Alternative Fuel, Repowering, and Energy Transition Study

January 2025

HAWAIʻI STATE ENERGY OFFICE

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Preface

Hawaiʻi is a national and global leader in energy transition policy and deployment. The State was the first in the nation to establish a legally binding commitment to produce all its electricity from renewable resources. Hawaiʻi has long been a leader in renewable energy integration, especially distributed energy resources, or rooftop solar, and the use of inverter-based technology to connect those resources to the grid reliably.

Despite substantial progress on renewable integration, Hawaiʻi has the highest electricity costs in the nation and Oʻahu has the highest average greenhouse gas emissions intensity[1] for electrical power generation in the country. On Oʻahu, both are attributed to the use of low-sulfur fuel oil (LSFO)[2] the largest source of power generation on island (Figure 1).[3]

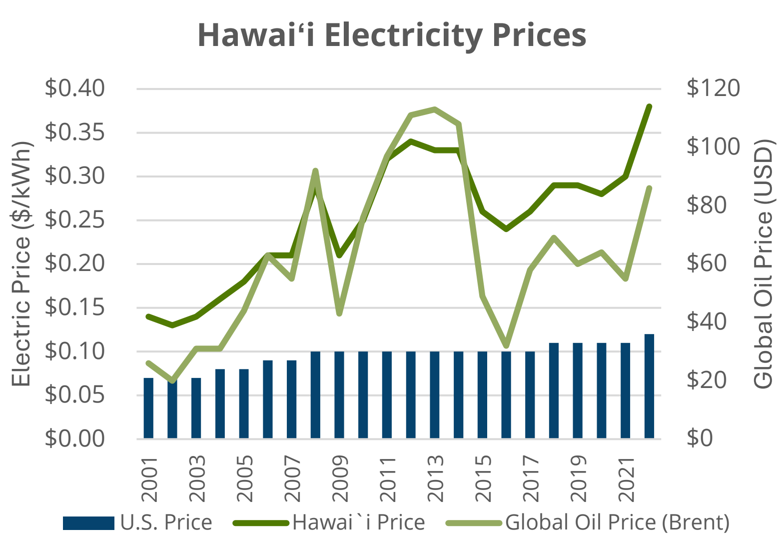

Figure 1. *Hawaiʻi Electricity Prices follow oil prices. Electricity prices from EIA; Brent oil prices from International Monetary Fund*

In contrast to the situation impacting much of the state, the island of Kauaʻi currently produces 60% of its electricity from renewable resources and routinely operates at 100% renewable energy generation for several hours a day. Fixed-price contracts for utility-scale renewables have been significantly more affordable than the oil generation replaced, providing Kauaʻi electricity ratepayers with the lowest average costs in the State.

During the run-up of oil prices post-Covid and following the Russian invasion of Ukraine,

[1] Greenhouse gas emissions intensity, or carbon intensity, is defined as the amount of greenhouse gases produced per unit of generation. For electric grid emissions intensity values are commonly expressed in metric tons of carbon dioxide equivalent per gigawatt hour of electric generation.
[2] Low-sulfur fuel oil (LSFO) is a type of residual fuel oil (RFO), it is often called bottom-of-the-barrel fuel because it comprises the leftover residuals from the crude barrel after distillates are refined for other fuels such as gasoline, diesel, and jet fuel.
[3] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

Kauaʻi was effectively shielded from oil price volatility, unlike the other islands. At the peak of the crisis, electricity bills increased by 58% on Maui and 92% on Molokaʻi.[4]

While Kauaʻi's success serves as a model for most of Hawaiʻi and its neighbors in the Pacific, Oʻahu faces a particularly challenging situation. Oʻahu's underlying energy demand is approximately 19 times greater than Kauaʻi's and represents approximately 70% of the State's generation needs, necessitating significantly more resources to meet the electrical energy demand. In contrast, Kauaʻi's net electricity generation represents approximately 5% of the State's total electrical generation needs (Figure 2).[5]

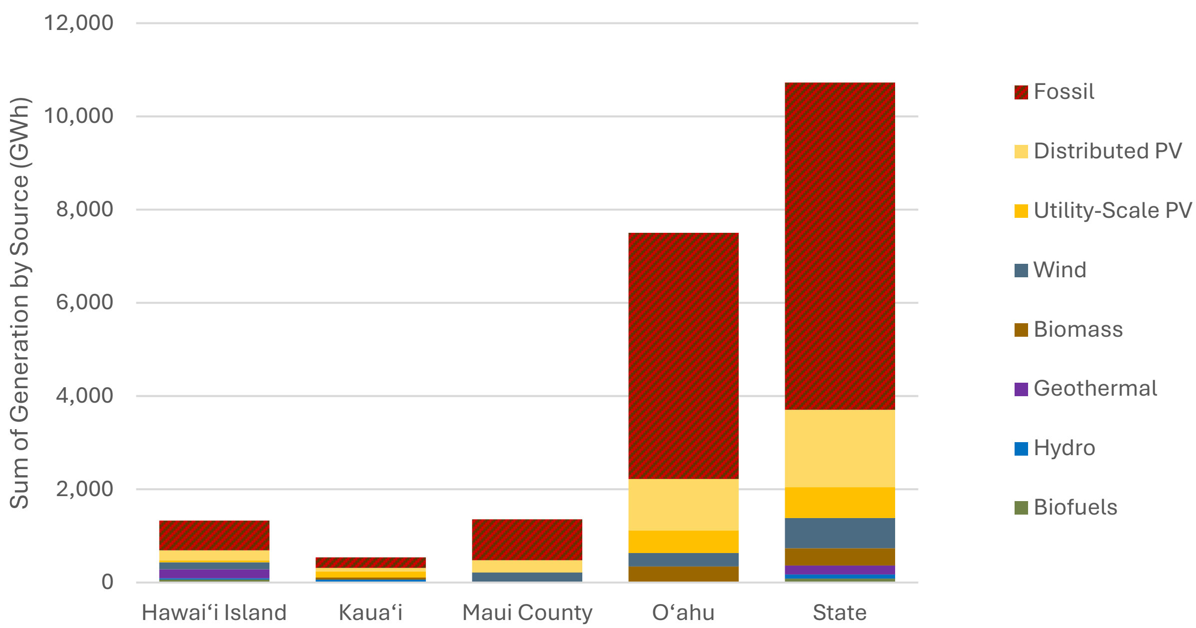

Figure 2. *County-specific generation by source (GWh). Data compiled by the Hawaiʻi State Energy Office (HSEO), Source Public Utilities Commission Docket 2007-0008. 2023 Renewable Portfolio Standards (RPS) Annual Status Reports.*

As Hawaiʻi makes progress, the State's largest electric utility, Hawaiian Electric, is undergoing challenges that have complicated and hindered Hawaiʻi's renewable energy transition. On the morning of August 8, 2023, a Category 4 hurricane passed south of the islands. It brought strong winds that knocked down power lines and sparked wildfires on Maui and Hawaiʻi Island. The reignition of a morning fire, fed by gale-force winds, resulted in a tragic wildfire that destroyed the town of Lahaina and claimed 102 lives.

