Economics of Accelerating Hawai‘i’s Energy Transition via LNG and other Alternative Fuels

Prepared for The Hawai‘i State Energy Office
August 2024

Contents

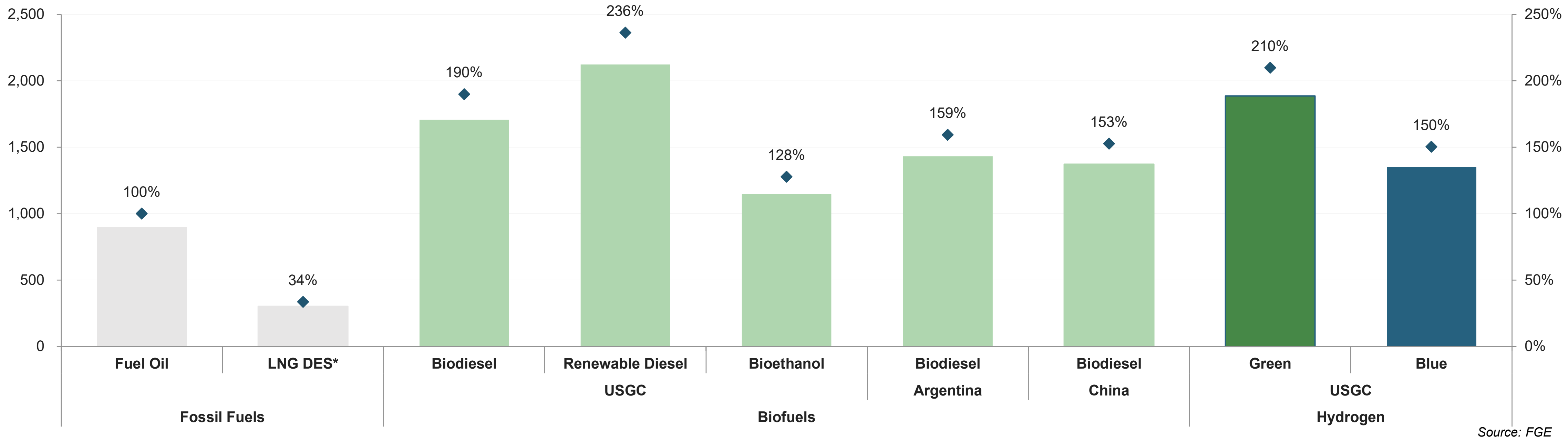
Click on the Table of Content Icon to Return Back

1. Executive Summary

Comparing costs of various alternative fuels for Hawaii (2024 estimates)

Based on 2024 commodity prices, LNG is the most cost-effective fuel for Hawaii

Cost of Alternative Fuel to Replace Fuel Oil Use in Power Generation based on 2023 Power Generation Data, US$ million and % of LSFO cost



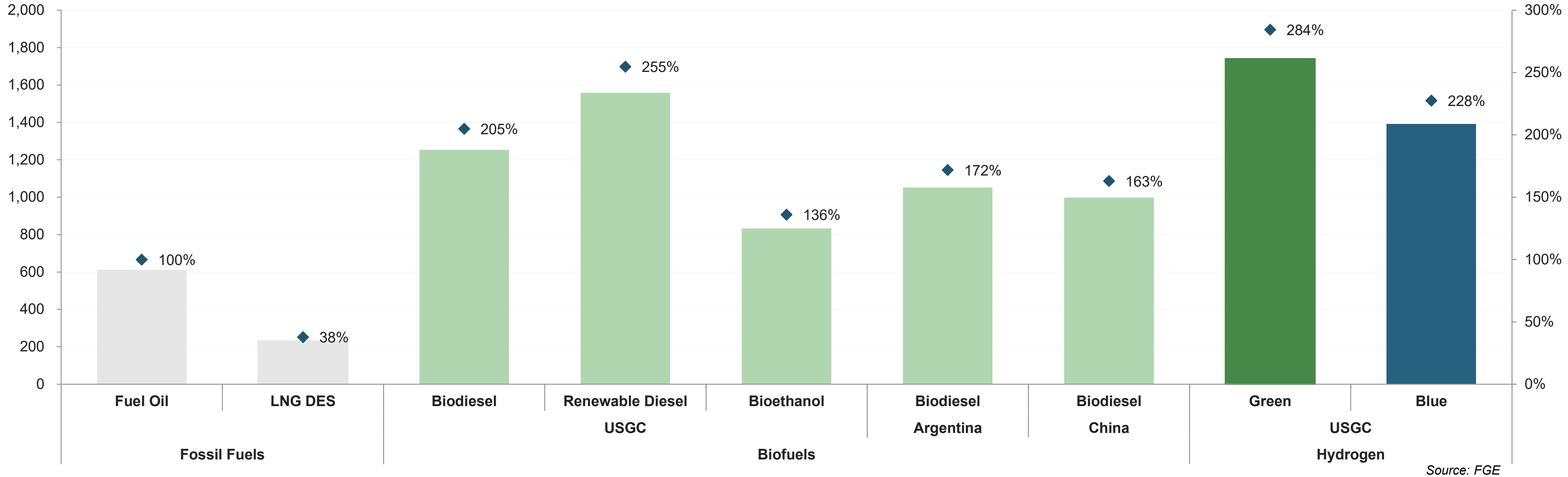
Source: FGE and DBEDT
**Assumes 1 mtpa under FSRU charter*

- Other than LNG, which would have presented cost savings of over 60% to low sulphur fuel oil (LSFO), alternative fuels for Hawaii's energy sector currently carry higher costs than LSFO.
- Efficiency rates and the energy content of various fuels significantly impacts power generation costs. In this analysis we are assuming 32% efficiency for petroleum products and LNG and 40% for biofuels. If new combined cycle gas turbine (CCGT) power plants are built, LNG efficiency will increase to 60% (see next slide).
- Green hydrogen, remains more expensive than biofuels, making it economically unviable in the short term, whereas blue hydrogen begins to compete with certain biofuels.
- Biodiesel sourcing options include Argentina, China, and the US Gulf Coast, but all involve price premiums compared with conventional fuels.

Comparing costs of various alternative fuels for Hawaii (2040 estimates)

Based on 2040 commodity prices in real US$ 2024, LNG is still the most cost-effective fuel for Hawaii

Cost of Alternative Fuel to Replace Fuel Oil Use in Power Generation based on 2023 Power Generation Data , US$ million and % of LSFO cost



Source: FGE
**Assumes 1 mtpa under FSRU charter*

- Looking forward to 2040, LNG is still by far the most cost competitive fuel option. In this analysis we assume LNG will be running in a new CCGT with efficiency at 60%. We assume the same efficiency rates for petroleum products and biofuels as the previous slide.
- Most other alternative fuels such as biofuels and green hydrogen see their costs drop. The only exception is blue hydrogen as the cost of natural gas in the US is expected to increase in 2040 compared to 2024 levels, thereby increasing costs for blue hydrogen from natural gas.
- While absolute power generation costs drop for all fuels, the % cost increase is higher vs LSFO in 2040 due to lower LSFO prices in 2040 ($80/b) compared to 2024 ($130/b).

LNG for Hawai‘i: Background and Assumptions (1)

The timing is right for Hawai‘i to take advantage of a global LNG surplus in the late 2020s; linking to oil guarantees a discount on petroleum products as well as providing a cleaner burning fuel source

- FGE has built a model looking at “All-in” costs for Hawai‘i to secure long-term (10-year) LNG supply via a floating, storage, and regasification unit (FSRU) that would be moored offshore Kalaeloa and commence in 2030. The following variables and costs have been assumed:

  - LNG demand scenarios of 0.4 million tonnes per annum (mtpa), 0.7 mtpa, and 1.0 mtpa. Demand would stem primarily from the power sector wherever oil is consumed in the State and to a lesser degree replacement of HawaiiGas’ SNG volumes and part of their non-utility gas volumes on Oahu. Moreover, additional demand could be created for LNG bunkering (i.e., Matson ships), power generation on military bases, and the transport sector (buses/garbage trucks, etc.).

  - A standard “vanilla” LNG supply contract that does not have any exotic “non price” terms such as the ability to flex up or down more than the standard 10% of the annual contract quantity, the ability to cancel a significant number of cargoes every year, etc.   Hawai’i could tender for a supply contract that has volumes ramping down in the later years, but this is impossible to model as it is project specific and negotiations over several other non-price terms would impact the price formula. Therefore, we have chosen an end date of 2040 for a standard LNG supply contract with straight line offtake. Further action could be taken for additional LNG imports beyond this date if warranted.

  - CAPEX costs for all associated infrastructure in this economic analysis have been provided by HDR (under contract with HSEO), while FGE has provided the fuel price forecasts for Brent, LSFO, and LNG delivered to Hawai‘i. While these CAPEX costs are preliminary, they provide the most updated cost estimates whereas previously the most recent data had come from HawaiiGas in their 2016 PSIP filing.* These figures are conservative and further engineering studies could result in even lower figures. The CAPEX numbers include the following:
    - US$300M for the FSRU, if one were to buy and convert an existing LNG ship; alternatively, the FSRU could be chartered at US$150,000/day.
    - US$108M for the buoy system for the FSRU and the sub-sea pipeline.
    - US$25M for onshore pipeline extension to Kahe and Wai‘au.
    - US$30M for an LNG import terminal on O‘ahu.
    - US$60M for storage on O‘ahu.
    - US$120M for a Jones Act-compliant ATB Barge.
    - US$58M for neighbor island (Hawai‘i /Maui) import facilities and LNG ISO containers for neighbor islands.

  - Note these costs are just looking at fuel costs and associated infrastructure to bring LNG to Hawaii and do not include CAPEX costs for any new power plants. Power plants will need to be upgraded regardless of the fuel supply source given the age of the existing fleet.

** Table 3, page,10. HawaiiGas response to HECO’s PSIP in January 2016*

LNG for Hawai‘i: Background and Assumptions (2)

The timing is right for Hawai‘i to take advantage of a global LNG surplus in the late 2020s; linking to oil guarantees a discount to petroleum products as well as providing a cleaner burning fuel source

- FGE is confident that Hawai‘i could get a delivered LNG price with a slope of around 11.8% Brent plus a constant for volumes of at least 0.4 million mtpa over 10 years, commencing in 2030. This is assuming a standard "vanilla" LNG supply contract. Similar deals have been signed for LNG buyers for delivery around this timeframe and prices could even come down further given the upcoming supply pressure on the market. The formula we are using for this analysis is P(LNG)=.118*Brent+0.60
  - For example, at US$80/b the price of LNG delivered to Hawai‘i would be: 0.118*80+.60= US$10.04/MMBtu
  - FGE's model allows for sensitivity analysis based on various potential "slope" offerings to see what the impact would be on the overall fuel price.

- FGE has also built a model for the FSRU costs that would allow Hawai‘i to either own the vessel or charter the vessel.
  - Purchasing the FSRU coupled with the infrastructure costs (US$700M) mentioned earlier would yield the lowest cost regasification tariff. The tariff decreases as throughput volumes increase, as economies of scale have a significant impact on FSRU costs. For example, the regas tariff at 1.0 mtpa would be $1.68/mmBtu, while the tariff would increase to $3.93/mmBtu at volume of 0.4 mtpa.
  - Chartering the vessel for 10 years coupled with the infrastructure costs (US$400M) mentioned above would cost slightly more than purchasing the FSRU. The regas tariff at 1.0 mtpa would be $1.93/mmBtu, while the tariff would increase to $4.55/mmBtu at volume of 0.4 mtpa.
  - The prices above need to be added to the fuel cost to get an "All-in" cost for LNG delivered to HECO's Kahe and Wai‘au power plants as well as Kalaeloa Partners.

Changing investment costs and import volumes (FSRU purchase scenario)

Hawai'i would need to import more than 0.4 mtpa of LNG to justify the economic investment vs continuing to burn LSFO; 1 mtpa yields significant savings

Investment Cost (US$ million)	Regas Tariff (US$/MMBtu)
400	1.25
450	1.32
500	1.39
550	1.46
600	1.54
650	1.61
700	1.68
750	1.75
800	1.82
850	1.90
900	1.97
950	2.04
1,000	2.11

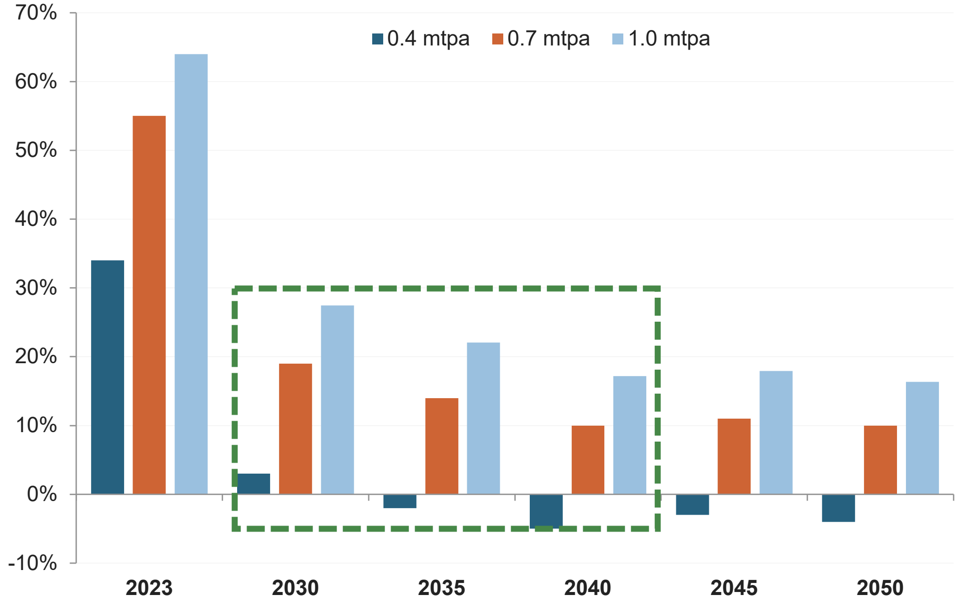
LNG Imports at US$700 million Base Case Investment Scenario (mtpa)	Regas Tariff (US$/MMBtu)	Average Annual Savings vs LSFO*
0.2	7.67	-19%
0.4	3.93	4%
0.6	2.68	15%
0.8	2.06	21%
1.0	1.68	25%
1.2	1.43	28%
1.4	1.26	30%
1.6	1.12	32%
1.8	1.02	33%

Source: FGE
** 2030-2040*

Hawai‘i LNG imports make economic sense if volume is above 0.4 mtpa

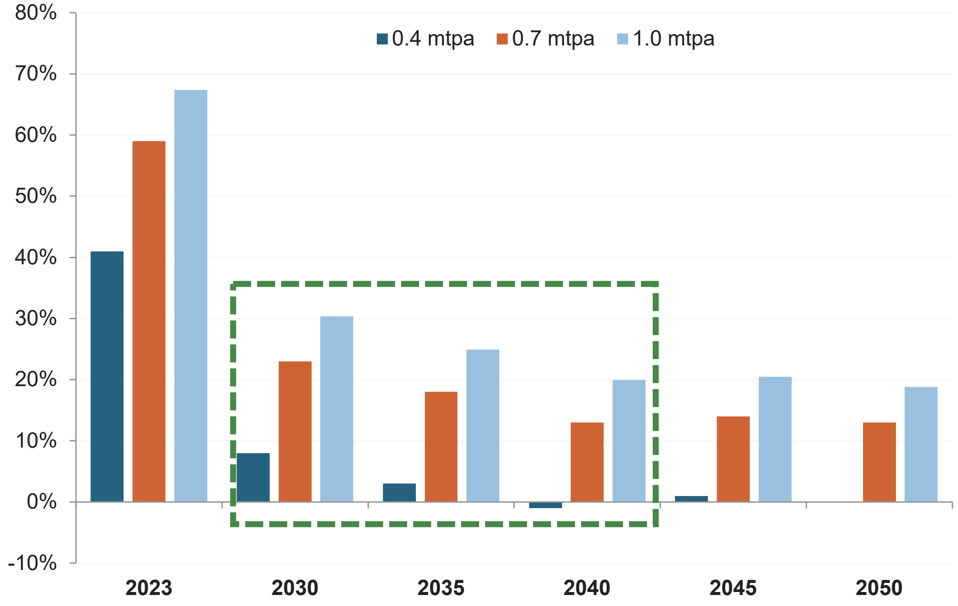
Higher LNG imports bring down FSRU costs as economies of scale are critical

LNG “All-in” % Savings Versus LSFO: FSRU Charter



Source: FGE

LNG “All-in” %Savings Versus LSFO: FSRU Purchase

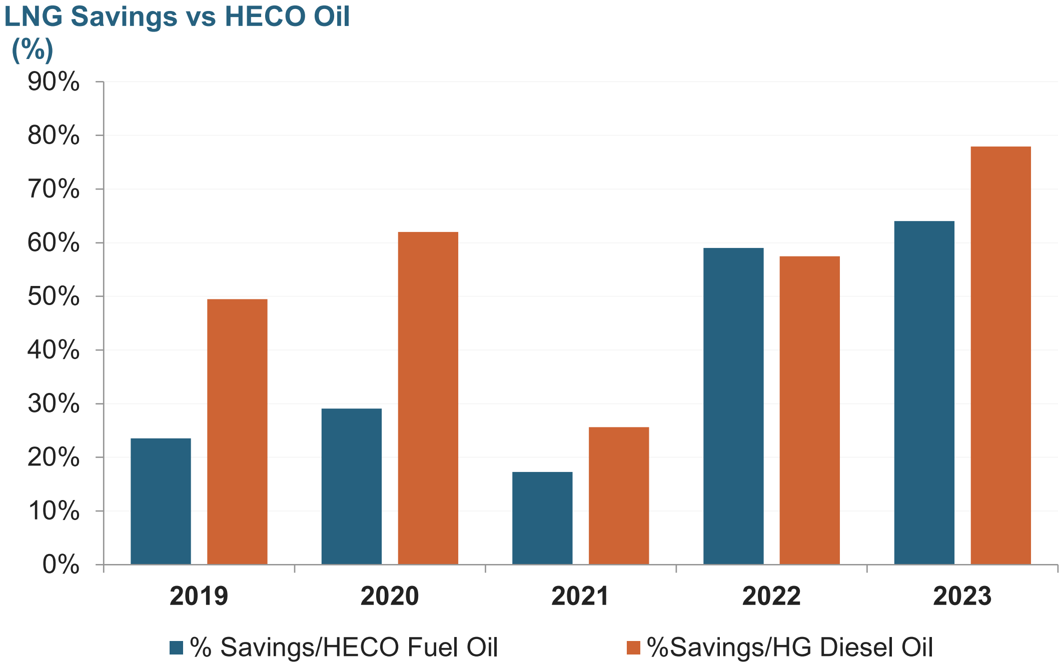


Source: FGE

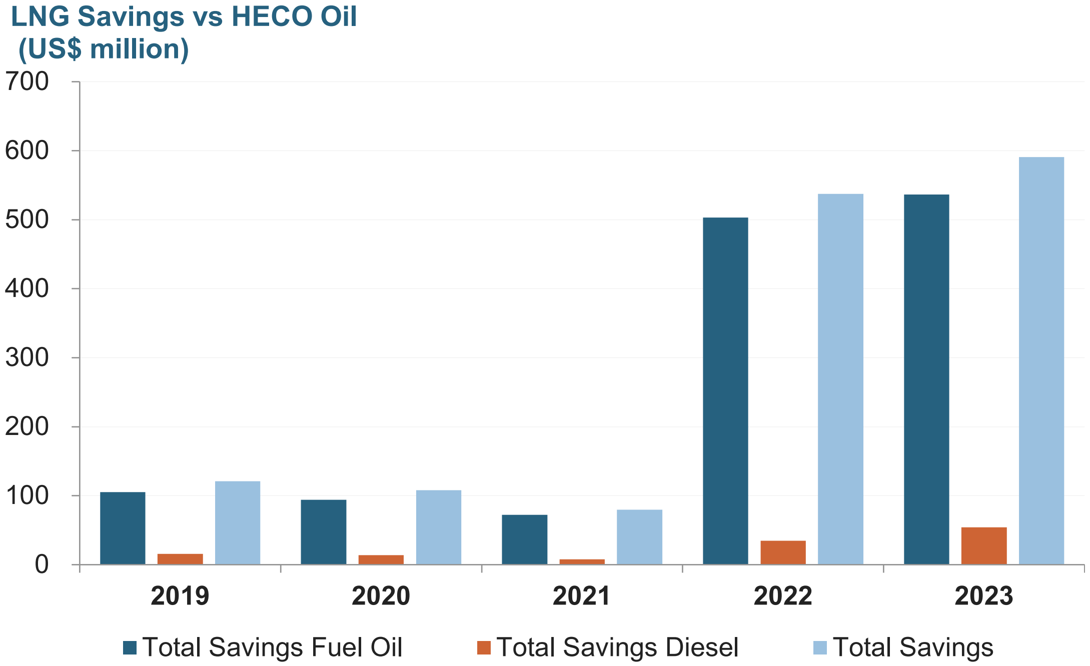
- LNG imports at 0.4 mtpa provide environmental benefits compared to LSFO but zero savings under the FSRU charter scenario. There are minimal savings under the FSRU purchase scenario at this volume.
- LNG imports at 0.7 mtpa provide environmental benefits compared to LSFO and noteworthy economic savings of potentially hundreds of million of dollars over the 2030-2040 period under both scenarios.
- LNG imports at 1.0 mtpa provide environmental benefits compared to LSFO and potential savings in the billions of dollars, benefiting all citizens, but especially ALICE families, under both scenarios.

Backcast shows significant savings for Hawai‘i even with the FSRU under charter

Savings during the 2019-2023 period would have been more than US$1.4 billion over the 5-year period if Hawai‘i imported 1 mtpa of LNG instead of burning oil for power generation.



Source: FGE



Source: FGE

- Hawai‘i could have had SIGNIFICANT fuel savings if it had imported LNG instead of burning LSFO and diesel over the last several years, even under the more expensive charterer model for the FSRU. Moreover, it would have lowered carbon dioxide emissions by 2.9 billion pounds annually, equivalent to removing more than 250,000 cars from Hawai‘i’s roads.
- If Hawai‘i were to purchase the FSRU the savings would have reached over US$1.5 billion over the last 5 years.
- **Indexing your LNG supply contract to oil ensures that Hawai‘i will get a fuel discount to alternative oil products and provides a firm, and cleaner burning fuel source which can complement intermittent renewables.**

What happens to Par if LNG replaces LSFO in Hawai'i?

The most likely outcome is a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal; other options can cost hundreds of millions of dollars

- Should Par lose its fuel oil and naphtha sales contracts with HECO and Hawai'i Gas, they have two decisions to make:
  1. Keep the refinery running or shut down refining operations
  2. Should they decide on the latter, the options would be whether to convert the site to an import terminal, a biofuels refinery, both (i.e., a smaller biofuels plant as well as an import terminal for conventional fuels), or total shutdown of all operations at the site.
- To answer the above questions and find the best commercial solution for Par Pacific regarding their Hawai'i refinery, a proper market study and financial model is required.
- Summarizing the points in Section 7 of the study, we can conclude the following:
  - It is unlikely that importing crude oil (from Africa and Latin America) and exporting naphtha and fuel oil to Asia is an economic option given exposure to long-haul freight on both crude and products.
  - Whether to invest in upgrading (fuel oil and naphtha) depends on the impacts of replacing 28 kb/d of naphtha and fuel oil exports with 11 kb/d of petcoke and VGO exports on the refining margin.
    - In other words, justifying such a big investment (several hundred million dollars) in upgrading would require a long-term investment recovery period, which may not be obvious given the potential decline in gasoline and diesel demand, as well as the need for exports of surplus petcoke and VGO, which would still erode the economics of such a high-cost investment.
  - Full conversion of the (crude) refinery to a biofuels refinery is also probably not easily justified given the challenge of sourcing feedstock availability (for a sizeable plant of say larger than 40-50 kb/d) and the potential need for investing in a hydrogen plant or hydrogen import facility (should the refining units that are currently a source of H2 for a small scale SAF plant are mothballed too). However, expansion of the under-construction 4 kb/d biodiesel/SAF plant is likely.
  - Closing the refinery would also not be a cost-free option as it would require sizeable expenses in decommissioning and environmental remediation and asset write-offs.
  - The least costly option seems to be mothballing the refinery and converting the site into an import terminal/storage site that would allow Par Pacific to join IES and turn into one of the major fuel suppliers for transport fuels (i.e., gasoline, jet fuel, and diesel).
    - Especially, given the US $90 million commitment for the biofuel plant on the refinery site, which requires some of the existing tank storage and related logistics, a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal remains the most likely option for Par.
- If Par Pacific closes its Hawai'i refinery and converts it into an import terminal, we do not foresee any notable cost implications for local consumers. Prices should remain static as local petroleum products have always been sold at close to import parity prices due to third party import capacity. Fuel import terminals on Oahu owned by IES and Sunoco act as a counterbalance if local petroleum prices are above market rates. In addition, there is plenty of petroleum product supply in the Pacific Basin due to refinery expansions and security of supply is not an issue.

Future of Hawai'i Gas if LNG comes to Hawai'i

Hawaiʻi Gas could replace all their existing SNG pipeline gas with regasified LNG and play a leading role in the energy transition with biogas and hydrogen

- Hawai'i Gas (HG) currently sells synthetic natural gas (SNG) via a pipeline network that spans 1,100 miles between Kapolei to Hawaiʻi Kai. Most customers are in the downtown and Waikīkī area and the gas is used for cooking, drying, hot water heating, co-generation, etc. The SNG is derived from naphtha that is provided locally by Par and then "cracked" at HG's synthetic natural gas plant.
- If Par loses the LSFO contract with HECO they are unlikely to provide HG with naphtha for their SNG production. However, the naphtha would not be needed by HG as the regasified LNG can easily be placed in HG's existing gas reticulation system with some minor extensions. Moreover, the imported LNG would be 4-5X cheaper than what HG currently pays for SNG, thereby saving their regulated customers money as well.
- HG also provides significant amounts of LPG, particularly propane and to a lesser extent butane, to commercial and residential customers throughout Oʻahu that are not connected to the pipeline. Some of the larger commercial and residential customers who have larger storage can utilize LNG while many residential customers will have to continue to rely on propane. The bottom line is that imported LNG will be cheaper for all those who can access it instead of SNG and LPG.
- Gas utilities such as HG are uniquely positioned to develop and invest in a decarbonized, clean-fuels system. A utility such as HG can deliver a mix of biogas and hydrogen to a subset of the customers the gas utilities already serve via their existing infrastructure and supply new sources of demand such as shipping and aviation with pipeline extensions. Existing infrastructure can be partially repurposed to deliver clean fuels such as biogas and green hydrogen. Biogas does not have many technical limitations with HG's existing infrastructure while hydrogen for existing pipelines is more challenging; gas pipelines can only handle about a 20% hydrogen blend before the pipes start corroding. Hydrogen currently comprises 10-15% of HG's SNG blend in their pipelines and they are looking to bring this up to 20% with some relatively minor improvements. If green hydrogen was available, it could be dropped into the existing pipeline system relatively easily and blended with regasified LNG. However, if Hawaiʻi wants to increase the hydrogen ratio to more than 20% then dedicated hydrogen infrastructure or substantial retrofits would need to be developed.
- In addition to building, owning, and operating the pipelines, HG has extensive knowledge to comply with the regulatory process and bring stakeholders together for key decisions. This is key in implementing policies that will support new fuels such as hydrogen.
- Hydrogen is the fuel of the future, and one Hawaiʻi should begin to prepare for. Hydrogen is flexible to use and easy to transport and does not emit carbon if derived from certain renewables, such as solar and wind. Electricity is not easy to store, can be costly, and has a large footprint for a space-constrained island such as Oʻahu. With hydrogen, the surplus renewable electricity can be used to produce green hydrogen: in this way, the electricity is converted into an energy source that is suitable for storage. The only challenge for green hydrogen right now is cost, but that is projected to change in the coming years as costs are forecast to fall, like what was exhibited by solar.
- HG can play a leading role in the transition to a lower carbon economy by initially blending biogas and hydrogen with the regasified LNG and then later building dedicated infrastructure for green hydrogen with their operational and regulatory know-how.

2. Energy Supply Chain

LNG, hydrogen, ammonia, and biofuels can all help fuel Hawaii's clean energy transition as we move away from oil. LNG is currently the only large-scale economic solution.

LNG

What is LNG?

Liquified Natural Gas

- LNG is natural gas cooled to -161° Centigrade, the temperature at which its main component methane liquefies.
- Its volume is reduced to around one six-hundredth of its volume as a gas.
- It is stored and transported at atmospheric pressure as a boiling liquid.
- It is an odorless, colorless liquid.
- Chemically, LNG is chiefly (>85%) methane, with smaller amounts of ethane, propane, butane, together with minor amounts of other substances.
- During combustion, natural gas produces around 35% less GHG emissions than Low Sulfur Fuel Oil.

Companies involved in LNG production and buyers

LNG suppliers' pool continues to increase, providing several options for prospective buyers

- Oil and gas companies
  - Shell, BP, ExxonMobil, TotalEnergies, Chevron, ConocoPhillips, Cheniere, Woodside, ENI, Novatek, etc.
- Japanese trading houses
  - Mitsubishi, Mitsui, Marubeni, Sumitomo, etc.
- National oil companies/governments
  - ADNOC, QatarEnergy, OQ, Pertamina, PETRONAS, Sonatrach, NNPC (Nigeria), Brunei govt, etc.
- Buyers
  - KOGAS, JERA, Osaka Gas, CPC, CNOOC, Tokyo Gas, etc.

- **A number of different kinds of companies are involved in LNG production. In the US, its primarily oil and gas companies and independent players while in Asia and the Middle East it's often led by national oil companies.**

- Traditional buyers
  - Japanese gas and power utilities, KOGAS, CPC European gas utilities, etc.
- Traders and aggregators
  - BP, Shell, TotalEnergies, ENI, Vitol, Gunvor, etc.
- Power companies/IPPs
  - ENEL, Edison (Italy), Eco-Electrica (Puerto Rico), AES (Dominican Republic), Iberdrola

- **Major oil and gas companies such as ExxonMobil and Chevron are now looking to build LNG portfolios and become traders/aggregators.**

The LNG value chain

Liquefaction and upstream production are the most expensive parts of the LNG value chain, while regasification via FSRU is on the lower end. Excludes end-use, the final stage of the LNG business cycle.

