement of molecules on behalf of capacity holders that include producers, natural gas marketers, and large individual end-users in the power and industrial sectors.

Figure 98: Map of Lower 48 Interstate (and Intrastate) Pipelines



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

FERC is the primary federal regulatory agency governing natural gas transmission. Pursuant to section 7 of the NGA, interstate pipelines and gas storage facilities must obtain certification from FERC before constructing or expanding facilities. Under applicable statutes, FERC will issue a certificate to a pipeline if there is a benefit to the public, including compliance with environmental standards. Current FERC policy is generally to issue certificates to all pipelines that comply with the statutory standards, but to let the market decide which pipelines will be built.

FERC also regulates the rates, terms, and conditions of service of natural gas transportation in interstate commerce. FERC's rate-making decisions are subject to the NGA, which specifies that rates, terms, and conditions must be "just and reasonable," and not unduly discriminatory. With limited exceptions, an interstate transmission pipeline operator's rates are established using one of the following methodologies:

- **The cost-of-service method.** This requires a pipeline operator to submit cost and revenue data to FERC that supports the operator's requested rate. This calculation methodology gives the operator the opportunity to recover the cost of providing service and earn a reasonable return on investment. This cost-based rate structure is an efficient tool preventing transportation service providers from using the well-developed interstate transmission infrastructure in the US as market power over customers which are "captive" to its interstate transportation services.
- **The negotiated rate method.** This allows an operator to charge a rate that is agreed upon by the pipeline operator and a shipper. To safeguard against unequal bargaining power, the shipper must have the option to select service under the pipeline operator's "recourse rate" that is based on the pipeline's cost of service.
- **The market-based rate method.** This may be employed when an operator can demonstrate that it lacks market power. In other words, the operator can prove that it does not wield excessive influence over the gas market/area that the proposed pipeline plans to serve. In these circumstances, an operator is authorized to charge rates consistent with market conditions. Some interstate pipeline operators have market-based storage rates (see the following "Storage" sub-section).

Pipeline shippers' rates generally have three parts. The first is a *demand rate*, where the holders of firm transportation capacity pay a monthly charge for service to the operator, regardless of how much gas was actually shipped by the customer. There is also a *commodity rate,* which is a unit charge paid by the shipper to the operator according to how much gas was actually shipped on the pipeline. A *fuel charge* is also levied by the operator, since gas pipelines use a portion of the fuel flowing through the pipeline itself to power its operations (compressor stations, etc). The fuel charge appears in published tariffs as a percentage of delivered gas at the inlet of the pipeline.

In limited circumstances, FERC allows natural gas interstate pipeline operators to track and flow through to customers increases and decreases in certain costs. The nature of these cost changes must be pre-approved by FERC, and each subsequent adjustment must be reviewed and approved by FERC before it takes effect. Shippers can contest pipeline rates by filing a complaint with FERC challenging a pipeline operator's service rates.

Given the sheer number of alternatives open to interstate pipeline customers, a pipeline's FERC approved maximum tariff rate is not necessarily an entitlement to collect such a rate. Rather, a pipeline's pricing power is disciplined by what the market will bear. As a result, a significant portion of interstate pipeline throughput is being transported at rates that have been discounted from the FERC-approved maximum tariff rates or under agreements where the pipeline and its customer have negotiated an alternative rate design and rate level.

In order for FERC to uphold its regulation over the interstate pipeline gas market, transparency on the part of the operator is paramount. Operators are mandated by law to place comprehensive pipeline schedules or tariff forms showing (among other things) all transportation rates and charges in the public domain. This is usually accomplished via a dedicated portal on the pipeline company's website. The tariff also shows a list of the pipeline's customers and the rules and conditions that capacity holders must abide by, such as scheduling, the quality of gas transported on the pipeline, and so on. In addition, pipeline transportation companies will maintain an electronic bulletin board showing capacity nominations. This enables third parties to identify any unutilized capacity and to bid for available, unutilized capacity. The bulletin board also displays data on customer rate discounts; maintenance schedules; damage and service interruption reports; and information about affiliated companies. Transparency is also enhanced by the special and periodic operational and financial reports filed by pipeline companies with FERC. This information helps FERC and other interested parties detect any instances of undue discrimination or preference.

Some natural gas transmission companies also provide marketing services, albeit through an affiliate company. The potential therefore exists for market manipulation.

FERC sought to remedy the potential for market abuse in October 2008, when it issued Order No. 717. This Order amended the Standards of Conduct governing, among other things, transactions by jurisdictional natural gas transmission providers and their affiliates. Under the terms of the Order, employees handling transmission functions and employees handling marketing functions (such as commodity sales) are required to operate independently of each other. Transmission employees also cannot convey information about transmission functions to marketing function employees. Finally, FERC ordered that electronic bulletin board posting requirements on transmission websites be streamlined to help FERC and other interested parties detect any instances of undue discrimination or preference.

Once natural gas pipeline projects are operating, the Department of Transportation's Pipeline and Hazardous Material Safety Administration, acting through the Office of Pipeline Safety, regulates, monitors, and enforces safety. The OPS collaborates with partnering agencies and departments to ensure pipeline operation safety, security, monitoring, and compliance. As of June 2010, 88 full-time PHMSA pipeline inspectors were employed to conduct the comprehensive OPS inspection and enforcement program to ensure that pipeline operators comply with all safety regulations.

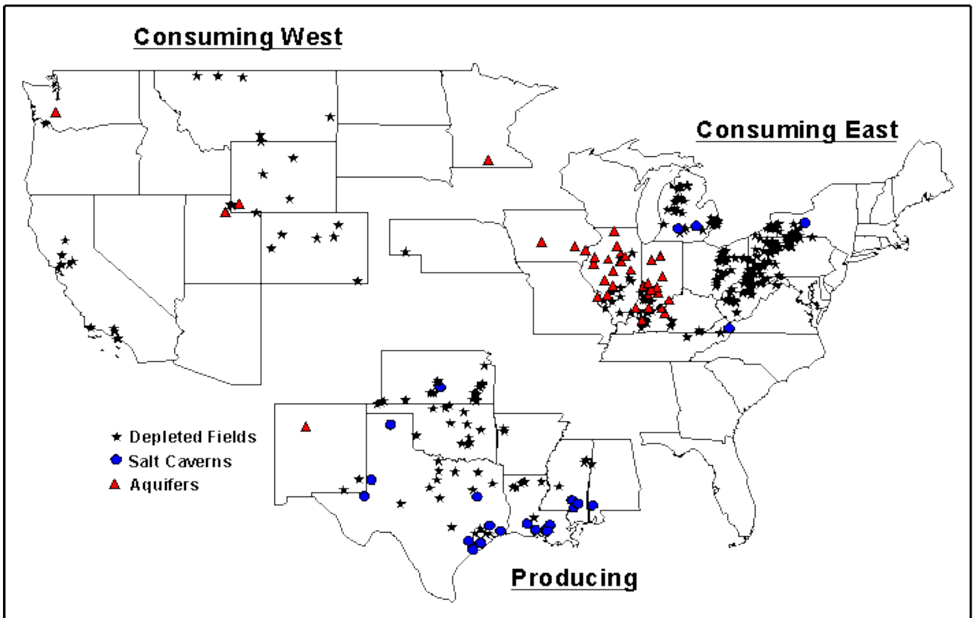
Although the federal government is responsible for developing, issuing, and enforcing pipeline safety regulations, most inspections are conducted by state regulatory agencies, which are responsible for regulation, inspection and enforcement of pipelines within state boundaries. The state agency regulations must be at least as stringent as the federal regulations. (It is understood, however, that the State of Hawaii lacked the monetary resources to conduct its own inspections, and has requested federal authorities to assume responsibility for the task.)

4.3.4. Storage

The US relies on vast quantities of gas storage capacity to act as a buffer for supply disruptions, or to help satisfy peak demand during cold snaps in the winter or (increasingly) heat-wave conditions during the summer. Storage can reduce the need for both swing natural gas production deliverability and pipeline capacity by allowing production and pipeline throughput to remain relatively constant. Customers may use storage to reduce pipeline demand charges, to hedge against natural gas price increase, or to arbitrage gas price differences. Pipeline transportation companies and LDCs use storage for operational flexibility and reliability, providing an outlet for unconsumed natural gas supplies or a source of natural gas to meet unexpected demand. Storage at market trading hubs often provides balancing, parking, and loan services.

Natural gas may be stored under pressure in a number of ways. The most common types of storage facilities are (1) depleted reservoirs in oil and/or natural gas fields, which represent the majority of natural gas storage; (2) aquifers; (3) salt cavern formations; and (4) above ground storage in LNG facilities. Today, the US boasts over 8.7 bcf of storage capacity, but working capacity is roughly half that amount. The vast majority of US storage capacity is located in the Gulf Coast and the Midwest (Figure 99). Consuming regions that were historically located very far from producing regions like the east coast have comparatively little storage capacity, and rely on LNG peak-shaving plants and trucking to help address periods of peak demand or supply disruptions.

Figure 99: Underground Gas Storage Capacity in the Lower-48 US



Source: Energy Information Administration (EIA), EIA GasTran Geographic Information System Underground Storage Data Base.

Prior to 1992, interstate pipeline companies owned a significant part of the natural gas flowing through their systems—including gas held in storage—and had exclusive control over the utilization of their storage facilities. Upon the issue of FERC Order No. 636, however, jurisdictional pipeline companies were required to operate their pipelines and storage facilities on an open-access basis. In other words, the major portion of working natural gas capacity (i.e., beyond what may be reserved by the pipeline/operator to maintain system integrity and for load balancing) at each site must be made available to third parties on a non-discriminatory basis. Companies submitted bids for available storage capacity via the aforementioned "open season" process called by the facility's owner, akin to an auction. Today, in addition to the interstate storage sites, many storage facilities owned/operated by large LDCs, intrastate pipelines, and independent operators also operate on an open-access basis. This has created opportunities for storage to be used as more than simply backup inventory or a supplemental seasonal supply source.

It follows that in this post-FERC Order No. 636 world, the owners/operators of storage facilities are not necessarily the owners of the natural gas held in storage. Most working natural gas storage capacity is leased to LDCs, end-users, or marketers who own the gas. Nevertheless, the type of entity that owns/operates the facility is often indicative of how that facility's storage capacity is utilized.

The ownership of the nation's gas storage facilities is diverse, but principal ownership falls into four broad groups: interstate pipeline companies; intrastate pipeline companies; LDCs; and independent storage service providers. It is believed that some 120 entities currently operate the ~400 active underground storage facilities in the lower-48 states. In turn, these operating entities are owned by, or are subsidiaries of, fewer than 80 corporate parents. If a storage facility serves interstate commerce, it is subject to FERC jurisdiction; otherwise, it is state-regulated.

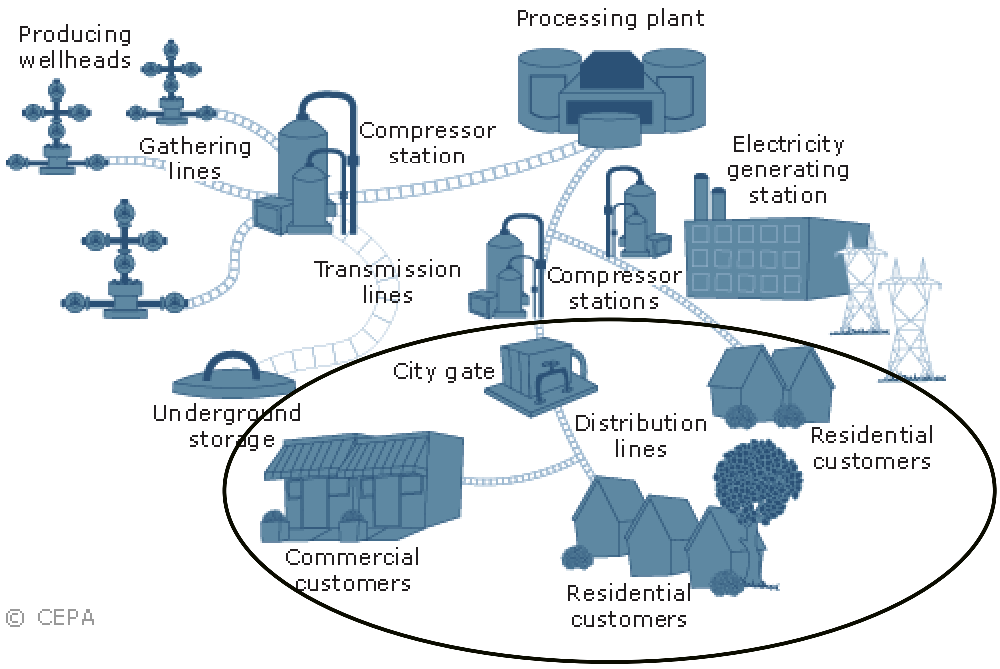
- Interstate pipeline companies depend greatly on underground storage to expedite load balancing and system supply management on their long haul transportation pipelines.
- Intrastate pipeline companies use storage capacity and inventories for similar purposes, in addition to serving end-user customers. Also, in some states, intrastate pipelines remain in the merchant function (i.e., purchasing and selling natural gas at wholesale) and utilize storage for their own gas inventory.
- LDCs historically have used underground storage exclusively to serve the needs of their retail customers directly. Now, however, some state restructuring rules have made it possible for LDCs to realize additional revenues by making storage services available to third parties.
- Independent storage service providers have developed many salt dome storage facilities and other high deliverability sites. These providers, often smaller companies, have been started by entrepreneurs who have focused on the potential profitability of specialized storage facilities. The facilities are utilized almost exclusively to serve third-party customers such as marketers and electricity generators who can benefit the greatest from the opportunities created by high deliverability storage.

Historically, storage capacity owners were allowed to charge tariffs tied to a regulated rate of return set by state or federal authorities. In recent years, however, regulators have approved requests by storage capacity owners to charge market-based rates for storage capacity, rather than the customary regulated rate of return. The legality of this move was codified in the Energy Policy Act of 2005. This move was geared to create additional incentive for the development of storage facilities because services can be structured and priced in ways to capture value that are not available with regulated, cost-based rates.

4.3.5. Distribution

Distribution is the last step in delivering natural gas to customers (Figure 100). Some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity interstate and intrastate pipelines (usually contracted through natural gas marketing companies).

Figure 100: Natural Gas Distribution's Position in the Value Chain



However, other users receive natural gas from their local gas utility, also called a local distribution company. In addition to interstate and intrastate pipeline companies, which deliver natural gas directly to primarily large-volume users, LDCs transport gas to specific customer groups. LDCs have different ownership mechanisms, ranging from private enterprises to municipal entities:

- **Investor-Owned**: An LDC whose stock is publicly traded, is generally granted exclusive territorial contracts covering large areas within a state.

- **Privately-Owned**: An LDC that is owned by private investors and whose stock is not publicly traded.
- **Municipal**: An LDC that is owned and operated by a municipal government. Most municipal LDCs were organized in areas located along the long-distance routes of the large interstate natural gas pipelines that were built during the first half of the 20th century but where the potential rates of returns on investment were not attractive enough for investor-owned or privately-owned utilities to build a distribution network. Many municipalities that operate their own natural gas distribution system contract with investor- or privately-owned utilities, granting an exclusive territorial contract (monopoly franchise arrangement) to the utility while retaining authority over rates, operations, and the type and quality of services provided within its jurisdiction.
- **Cooperative**: An LDC that operates on a cooperative non-profit basis for the mutual benefit of its members. No interest or dividends are paid out of earnings although the company is obligated to pay, by credits to a capital account for each member, any excess revenues received beyond annual operating costs and expenses. Anyone, or any firm, may become a member by paying a fee, agreeing to purchase its natural gas needs from the cooperative, and being approved for membership by the board of directors.

In 2006, 257 LDCs classified themselves as investor-owned, 931 as municipals, 104 as privately-owned, and 15 as cooperative. Even though the number of municipal LDCs far exceeded the number of investor-owned LDCs, investor-owned LDCs supplied over 90% of the total volume of natural gas deliveries for 2006.

LDCs compete with other end-user groups for available gas supplies. In Order No. 636, FERC required interstate pipelines to separate or unbundle their services for gas transportation and sales. Regulators in many states have also required LDCs to offer unbundled sales and transportation services for large customers located in their distribution systems. As a result, LDCs, large industrial customers, and electric utilities now buy gas directly from producers or marketers in a competitive market; contract with interstate pipelines for transportation; and separately arrange for storage and other services formerly provided by interstate pipelines or LDCs (such as nominating, balancing, parking, loaning, metering, and billing) from marketers, market centers, hubs, storage operators, and other third-party providers. This latter step is, of course, of concern only to end-users such as power generators or industrial end-users; the LDC (which oversees virtually all of the needs of residential and commercial end-users) can attend to its own storage and “other service” requirements.

The operation of a local distribution network by an LDC is governed by the state regulatory authority with jurisdiction where the facilities are located. The LDC may be required to obtain certificates of public convenience and necessity to serve in the state and comply with all applicable safety regulations. Access to the natural gas distribution grid, however, is the purview of both federal and state regulatory agencies. As a result, the requirements differ from state to state. Generally, LDCs are granted the exclusive right to serve customers within a geographic area.

Local distribution companies do not earn any money from the sale of the natural gas itself, whether the utility owns the natural gas or transports it on behalf of the customer. The companies simply pass the cost of the gas straight through to the consumer. State public utility commissions regulate the rates, terms, and conditions of service of natural gas distribution by investor-owned utilities. The commissions also ensure that gas utilities operate in the public interest. For example, they may prohibit utilities from turning off a residential customer’s gas service for non-payment during cold weather, they may ask for expanded safety programs, or they may require utilities to offer energy conservation programs. In general, the rates, terms and conditions of service of publicly-owned distribution utilities are subject to regulation by local agencies.