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[4] HSEO analysis. On Maui, average monthly bill increased from $143.46 in January 2021 to $226.77 in August 2022, and on Molokaʻi average monthly bills increased from $152 to $291 over the same time period.

[5] U.S. Energy Information Administration, Electric Plant Fuel Monthly, Supply and Disposition of Energy Reports; PUC Docket Filing 2007-0008 Renewable Portfolio Law Examination 2023.

Consequently, the subsequent downrating of Hawaiian Electric's credit rating after the tragedy has increased the cost of debt financing for the utility and independent power producers, challenging the financing of future renewable energy projects and necessary capital expenditures to continue moving the energy transition forward.

In recent months, Hawaiian Electric has taken significant actions to reduce uncertainty around its financial situation and the impact of wildfire litigation on customers. It has committed to use shareholder funds, not money from customer bills, to pay its share of the wildfire settlement. Its parent company, Hawaiian Electric Industries (HEI), has raised funds through the sale of assets and the issuance of stock.

The State's 100% Renewable Portfolio Standards (RPS) and decarbonization policies continue to be the policy drivers of Hawaiʻi's energy transition. Post-Maui wildfires, current plans will not deliver affordable energy and attract capital to build a resilient, decarbonized energy ecosystem, necessitating the completion of this report.

Furthermore, current plans would likely result in Hawaiian Electric's continued burning of liquid petroleum fuels, although at diminishing levels and with planned exceedance of RPS milestones in 2030, until a total phase-out in 2045. Its long-term plans rely heavily on solar and wind, switching to biofuels (biodiesel or renewable diesel) with the forecasted added cost of more expensive biofuels borne by ratepayers and yet-to-be-determined lifecycle carbon saving.

The Pathways to Decarbonization Report to the 2024 Hawaiʻi State Legislature, prepared by the Hawaiʻi State Energy Office (HSEO) in 2023, confirmed that Hawaiʻi's continued reliance on LSFO and diesel has been a major contributor to the high costs of energy and the largest contributor of carbon emissions on the islands.[6] Oʻahu, where 67% of electricity comes from residual fuel oil (RFO),[7] will continue to be the most challenging island to transition due to its large population, growing electricity demand, and limited land availability.

In 2024, the Hawaii Public Utilities Commission (PUC) accepted Hawaiian Electric's 2023 Integrated Grid Plan (IGP). Under the IGP's Preferred Base Scenario, 3,300 megawatts (MW) of installed utility-scale, ground-mounted solar capacity is projected to be necessary to meet the requirements of the RPS.[8] Assuming, 0.15 MW / acre, HSEO estimates the installed capacity of this solar will require approximately 22,000 acres of land, occupying approximately 90% of the technically feasible land

[6] Residual fuel oil refers to a heavier, thick fuel oil left over after refining (or distilling out the lighter grader components of crude), Low sulfur fuel oil (LSFO) is a type of RFO, specifically refined to contain a lower sulfur level compared to traditional residual fuel oils. It is different from diesel, which is a distillate fuel (DFO) a lighter and cleaner burning fuel than RFO.

[7] U.S. Energy Information Administration, Electric Plant Fuel Monthly, Supply and Disposition of Energy Reports; PUC Docket Filing 2007-0008 Renewable Portfolio Law Examination 2023.

[8] Hawaiian Electric. (2022). Oʻahu Grid Needs Assessment. Retrieved from https://www.hawaiianelectric.com/a/11166

estimated to be available for utility-scale solar energy production.[9] It is important to recognize that developing this amount of land for solar will take time, requires careful planning to address a broad range of land-use concerns, and necessitates upgrades to infrastructure to integrate and interconnect this significant amount of solar capacity into the grid, further highlighting why the energy transition is a gradual process.