Upstream

Gas Production

US$4-US$6 billion investment
(typically for 2 Bscf/d of gas conventional production)

Transportation

Pipeline Transportation

Liquefaction

Pre-treatment → **Liquefaction** → **Storage** → **Loading**

US$6-US$12 billion Investment
(for a typical liquefaction facility with 10 mtpa capacity)

Shipping

Shipping

Cost of modern LNG vessel:
US$250-US$260 million

Regasification

Unloading → **Storage** → **Regasification**

Distribution

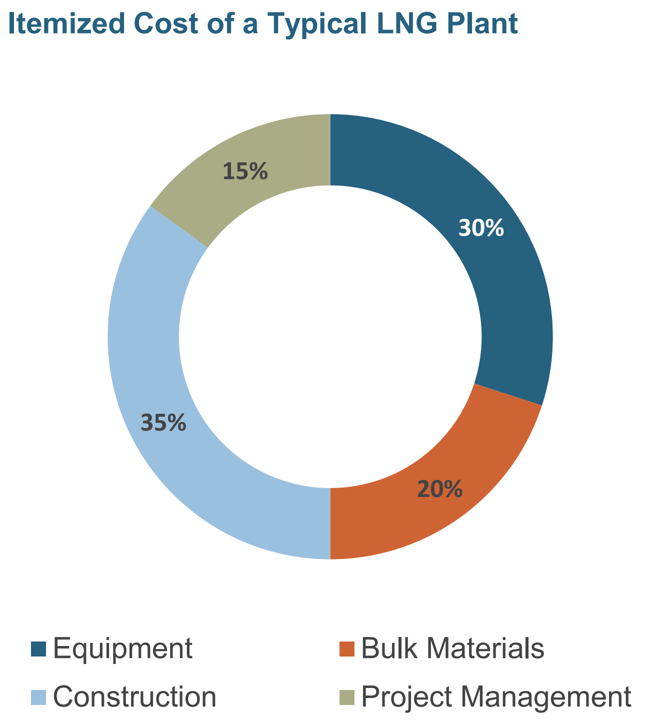
Transport to End-Users

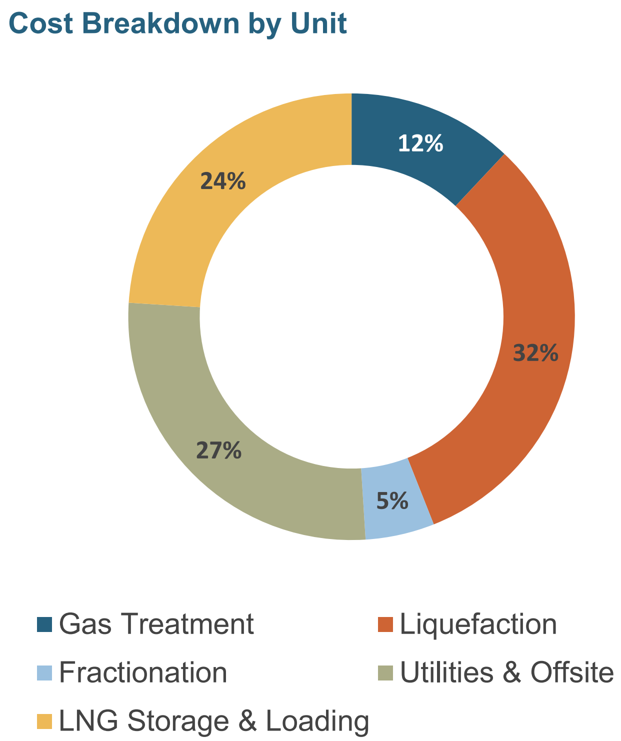
Cost of a typical land-based LNG regas terminal:
US$1-US$2 billion

Value of a modern FSRU:
US$340-US$400 million

Capital cost elements for a typical LNG project

Main elements of required capital cost for construction of LNG plants are as follows



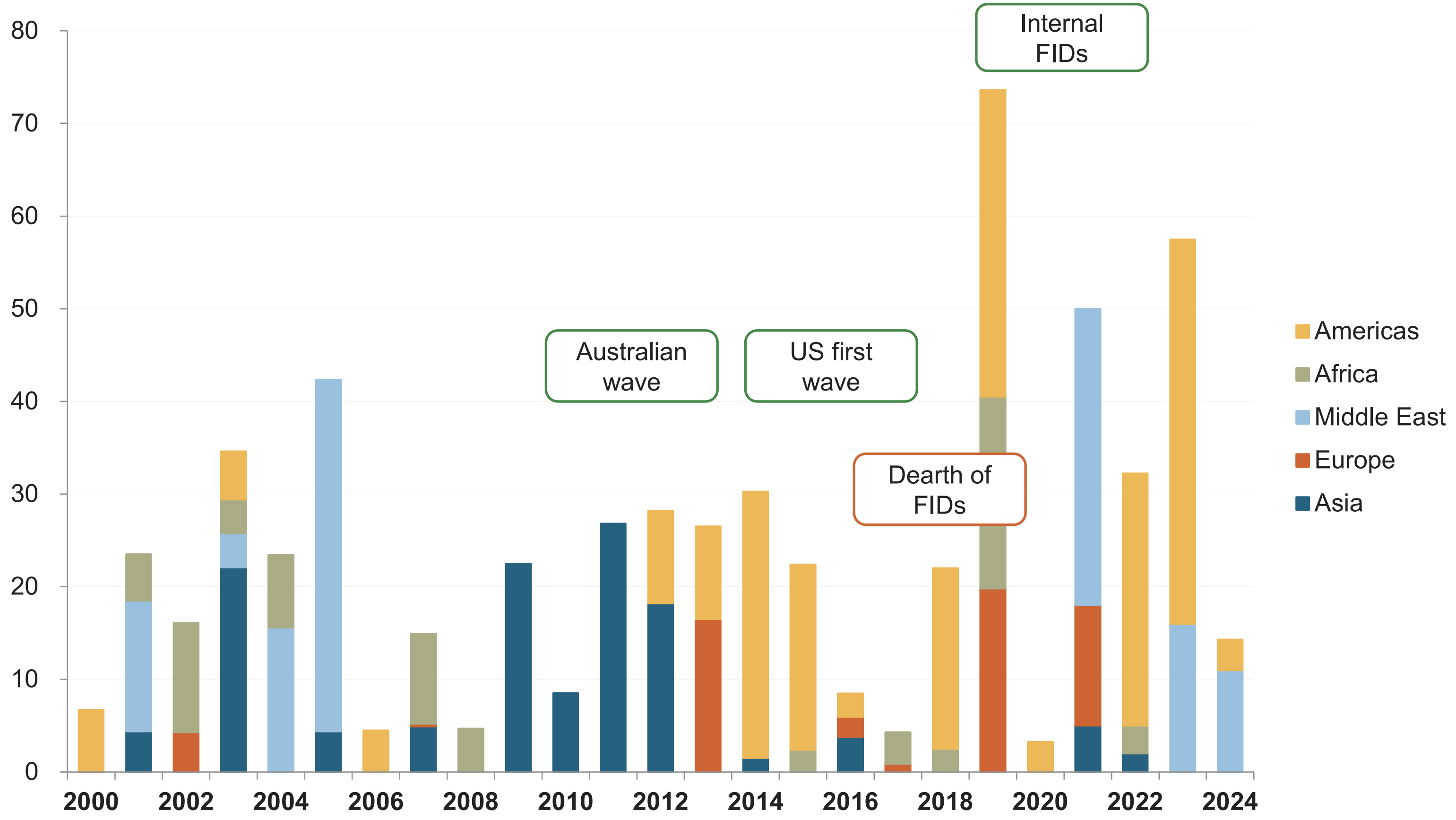


- The above charts are indicative and actual cost breakdown varies project to project, depending on many factors such as location, gas quality and project technical designs, etc.

LNG supply final investment decisions (FIDs) continue to grow

A wave of LNG supply is coming to the market which is great news for buyers as supplies are plentiful

FIDs on Liquefaction Capacity, mtpa



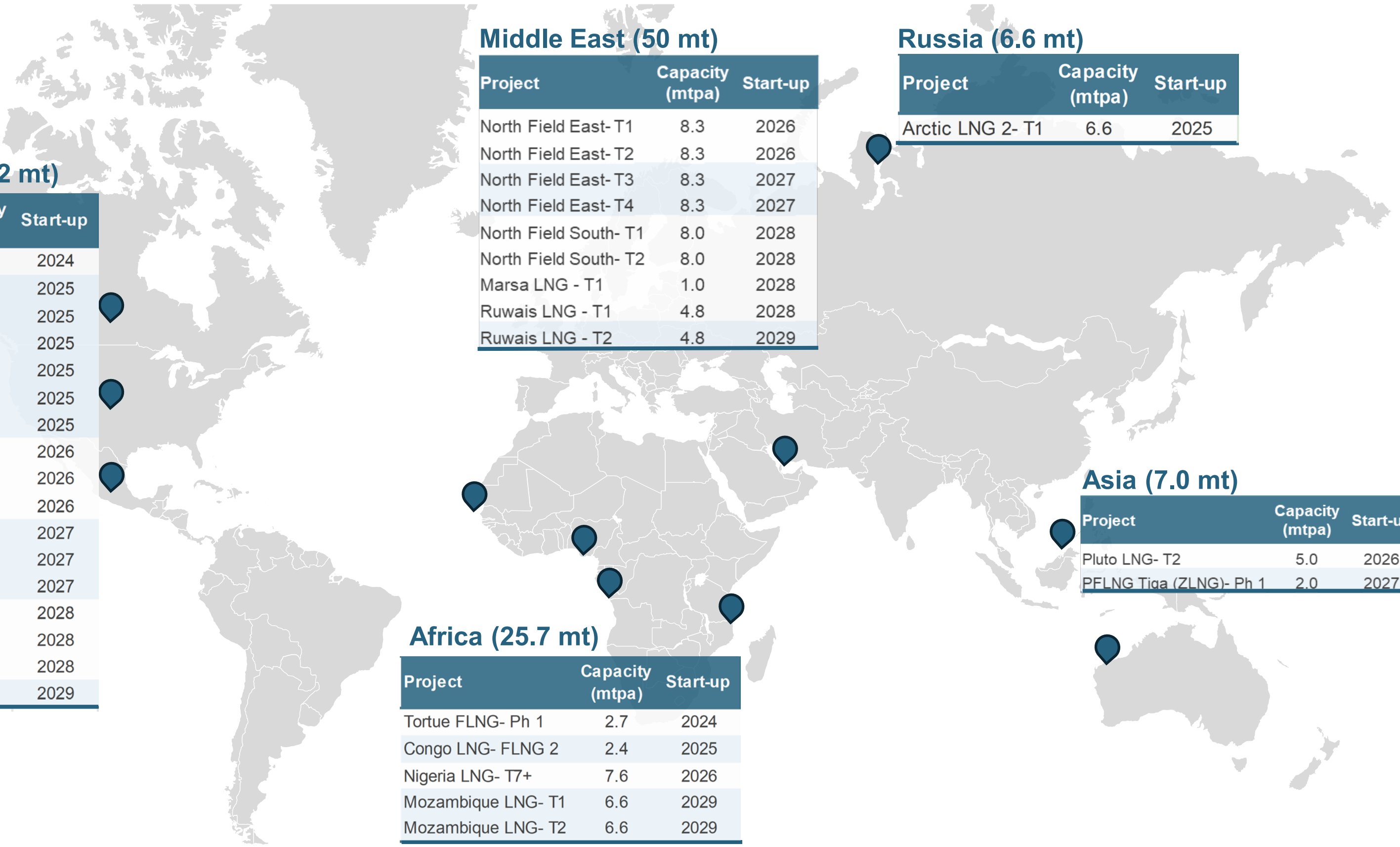
Only includes new liquefaction capacity, excludes backfill projects
Source: FGE LNG ODS

- Significant tailwinds were seen for liquefaction projects in 2022 and 2023 following the Russia-Ukraine war. A wide range of buyers signed long-term contracts, especially with US projects.
- Europe's decarbonization goals hinder some buyers' LNG procurement plans.
- Asian buyers shift their focus on to more firm supply over LNG from pre-FID projects. Project developers that have yet to cash in on the wave of SPA signings could face headwinds. **It is now or 'wait a few years' for these projects.**

A wall of supply begins to enter the market from 2025

Global LNG supply to increase by at least 50% by the late 2020s based on LNG supply currently under construction

Under Construction (Post-FID) Terminals



The Americas (103.2 mt)

Project	Capacity (mtpa)	Start-up
Plaquemines - Ph1	13.3	2024
Golden Pass - T1	6.0	2025
ECA LNG - Ph1	3.3	2025
LNG Canada - T1	7.0	2025
Corpus Christi - Stg3	10.4	2025
Plaquemines - Ph2	6.7	2025
LNG Canada - T2	7.0	2025
Golden Pass - T2	6.0	2026
Golden Pass - T3	6.0	2026
Fast LNG - FLNG 2	1.4	2026
Port Arthur - T1	6.5	2027
Rio Grande - T1	5.9	2027
Woodfibre LNG - T1	2.1	2027
Port Arthur - T2	6.5	2028
Rio Grande - T2	5.9	2028
Rio Grande - T3	5.9	2028
Cedar FLNG - Ph1	3.3	2029

Middle East (50 mt)

Project	Capacity (mtpa)	Start-up
North Field East- T1	8.3	2026
North Field East- T2	8.3	2026
North Field East- T3	8.3	2027
North Field East- T4	8.3	2027
North Field South- T1	8.0	2028
North Field South- T2	8.0	2028
Marsa LNG - T1	1.0	2028
Ruwais LNG - T1	4.8	2028
Ruwais LNG - T2	4.8	2029

Russia (6.6 mt)

Project	Capacity (mtpa)	Start-up
Arctic LNG 2- T1	6.6	2025

Asia (7.0 mt)

Project	Capacity (mtpa)	Start-up
Pluto LNG- T2	5.0	2026
PFLNG Tiga (ZLNG)- Ph 1	2.0	2027

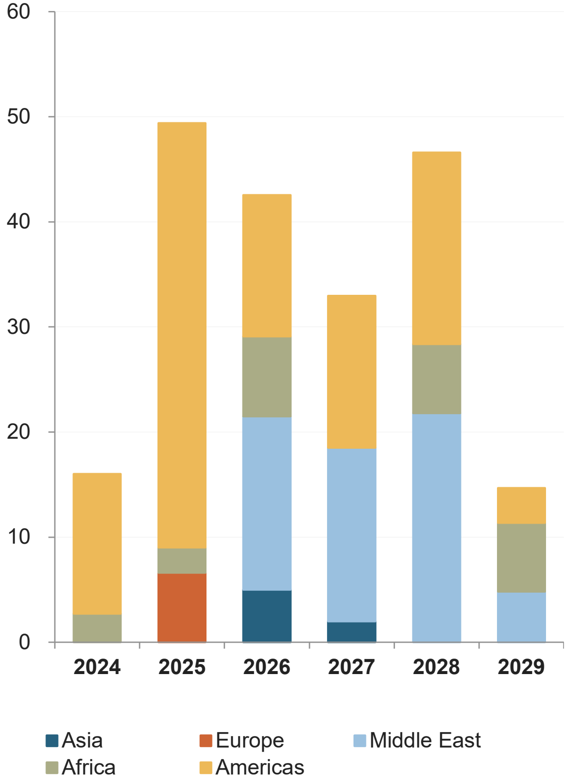
Africa (25.7 mt)

Project	Capacity (mtpa)	Start-up
Tortue FLNG- Ph 1	2.7	2024
Congo LNG- FLNG 2	2.4	2025
Nigeria LNG- T7+	7.6	2026
Mozambique LNG- T1	6.6	2029
Mozambique LNG- T2	6.6	2029

Source: FGE LNG ODS

Note: Mozambique LNG construction is currently paused but expected to resume in 2024
Tables only include new liquefaction capacity, excludes backfill projects
Arctic 2 LNG- T2 is under construction but undergoing redesign

Under Construction LNG Supply by Start-Up Year, mt

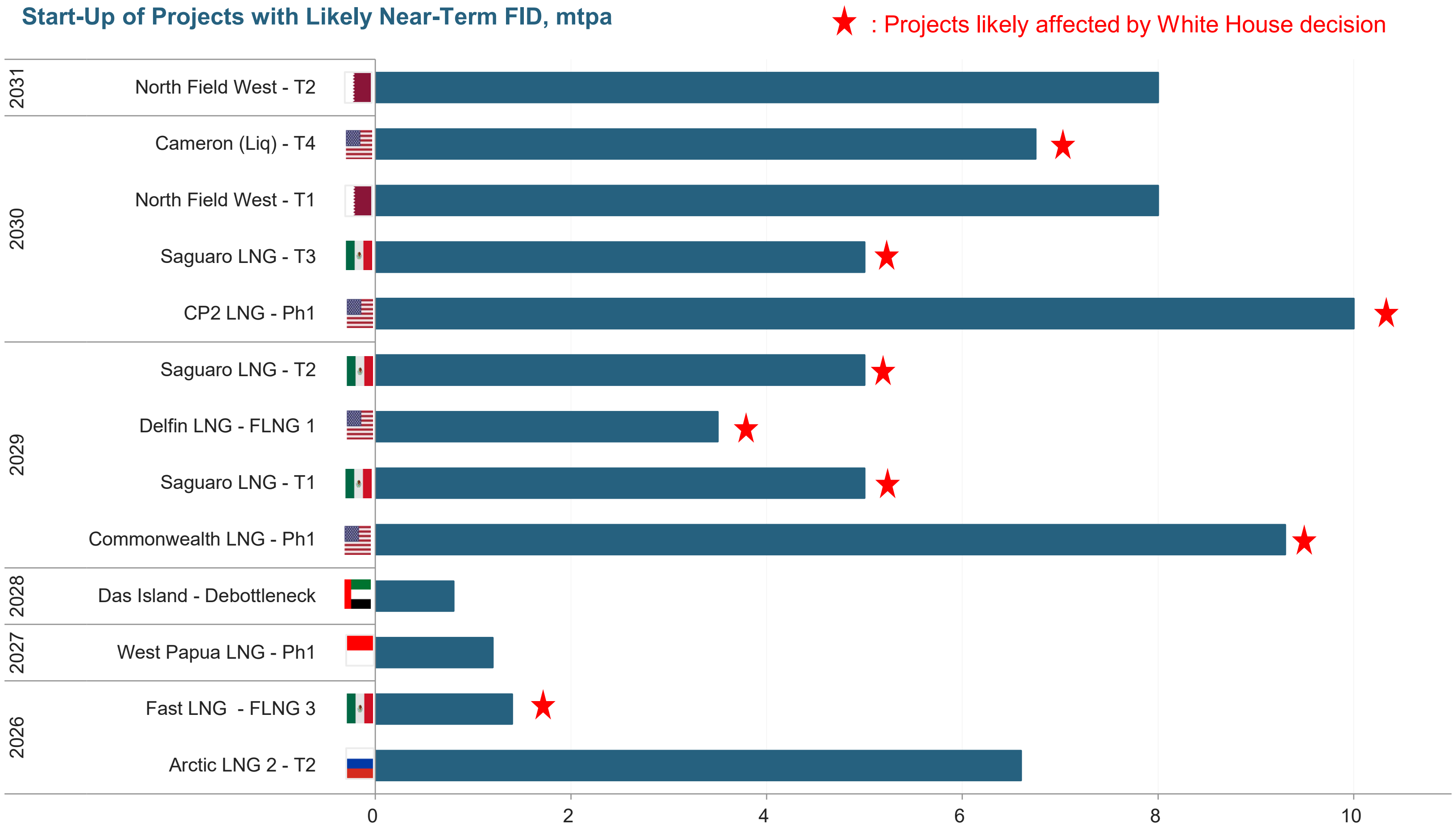


Source: FGE

Around 61 mtpa set to make FID, but 45 mtpa likely affected by Biden pause

The Biden LNG pause impacts projects in the USA that were expected to make FID in 2024, but not those under construction

Start-Up of Projects with Likely Near-Term FID, mtpa

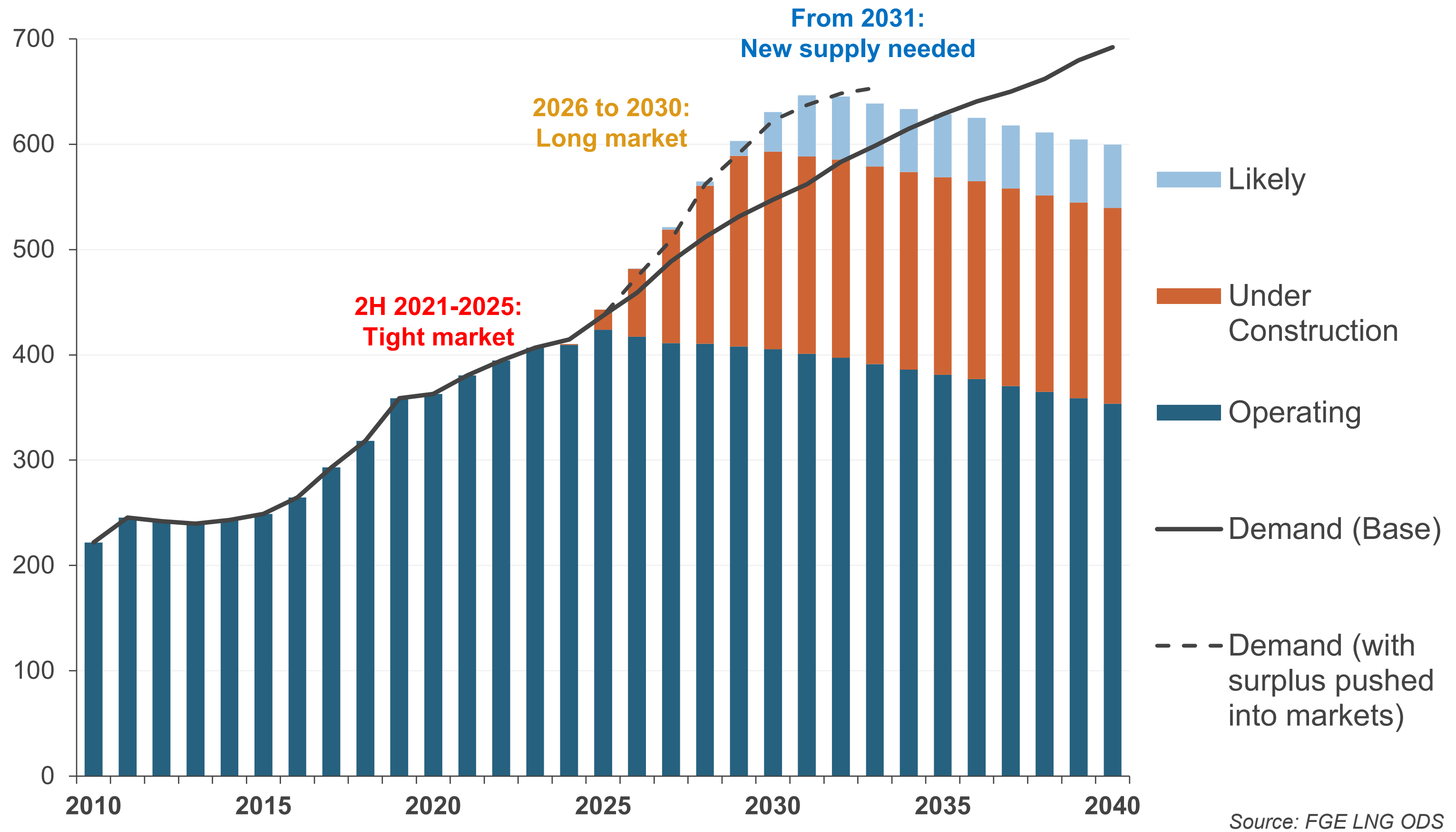


- In January 2024, the Biden Administration initiated a pause on new LNG projects in the United States that did not have a non-FTA license in place. Non-FTA licenses, issued by the US Department of Energy, are key to sanctioning FIDs for LNG projects as it allows the LNG to go to any country in the world.
- The pause was done for political reasons as Biden tried to drum up support from his base for the November 2024 election.
- The pause is ongoing even with Biden dropping out of the election. FGE expects the pause to be lifted in early 2025 after the election.
- The Biden pause does not mean that the LNG projects will never get developed. Instead, it delays the FIDs, and ultimately production, by approximately a year.

The LNG market becomes a “buyers’” market in 2026/2027

The market goes from tight to surplus by 2026/2027, presenting buyers opportunities to secure lower cost LNG supply

Global LNG Supply vs Demand, mt

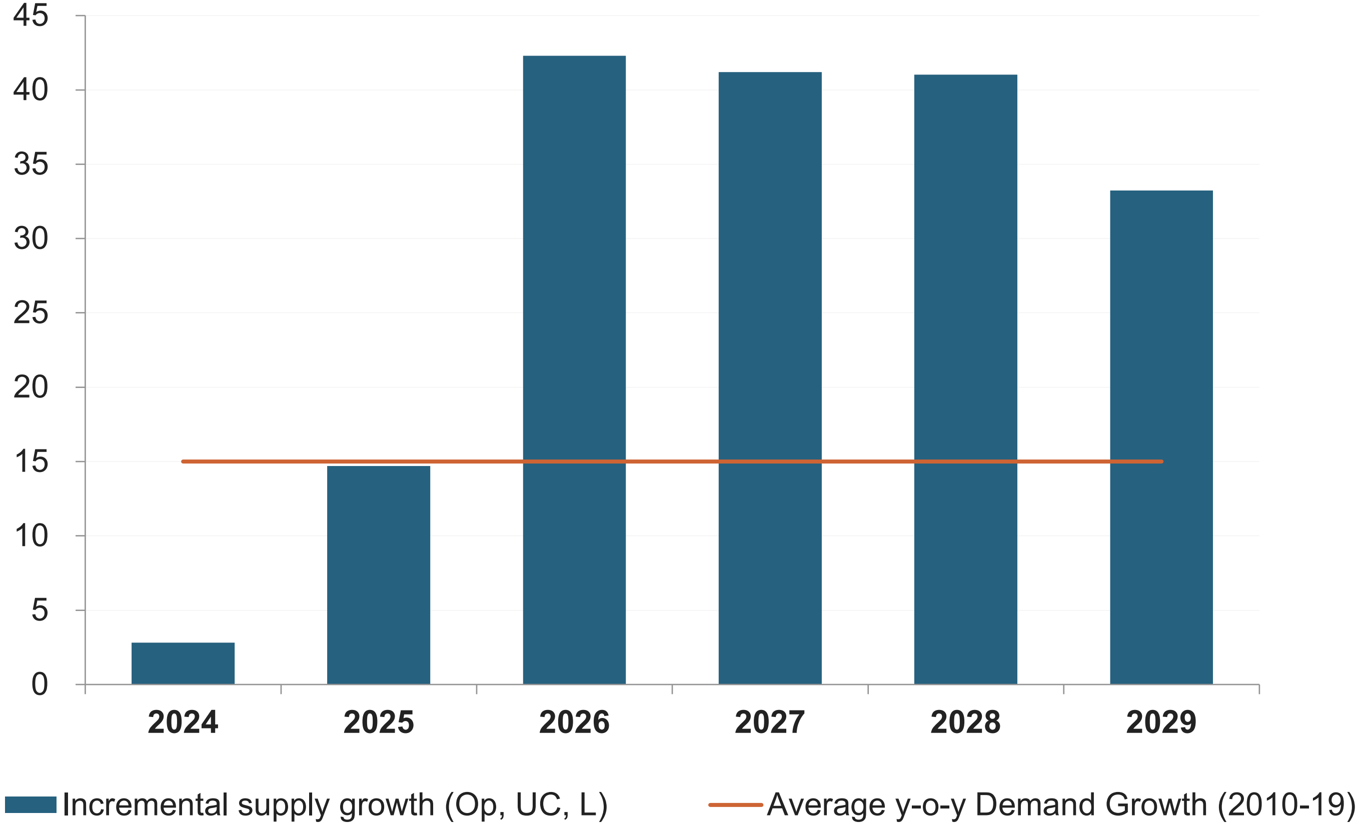


Source: FGE LNG ODS

- **Tight 2H 2021-2025:** A tight European gas market pulls LNG from global markets. Supply growth dried up due to an earlier slowdown in FIDs, while Asian demand continues to grow.
- **Long from 2026 to 2030:** A wave of supply hits the market. Europe continues to soak up LNG to phase out coal, while lower prices attract Asian players back into the market. Some US LNG shut-ins will also help balance the market. Some time will be needed to absorb the new LNG supply. Despite low prompt prices, established LNG buyers and IOCs should look to support pre-FID projects.
- **Tight from 2031:** In the absence of FIDs over 2025-27, tightness could emerge from 2031.

LNG supply growth extremely strong from 2026-2028

Y-o-Y Supply Growth Outlook, mt



Supply includes output from operating (Op), under-construction (UC), and likely (L) projects and takes into account possible outages and delays to project start-ups

Source: FGE

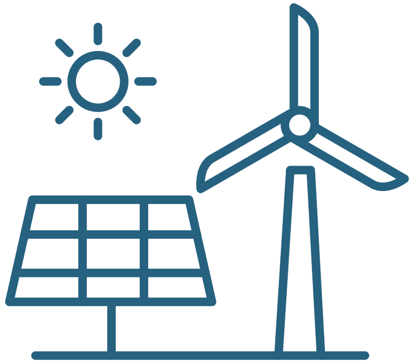
- The next supply wave will add volumes of unprecedented levels to the LNG market over 2026-30.
- Prompt LNG prices will soften significantly to encourage a push into Asian and European markets. Low prices are also necessary to shut in some US LNG, especially in 2026 and 2027.
- Buyers should be mindful of market cycles and consider LNG requirements beyond 2031 to secure term volumes at attractive slopes.
- Interest from emerging buyers in pre-FID supply will be limited. IOCs, traders, and established buyers are presented with an opportunity to support some pre-FID projects in a bid to take advantage of a potential market tightness from 2031.

Hydrogen/Ammonia

Hydrogen storage & power generation value chain

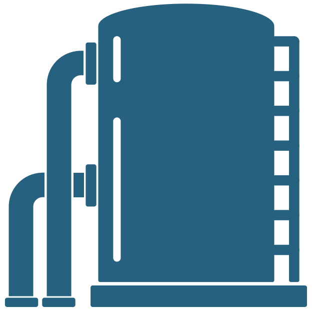
The value chain is formed of three key components

Hydrogen Production



- Low-carbon hydrogen production can be ‘**green hydrogen**’, produced with renewable electricity and water, or ‘**blue hydrogen**’, produced from natural gas using carbon capture.
- Both can be used for power generation, but **green hydrogen** is used for storing excess renewable power.

Hydrogen Storage



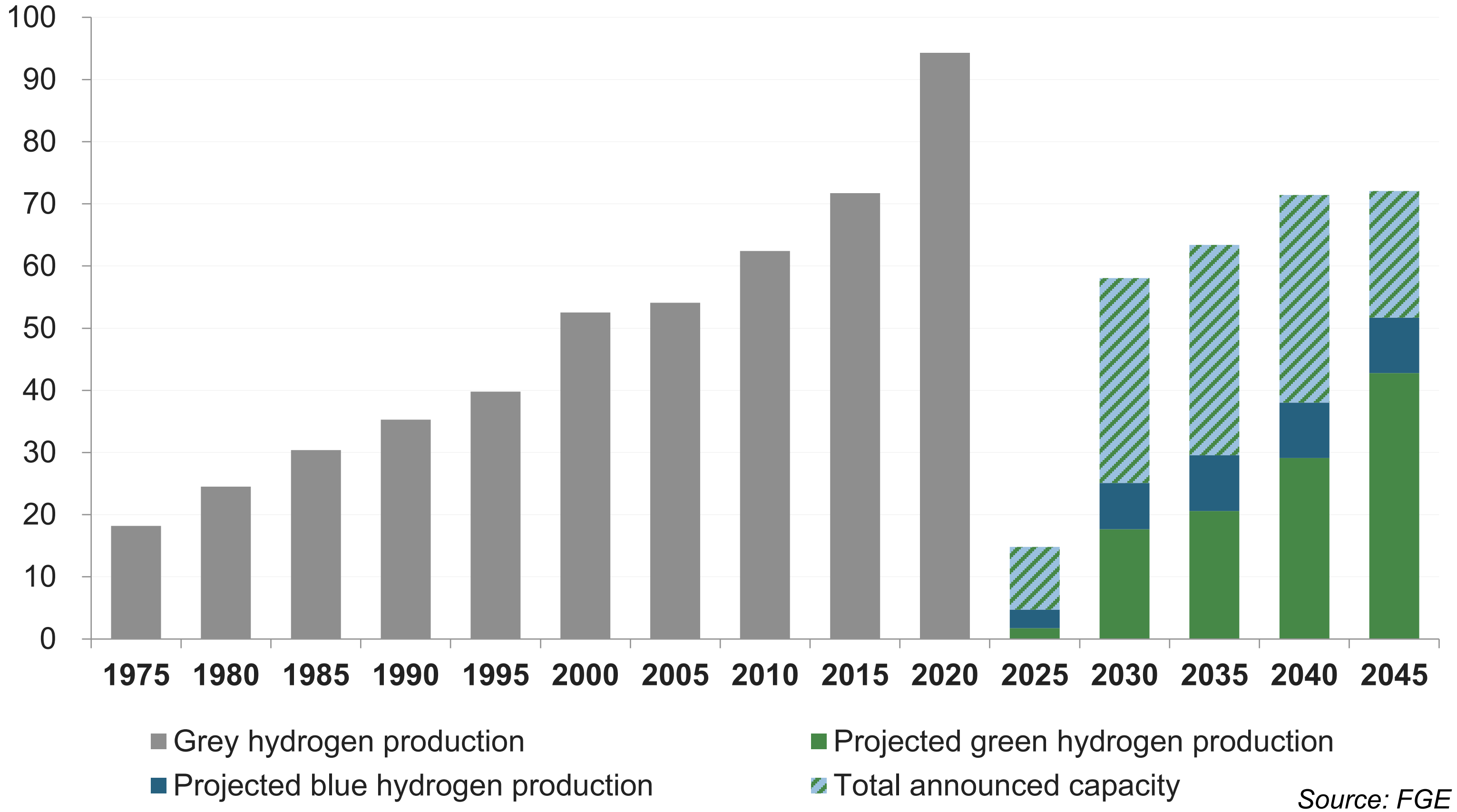
- There are multiple different types of storage, such as pressurized tanks, salt caverns or depleted oil and gas fields, each tailored to different applications.

Power Generation

- The hydrogen can be used to generate power either using fuel cells, or in gas-fired power plants.

Historical hydrogen production and projected clean hydrogen production

Global Hydrogen Production, mtpa

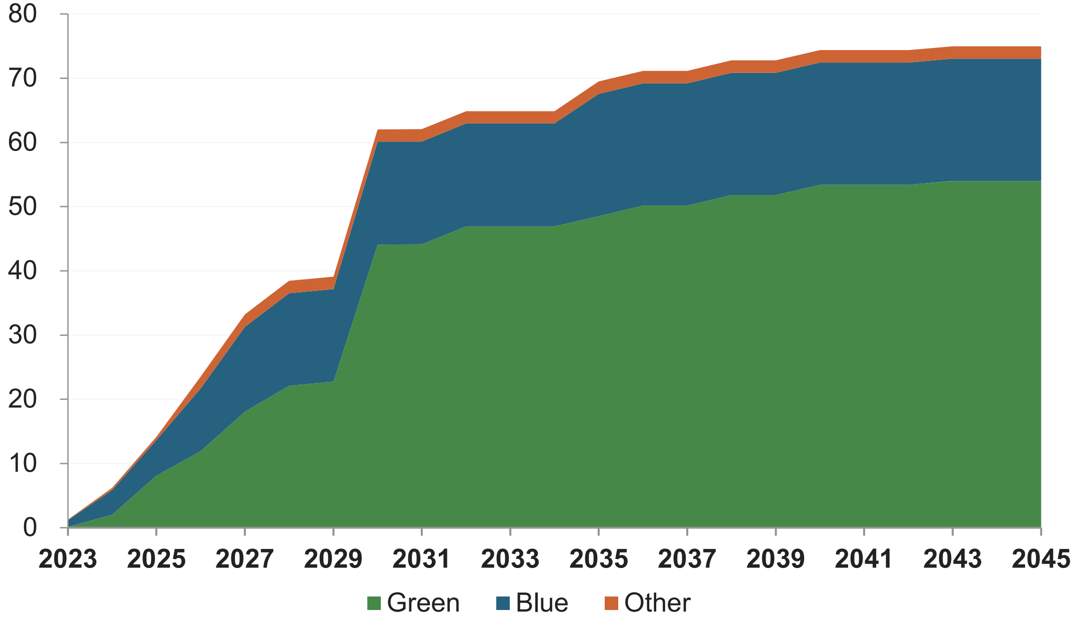


Source: FGE

- Hydrogen production has been dominated by conventional ‘grey’ hydrogen production.
- Announced projects imply a rapid growth in clean hydrogen production, particularly green hydrogen.
- Green hydrogen production relies on access to renewable power generation.
- This will be the limiting factor in green hydrogen capacity growth, which we predict will fall well below planned capacity.