Natural gas utilities have tariffs on file with state commissions that contain approved rates, terms, and conditions of service. Periodic adjustments may be made to rates and terms of service, either at the LDC’s request or by order of the governing state regulatory authority. (Changes are typically made on the basis of changes in operating costs or the applicable law. New capital investments may also be the basis for a rate increase request.) Utilities also have posted fees on file with the state commission that contain the current “purchased gas adjustment (PGA) charge.” The PGA is a volumetric rate for recovering the cost of the natural gas commodity. Customers pay the sales tariff rate or the transportation tariff rate to obtain those services, and, if applicable, customers pay the current PGA fee for the amount of gas the utility distributes on their behalf during the billing period. Most utilities are allowed to adjust the PGA fee monthly with a tracking mechanism, while other companies are allowed to adjust the fee quarterly or annually. Most utilities are allowed to true-up over- or under-collections of PGA costs at the end of the year, but not all companies may recover carrying costs on the under-collected portion of their PGA costs.

Publicly-owned natural gas distribution systems are not-for-profit local distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities. These utilities own the natural gas being distributed for their customers and charge a fee for the distribution service. In addition, publicly-owned utilities pass through and recover the commodity costs of natural gas that they acquired for their customers by charging a volumetric rate.

Unlike privately-owned distribution and transmission pipelines, few publicly-owned gas distribution systems have gas rates set by their state's public utilities commission. With few exceptions, rates for a public gas utility are set by its governing body, which may be an elected city or county council or an elected or appointed utility board. There is frequently no requirement that the rate charged by the utility be based on the cost of service, and the utility will charge whatever rate the governing body determines is appropriate in the circumstances. Some public gas systems budgets are kept separate from the budgets of the city and/or county budgets, but in other cases the utility budget is part of the overall local government budget.

Publicly-owned utilities do not have the return, or profit, component of costs in their rates. In addition, as they do not incur state and federal income taxes, there is no recovery of these taxes in their rates. Capital is raised by issuing bonds, either municipal bonds or revenue bonds. Customers of municipal utilities pay the PGA rate for the amount of gas the utility distributes on their behalf during the billing period. However, municipal utilities typically do not utilize tracking mechanisms to recover any other cost increases that the utility incurs. Rate changes must be approved by the city council or the utility board.

Whatever the ownership structure of the LDC, most contracts for natural gas distribution are either established by a filed tariff or bilateral service agreements with terms specific to the customer being served with respect to terms such as quantity of the commodity and the type of service. However, certain terms of service will likely be the same for all customers of the LDC in the same class. There is typically little flexibility for negotiation for individual customers with respect to the terms of a service agreement.

4.3.6. Conclusion

There is no direct government agency charged with direct day-to-day oversight of natural gas producers and marketers. Under the current regulatory regime, only pipelines and LDCs are directly regulated. Interstate pipeline companies are regulated in the rates they charge, the access they offer to their pipelines, and the siting and construction of new pipelines. Similarly, LDCs are regulated by state utility commissions, which oversee their rates and construction issues, and which ensure that proper procedures exist for maintaining adequate supply to customers.

The regulation of LNG infrastructure, on the other hand, occupies a slightly different position relative to the other components of the US natural gas value chain. The owners of LNG import terminals are no longer required to offer third-party access on a non-discriminatory basis at a regulated rate of return. However, their construction must be sanctioned by FERC and a string of other federal, state, and local bodies. The owners are allowed to charge their tenants market-based rates for service. Other federal bodies like DOE and DOS have jurisdiction over permits for the import and export of natural gas at an LNG terminal. This also applies to pipeline sales and purchases on the borders shared with Canada and Mexico.

Regulated ratemaking is a laborious process. Even with expeditious practices, typical rate cases at the utility level may take between eight and 15 months, and an operator's financial picture can change significantly in that time. A technically correct rate structure covers the total cost of serving customers, including an adequate return to the operator. Cost is an important guide in ratemaking, but in practice rates are designed within a framework that includes many factors in addition to costs, and the importance of these factors changes over time.

4.4. *Hawaii's Natural Gas/LNG Regulatory Structure, Policies, and Practices*

The potential introduction of LNG to Hawaii's energy mix requires careful consideration of the regulatory regime applicable to all associated infrastructure. After all, the sheer number of natural gas importers (via pipeline and LNG), pipeline transportation companies, and natural gas/electricity utilities was conducive to the liberalization of the mainland energy business, but these market conditions are not present in Hawaii. That is not to say that the lack of infrastructure and choice regarding energy supplies, in Hawaii, not to mention the island state's isolation from the mainland, absolves FERC of regulatory oversight in Hawaii. The issue of regulatory oversight is critical, as any uncertainty governing federal and state jurisdiction over the receiving facilities and associated pipelines could adversely affect the timing of LNG deliveries to Hawaii. Moreover, a lack of clarity concerning import terminal capacity access and anticipated rates of return generated by throughput could affect investors' willingness to participate in a Hawaii LNG initiative, thereby casting further doubt on both the feasibility and timing of a Hawaii LNG project.

4.4.1. LNG Infrastructure Regulations

This section of the report will identify any gaps in federal and state regulatory oversight relating to natural gas and LNG delivery infrastructure. It will also consider what, if any, legislative and regulatory changes would be required to facilitate the introduction of natural gas into Hawaii's energy mix.

Several entities have evinced interest in building LNG import infrastructure in Hawaii and/or supplying LNG to a planned terminal.[22] As of December 2012, however, only one project has acquired the degree of definition needed to support the initiation of the federal regulatory process, thereby putting much of the project's details in the public domain. In August 2012, HAWAIIGAS, formerly known as The Gas Company, formally outlined a plan to bring LNG to the island of Oahu. The company hopes to use LNG to supplant synthetic natural gas currently produced from costly naphtha. However, there are also plans to ensure the supply of regasified LNG to converted power plants. HAWAIIGAS is also considering the possibility of gas sales to other, albeit much more marginal end-users, such as the transportation sector.

By way of background, HAWAIIGAS is currently the sole gas utility in the Hawaiian Islands. It has been owned by an arm of Australia's Macquarie Investment Bank since 2006. HAWAIIGAS owns and operates a synthetic natural gas plant and more than 1,000 miles of pipeline serving over 35,000 utility customers (businesses and households). The business serves an additional 33,000 non-utility customers via on-site propane tanks or portable gas cylinders. Although HAWAIIGAS is the State's only existing gas utility, its gas franchise is not exclusive; the state legislature has the right to alter, amend, or repeal this franchise. The legislature is also empowered to grant additional franchises for the operation of competitive or other public utilities. HAWAIIGAS' utility business is regulated by the Hawaii Public Utilities Commission. This fact will be of great relevance later on this section, since—depending on the business model chosen by the developers of Hawaii LNG infrastructure, be it the facility proposed by HAWAIIGAS or another entity that puts itself forward at a later date.

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[22] HECO as well as other players who cannot be named at this time due to confidentially agreements have all undertaken studies to evaluate their participation in LNG import infrastructure.

HAWAIIGAS' proposal is the only project that has formally initiated the regulatory process to date. It is therefore practical to examine the jurisdictional issues raised by HAWAIIGAS in its official filings. This should not, however, be viewed as an "endorsement" of the project by the Consultant as Hawaii's "only" possible LNG venture. Rather, the project's scope/definition and its promotion by the State's only existing gas franchise render it a useful "litmus test" for the purpose of not only this report, but also other potential Hawaii LNG import terminal developers that put their names forward in the future.

Since HAWAIIGAS' proposal is the only project that has formally been announced to date, it is possible to use this project as a test case. HAWAIIGAS' LNG import proposal has three phases, which (according to the company) will be carried out mostly in parallel.

- **Phase 1** entails the procurement of up to 20 40-foot cryogenic intermodal containers ("ISO" containers) that will be transported to Hawaii on common carrier cargo vessels. These containers will be stored on a site owned and controlled by HAWAIIGAS. The nominated site is at Pier 38, Honolulu Harbor. This site will also feature mobile LNG vaporization/regasification units that will be used to inject the gas into the Applicant's distribution pipeline or directly into an end-use customer's facilities. FERC authorization for Phase 1 development was sought in August 2012.
- **Phase 2** involves the installation of permanent cryogenic storage tanks and pipes that connect the new storage infrastructure to permanent regasification units.
- **Phase 3** encompasses the construction of larger and permanent storage and receiving facilities in Hawaii.

FERC will assume jurisdiction over the licensing of all proposed Hawaii LNG import capacity that is located onshore or in state waters. As stated earlier, the Energy Policy Act of 2005 confirmed FERC's exclusive jurisdiction over US LNG import terminal siting. HAWAIIGAS' August 2012 application to FERC for permission to implement Phase 1 of its LNG import strategy in and of itself denotes the utility's acceptance of FERC oversight. (A project located in Federal waters would fall under Coast Guard and MARAD jurisdiction, but to date, no such proposal has been officially submitted by a prospective LNG terminal developer for Hawaii.)

- The LNG required to underpin HAWAIIGAS' Phase 1 development will be sourced from an as-yet (publicly) unspecified source from the mainland.

Phase 1's LNG volumes will therefore be transported from the continental US to HAWAIIGAS' distribution system. This falls under the definition of interstate natural gas transportation by waterborne vessel. By statute, an LNG terminal may be defined as a facility that receives interstate gas supplies transported by ship. HAWAIIGAS' proposed Phase 1 facilities therefore fall under FERC's NGA Section 3(e) exclusive jurisdiction over onshore US LNG terminal facilities.

- HAWAIIGAS' proposed Phase 1 facilities will not require the disturbance of any land or modification of any existing structures. Hence, HAWAIIGAS has not sought FERC permission to *site, construct,* or *expand* an LNG terminal; merely to *operate* an LNG terminal.
- HAWAIIGAS' proposed Phases 2 and 3 (permanent storage and gasification facilities) will be the subject of a separate NGA Section 3 application or applications to FERC.

HAWAIIGAS' application to FERC for Section 3 authorization to operate an LNG import terminal is a first for the Commission. FERC has processed literally dozens of LNG import terminal applications on the mainland over the past 40 years, but it has never received a petition for permission merely to *operate* an LNG terminal that—moreover—receives only gas transported under interstate commerce. The applications for Section 3 authorization for US LNG infrastructure have generally entailed the construction *and* operation of greenfield or brownfield capacity. HAWAIIGAS' application for a certificate of public convenience and necessity to operate Phase 1 is therefore somewhat of a test-case for the Commission.

Prospective Hawaii LNG importers seeking LNG from planned mainland export facilities are also charting new regulatory waters relative to their continental US import counterparts. Traditionally, mainland importers have sought LNG from sellers abroad, primarily from the Atlantic Basin/Mediterranean region and the Middle East. However, the rise of North American unconventional gas production (namely shale gas) has displaced continental US LNG imports to a great degree in recent years and laid the groundwork for plans to convert many of these facilities into export centers. The fact that volumes from these terminals will be sold at a price indexed to Henry Hub, rather than the crude oil indexation favored by LNG sellers in other regions, has placed the continental US at the top of the potential supply list for prospective Hawaii LNG importers who are moreover seeking to reduce Hawaii's exposure to high oil prices. Given shale gas' recent rise to prominence, however, it is unsurprising that there should be no precedent for the transportation of US-sourced LNG to another state throughout the US' ~40-year history of exporting and importing LNG. (Alaska's Kenai LNG project has operated since 1969, but its full commitment to Japanese sellers, plus its distant location relative to the US' "core four" import terminals on the east and Gulf coasts precludes the citation of Alaska as a precedent.)

Under Section 3 of the NGA, the sponsor of a US LNG import terminal must secure permission from the Department of Energy to import natural gas to the US. However, prospective Hawaii LNG terminal sponsors are likely to at least consider, if not actively seek, volumes from the continental US. Terminal sponsors with a view to buying LNG from the mainland would not be importing gas from a foreign source. Unless a Hawaii importer seeks gas from a foreign source, FGE believes that DOE import authorization will not be required. If on the off-chance that a Hawaii LNG importer seeks to land LNG from Canada (where there are multiple shale gas-based LNG export proposals) or Mexico (where the possibility of exports from a reconfigured terminal(s) on the Pacific Coast cannot reasonably be ruled out), then DOE import authorization will be required.

FERC's jurisdiction over the licensing of Hawaii LNG import infrastructure does not, of course, negate the role of state and local entities in the regulatory process. As discussed in Section 4.3.2 of this report, FERC will have the lead role in licensing the terminal, but will co-ordinate the review process with state and local agencies. For example, the State Governor has already named the Hawaii State Department of Transportation—Harbors Division to consult with FERC regarding state and local safety considerations for Phase 1 of the HAWAIIGAS project. Other state and local agencies likely to have a voice in the licensing of any Hawaii LNG import initiative includes the Department of Health, which is charged with implementing federal and state air, water, noise, and hazardous waste regulations; the Office of Environmental Quality Control (OEQC), which is responsible for disseminating environmental notices; the Office of State Planning, which oversees Coastal Zone Management regulations; the Department of Land and Natural Resources, which deals with ocean, reservoir, and geothermal permitting and stewardship of state lands); and country governments, which oversee zoning, shoreline management areas, building permitting, and implementing energy codes.

As the State's resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages, Hawaii's Department of Business, Economic Development & Tourism will also take an active interest in the operation of a Hawaii LNG terminal. DBEDT's director is designated as the Energy Resources Coordinator (ERC), which is duty-bound to (among other things) to promote Hawaii energy policies as an advisor to the legislature and governor. As such, DBEDT needs to be consulted and informed regarding the State's LNG plans and decisions so the ERC can take these plans into account when deliberating over Hawaii's energy mix/plans. As will be discussed at greater length later in this report, there is a difference of opinion as to whether Hawaii LNG imports are consistent with the objectives of the Hawaii Clean Energy Initiative of 2008; the Director's views on the subject might therefore be of some importance. Moreover, DBEDT's Research & Economic Analysis Division (READ) collects information used to generate economic forecasts that contribute to long-term statewide planning. The reporting and evaluation of information from petroleum suppliers would naturally be of great interest to DBEDT. As such, FGE expects that DBEDT will closely monitor operations at a Hawaii LNG import terminal, with an eye to details such as volume, seasonality, and the price of LNG discharges at the facility.

There is also scope for two more state agencies to play a role in the regulation of a Hawaii LNG terminal once it begins operating: Hawaii's Public Utilities Commission (PUC) and the Hawaii Division of Consumer Advocacy (DCA). These two agencies comprise the core of Hawaii's utility regulation program. The PUC is responsible for the supervision of all aspects of the State's public utilities. It is a quasi-judicial tribunal, which regulates public service companies operating in the State. The PUC has broadly defined powers and duties to exercise "general supervision...over all public utilities" including the determination of utility tariffs and fees and all aspects of the operation, financing, and management of public utilities. The DCA conducts auditing and analysis as a part of their role representing consumer interests. However, the exact scope and definition of their involvement, is greatly contingent on the business model selected by the developer, as well as the identity of the developer itself.

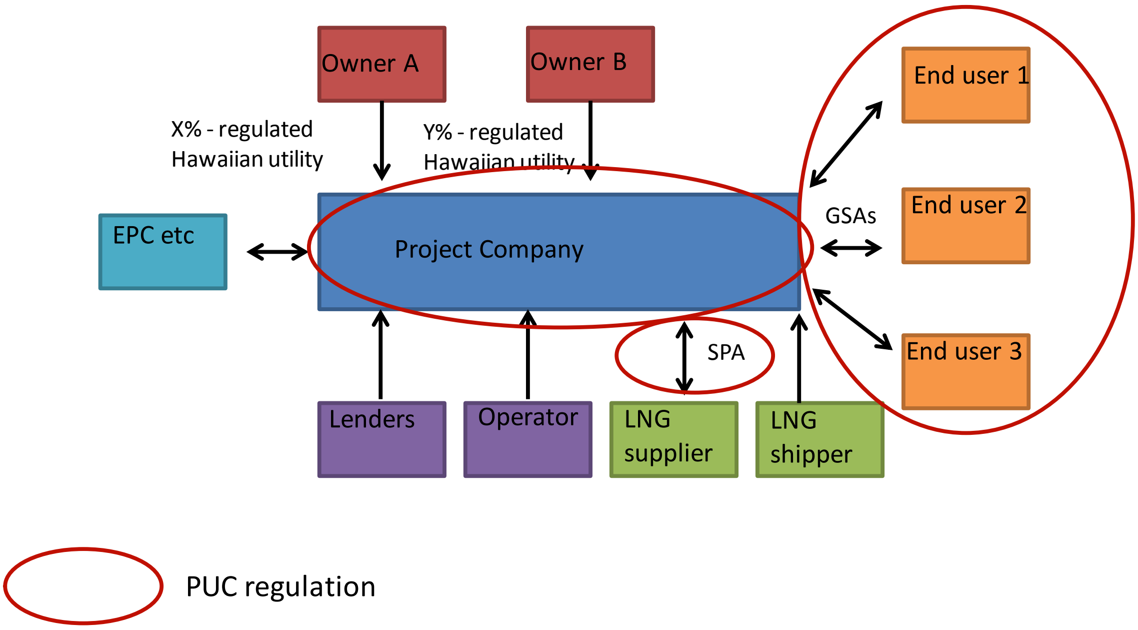
According to the Energy Policy Act of 2005, US LNG terminals are no longer required to offer third-party access on a non-discriminatory basis at a regulated rate of return (set by FERC, not the relevant state public utility commission). This holds true until the year 2015. If a Hawaii LNG terminal developer submits an application to FERC for a certificate of public convenience and necessity to build and operate a Hawaii regasification facility onshore or in State waters after that date, there is no guarantee that the developer will have the right to exclusively utilize capacity and charge its affiliate market-based rates for terminal service. On paper, FERC might require a post-2015 Hawaii LNG import terminal developer to hold an open season for capacity and require the developer to submit to a regulated rate of return. (By contrast, an offshore Hawaii LNG terminal developer would not be obliged to offer capacity to third parties at any point in time.) It is not the task of the Consultant to speculate on the outcome of FERC's decision for post-2015 LNG import terminal regulation, but it is certainly an issue worthy of notice.