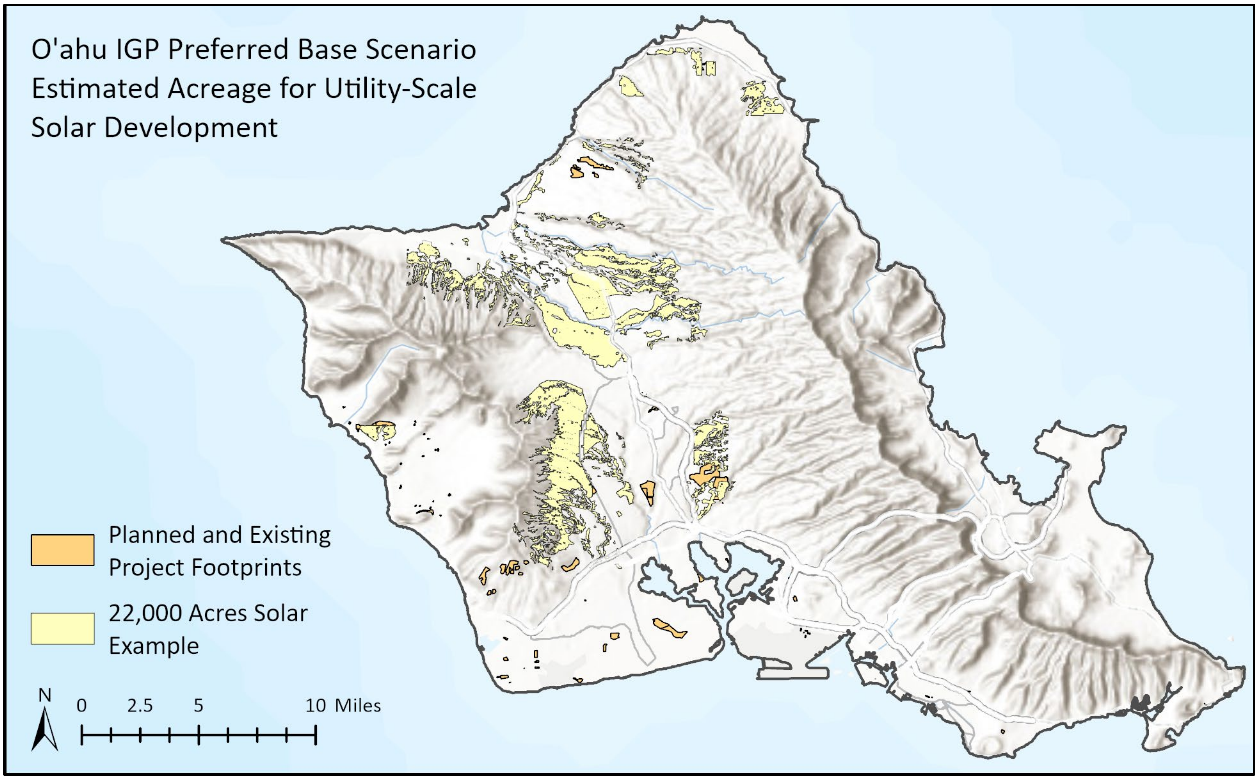

Figure 3 *Estimated acreage for utility-scale solar development. This figure illustrates the estimated acreage required to meet the projected 3,300 MW of utility-scale solar capacity. The area shaded yellow (22,000 acres) represents the estimated land area needed to meet the IGP preferred base scenario over the technical feasibility layer as assessed by the Technical Potential Study. The area shaded is within the Alt-1 Technical Feasibility Area. Note – figure is for illustrative purposes only, technical potential does not indicate where solar will be sited.*

Additionally, HSEO has observed that about 20% of Hawaiian Electric's generation fleet has recently been offline or operating at a significantly derated capacity, calling into question whether it has adequate reliability reserves to address contingencies, forecast errors, and uncertainties inherent in the assumptions and methodology. The unreliability of generators designated by the utility to serve as a backup during an expected loss of load events has been the cause of recent service disruptions.

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[9] Grue, N., Waechter, K., Williams, T., & Lockshin, J. (2020). *Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company*. National Renewable Energy Laboratory. Updated July 30, 2021.Retrieved from https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20210730_sc_heco_tech_potential_final_report.pdf

Reliable generators are essential to serve as routine backup and flexibility is necessary to integrate more intermittent renewables on the grid.

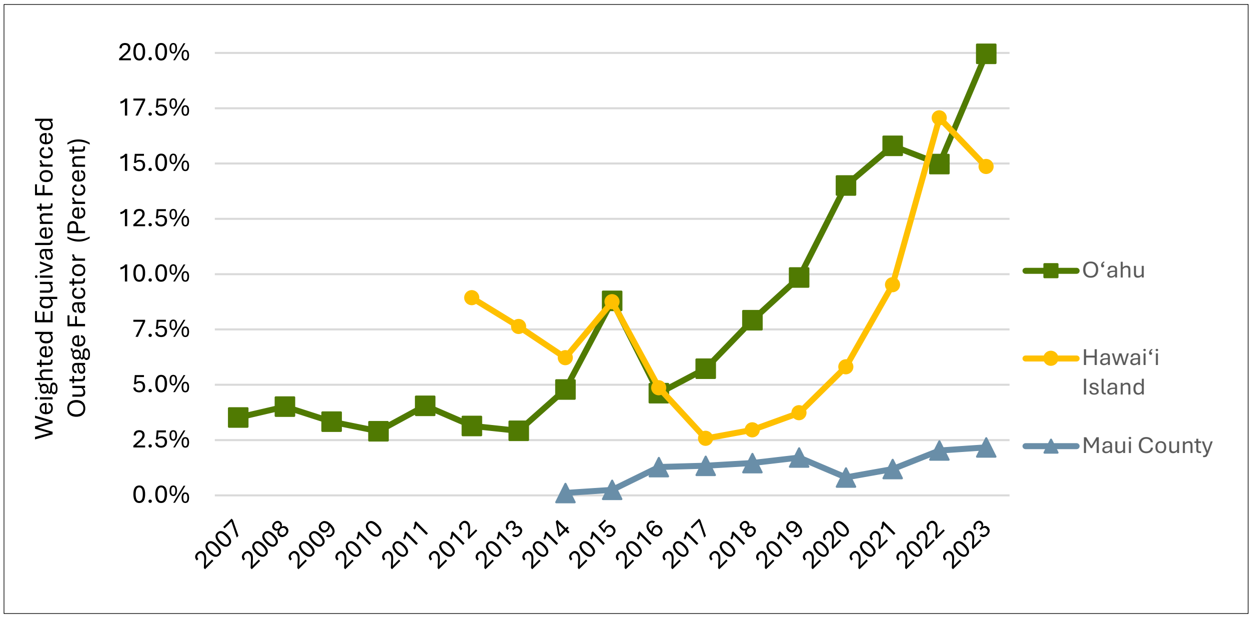

Figure 4 *Hawaiian Electric Territory Weighted Equivalent Forced Outage Factor (%), shows the increasing unavailability of HECO firm generators due to unplanned outages (Source: HNEI/Telos, Hawaiian Electric Power Supply and Generation Key Performance Metrics).*

Hawaiian Electric, at various times over the past 15 years, sought regulatory approval to replace aging firm generation facilities on Maui and O‘ahu as well as plan for the retirement of the coal-fired plant on O‘ahu, which closed in 2022. A number of factors, including changes in state energy policy and regulatory guidance, have resulted in the continued reliance on a generation fleet that continues to age.

The company currently plans to upgrade or construct a total of 660 MW of thermal capacity statewide, including 560 MW of fuel-flexible thermal capacity on O‘ahu, which will help address reliability issues.[10] However, the proposed use of biofuels in these new and refurbished plants is expected to impose substantial costs on ratepayers. In recognition of this, Hawaiian Electric has reserved the option to continue using fossil fuels at these plants. [11]

The planned thermal capacity projects are critical to ensure grid reliability and will provide improved powerplant efficiency; however, HSEO asserts that, as proposed, the Stage 3 thermal projects and likely the IGP RFP thermal projects, will result in one of two outcomes: either (1) higher electricity prices if biofuels are available and the PUC approves their costs,

[10] Hawaiian Electric Stage 3 Projects, Renewable Project Status Board

[11] Hawaiian Electric's Response to PUC-HECO-IRs 23-28 Hawai‘i Public Utilities Commission Docket No. 2024-0258 – To Institute a Proceeding Relating to a Competitive Procurement Grid Scale Resources, Non-Wires Alternatives and Grid Services. December 31, 2024.

or (2) the continued reliance on liquid oil-based fossil fuels, such as Low Sulfur Fuel Oil or ultra-low sulfur diesel.