Global clean hydrogen production based on proposed projects

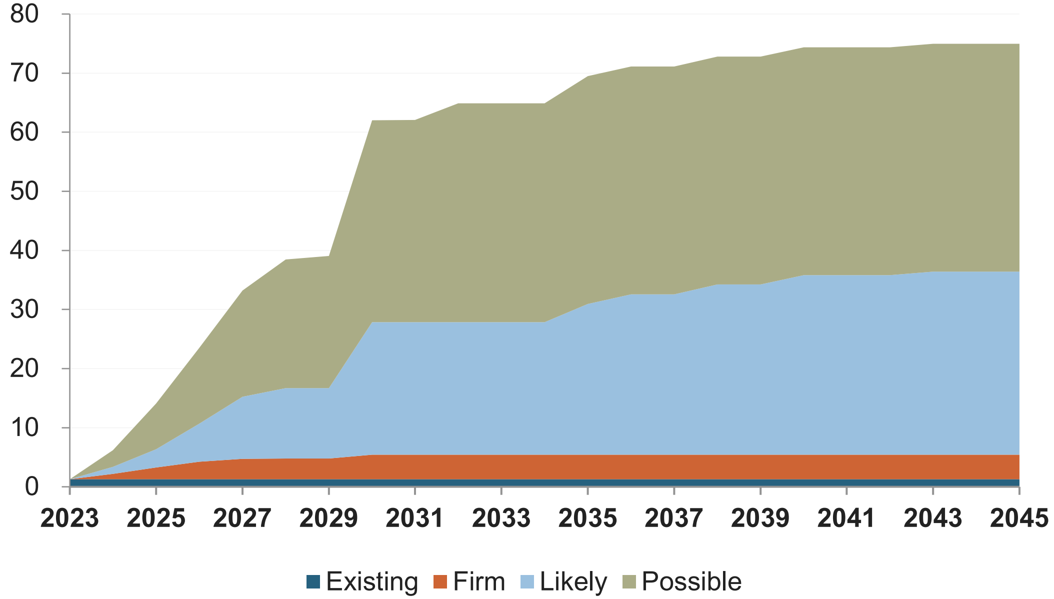
Global Clean Hydrogen Production, mtpa



Source: FGE

- By 2045:
- **Green:** 52.0 mtpa (72.0%)
- **Blue:** 18.9 mtpa (25.4%)
- **Other:** < 1 mtpa (2.6%)

Global Clean Hydrogen Production by Likelihood, mtpa

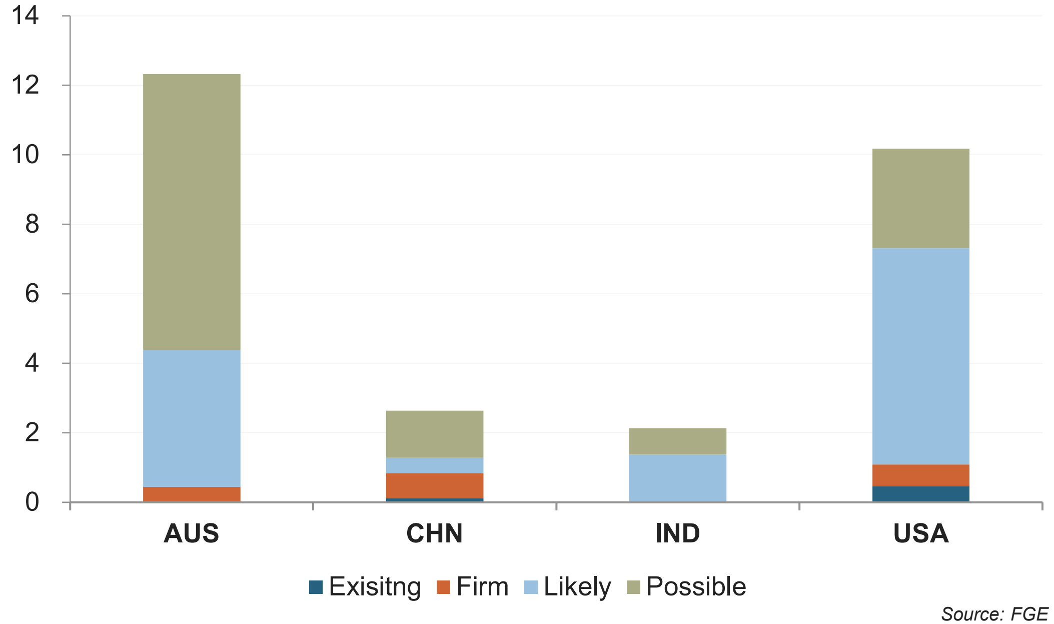


Source: FGE

- Planned projects up to 2045:
- **Existing:** 1.3 mtpa (1.7%)
- **Firm:** 4.1 mtpa (5.5%)
- **Likely:** 31.0 mtpa (41.3%)
- **Possible:** 38.5 mtpa (51.4%)

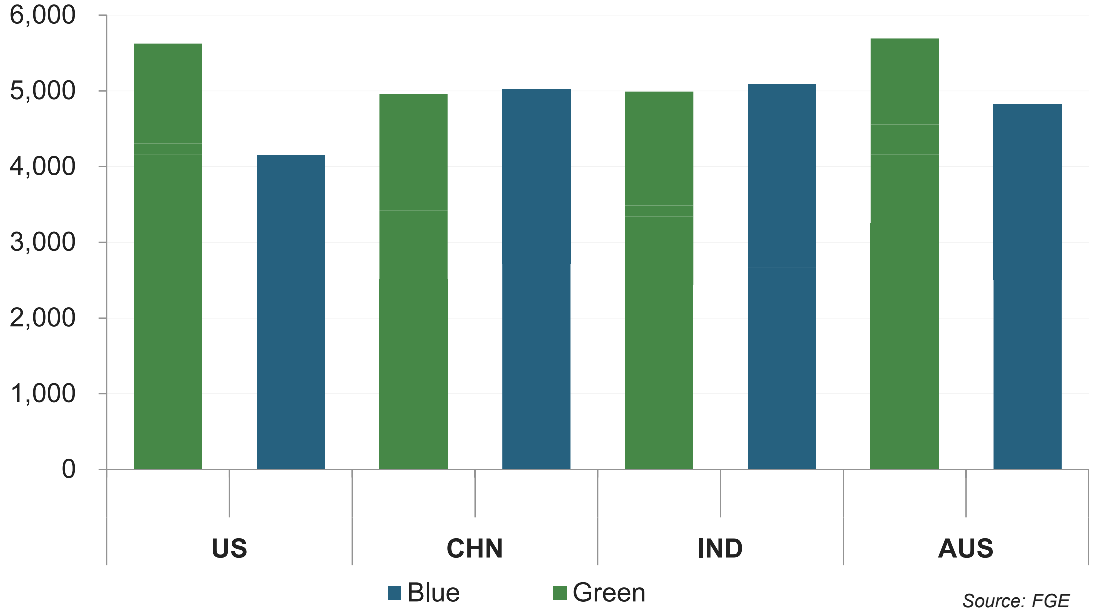
Where will Hawai‘i be able to get its hydrogen from?

Selected Clean Hydrogen Exporters: Production by Likelihood by 2035, mtpa



Source: FGE

Green Vs Blue Hydrogen Levelised Cost of Delivery, 2023, US$/tonne H2



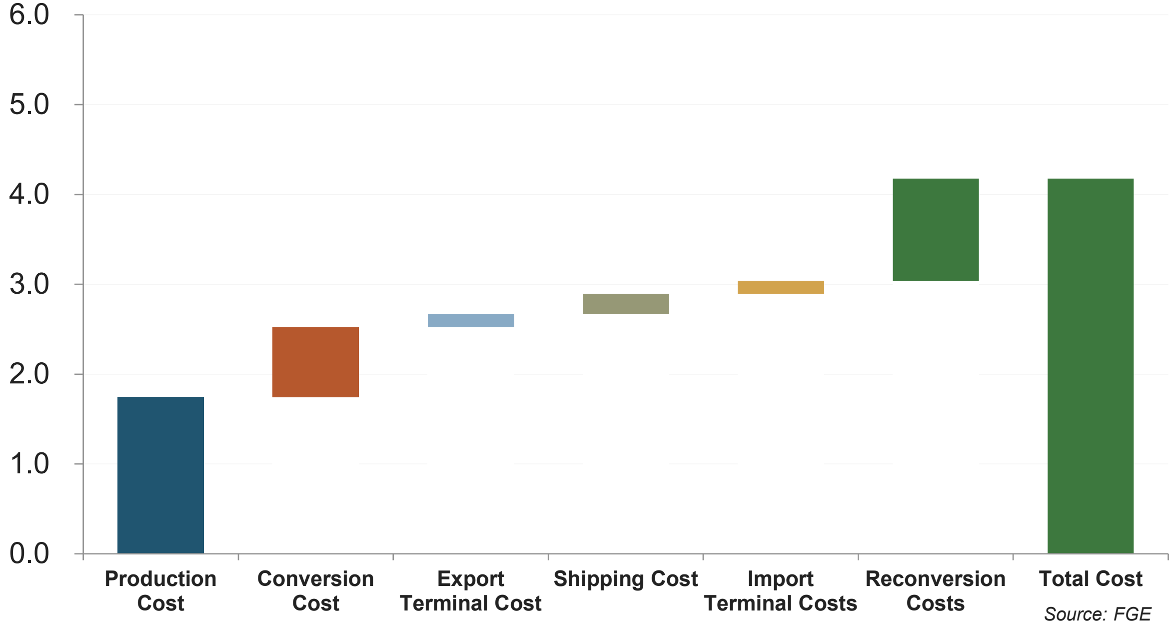
Source: FGE

- Australia and the US are the largest potential sources of clean hydrogen imports, dwarfing India and China in terms of planned production.
- However, due to low renewable energy costs and high natural gas prices in China and India, blue and green hydrogen are competitive with each other in these countries.
- In contrast, blue hydrogen is significantly cheaper in the US due to low natural gas prices.

Levelized cost of delivery of clean hydrogen to Hawai'i from the US: 2023

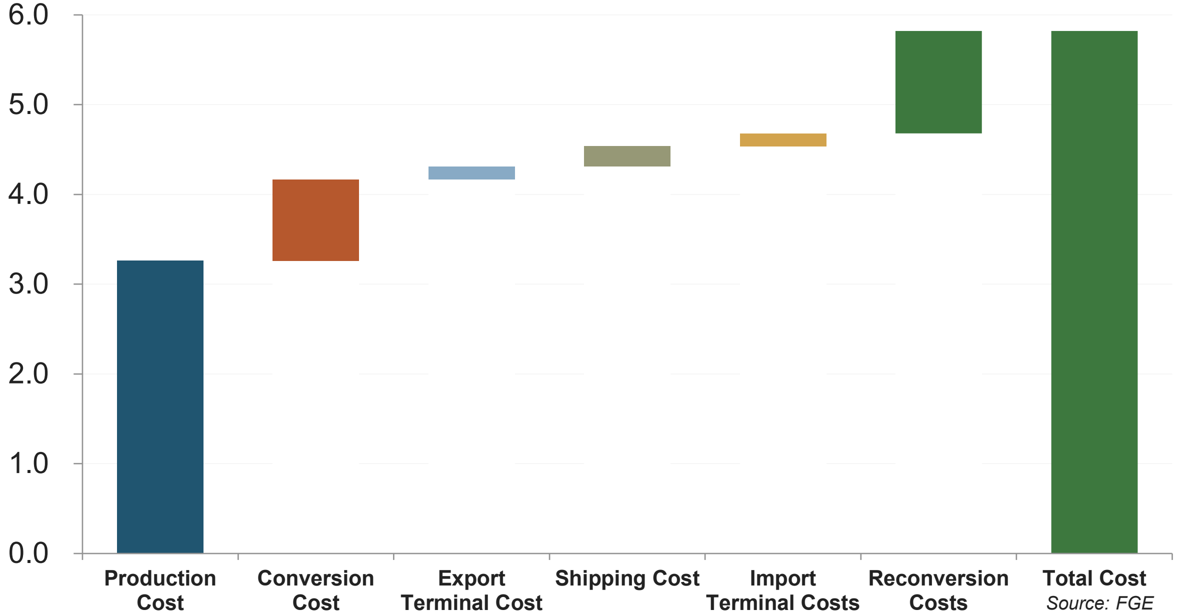
These levelized cost models utilize the US' solar power electricity and natural gas prices, while the hydrogen carrier selected has been ammonia

Breakdown of Levelized Cost Components of Blue Hydrogen from USGC to Hawaii, 2023, US$/kg



Source: FGE

Breakdown of Levelized Cost Components of Green Hydrogen from USGC to Hawaii, 2023, US$/kg



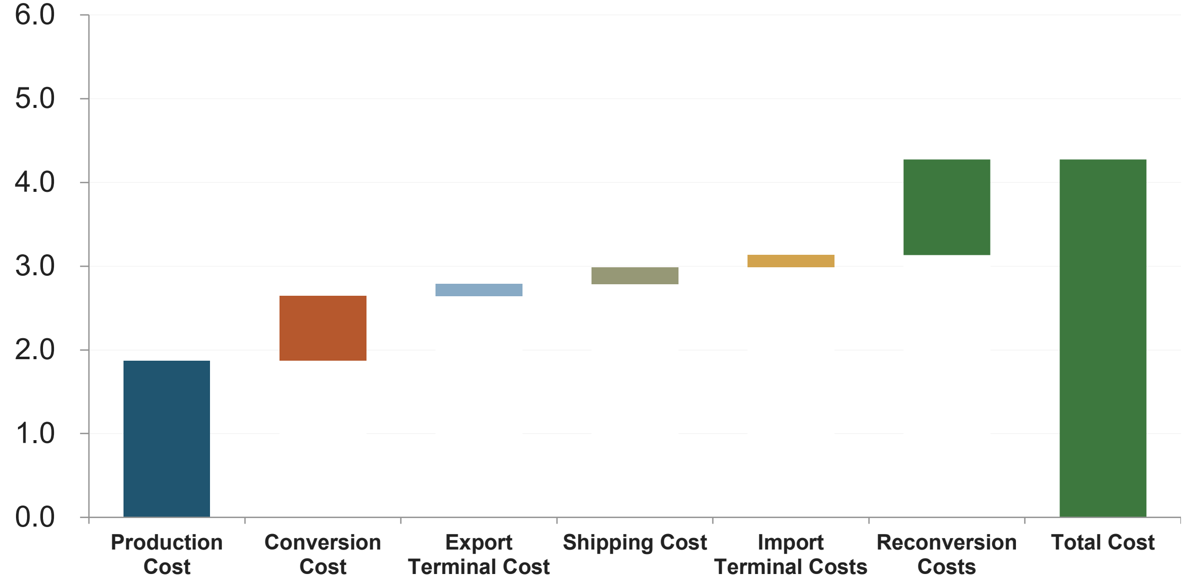
Source: FGE

- The main difference in the levelized cost of delivery of blue and green hydrogen from the US is the CAPEX of each project, with high electrolyzer costs and low production efficiencies increasing green hydrogen production costs.
- As both hydrogen types are transported in the form of the same carrier, ammonia, the transport costs are very similar.
- The price difference for green hydrogen adds a cost of US$1.6/kgH2.

Levelized cost of delivery of clean hydrogen to Hawaii from the US: 2040

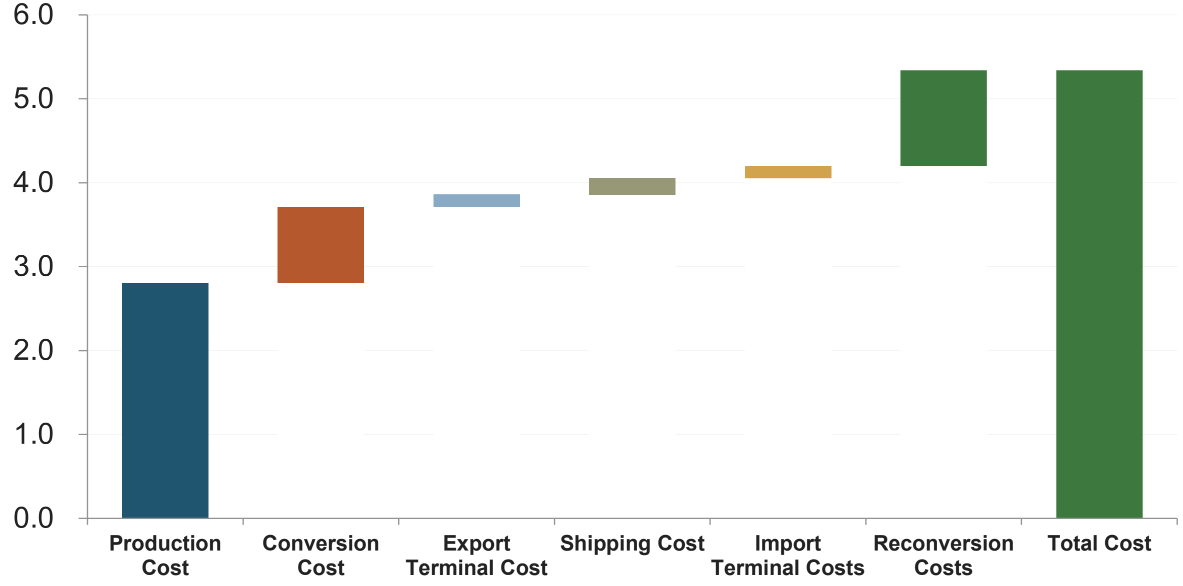
These levelised cost models utilize the US' solar power electricity and natural gas prices, while the hydrogen carrier selected has been ammonia

Breakdown of Levelized Cost Components of Blue Hydrogen from USGC to Hawaii, 2040, US$/t



Source: FGE

Breakdown of Levelized Cost Components of Green Hydrogen from USGC to Hawaii, 2040, US$/t



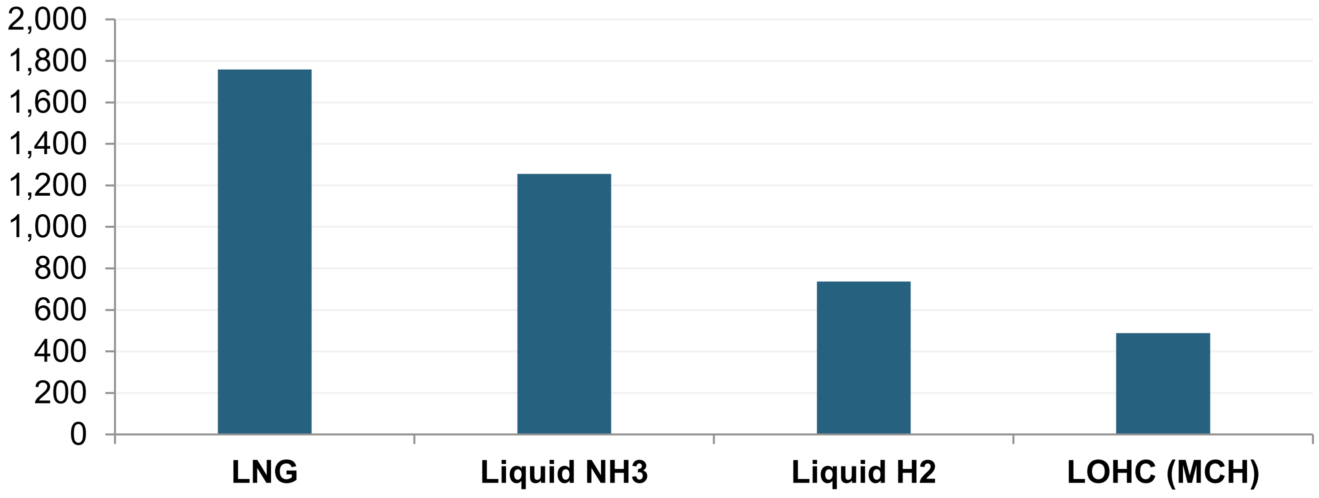
Source: FGE

- The price of natural gas is expected to remain very similar, resulting in a small increase of US$0.12/kgH2 in 2040 for the cost of delivery of blue hydrogen.
- Meanwhile, solar production costs will decrease. This will lower green hydrogen's delivery cost by US$0.45/kgH2.
- This will lead to a lower price gap between green and blue hydrogen ($1.1/kgH2).

Challenge 1 for Japanese hydrogen import plans: Efficiency and density

Comparison of Three Main Hydrogen Carriers		Liquid NH3	Liquid H2	LOHC (MHC)
Energy requirement - conversion	*MWh/ton H2*	5.75	12	0.5
Energy requirement - re-conversion	*MWh/ton H2*	11.2	0.6	15
Volumetric storage density	*kg H2/m3*	121	71	47
Storage temperature	*°C*	25 or -33	-253	25
Storage pressure	*bar*	10 or 1 (atmospheric)	1 (atmospheric)	1 (atmospheric)

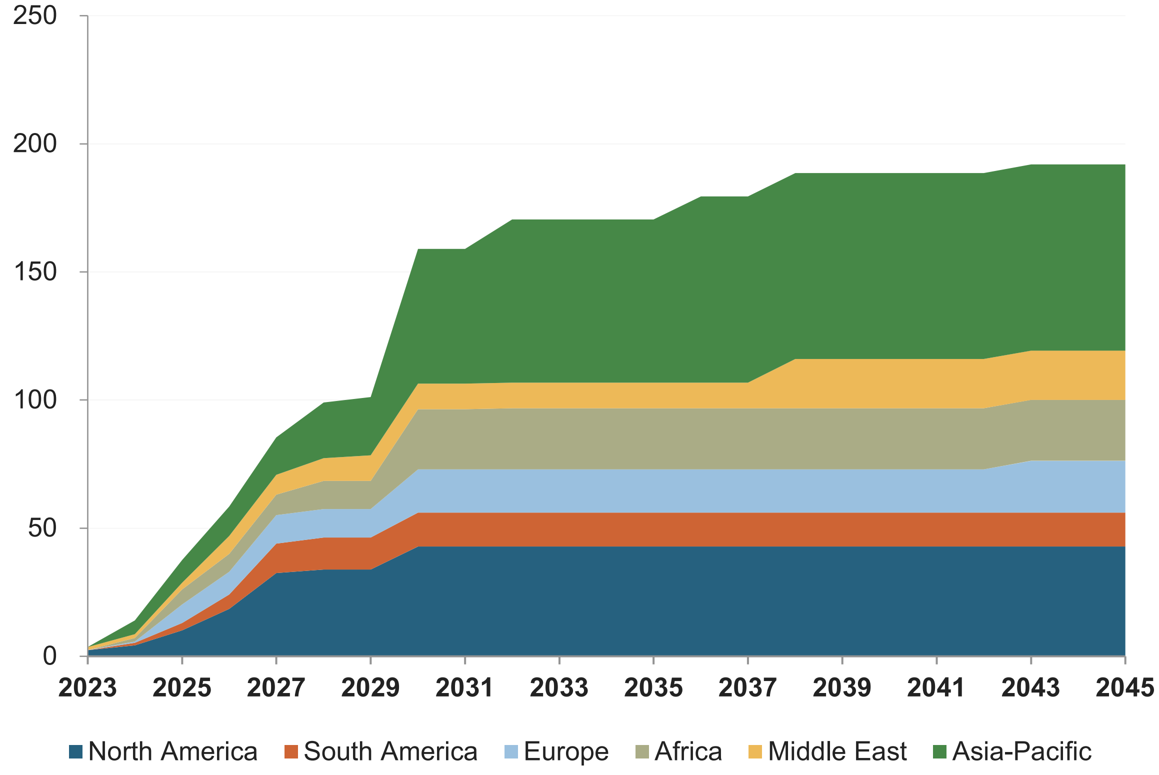
Transported in One Q-Max LNG Carrier Equivalent, GWh



- Importing seaborne ammonia to burn directly for electricity is difficult to justify from an EROEI (Energy Return on Energy Invested) perspective.
- Production of one ton of green ammonia, which contains 5.2 MWh of energy, requires approximately twice as much renewable electricity. When burnt at a coal or gas-fired plant, the green ammonia will yield even less electricity.
- Japan generated 307 TWh of electricity from coal in 2021.
- In order to replace 20% of this with direct burning of ammonia, the country would require approximately 20 mtpa of ammonia–this is equivalent to today's entire global international ammonia trade.

Clean ammonia market outlook by region

Global Announced Clean Ammonia Production Capacity by Region, mtpa

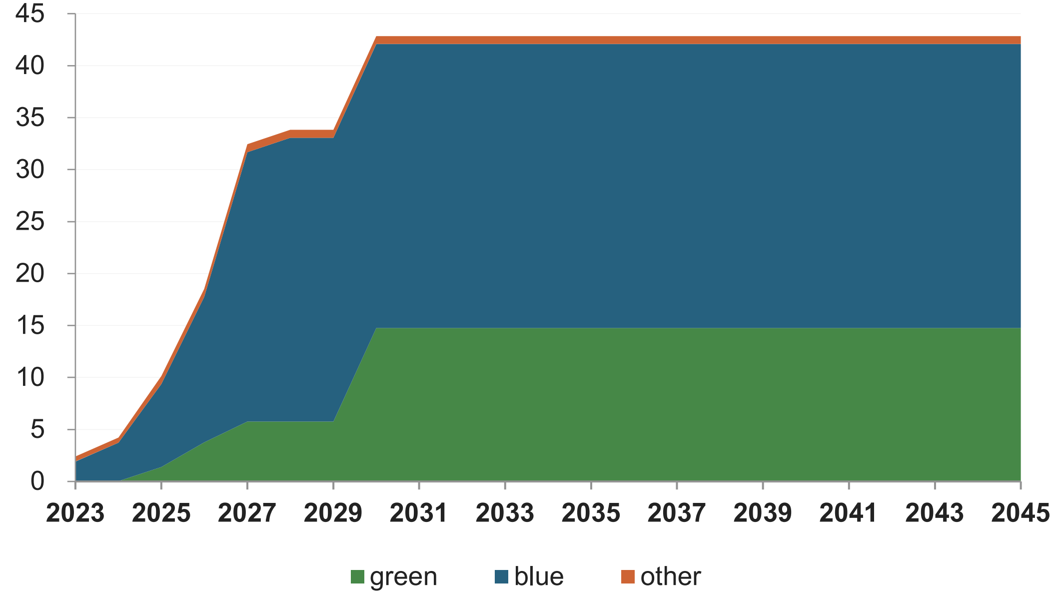


Source: FGE

- We expect North America and Asia Pacific to play a substantial role in global clean ammonia production, with 42.8 mtpa and 72.6 mtpa of announced capacity by 2045, respectively.
- The Middle East looks set to play a more significant role for clean ammonia production than for clean hydrogen, with the 19 mtpa of announced capacity of ammonia production by 2045 amounting to 10% of the global total.
- South America has announced 13 mtpa.
- As with green hydrogen, green ammonia production capacity is ultimately limited by the amount of available renewable power generation.
- Several mega-scale planned green ammonia projects intend to utilize bespoke renewable power generation, offsetting this effect to a degree.
- InterContinental Energy's Asian Renewable Energy Hub (Australia) with 26 GW of dedicated solar and wind planned and Western Green Energy Hub (Australia) with 50 GW dedicated solar and wind planned.
- CWP's AMAN Green Hydrogen Project (Mauritania), with 30 GW dedicated solar and wind.
- InterContinental Energy's Green Energy Oman Al-Wusta Project (Oman) with 25 GW dedicated solar and wind planned.

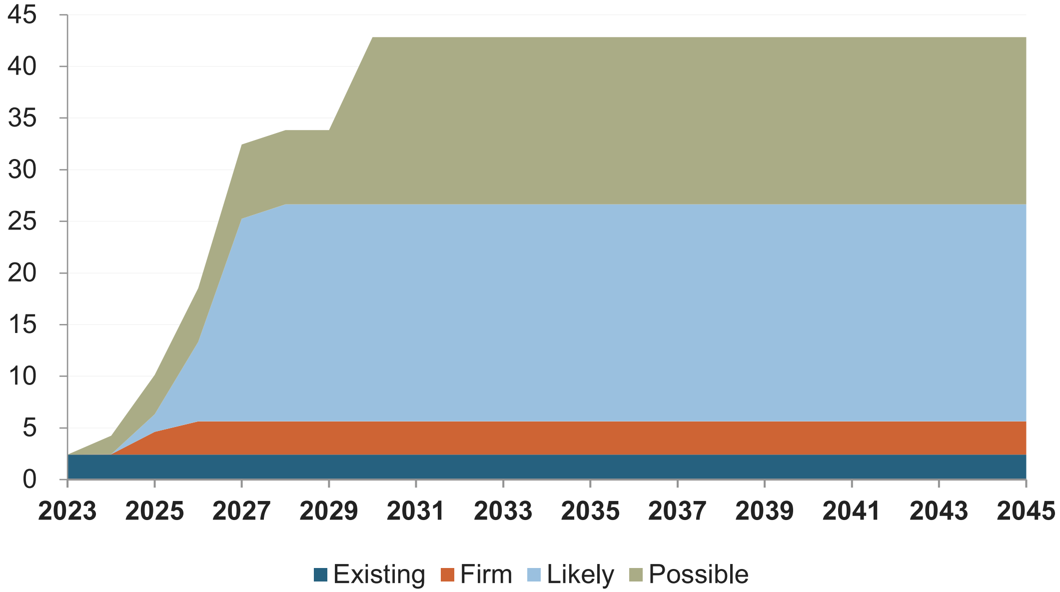
North American clean ammonia production based on proposed projects

North America Clean Ammonia Production by Likelihood, mtpa



Source: FGE

North America Clean Ammonia Production by Likelihood, mtpa



Source: FGE

- By 2045:
- **Green:** 14.7 mtpa (34.5%)
- **Blue:** 27.3 mtpa (63.7%)
- **Other:** 0.8 mtpa (1.8%)

- Planned projects up to 2045:
- **Existing:** 2.4 mtpa (5.6%)
- **Firm:** 3.2 mtpa (7.5%)
- **Likely:** 21.0 mtpa (49.1%)
- **Possible:** 16.1 mtpa (37.8%)

Selected US Clean Hydrogen and Ammonia Projects

Project	Category	End Product	End Use	Production Start	Project Status	Project Likelihood	Hydrogen Output Total, ktpa	CAPEX ($)
Hydrogen City Texas	green	hydrogen	undisclosed	undisclosed	feasibility study	possible	3,000	undisclosed
ExxonMobil Baytown	blue	ammonia	refining	2027	FEED	likely	929	undisclosed
OCI Beaumont Ammonia 2	blue	ammonia	export	2025	under construction	firm	793	$450 million
Air Products Louisiana Clean Energy Complex	blue	ammonia	undisclosed	2026	feasibility study	likely	690	$4.5 billiom
Adams Fork Energy Clean Ammonia	blue	ammonia	power generation	2026	planned	likely	389	undisclosed
CF Industries Mitsui TBC US Gulf Coast	blue	ammonia	agriculture	2027	FEED	likely	360	$2 billion
North Dakota Hydrogen Hub	blue	hydrogen	undisclosed	2026	feasibility study	likely	310	$2 billion
CF Industries Donaldsonville, Louisiana (blue retrofit)	blue	ammonia	agriculture	2025	concept	likely	306	undisclosed
HIF Matagorda USA	green	synthetic fuels	undisclosed	2027	feasibility study	likely	300	undisclosed
AmmPower Port of Louisiana	green	ammonia	marine fuel	undisclosed	concept	possible	263	undisclosed
CIP SFG US Gulf Coast	blue	ammonia	undisclosed	2027	FEED	likely	263	undisclosed
OCI Beaumont Ammonia 1	blue	ammonia	chemical feedstock	2021	operational	existing	263	undisclosed
Yara Enbridge EIEC Corpus Christi	blue	ammonia	undisclosed	2028	planned	likely	252	$2.9 billion
Nutrien Geismar Nitrogen	blue	ammonia	mining	2027	pre-FID	likely	216	$2 billion
Koch Grön Louisiana	green	synthetic fuels	transport fuel	2030	feasibility study	possible	175	$9.2 billion
DG Fuels SAF Louisiana	green	synthetic fuels	aviation	2025	feasibility study	possible	147	undisclosed

Source: FGE

- US has approximately 15.6 mmtpa of current announced clean hydrogen capacity
- Much greater role for blue hydrogen and ammonia than other regions such as Europe, Australia and even the Middle East
- Large emphasis on ammonia production, in part for export purposes but also more generally for other applications as well
- However, there are currently no Jones Act compliant ships capable of transporting ammonia to Hawaii so therefore purpose-built vessels may need to be built in the future or look to elsewhere like other production hubs such as China, India and Australia.