This in turn poses an interesting question for Hawaii LNG terminal developers pursuing an onshore configuration or an offshore facility located in State waters: namely, whether FERC or Hawaii's PUC would have the power to establish the terminal's tariff rate if FERC elected *not* to exempt the facility from regulated third-party access at regulated rates of return. After all, the PUC is responsible for the supervision of all aspects of the State's public utilities and is empowered to prescribe rates, tariffs, charges, and fees and determine the allowable rate of earnings in establishing rates. If a State utility company sponsored a proposal for an LNG import terminal after 2015, and FERC exercised the option *not* to exempt the terminal from regulated third-party access at regulated rates of return, the question of who would set the rate—FERC or PUC—might arise. Without wishing in any way to speculate on the outcome of FERC's decision for post-2015 LNG import terminal regulation, it is nevertheless important to raise this point to help fulfil the Consultant's scope of work and highlight any potential gaps—or overlaps—between Federal and State regulatory oversight over a Hawaii LNG project.

Although FERC will have exclusive jurisdiction over licensing a Hawaii terminal located onshore or in State waters, the PUC will be involved in the regulation of an LNG terminal to some degree. Deciding the exact nature of that 'degree', however, is difficult. The Consultant can only postulate that the extent of the PUC's regulation over the terminal will be largely contingent on the business model selected by a Hawaii LNG import terminal developer—which in turn will be driven by FERC's decision on whether to allow a post-2015 Hawaii developer proprietary access to the terminal. Operating on the assumption that FERC's terminal access policy does not change post-2015, there are multiple potential project configurations that exist, and the PUC's role will vary accordingly. For example:

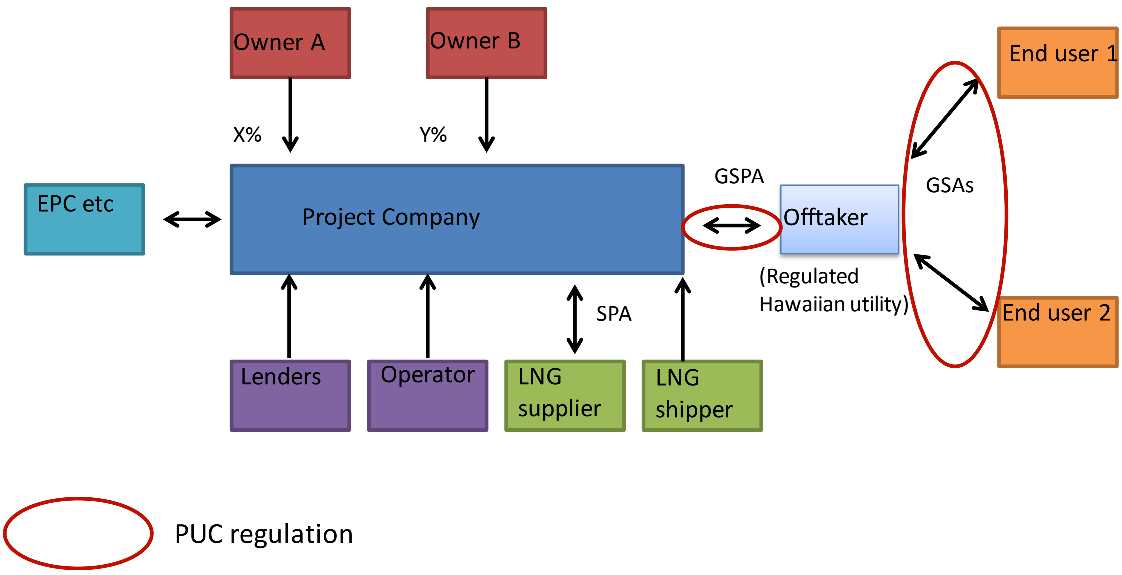
- If a regulated utility company like (but not confined to) HAWAIIGAS or HECO adopted an integrated business model or tolling model to own and operate the terminal, the Consultant believes that the PUC would seek to regulate the facility's rates and possibly the fuel supply contract(s) underpinning the terminal. That is because the gas would be sold to regulated entities: it is a matter of law that HAWAIIGAS and HECO, as regulated entities, cannot make a profit on fuels (Figure 101).

Figure 101: Integrated Business Model – Possible Areas of PUC Regulation



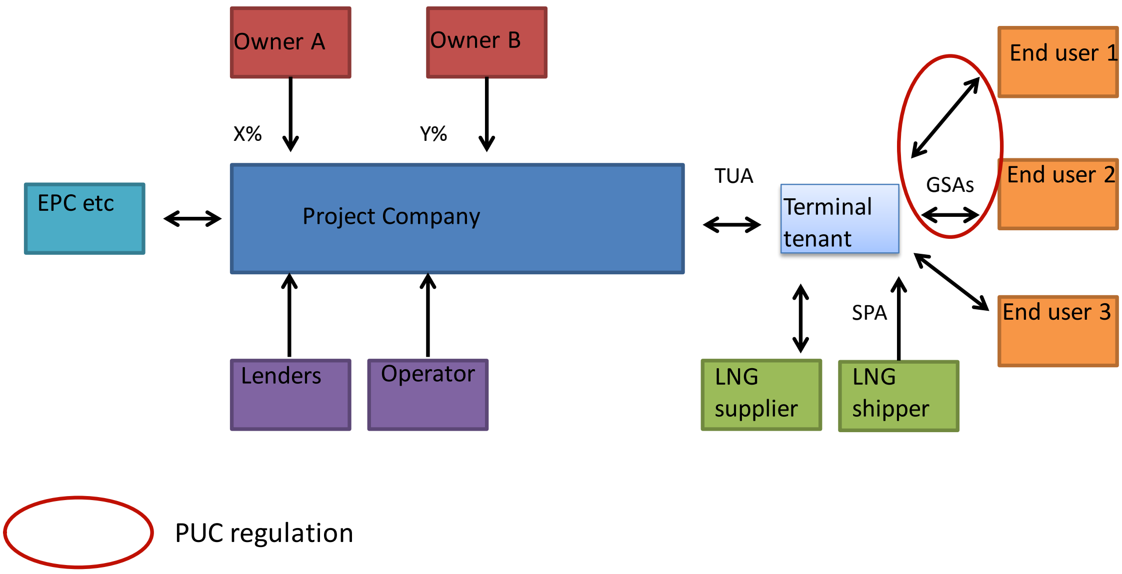
- If a modified integrated project structure was established, where non-utility owners were responsible for procuring LNG and selling regasified volumes to a single entity (for example, a regulated gas or power utility company, who would act as the intermediate offtaker) who then sold these volumes to end-users, PUC oversight would extend over the intermediate offtaker and the terminal owner(s) GSPA, as well as GSAs between the intermediate offtaker and any regulated utility customers (Figure 102). Sales by even a regulated utility to a non-utility customer, however—much like HAWAIIGAS' existing LPG sales to non-utility customers—would not fall under PUC purview.

Figure 102: Modified Integrated Project Structure and Possible PUC Oversight



- However, if a private entity is established to own and operate the terminal (i.e., a merchant business model), PUC oversight would extend only to the fuel supply contracts with regulated entities like HAWAIIGAS (or another new utility gas franchise holder) and HECO (Figure 103).
    - The terminal owner could seek proprietary access to the facility and sign gas sales agreements with regulated entities, where PUC jurisdiction would apply to these contracts; but
    - Gas sales agreements with non-regulated entities (i.e., not the power sector: end-users like the vehicular sector) would not be regulated by the PUC. However, much will depend on how quickly demand by non-regulated entities ramps up. This mode of operations has a precedent at the refineries currently supplying HECO and HAWAIIGAS: although the refineries themselves are not PUC regulated, the PUC has taken an interest in the contracts supplying LSFO and naphtha sales to HECO and HAWAIIGAS respectively, since downstream fuel prices are regulated. However, refinery sales to non-regulated entities (e.g., jet fuel) are not overseen by the PUC.

Figure 103: Merchant Model – Possible PUC Regulation



In short, it is the consultant's view that FERC will have lead jurisdiction over the licensing of an onshore LNG import terminal. Depending on the business model adopted to build, own, and operate the facility, Hawaii's PUC will demand oversight over any gas sales agreements concluded by regulated utility companies at the very least—and demand a voice in the regulation of LNG terminaling rates at the most (Figure 104).

Figure 104: LNG Terminal Business Models and Possible Area(s) of PUC Oversight

Business Model	Possible Area of PUC Oversight
Integrated or tolling project owned by regulated utility	Terminalling rates; LNG SPA (?); GSAs with end-users
Modified integrated project by non-regulated utility	GSPA with intermediate offtaker, if offtaker is a regulated utility; intermediate offtaker's GSAs
Merchant model	GSAs between terminal tenants and regulated Hawaii utility downstream customers

If a business model is chosen that does trigger a PUC role in regulating the terminal's rates, a perceived regulatory gap in FERC oversight over a Hawaii LNG terminal becomes apparent courtesy of the so-called Hinshaw Exemption. This was brought to light by HAWAIIGAS' August 2012 FERC filing for Part 1 of its LNG project. As such, FGE will use the HAWAIIGAS project to explore this point further. HAWAIIGAS stated in its August 2012 FERC filing:

"Under NGA Section 1(c), the provisions of the NGA do not apply to any person engaged in the transportation or sale of natural gas for resale in interstate commerce, or to any facilities used by such person for such transportation or sale, if: (i) the natural gas is received within or at the boundary of a state; (ii) the natural gas is ultimately consumed in that state; and (iii) the rates and services applicable to such person and facilities are subject to regulation by the state utility commission. This so-called "Hinshaw exemption" raises the general question as to whether a company and its LNG terminal facilities would be exempt from the Commission's NGA Section 3 jurisdiction by virtue of Section 1(c), assuming all the criteria of section 1(c) are met."

However, HAWAIIGAS appears sanguine that the Hinshaw exemption does not apply either to its proposed Phase 1 LNG terminal project or to Section 3(e) jurisdictional LNG terminals in general. HAWAIIGAS argues that, having taken title to LNG in the Continental US, regasified LNG will be injected into its distribution system, rather than taking title to the gas within or at the boundary of the State and injecting LNG into its transmission network. In interpreting section 1(c) of the NGA, FERC has previously determined that a Hinshaw pipeline 'receives' natural gas at the point of physical delivery to its system, not the point at which title passes.

HAWAIIGAS also maintains that the Hinshaw exemption does not apply to Section 3 of the NGA, which gives FERC oversight into the siting, construction, expansion, and operation of any US onshore LNG terminal: "If the Hinshaw exemption were interpreted as applying to the Commission's jurisdiction over the operation of LNG terminals under Section 3(e), it would be contrary to the intent of Congress to have the Commission provide uniform environmental and safety review of LNG terminals in the US", HAWAIIGAS noted in its August 2012 FERC filing.

- The Hinshaw exemption recognizes that states are entitled to regulate "matters primarily of local concern." The licensing of LNG import infrastructure is certainly a matter that affects the host state—as discussed previously, the host state does have a voice in the process that is coordinated by FERC—but the licensing of LNG import infrastructure is also a matter of federal interest and requires a uniform safety and security standard. This is something that individual states generally do not have the time and money to conceive, implement, and enforce. This was a driving factor behind the Energy Policy Act of 2005, which affirmed FERC's lead role over onshore LNG terminal regulation.

If the Hinshaw exemption was applicable to the siting, construction, expansion, and operation of a Hawaii LNG terminal, and FERC's oversight was negated, the State of Hawaii would have no jurisdiction, either. Hawaii's PUC, for example, has broadly defined powers and duties to exercise general supervision over all public utilities, including the determination of utility tariffs and fees and all aspects of the operation, financing, and management of public utilities. But it is not set up to vet an application to construct or operate an LNG import terminal. In other words: applying the Hinshaw exemption to HAWAIIGAS' Phase 1 facilities (or to the siting, construction, modification, or operation of any other LNG terminal proposed for Hawaii) would result in a regulatory gap as neither the FERC nor the State would have jurisdiction.

HAWAIIGAS has indicated from the outset that it is not interested in invoking the Hinshaw exemption to avoid FERC regulation. To do so would place its terminal in a regulatory no-man's land. This in itself is inimical to the company's interest in bringing LNG to the State in a timely fashion. The fact that HAWAIIGAS submitted an application to FERC in August 2012 for permission to operate Phase 1 of its project is proof in and of itself that HAWAIIGAS has no desire to circumvent FERC oversight. Its application to FERC is proof in and of itself that HAWAIIGAS is satisfied for the terminal's safety and security provisions to be approved by FERC. An examination of HAWAIIGAS' active FERC docket for Section 3 authorization to operate Phase 1 of its LNG import terminal shows that the PUC has not filed an objection with FERC contesting federal regulatory oversight over HAWAIIGAS' facilities. This appears to indicate the PUC's acquiescence to FERC oversight over HAWAIIGAS' planned Phase 1

LNG project. No other Hawaii LNG terminal sponsor has indicated whether or not it would seek to invoke the Hinshaw exemption, largely because their projects have not advanced to the stage where the notion is publicly debatable. As such, the Consultant cannot comment on other developers' views on the matter.

4.4.1.1. *Expanded Role for Hawaii's PUC?*

As discussed previously, the extent of PUC's involvement in a Hawaii LNG import terminal will depend on two factors: FERC's decision on whether to apply the Hackberry dispensation to a post-2015 Hawaii facility and the business model selected by the project's owner. Assuming that regulated entities like HAWAIIGAS or HECO sign up as end-users, it is certain that the PUC will oversee the gas sales agreements by these companies with the company that owns the terminal. If, however, a regulated Hawaii utility company also decides to build, own, and operate a Hawaii LNG terminal and procures LNG for sale to regulated local entities, then the PUC's authority might extend a little further, with the PUC setting the facility's rates of return (assuming FERC does not assume jurisdiction post-2015, as discussed in Section 4.4.1.). PUC could also demand a voice in the LNG supply contract that underpins these sales.

When a country or state first begins importing LNG, it raises a host of new questions that the PUC (or a similar body) must address. The PUC can leverage some it its existing body of knowledge to the State's nascent LNG import enterprise, but many issues unique to the LNG business present uncharted waters for the PUC. The PUC obviously has familiarity with the international energy business, given its historic role in regulating sales from Hawaii's two refineries to HAWAIIGAS and HECO. However, there is a significant difference between the international oil business and the LNG business—especially LNG supply contracts. Although there are short-term and spot sales in LNG, most LNG is sold on a medium-term (4-9 years) or long-term (10-25 years) basis. In addition, the pricing formulas vary widely, and can be indexed to oil, gas, composites, or import prices in third countries. HAWAIIGAS has obviously raised the possibility of buying LNG from the Continental US, where prices would be linked to Henry Hub. However, the possibility exists—albeit remote, given Hawaii's intent to reduce its exposure to oil prices—for LNG to be imported from a foreign source that is indexed to crude oil (e.g., Australia or Canada). No matter how imports are structured in terms of the buyers, Hawaii's PUC might require an expanded staff and new skills to deal with this very different set of contractual issues.

According to FGE interviews with one State energy agency, the PUC could require up to half a dozen new staff to oversee the terminal's regulation, especially if a business model is selected that puts both the terminal and SPAs underpinning the facility under PUC purview. Indeed, the PUC might require new staff in very short order, if they are to review the SPA concluded by the terminal's owner. In many cases, but by no means all, SPAs are concluded prior to the commencement of operations at the LNG import terminal. SPA negotiations themselves are often protracted and take some time to finalize. This suggests a need for PUC recruitment to begin sooner rather than later.

Staff members would require some LNG commercial experience. However, the PUC's direct presence at the negotiating table during talks between the seller and buyer might not be viewed kindly by the seller. Commercial LNG negotiations are invariably a sufficiently complicated affair without the addition of third parties. Even if the PUC did not have a seat at the negotiating table, the knowledge that the buyer would require PUC acquiescence to any seller's proposal and thereby prolong negotiations, likewise might not be viewed favorably by the seller.

Additional PUC manpower would also be required to help establish rates for terminaling service and to vet the gas sales agreements signed by a regulated utility.

- The onus will be on the PUC to determine returns and the allocation of risk to the terminal's developers. New staff members would ideally have experience in LNG terminal operations—perhaps staff members with employment experience at older mainland US terminals that offered tenants regulated rates of return, for example.
  - If a terminal is built and expansions are sanctioned in fairly short order, enough work would be created to keep PUC staff busy for quite some time, as the onus will be on the PUC to ensure that the rights of existing tenants are not compromised by the provision of expanded terminal service to a new entity.

However, other State energy players interviewed by FGE disagreed with the hypothesis that additional the PUC resources would be required if Hawaii became an LNG importer. They countered that PUC could easily subcontract the PUC vetting of an LNG SPA and/or gas sales agreement at the terminal's tailgate to a third party with extensive knowledge of these matters. After all, the current State gas franchise holder's rate reviews, etc., appear before the PUC quite rarely; consequently, it might be a poor resource management for the PUC to hire additional manpower for the one-off signing of an SPA and gas sales agreement. Any rate revisions in the future or LNG SPA price renegotiations could likewise be subcontracted if and when the need arises. There are several consulting firms with extensive experience in these matters, virtually all of which are staffed by employees that have well-documented experience in the sale and purchase of LNG, terminal operations, and LNG regulatory issues.

There is also a "middle of the road" approach, which postulates that the PUC would initially retain the services of a consulting firm to provide initial assistance if and when LNG comes to Hawaii. Part of the consultant's mandate, however, would be the training of PUC personnel, so that the consultant's services would eventually no longer be required. It is understood that many the PUC consulting contracts include some measure of staff training in the area of expertise. Additional staff could be required, but PUC staff members do not typically work in only one subject area. FGE can only conclude that opinions about the additional manpower needed by PUC to help oversee a Hawaii LNG import terminal appear mixed. Ultimately, it remains to be seen which school of thought will win out.