The Stage 3 power purchase agreements (PPAs) applicable for Independent Power Producers (IPPs) and General Order No. 7 (GO7) applications have not yet been submitted to the PUC since project selection in December 2023. With the increasingly unreliable condition of the thermal power plant fleet, HSEO included in this study the evaluation of options for power plant investment. Further, considering Hawaiian Electric’s current position, the state has a fiduciary responsibility to understand the options and impacts of outside investment regarding necessary thermal plant modernization, grid improvements, and facilitating market-priced power purchase agreements in the near term.

Recognizing the unacceptable risks of continuing down the current pathway, Governor Josh Green, M.D., tasked HSEO with developing a new energy strategy to reduce energy costs, increase generation reliability and resilience, and achieve carbon emission reductions in the electricity sector, post-Maui wildfires, while achieving two key objectives:

- Accelerate Hawai‘i’s energy transition to renewable and carbon-free energy.
- Evaluate options to replace residual fuel oil for power generation and create opportunities for capital investments in grid infrastructure, and power generation to ensure and enhance energy system reliability and resilience.

Governor Green made it clear that the new energy transition strategy must ensure that all future investments in Hawai‘i’s growing, integrated electricity system result in a portfolio of fuels, power generation assets, and infrastructure that provide affordable electricity, energy security, resilience, and reliability.

Executive Summary

This Alternative Fuel, Repowering, and Energy Transition Study is part of a broader effort to develop an energy transition strategy to support national security, safeguard energy infrastructure, increase energy affordability, and accelerate renewable adoption. This study builds on past studies, reports, and research from HSEO, HDR, ICF, Facts Global Energy (FGE), National Renewable Energy Lab (NREL), Hawaiian Electric and Integrated Grid Plan (IGP) stakeholders, and others.

The study is focused on the combustion power plant, or *firm generation,* component of the electric grid, particularly on Oʻahu.[12] Firm, dispatchable generation from combustion units remains fundamental to grid reliability, and new combustion turbines better integrate intermittent renewable resources than centuries-old steam technology. Accordingly, actions related to resolving current shortfalls in utility steam plants complement the development of zero- and low-emission technologies like solar, wind, geothermal, and battery storage.

The study scope included the following main tasks:

1. Evaluating technology and functionality
2. Conducting economic analysis
3. Reviewing regulatory and policy frameworks

The continued development of intermittent renewable energy sources continues to be a priority of the state. Even when considering these projects are pursued to the greatest extent possible, however, the "fuels component" of the generation portfolio must be addressed to solve immediate grid needs and ensure system resource adequacy and reliability in the near term. Hawaiʻi's transition to a decarbonized energy system involves a variety of fuel options at different stages of development. To develop a pathway that meets policy targets while minimizing the impact on ratepayers, all available fuel options were reviewed relative to commercial viability, cost-effectiveness, and lifecycle carbon intensity (Table 1).

Based on the evaluation criteria four priority fuels emerged:

1. Imported Liquefied Natural Gas (LNG, also called natural gas or methane gas)
2. Imported Hydrogen
3. Local Renewable Natural Gas (RNG or biomethane)
4. Imported Biodiesel and/or Renewable Diesel (RD)

Importantly, locally produced biodiesel scored high for many of the commercial viability criteria, as well as the carbon intensity criteria; however, the aggregated scores were not high due to scalability and fuel availability in the near term.

[12] Firm Energy or Firm Generation refers to a synchronous machine-based technology that is available at any time under system operator dispatch for as long as needed, except during periods of outage and deration, and is not energy limited or weather dependent.

Table 1. *Evaluation matrix of reviewed fuels relative to Technical Maturity, Commercial Viability, Cost Effectiveness, and Lifecycle Carbon Intensity*

	COMMERCIAL VIABILITY					COST-EFFECTIVENESS	LIFECYCLE CARBON INTENSITY
Fuel	**Commercial Viability Score**	*Scalability (Production) 35%*	*Technology Readiness Level (TRL) 30%*	*Fuel Availability 20%*	*Transportation Logistics 15%*	**Avoided Cost of Carbon (LCOE$/MTCO2e)**	**Total Lifecycle Emissions (gCO2e/kWh)**
Methane/LNG – Imported	5.00	5	5	5	5	$233 – $594	630
Hydrogen w/ Ammonia as a carrier – Imported	3.15	4	3	2	3	N/A	350
Biomethane/Renewable Natural Gas (RNG) – Local	3.15	2	5	1	5	$227 – $578	--
Biodiesel/Renewable Diesel (RD) – Imported	3.00	1	5	2	5	$91 – $274	335-777
Biomethane/RNG – Imported	2.90	2	5	2	2	$240 – $611	--
Biodiesel/RD – Local	2.85	2	4	1	5	$88 – $266	200-410
E-Methane/SNG – Imported	2.65	1	5	1	4	–	–
Hydrogen – Local	2.60	2	3	2	4	N/A	40
E-Methane/SNG – Local	2.55	1	4	2	4	–	–
E-Ammonia – Imported	2.05	1	4	2	4	–	–
E-Diesel – Imported	2.05	2	1	3	3	–	–
E-Methanol – Local	1.90	1	4	1	2	–	–
E-Diesel – Local	1.75	1	2	1	4	–	–
E-Methanol – Imported	1.60	1	2	1	3	–	–
E-Ammonia – Local	1.30	1	1	1	3	–	–

Power plants across the State were analyzed for their appropriateness in adopting lower-carbon fuels. This review provided an assessment of power plants on O‘ahu, Hawai‘i Island, Maui, Moloka‘i, and Lāna‘i, but after the initial rounds of modeling and preliminary economic assessments, it was evident that LNG was only applicable for O‘ahu. O‘ahu has substantially higher electrical energy demand and significant land use constraints, the costs associated with interisland gas transport were not worth imposing on the outer islands. Consequently, Maui Nui and Hawai‘i Island should proceed solely with renewable energy acceleration, prioritizing renewable energy development to rapidly replace diesel and naphtha-fueled electricity generation. This can be accomplished by focusing on addressing interconnection and permitting bottlenecks to integrate additional renewable energy sources, enhancing grid services such as smart inverter installation and synchronous condensers, and exploring and advancing the deployment of other alternative dispatchable fuels, including locally produced biodiesel or renewable diesel. Policies, executive action, and ongoing state assistance to support this acceleration are necessary.

The plan developed by this study calls for constructing a new power plant and converting existing power plants on O‘ahu that are capable of dual-fuel operation, increasing reliability and flexibility while transitioning from carbon-intensive fossil fuels to cleaner alternatives. The alternative sets forth an energy transition on the island of O‘ahu to establish baseline data and allow for further analysis and refinement to ensure this pathway balances policy goals, financial feasibility, and community acceptance while minimizing adverse impacts on ratepayers.