Selected Australian Clean Hydrogen and Ammonia Projects

Project	Classification	Category	End Product	Project Status	Project Likelihood	Production Start	Hydrogen Output Total, ktpa	CAPEX ($mil)
Asian Renewable Energy Hub	green	ammonia	undisclosed	FID 2025	likely	2036	1,621	36,000
Evergreen	green	hydrogen	export	concept	possible	undisclosed	1,226	30,000
CQH2 Gladstone - phase 2	green	hydrogen	undisclosed	feasibility study	possible	2030	900	undisclosed
Amp Energy Eyre	green	ammonia	export	planned	possible	2028	876	undisclosed
Cape Hardy Green Hydrogen Project Phase 2	green	ammonia	undisclosed	concept	possible	undisclosed	876	undisclosed
HyEnergy Zero Carbon Hydrogen - phase 2	green	hydrogen	undisclosed	concept	possible	2030	782	undisclosed
H2Perth Blue - phase 2	blue	ammonia	undisclosed	feasibility study	possible	2024	550	660
Collinsville Green Energy Hub Ark Energy plant	green	ammonia	undisclosed	proposed	possible	2030	525	4,800
H2-Hub Gladstone - phase 2	green	ammonia	undisclosed	planned	possible	2030	525	4,700
H2Perth - electrolysis - phase 2	green	ammonia	undisclosed	feasibility study	possible	undisclosed	525	500
Murchison Hydrogen Renewables Project	green	ammonia	mining	planned	possible	2030	525	12,000
Project GERI - phase 2	green	ammonia	undisclosed	planned	likely	undisclosed	525	undisclosed
Desert Bloom Hydrogen - phase 2	green	hydrogen	undisclosed	feasibility study	possible	2027	410	10,750
Port Pirie Green Hydrogen Project - phase 2	green	ammonia	export	planned	possible	undisclosed	365	500
Hunter Energy Hub	green	ammonia	undisclosed	feasibility study	possible	undisclosed	350	undisclosed
Sun Brilliance West Australia Project - phase 3	green	hydrogen	export	planned	possible	2028	310	6,800

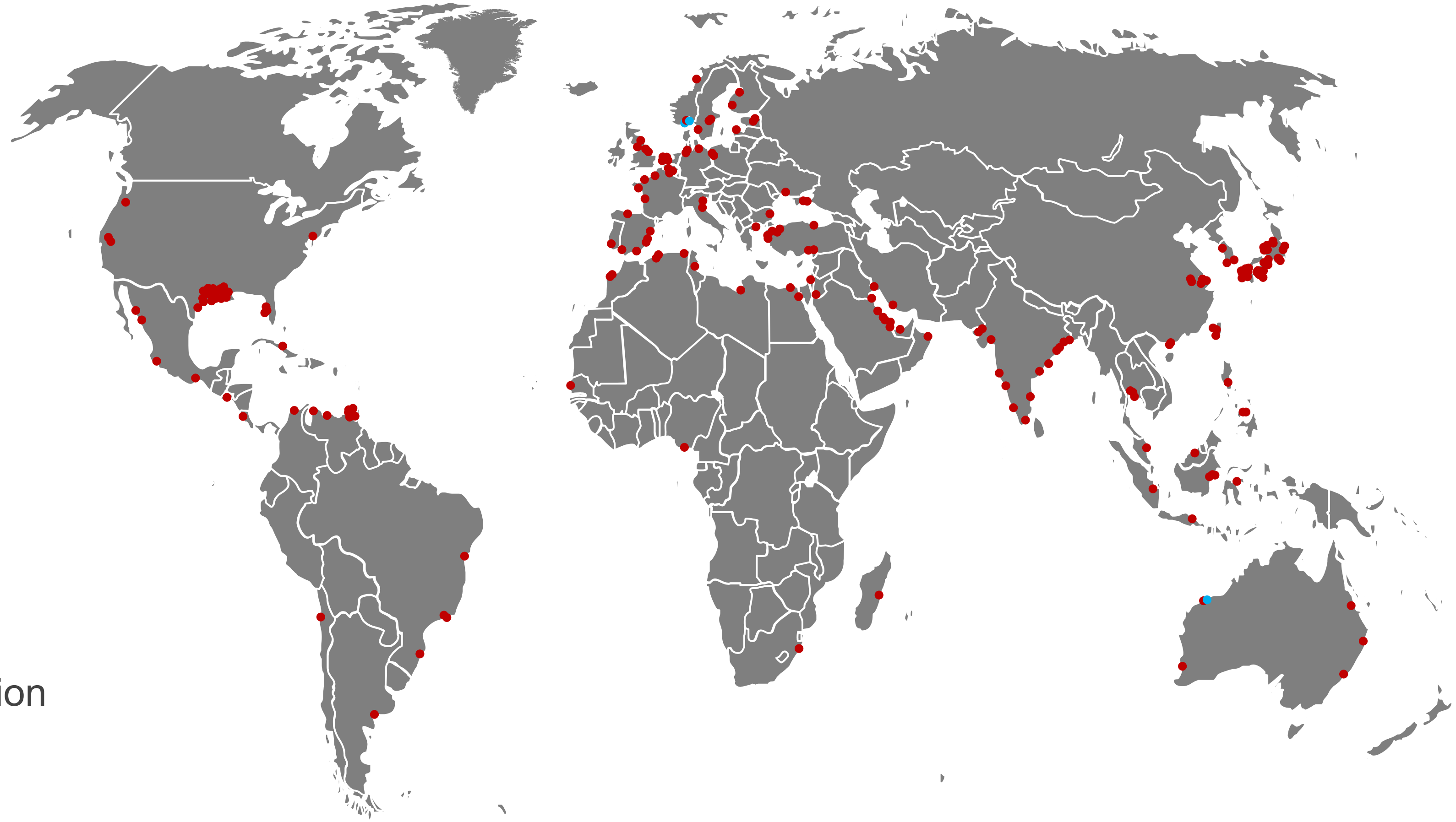
Source: FGE

- If there are no Jones Act compliant ships capable of transporting ammonia to Hawaii in the coming decade, the State could instead look to Australia which has planned hydrogen production capacity of approximately 18.7 mmtpa.
- Compared to the US, Australia has majority planned green hydrogen production, with a 95% share.
- Due to the expensive nature of green hydrogen production, the likelihood of these projects are not as strong as the US blue dominated hydrogen production.

Global ammonia terminals

Current total number: 206 terminals

Current total capacity: 5.5 mt

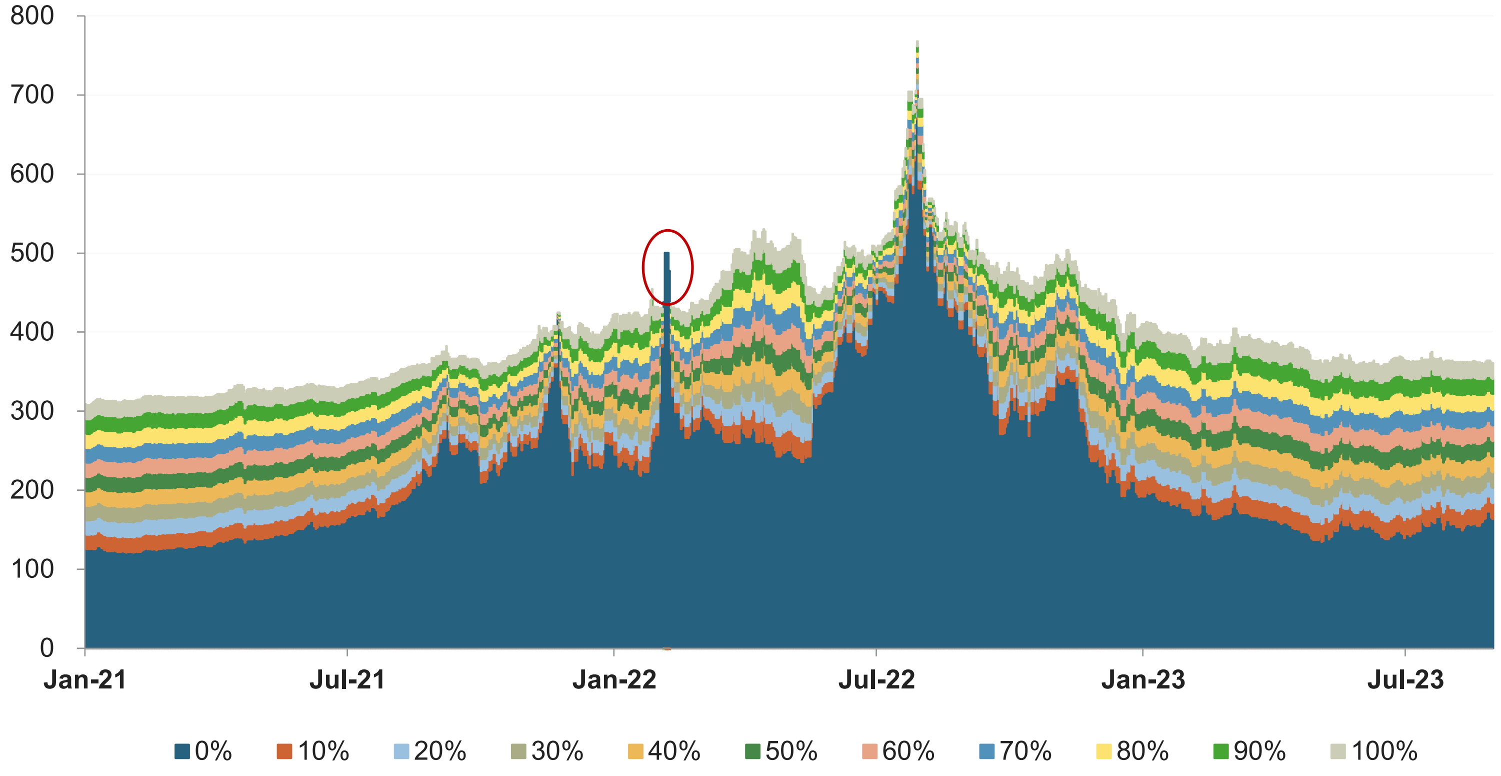


Key:
- operational
- under discussion

How much does green hydrogen production, storage, and co-firing cost?

Assuming a base carbon price of US$100/t, hydrogen co-fired power generation can become cost competitive at high natural gas prices

Levelized Cost of European Gas Fired Power Generation for Different Green Hydrogen Blending Rates, US$/MWh



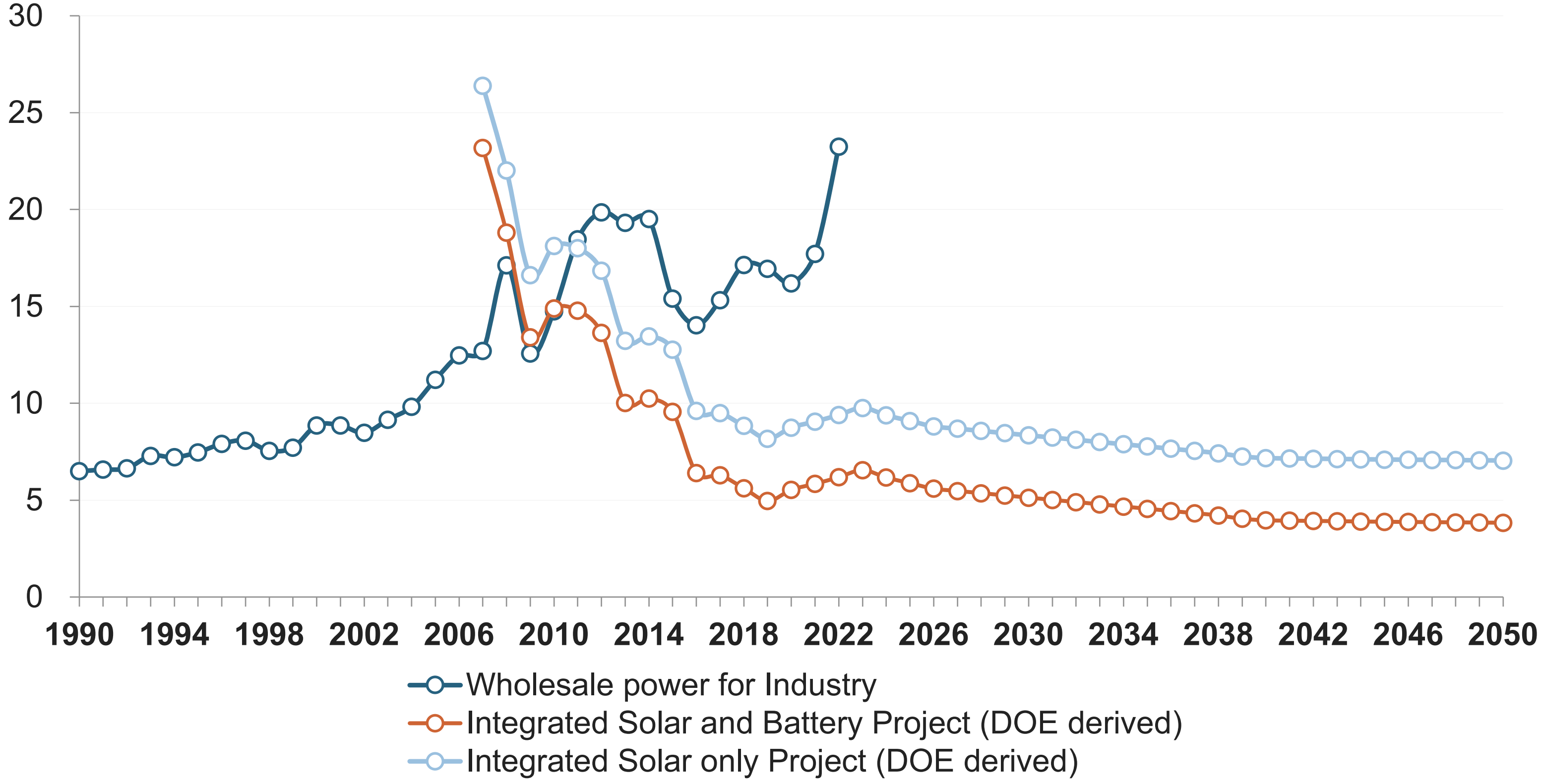
Source: FGE

- In Europe, when natural gas prices are relatively low, hydrogen co-firing comes at a substantial premium to natural gas-fired power generation.
- At higher gas prices, co-firing becomes increasingly viable.
- From January 2021 to October 2023, the spread between 30% green hydrogen co-fired and 100% natural gas fired power generation was US$52/MWh.
- For 100% hydrogen firing, this figure was US$173.35/MWh.
- Twice, however, high natural gas prices made hydrogen co-firing *cheaper*, both at 30% and 100% rates.

Levelized Cost of Green Hydrogen Production in Hawaii

Electricity cost is the main factor!

Levelized Cost of Electrolytic Hydrogen by Source (Grid versus Integrated Solar Projects), US$/kg



Source: FGE, EIA, DOE

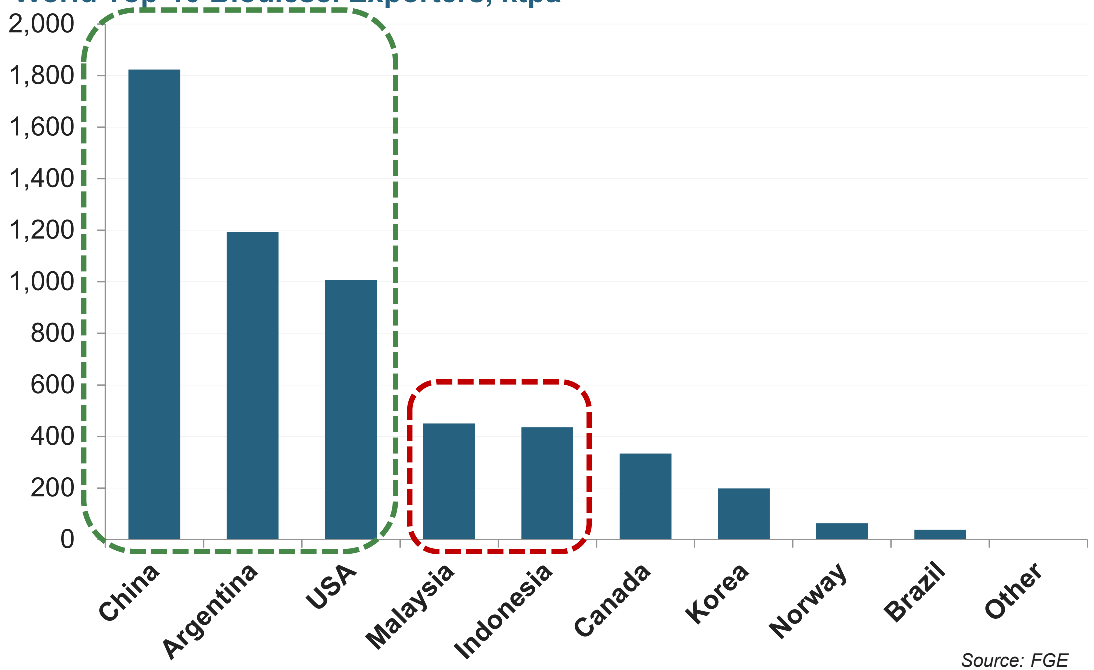
- Due to the high price and carbon intensity of grid electricity in Hawai'i the cost of producing electrolytic hydrogen from this method is prohibitive and not environmentally friendly.
- Using solar power for green hydrogen production should deliver significantly lower costs.
- However, in Hawaii it makes more sense to use solar for grid electricity rather than creating green hydrogen for power generation. Green hydrogen is more suitable and economic for hard to abate sectors like industry rather than the power sector.

Biofuels

Where will Hawai‘i be able to source its Biodiesel and Renewable Diesel from?

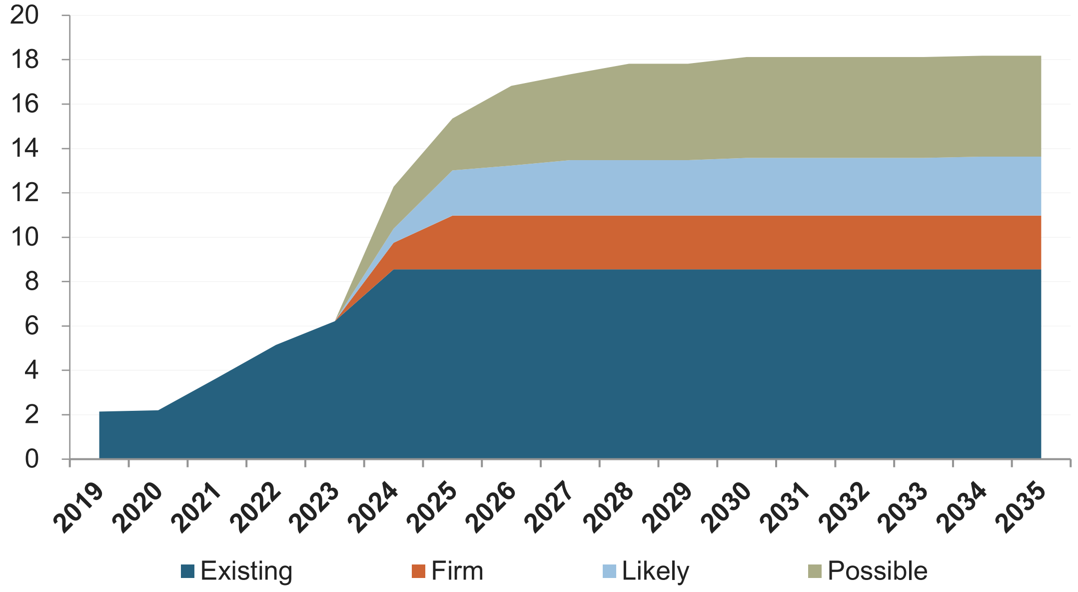
The US and future biofuels from Par will likely provide the bulk of Hawai‘i’s biofuel supply due to regulations restricting palm oil biofuels from S.E. Asia

World Top-10 Biodiesel Exporters, ktpa



Source: FGE

North America Renewable Diesel Production Outlook by Likelihood, mtpa



Source: FGE

- China, Argentina and the US are the world’s largest biodiesel exporters, followed by Malaysia and Indonesia. However, due to regulations restricting palm oil-based biofuels in the US and emissions associated with palm oil we don’t think Malaysia and Indonesia are viable sources of biofuel imports.
- North America has the largest planned renewable diesel production capacity growth during the coming years, accounting for 44% of global planned production.
- As of 2024, we estimate that US renewable diesel production from existing and firm projects will reach almost 11 mtpa in 2025.
- Biodiesel is a renewable fuel that can be manufactured from vegetable oils, animal fats, or recycled restaurant grease for use in diesel vehicles or any equipment that operates on diesel fuel. Renewable diesel is a fuel made from fats and oils, such as soybean oil or canola oil, and is processed to be chemically the same as petroleum diesel.

Can the US (Hawaii) import palm oil from Malaysia and Indonesia?

US biofuel production and the renewable fuel standard (RFS) program

Fuel Type	Lifecycle GHG Emissions Compared with the Petroleum Fuel it Displaces (%)	Fuel example	Feedstock
Biomass-based Diesel	50	Biodiesel	UCO, Soybean Oil, Canola Oil
Cellulosic Biofuel	60	Cellulosic Ethanol	agricultural residues (Corn starch), forestry residues (wood chips)
Advanced Biofuel	50	Renewable Diesel	UCO, animal Fats
Renewable Fuel	20	Ethanol	Corn starch

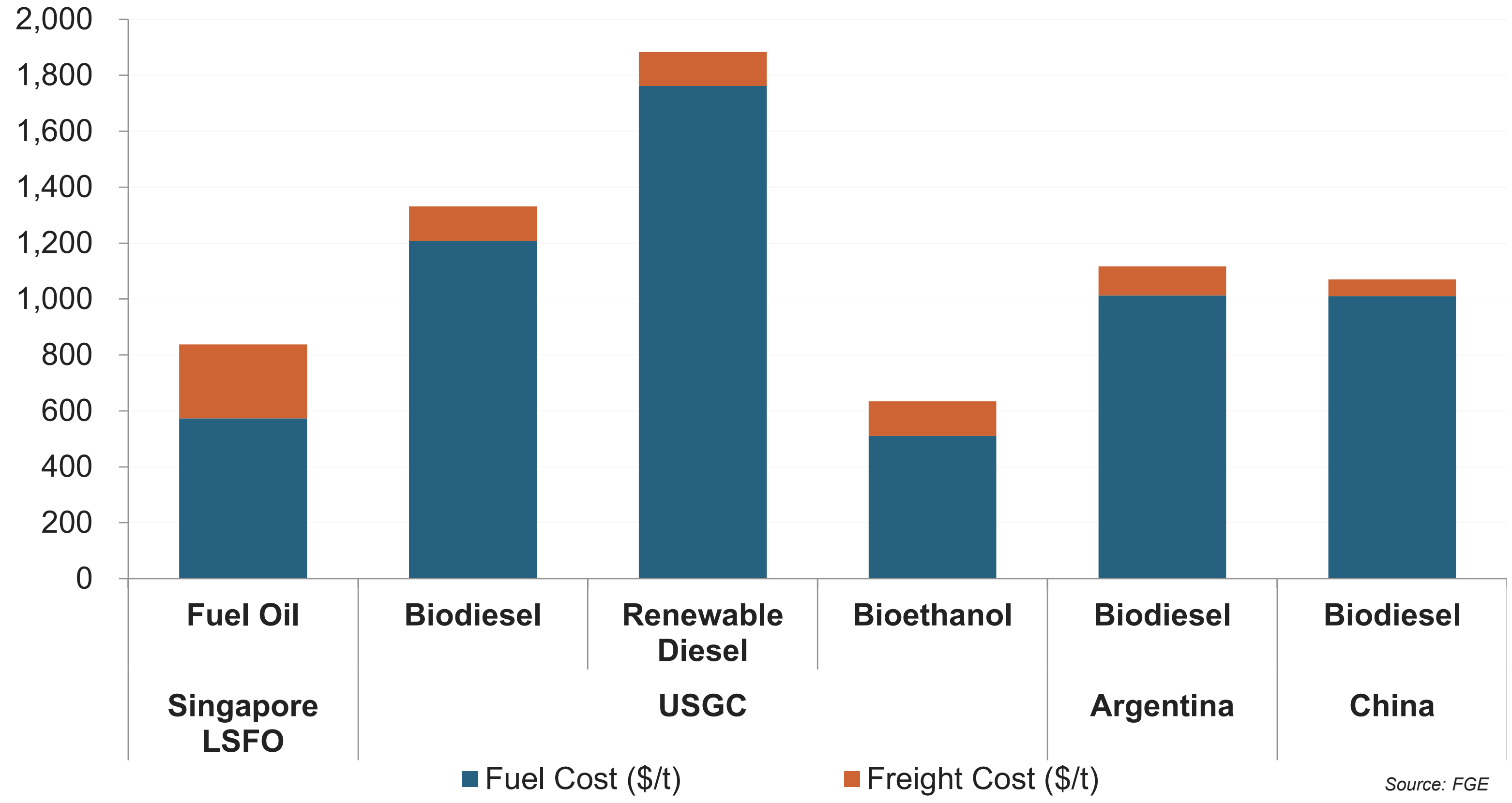
Source: US EPA
https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

- The US Environmental Protection Agency (EPA) has approved biofuel production pathways under the RFS program under all four categories of renewable fuels, as shown in the table.
- The US EPA preliminary findings of palm oil emissions analysis is that it does not reach the 20% lifecycle emissions reduction threshold to apply as a renewable fuel under the RFS.
- Meanwhile, production plants that began production or construction before December 2007 can produce RFS-eligible fuels from any renewable biomass, including palm oil.
- The US' approach is to prioritize domestic oils like soybean for renewable diesel, while imported palm oil may indirectly fill gaps in other sectors.
- This approach aims to support US agriculture and reduce dependence on imported oils for the growing biofuel industry.
- In 2023, the US government proposed the FOREST Act bill to prevent imports of products associated with de-forestation (five commodities including palm oil). However, the bill did not get sufficient backing from Congress to pass.

Cost of importing various categories of biofuels to Hawaiʻi

These price estimates for fuel oil and biofuels reflect current prices for 2024

Hawaiʻi Import Cost Comparison: Fuel Oil vs Biofuels from USGC, Argentina and China, US$/t



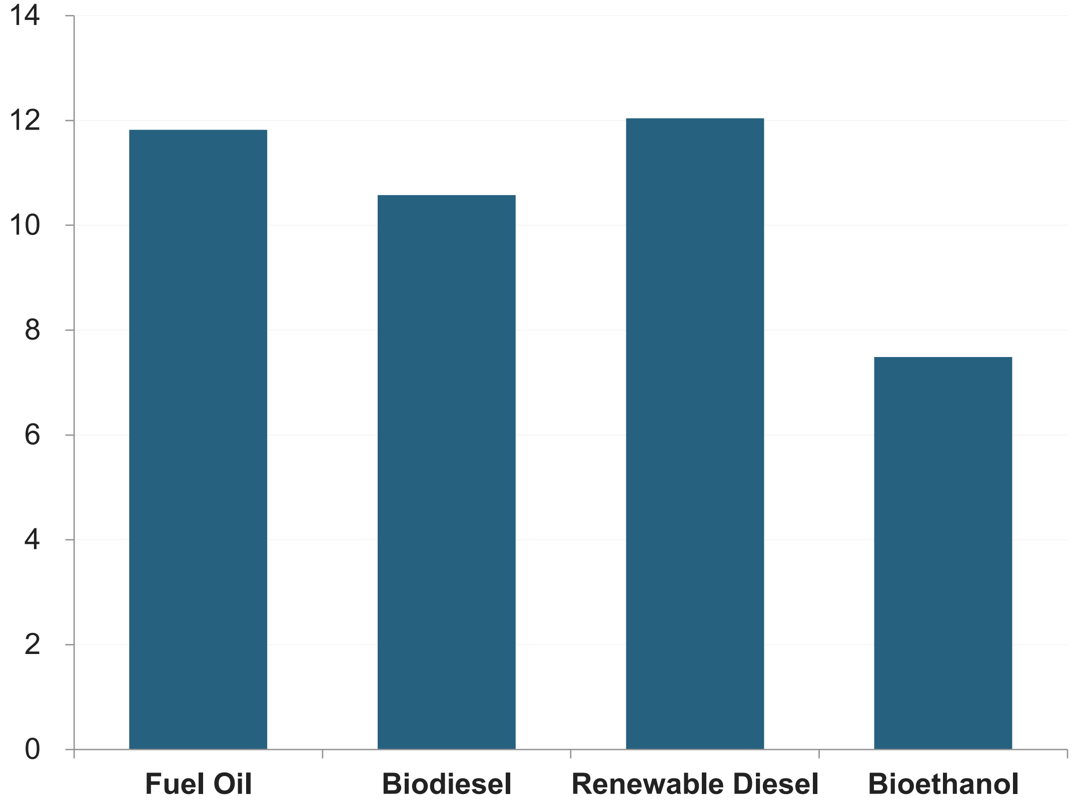
Source: FGE

- World's top-3 biodiesel exporters are China, Argentina and US.
- The only biofuel that is cheaper for Hawaiʻi to import in comparison to fuel oil is ethanol from the continental US.
- Biodiesel imports from Argentina and China offer slightly higher prices to fuel oil from Singapore.
- Both biodiesel and renewable diesel imports from the US are significantly costlier due to the higher product price.
- Note, while accounting for a small share of the overall import cost, freight costs from the US are generally higher than from Argentina and China.

Specific fuel emission comparison at the stack

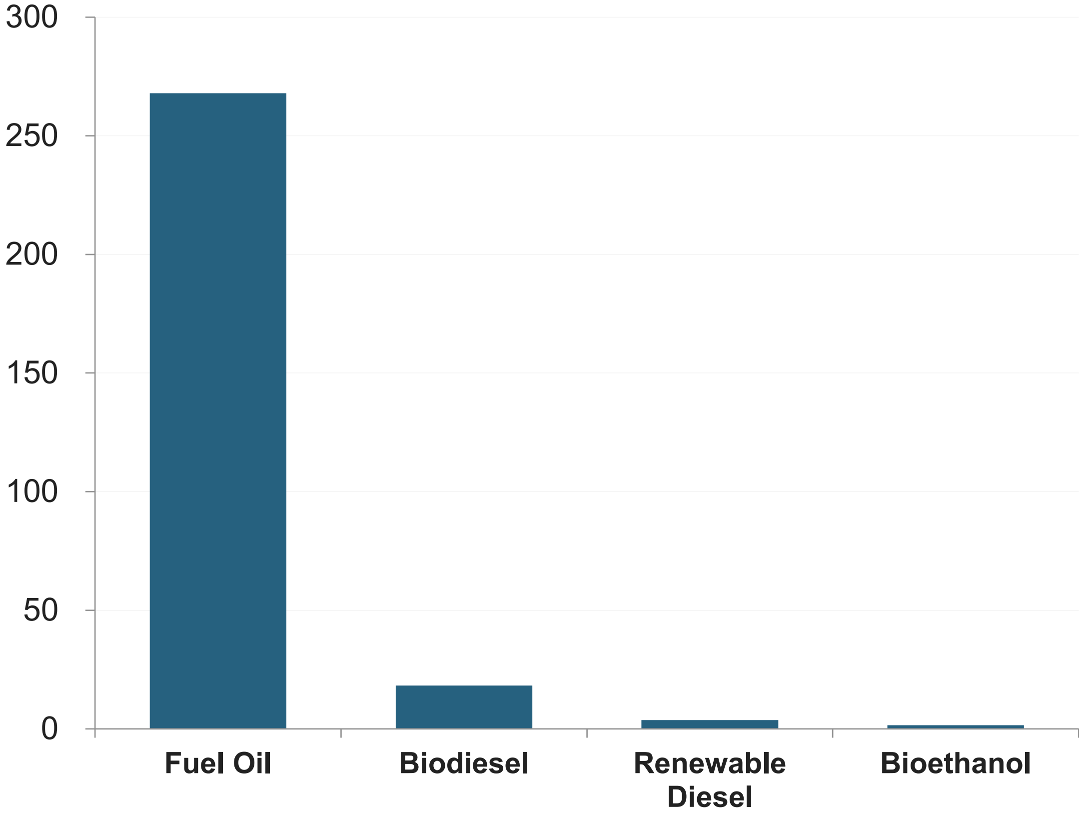
While fuel oil and biofuels have approximately the same specific energy densities, significant emissions reduction in power generation can be achieved by replacing fuel oil with biofuels.

Energy Density of Fuel Oil vs Biofuels (MWh/t)



Source: FGE

CO_2 Emissions of Fuel Oil vs Biofuels, kg/MWh*



Source: FGE

**Inclusive of biogenic emissions factor, values taken from Defra*

3. LNG System Cost and Savings

The “All-in” LNG cost can save Hawai‘i billions of dollars in fuel costs while lowering carbon emissions and complementing intermittent renewables

LNG for Hawai‘i: Background and Assumptions (1)

The timing is right for Hawai‘i to take advantage of a global LNG surplus in the late 2020s; linking to oil guarantees a discount on petroleum products as well as providing a cleaner burning fuel source

- In 2016, Hawai‘i Gas and a global LNG supplier had an integrated LNG Sales and Purchase Agreement for the supply of up to 1 million tonnes per annum (mtpa) of LNG for 15 years. The project was slated to come online in 2019. The LNG was to be shipped from abroad (no Jones Act issue) and stored 1-mile offshore Kalaeloa on a Floating Storage and Regasifcation Unit (FSRU) vessel. The LNG was to be regasified on the FSRU and sent onshore to Campbell Industrial Park to take advantage of existing infrastructure.
  - Hawai‘i Gas’ proposed infrastructure additions for the project included the FSRU, Buoy, Sub Sea Pipeline, Gas Treatment Facility, short Land Based Pipeline Extensions and a Power Plant Upgrade at a total cost estimated at US$400 million*.
    - Estimates place the total cost of the buoy, subsea pipeline, and pipeline extensions at US$200 million. This could be recovered in less than 1 year based on projected fuel savings vs oil.
    - Estimates place the total cost of the FSRU at US$200 million over 15 years, which would be recovered over the contract period. After the contract ends the FSRU could simply sail away and there would be no stranded asset.
  - The contract also had unique flexibility arrangements, allowing Hawai‘i Gas to flex down supply in future years as renewables continued to eat into oil’s share of power generation, which currently accounts for most of the power generation on Oahu. This type of arrangement can again be secured in the new contract thereby allowing Hawai‘i to continue its energy transition at a pace that best fits its needs.
- FGE was involved in supporting Hawai‘i Gas in their commercial discussion with the supplier. The price was linked to oil at a discount, thereby guaranteeing a fuel price discount to existing oil products. If Hawai'i choses to pursue the purchase of LNG, **FGE recommends that Hawai‘i again follows this pricing model, essentially guaranteeing a discount to competing oil products, LSFO and Low Sulfur Diesel.**

** Table 3, page,10. HawaiiGas response to HECO’s PSIP in January 2016*

LNG for Hawai‘i: Background and Assumptions (2)

The timing is right for Hawai‘i to take advantage of a global LNG surplus in the late 2020s; linking to oil guarantees a discount on petroleum products as well as providing a cleaner burning fuel source

- FGE has built a model looking at “All-in” costs for Hawai‘i to secure long-term (10-year) LNG supply via a floating, storage, and regasification unit (FSRU) that would be moored offshore Kalaeloa and commence in 2030. The following variables and costs have been assumed:
    - LNG demand scenarios of 0.4 million tonnes per annum (mtpa), 0.7 mtpa, and 1.0 mtpa. Demand would stem primarily from the power sector wherever oil is consumed in the State and to a lesser degree replacement of HawaiiGas’ SNG volumes and part of their non-utility gas volumes on Oahu. Moreover, additional demand could be created for LNG bunkering (i.e., Matson ships), power generation on military bases, and the transport sector (buses/garbage trucks, etc.).
    - A standard “vanilla” LNG supply contract that does not have any exotic “non price” terms such as the ability to flex up or down more than the standard 10% of the annual contract quantity, the ability to cancel a significant number of cargoes every year, etc. Hawai’i could tender for a supply contract that has volumes ramping down in the later years (like Hawai'i Gas), but this is impossible to model as it is project specific and negotiations over several other non-price terms would impact the price formula. Therefore, we have chosen an end date of 2040 for a standard LNG supply contract with straight line offtake. Further action could be taken for additional LNG imports beyond this date if warranted.
    - CAPEX costs for all associated infrastructure in this economic analysis have been provided by HDR (under contract with HSEO), while FGE has provided the fuel price forecasts for Brent, LSFO, and LNG delivered to Hawai‘i. While these CAPEX costs are preliminary, they provide the most updated cost estimates whereas previously the most recent data had come from HawaiiGas in their 2016 PSIP filing.* These figures are conservative and further engineering studies could result in even lower figures. The CAPEX numbers include the following:
        - US$300M for the FSRU, if one were to buy and convert an existing LNG ship; alternatively, the FSRU could be chartered at US$150,000/day.
        - US$108M for the buoy system for the FSRU and the sub-sea pipeline.
        - US$25M for onshore pipeline extension to Kahe and Wai‘au.
        - US$30M for an LNG import terminal on O‘ahu.
        - US$60M for storage on O‘ahu.
        - US$120M for a Jones Act-compliant ATB Barge.
        - US$58M for neighbor island (Hawai‘i /Maui) import facilities and LNG ISO containers for neighbor islands.
    - Note these costs are just looking at fuel costs and associated infrastructure to bring LNG to Hawaii and do not include CAPEX costs for any new power plants. Power plants will need to be upgraded regardless of the fuel supply source given the age of the existing fleet.