4.4.1.2. *Regulatory Changes to Facilitate Hawaii LNG Imports?*

The purpose of this section is to consider what, if any, legislative and regulatory changes would be required to facilitate the introduction of natural gas into Hawaii's energy mix. FGE believes the existing US LNG regulatory regime provides sufficient guidance for the construction and operation of an LNG terminal in Hawaii—the role of the PUC will ultimately gain clarity once the business model of a Hawaii LNG import terminal is delineated—but reconciling the goals of the Hawaii Clean Energy Initiative (HCEI) with the concept of Hawaii LNG imports is essential. This, however, is likely to be a politically delicate matter. For the sake of convenience, FGE will cite HAWAIIGAS' proposal as the proxy for a Hawaii LNG import terminal. Once again, this should not be interpreted as an indication of the Consultant's "endorsement" of the proposal; FGE stresses that the arguments "for" and "against" the concept of Hawaii LNG imports apply to any proposed project serving the State.

By way of background, HCEI was conceived to reduce the State's dependence on imported fossil fuels and incorporate cleaner and locally-sourced energy into Hawaii's energy mix. The stated goal is for Hawaii to derive 70% of its electricity and ground transportation needs by 2030 from a mix of efficiency savings and fuel switching. As part of the HCEI, an historic agreement was signed in October 2008 by the Hawaii Electric companies, the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development & Tourism, and the State of Hawaii Consumer Advocate. It was envisaged that 30% would come from efficiency measures and locally generated renewable sources would comprise the remaining 40%. Major highlights of the 2008 agreement included a commitment from the Hawaii Electric companies to retire older power plants fuelled by fossil fuels; the conversion of existing fossil fuel generators to renewable biofuels, ultimately using crops grown locally and in a sustainable manner; and a ban on the construction of any new coal-fired power plants in the State. In addition, there are existing State statutes that have set HCEI's clean energy goals into law, specifically the Renewable Portfolio Standards (RPS) and Energy Efficiency Portfolio Standard (EEPS).[23]

Unsurprisingly, expressions of interest by various players in the concept of Hawaii LNG imports have not been kindly received by the HCEI supporters that adopt a more conservative view of the Initiative. This is illustrated by the Motions to Intervene in HAWAIIGAS' Phase 1 LNG FERC filing by bodies such as Blue Planet and the Sierra Club. For example, Blue Plant argued that, as an imported fossil fuel, LNG was inimical to the objectives spelled out in the HCEI. The organization noted "…the effect of the comprehensive LNG plan will be to continue and deepen Hawaii's dependence on imported fossil fuels in a manner that is contrary to established State of Hawaii energy law and policy." Blue Plant further stated that LNG imported into Hawaii pursuant to HAWAIIGAS' proposed plan is not a "clean energy" within the meaning of HCEI.

Some supporters of Hawaii LNG imports obviously take an opposing view, while being careful to stress their continued support of HCEI. First and foremost, these supporters object to the classification of LNG as an "imported fossil fuel." LNG advocates favor bringing LNG to Hawaii from the mainland, which in their eyes, constitutes interstate commerce rather than importation from a foreign country. As such, LNG does not constitute a form of increased reliance on imported energy. These Hawaii LNG proponents moreover take issue with the definition of LNG as a "fossil fuel," for according to the federal Energy Policy Act of 1992, compressed natural gas (CNG) and LNG are considered "alternative fuels." The Energy Policy Act of 1992 was promulgated to reduce US dependence on imported petroleum and improve air quality by addressing all aspects of energy supply and demand, including alternative fuels, renewable energy, and energy efficiency. The Act consists of twenty-seven titles detailing various measures designed to lessen the nation's dependence on imported energy, provide incentives for clean and renewable energy, and promote energy conservation in buildings. Other "alternative fuels" according to EPAct 1992 include methanol, denatured ethanol, and other alcohols; LPG; hydrogen; coal-derived liquid

[23] Under Hawaii's Renewable Portfolio Standard, each electric utility company that sells electricity for consumption in Hawaii must adhere to a given percentage of "renewable electrical energy" sales by certain times. The Energy Efficiency Portfolio Standards of 2009 set a goal of 4,300 GWh reduction in electricity use by 2030. This goal can be adjusted by the PUC by rule or order.

fuels; fuels (other than alcohol) derived from biological materials; electricity (including electricity from solar energy); and any other fuel the Secretary of Energy determines, by rule, is substantially not petroleum and would yield substantial energy security benefits and substantial environmental benefits. In short, LNG is not an "imported fossil fuel," according to these Hawaii LNG advocates.

These Hawaii LNG import supporters believe that LNG's classification as an "alternative fuel" by the Federal government renders the concept of Hawaii imports consistent with the goals spelled out in the HCEI. In its August 2012 application to FERC for a certificate of public convenience and necessity to operate Phase 1 of its LNG project, HAWAIIGAS stated that, "*…gas from LNG will be used to meet up to 75% of the Company's customers' requirements. It also will provide fuel for up to 400 MW of existing and new conventional and/or combined cycle power generation facilities, as well as for industrial and other commercial applications in the State. In addition, implementation of the Company's LNG strategy will help the State achieve the 'Hawaii Clean Energy Initiative' goal of replacing up to 70% of the energy sourced from oil with energy produced from renewable sources or saved through energy efficiency programs, an initiative that was adopted to reduce the State's heavy dependence on petroleum.*" HAWAIIGAS maintained that its plans to import LNG were, "…consistent with state law and policy, and in particular furthers the important goals of strengthening fuel diversity, reducing the environmental impacts associated with energy production, and maintaining system reliability during emergencies or other disruptions to gas supply."

It is worth pointing out, however, that some people disagree with the notion that LNG is an "alternative fuel," but have nevertheless expressed their support of the concept of State LNG imports. This support is given on the grounds that LNG may yield significant cost savings for the State, if all the attendant LNG procurement challenges can be successfully addressed. There is also the sentiment that gas sourced from the mainland translates to greater energy supply security compared to crude oil sourced from the Middle East, even though that oil is refined in Hawaii. The fact that natural gas combustion is cleaner than that of LSFO is also a mark in its favor, even though the supporter as an individual does not subscribe to the argument that LNG is an alternative fuel.

It is not the purpose of this section of the report to vet the arguments "for" and "against" Hawaii LNG imports and determine a "winner." Rather, FGE has been charged with identifying any changes in legislation that would be required to accommodate Hawaii LNG imports, and the clash between Federal and State notions of what constitutes an "alternative fuel" is surely the biggest (and most contentious) issue. Simply put: for Hawaii to become an LNG importer, the legislature, State energy entities, as well as supporters of HCEI that are private citizens must all find a way to reconcile the concept of Hawaii LNG imports with the State's energy goals from a legal (and personal) standpoint. This will, however, be much more easier said than done.

Changes in legislation may or may not be the only policy decisions required to accommodate Hawaii LNG imports. Even with no actions required by the State legislature, there may be numerous requirements and decisions by regulatory and administrative agencies. It is not, however, the intent of this section to review these details, as such a review is outside the scope of this report.

4.4.2. LNG Infrastructure Ownership and Operation

The purpose of this section is to consider the pros and cons of ownership or control over some or all of Hawaii's critical LNG infrastructure supply chain components by either Hawaii's electric utilities or Hawaii's gas utility. This section will also present the pros and cons of a separate utility franchise(s) operating an LNG import terminal, gas storage, and high pressure natural gas pipeline network in Hawaii. Once again, FGE must stress that the extent of companies' involvement in a Hawaii LNG terminal will be decided by the business model chosen for the initiative. Moreover, is not the purpose of this report to analyze the pros and cons of various LNG import terminal business models, but merely to discuss the pros and cons of various stakeholders' involvement in a Hawaii LNG import initiative in one form or another. This discussion follows below.

4.4.2.1. *Electric Utility Role*

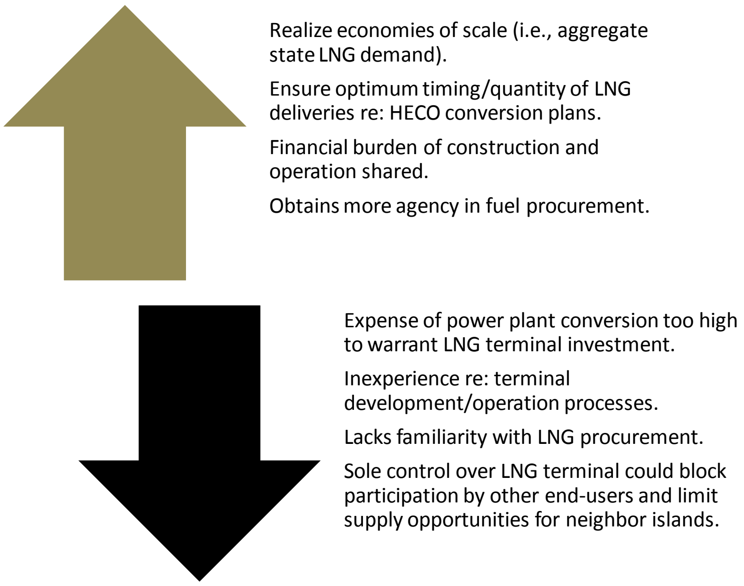
It is the Consultant's view that the State electric utility's joint venture participation in a Hawaii LNG import terminal—or at the very least, as an offtaker—has unquestionable advantages. If oil-fired units are converted to natural gas, the State's power generation business will account for the lion's share of LNG demand, especially in the initial years of operation while other, much smaller potential areas of demand like transportation are ramping up. Indeed, without HECO's involvement in an LNG terminal serving the State, there may be insufficient demand to justify the expense of building a baseload LNG tanker discharge facility in Hawaii, so its participation in a Hawaii LNG import initiative—whatever form it may take—is crucial. With the State's power sector on board, other potential Hawaii natural gas end-users can band together and account for a solid block of LNG demand, thereby enabling a terminal to achieve the desired economies of scale.

The Consultant also postulates that HECO's participation in a joint venture LNG import initiative could have advantages on other fronts. Including HECO as an owner in an import terminal consortium, for example, would help spread the financial burden of construction and operation. If a business model is selected that calls for stakeholders' involvement in the negotiation of an LNG SPA, HECO's inclusion might give the utility company a sense of urgency and control over its fuel procurement—something that might be especially appealing to HECO's management, given the utility's current dependence on Hawaii's two refineries for LSFO supplies. No one is better positioned than HECO itself to understand its own fuel requirements; hence, inviting the utility to participate in the terminal and giving it a voice in SPA negotiations will ensure that the quantity and timing of fuel deliveries matches HECO's own development schedule for the conversion/installation of gas-fired powered generation capacity. Hawaii is, after all, in the fairly unique position of building LNG import capacity to serve nascent LNG demand—this is a stark contrast to existing terminals on the mainland, which were built to help serve *existing* gas demand. Of course, if a business model is chosen where offtakers like HECO do not participate in the terminal or procure supplies, it is exceedingly likely that, as the biggest potential LNG consumer in the State, the terminal's developers and fuel suppliers would size the terminal and procure supplies with reference to HECO's requirements, since it would be acting as the primary demand aggregator.

The Consultant believes there are also potential downsides to sole HECO control over a Hawaii LNG import terminal ownership consortium and the possible procurement of LNG supplies. First, LNG terminal construction is not cheap, and HECO could justifiably argue that the costs of converting its oil-fired power plants to natural gas (if it acquiesces to this) and building more renewable plants are high enough without the added burden of co-sponsoring an LNG import terminal. Second, if a business model is chosen that requires the terminal's sponsors to procure LNG supplies (e.g., a tolling facility or a merchant model with HECO as a core tenant), HECO lacks the advantage of LNG procurement experience, which might prolong the procurement process and lend an air of uncertainty to the process on HECO's side. To that end, HECO may prefer to limit its involvement in a Hawaii LNG import terminal development efforts, and merely confine its role to that of an offtaker. However, confining its role to that of an offtaker might put HECO in a similar position as it is today *vis a vis* fuel procurement—that is dependent on a single source of supply with no control over the source of LNG supply or the purchase price. This prospect may not be viewed favorably by HECO.

On the other hand, thought must be given to the possibility of HECO going further and actually sponsoring 100% of a Hawaii LNG import terminal. If HECO elects not to cooperate with other Hawaii end-users and sponsors its own facility—or form an alliance with an LNG terminal development company where it is the sole 'anchor' customer—there are concerns that HECO will satisfy its own gas demand only. After all, HECO's business mandate is not to provide gas to other end-users, but rather, to own, operate, maintain, and fuel its power generation assets to the best of its ability. Nothing in HECO's business charter requires HECO to provide fuel to other, especially non-power generation-related end-users. This is an issue for other potential Hawaii LNG end-users, who lack the demand in their own right to support a Hawaii LNG terminal. The importance of HECO participation in a Hawaii LNG import initiative—or at the very least, support in the form of an LNG offtake agreement—is certainly vital, but not at the risk of locking other potential end-users out of the terminal.

Figure 105: Pros and Cons of HECO Involvement in a Hawaii LNG Initiative



4.4.2.2. *Gas Utility Role*

A utility company that holds a State gas franchise is another candidate to develop—or co-develop—a Hawaii LNG import terminal. After all, any Hawaii LNG import terminal will require access to distribution infrastructure to reach end-users, and traditionally, this is a province of gas utility companies.

A gas utility company is also in a good position to arrange sales to other potential end-users. This could be accomplished by a gas utility company participating in an integrated LNG terminal project, where the terminal company concludes gas sales agreements directly with other end-users; a modified integrated project, where a gas utility company could act as the sole 'offtaker' and then arrange sales to third parties; a 'merchant' project structure, where a gas utility company has a terminal use agreement with the project development company, procures LNG supplies itself, and then arranges regasified LNG sales directly; or even a tolling arrangement, where a gas utility procures its own LNG, takes title to the regasified LNG at the terminal tailgate, and uses a portion of the LNG in its own operations while selling the remainder to third parties.

Whatever project structure is chosen by a gas utility LNG developer, the regasified LNG must find its way into the local distribution system. Today, HAWAIIGAS is the owner and operator of the only existing regulated gas processing and pipeline distribution network on the islands of Hawaii. A new gas franchise holder could attempt to petition HAWAIIGAS for access to its system or elect to build its own take-away infrastructure to serve customers. (The Consultant understands that any other individual offtakers have the legal right to build their own pipelines to serve their own needs, too.) However, utilizing existing gas infrastructure is generally the preferred option for petroleum developers around the world, given the inherent savings in time and money. An LNG terminal developer in the State is unlikely to be an exception to this rule, given the not-inconsiderable expense of licensing, building, and operating the regasification terminal itself. HAWAIIGAS is already competitively positioned to ensure the carriage and delivery of gas to its own customers as well as to other end-users and therefore boasts a competitive advantage in this regard. Going through HAWAIIGAS is not, of course, the only option.

A gas utility's involvement in an import project—even if it is only the intermediate offtaker—has advantages for regulated utility offtakers like HECO. For many years now, HECO has expressed concern about dependence on private companies like Chevron and Tesoro for its fuel supplies. By contrast, purchasing gas from an intermediary like a regulated gas utility company would be much more advantageous than purchasing from a private company; if fuel purchase prices proved to be an issue for HECO, then HECO could appeal to the PUC and ask the Commission to address its concerns. After all, a regulated gas utility's gas sales agreements would be subject to PUC oversight. By contrast, a regulated utility like HECO would have no such recourse if purchasing regasified LNG from a private entity.

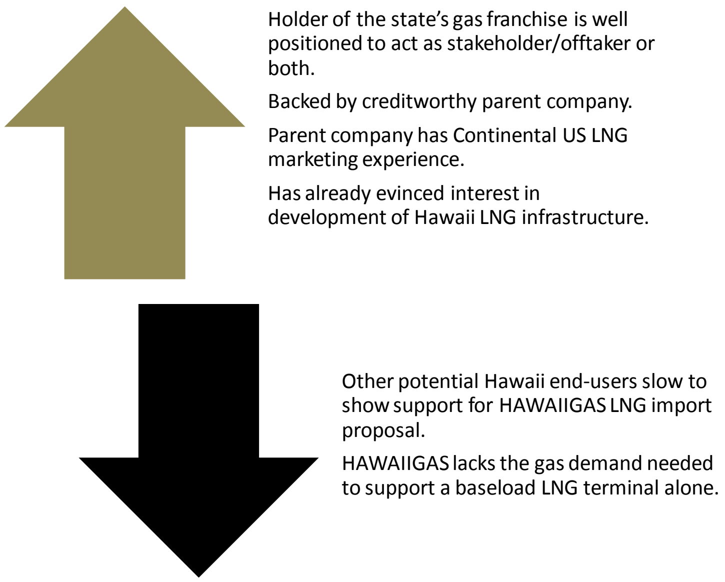
The State's existing gas franchise holder enjoys a company-specific advantage as the developer or co-developer of Hawaii LNG import infrastructure: its balance sheet. The company is backed by the Macquarie Infrastructure Company, a listed infrastructure fund managed by a subsidiary of Australia's Macquarie Group. Macquarie Group operates in 28 countries around the world; employs over 14,200 people; and has US$339 billion under management. Quite simply, HAWAIIGAS has the balance sheet to support an LNG terminal in its own right. Through its relationship with Macquarie, the State's existing gas franchise holder brings to the table an asset that is lacking by many other Hawaii energy entities: commercial LNG experience. Until recently, an arm of Macquarie was involved in the marketing of LNG from the proposed Freeport LNG export project in the US Gulf of Mexico. In November 2010, a Macquarie affiliate and the Freeport LNG venture concluded an agreement to jointly market liquefaction capacity from the Texas terminal, but this agreement dissolved in early 2012. Although Macquarie Energy will not be part of the liquefaction marketing efforts, the bank is still participating in the financing of the project, which has grown to a proposed 18 mmtpa. This is not to say that HAWAIIGAS has the promise of supplies from this venture; rather, that its parent company has accrued some valuable experience marketing LNG from this venture, and gaining valuable market intelligence about the competitive landscape. All Hawaii LNG terminal sponsors will be competing with a wide range of buyers for volumes from proposed mainland US LNG export projects, but HAWAIIGAS has a valuable resource in its parent company, which is in a position to convey to HAWAIIGAS what is acceptable to potential Continental US LNG sellers in terms of pricing and other contractual expectations. Of course, there are many other entities that have as much or more commercial LNG experience than Macquarie, even from future US export facilities. That expertise could be tapped by any potential Hawaii LNG buyer by way of a strategic alliance, but as yet, no such alliance has been publicly announced.