Existing and former power plant locations were evaluated based on minimizing capital costs and land use impacts by utilizing existing infrastructure. Table 2 provides a subjective evaluation of O‘ahu’s existing power plants for potential natural gas conversion or replacement.

Table 2. *O‘ahu Power Plant natural gas conversion evaluation*

	Barbers Point Combined Cycle	Kalaeloa Partners	Campbell Industrial Park	Kahe	Waiau	H-Power	Schofield
Age of Generating Units *Older Units Preferred*	✔	✔	–	✔	✔	✔	✖
Total Rated Capacity (MW) *Higher Capacity Preferred*	✔	✔	✔	✔	✔	–	–
Generation Fuel Type *Higher Carbon Intensive Fuel Preferred*	✔	✔	–	✔	✔	✖	–
Existing Upgrade Plans *No Plans Preferred*	✔	–	✔	✔	–	✔	✔

	Barbers Point Combined Cycle	Kalaeloa Partners	Campbell Industrial Park	Kahe	Waiau	H-Power	Schofield
Location *Closer Proximity to Natural Gas Infrastructure Preferred*	Preferred	Preferred	Preferred	Neutral	Neutral	Preferred	Not Preferred
Candidate for Natural Gas Generation	Preferred	Preferred	Preferred	Preferred	Preferred	Not Preferred	Not Preferred

Preferred Neutral Not Preferred

The study presents a preliminary pathway to meet Hawai‘i’s RPS law and decarbonization objectives, with Liquefied Natural Gas (LNG) emerging as the most cost-effective transitional fuel to be used until carbon-emitting fossil fuels can be permanently eliminated by 2045 through a combination of hydrogen and renewable diesel, some of which should be locally produced to the extent possible.

The preliminary pathway to meet the projected future power demand at the lowest cost and lowest emissions involves transitioning to LNG as a primary thermal energy source, with built-in fuel flexibility in new generation infrastructure to accommodate lower-carbon, fossil-free alternatives as they mature and become more cost-effective. This approach anticipates the maturation of carbon-free alternatives for combustion, such as hydrogen and ammonia technologies, by 2045 and minimizes stranded asset risks by incorporating flexible-fuel infrastructure that can adapt to technological and economic advancements, or fuel switch to other decarbonized alternatives if/when they become more cost-effective.

While similar plans to use LNG to displace imported oil were pursued by Hawaiian Electric in the early 2010s—and included the replacement of existing power plants with efficient, fuel-flexible generators—these efforts were largely abandoned due to the previous administration's stance on LNG and its exclusive commitment to bypassing any transition fuels.

The study strategy emphasizes that LNG aligns with carbon, cost, and investment goals, serving as a bridge fuel without compromising Hawai‘i’s long-term decarbonization targets. The migration pathway accounts for the complexity of energy demands by recommending investments in infrastructure and dual-fuel power plants, with future compatibility for hydrogen or biofuels as those markets emerge.

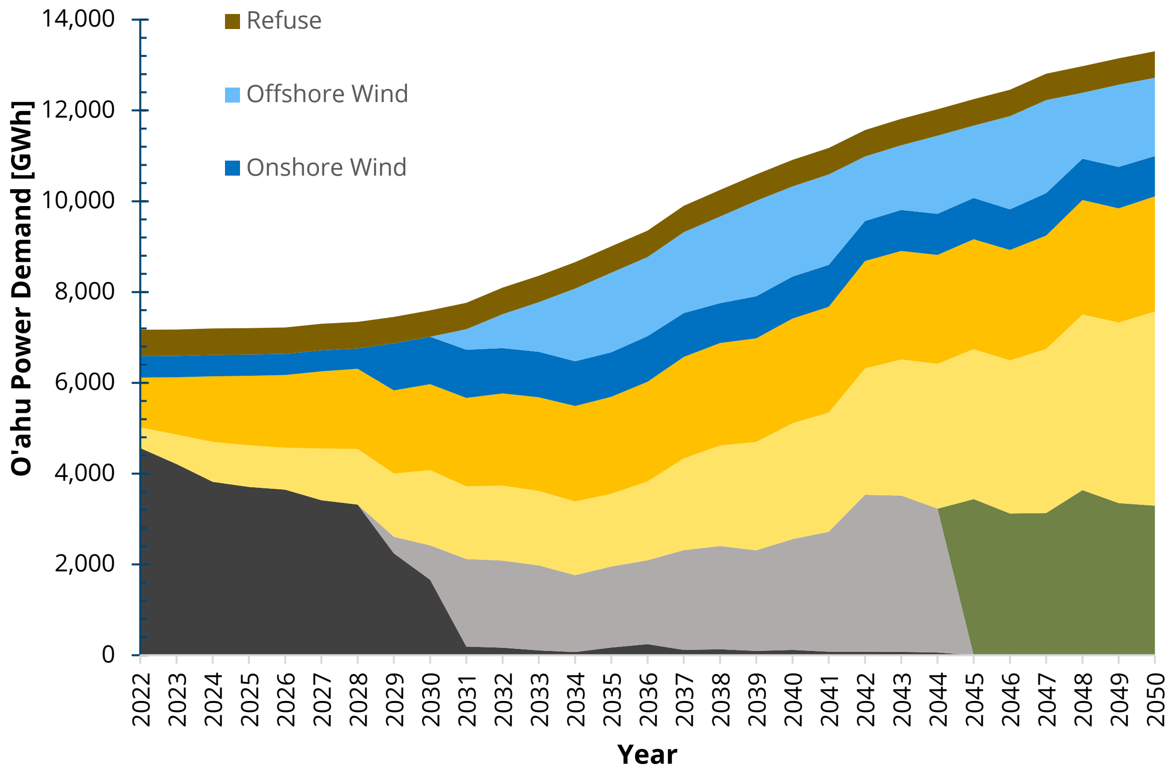

Figure 5. *O'ahu forecasted future power demand and generation portfolio by technology type, based on conservative electrification forecast and capacity expansion modeling.*

With careful planning and timely action, an interim transition to natural gas can yield meaningful cost savings while also reducing risk and lowering emissions. The assumed fuel mix displaced by natural gas and the ability to re-use the infrastructure constructed for a natural gas transition strongly impact the results of the economic evaluation. There can be significant potential for savings if the fuel mix displaced by LNG is more expensive than LSFO, such as the fuel costs expected for biofuels.

Alternative 3A pathway aligned with the displaced fuel mix that matched modeling results and resulted in a 15.2% decrease in residential energy costs, equivalent to approximately $340 in ratepayer savings per year (Figure 6).