** Table 3, page,10. HawaiiGas response to HECO’s PSIP in January 2016*

LNG for Hawaii: Background and Assumptions (3)

The timing is right for Hawai‘i to take advantage of a global LNG surplus in the late 2020s; linking to oil guarantees a discount to petroleum products as well as providing a cleaner burning fuel source

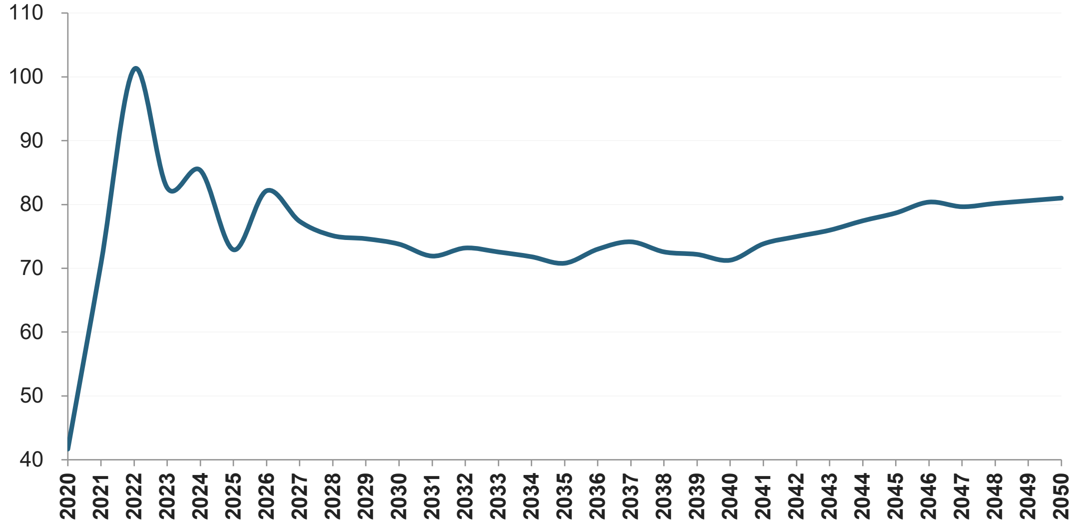
- FGE is confident that Hawai‘i could get a delivered LNG price with a slope of around 11.8% Brent plus a constant for volumes of at least 0.4 million mtpa over 10 years, commencing in 2030. This is assuming a standard “vanilla” LNG supply contract. Similar deals have been signed for LNG buyers for delivery around this timeframe and prices could even come down further given the upcoming supply pressure on the market. The formula we are using for this analysis is P(LNG)=.118*Brent+0.60
  - For example, at US$80/b the price of LNG delivered to Hawai‘i would be: 0.118*80+.60= US$10.04/MMBtu
  - FGE’s model allows for sensitivity analysis based on various potential “slope” offerings to see what the impact would be on the overall fuel price.

- FGE has also built a model for the FSRU costs that would allow Hawai‘i to either own the vessel or charter the vessel.
  - Purchasing the FSRU coupled with the infrastructure costs (US$700M) mentioned earlier would yield the lowest cost regasification tariff. The tariff decreases as throughput volumes increase, as economies of scale have a significant impact on FSRU costs. For example, the regas tariff at 1.0 mtpa would be $1.68/mmBtu, while the tariff would increase to $3.93/mmBtu at volume of 0.4 mtpa.
  - Chartering the vessel for 10 years coupled with the infrastructure costs (US$400M) mentioned above would cost slightly more than purchasing the FSRU. The regas tariff at 1.0 mtpa would be $1.93/mmBtu, while the tariff would increase to $4.55/mmBtu at volume of 0.4 mtpa.
  - The prices above need to be added to the fuel cost to get an “All-in” cost for LNG delivered to HECO’s Kahe and Wai‘au power plants as well as Kalaeloa Partners.

Background and Assumptions (4)

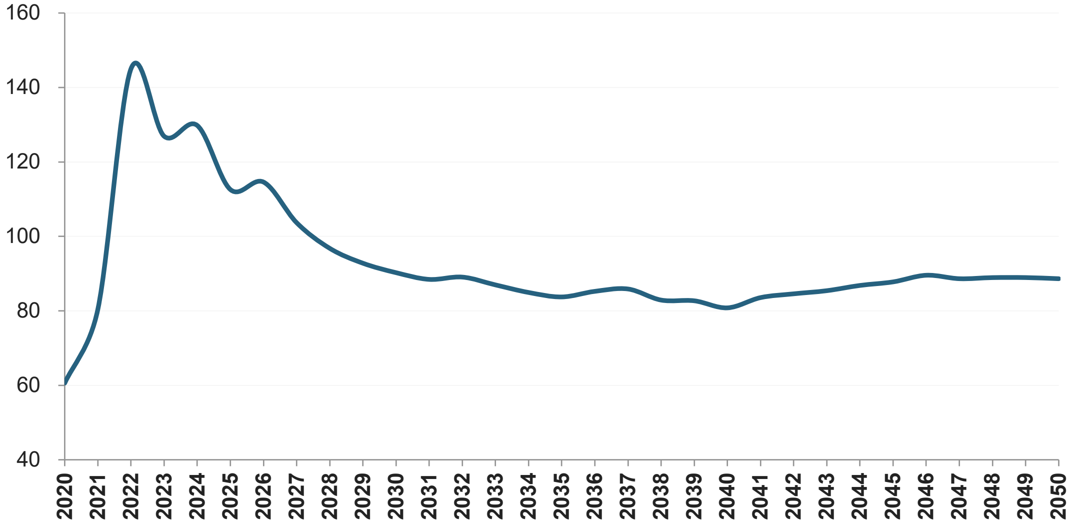
FGE's Brent long-term forecast drives our LSFO price forecast

Brent Crude Outlook, (Real 2024)
US$/b



Source: FGE, Forecast 2024 onwards

LSFO DES Hawai'i Outlook, (Real 2024)
US$/b



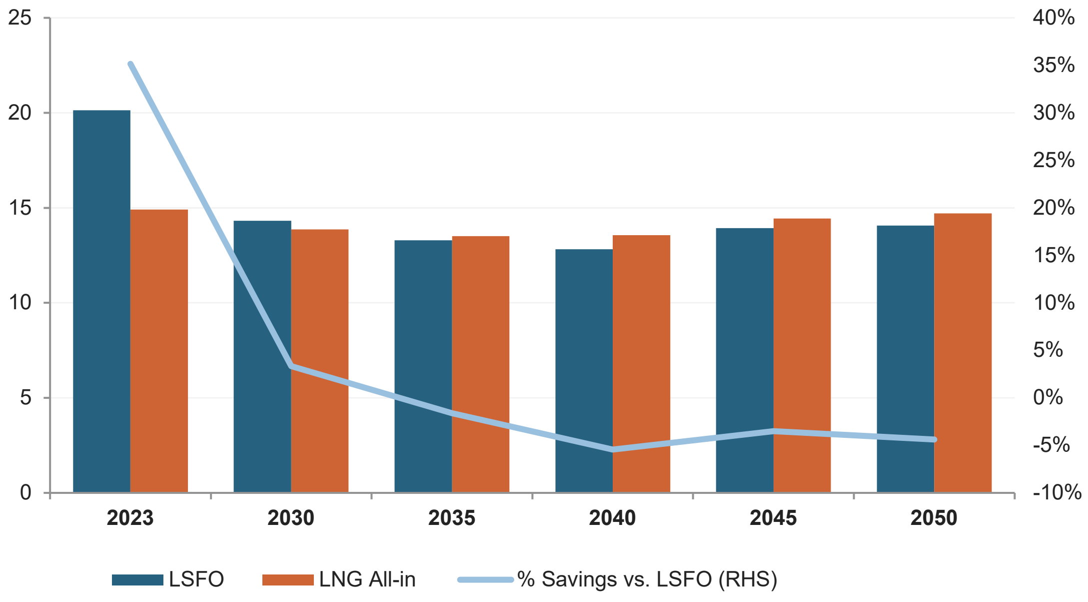
Source: FGE, Forecast 2024 onwards

- HECO's LSFO is sourced locally from Par and priced at a slight discount to import parity to ensure local consumption. For the sake of this analysis FGE will model the import cost of LSFO from Singapore, a major oil refining and price discovery center, to Hawai'i.
- FGE's LSFO DES Hawai'i price forecast is based on Singapore 0.5% LSFO which is a similar spec to HECO's fuel oil in their powerplants. The premium to Brent is primarily due to freight which has been under extreme pressure over the last couple of years due to shipping disruptions in the Red Sea.
- Based on DBEDT data, from 2020-2023 the historical price premium of LSFO over Brent ranged from a low of US$10/b in 2021 to a high of US$44/b in 2022 and 2023. Over the last 10 years this premium has averaged US$21/b.

At 0.4 mtpa LNG provides no savings for Hawai'i compared to LSFO

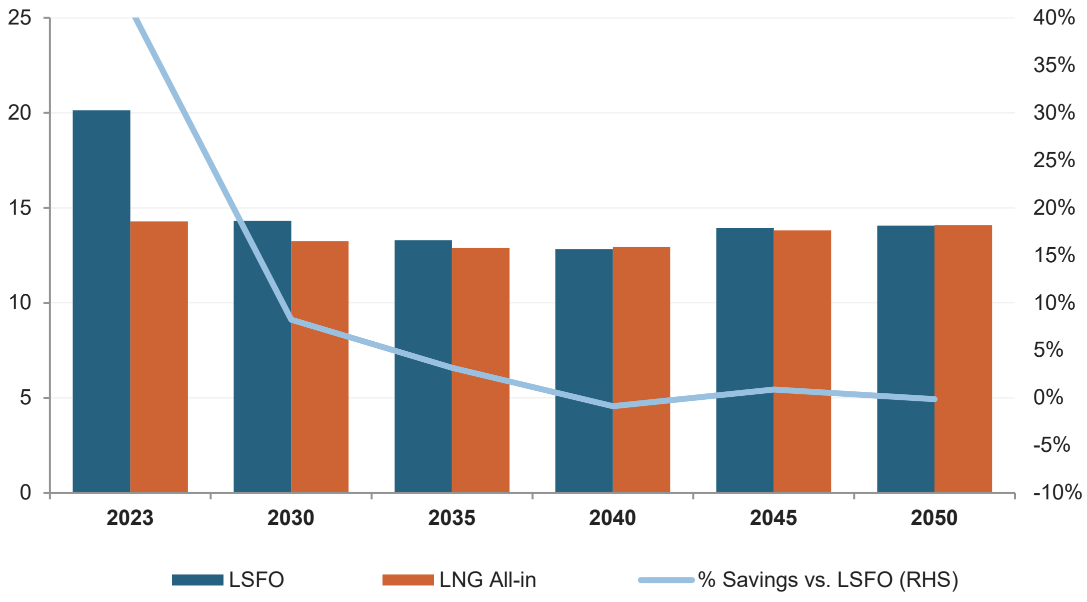
LNG imports at this volume provides environmental benefits compared to LSFO but zero savings under the FSRU charter scenario and minimal savings under the FSRU purchase scenario

LNG Savings vs LSFO under FSRU Charter (US$/MMBtu)



Source: FGE

LNG Savings vs LSFO under FSRU Purchase (US$/MMBtu)



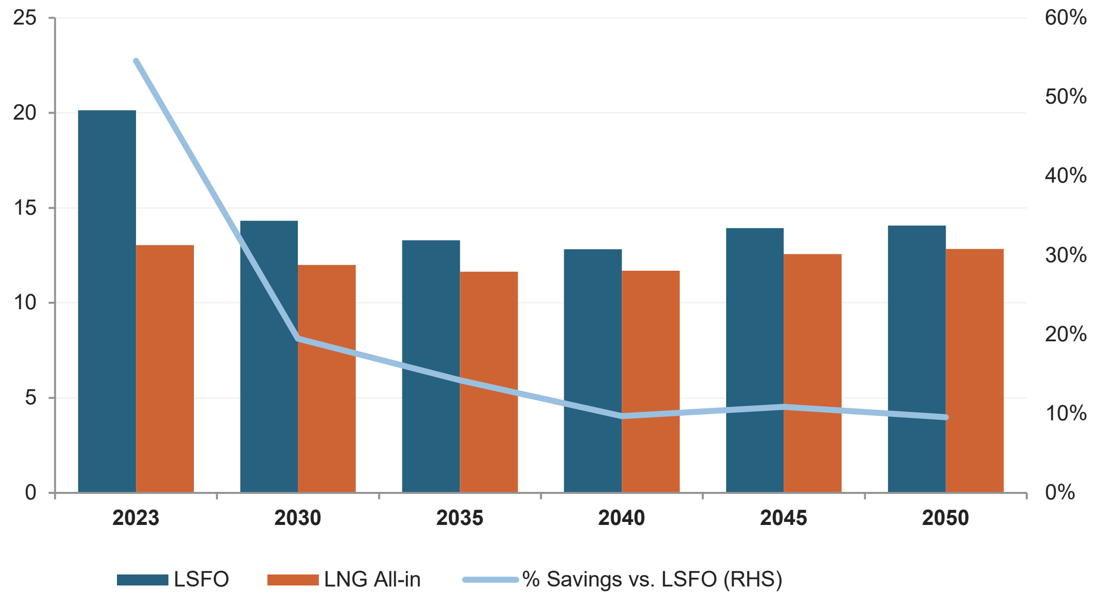
Source: FGE

- At 0.4 mtpa, Hawaii's LNG imports costs break-even versus LSFO under the more expensive FSRU charter scenario over 2030-2040. While more environmentally friendly then LSFO, there are no economic savings for consumers.
- At 0.4 mtpa, under the FSRU purchase scenario, Hawaii's potential LNG "All-in" annual savings vs LSFO are minimal. The average annual savings under this scenario is only 4%.

At 0.7 mtpa LNG provides savings vs LSFO whether you charter or purchase the FSRU

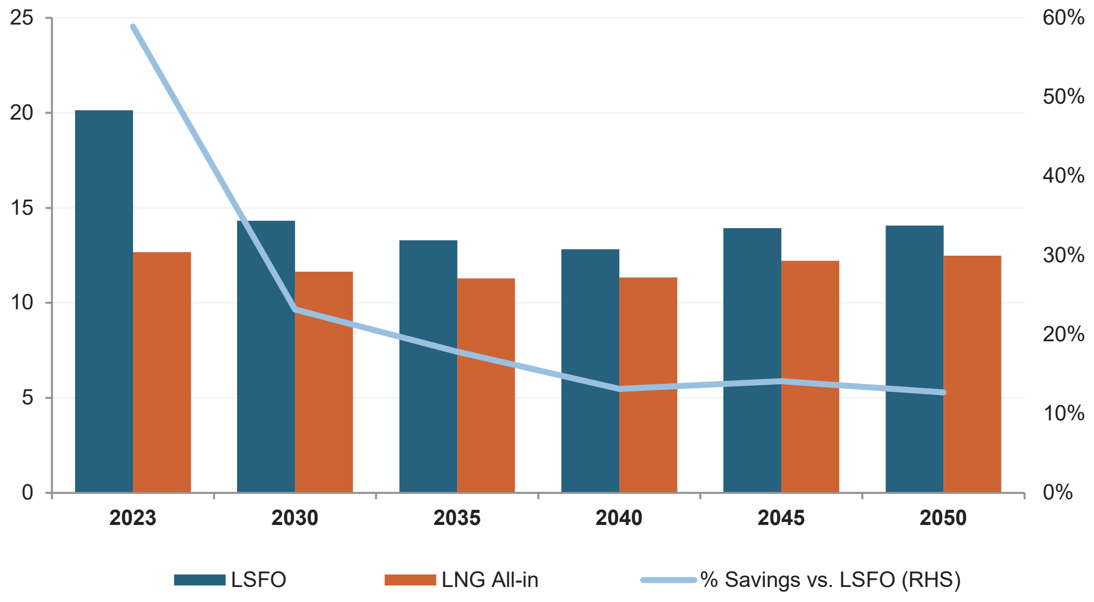
LNG imports at this volume provides environmental benefits compared to LSFO and noteworthy economic savings

LNG Savings vs LSFO under FSRU Charter (US$/MMBtu)



Source: FGE

LNG Savings vs LSFO under FSRU Purchase (US$/MMBtu)



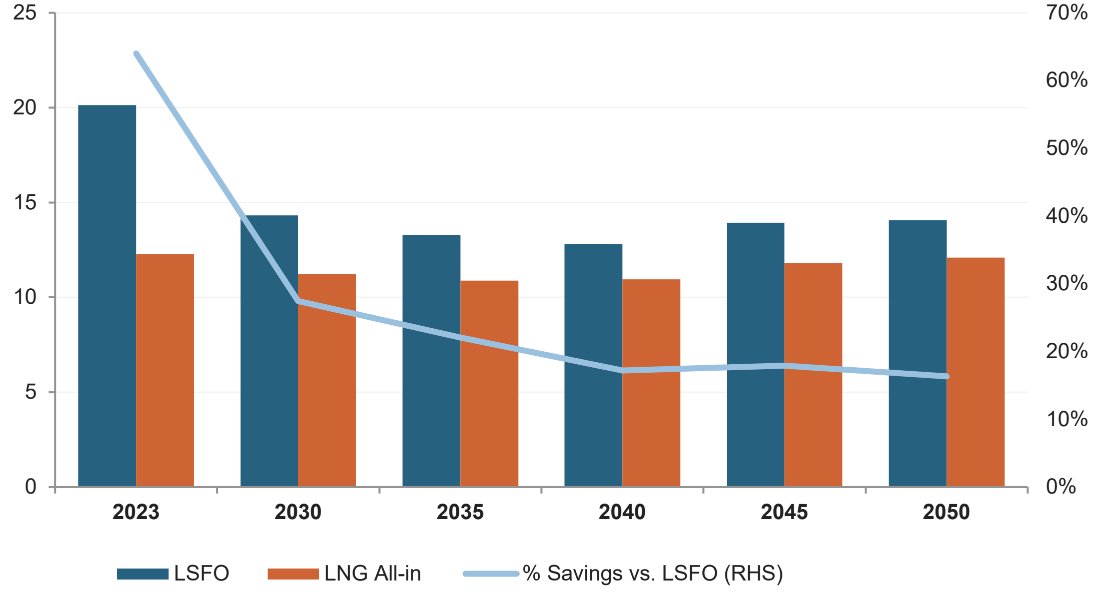
Source: FGE

- At 0.7 mtpa, Hawaii's potential LNG "All-in" annual savings vs LSFO will range between 10%-19% over 2030-2040 based on the more expensive FSRU charter scenario. Between 2030-2040, the average annual savings under this scenario is 15%. The economic savings will be in the hundreds of millions of dollars over the ten-year period.
- At 0.7 mtpa, under the FSRU purchase scenario, Hawaii's potential LNG "All-in" annual savings vs LSFO will range between 13-23% over 2030-2040. Between 2030-2040, the average annual savings under this scenario is 18%.

At 1.0 mtpa LNG provides savings vs LSFO whether you charter or purchase the FSRU

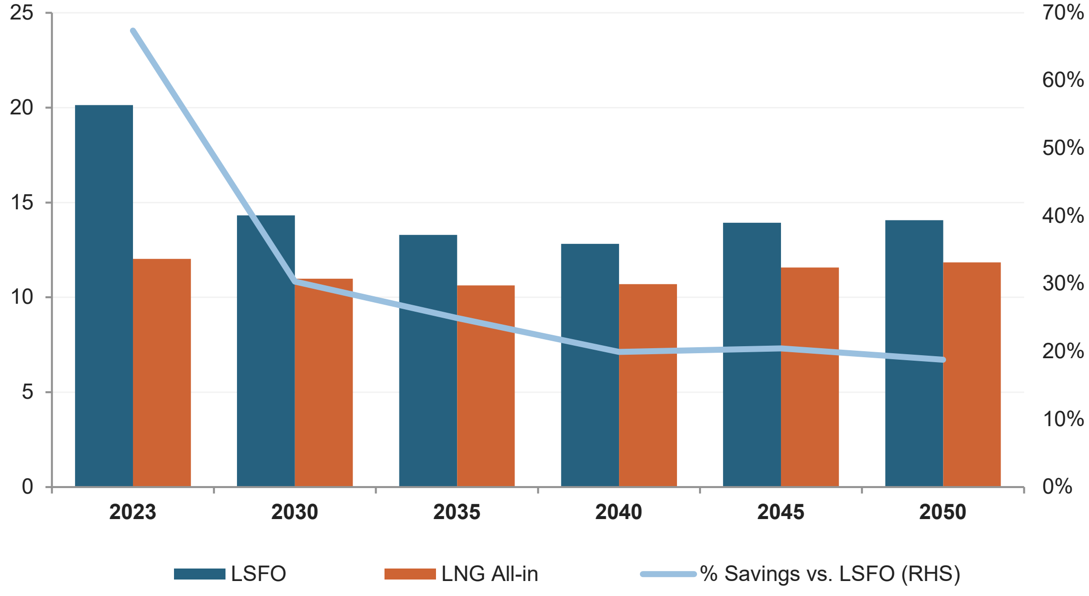
LNG imports at this volume provides environmental benefits compared to LSFO and significant economic savings

LNG Savings vs LSFO under FSRU Charter (US$/MMBtu)



Source: FGE

LNG Savings vs LSFO under FSRU Purchase (US$/MMBtu)



Source: FGE

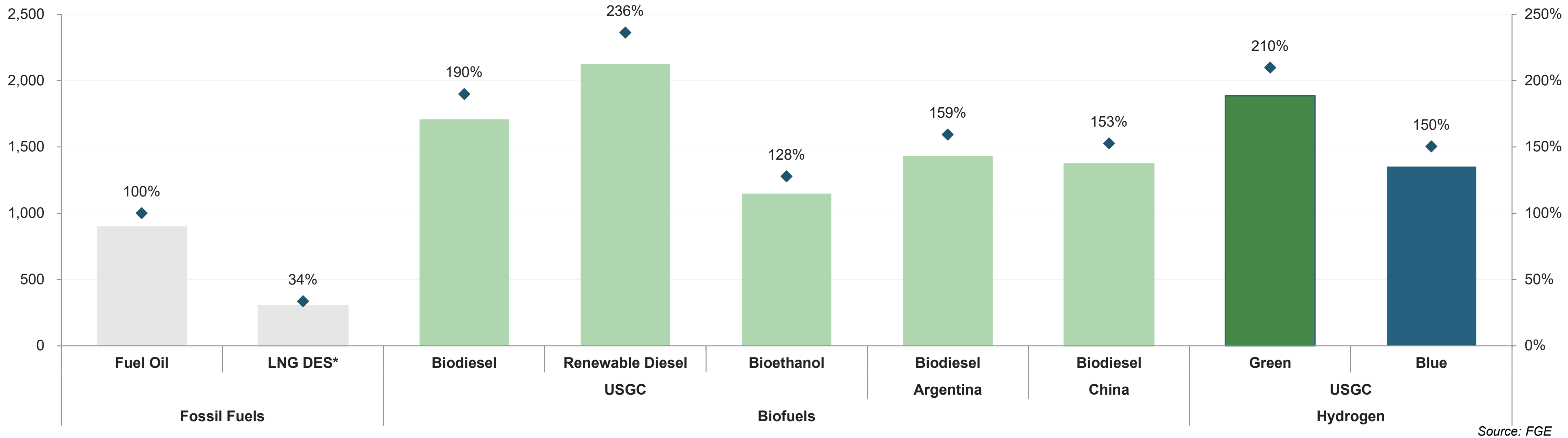
- At 1.0 mtpa, Hawaii's potential LNG "All-in" annual savings vs LSFO will range between 17%-27% over 2030-2040 based on the more expensive FSRU charter scenario. Between 2030-2040, the average annual savings under this scenario is 22%. The savings will be in the billions of dollars, providing significant electricity cost savings to Hawaii's citizens, especially ALICE families.
- At 1.0 mtpa, under the FSRU purchase scenario, Hawaii's potential LNG "All-in" annual savings vs LSFO will range between 20%-30% over 2030-2040. Between 2030-2040, the average annual savings under this scenario is 25%.

FGE FACTS GLOBAL ENERGY 40 YEAR ANNIVERSARY 1984-2024

Comparing costs of various alternative fuels for Hawaii (2024 estimates)

Based on 2024 commodity prices, LNG is the most cost-effective fuel for Hawaii

Cost of Alternative Fuel to Replace Fuel Oil Use in Power Generation based on 2023 Power Generation Data, US$ million and % of LSFO cost



Source: FGE

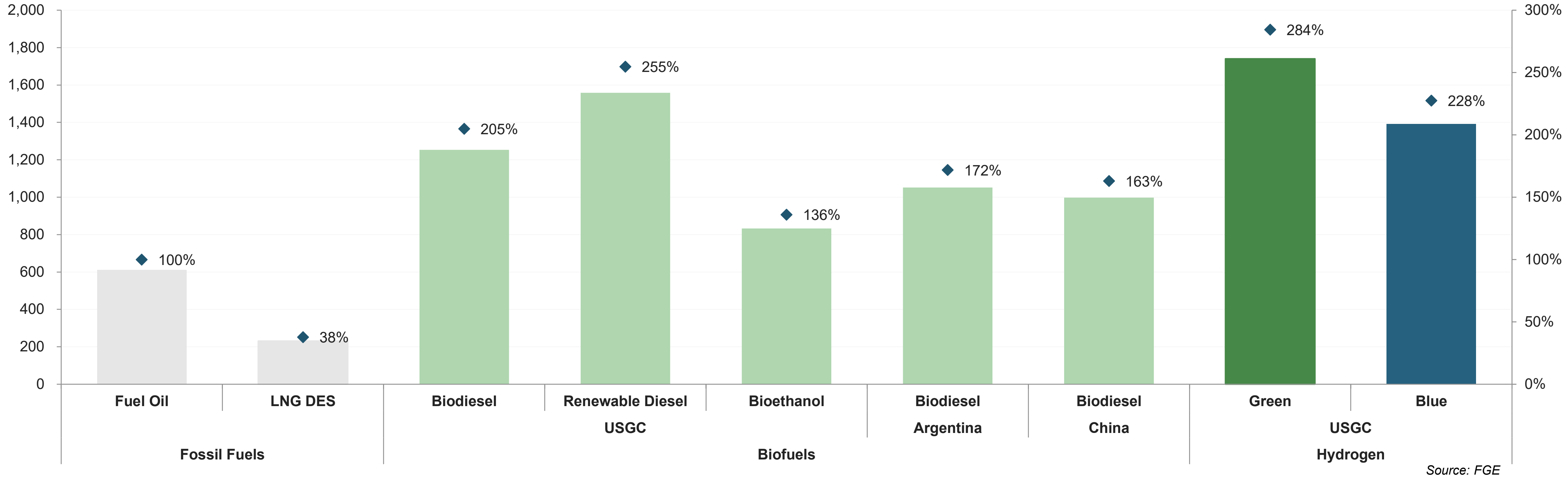
Source: FGE and DBEDT
**Assumes 1 mtpa under FSRU charter*

- Other than LNG, which would have presented cost savings of over 60% to low sulphur fuel oil (LSFO), alternative fuels for Hawaii's energy sector currently carry higher costs than LSFO.
- Efficiency rates and the energy content of various fuels significantly impacts power generation costs. In this analysis we are assuming 32% efficiency for petroleum products and LNG and 40% for biofuels. If new combined cycle gas turbine (CCGT) power plants are built, LNG efficiency will increase to 60% (see next slide).
- Green hydrogen, remains more expensive than biofuels, making it economically unviable in the short term, whereas blue hydrogen begins to compete with certain biofuels.
- Biodiesel sourcing options include Argentina, China, and the US Gulf Coast, but all involve price premiums compared with conventional fuels.

Comparing costs of various alternative fuels for Hawaii (2040 estimates)

Based on 2040 commodity prices in real US$ 2024, LNG is still the most cost-effective fuel for Hawaii

Cost of Alternative Fuel to Replace Fuel Oil Use in Power Generation based on 2023 Power Generation Data , US$ million and % of LSFO cost

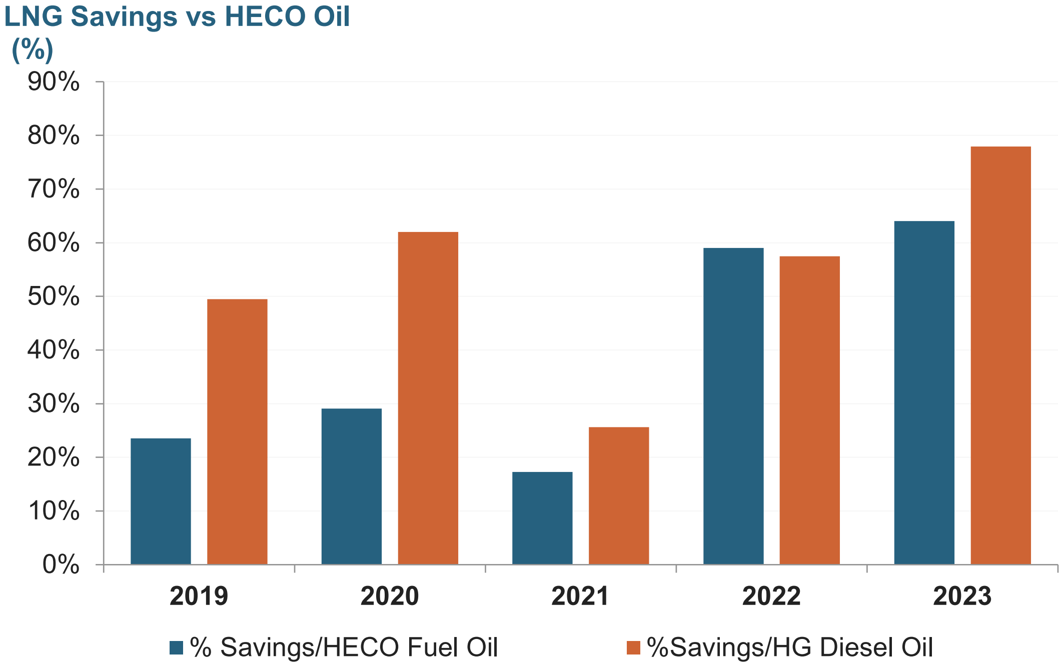


Source: FGE
**Assumes 1 mtpa under FSRU charter*

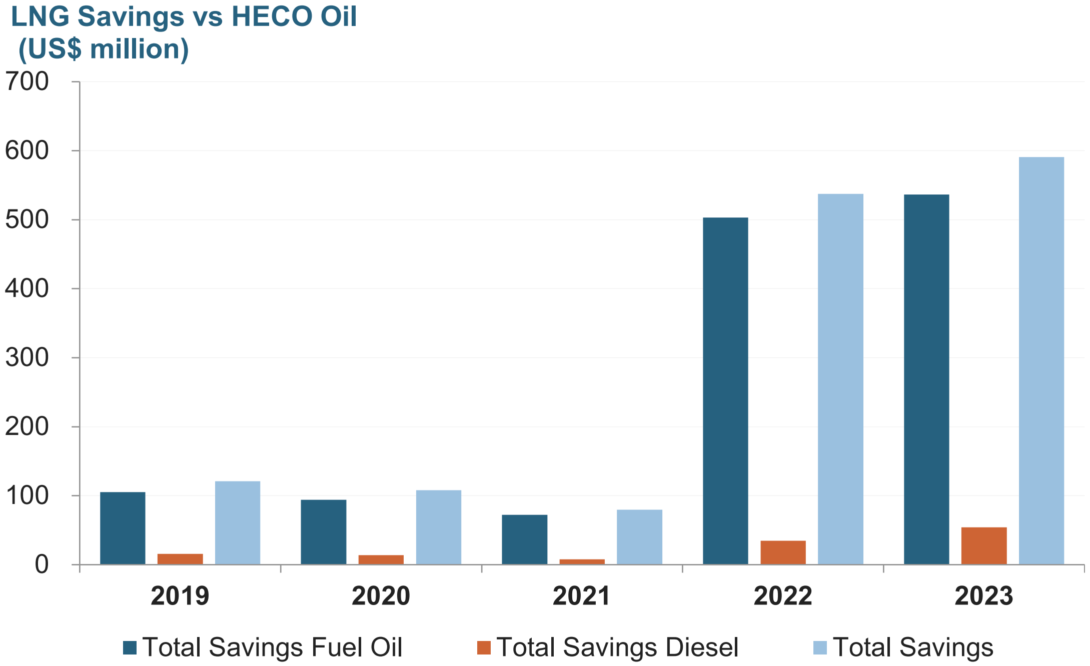
- Looking forward to 2040, LNG is still by far the most cost competitive fuel option. In this analysis we assume LNG will be running in a new CCGT with efficiency at 60%. We assume the same efficiency rates for petroleum products and biofuels as the previous slide.
- Most other alternative fuels such as biofuels and green hydrogen see their costs drop. The only exception is blue hydrogen as the cost of natural gas in the US is expected to increase in 2040 compared to 2024 levels, thereby increasing costs for blue hydrogen from natural gas.
- While absolute power generation costs drop for all fuels, the % cost increase is higher vs LSFO in 2040 due to lower LSFO prices in 2040 ($80/b) compared to 2024 ($130/b).