There are, however, disadvantages to a gas franchise holder spearheading an LNG import initiative. The biggest issue is insufficient demand to support an LNG import initiative in its own right. If a State gas franchise holder cannot broker an alliance (be it a joint-venture agreement to develop a terminal or gas sales agreements at the terminal's tailgate) with major existing end-users, then it is exceedingly unlikely that a solo-sponsored initiative will succeed in a timely fashion, given the twin factors of the gas franchise holder's own modest demand (HAWAIIGAS is a good example of this) and the time needed for other potential demand centers like transportation to ramp up significantly.

Another disadvantage of a gas utility-sponsored initiative is deciding who would spearhead the project. As stated previously, HAWAIIGAS is the State's only current franchise holder, but it is legally possible for a new gas franchise to be awarded by the State. This new franchise could conceivably spearhead an LNG terminal project also.

However, such a move might entail a degree of time-consuming debate by the legislature, not to mention provoking a degree of contention in some quarters (e.g., HAWAIIGAS itself). This might further stoke the fuel of controversy that surrounds the very topic of LNG in Hawaii, thereby further disfavoring the concept.

Figure 106: Pros and Cons of State Gas Utility Involvement in an LNG Project



4.4.2.3. *Separate Franchise*

Another option that exists is for a third party to build an LNG import terminal to guarantee LNG supplies for State end-users like HECO and a State gas franchise holder. This third party could employ a merchant business model for the project—in other words, allowing Hawaii end-users to negotiate a terminal use agreement for terminaling service at an agreed-upon fee. The terminal's core tenants would be responsible for procuring LNG for their own use. Alternatively, this third party could employ a modified integrated model, putting the onus on the developer to control capacity at the terminal, arrange for LNG supplies, and execute a GSPA with the company that will market regasified LNG at the terminal's tailgate. (This latter option does not necessarily preclude investment by a gas franchise holder, HECO, or any other Hawaii entity from participating in the terminal—the structure outlined above is for illustrative purposed only.)

This 'third party' would most likely be an experienced LNG import terminal development company, or possibly even an integrated petroleum company that has a presence in all components of the value chain, from LNG import terminal development experience to guaranteed sources of LNG supply. Multiple LNG development companies have ventured to build LNG import capacity on the mainland, and one or two have actually succeeded. They and other mainland import terminal owners/capacity holders might be contenders to build in Hawaii also.

- Mainland US terminal developers have experience with the FERC permitting process, which is no small advantage, given the ~US$50 million application process for a baseload taker discharge facility and approximately eighteen months needed to license an onshore facility. Some of these companies have outstanding credit ratings.
- A third party would shoulder some or all of the financial burden of developing a Hawaii import terminal, thereby relieving the balance sheets of regulated utility companies like HAWAIIGAS or HECO.
- A third-party developer lends an air of 'neutrality' to the concept of Hawaii LNG imports, which is inextricably linked with domestic politicking. Hawaii companies might have trouble working together or resist others' attempts to lead an import initiative, but working under the aegis of a non-Hawaii 'neutral' third party could spur development efforts by providing an umbrella for cooperation.
- The terminal developer would view the market access offered by State regulated utility companies as good enough incentive to justify the investment. The addition of new end users as the market matures represents good expansion potential.
- If a business model is chosen that puts the onus of sourcing LNG supply on the terminal's third-party developer, and the developer has access to LNG supply, this might provide even further incentive for involvement, since Hawaii is a viable market option for available supply.
  - There might even be scope for an LNG terminal developer that lacks access to LNG supply and a company with LNG supply but without interest in building a Hawaii terminal to co-operate, thereby further opening the pool of available avenues for involvement by interested third parties.

- On the down side, outside investors might be reluctant to evince anything more than preliminary interest until Hawaii end-users are all on board—especially HECO.
- Developers/third party LNG suppliers with only oil-indexed LNG volumes available could experience difficulty selling LNG to Hawaii buyers that is indexed to the price of oil.

- Regulated State utility companies like HAWAIIGAS and HECO could view a 100% merchant LNG play as a continuation of the status quo. They are currently dependent on Hawaii's two refineries—both private companies—for oil products. Relying on a merchant LNG developer and LNG supplier would likewise eliminate any opportunity for these companies to control fuel import infrastructure and to strike fuel supply deals except through a private company.

FGE interviews with officials from State energy companies and government employees brought into focus the issue of existing oil refiners' fates if LNG was incorporated into the State's energy mix, and the potential for them to compensate for lost market share by getting involved in the State's LNG business. (Refinery shutdowns may be inevitable even if Hawaii decides against LNG imports, as discussed in great detail in Chapter 3.) If HECO decided to convert existing oil-fired power generation capacity into natural gas, then the power sector's reliance on imported oil will shrink to the point where refinery operations may no longer be viable. However, if one or both of Hawaii's refining companies was to consider involvement in a Hawaii LNG import terminal in one form or another—as an investor in the terminal and/or as an LNG supplier—this might ameliorate any losses resulting from the end of LSFO sales to the power generation sector.

This is probably more of a consideration for Hawaii refinery owner Chevron, which already has a strong presence in the global LNG business via multiple existing or planned export projects in Australia, West Africa, and South America, and who also boasts experience as an onshore and offshore LNG import terminal developer in the US.

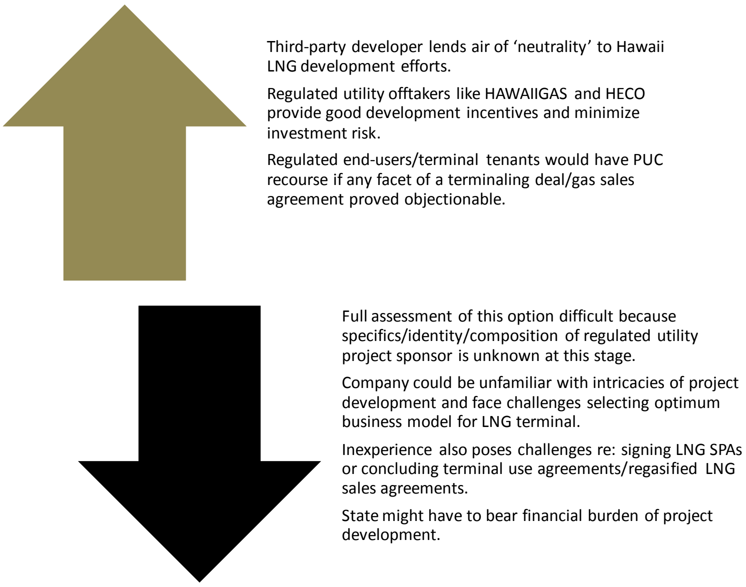
- Chevron is also an existing import capacity holder at a Gulf Coast terminal in Louisiana, but there is no public evidence to suggest Chevron's interest in a Hawaii LNG venture.
    - It also remains to be seen if such an arrangement would be acceptable to Hawaii end-users that have depended on private entities Chevron and Tesoro for fuel supplies for many years already. Hawaii LNG end-users might look askance at putting themselves in a similar position of dependency for LNG supplies.
- By contrast, Tesoro, which controls the State's other refinery, is merely an independent refiner and marketer of petroleum products, and has never evinced interest in the global LNG business. Tesoro also has active plans to exit the Hawaii refining business, and is therefore especially unlikely to consider a position in the State's LNG development.

Figure 107: Pros and Cons of Third-Party LNG Development in Hawaii

Another "third-party developer" option is for end-users like HAWAIIGAS and HECO to purchase LNG from a special purpose vehicle (SPV) conceived to develop a terminal project for the State, where the SPV is also a regulated by the State. This entity could be established especially by the State to oversee the project. It is, of course, not the purpose of this report to speculate on the possible identity of this SPV, or the various processes surrounding its creation by the State. It is, however, FGE's task to consider all the conceivable options for Hawaii LNG import terminal ownership, and this is an option that cannot in good conscience be eliminated at this stage.

As with all the preceding options evaluated in this section of the report, there are undoubted pros and cons to this alternative. On the plus side, end-users like HAWAIIGAS and HECO, as well as other potential non-regulated end-users, might appreciate the appearance of impartiality inherent in buying regasified LNG (or signing a tolling agreement—again, much depends on the business model ultimately selected by the developer) from a project sponsor that is not an end-user. A terminal developer that is not an end-user but still subject to State oversight would carry another advantage for companies like HAWAIIGAS and HECO: recourse to the PUC if any elements of the deal—e.g., terminal throughput costs or regasified LNG sales costs—were deemed unacceptable to tenants/end-users at any point in time. On the negative side, the specifics of project formation must be unknown at this point because FGE cannot know how the State would go about actually creating a regulated utility LNG terminal developer. This renders the task of analyzing this development option more difficult. However, FGE can only speculate that such a developer might have limited LNG project development experience, and might require substantial aid in choosing a business model that best fits the State's needs. Depending on the model selected, the developer would encounter the challenges posed by a lack of familiarity with the intricacies of concluding LNG SPAs/tolling agreements/regasified LNG sales agreements with the relevant parties. Finally, the State might have to bear the financial burden of project development by backing the creation of a regulated utility development company to sponsor an LNG project.

Figure 108: Pros and Cons of Regulated Third-Party LNG Development in Hawaii



4.4.3. Conclusion

Thanks to the intense level of LNG import terminal development on the mainland over the past decade, the regulatory regime governing siting, permitting, construction, and operation has achieved great clarity. FGE believes that FERC will have jurisdiction over an onshore Hawaii import terminal or an offshore facility located in State waters, whereas the Maritime Administration and the Coast Guard would vet applications for offshore capacity located in federal waters. State and local entities would also have a voice in the licensing process, but this would ultimately be overseen by Washington, D.C.

There may be scope for the PUC to demand a voice in setting a Hawaii import terminal's rates for terminaling service—assuming that FERC allows the so-called Hackberry dispensation to remain in place for onshore facilities post-2015—but much will depend on the ownership structure and business model selected for a Hawaii import terminal. If the terminal is owned by regulated Hawaii utilities, for instance, the PUC's role may be greater compared to a facility that is owned by a non-utility company that is not subject to PUC oversight. Nevertheless, any regasified LNG sales agreements by regulated entities are certain to fall under PUC purview. It remains to be seen whether the PUC will require additional staff to handle the additional workload, or whether existing PUC resources will be sufficient if combined with the services of an external LNG consulting company for particularly new or one-off tasks.

Although HAWAIIGAS' proposal for a State import facility is the only project that has gained any public exposure, it is by no means the only entity that has considered building an import terminal. FGE sees pros and cons to the myriad of LNG ownership structures that are possible: a facility led by HECO, a state gas franchise holder, a private development company, or even some sort of combination of all three. Whatever the ownership structure, FGE maintains that cooperation between Hawaii end-users—whether as project sponsors or offtakers—is essential for the project to proceed, since economies of scale are a key component of success.

APPENDIX & BACKGROUND MATERIAL

Introduction

The four-part structure of this study requires a large degree of repetition, especially with regards to historical and technical background. Those who are reading the full study should not be forced to wade through the same material multiple times. Therefore, we have provided this condensed "background" section. It provides a basic grounding in the oil market, with an emphasis on the special position of the Asia Pacific oil market. It gives an overview of LNG. It briefly compares oil and LNG markets, and then closes with an explanation of important concepts in the electric power industry, including types of generating technology and the problem of matching output to the load curve.

Those who are already familiar with energy issues and technology can skip this chapter entirely, or read only those parts where a refresher is needed.

The Asia Pacific Oil Market in Context

We live in a world of expensive oil, and we expect oil prices to increase as time goes by. This was not always the case. The real price of oil drifted steadily downward after 1950. The price of a barrel of oil in 1970 was US$1.80, and had been at that price since 1961. Given inflation, this meant the real price fell steadily; in 2010 dollars, the price in 1961 was US$13.11/bbl, and by 1970 the price had declined to US$10.10/bbl.

Although OPEC was founded in 1960, it did little until the early 1970s, when the 1973/74 Arab Oil Embargo changed the playing field. Until the battles between OPEC and the private oil companies, the world trade in oil and the oil price, was largely controlled by the major multinationals known as the "Seven Sisters." (Takeovers and mergers have left us with only Four Sisters today: BP, Chevron, ExxonMobil, and Shell.)

For a time, oil-exporting nations attempted to control the market as the Seven Sisters had, but by the middle of the 1980s their attempts failed and prices plummeted. No one could "set" the price of oil any longer. The growth of a large and active spot market let players of every size sell or buy oil on contracts that were indexed to spot market prices, and by the end of the 1980s, the futures markets in oil acted as another possible index.

From a closely managed industry, with a few large players controlling (or attempting to control) prices, the industry has been transformed into a real market. Although some find this frightening because prices move in unexpected ways, the free market in oil and oil products has made the world supply system more flexible. The “Oil Weapon” is an outdated concept. Neither the multinationals nor the oil-exporting countries can create any sort of effective embargo, because today it is market with thousands of sellers rather than a few.

The threat of physical supply cutoffs is now largely restricted to disasters. A good example is seen in the first Gulf War in 1991. Iraq’s invasion of Kuwait and the Neutral Zone cut off exports of Kuwaiti crude oil, as well as some Saudi supplies; and Iraq itself was of course denied export of crude through the Gulf. Did this mean that customers buying Kuwaiti, Saudi, or Iraqi crude were suddenly cut off from the ability to procure oil? No. Prices shot up (briefly), and there was a lot of frantic trading and realignment, but oil supplies continued to move to where they were needed. There were no lines at gas stations and no brownouts from power stations.

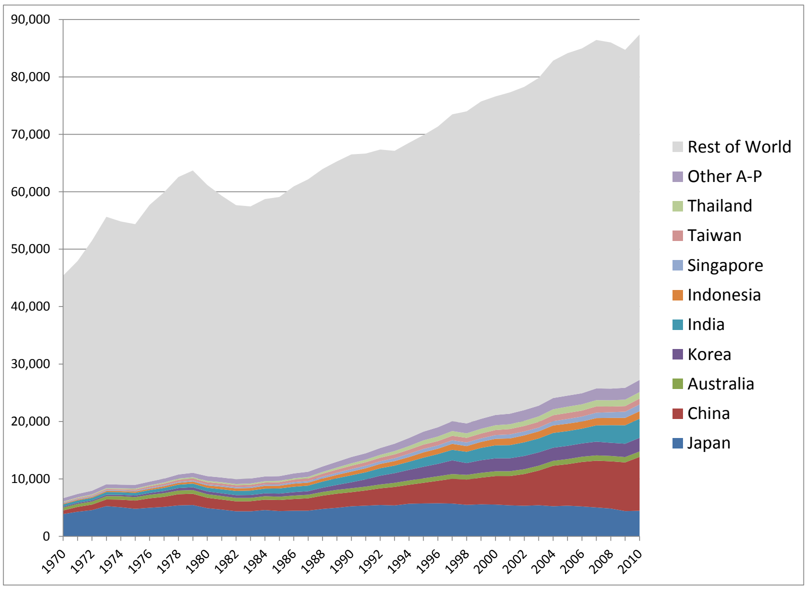
When the term “energy security” first became popular back in the 1970s, the main fear was the cutoff of supply from one or more producers, resulting in a physical shortage. Today, physical shortages can still come from natural disasters that destroy delivery infrastructure (Katrina, Fukushima, Sandy), but the “embargo” concept is dead: the market is too flexible.

Energy security today is more a problem of economic exposure to an unpredictable oil market. No matter what happens, oil supplies can be obtained—but the prices can be so high as to knock an economy into recession.

Another major change happened after 1970: the Asian Economic Miracle. In 1970, Japan was the only country in the Asia-Pacific region with oil consumption of over 1 million barrels per day. Today there are eight Asia-Pacific countries in the “million barrels per day club” (and, with Australia at 940,000 b/d, there are almost nine).

As the figure below shows, despite long periods of high prices, world oil demand has been generally strong and growing. The only major dip came in the early 1980s, when OPEC attempted to maintain artificially high prices (and, for a short while, succeeded).

Figure 109: Asia Pacific Oil Consumption in a Global Context (kb/d)



Beginning in the late 1980s, Asia Pacific demand has been the main engine of demand growth. In 1970, the Asia Pacific share of oil demand was 15% of the world total. By 2010, the share of demand had more than doubled, to 31% of the world total. Preliminary figures suggest that Asia Pacific oil demand today is a third of the world total (which might not be surprising for a region with two-thirds of the world's population).

Asia Pacific oil demand may be high, but current figures show that the region has a mere three percent of the world's oil reserves. The result is easy to understand—Asia takes a disproportionate share of the world's total oil imports. As the figure below shows, Asia accounts for 47% of all world oil imports (crude and products combined). This is more than the two next-largest regions (North America and Europe/FSU) combined.