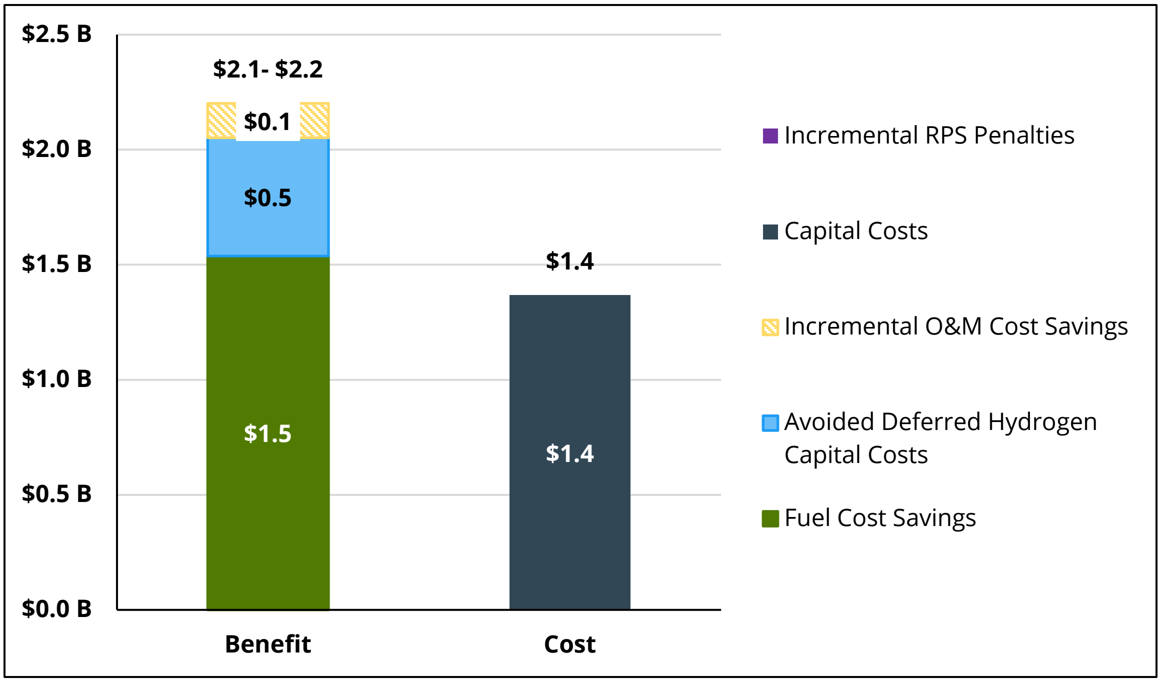

Figure 6. *Alternative 3A net present value of LNG transition. Evaluation includes analysis of all fuel cost savings of biodiesel, some solar, and some LSFO.*

The results of HSEO's evaluation of fuels and power plant upgrades based on the criteria of technological maturity, commercial viability, cost-effectiveness, and lifecycle carbon intensity are summarized below:

- Land availability and other factors indicate that local energy supply is insufficient to meet both current and forecasted demand. Accordingly, some energy imports will persist for both the electric and transportation sectors even after Hawai'i satisfies the 100% RPS.
- The current Hawaiian Electric grid and development plans have unnecessarily high carbon emissions primarily due to substantial reliance on LSFO as well as powerplant inefficiency.
- Planned thermal capacity projects are critical to ensure grid reliability and will provide some improved powerplant efficiency; however, HSEO asserts that, as proposed, the Stage 3 thermal projects and likely the IGP RFP thermal projects, will result in one of two outcomes: either (1) higher electricity prices if biofuels are available and the PUC approves their costs, or (2) the continued reliance on liquid oil-based fossil fuels, such as Low Sulfur Fuel Oil or ultra-low sulfur diesel.
- Power plants could be converted, and a new power plant could be built to run on gas supplied by a Floating Storage Regassification Unit (FSRU) and associated gas infrastructure.
- LNG emerged as the near-term fuel with the potential to cost-effectively reduce the State's greenhouse gas emissions during the transition to economywide decarbonization in 2045, but more analysis is needed to quantify a range of potential benefits and to identify how those benefits can be maximized to residents at the appropriate level of infrastructure buildout.

- The import of LNG, as an alternative to LSFO, could result in as much as 38% to 44% reduction in lifecycle carbon intensity when used in more efficient power plants. Methane gas can be used as a replacement for residual oil until it is phased out completely by 2045, as local production of biodiesel is accelerated and technology advances for the import of green ammonia and hydrogen.
- A new strategy combining policy guardrails and acceleration of renewable energy is necessary to maintain energy transition momentum and ensure that lower carbon fuels, such as LNG, will enable economywide decarbonization by 2045, not distract from it. There is a narrow, but beneficial, path for the inclusion of LNG in the energy portfolio. Its build-out should not allow for backsliding on the RPS.

Ultimately, the preliminary pathway balances ratepayer impacts and carbon reductions while improving grid reliability. Hawai'i's new energy strategy for O'ahu can meet future power demand at the lowest cost and emissions by seeking investment in new and converted flexible-fuel generation replacing residual oil with LNG in the near term & lower-carbon, fossil-free alternatives like hydrogen and ammonia technologies in the long term. This approach anticipates the maturation of hydrogen and ammonia technologies by 2045 and minimizes stranded asset risks by incorporating dual-fuel infrastructure that can adapt to technological and economic advancements. Concurrent acceleration of renewable energy and policy guardrails on investments will maintain energy transition momentum.

The Alternative Fuel, Repowering, and Energy Transition Study and any subsequent policies and actions will be integrated into a statewide energy transition strategy which will also account for other fuels and islands not included in this study. Any associated plans stemming from a proposed strategy shall be subject to acceptance by the utility and would require subsequent approval from the PUC and the appropriate permitting agencies.

This study was limited to desktop technical feasibility analysis and did not include outreach and engagement with key stakeholders, communities, regulatory, or permitting agencies which are essential in determining the ultimate viability and implementation of the alternatives discussed herein. The study is not a proposed plan, the actions discussed will require further analysis, pursuit by the electric utility, and appropriate regulatory approval. If pursued, it is likely many of the actions and concepts of the reports would be adjusted to meet the needs of the utility. Public engagement will play a key role in any future project planning moving forward. Although community and stakeholder feedback was not solicited for this study, the study provides valuable data, background, and context to guide and inform future feedback.