Backcast shows significant savings for Hawai‘i even with the FSRU under charter

Savings during the 2019-2023 period would have been more than US$1.4 billion over the 5-year period if Hawai‘i imported 1 mtpa of LNG instead of burning oil for power generation.



Source: FGE



Source: FGE

- Hawai‘i could have had SIGNIFICANT fuel savings if it had imported LNG instead of burning LSFO and diesel over the last several years, even under the more expensive charterer model for the FSRU. Moreover, it would have lowered carbon dioxide emissions by 2.9 billion pounds annually, equivalent to removing more than 250,000 cars from Hawai‘i’s roads.
- If Hawai‘i were to purchase the FSRU the savings would have reached over US$1.5 billion over the last 5 years.
- **Indexing your LNG supply contract to oil ensures that Hawai‘i will get a fuel discount to alternative oil products and provides a firm, and cleaner burning fuel source which can complement intermittent renewables.**

LNG Supply: Portfolio approach vs dedicated supply

Portfolio supply allows the supplier flexibility, resulting in more efficient and cost-effective deliveries vs dedicated supply

- Historically, LNG supply was traded on a point-to-point basis (i.e. Australia to Japan). Often, the developer of the export project required significant project financing for the billions of dollars in loans. To get the required financing, the developer would sign a long-term contract with a creditworthy offtaker and then take that contract to the bank to get the financing. This is how the global LNG business developed, and this type of trade was the standard for many decades.
- As the global LNG market matured and LNG projects were amortized, LNG suppliers had more options on how to place their volumes. They could sell volumes on a long-term basis, mid or even short-term basis, and even to less credit worthy markets that had strong growth potential. Moreover, a lot of these developers were flush with cash and benefited from the rise of commodity prices over the last 15 years. This led to strong balance sheets and in some cases, developers taking final investment decisions (FIDs) on new LNG supply without long-term contracts in place. The rise of new LNG export provinces such as the US and Canada, where natural gas was priced on different indices, further added to the optionality and liquidity in the market.
- The LNG industry is really a logistics play, rather than a commodity play. Most of the final delivered cost is tied up in the transformation of the natural gas itself to LNG (liquefaction) and then shipping this specialized product to an end user market. In many cases the cost of the commodity itself is a fraction of the overall delivered LNG price. For example, last year in the US the cost of natural gas feedstock to Japan accounted for around 25% of the delivered LNG price to Japan.
- As liquidity in the market increased and developers built new LNG export supply in various parts of the world, they began to offer “portfolio” LNG supply instead of LNG supply dedicated from a specific project. Under a portfolio supply approach, LNG volumes, with specific pre-agreed upon gas quality specifications, could be sourced from anywhere in the world where the LNG supplier has access to volume. It could come from Australia, Qatar, USA, etc. if it met the required volume needs and gas specifications of the buyer. By enabling this flexibility, suppliers can offer lower prices as they can now provide the lowest cost sources of supply depending on factors such as domestic natural gas prices, shipping rates, etc. In most cases, portfolio supplies were priced cheaper than specific project dedicated supply as it allowed the LNG supplier the flexibility to deliver LNG efficiently.
- If a buyer does not want to source LNG from say fracked gas or a high emissions LNG project, they can ask the supplier to not include these sources as supply options. Of course, the more restrictions that are placed on supply options, the higher the price is likely to be. Buyers are increasingly asking LNG suppliers to account for GHG emissions in their LNG cargoes and this is something Hawai‘i can request if desired. Most major LNG exporters are part of the International Group of Liquid Natural Gas Importers (GIIGNL) framework, which provides a common source of best practice principles in the monitoring, reporting, reduction, offsetting and verification, of GHG emissions associated with a delivered cargo of LNG.

4. LNG Technology and Function Requirements

An FSRU import solution is the best option for Hawai‘i as it minimizes cost and onshore infrastructure; it is also a deployable asset that can sail away once the contract is over.

FSRUs/FSUs provide quick and flexible access to LNG/natural gas

Onshore Terminal

Pros

- Site-specific and optimized design, plus potential integration with power plants.
- Send-out capacity of onshore terminal can be much higher than for FSRUs.
- Large onshore storage capacity can provide resilience to supply interruptions.
- Operating costs are typically lower than FSRU charter rates.
- Easier expansion, subject to land availability.

Cons

- It may be the most expensive option.
- Long construction period (3-4 years).
- Availability of land may be a challenging issue.
- Permitting procedure is typically more complex than for FRSU projects.

FSRU

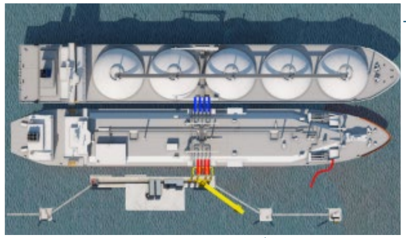
Pros

- Lower initial CAPEX.
- FSRU/FSUs can be chartered through mid- or long-term contracts.
- Faster implementation, if a suitable FSRU/FSU is available in the market.
- Flexibility to meet gas demand in multiple locations.
- Permitting procedure is easier than for onshore terminals.
- Minimal or no land requirement.
- Lower environmental impact.

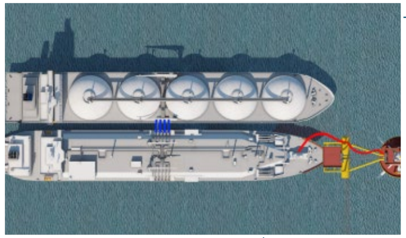
Cons

- Operating costs can be higher if ship is chartered.
- Throughput is limited by capacity of the on-board regasifiers (typically 500-750 MMscf/d baseload and up to 1 Bscf/d peak load).
- Limited storage capacity.
- Limited potential for vessel capacity expansion.
- No backup in case of delay in delivering a cargo.

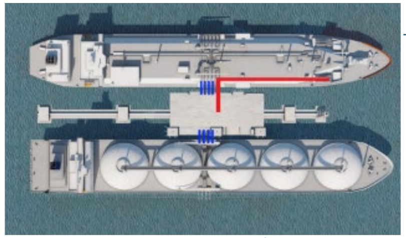
Common FSU/FSRU Configurations



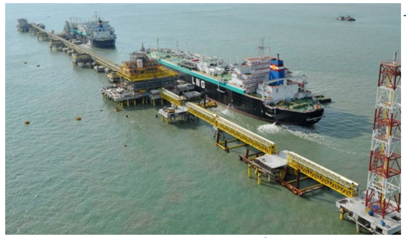
Single berth FSRUs, for instance in Nusantara Regas Satu, Salvador Brazil, Dubai. LNG ships can moor alongside the FSRU and offload LNG for regasification. This low-cost option works best in protected harbors or near-shore with water depths of 15-30 meters and mild weather conditions.



Singe Point Mooring FSRUs. There are numerous mooring options, depending on the site and conditions. Some specific solutions include mooring towers, yokes, and turrets (internal or external to the FSRU). Examples: Lampung, offshore Livorno Italy.



Cross-dock FSRUs: Segregated berths for LNG ships and FSRUs provide flexibility and improved availability. This design allows for adding more vaporizer capacity and further berths for an FSU or another FSRU. Examples: Guanabara Bay Brazil.

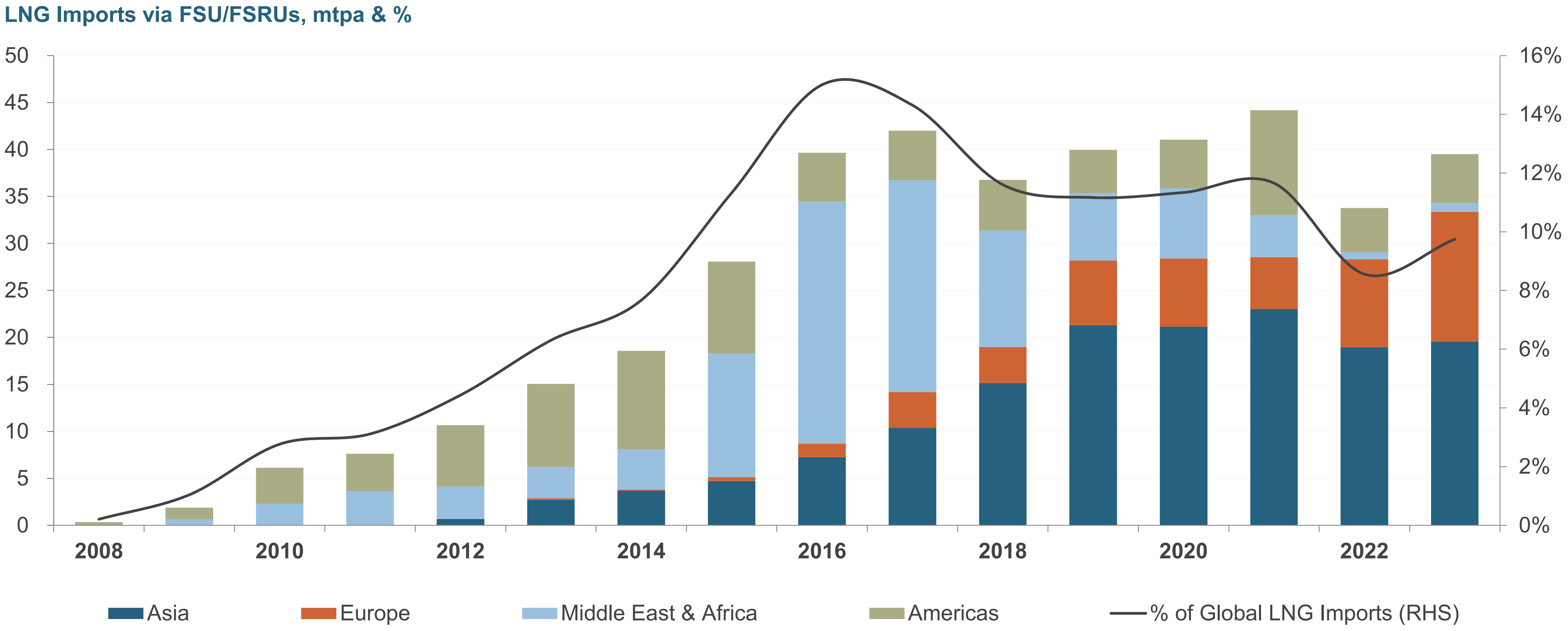


The regasification unit can be installed on jetty while the storage units can be FSUs. There may be a similar design that utilizes an onshore regasification unit connected to an FSU. Malaysia, Malta, and Bahrain are some examples using FSU in their LNG import terminal design.

Regasification unit can be developed on a floating platform/barge, while it can utilize an FSU for LNG storage. Such a design was proposed, and a unit was built for LNG imports to Ghana. But the project never materialized due to affordability issues for paying high LNG import prices. The FRU unit is currently laid-up.

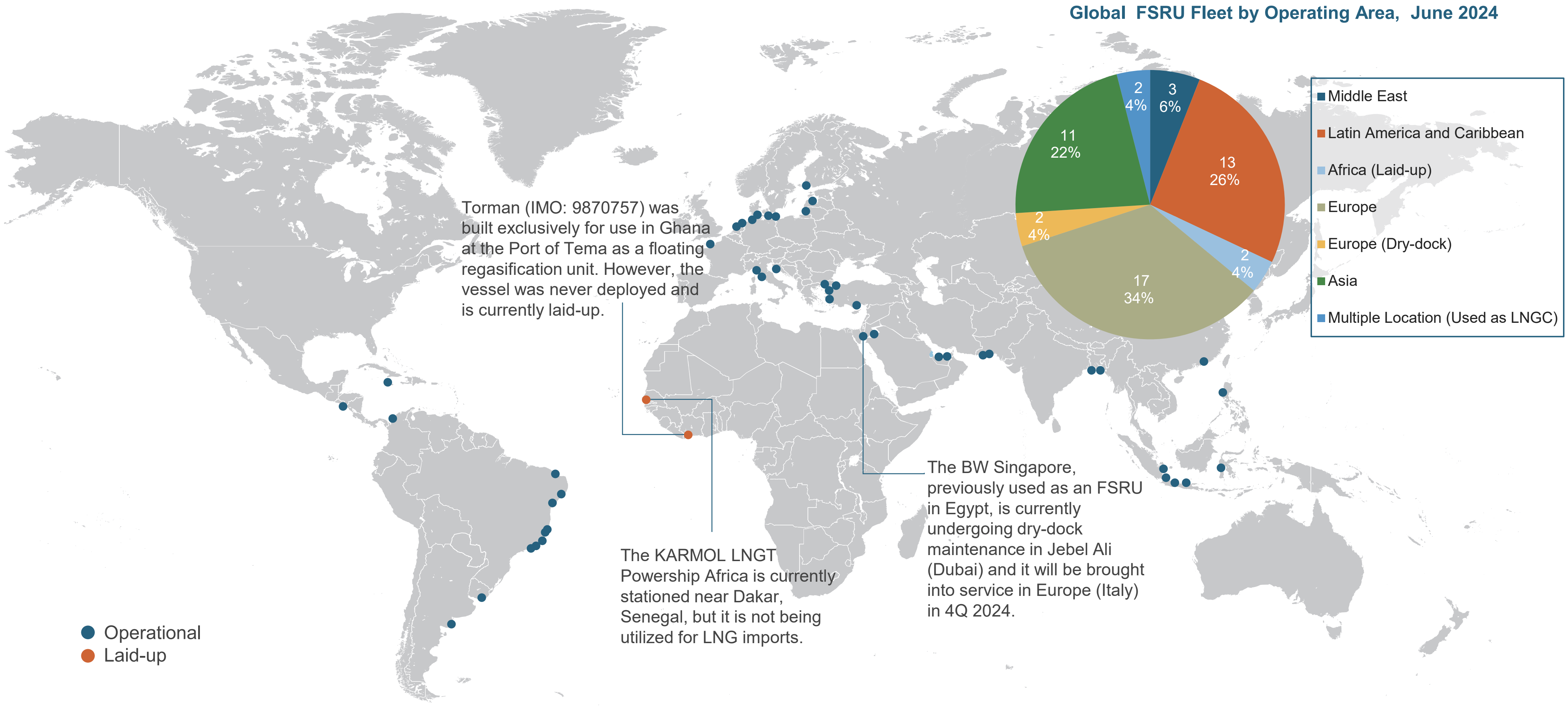
Source: ExxonMobil, FGE

About 10% of global LNG imports are through FSRU/FSU projects



Source: FGE

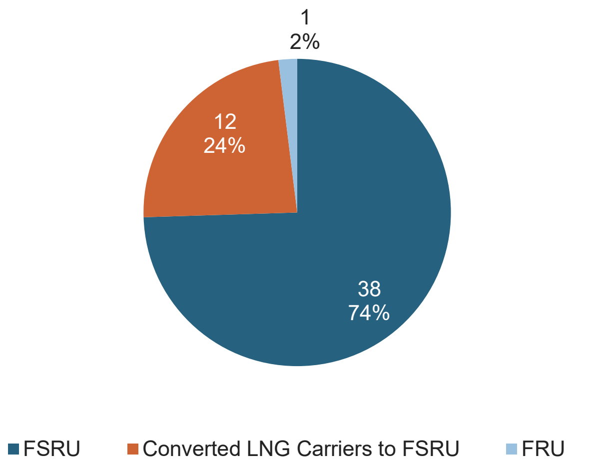
FSRUs in service for LNG imports



Source: FGE

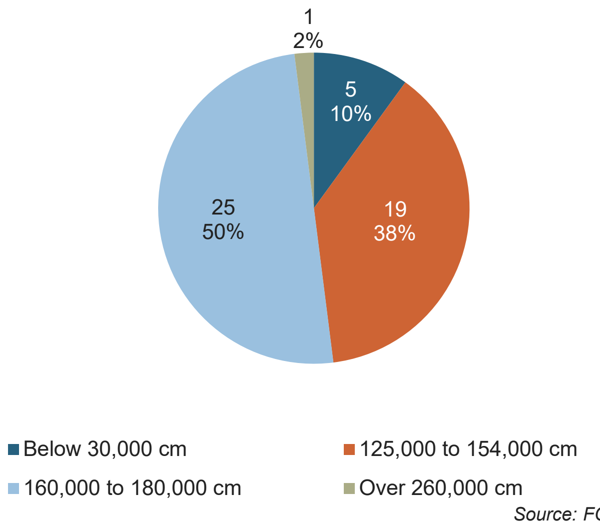
Global FSRU fleet snapshot (as of June 2024)

FSRU Fleet—by Type



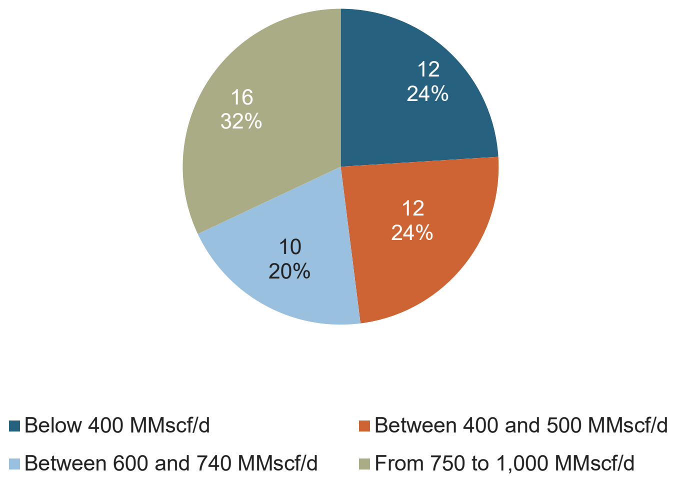
Source: FGE

FSRU Fleet—by Storage Capacity



Source: FGE

FSRU Fleet—by Send-out Capacity

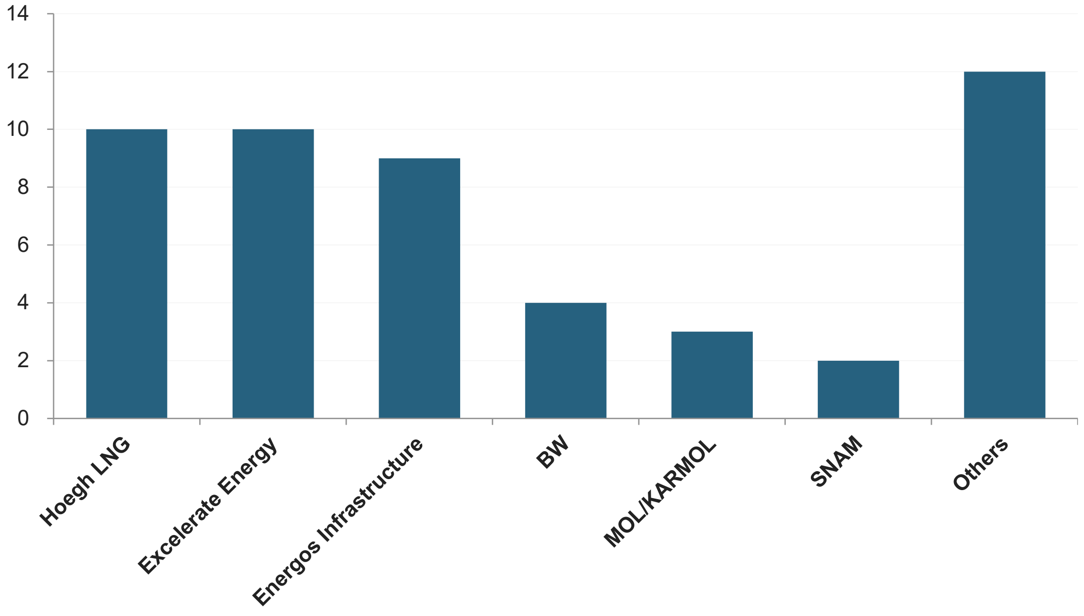


Source: FGE

- The global FSRU fleet currently comprises 50 vessels. The fleet includes 12 converted FSRUs and one floating regasification unit (FRU). About half of the fleet has a storage capacity of between 160,000 cm and 180,000 cm.

FSRU chartering status indicates limited opportunities for existing vessels and new builds, but securing a conversion remains a viable option

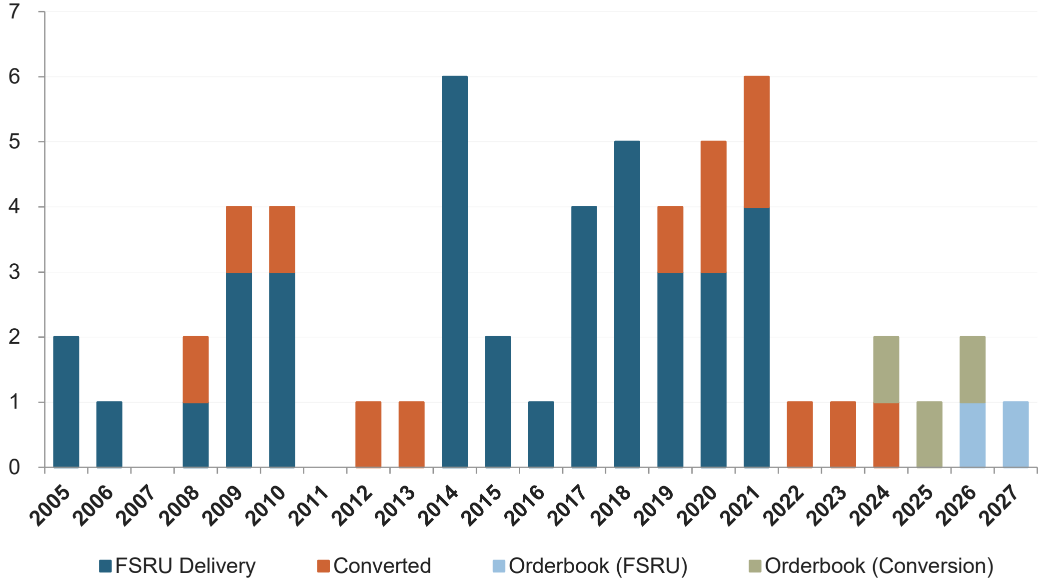
FSRU Fleet Chartering Status, June 2024



Source: FGE

- Excelerate Energy and Höegh LNG are currently the largest FSRU suppliers in the market. While Höegh LNG has all of its fleet locked under long-term contracts, Excelerate Energy is the only supplier with an open orderbook, with a delivery scheduled for 2026. Excelerate is highly likely to deploy its new build FSRU in Bangladesh.

Global FSRU Fleet—Existing & Orderbook, June 2024



Golar Spirit was converted to an FSRU in 2018 and remained in service until 2014. The vessel was ultimately scrapped in 2023.

Source: FGE

- The FSRU fleet is set for expansion with five new units by the end of 2027. Currently, two newbuilds are on orderbook at a Korean shipyard, Hyundai, while two ships are undergoing conversion to FSRUs in China and Singapore. KARMOL is also likely to commence a new conversion project soon, with the vessel expected to be delivered by 2026. Additionally, two more candidates are planned for conversion, although their timeline is yet to be determined.

FSRUs provided a swift solution to Europe's gas supply crisis and are expected to continue playing a crucial role in the near term

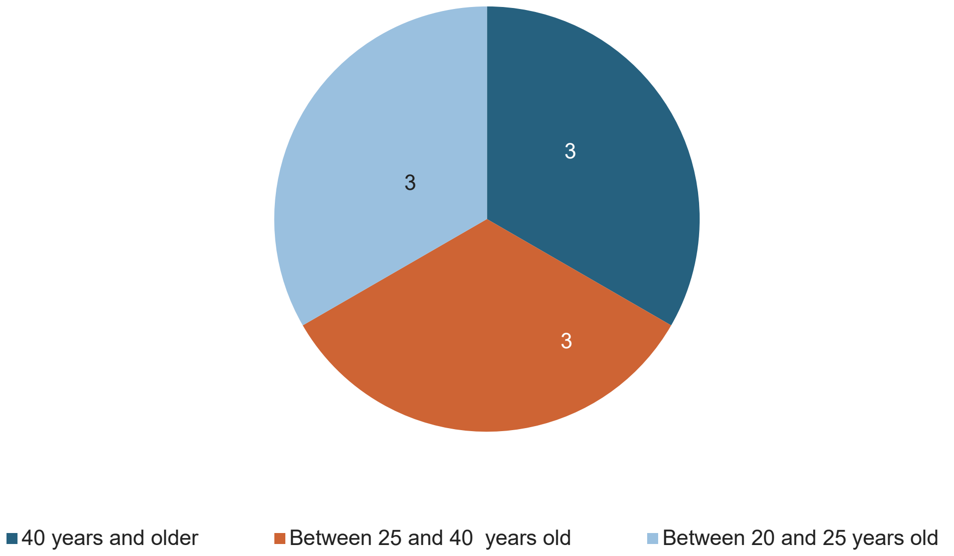
- Currently, there are 17 FSRUs in operation in Europe, with one conversion project underway in China for deployment in Cyprus.
- Additionally, two vessels, namely BW Singapore and Excelsior, are undergoing drydock preparations for use in Italy and Germany.
- Snam still considers the conversion of the Golar Arctic for deployment in Portovesme. The vessel is currently used as an LNG carrier. As other FSRUs can meet the Italian LNG requirements, Snam may also consider other alternatives for her, including long-term charter or asset sale.
- Furthermore, Uniper has chartered Energos Force, which can serve as an FSRU in Germany in case of emergency. The vessel is currently used as an LNG carrier.
- There are also proposed FSRUs that have yet to secure their vessels:
  - Poland: Gdansk LNG (a new orderbook possibly by MOL)
  - Albania: Vlora Terminal
  - Greece: Dioriga Gas, Thrace LNG, Argo LNG
  - Ireland: Shannon LNG and Mag Mell
  - Latvia: Skulte LNG
  - Croatia: LNG Croatia (2nd FSRU)

The choice between purchasing, ordering, converting, or chartering depends on the project technical specifics, desired capacity, budget, and timeline

- A modern FSRU, typically sized at 160,000-180,000 cm with a send-out capacity of 750-1,000 MMscf/d, can be purchased or ordered at a typical cost ranging from US$330-US$365 million per vessel. However, smaller converted FSRUs utilizing older ships may come at significantly lower prices. For instance, it is possible to purchase an old LNG carrier built in the early 2000s for around US$20-US$55 million, depending on its condition, and convert it into an FSRU at an additional cost of US$100-US$150 million.
- Note, above figures are indicative, and FSRU costs can vary based on project design. For example, FSRUs may be moored at a port, requiring pipeline connections, or they may be located onshore with offshore mooring buoys and offshore pipeline connections or segregated offshore berths for LNG handling, among other considerations.
- FSRUs are also obtained through charter agreements, typically ranging from 5 to 15 years, with options to extend it for longer periods. FSRU charter rates are influenced by several factors, including vessel specifications (storage capacity and send-out rates), required technical modifications, project location, contract duration, vessel age, charterer's credit score, and whether fuel costs are included in the rates. Before 2022, chartering FSRUs with a storage size of 160,000-180,000 cm and a send-out capacity of 750-1,000 MMscf/d could cost as low as US$80,000-US$120,000 per day. However, the Ukraine war significantly disrupted the market, depleting available FSRUs in Europe, causing charter rates to surge to US$180,000-US$200,000 per day.
- Current charter rates for FSRUs are not currently transparent due to limited chartering activities for modern vessels. However, we can use the typical cost of a converted vessel as a guideline. Assuming a capital investment of US$300 million for a converted vessel, long-term charter rates for the FSRU may range from US$130,000 to US$150,000 per day, depending on factors such as desired send-out capacity, vessel age, storage capacity, and other technical parameters. This range, nevertheless, is still considerably higher than pre-war levels.
- The timeline for conversion depends heavily on the shipyards' workload and may vary accordingly. The most impressive conversion time records have been between 8 and 10 months for projects in Greece (Alexandroupolis) and Brazil (Barcarena). However, the timeframe can be extended, potentially reaching up to 18 months. Additionally, the project timeline must be adjusted to account for the necessary time for site preparation and the construction of the required infrastructure (such as pipelines etc.) to connect the FSRU to the pipeline grids.
- Based on the timeline outlined above, it is highly likely for Hawaiʻi to comfortably meet the target of commencing gas/LNG imports in 2028. This is of course contingent on factors such as conducting detailed technical studies, the final investment decision timeline, selecting a reliable vessel/LNG supplier and shipyard etc., and completing the tendering and contract awarding process.

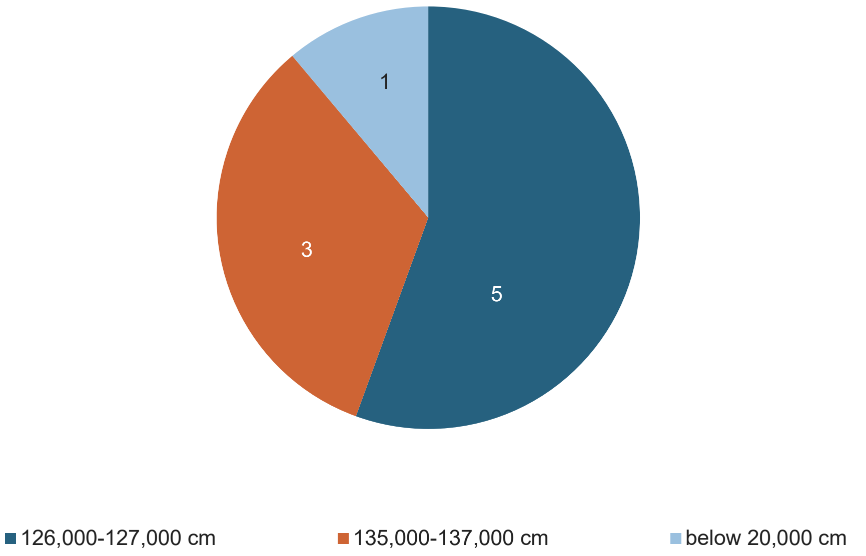
Old steam turbine/laid-up vessels can be secured at competitive prices/rates for conversion projects

Laid-Up Vessels By Age



Source: FGE

Laid-Up Vessels By Storage Size



Source: FGE

- There are currently over 200 ships with steam turbine propulsion (ST) systems, which must be gradually phased out by shipowners due to their low efficiencies, limited storage capacity, ship age, and high boil-off rate. Some legacy suppliers have already started modernizing their fleet, and they are willing to sell or charter their old fleet for FSRU/FSU conversion projects. For example, ADNOC is one of the companies that recently started chartering its old fleet as FSUs to Asian players. In a similar move, Australian NWS sold 5 old LNG carriers to Sinokor and Karpowership/KARMOL for conversion. NWS will soon be ending DES deliveries and will not require an old fleet. KARMOL is looking for at least a few conversions for the fleet.   There is also a list of ST vessels currently laid up that can be nominated for conversion. There are currently 9 ships at laid-up status. One of these laid-up ships, recently purchased by Indonesian Arcadia, from NFE (Golar Mazo, built in 2000) at only US$20 million for an extensive repair service before redeployment in Indonesia.

Estimating regasification fees for Hawai‘i for a purchased and chartered FSRU vessel at 1mtpa

Cost Assumption for LNG Imports into Hawai‘i by HDR

Cost Component	US$ million
Vessel Cost (180,000 cm)	300
Buoy and Sub Sea Pipeline	108
Onshore Pipelines	25
LNG Import Terminal Oahu	30
Oahu Natural Gas Storage	60
ATB Barge (Jones Act Compliant)	120
Neighbor Island Import Facilities and LNG ISO Containers	58

- Regasification tariffs, including associated infrastructure costs based on purchasing and/or converting an old vessel, is estimated at around US$1.68/MMBtu.
  - This estimation assumes approximately 1.0 mtpa of LNG imports, a 70/30 debt/equity ratio, a 10-year project life, a cost of finance at 5%, and an internal rate of return (IRR) at 12%.
- These fees will increase slightly, if the State chooses to charter the unit from a market player. With a charter rate of US$150,000/day, the regas cost can rise to around US$1.93/MMBtu.
- Minimizing investment costs through an optimum technical design and maximizing or optimizing utilization rates for facilities are key factors with significant impacts on regas tariffs. A following sensitivity analysis illustrates a better understanding of these impacts.