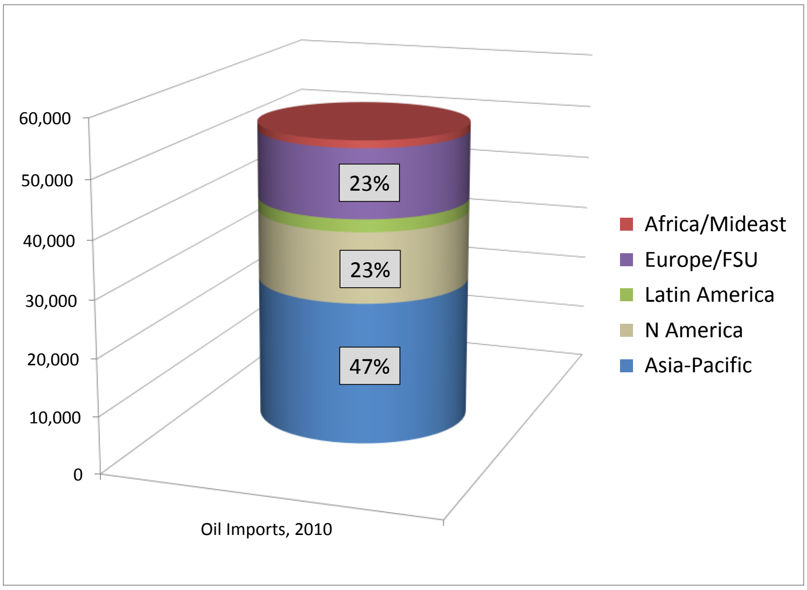
Asia's reliance on oil imports continues to grow, but in the world geography of oil, Asia in poorly located. There are significant oil producers around the Pacific Rim. Traveling clockwise, Australia, Indonesia, Brunei, Malaysia, Vietnam, China, Eastern Russia, Alaska, Canada, California, Mexico, Ecuador, and Peru are all important oil producers.

Asia Pacific producers generally consume most of their own output, and this tendency is increasing as demand grows. Preliminary figures for 2012 suggest that although Asia Pacific oil production has exceeded 8 million b/d, less than 1.7 million b/d is available for export. (These numbers should be contrasted with oil consumption of over 28 million b/d.) Most of this volume is sold to other Asian nations, but some moves to the US West Coast. The majority of Asia Pacific crudes are quite desirable, because almost all of the crudes in the region are low in sulfur, and Hawaii is almost entirely reliant on these crudes.

The one bright spot in supply around the Pacific Rim is Eastern Siberia, where Russia's Sakhalin and ESPO crudes are increasing their level of exports at a steady rate.

Alaskan and Californian crude are almost entirely used up by US West Coast refineries (and US crudes cannot be exported in any case).

Figure 110: World Oil Imports by Region (kb/d)



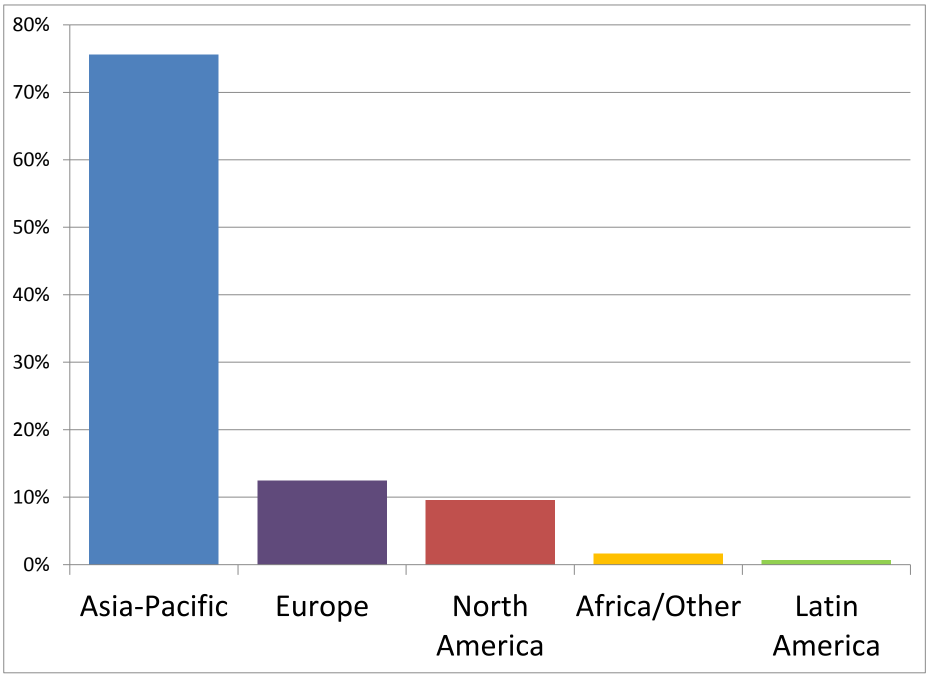
Canadian crude is produced primarily in the center of the country, and its exports are almost all delivered by pipeline to the United States; at present, little of it can reach Asia. Mexican production is primarily in the Gulf of Mexico, and there is no oil export terminal on Mexico's West Coast. Peru's exports are only about 60 kb/d, and although Ecuador's exports are more than 300 kb/d, much of it is sold to the US.

The consequence of this geographical quandary is that the Asia-Pacific region has to reach westwards for the bulk of its oil imports. There is significant oil available for export in North Africa, West Africa, the North Sea, and the Gulf of Mexico, but by far the closest major source is the largest exporting region, the Middle East.

Although most people still believe that the US and Europe are heavily dependent on Middle East oil, the world has undergone a major, and largely unnoticed shift. Oil demand is falling in the US and Europe, and at the same time oil production is strong in many parts of Africa and Latin America—and is soaring in the US as well.

The picture as of 2010 is shown in the figure below. The Asia-Pacific region now accounts for more than three-quarters of the Mideast's oil exports—taking 14.3 million b/d of the Mideast's 18.9 million b/d of supply.

Figure 111: Destination of Middle East Oil Exports by Region, 2010 (%)



But the exports from the Middle East do not close the supply-demand gap in Asia. The region also reaches out for more than 2.2 million b/d of oil from Africa, and pulls additional volumes from Latin America, Europe, and the Former Soviet Union.

The imports from Africa are especially important. Oil exports from the Middle East are generally high in sulfur. Africa is one of the few areas in the world with significant exportable volumes of low-sulfur crudes. Since most Asian crudes are also low in sulfur, many of the refineries in the region were designed to run on low-sulfur crudes.

In addition, Asian environmental controls were once close to nonexistent, but the region has instituted a drive for clean fuels that is breathtaking in its rate of progress. Products like 0.5% sulfur diesel, which used to be standard road fuel, are being pushed into peripheral markets such as marine bunkers. The result has been that ever-greater value has been placed on scarce, low-sulfur fuels. The price differentials are so high that it is worthwhile to bring large volumes of low-sulfur crudes from West Africa and elsewhere in the Atlantic, despite the huge shipping distance.

Unfortunately, these are exactly the kinds of crudes that Hawaii refiners need to comply with environmental standards (see Chapter 3). Apart from Asia, the only major sources of these crudes are far from Hawaii, in the Atlantic Basin. This puts Hawaii buyers in competition for some of the world's most expensive crudes. (By contrast, California refiners have made such large investments in processing that they can handle some of the worst crudes in the world and still meet environmental specifications.)

There is no sign that this situation will change. Hawaii refiners must import expensive Asia Pacific crudes, or can search for better deals far away—in which case the transport costs make the crudes even more expensive by the time they are delivered.

The LNG Supply "Chain"

Back in the early 1990s, Fereidun Fesharaki famously remarked that, "Oil is like dating, but LNG is like a marriage." Although the market has evolved considerably over the ensuing quarter-century, the quote is often repeated, and the basic argument is still essentially true. Every port in the world has facilities for handling at least some oil-product imports or exports, and there are hundreds of ports that trade in crude oil. LNG, on the other hand, is a highly specialized commodity that requires expensive and relatively uncommon facilities at every step from the producer's gas field to the importer's gas system.

A traditional LNG "chain" usually starts at the producer's gas fields, where liquids and contaminants are stripped from the gas. Gas feeds for LNG need to be of a relatively precise composition. There are basically two "grades" of LNG, "lean" and "rich." Lean LNGs have slightly lower Btu content, and are composed of liquid methane and ethane, and tiny amounts of heavier gases. Rich LNGs are still mostly methane, but a considerable amount of ethane and some small volumes of LPG are included.

The pipeline or power generation systems of some users can handle only lean LNG (more common), while others can handle only rich LNG (common in Japan). Some, especially in Europe, have considerable flexibility. The result, however, is that not all sellers can sell to all buyers.

Once the gas is cleaned and stripped to the right concentrations of hydrocarbons, it enters a liquefaction plant, where the temperature of the gases is gradually lowered to -260° F. (The procedure is usually called a liquefaction "train" because the temperature is lowered through a number of sequential steps.) The LNG is then moved into insulated storage tanks, where it remains until it is picked up by an LNG tanker—a specialized vessel designed solely for moving LNG.

At the import terminal, the LNG is pumped into the importer's storage tanks. It is then run through as regasification unit as required by demand conditions.

All of these links in the chain represent large investments, and over time, the typical size of each element in the system has grown larger to get the lowest price per unit capacity. The first LNG liquefaction plants were typically under 1 million tonnes per year (usually abbreviated as mmtpa, million metric tonnes per annum). In the 1990s, the typical size was increased to around 2.5 mmtpa. In recent years, the Qatari “megatrains” have taken train sizes to nearly 8 mmtpa.

Most LNG projects will have more than one liquefaction train, and many LNG plants contain multiple projects built over the course of many years. For example, the Qatargas II project consists of two 7.8 mmtpa trains, totaling 15.6 mmtpa. But the Qatargas plant has seven different projects, totaling almost 41 mmtpa.

Compared to the world oil market, the world LNG market is quite small. Total LNG demand is around 242 mmtpa. That means that a single Qatari megatrain amounts to more than three percent of the world market; a project like Qatargas II is almost seven percent of world demand. By way of comparison with oil, a major 250,000 b/d refinery is less than one-quarter of one percent of world oil demand. Every liquefaction plant is an important element of the world market.

The cost of liquefaction plants varies tremendously depending on location; less than half of the cost is usually the liquefaction plant itself. Most major LNG export projects have been located near remote gas reserves; often ports, and even new cities, must be built.

In addition, the capacity for building major LNG projects is limited by the availability of engineering and skilled labor. The cost of liquefaction plants tended to fall steadily from the 1980s until the early 2000s, but a large number of new projects and shortages of labor and specialized fabrication facilities have caused prices to skyrocket. This is especially true with reference to the new, remote Australian projects. These projects have total costs of US$30 billion and up.

With tens of billions tied up in single projects, the companies involved cannot afford to take chances on the market. In general, LNG SPAs (sales and purchase agreements) are negotiated well before a project is complete, and memorandums of understanding are often concluded well before any final decisions taken. SPAs run from short term (less than four years) to medium term (four to ten years), and long term (more than ten years). Sales agreements running 15-20 years are not uncommon, binding the seller and buyer together for up to two decades.

Such long-term arrangements are needed to protect both parties. The market is not large enough for a buyer to be able to count on purchasing needed volumes whenever required. Even large volumes of oil are always available at some price, but in some situations there may be almost no uncommitted volumes of LNG. Similarly, the seller has a limited number of possible buyers, since the number of LNG import terminals around the world is quite limited.

In addition, most of the supply contracts in the world today include destination controls. That means that the seller generally cannot resell LNG that they buy to some other country, or reassign their contract. This is an attempt by sellers to control the market, and, as the next section will show, to date sellers have been quite good at establishing very different prices for different buyers (something that does not occur in a free and efficient market).

Both buyers and sellers, of course, must have access to LNG carriers (also called LNG tankers). LNG carriers typically cost around US$200 million. The typical LNG tanker holds around 145,000 cubic meters (cbm), equivalent to about 62,000 tonnes of LNG; but there are now vessels of up to 266,000 cbm (nearly 120,000 tonnes of LNG). The larger ships are too big to access many ports, and deliver such large volumes that they exceed the storage capacity of some smaller buyers.

LNG storage and regasification facilities are nowhere near as costly as liquefaction plants, but they can still be quite costly—from US$100 million to about US$2 billion for larger terminals. Much of this depends on the size of the facility, but often a large share of the cost is for constructing new port facilities. A number of US facilities invested large sums in LNG import infrastructure, and much of the cost was to ensure they could handle giant LNG carriers.

That, then, is the traditional LNG supply chain—buyers and sellers tied together through huge specialized investments and long-term contracts. On the supply side, most liquefaction projects have needed many millions of tonnes of capacity to be worthwhile, and it has been a rule of thumb that buyers need at least 1 mmtpa of demand for the economics of importing to work, and a higher number than that is considered far more workable.

There are signs that the traditional model is beginning to shift, however. Many of the multinationals involved in LNG are beginning to hold "portfolios" of LNG volumes from different locations that they can sell on to buyers without long-term dedicated contracts. Smaller buyers are beginning to enter the market, negotiating for supply volumes that are well below traditional economic sizes. Many of the new buyers are also refusing to lock themselves into long-term contracts, since they believe that contract prices today are higher than they will be by the end of the decade.

In addition, many of the newer buyers are choosing to keep much of their infrastructure offshore. FSUs (Floating Storage Units) and FSRUs (Floating Storage and Regasification Units) are essentially converted LNG tankers or dedicated structures permanently moored, and supplied by other LNG tankers that deliver new cargoes. Not only are such options often cheaper than onshore storage and regasification, the setup time is far less—usually 12 months before first LNG delivery, as opposed to 3-5 years for the traditional option.

The liquefaction link in the chain is also changing rapidly. Although the trend for decades has been toward larger and larger units, there is a growing market in the US for mini, small, and mid-sized liquefaction projects. There have always been small plants for peak-shaving—LNG liquefied locally and stored to ensure gas supply at times of high demand—but now there are small plants designed to feed fleet vehicles in cities, and a mid-sized plant in Boron, California, that ships LNG to the Ports of Los Angeles and Long Beach for their clean-fuel efforts. Although the Boron LNG plant is small (106 ktpa), its cost per annual tonne of capacity was far less than the megaprojects currently planned around the world. Other companies are looking into building small liquefaction plants at ports to supply LNG as bunker fuel.

One thing that is quite different about the new, smaller LNG projects in the US is that they are tied directly into the existing gas grid for their supply, rather than some remote, isolated gas field. This may mean somewhat higher feedstock prices, but it means that the gas supply is already clean and balanced, and that the supply can be ramped up to handle any desired future expansions.

Even the large LNG export plants now being debated in the US have a different approach. As in the past, the plant owners wanted to assure themselves that there would be buyers (or in some cases, buyers who are also investors). But instead of a long-term, destination-controlled linked to some external index, the new export projects so far seem to be adopting a “tolling” approach. The gas is delivered from the transmission system to the plant. The LNG buyer procures the gas on whatever terms it can negotiate, and the liquefaction plant simply charges a flat fee for every tonne of LNG processed. The price is then simply the gas price (probably linked to the Henry Hub gas spot price) plus the fee. The linkage of prices to pipeline gas prices, plus the lack of destination controls, is a major change in the nature of LNG contracts on the world market.

The Regional Structure of the LNG Market

Although natural gas is traded internationally, access to gas imports is far more restricted than access to oil imports. Almost every seaport in the world can import at least some volume of oil products; oil transport and storage use relatively simple and cheap infrastructure. The need to keep gas under pressure means that the only cheap place to store gas is under the ground.

Traditionally gas was moved by pipeline, and pipelines today continue to carry 70% of international gas trade. The other 30% of trade is via sea, in the form of LNG. Although LNG still contributes less than a third of world gas trade, LNG trade in 2010 expanded by 22%, as compared to a 5% expansion in pipeline gas trade.

For reasons of physical geography, much of the world is not suitable for pipeline trade in gas. Political geography can be an even greater challenge. Over the years, many plans for exports of gas via pipeline from the Middle East—such as the Iran-Pakistan-India “Peace Pipeline”—have foundered on the hard reefs of political realities.

In principle, LNG offers greater freedom of trade, but today there are only 18 LNG exporters in the world, and only 90 regasification plants. Many of the world’s largest gas producers do not have gas liquefaction. With limited pipeline connections in many areas, and limited trade in LNG, the gas market is inherently fragmented. In early 2012, gas was sold into Japan for as high US$18/mmBtu at the same time that wholesale prices were US$9/mmBtu in the UK, less than US$2/mmBtu in the US, and US$0.75/mmBtu in Saudi Arabia.

Although the market is fragmented, there are certain hubs that are generally taken as representative of the base price in the region. In the US, prices are generally linked to the spot prices at Henry Hub (HH), which is a physical hub in Louisiana that interconnects thirteen major pipeline systems.

The price of gas at various points in the continental US is generally given as a differential from Henry Hub. Henry Hub also serves as the delivery point for the New York Mercantile Exchange (NYMEX) futures contracts in natural gas. Because of the transparency of the Henry Hub spot market and the high liquidity offered by both spot and futures trades, Henry Hub is increasingly being used as a reference point for other gas contracts in the Western Hemisphere. Most LNG sales into North America are tied to Henry Hub prices, because those are the prices with which imports must compete.

In Europe, the liberalization of the natural gas market has led to the emergence of spot markets, mostly in Northwest Europe (mainly the UK, Belgium, and the Netherlands).

The most widely referenced price is the United Kingdom National Balancing Point (NBP—a notional point in the transportation system). In Belgium, natural gas is traded at the Zeebrugge Hub. In these countries and nearby areas, LNG contracts tend to be tied to those prices. The emergence of these markets is a comparatively recent phenomenon, however, in much of continental Europe LNG contract prices continue to be set by linkages to Brent or to the spot prices of gasoil and fuel oil.

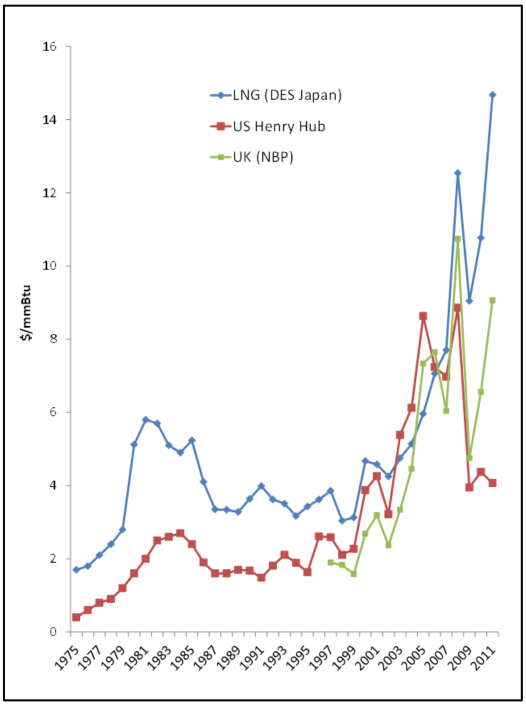
In many ways, Europe is the most complicated of the regional gas markets. There is substantial production in Europe itself (especially in the North Sea). There are large imports via pipeline, with Russia being the largest supplier, but also large imports from North Africa. (Turkey also imports pipelined gas from Iran.) Europe also imports substantial volumes of LNG from Africa, the Middle East, the Americas, and, on occasion, from as far away as Australia.