Introduction

The Hawaiʻi State Energy Office (HSEO) presents this Alternative Fuel, Repowering, and Energy Transition Study (study) as part of a broader effort to develop an energy transition strategy to replace petroleum-based fuels, attract investment, and enhance energy resilience. The strategy aims to support national security, safeguard energy infrastructure, and accelerate renewable adoption. This study builds on past research from HSEO, HDR, Facts Global Energy (FGE), National Renewable Energy Lab (NREL), Hawaiian Electric, and others.

A series of interrelated challenges and priorities shape Hawaiʻi's energy ecosystem. One of the most pressing issues Hawaiʻi faces is extremely high electricity rates and the intensity of carbon emissions, which surpass those of the rest of the nation. The State's RPS mandates a transition to 100% renewable energy to meet the statewide 2045 net-zero goal. In the wake of the recent Maui wildfires, there is a pressing need to overhaul the current energy infrastructure to ensure a resilient, cost-effective, and decarbonized energy ecosystem.

A key consideration is attracting capital for future energy investments to prioritize resilience and adaptability to harden Hawaiʻi's energy ecosystem to withstand future climate-related disasters. Renewable energy sources like solar and wind are central to a decarbonized approach. However, these intermittent energy sources are subject to variability and introduce challenges in maintaining grid reliability.

HSEO is tasked with analyzing and evaluating energy strategies to support Hawaiʻi meeting its Renewables Portfolio Standard (RPS) mandates as established by Hawaiʻi Revised Statutes (HRS) §269-92 (100% by 2045) and its statewide net negative emissions targets as established by HRS §225P-5—to sequester more atmospheric carbon and greenhouse gases than emitted within the State as quickly as practicable, but no later than 2045. While the transition to an alternative fossil-based fuel was evaluated, a core objective of the analysis was to ensure any investments made would not compromise the statewide 2045 RPS and 2045 net-negative target.

The current study builds on more than ten years of related studies (Table 3), augmenting the body of knowledge with additional engineering and economic analyses, and evaluation of permitting requirements. The Power Supply Improvement Plans (PSIPs) and the recent Integrated Grid Plan (IGP) and Pathways analysis from Hawaiian Electric and HSEO are core reference studies and data sources.

Table 3. *HSEO energy option evaluation research (2012-2024)*

2010-2015	2016	2023	2024	
APRIL 2012 **National Academy of Sciences** Greater focus needed on methane leakage from natural gas infrastructure **OCTOBER 2012** **Galway Energy Advisors, LLC** LNG Imports to Hawaiʻi: Commercial & Economic Viability Study **JUNE 2013** **HNEI** Liquefied Natural Gas for Hawaiʻi: Policy, Economic, and Technical Questions **JUNE 2015** **HNEI** Hawaiʻi Renewable Portfolio Standards Study	**APRIL** **Hawaiian Electric** Power Supply Improvement Plans: Supplemented, Amended, and Updated **MAY** **Hawaiian Electric** Liquefied Natural Gas Fuel Supply Transport Agreement	**APRIL** **E3** Hawaiʻi Pathways to Net Zero **MAY** **Hawaiian Electric** Integrated Grid Plan **DECEMBER** **Hawaiʻi State Energy Office** Hawaiʻi Pathways to Decarbonization, Act 238, Session Laws of Hawaiʻi 2022	**JANUARY** **Hawaiian Electric** Consolidated Annual Fuel Report **U.S. Environmental Protection Agency (EPA)** eGRID with 2022: The Emissions & Generation Resource Integrated Database **APRIL** **Argonne National Laboratory** Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model 2023	**JUNE** **U.S. Energy Information Administration (EIA)** Petroleum & Other Liquids Price Data **JULY** **National Renewable Energy Laboratory (NREL) and HSEO** Engage Model Updates **Hawaiian Electric** Integrated Grid Plan: Action Plan Annual Update **AUGUST** **Facts Global Energy (FGE)** Economics of Accelerating Hawaiʻi's Energy Transition via LNG and other Alternative Fuels

The study scope included the following main tasks:

- Evaluating technology and functionality
- Conducting economic analysis
- Reviewing regulatory and policy frameworks

The study focused on assessing alternatives for residual and diesel fuel and selected thermal generators used for power generation, intending to find opportunities to:

- Provide cost and carbon savings.
- Rapidly mitigate oil price volatility associated with petroleum-based liquid fuels.
- Attract capital to sustain operations and improvements in electrical system operations to support the State's energy transition, improve reliability, and reduce economic risk to ratepayers and energy stakeholders post-Maui wildfires.

Low-Sulfur Fuel Oil (LSFO) is the primary fuel for power plants that provide generation and grid stability on Oʻahu, but the volatile prices and high cost of LSFO cannot be sustained. Given this, the study focused on the "firm energy" component of the electric grid, particularly on Oʻahu. The study acknowledges that firm energy actions must occur alongside efforts to accelerate the development of zero- and low-emission technologies like solar, wind, geothermal, and battery storage.

Technical and Functional Evaluation

Hawaiʻi Energy Ecosystem Characterization

The development timelines of intermittent renewables at the scale necessary have not demonstrated the required pace to fully retire power plants as described in the current grid planning efforts. Development timelines would need to be condensed from an average of five years to under three years.

Slow development times for intermittent renewable energy projects in Hawaiʻi can be attributed to several key factors:

- Lengthy regulatory and permitting processes at local, state, and federal levels, including environmental impact assessments, land-use approvals, and community consultations, often extend project timelines.
- Interconnection challenges, such as limited transmission infrastructure and complexities in grid interconnection processes, also contribute significantly to delays, as does the need for interconnection studies and system upgrades.
- Community opposition and concerns regarding land use, cultural impacts, and environmental preservation may slow progress, particularly when engagement and outreach efforts are insufficient or delayed.
- Reliance on imported materials and equipment and challenges associated with supply chain delays and constraints.
- Difficulties securing project financing.

While battery storage technologies can provide backup during periods of low solar or wind output, the technology faces challenges in achieving cost-effectiveness and scalability for widespread deployment. Current battery systems are typically optimized for four-hour durations, and significantly more battery capacity would be required to accommodate prolonged periods of low wind and solar generation. Furthermore, these storage technologies must be paired with sufficient renewable energy generation projects. Without this pairing, they risk charging from high-emission sources like residual fuel oil, which could lead to increased overall emissions and even higher costs. Finally, it is important to recognize that these battery-dispatchable technologies still provide valuable grid services despite this concern.

Combustion using fuels like LNG, biodiesel, RNG, and hydrogen must be considered to balance the further adoption of renewable energy sources. Primarily, these fuels store large amounts of energy in a relatively small area and power plants using combustion still provide critically important physical stability to the grid, especially on systems with high levels of wind and solar. Hawaiʻi must shift away from the high-emission fuel currently serving these purposes and transition to a cleaner energy system, which requires careful consideration of fuels that can be generated and consumed within Hawai'i's energy ecosystem.