Changing investment costs and import volumes (FSRU purchase scenario)

Hawai'i would need to import more than 0.4 mtpa of LNG to justify the economic investment vs continuing to burn LSFO; 1 mtpa yields significant savings

Investment Cost (US$ million)	Regas Tariff (US$/MMBtu)
400	1.25
450	1.32
500	1.39
550	1.46
600	1.54
650	1.61
700	1.68
750	1.75
800	1.82
850	1.90
900	1.97
950	2.04
1,000	2.11

LNG Imports at US$700 million Base Case Investment Scenario (mtpa)	Regas Tariff (US$/MMBtu)	Average Annual Savings vs LSFO*
0.2	7.67	-19%
0.4	3.93	4%
0.6	2.68	15%
0.8	2.06	21%
1.0	1.68	25%
1.2	1.43	28%
1.4	1.26	30%
1.6	1.12	32%
1.8	1.02	33%

Source: FGE

** 2030-2040*

FSRU fleet list and the ship technical specifications

Vessel Name	Owner	IMO	Delivery Year	Storage Capacity (cm)	Vessel Type	FSRU Charterer	Location	Contract Status	Chartering Expriy Date	Send out Capacity (MMscf/d)	Regas Capacity (mtpa)
ENERGOS FREEZE	Energos Infrastructure	7361922	1977/2010	125,000	Converted FSRU	New Fortress Energy	Jamaica	Committed	Nov-33	474	3.6
NUSANTARA REGAS SATU	Energos Infrastructure	7382744	1977/2012	125,000	Converted FSRU	PT Nusantara Regas	Indonesia	Committed	Dec-2025*	484	3.7
KARMOL LNGT POWERSHIP ASIA	MOL (50%), Karpowership (50%)	8608705	1991/2022	126,936	Converted FSRU	Ceiba Energy	Brazil	Committed	Jan-38	168	1.3
KARMOL LNGT POWERSHIP AFRICA	MOL (50%), Karpowership (50%)	9043677	1994/2021	127,386	Converted FSRU	Karpowership	Senegal	Committed	Jun-26	168	1.3
BW TATIANA	BW	9236626	2002/2021	137,000	Converted FSRU	Energía del Pacífico	El Salvador	Committed	May-36	280	2.1
ENERGOS WINTER	Energos Infrastructure	9256614	2004/2009	138,000	Converted FSRU	Petrobras	Brazil	Committed	Aug-26	493	3.8
FSRU TOSCANA	Offshore LNG Toscana (OLT)	9253284	2004/2013	137,500	Converted FSRU	OLT	Italy	Committed	Unknown**	363	2.8
LNG CROATIA	LNG Hrvatska	9256767	2005/2020	140,000	Converted FSRU	LNG Croatia	Kirk Island	Committed	Jan-31	250	1.9
EXCELLENCE	Excelerate Energy	9252539	2005	138,124	FSRU	Petrobangla	Bangladesh	Committed	Aug-33	600	4.5
EXCELSIOR	Excelerate Energy	9239616	2005	138,000	FSRU	German Government	To be Used in Germany	Committed/Dry Duck	Feb-28	500	3.7
SUMMIT LNG	Excelerate Energy	9322255	2006	138,000	FSRU	Summit LNG Corporation	Bangladesh	Committed	Aug-32	500	3.8
EXPLORER	Excelerate Energy	9361079	2008	150,900	FSRU	DUSUP	UAE (Dubai)	Committed	Dec-31	800	6.1
EXPRESS	Excelerate Energy	9361445	2009	150,900	FSRU	ADNOC	UAE (Abu Dhabi)	Committed	Aug-2024***	500	3.8
EXQUISITE	Excelerate Energy (45%), Nakilat (55%)	9381134	2009	151,035	FSRU	Engro	Pakistan	Committed	Mar-30	690	5.2
NEPTUNE	Hoegh LNG (50%), MOL (48.5%), Tokyo LNG Tanker (1.5%)	9385673	2009	145,130	FSRU	TotalEnergies	Germany	Committed	Dec-29	750	5.7
CAPE ANN	Hoegh LNG (50%), MOL (48.5%), Tokyo LNG Tanker (1.5%)	9390680	2010	145,130	FSRU	TotalEnergies	France	Committed	Jun-30	750	5.7
EXEMPLAR	Excelerate Energy	9444649	2010	150,900	FSRU	Gasgrid	Finland	Committed	Dec-32	630	4.8
EXPEDIENT	Excelerate Energy	9389643	2010	150,900	FSRU	Enersa/YPF	Argentina	Committed	Apr-35	500	3.7
EXPERIENCE	Excelerate Energy	9638525	2014	173,400	FSRU	Petrobras	Brazil	Committed	Jun-29	794	6.0
ENERGOS ESKIMO	Energos Infrastructure	9624940	2014	160,000	FSRU	Hashemite Kingdom of Jordan	Jordan	Committed	May-25	725	5.5
ENERGOS IGLOO	Energos Infrastructure	9633991	2014	170,000	FSRU	Gasunie	Netherlands	Committed	Jul-27	725	5.5
HOEGH GALLANT	Hoegh LNG	9653678	2014	170,051	FSRU	New Fortress Energy	Jamaica	Committed	Oct-31	500	3.8
INDEPENDENCE	Hoegh LNG	9629536	2014	170,132	FSRU	LITGAS	Lithuania	Committed	Dec-2024**	384	2.9
PGN FSRU LAMPUNG	Hoegh LNG	9629524	2014	170,132	FSRU	PT PGN	Indonesia	Committed	Jul-34	360	2.7
BW SINGAPORE	SNAM	9684495	2015	170,000	FSRU	SNAM	Egypt/To be Used in Italy	Committed/Dry Duck	Dec-43	750	5.7
GOLAR TUNDRA	SNAM	9655808	2015	170,000	FSRU	SNAM	Italy	Committed	Jan-43	725	5.5
HOEGH GRACE	Hoegh LNG	9674907	2016	170,032	FSRU	Sociedad Portuaria El Cayao S.A. E.S.P. (SPEC)	Colombia	Committed	Jun-36	500	3.8
HUA XIANG 8	PT Sulawesi Regas Satu	9738569	2016/2020	14,000	Converted FSRU	PT Sulawesi Regas Satu	Indonesia	Committed	Dec-37	10	0.1
BW INTEGRITY	BW/Mitsui	9724946	2017	170,000	FSRU	Pakistan Gas Port	Pakistan	Committed	Oct-32	750	5.7
EMSHAVEN LNG	Exmar	9757694	2017	25,000	FSRU	Gasunie	Netherlands	Committed	Aug-27	600	4.5
HOEGH GIANT	Hoegh LNG	9762962	2017	170,032	FSRU	Compass Gas & Energy	Brazil	Committed	Jul-33	750	5.7
BAUHINIA SPIRIT	MOL	9713105	2017	263,000	FSRU	Hong Kong LNG Terminal Limited (HKLTL)	Hong Kong	Committed	Apr-48	800	6.1
ENERGOS NANOOK	Energos Infrastructure	9785500	2018	170,000	FSRU	Centrais Elétricas de Sergipe (CELSE)	Brazil	Committed	Feb-45	725	5.5
HOEGH ESPERANZA	Hoegh LNG	9780354	2018	170,032	FSRU	German Government	Germany	Committed	Jun-29	750	5.7
HOEGH GANNET	Hoegh LNG	9822451	2018	166,630	FSRU	German Government	Germany	Committed	Jan-32	1,000	7.6
KARUNIA DEWATA	JSK Group (50%), PT Pelindo III (50%)	9820881	2018	26,000	FSRU	JSK Group	Indonesia	Committed	Jan-38	50	0.4
MARSHAL VASILEVSKIY	Gazprom JSC	9778313	2018	174,000	FSRU	Gazprom	Russia	Committed	Dec-43	358	2.7
BW MAGNA	BW	9792591	2019	173,400	FSRU	Gas Natural Acu	Brazil	Committed	Dec-42	740	5.6
TURQUOISE P	Kolin (20%), Kalyon Group (50%), Onal Brothers (20%)	9823883	2019	170,000	FSRU	Etkiliman	Turkey	Committed	Dec-29	1,000	7.6
HOEGH GALLEON	Hoegh LNG	9820013	2019	170,000	FSRU	AIE	To be Used in Australia	Committed/Currently In Service as LNGC	Jun-38	750	5.7
EXELERATE SEQUOIA	Excelerate Energy	9820843	2020	173,400	FSRU	Petrobras	Brazil	Committed	Jan-34	750	5.7
VASANT	Triumph Offshore	9837066	2020	180,000	FSRU	Swan Energy	Turkey/India	Committed	Nov-40	660	5.0
TORMAN	Gasfin Development	9870757	2020	28,000	FRU	Tema LNG Terminal Co (TLTC)	Ghana	Committed/Laid-up	Jan-41	250	1.9
JAVA SATU	Jawa Satu Regas PT	9854935	2021	170,000	FSRU	Jawa Satu Regas PT	Indonesia	Committed	Feb-41	320	2.4
ERTUGRUL GAZI	Turkiye Petroleum	9859820	2021	170,000	FSRU	Botas	Turkey	Committed	Apr-45	988	7.5
ENERGOS POWER	Energos Infrastructure	9861809	2021	174,000	FSRU	Uniper	Germany	Committed	Jan-30	500	3.8
ENERGOS FORCE	Energos Infrastructure	9861811	2021	174,000	FSRU	Uniper	To be Used in Germany	Committed/Currently In Service as LNGC	Jan-30	500	3.8
BW BATANGAS	BW	9368302	2009/2019	162,500	Converted FSRU	First Gen	Philippines	Committed	Sep-27	750	5.7
ENERGOS CELSIUS	Energos Infrastructure	9626027	2013/2023	160,000	Converted FSRU	NFE	Brazil	Committed	Dec-38	750	5.6
ALEXANDROUPOLIS	Gaslog	9390185	2010/2023	153,600	Converted FSRU	Gastrade	Greece	Committed	Nov-38	730	5.5

*With option to purchase the vessel after chartering expiring date.
**Vessel ownership with no chartering agreement.
*** Charter may exercise extension option.

Source: FGE

5. US LNG Supply Options and the Jones Act

The Jones Act precludes Hawai‘i from importing US LNG, but a recent ruling on LNG exports to Puerto Rico offers hope for a waiver.

The Jones Act means Hawai‘i will not likely be able to source US LNG

However, a recent ruling may make it possible for Hawai‘i to get a waiver

- The Jones Act, Section 27 of the Merchant Marine Act of 1920, is an antiquated federal law that regulates maritime commerce in the United States. Essentially, it requires goods shipped between U.S. ports to be transported on ships that are built, owned, and operated by United States citizens or permanent residents.

- **Why does this matter?**
  - In 2023, the United States was the largest supplier of LNG in the world (~90 mt) and its LNG export capacity is set to more than double in the next ten years. US sourced LNG could provide a secure and cost-effective source of supply for Hawaii.
  - However, there are no larger scale Jones Act compliant LNG vessels currently in operation as the United States has not built a standard size LNG ship in America since the early 1980s. Currently, there are only a few small-scale Jones Act compliant LNG vessels that are used for LNG bunkering/refueling and are not large enough to deliver LNG cargoes to Hawaii.
  - Moreover, the US maritime lobby is a powerful force in Congress that has ensured that the Jones Act will remain in place, thereby protecting their industry and associated jobs with a captive market.

- **Is a Jones Act Exemption possible?**
  - In 2015, Hawaii's senators broached the idea of a Jones Act exemption for Hawai‘i to bring in US LNG and were unsuccessful. However, there is recent precedence that has allowed New Fortress Energy (NFE) to bring in US sourced natural gas that is processed in Mexico to their LNG receiving terminal in Puerto Rico on foreign flagged ships.
    - *Jan. 29, 2024: New Fortress Energy Inc. (NASDAQ: NFE) (the "Company") announced that U.S. Customs and Border Protection has issued a ruling confirming that the transportation of LNG produced at the Company's FLNG facility located offshore Altamira, Mexico by non-U.S. qualified vessels would not violate the Jones Act. As a result of this ruling, NFE is now able to sell and deliver LNG produced at its FLNG facility located offshore Altamira, Mexico to U.S. locations, including Puerto Rico. Puerto Rico is a key downstream market for the Company.*
  - Given NFE's recent exemption, it may be possible to get a similar waiver for Hawai‘i for any LNG that is exported from the Pacific Coast of Mexico that utilizes US natural gas as a feedstock for LNG exports. The Costa Azul terminal due online in 2025 and located in Baja, California falls under this category. In addition, the soon to be under construction Saguaro Energia LNG project by Mexico Pacific in Sonora Mexico also is also utilizing US natural gas as feedstock for LNG exports and could potentially come to Hawai‘i on foreign flagged vessels..

6. Discussion on Experienced Companies who Can Help Hawai'i's Energy Transition Via LNG Imports

Shell, TotalEnergies and JERA are all world class energy companies with extensive experience in LNG shipping, LNG procurement, LNG trading, and in some cases significant thermal and renewable power generation assets.

JERA

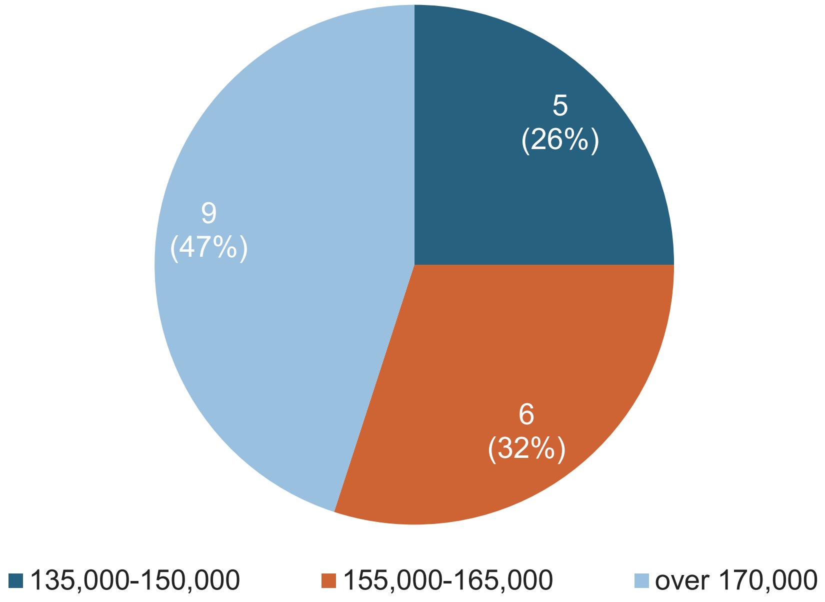
19 Vessels that JERA owns and controls (as of June 2024)

Vessel Name	Ownership Shares	Operator Shares	Delivery Year	Capacity (cm)	Propulsion Type
Prima Carrier	TEPCO (70%), NYK (20%), Mitsubishi (10%)	NYK	2006	135,000	Steam
Alto Acrux	NYK	NYK	2008	147,798	Steam
Cygnus Passage	Cygnus LNG Shipping: TEPCO (70%), NYK (15%), Mitsubishi (15%)	NYK	2009	145,400	Steam
Pacific Enlighten	Kyushu Electric, TEPCO, Mitsubishi, NYK, MOL	NYK	2009	147,200	Steam
Esshu Maru	Mitsubishi, MOL, Chubu Electric	MOL	2014	155,300	Steam
Pacific Arcadia	NYK (15%), TEPCO (70%), Mitsubishi (15%)	NYK	2014	145,400	Steam
Seishu Maru	Mitsubishi (40%), NYK (20%), Chubu Electric (40%)	NYK	2014	155,865	Steam
Kool Kelvin	CoolCo (Golar 31.3%, Easter Pacific Shipping 38%, Public Investors)	CoolCo	2015	162,000	TFDE
Enshu Maru	K-Line	K-Line	2018	164,700	Steam Reheat
Pacific Mimosa	NYK	LNG Marine Transport Ltd: JERA (70%), Mitsubishi Corp (15%), NYK (15%)	2018	155,300	Steam Reheat
Bushu Maru	Trans Pacific Shipping 6 Limited (NYK 50%, JERA 50%)	NYK	2019	180,000	STaGE
Maran Gas Andros	Maran Gas Maritime	Maran Gas Maritime	2019	173,608	MEGI
Nohshu Maru	Trans Pacific Shipping 5 Ltd: JERA (50%), MOL (50%)	MOL	2019	180,000	STaGE
Shinshu Maru	Trans Pacific Shipping 7 Ltd: JERA (50%), NYK (50%)	NYK	2019	177,277	DFDE
Sohshu Maru	MOL (50%), JERA (50%)	MOL	2019	177,269	DFDE
Elisa Larus	NYK	NYK	2020	174,000	XDF
Gaslog Wales	GasLog	Gaslog	2020	180,000	XDF
Yiannis	Maran Gas Maritime	Maran Gas Maritime	2021	174,093	MEGI
Energy Fidelity	Alpha Gas	Alpha Gas	2023	170,200	XDF

Source: FGE

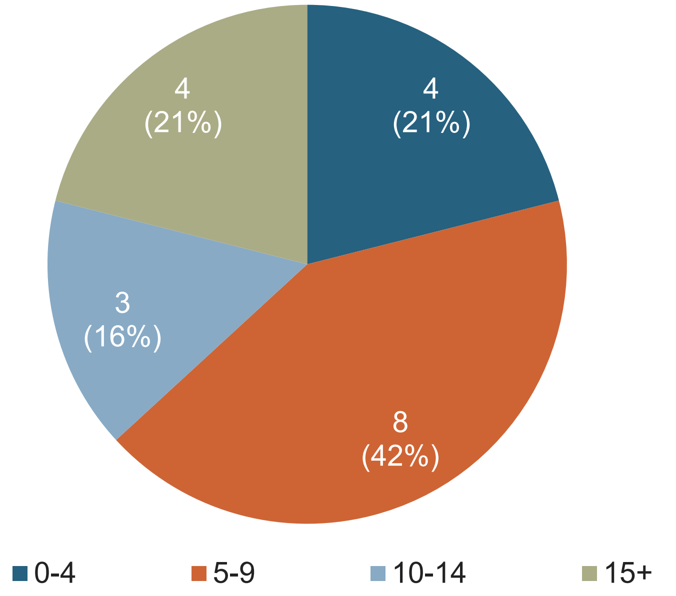
Specifications of JERA controlled vessels

Ships by Capacity, cm



Source: FGE

Ships by Age, Years



Source: FGE

- Currently, JERA controls a fleet of 7 LNG ships that utilize steam turbine propulsion systems, belonging to the older generation of LNG vessels. These ships typically consume 40%-50% more fuel during voyages compared to newer/modern vessels. As environmental regulations for GHG emissions are expected to tighten in the coming years, these older ships limit JERA's flexibility to minimize shipping costs effectively for LNG trade across basins.
- These ships are all over 10 years old and are likely the first candidates for conversion into other uses, such as FSRUs, or will be restricted to Asia trade routes in favor of newer, more efficient propulsion technologies.

Other (Key) Assets: Thermal power plants

Domestic Thermal Power Plants

Location	Fuel for Generation	Generation Capacity (GW)	Joint Venture Partner
Joetsu	LNG	2.38	-
Hirono	Coal, City Gas, Crude	4.40	Hirono IGCC Power GK
Hitachinaka	Coal	2.00	-
Hitachinaka -J/V	Coal	0.65	Hitachinaka Generation
Kashima	City Gas	1.26	-
Goi	LNG	2.34	ENEOS
Chiba	LNG	4.38	-
Anegasaki	LNG	1.20	-
Anegasaki	LNG	1.94	-
Sodegaura	LNG	3.60	-
Futtsu	LNG	5.16	-
Yokosuka	Coal	1.30	-
Minami Yokohama	LNG	1.15	-
Yokohama	LNG	3.02	-
Higashi Ohgishima	LNG	2.00	-
Kawasaki	LNG	3.42	-
Shinagawa	City Gas	1.14	-
Atsumi	LNG, Fuel Oil	1.40	-
Hekinan	Coal	4.10	-
Taketoyo	Coal, Biomass	1.07	-
Chita	LNG	1.71	-
Chita Daini	LNG	1.71	-
Shin Nagoya	LNG	3.06	-
Nishi Nagoya	LNG	2.38	-
Kawagoe	LNG	4.80	-
Yokkaichi	LNG	0.58	-
Total GW Capacity		**62.15**	

Source: FGE, Company Website

Overseas Thermal Power Plants

Market	Location	Generation Type	Generation Capacity (MW)	Joint Venture Partner
Mexico	Valladolid	Natural Gas	525	Mitsui & Co
USA	Maine	Natural Gas	175	-
USA	Oklahoma	Natural Gas	1,229	Tenaska, ITOCHU
USA	Texas	Natural Gas	845	Osaka Gas, Mitsubishi Corporation, ITOCHU, Tenaska
USA	Virginia	Natural Gas	885	Tenaska, J-POWER, ITOCHU
USA	Ohio	Natural Gas	702	AP, BCPG, Ullico, Prudential
USA	New York	Natural Gas	1,100	DBJ, Idemitsu Kosan Co. Ltd., Nuveen, Advanced Power, BlackRock, Kiwoom
USA	New Jersey	Natural Gas	972	EGCO, DBJ, GS-Platform Partners
USA	Pennsylvania	Natural Gas	790	Starwood Energy Group Global
USA	Massachusetts	Natural Gas	333	Starwood Energy Group Global
USA	Massachusetts	Oil, Natural Gas	1,458	-
Indonesia	Cirebon	Coal	1,000	Marubeni, Indika Energy/IMECO, ST International, Korea Midland Power Co.
Philippines	Luzon Island	Coal, Natural Gas	3,592	Marubeni, Aboitiz Power, Korea Electric Power, Mitsubishi Corporation, Kyushu Electric
Bangladesh	Meghnaghat	Natural Gas	718	Reliance Power
Taiwan	Changhua	Natural Gas	980	Taiwan Cogeneration
Taiwan	Tainan	Natural Gas	980	Taiwan Cogeneration
Thailand	Ratchaburi	Natural Gas	1,400	Hongkong Electric Company, Ratchaburi, PTT, Toyota Tsusho,Saha-Union
Vietnam	Ho Chi Minh City	Natural Gas	715	Electricite de France (EDF), Sumitomo Corporation
Oman	Sur Industrial Area	Natural Gas	2,000	Marubeni, Nebras Power, Multitech
Qatar	Doha	Natural Gas	2,520	QEWC, QP, QF, Mitsubishi Corporation
Qatar	Mesaieed Industrial Area	Natural Gas	2,000	Qatar Electricity & Water Company, Qatar Petroleum, Marubeni
Qatar	Ras Laffan Industrial Area	Natural Gas	2,730	Qatar Electricity & Water Company, Qatar Petroleum, ENGIE, Mitsui & Co., Shikoku Electric Power Compan
UAE	Abu Dhabi	Natural Gas	2,200	ENGIE, Abu Dhabi Water and Electricity Authority
Total GW Capacity			**29,849**	

Source: FGE, Company Website

Other (Key) Assets: Renewable power generation

Market	Location	Generation Type	Generation Capacity (MW)	Joint Venture Partner
Thailand	Phetchaboon	Solar	18.4	GUNKUL
Thailand	Nakhon Nayok	Solar	8	GUNKUL
Thailand	Phichit	Solar	4.5	GUNKUL
Taiwan	Miaoli	Wind	128	Ørsted A/S, Macquarie, Swancor
Taiwan	Miaoli	Wind	376	Macquarie, Synera Renewable Energy
Thailand	Nakhon Ratchasima	Wind	180	Aeolus, RATCH
UK	Essex	Wind	173	Ørsted A/S, Development Bank of Japan
USA	Texas	Wind	300	-
Total GW Capacity			**1,188**	

Source: FGE, Company Website

- JERA currently holds interest in 10 international renewable power generation projects, with a capacity of 1.2 GW.
- JERA holds interest in 23 international thermal power plants, with a total capacity of 29.8 GW.
- Domestically, JERA operates 28 thermal power plants with 62.2 GW of capacity.

Other (Key) Assets: LNG Receiving terminals

Regas Terminals	Ownership Equity	Regas Capacity (mtpa)
Chita	95%*	10.5
Chita Kyodo	50%**	7.0
Kawagoe	100%	5.5
Yokkaichi LNG Centre	100%	6.2
Joetsu	100%	2.3
Futtsu	100%	18.5
Sodegaura LNG	50%***	28.6
Higashi-Ohgishima	100%	12.8
Negishi LNG	50%****	9.8

Source: FGE
**Partnered with Toho Gas*
***Partnered with Toho Gas*
****Partnered with Tokyo Gas*
*****Partnered with Tokyo Gas*

- JERA holds ownership stakes in 9 LNG receiving and regasification terminals in Japan.
- They have access to 101.2 mt of capacity through these terminals.

Equity

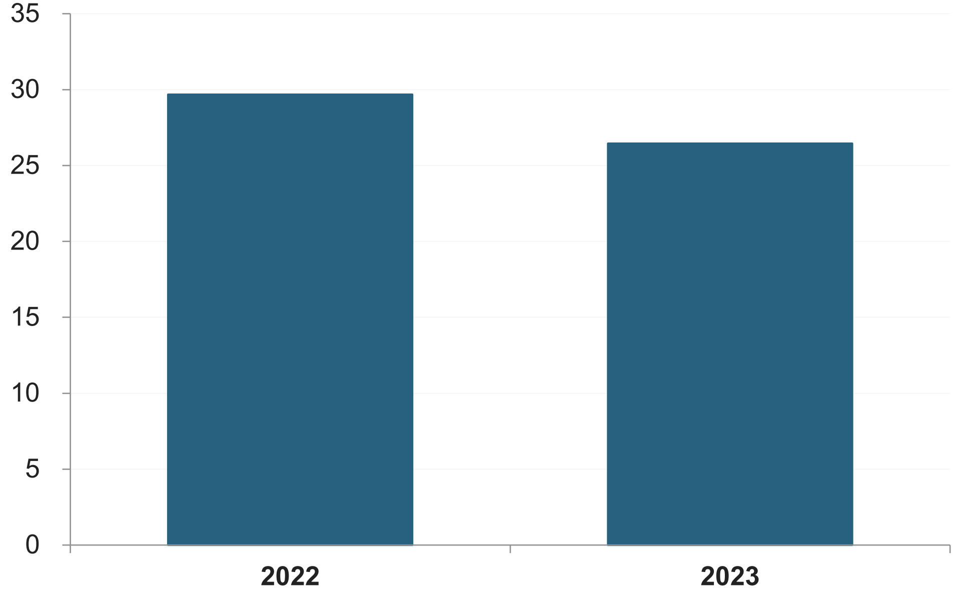
- JERA's most recent consolidated financial results are for fiscal year (FY) 2022.
    - FY2022 denotes the period from April 1, 2022 to March 31, 2023.
    - FY2023 consolidated financial results are expected to be available by the end of April 2024.
- JERA's equity was JPY2,039.7 billion as of March 31, 2023 vs. JPY1,731.6 billion as of March 31, 2022.

Using the officially announced numbers, we have not converted into US$ due to the number of markets and currencies JERA invests in.

LNG Procurement: JERA is Japan's largest LNG importer

- Japan imported over 65 mt in 2023.
- JERA is Japan's largest LNG importer. JERA's total imported volume (long-term and spot volume) was around 26.5 mt in 2023.
- Strong energy saving measures and increased nuclear capacity contributed to lower LNG demand.

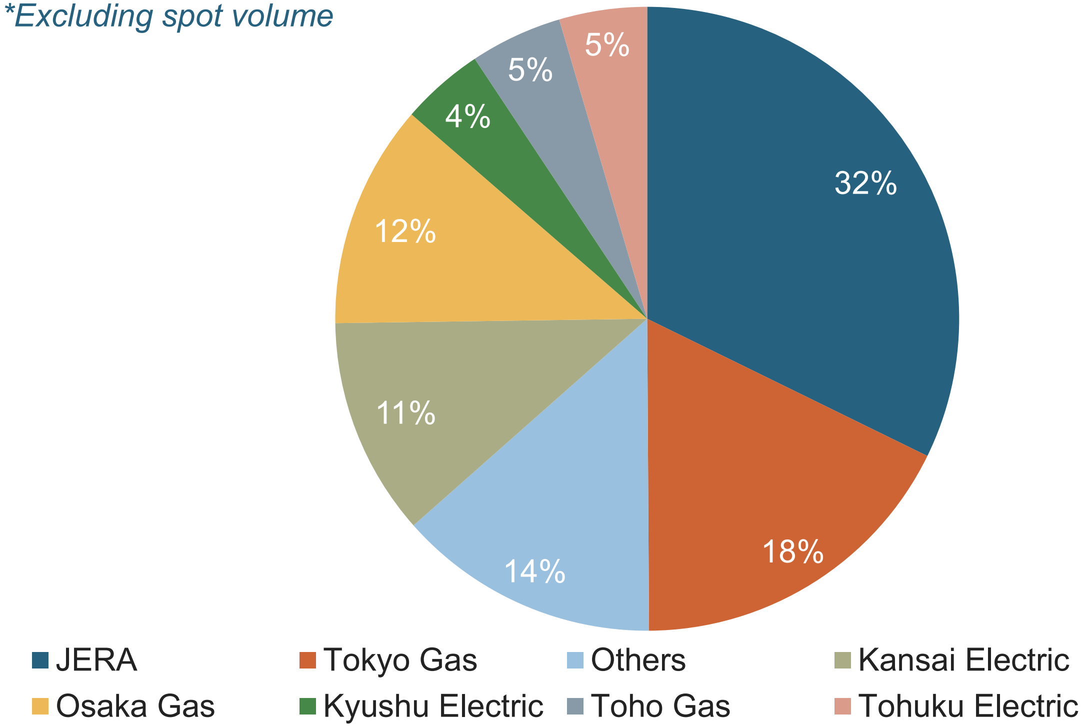
JERA's LNG Imports, mt



Source: FGE

Share of LNG Long-Term Contracts* by Utility (2023)

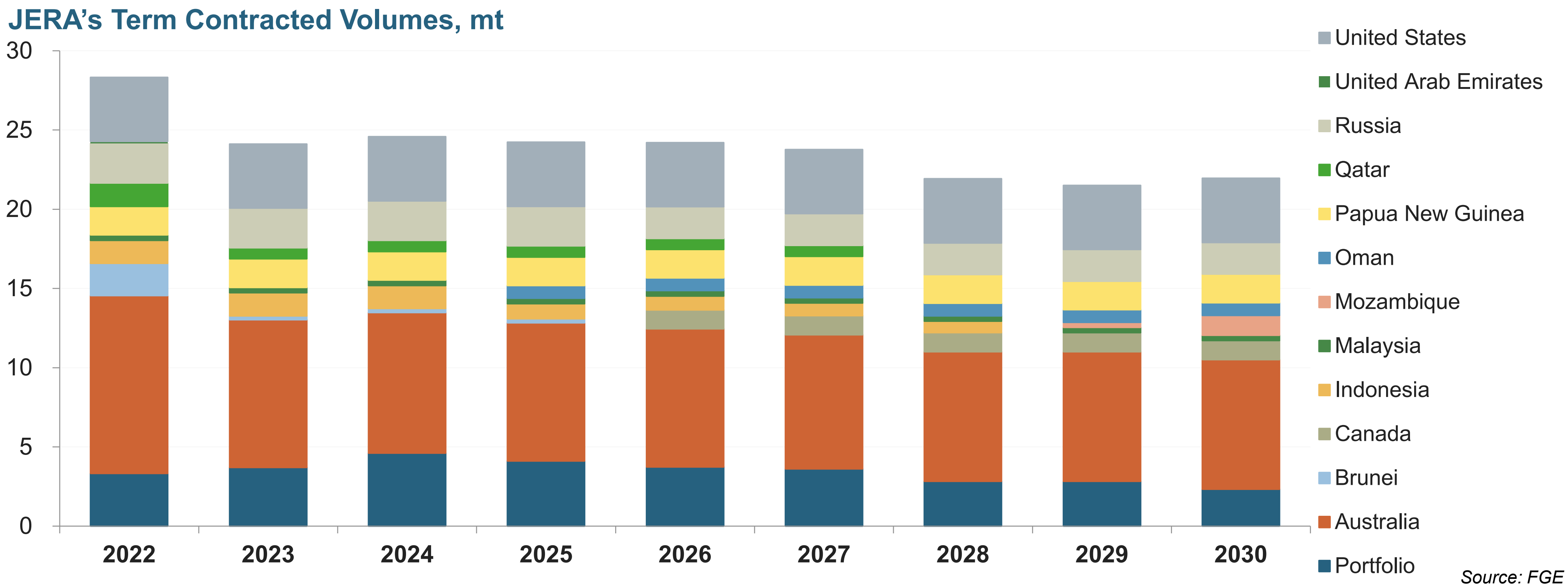
**Excluding spot volume*



Source: FGE

- JERA's long-term LNG contracts account for 32% of Japan's total LNG term contracted volumes.

LNG Portfolio: Australia accounts for 40% of the total long-term contracts*



Source: FGE

**Term contracts, excluding short-term and spot volumes*

- JERA's Global CEO is keen to invest in Australia and the US.
- JERA's dependency on Middle Eastern supplies declined significantly for the past few years as their term contracts with Abu Dhabi and Qatar (QG1 project) expired.

Key International Subsidiaries: Strategic structure for LNG businesses

Main Overseas Subsidiaries	Headquarters	Operations
JERA Global Markets Pte. Ltd. (JERAGM)	Singapore	LNG and coal trading
JERA Asia Pte. Ltd.	Singapore	Project development in energy related fields of business in Asia
JERA Power (Thailand) Co., Ltd.	Thailand	Power generation operation/maintenance and engineering services in Thailand
JERA Power International B.V.	Netherlands	Investment in overseas businesses
JERA Australia Pty Ltd.	Australia	Gas resource development and LNG production in Australia
JERA Americas Inc.	USA	Managing Power and Fuel related business in the Americas
JERA Energy America LLC	USA	Exporting US LNG from Freeport Project
JERA LNG Portfolio Strategy Pte. Ltd. (JERA LPS)	Singapore	Maximize JERA's LNG portfolio by improving existing SPAs

Source: FGE, Company Website

- Of their international subsidiaries, JERA Global Markets (JERAGM) and JERA LNG Portfolio (JERA LPS) play key roles in JERA's LNG business. They operate independently but report to HQ.
- JERAGM is a trading arm, in principle, who manages spot/short-term volumes (up to 4 years).
- JERA LPS is in charge of price reviews (PRs) of the existing LNG contracts.
- As of April 1, 2024, Ryosuke Tsugaru, from Mitsubishi Corp., will be promoted to Chief Low Carbon Fuel Officer (CLCFO) and Head of the LNG Division at JERA HQ and play a critical role in JERA's LNG procurement/trading strategies.

LNG Supply Evaluation Criteria: JERA

Company Reliability	Financial Stability	LNG Supply Availability	LNG Fleet Availability for DES Supply Terms	LNG Supply Portfolio	Supply Flexibility			Involvement in Retail LNG Business	Ability to Assist in Developing LNG Import Infrastructure	Ability to Participate in Integrated Power Projects	Environmental & Sustainability Practices	Regulatory Compliance
					Price Indexation	Size of Sales	Duration					
High	Yes	Yes	Yes	Global (US, ME, East Africa, & Asia Pacific)	Yes (Brent, HH, Hybrid, etc.)	Yes	Yes	Yes (LNG Bunker Supplier in Japan)	Yes	Yes	High	High

- JERA has procured LNG from various suppliers in the Middle East, Asia Pacific, Mozambique, Canada, and the US, and has flexibility in offering oil, HH, or hybrid price indexation for LNG re-sales. While JERA may have a much smaller trading portfolio compared with Shell or TotalEnergies, we see high flexibility in the size of sales to fully cover Hawaii's LNG requirements.
- Like Shell, JERA has access to Canadian LNG which has the lowest GHG emissions of any LNG project in the world.
- Moreover, JERA's corporate mission is to decarbonize their energy system and move towards cleaner fuels. They are even more focused on this mission than Shell and TotalEnergies as they are a consumer and more importantly are being pushed by the Japanese government. JERA's ability to handle FSRU conversions of its old LNG vessel fleet, its extensive LNG procurement and trading expertise as the world's largest LNG buyer, its corporate DNA as an electric utility, its creditworthiness, and affinity for Hawaii, make it a solid candidate to work with the State of Hawai'i and HECO on the decarbonization journey.