Asian LNG prices are generally linked to crude oil prices—in particular to the Japan Custom Cleared (JCC) price. (This is also referred to as the "Japan Crude Cocktail" price.) JCC is the average price of crudes imported into Japan every month and is published by the Ministry of Finance on a monthly basis.

Japan is the largest importer of LNG in the world, and accounts for over half of all the LNG imports in Asia. Japan, South Korea, and Taiwan have virtually no domestic gas production and no pipeline connections to other countries—and also have virtually no domestic oil production. These three countries have long formed the dominant LNG importing group in Asia, but they have recently been joined by China, India, and Thailand—countries that are short of energy resources, but nonetheless have substantial domestic production.

The figure below shows the key indicator prices for natural gas in the three major regions. As with most energy commodities, the history of international energy prices can be seen in the high prices of the early 1980s and in the first decade of the 2000s, but the correlations with the history of the oil market are not tight and the relationships are far from simple.

Figure 112: Regional Natural Gas Price Comparison

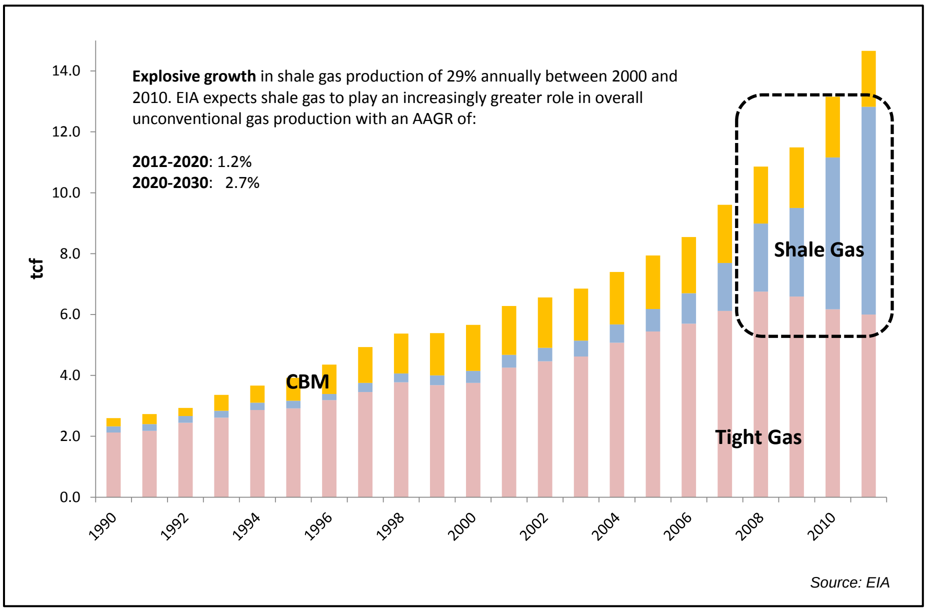


For most of the last three decades, the US and Europe experienced much lower gas prices than Asian importers. While Japanese LNG imports were firmly tied to crude, gas prices in the US and Europe were competing against pipeline supplies. This long-standing relationship reversed for the first time in 2003 in the face of North American gas shortages, driving Henry Hub prices above Japanese LNG imports. In 2005, Hurricane Katrina drove US gas prices to record levels. Since at the margin the US was reliant on LNG imports, competition for Atlantic Basin supplies carried NBP prices up as well. There were projections that the Atlantic Basin would begin to operate as an integrated regional gas market—and that the LNG trade would increasingly integrate international gas prices.

As the previous figure showed, though, by 2008, this "trend" evaporated. Atlantic Basin prices dropped back below Asian LNG prices. Moreover, US prices at Henry Hub moved off on their own trajectory, falling even as Japanese and NBP prices soared.

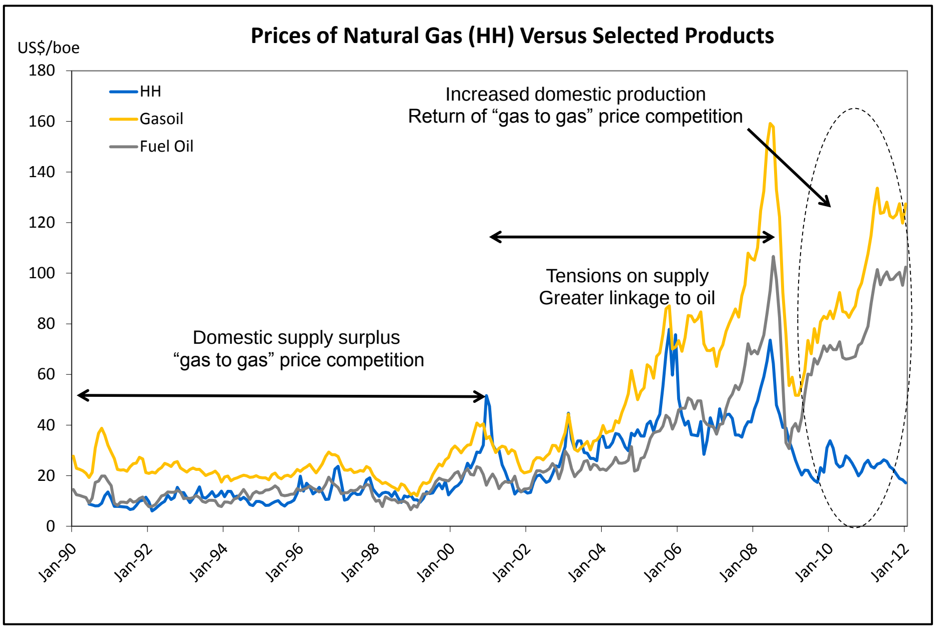
The cause of the change was the US "shale gas revolution." As illustrated below, after 2007 shale gas production began a period of explosive growth, augmenting stagnating supplies of tight gas and slow-growing supplies of coal-bed methane (CBM). Unconventional gas (shale plus CBM) accounted for about 36% of total US gas supply in 2011; unconventional gas plus non-traditional production (tight gas) made up 61% of total production.

Figure 113: US Shale Gas Revolution



The following figure shows the history of Henry Hub pricing against the prices of gasoil and fuel oil from 1990 to the present. Through the 1990s, Henry Hub prices were determined mainly by competition between North American sources of gas (including pipeline imports from Canada). As discussed above, supply shortages and increased reliance on marginal imports of LNG pulled US prices up sharply through 2008, but since that time oil prices have surged while gas prices have fallen sharply.

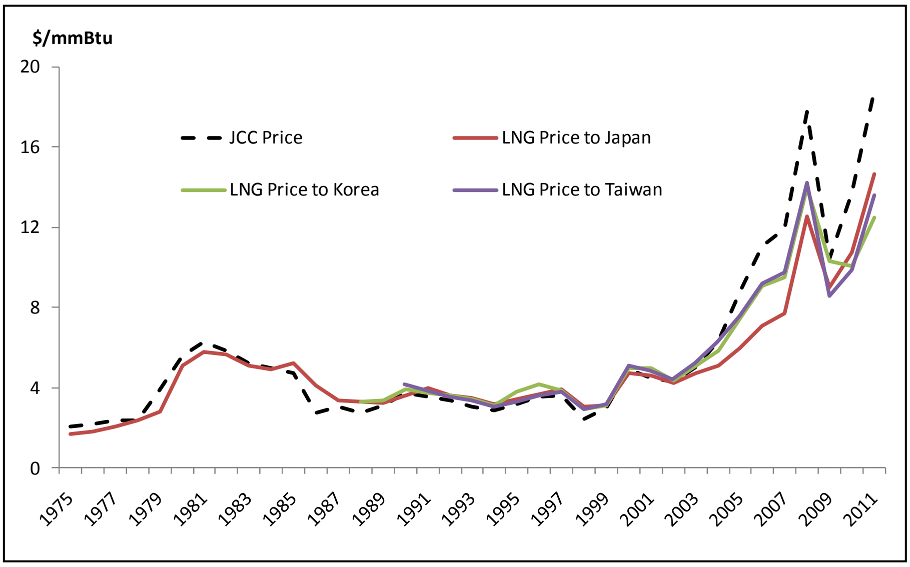
Figure 114: Decoupling of US Prices from Oil Markets



LNG prices in Asia followed a very different path. Increased oil prices resulted in increased LNG prices, but not on a one-to-one basis. Many Asian LNG contracts are linked to oil by "S-curves," which provide floors and ceilings in the direct linkage of prices to the JCC. In the 2003-2007 period, these were a factor in allowing Henry Hub prices to climb above Asian LNG prices.

In the face of higher oil prices, this discount relative to crude tended to strengthen Asian demand for LNG. The discount has been eroded in recent years, however. As figure shows, some Japanese contracts came due for renegotiation in 2010, and this tended to bump up in pricing levels—taking Japanese prices above Korean and Taiwanese levels. This increase in prices was exaggerated by the Japanese earthquake and tsunami, followed by the Fukushima disaster, which drove up Japanese LNG requirements. These additional supplies were obtained primarily through new short-term and mid-term contracts, often at prices well above those offered by existing long-term contracts.

Figure 115: Kick-in of 'S'-Curves in Long-Term Asian Contracts



In summary, although many expected a gradual convergence of prices in the main regional gas markets, the last few years have seen a great divergence. In 2011, Japanese prices were almost US$15/mmBtu, Henry Hub prices were a little over US$4/mmBtu, and UK NBP prices were a little over US$9/mmBtu.

To date in 2012, Japanese prices have continued to increase, US prices have continued to fall, and NBP prices have remained generally steady. The three distinct regional markets for gas have been restored. The expected increases in shale gas output in the US in coming years will ensure that the three markets will maintain very different pricing regimes.

The fact that there are three distinct regional gas markets does not mean that there are three distinct LNG markets. After all, LNG is less than a third of world gas trade, and less than 10% of world gas demand. In many major consuming countries, domestic production is by far the dominant source of supply.

Fortunately, it is possible to track almost all of the LNG volumes into the major markets from all of the primary suppliers. Price data is not quite as comprehensive, but all but a few percent of the transactions can be identified. The exporters and importers included in this exercise are shown below.

Figure 116: LNG Exporters and Regional Importers

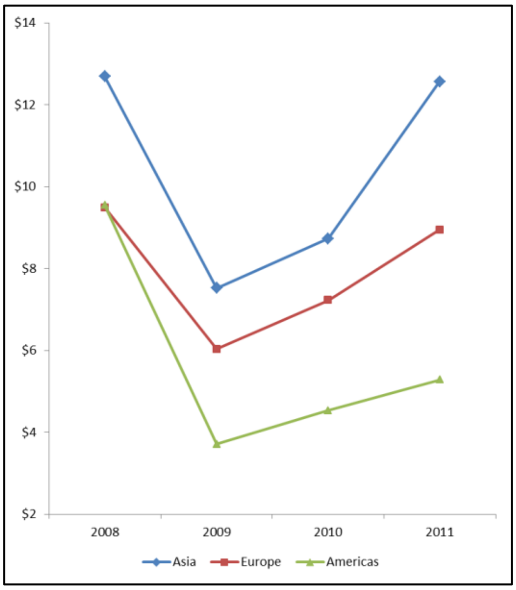
EXPORTERS	IMPORTERS		
	AMERICAS	*EUROPE*	*ASIA*
Abu Dhabi			
Algeria	Argentina	Belgium	China
Australia	Brazil	France	India
Brunei	Canada	Greece	Japan
Egypt	Chile	Italy	Korea
Eq. Guinea	Dominican Rep.	Netherlands	Taiwan
Indonesia	Mexico	Portugal	Thailand
Libya	Puerto Rico	Spain	
Malaysia	United States	Turkey	
Nigeria		United Kingdom	
Norway			
Oman			
Peru			
Qatar			
Russia			
Trinidad-Tobago			
United States			
Yemen			

Most countries keep price and volume data on imports, and the price data can be supplemented or cross-checked with knowledge of contract arrangements when known.

Of course, not every region imports from every exporter, but the trade network spreads quite wide. In our period of analysis, 2008-2011, out of the 18 exporters listed, the Americas imported from 11; Europe imported from 12; and Asia imported from 17 (all of the exporters except Libya).

Tabulating all available price and volume data allow for regional average import prices to be determined for each year. Those results are shown below.

Figure 117: Average LNG Import Prices by Region, 2008-2011 (US$/mmBtu)

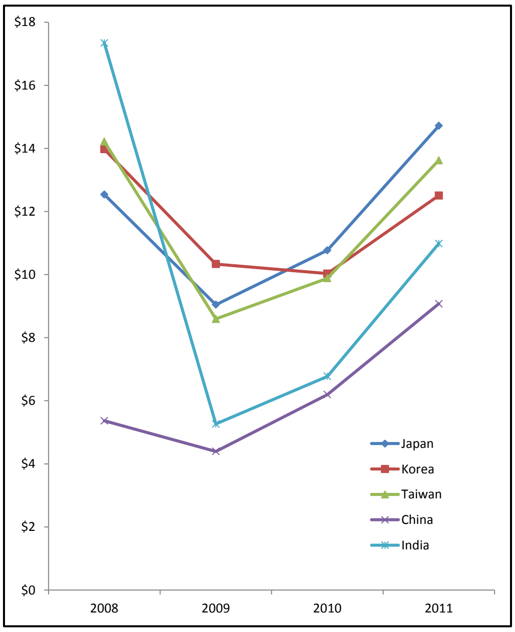


The results shown here confirm that the three regional gas markets also have three distinct patterns of LNG import prices. Although this was not a forgone conclusion, it stands to reason that LNG prices would have to reflect the general shape of the overall price trends displayed earlier; after all, LNG imports need to compete with the prices in each market.

A one-to-one correspondence between regional LNG import prices and spot-market prices such as Henry Hub or NBP should not be expected. Comparatively little LNG is sold on a spot basis—although contracts in the Atlantic Basin increasingly link the LNG price to spot prices. To some extent, the problem is circular, since LNG imports themselves affect the Henry Hub and NBP prices. (It should be noted that the influence of LNG imports on Henry Hub prices is declining rapidly as US imports of LNG plummet.)

Even in Asia, the relationship between the regional average price and the indicator price (Japan imports) is not simple. Although Japan dominates the regional average price because its imports account for more than half of the regional total, the newer buyers, China and India, show very different LNG prices.

Figure 118: Asian LNG Import Prices, 2008-2011 (US$/mmBtu)



Apart from the quirky price seen in India in 2008 (the result of a complex series of events), in general the newer importers are procuring supplies on better terms than the traditional importers (Japan, Korea, and Taiwan). Japan is now paying higher prices than Korea and Taiwan, and prices significantly higher than the regional average. As trade in LNG expands and more countries become LNG importers, the prevailing Japanese import prices become a less reliable guide to the overall LNG market in Asia. The region lacks a regional price marker or hub, and most contract prices are the outcome of bilateral negotiations; the variance between countries and even between contracts in the same country can be quite large.

The average prices diverge widely between regions; in 2011, the Asian regional average price was more than 40% above the European average price, and more than 150% above the average price in the Americas. Individual exporters must price their exports into a region so as to be in general alignment with these prices.

As Figure 112 showed, however, even the averages can mask large divergences between country averages in a region. What is clear from all of the data is that there is no such thing as a world LNG price.

Where does that leave Hawaii? The State sits midway between possibly the most expensive gas market in the world (Japan), and one of the cheapest (the US mainland). At Japanese prices, plus extra delivery costs to Hawaii, LNG might be about the same price as oil—around US$24/mmBtu. On the other hand, current US gas prices at Henry Hub are around US$3.30/mmBtu—less than 15% of Hawaii oil prices. The gap between

Henry Hub prices and the price of oil is so wide that it offers scope for substantial savings.

In addition, as discussed earlier, the LNG market is changing. The wave of projects under construction in Australia will make that country the world's largest exporter by 2020 (displacing Qatar)—although some people now project that the US will become the world's largest exporter. Most observers think that Asian LNG prices will tend to fall late in this decade. Indeed, were it not for Fukushima, prices might be on a downward trend already.

Power Generation Terms and Technology

This is not the place for a wide-ranging discussion of power generation technologies, but a few basic concepts need to be understood.

Thermodynamic Concepts

Thermal Efficiency: Thermal efficiency is simply the Btus of electricity generated from a given number of Btus of fuel. To complicate matters, electricity is generally measured in kilowatt hours (kWh), a unit of energy that contains about 3,412 Btus.

To take a simple example, an oil-fired power plant might generate 97 kWh for every 1 mmBtu of fuel burned. In this case, the efficiency is

Btus Out / Btus In = (97 kWh x 3,412 Btu/kWh) / 1,000,000 Btus = 33.1%

For hydroelectricity, wind, solar, nuclear, and other sources, the efficiency is less meaningful, since the input energy is either free (hydro, wind, solar), or negligible compared to the capital costs (nuclear). But thermal efficiency is critical in understanding and comparing fossil fuels.

Heat Rate: The heat rate is in many ways the thermal efficiency flipped upside down: it is the number of Btus needed to generate a kWh. Typical heat rates on Oahu are in the range of 10,000-11,000 Btus/kWh—but there are some plants that are much higher or lower. The lower the heat rate, the more efficient the process.

Types of Thermal Generation

There are really only two major ways of generating electricity from combustion—steam turbines and combustion turbines. Unfortunately, they are known by several different names!