7. Implications and Future Roles for Existing Fuel Suppliers

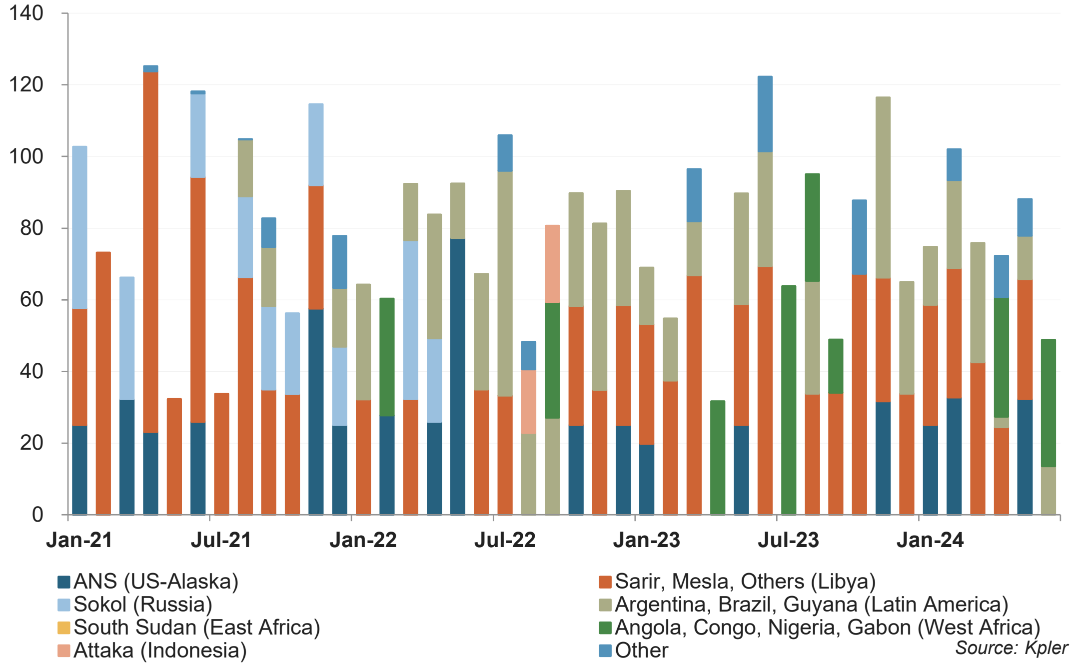
The most likely outcome if Par loses the LSFO contract with HECO is a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal

Par Hawai‘i refinery and some current facts and figures on fuels balances

- Par Hawai‘i is a 95 kb/d refinery, with some upgrading capacity (i.e., limited upgrading and quality improvement ratio to throughput, vs typical complex refineries).
- Par Petroleum has been running the plant at around 80 kb/d on average post closure of the IES refinery and the recovery from the COVID-19 demand fall.
- Local supply of key products:
  - On average, the refinery produces 26%-27% naphtha/gasoline, some 40% distillates (jet fuel and diesel), and around 30% fuel oil.
  - At 80 kb/d run rate, that translates into:
    - Around 6 kb/d of naphtha (that is sold to Hawai‘i Gas for SNG production)
    - Some 15 kb/d of gasoline,
    - Over 15 kb/d of jet fuel,
    - Over 16 kb/d of diesel, and
    - Around 23 kb/d of fuel oil.
- Demand for key products:
  - Currently (1H 2024), as per DBEDT monthly stats, Hawai‘i utilities burnt 19 kb/d of fuel oil, 7 kb/d of diesel, and around 0.1 kb/d of biodiesel.
  - Gasoline demand has recovered to a fairly stable level of 27-28 kb/d since 2021 through 1H 2024 (still short of pre-COVID levels of over 30 kb/d).
  - Road diesel demand has averaged around 14 kb/d since 2022 through 1H 2024, just above pre-COVID levels (of 12-13 kb/d).
  - Domestic jet fuel sales averaged just below 20 kb/d in 2023, well above pre-COVID levels in 2019.
    - In 1H 2024, however, domestic jet fuel sales dropped back to 16 kb/d, perhaps due to seasonal reasons (typically peak of domestic trips to Hawai‘i is during 3Q) but also perhaps less consumer spending on travel in 2024 than 2022/2023 (as COVID-related savings are running out).
    - These statistics exclude sales to international flights, from non-bonded storage tanks (estimated at around 15 kb/d).
    - Most of the jet fuel imports supply this portion of the jet fuel demand in Hawaii.
- Products imports:
  - Supply from Par Hawai‘i refinery fails to meet demand for products, hence fuel suppliers have been importing the balance, of mainly jet fuel (20-30 kb/d) and gasoline (10-15 kb/d) as well as a small amount of diesel (3-5 kb/d).

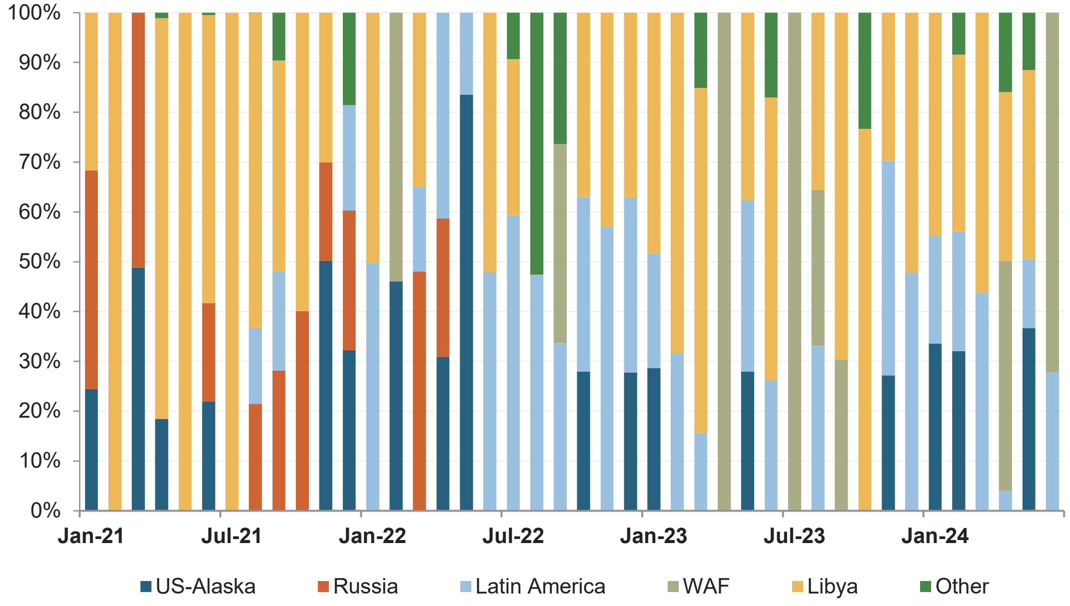
Par Petroleum's crude imports

Hawai'i: Crude Oil Imports by Origin, kb/d



Source: Kpler

Hawai'i: Crude Oil Imports by Origin, %

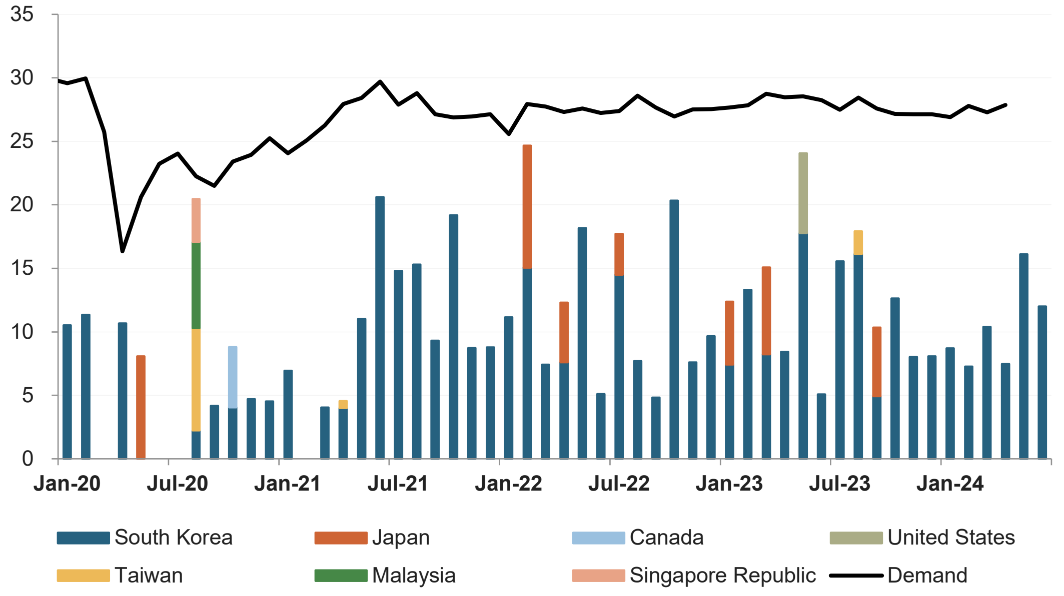


Source: Kpler

- Libyan crude imports to Hawai'i managed to supply 40% of Hawaii's total crude oil demand during 2023-1H2024 (at 33 kb/d on average). With stable production expected from Libya in 2024 (at around 1.1 mmb/d), we will probably see a sustained level of Sarir/Mesla crudes continuing to come to Hawai'i in the foreseeable future.
- Russian Far East crudes will continue to be absent from Hawai'i's crude diet in the foreseeable future as well.
- In the absence of Russian crude, some cargoes of Alaskan ANS (over 10% of total imports) have been coming to Hawaii. More importantly, however, Latin American grades (mainly from Argentina but also Brazil and recently Guyana) and WAF grades (from other sources than Libyan, such as Nigeria, Gabon, and Angola) have become a main ingredient of the crude throughput in Par refineries, supplying nearly 50% of the total crude imports (20+% LatAm grades, and 20+% WAF grades).

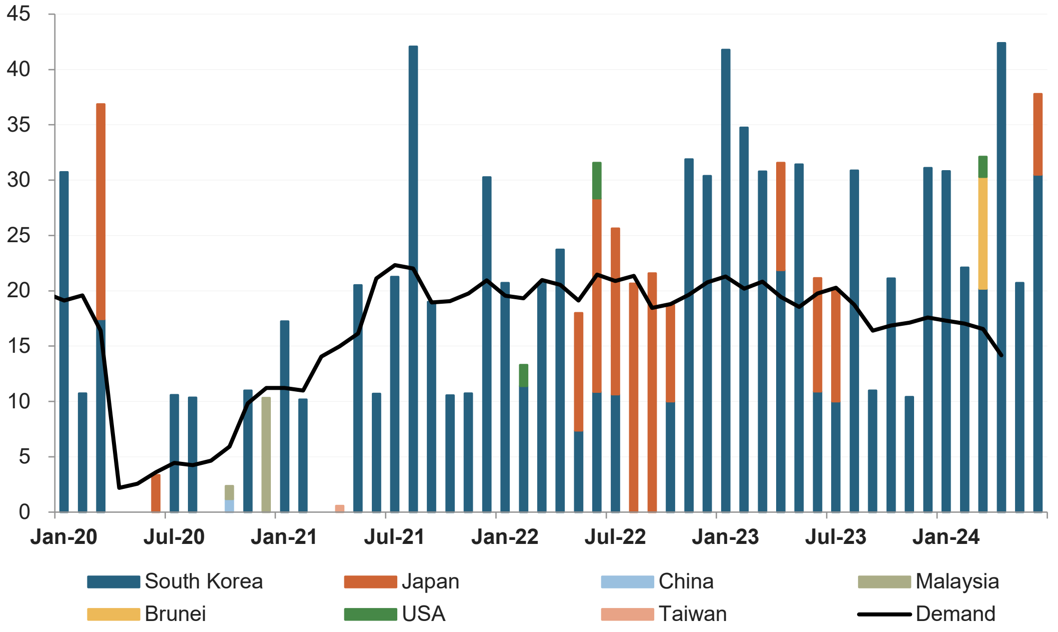
South Korea: The primary supplier of products to Hawai'i

Hawai'i: Gasoline Demand and Imports by Source, kb/d



Source: Kpler, DBEDT

Hawai'i: Jet Fuel Demand and Imports by Loading Country, kb/d



Source: Kpler, DBEDT

- South Korea remains the main source of fuel imports (mainly gasoline and jet fuel) in Hawai'i. In fact, it has been the sole supplier of gasoline since 4Q 2023.
- Japanese traders (ENEOS, Idemitsu, Fuji Oil) supplied Hawai'i some volumes around mid-2023, but the arrangement with Japanese suppliers proved to be short-lived. Yet spot cargoes of jet have arrived in 1H 2024 from Asia (Brunei and Japan).

Par's financial results (1)

Par: Profitability Skyrocketed in 2022, While 2023 Yielded Even Better Results!

	2018	2019	2020	2021	2022	2023	1Q-23	1Q-24
Ref Throughput, Par Hawaii (kb/d)	**116**	**109**	**73**	**82**	**82**	**81**	**76**	**79**
Adjusted Gross Margin ($/bbl)	5.37	3.30	-1.63	4.56	13.99	15.25	19.11	14.00
Production costs per bbl ($/bbl)	3.65	3.25	4.03	3.98	4.86	4.57	4.54	4.89
DD&A ($/bbl)	0.66	0.40	0.55	0.66	0.67	0.65	0.73	0.60
Ref Throughput, Wyoming (kb/d)	**16**	**17**	**12**	**17**	**17**	**18**	**17**	**17**
Adjusted Gross Margin ($/bbl)	15.29	18.82	3.94	14.47	26.50	25.15	27.54	14.84
Production costs per bbl ($/bbl)	7.06	6.32	8.69	6.22	7.32	7.50	7.41	7.86
DD&A ($/bbl)	2.39	2.93	4.34	2.86	2.85	2.69	2.78	2.77
Ref Throughput, Washington (kb/d)	**-**	**39**	**39**	**36**	**36**	**40**	**40**	**31**
Adjusted Gross Margin ($/bbl)	-	11.26	3.88	2.98	18.00	9.41	11.07	6.13
Production costs per bbl ($/bbl)	-	4.52	3.50	3.86	4.01	4.12	4.25	6.07
DD&A ($/bbl)	-	1.56	1.39	1.57	2.19	1.91	1.81	2.44
Ref Throughput, Montana (kb/d)	**-**	**-**	**-**	**-**	**-**	**54.4**	**-**	**53.1**
Adjusted Gross Margin ($/bbl)	-	-	-	-	-	21.1	-	13.8
Production costs per bbl ($/bbl)	-	-	-	-	-	10.8	-	12.4
DD&A ($/bbl)	-	-	-	-	-	1.5	-	1.4
Net income (loss), mil$	39.4	40.8	-409.1	-81.3	364.2	728.6	237.9	-3.8
Reported Adjusted Net Income (Loss), mil$	**49.3**	**90.2**	**-249.8**	**-36.1**	**474.7**	**501.2**	**137.5**	**41.7**

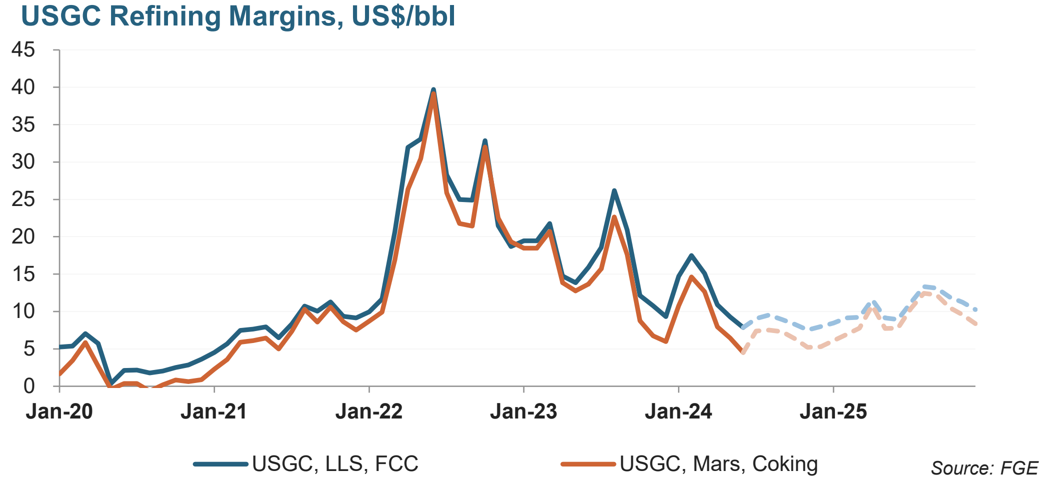
HAWAII	44.7	-13.9	-165.2	-2.4	252.6	295.8	95.0	60.8
WYOMING	35.0	59.4	-40.9	33.2	98.3	97.7	26.4	6.4
WASHINGTON	N/A	73.5	-14.5	-32.5	152.9	49.3	17.9	-6.7
MONTANA	N/A	N/A	N/A	N/A	N/A	176.9	N/A	-0.1
Calculated Profit/(Loss) - including DD&A (mil$)	**79.6**	**119.0**	**-220.6**	**-1.6**	**503.8**	**619.8**	**139.3**	**60.4**

Source: Par Pacific SEC Filings

- With the unprecedented state of the oil market post-Russia's invasion of Ukraine, US refining margins surged to the US$25-US$40/bbl range in 2022. While they declined to the US$10-US$25/bbl range in 2023, still it remained higher than the max levels in the past.
- In 2024, however, the USGC FCC margin slipped further to an average of US$12.6/bbl during 1H, and we forecast it to slide further down to the US$7.5-US$9.5/bbl range during 2H 2024 (averaging US$8.5/bbl). We forecast the USGC LLS margin to slightly recover to US$10.6/bbl in 2025.
- Par's total refining (and logistics and retail) business' net income surged to a record high of some US$200 million in 2Q 2022. While it did drop to around US$100 million in 2Q 2023, mainly on the back of purchasing assets in Montana, it made a huge return to near US$200 million in 3Q-4Q 2023 and Par managed to push its adjusted net income above US$500 million, a new record high for Par in 2023.
- Calculating their P/L using their reported gross margin and per barrel costs (including DD&A), Par made over US$1 bn of profit from its refining assets during the 2022-2023 period, led by the Par Hawai'i refinery contributing to nearly half of the Par group's total profit from refining business.
- In 1Q 2024, due to a sizeable y-o-y drop in product cracks and refining margins (e.g., USGC FCC margin averaging 30% lower y-o-y in 1Q 2024), Par's refining profits dropped to less than half of 1Q 2023, mainly due to lower profitability of their US mainland refineries. Par Hawai'i was basically their only profit center in 1Q 2024.

Par's financial results (2)

Par: Share prices surged to an all time high of US$40 in Feb 2024 but has been on decline since 27 Feb!



Source: FGE

Source: MarketWatch

- Par's stock price started to surge around mid-2022, in line with a huge surge in refining margins at that time. Despite the declining trend in margins (on a moving average) since June 2022, huge profits due to absolute levels kept pushing refiners' share prices through 2022 and all the way till end-2023.
- Despite very strong results painted by their 10K filing for 4Q 2023—released on 27 Feb 2024, relatively poor results for 4Q 2023 (implied results for the last quarter as the 4Q filing only presents full year results) combined with declining refining margins (hence signaling even poorer results for 1Q 2024 results, which was confirmed in their 1Q 2023 filing, realized on May 6) put the brakes on Par's incremental stock price (which peaked at US$40.38 on 26 Feb 2024, only the day before their 4Q 2023 results were published) and since then their share price has been trending down, dropping just below US$23 on 10 July 2024 (i.e., 42.5% drop since its peak in February).
- A flat to declining outlook for US refining margins in the short term (next 18 months) means that the share price is likely to stay in the US$20-US$25 per share (given our margin forecast) over the coming year—still reasonably healthy and strong in a historical context.

Future of Par Hawai‘i refinery if the LSFO contract with HECO is gone

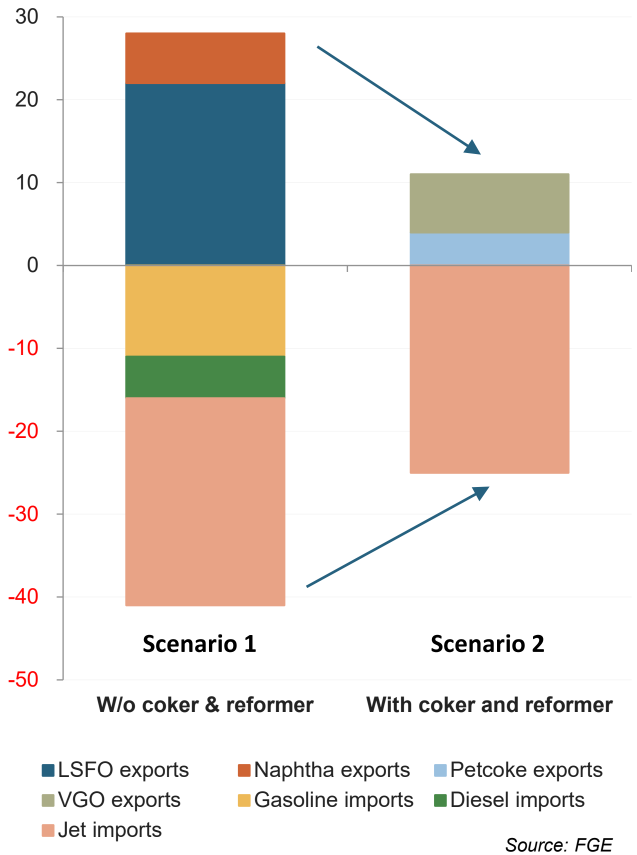
- If Par Pacific loses demand for its LSFO (due to HECO switching to LNG as a fuel), it would also imply a loss of offtake for its naphtha supply to Hawai‘i Gas, as there will be no more naphtha-based SNG production.
- In that case, Par Pacific would face several scenarios:
    1. Continue running at current levels and export its LSFO and naphtha surplus.
    2. Continue running at current levels and invest in additional upgrading (incremental hydrocracking and reforming) capacity to convert the surplus fuel oil and naphtha into gasoline and middle distillates (which the State is short of). In addition, the refinery may well have to invest in utility and infrastructure projects as well.
    3. Reduce runs to levels that its upgrading capacity can convert most, if not all, of the naphtha and fuel oil into gasoline and middle distillates (in this case, the State will have to increase its imports of gasoline and middle distillates to cover the increased shortfall).
    4. Mothball crude units and most of the upgrading capacity and convert the plant into a biofuels plant, running some of the hydrotreating units in that operation.
    5. Mothball the refinery and convert the site into a storage terminal—similar to what was done to the IES plant.
- All of the above options come with caveats that depend on several factors to determine their financial (and technical) feasibility.

What are the considerations and implications of each scenario?

- Relevant to scenario 1: Generally freight economics do not favor refining operations that would import crude (from distant markets) and then have to export products (back to distant markets) as well.
- Relevant to scenarios 1 to 3: If Par is no longer required to produce LSFO, they can change their throughput mix away from typically more expensive heavy/waxy sweet crudes, which are limited in quantity compared with other grades, to a wider range of feedstocks. While feedstock optimization could potentially offer some improvement on the economics of the refinery, running lighter (and sweet) crudes may well exacerbate the naphtha surplus position. Also, such crudes tend to be expensive as well.
- Regarding scenario 3: It is important to note that investment in fuel oil upgrading is not a cheap option (hundreds of million dollars), especially if the life of the asset is uncertain.
- Relevant to scenario 4: Converting some of the refinery units into a biofuel facility could easily cost hundreds of million dollars (e.g. investment cost of US$84 million for the case of the Come-by-Chance refinery conversion in Canada – converting a 140 kb/d mothballed refinery to an 18 kb/d renewaable fuels refinery) as well as potential issues sourcing the necessary feedstock for such an operation; not only the volume required but at an economically attractive price.
  - While Par has already committed a US$90 million investment to its Hawai‘i Sustainable Aviation Fuel (SAF) project, a 4 kb/d plant converting locally grown oil seed crops to renewable diesel, SAF, renewable naphtha and LPG, the project is considered small scale and could be considered a separate decision from full conversion of the 94 kb/d refinery to a biofuels site.
- Relevant to scenario 5 (Par shutting down its Hawai‘i refinery):
  - In the event of the refinery closing, product imports would need to increase by around 50 kb/d (i.e., importing some 90 kb/d of products; i.e., more than double the current level).
  - We believe there will be some financial investment required to turn the refinery into an efficient, low-cost import facility as well. It is not a no-cost option.
    - Cost of converting a refinery into an import terminal depends on many factors including but not limited to the size of the operations pre- and post-conversion.
    - E.g., the 76 kb/d Batangas refinery in the Philippines was converted into a product terminal in 2003, costing Caltex some US$15 million, but conversion of the 135 kb/d Marsden Point refinery in 2022 cost Refining New Zealand nearly US$145 million, and the full decommissioning, demolition and conversion of the 135 kb/d Kurnell refinery into Australia’s largest fuel import terminal in 2014 cost Caltex around US$270 million.
  - Having said that, it is worth noting that since the State has already transitioned from a 150 kb/d refining throughput (when both sites were operational) to a single plant running at around 82% utilization (in 2023) while importing some 40 kb/d of products, surviving a scenario where Par Pacific opts for scenario 5 would not be a disaster, especially considering that all infrastructure is in place for storage tanks and jetties/moorings used for crude and product imports.
- Regarding scenarios 4 and 5: importing all of the State’s fuel requirements (i.e., gasoline, jet fuel, and diesel) in principle **should not have significant cost implications for consumers as fuels are priced at near import parity, making it possible for suppliers to complement local supply with imports**.

Investing in expanding secondary unit capacities (scenario 2)

Hawai‘i Oil Exports/(Imports), kb/d



Source: FGE

- With the potential loss in offtake for the refinery’s naphtha and LSFO, the refinery will be faced with the challenge of offloading these two products, which are typically sold internationally at a discount (or small premium at best in certain market conditions) vs. crude prices.
- The refinery could invest in the expansion/construction of secondary units, which would increase the volume of high-value products (e.g., gasoline, diesel) and minimize the production of naphtha and fuel oil.
- Assuming an 80 kb/d run rate, this translates into some 6 kb/d of naphtha and around 23 kb/d of fuel oil.
- Naphtha:
    - The refinery’s existing catalytic reformer, which upgrades naphtha into gasoline, is assumed to be operating at max capacity. Hence, the additional 5-6 kb/d of naphtha would require an expansion of the reformer unit (by 6 kb/d).
    - We estimate this project to cost **US$50 million**, which will increase the production of **gasoline from 15 kb/d to 20 kb/d (i.e., 5 kb/d less import requirements)**.
- Fuel oil:
    - The refinery’s visbreaker unit, which upgrades residue (i.e. fuel oil) into diesel, is also assumed to be operating at maximum capacity. However, visbreaker units are increasingly uncommon and cokers are the predominant heavy-upgrading units due to more favorable yields. The additional residue would require the construction of a (23 kb/d) coker.
    - We estimate this project to cost **US$600 million**, which will increase the production of **gasoline from 15 kb/d to 21 kb/d (i.e., 6 kb/d less import requirements)** and **diesel from 16 kb/d to 21 kb/d (i.e., 5 kb/d less import requirements)**. Furthermore, the project would produce around 4 kb/d of petcoke and 7 kb/d of VGO.
- These projects would not only eliminate the need to export LSFO (23 kb/d) and naphtha (6 kb/d), which would erode refining margins for Par, but it would almost eliminate import requirements (around 16 kb/d of gasoline and diesel combined). However, there will be some 11 kb/d (combined) of petcoke and VGO to be exported (i.e., half of the original surplus LSFO).
- Both projects would require significant injection of capital funds and are unlikely to happen.

Summary: What would Par Hawai‘i do?

The most likely outcome is a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal; other options can cost hundreds of millions of dollars

- Should Par lose its fuel oil and naphtha sales contracts with HECO and Hawai'i Gas, they have two decisions to make:
    1. Keep the refinery running or shut down refining operations
    2. Should they decide on the latter, the options would be whether to convert the site to an import terminal, a biofuels refinery, both (i.e., a smaller biofuels plant as well as an import terminal for conventional fuels), or total shutdown of all operations at the site.
- To answer the above questions and find the best commercial solution for Par Pacific regarding their Hawai'i refinery, a proper market study and financial model is required.
- Summarizing the points highlighted in the previous slides, however, we can conclude the following:
    - It is unlikely that importing crude oil (from Africa and Latin America) and exporting naphtha and fuel oil to Asia is an economic option given exposure to long-haul freight on both crude and products.
    - Whether to invest in upgrading (fuel oil and naphtha) depends on the impacts of replacing 28 kb/d of naphtha and fuel oil exports with 11 kb/d of petcoke and VGO exports on the refining margin.
        - In other words, justifying such a big investment (several hundred million dollars) in upgrading would require a long-term investment recovery period, which may not be obvious given the potential decline in gasoline and diesel demand, as well as the need for exports of surplus petcoke and VGO, which would still erode the economics of such a high-cost investment.
    - Full conversion of the (crude) refinery to a biofuels refinery is also probably not easily justified given the challenge of sourcing feedstock availability (for a sizeable plant of say larger than 40-50 kb/d) and the potential need for investing in a hydrogen plant or hydrogen import facility (should the refining units that are currently a source of H2 for a small scale SAF plant are mothballed too). However, expansion of the under-construction 4 kb/d biodiesel/SAF plant is likely.
    - Closing the refinery would also not be a cost-free option as it would require sizeable expenses in decommissioning and environmental remediation and asset write-offs.
    - The least costly option seems to be mothballing the refinery and converting the site into an import terminal/storage site that would allow Par Pacific to join IES and turn into one of the major fuel suppliers for transport fuels (i.e., gasoline, jet fuel, and diesel).
        - Especially, given the US $90 million commitment for the biofuel plant on the refinery site, which requires some of the existing tank storage and related logistics, a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal remains the most likely option for Par.
- If Par Pacific closes its Hawai'i refinery and converts it into an import terminal, we do not foresee any notable cost implications for local consumers. Prices should remain static as local petroleum products have always been sold at close to import parity prices due to third party import capacity. Fuel import terminals on Oahu owned by IES and Sunoco act as a counterbalance if local petroleum prices are above market rates. In addition, there is plenty of petroleum product supply in the Pacific Basin due to refinery expansions and security of supply is not an issue.

Future of Hawai'i Gas if LNG comes to Hawai’i

Hawai‘i Gas could replace all their existing SNG pipeline gas with regasified LNG and play a leading role in the energy transition with biogas and hydrogen

- Hawai’i Gas (HG) currently sells synthetic natural gas (SNG) via a pipeline network that spans 1,100 miles between Kapolei to Hawai‘i Kai. Most customers are in the downtown and Waikīkī area and the gas is used for cooking, drying, hot water heating, co-generation, etc. The SNG is derived from naphtha that is provided locally by Par and then “cracked” at HG’s synthetic natural gas plant.
- If Par loses the LSFO contract with HECO they are unlikely to provide HG with naphtha for their SNG production. However, the naphtha would not be needed by HG as the regasified LNG can easily be placed in HG’s existing gas reticulation system with some minor extensions. Moreover, the imported LNG would be 4-5X cheaper than what HG currently pays for SNG, thereby saving their regulated customers money as well.
- HG also provides significant amounts of LPG, particularly propane and to a lesser extent butane, to commercial and residential customers throughout O‘ahu that are not connected to the pipeline. Some of the larger commercial and residential customers who have larger storage can utilize LNG while many residential customers will have to continue to rely on propane. The bottom line is that imported LNG will be cheaper for all those who can access it instead of SNG and LPG.
- Gas utilities such as HG are uniquely positioned to develop and invest in a decarbonized, clean-fuels system. A utility such as HG can deliver a mix of biogas and hydrogen to a subset of the customers the gas utilities already serve via their existing infrastructure and supply new sources of demand such as shipping and aviation with pipeline extensions. Existing infrastructure can be partially repurposed to deliver clean fuels such as biogas and green hydrogen. Biogas does not have many technical limitations with HG’s existing infrastructure while hydrogen for existing pipelines is more challenging; gas pipelines can only handle about a 20% hydrogen blend before the pipes start corroding. Hydrogen currently comprises 10-15% of HG’s SNG blend in their pipelines and they are looking to bring this up to 20% with some relatively minor improvements. If green hydrogen was available, it could be dropped into the existing pipeline system relatively easily and blended with regasified LNG. However, if Hawai‘i wants to increase the hydrogen ratio to more than 20% then dedicated hydrogen infrastructure or substantial retrofits would need to be developed.
- In addition to building, owning, and operating the pipelines, HG has extensive knowledge to comply with the regulatory process and bring stakeholders together for key decisions. This is key in implementing policies that will support new fuels such as hydrogen.
- Hydrogen is the fuel of the future, and one Hawai‘i should begin to prepare for. Hydrogen is flexible to use and easy to transport and does not emit carbon if derived from certain renewables, such as solar and wind. Electricity is not easy to store, can be costly, and has a large footprint for a space-constrained island such as O‘ahu. With hydrogen, the surplus renewable electricity can be used to produce green hydrogen: in this way, the electricity is converted into an energy source that is suitable for storage. The only challenge for green hydrogen right now is cost, but that is projected to change in the coming years as costs are forecast to fall, like what was exhibited by solar.
- HG can play a leading role in the transition to a lower carbon economy by initially blending biogas and hydrogen with the regasified LNG and then later building dedicated infrastructure for green hydrogen with their operational and regulatory know-how.

Thank You

If you have any questions regarding this presentation, please contact us at

FGE@fgenergy.com or **+44 (0) 20 7726 9570 (London) | +65 6222 0045 (Singapore)**

Head Office: FGE House, 133 Aldersgate Street, London, EC1A 4JA United Kingdom. **Asian Head Office**: 8 Eu Tong Sen Street, #20-89/90 The Central, Singapore 059818