Steam Turbines: These are the traditional form of power generation from combustion. The fuel is burned under a boiler to generate steam; the steam turns a turbine to generate power. The technology is quite common across a variety of fuels. Most coal plants are steam turbines, and nuclear plants are simply units where the nuclear fission heats water and turns a steam turbine. Even some large-scale solar power plants, such as that in Daggett, California, concentrate sunlight to create steam to turn a steam turbine. The majority of power in Hawaii is generated from steam turbines.

Steam turbines have limits on their efficiency. Although some manage to convert 37% of their input energy into electricity, 30-34% is more typical. On Oahu, most of the steam turbines operate in the 30-34% efficiency range (heat rates of 10,000-11,000 Btu/kWh) but some that are used for peaking power (see below) have efficiencies of only about 25%. Steam turbines are slow to bring up to full power production from a "cold start," so if variations in power demand are expected, they are often kept running at low rates of power output—a procedure called "spinning reserve." The advantage of spinning reserve is that it can power up quickly; the disadvantage is that it is still burning fuel rather inefficiently when it is not generating significant power.

Gas Turbines: These, in both simple and combined cycle setup, are discussed in length in Chapter 1.

Operational Concepts

There are many terms in power operations. Several of them are critical to understanding the possible role of gas and renewables in Hawaii's energy outlook.

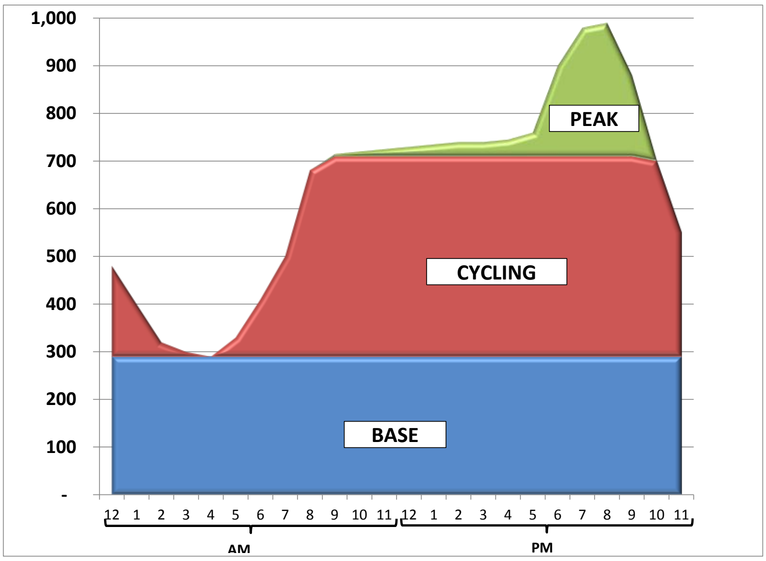
Baseload Plants: Baseload power plants are intended to be run at high utilization, around the clock. In effect, their output is typically flat. Because of this, the baseload capacity in a system is by definition less than the minimum power demand—that is, there is always room for a baseload plant to run. This is generally the most efficient way to run a plant. All other things held equal, it also results in the lowest capital costs per kWh, since the plant generates the maximum amount of electricity from its capacity.

Cycling or Intermediate Plants: Cycling or Intermediate plants run at fairly high utilization during much of the day, but are largely idled during periods of low demand (usually in the hours after midnight and before dawn).

Peaking Plants: Peaking plants are run only for short periods of the day, during periods of high demand. All other things held equal, these tend to have the highest capital costs per kWh, because the capacity sits idle most of the time.

The figure below shows a highly simplified view of the role of Baseload, Cycling, and Peaking generation in meeting the needs of a utility whose maximum demand is near 1,000 MW.

Figure 119: Example of Baseload, Cycling, and Peaking Capacity (MW)

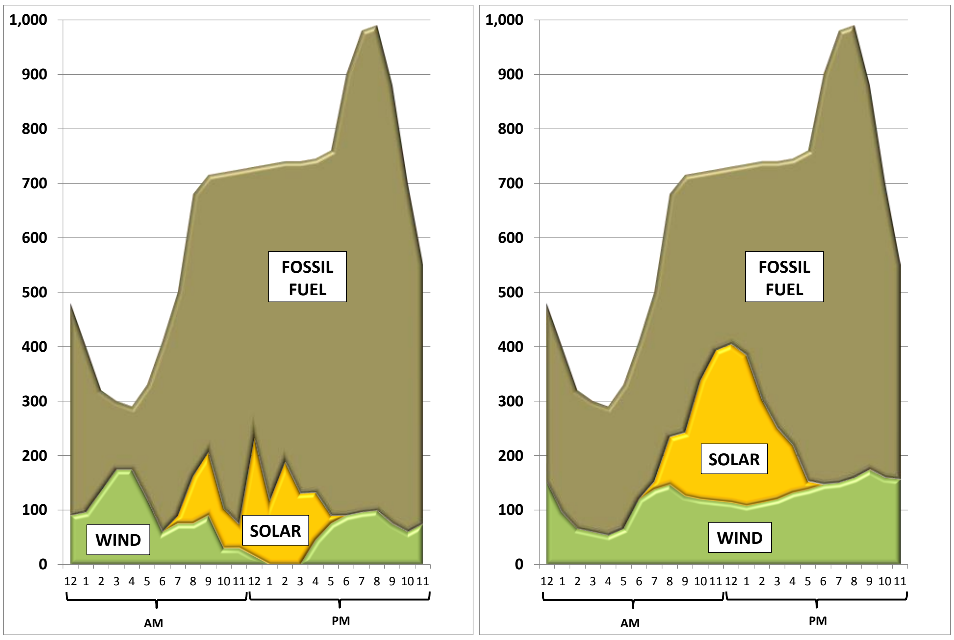


Dispatchable and Non-Dispatchable Generation: Dispatchable generation is the capacity that the operator can choose to utilize or not utilize. In general, fossil-fueled power plants are "highly dispatchable," in that the operator can run them or turn them off (or cycle them down to lower levels of operation).

Non-dispatchable generation is "use-it-or-lose-it" power. The best examples are wind or solar power, which must be used whenever they are available, and may without notice become entirely unavailable. In general, renewables are thought of as non-dispatchable, intermittent power sources, but this applies mainly to wind and solar; most biofueled plants, as well as geothermal and OTEC, are dispatchable and non-intermittent. (Although they are technically dispatchable, OTEC and geothermal tend to be run at high utilization, as their capital costs are high and their fuel costs are zero.)

Intermittent, non-dispatchable power sources such as wind and solar force the dispatchable portion of the generation mix to adapt. The figure below gives an example of what may happen with a daily load curve with a set amount of solar and wind included in the utility grid, but on days with clouds and fluctuating wind as opposed to days with predictable sunshine and steadier wind.

Figure 120: Example of 590 MW of Intermittent Renewables on Different Days

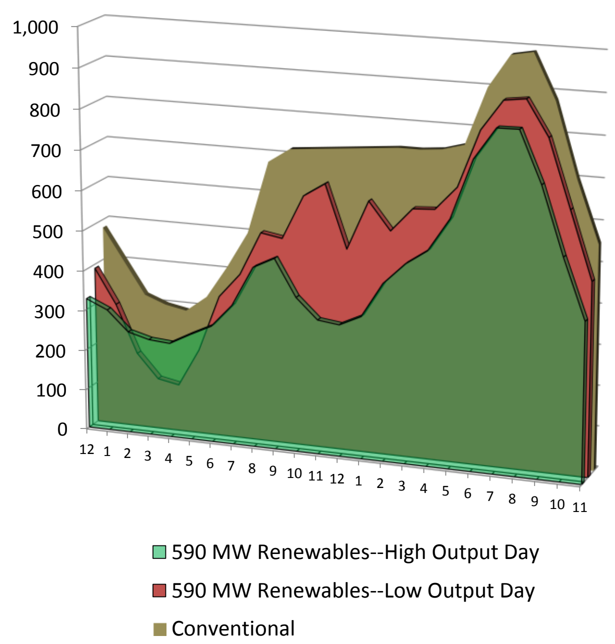


The net effect is to change the pattern of utilization for the fossil fuel plants. It not only makes the pattern of demand less certain from day to day, but also from minute to minute. From the point of view of the dispatchable plants, the peaks tend to get sharper and the valleys tend to get deeper. In fact, the absolute peak, which tends to be in the evenings, might stay as high as it ever was.

Another effect is to cut away at the whole concept of baseload generation—at least as far as fossil fuels are involved. (In fact, recently there have been articles proclaiming that "baseload power is dead"—although this pronouncement seems a bit premature.) The net effect is to cut the use of fossil fuels—but it may not cut the total amount of fossil-fuel generation capacity needed by a utility.

The figure below shows the implications of the previous example for the call on fossil-fuel generation in the previous two examples. The smooth curves become rougher, and the daily variability increases.

Figure 121: Fossil Fuel Generation Pattern Implied by Example Above



This is not an attempt to suggest that intermittent renewables are unworkable or uneconomic. The point is that when intermittent, non-dispatchable power is introduced into a utility grid, it creates new kinds of demands on the conventional power plants, which must engage in "load-following," which means that they must bridge the gap between what the renewables are providing and whatever the customers are demanding.

This means faster response times, more peaking and cycling capacity, and less baseload. If steam turbines are the main source of power generation, those turbines will have to spend more time as spinning reserve, ready to ramp up and down, than running at high utilization. Steam turbines can perform load-following, but no one would argue that it is optimal.

Gas turbines running natural gas have done a flourishing business in areas such as California and Germany, where renewables have been rolled in by government mandate. In California, this began well before US gas prices began to fall, simply because it was the cheapest and most efficient way of dealing with the new fluctuating supply of wind power. In Germany, it has happened despite the fact that German gas prices are very high. There is good reason to argue that gas turbines, and, to a lesser extent, CCGTs, are the only practical solution to large quantities of intermittent renewables in the grid.

Puerto Rico: A Precedent for Hawaii?

This section of the Appendix looks briefly at Puerto Rico's initial foray into LNG imports. Although not originally part of the Scope of Work, the Consultant was asked to provide an overview of the factors behind Puerto Rico's decision to import LNG, and describe the structure of the Commonwealth's first LNG project. After all, there are some similarities between the energy supply/demand profiles of Puerto Rico and Hawaii. By briefly looking at the practices adopted by energy companies and Puerto Rican government officials to bring LNG to the Commonwealth, the Client could—after much further discussion and analysis—determine whether Puerto Rico's experiences offer any sort of precedent for a Hawaii LNG import initiative, and if so, whether even some of the solutions adopted by Puerto Rico are transposable to Hawaii.

Puerto Rico and Hawaii's energy markets have many common elements:

- They are islands isolated from the vast and competitive Continental United States energy markets;
- Both are extremely dependent on fossil fuels (namely, oil) in primary energy use and power generation. Consumers in Puerto Rico and Hawaii pay much higher prices for electricity than their mainland counterparts;
- Neither island produces crude petroleum to supply their needs and is therefore highly dependent on imports;
- Puerto Rico and Hawaii both support cleaner energy initiatives and view their power generation facilities as key for realizing cleaner environmental objectives; and
- Puerto Rico and Hawaii are dominated by a single large power producer/distributor, unlike the far more competitive mainland US markets.
    - Puerto Rico's power sector is overseen by the Puerto Rico Electric Power Authority (PREPA), the public corporation responsible for the generation, transmission, and distribution of electricity on the island;
    - Hawaii is dominated by Hawaiian Electric Industries Inc., which is the largest supplier of electricity in the State of Hawaii, supplying power to the vast majority of Hawaii's population through its electric utilities: Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited; and

- Both PREPA and the Hawaii Electric group of companies must maintain a relatively high reserve margin due to their inabilities to import power from external sources.

In 1993, the Government of Puerto Rico instituted a new energy policy that proposed to diversify fuels used for power generation; increase the PREPA system's capacity, and allow private sector participation in the design, construction and operation of two new power plants. Puerto Rico was at the time 98-99% dependent on fuel oil (much of it high sulfur No. 6 oil) for power generation. PREPA duly sought proposals for the Commonwealth's first independent power generation plants under the federal Public Utility Regulatory Policies Act (PURPA) of 1978. PURPA's passage forced regulated, natural monopoly electric utilities to buy power from other more efficient producers, if that cost was less than the utility's own "avoided cost" rate to the consumer. The EcoEléctrica LNG import terminal and associated power plant was conceived by joint-venture partners Enron (50%) and Edison Mission Energy (50%)[24] in response to PREPA's request for proposals. PREPA evaluated about a dozen bids and announced the winners around 1995: a coal-fired venture and the EcoEléctrica project.

The EcoEléctrica project has multiple components:

- A baseload LNG tanker discharge terminal located on a 36-acre site on Punta Guayanilla Bay in Peñuelas. The terminal had an initial sendout capacity of 93 mmcf/d[25] and possessed a single 160,000 cubic meter storage tank and a single unloading berth;
- A combined cycle cogeneration plant with a nominal capacity of 545 MW. (Only 507 MW of this capacity is contracted.) The power plant was designed to run on LNG, LPG, and distillate fuel oil (No. 2 low-sulfur fuel oil). PREPA bought the electricity generated by the power plant under a 22-year Power Purchase Agreement (PPA). The PPA commenced in 2000; and
- A desalination plant to supply all the water needed for the plant's operations. Excess water production is sold to PREPA for use in its generating plants, and to the Puerto Rico Aqueduct and Sewer Authority for use in local markets.

As a US territory, the EcoEléctrica project was subject to US federal laws and regulations governing the importation of natural gas and LNG terminal siting/permitting/construction/operation. The Federal Energy Regulatory Commission

[24] The project is now owned by Gas Natural Fenosa (47.5%), Edison (50%), and General Electric (2.5%).
[25] Expanded sendout capacity (another 93 mmcf/d tranche) entered service in the summer of 2012.

(FERC) and the Office of Pipeline Safety vetted the project's safety and security provisions. FERC also led the preparation of the project's Environmental Impact Statement (EIS) to satisfy the requirements of the National Energy Policy Act (NEPA). The Puerto Rico Planning Board had authority over location approval and land use control, and assisted FERC with the preparation of the EIS to satisfy the conditions spelled out by NEPA. The project's permitting, financing, and contract finalization were completed in late 1997. The power plant went online in December 1999 and initially operated on LPG. The LNG terminal was ready by July 2000, at which point the power plant began burning regasified LNG.

EcoEléctrica's business structure is best described as a "downstream integrated import project." This is one where the import facilities are tied to one or more specific offtakers, like a power plant, a gas pipeline, or a seawater desalination plant. (Other examples include the troubled Dabhol project in India and the AES Andres project in the Dominican Republic.) Generally, what distinguishes this type of project is the common ownership of all the different components of the project, either under a single owner or affiliated ownership within a single group.

EcoEléctrica has access to the LNG receiving terminal, storage, regasification and send-out facilities by virtue of its direct ownership of the terminal facilities, but Enron also signed an LNG tolling services agreement which provided for future LNG throughput unrelated to the associated power plant facilities. (This tolling agreement, which gives EcoEléctrica additional revenues from volumes supplied to other facilities through its LNG terminal, was picked up by Gas Natural (now Gas Natural Fenosa) when it purchased Enron's share of the business in 2003.) A Kenetech affiliate served as the administrative manager for the project.

EcoEléctrica was also responsible for procuring the LNG required to support the project. The joint venture duly signed a 20-year LNG sale and purchase agreement with Cabot LNG[26] for roughly 0.5 million tonnes per annum (mmtpa) of LNG from the greenfield Atlantic LNG export project in Trinidad.[27] This translated to nine or ten cargoes annually, according to the SPA. Cabot, which owned a small stake in the then-single train Atlantic LNG project, contracted for a total of 1.8 mmtpa from the Trinidadian venture, some of which went to Puerto Rico with the remainder destined for its Everett import terminal in the northeast US. The price of LNG delivered to Puerto Rico is partly Henry Hub-based, but the formula has other components, namely

[26] Cabot was subsequently acquired by Tractebel, which is now part of the GDF SUEZ conglomerate.
[27] This project has since been expanded and features a total of four liquefaction trains.

linkage to the Puerto Rico Consumer Price Index plus indexation to propane prices—specifically, [US Gulf Coast] Mont Belvieu propane prices.

PREPA remains concerned about the fuel oil's share of the nation's power generation mix and is undertaking a large-scale conversion of several fuel oil-powered generation facilities to natural gas. Additional LNG import capacity in Puerto Rico is required to support these conversions. A detailed discussion on these newer power plant/LNG developments in Puerto Rico is outside the scope of this Appendix, but it is fair to surmise that Puerto Rico's LNG demand will increase as more conversions are completed and sufficient quantities of LNG are procured to feed them:

- A recently-commissioned (albeit small) expansion of EcoEléctrica's sendout rate yields some of this required additional LNG import capacity. Regasified LNG will flow from the terminal to the 990 MW Costa Sur power plant via an existing pipeline pursuant to a tolling agreement between EcoEléctrica and Gas Natural Fenosa. The Spanish company makes available to the Authority, subject to the payment of certain fees and costs, services at the EcoEléctrica terminal including the berthing of LNG vessels; the unloading, receipt, and storage of LNG for PREPA's account; regasification; and the transport of regasified LNG via the terminal's tailgate pipeline to the power plant. The terms of this tolling services agreement expires in August 2020. Gas Natural Fenosa also procures the LNG required to support this arrangement: in April 2012, the company announced the startup of a two-year LNG supply contract with PREPA for 2 billion cubic meters (bcm; 1.5 mmt) of LNG over the whole period. The LNG is supplied from Gas Natural Fenosa's global LNG supply portfolio.
- New LNG import capacity will also supply some of the fuel needed to support PREPA's plant conversions. For example, Excelerate Energy is developing plans to station a floating, storage, and regasification unit (FSRU) about four miles offshore the southern coast of Puerto Rico. Known as the Aguirre GasPort®, this new facility will provide fuel to the 1,500 MW Central Aguirre power plant. Some of this power plant's capacity has already been converted to run on natural gas.