Given this context, this study confirmed prior work that identified LNG as a key component of lowering the state's carbon emissions and promoting additional renewable energy integration onto the grid (*See Evaluation and Analysis of Alternative Fuels*). Compared to LSFO, its lower carbon emissions make it a lower carbon choice in the short- to medium-term option that aligns with the State's energy goals. Importantly, LNG has both lower prices and less price volatility than LSFO making it a potential mechanism to address high energy prices and Hawai'i's affordability challenges. LNG offers the added benefit of flexibility for future transitions, as infrastructure built for LNG can later be adapted for hydrogen-based energy.

While local biofuels are an important part of the strategy, their scalability is constrained by high production costs, limited agricultural land, and lifecycle emissions concerns, particularly for imported feedstocks. Considering the limited land availability for power generation, installing solar farms is 67 times more land-efficient than planting common biodiesel feedstocks (Figure 7).[13] Another consideration is the decommissioning and handling of solar photovoltaic (PV) panels and BESS beyond their useful lifespans. While not an impediment to widescale solar deployment, it is a necessary consideration.

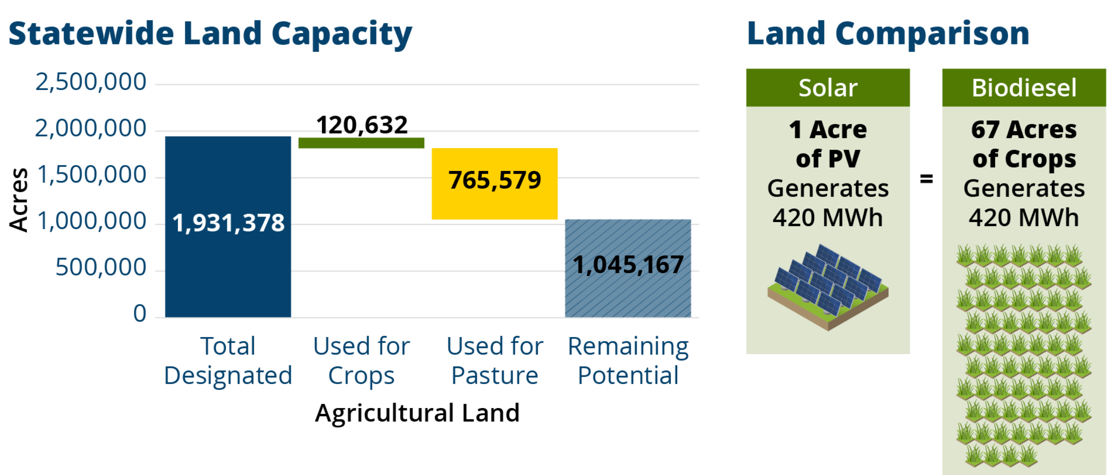

Figure 7. *Left: Hawai'i statewide agricultural land capacity by current use.[14] Right: Graphic depiction showing overall land-use efficiency of two energy-generating technologies. See the Biodiesel section for an explanation of the comparison. Estimates vary by feedstock, soil, microclimate, and other factors. For illustrative purposes only.*

[13] HSEO/HDR analysis. See Biodiesel section.

[14] Perroy, R., & Collier, E. (2022, April 1). 2020 Update to the Hawai'i Statewide Agricultural Land Use Baseline. https://hdoa.hawaii.gov/wp-content/uploads/2022/04/2020_Update_Ag_Baseline_all_Hawaiian_Islands_v5.pdf

While hydrogen, using green ammonia as a carrier, is not yet commercially viable, its potential as a clean fuel for power generation and transportation makes it a potential long-term solution for Hawaiʻi. The current lack of commercially available no- or low-carbon fuel for combustion also underscores the need to eliminate our dependency on the worst-emitting fossil fuel option as quickly as practicable. Biodiesel and RNG are other potential alternatives that present opportunities. With technological advancements and cost reductions expected over the next decade, hydrogen, biodiesel, and RNG are anticipated to play a significant role in the State's energy future, potentially replacing LNG as the primary fuel source by 2045.

Fuel Demand Components

Oʻahu Power Plant Demand

Oʻahu is home to the State's largest power generation facilities, which rely on a combination of petroleum liquids including LSFO, Ultra Low Sulfur Diesel (ULSD), No. 2 Diesel Oil, and Industrial Fuel Oil (IFO).

About 67% of power generation on Oʻahu comes from fossil fuels, consuming more than 55 million MMBTUs (Million British Thermal Units) of petroleum liquid annually.[15] The island's energy strategy focuses on transitioning away from these high-emission fuels toward cleaner alternatives.

Table 4. *Oʻahu power plant fuel heat input*

Oʻahu Power Plant	Generation Fuel Type	Annual Heat Input from Combustion (MMBtu)[1]
Kalaeloa Partners (KPLP)	LSFO	9,500,000
Campbell Industrial Park[2]	Diesel / Biodiesel	1,700,000
Waiau Power Plant	LSFO/Diesel	10,500,000
Kahe Power Plant	LSFO	27,000,000
Schofield Generating Station	ULSD / Biodiesel	140,000
H-Power Plant	Municipal Solid Waste	7,000,000

1. Based on 2022 eGRID Data which included generation due to the now decommissioned Barbers Point coal plant. The heat input may be higher in subsequent years.

[15] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

2. Campbell Industrial Park is a biodiesel-compatible power plant; however, the plant has not burned biodiesel since 2019.

Neighbor Island Power Plant Demand

As is the case in Oʻahu, many of the existing power plants on the neighboring islands currently rely on petroleum liquids. While the energy demand on these islands is comparatively lower than Oʻahu, there are opportunities for conversion to lower carbon fuels.

Table 5. *Hawaiʻi Island power plant fuel heat input*

Hawaiʻi Island Power Plant	Generation Fuel Type	Annual Heat Input from Combustion (MMBtu)[1]
W H Hill	IFO / ULSD	2,300,000
Kanoelehua	ULSD / Diesel	78,000
Keāhole	ULSD / Diesel	2,900,000
Puna	LSFO/Diesel	800,000
Waimea	LSFO/Diesel	23,000
Hāmākua Energy	LSFO/Diesel	1,900,000

1. Based on 2022 eGRID Data

Table 6. *Maui power plant fuel heat input*

Maui Island Power Plant	Generation Fuel Type	Annual Heat Input from Combustion (MMBtu)[1]
Kahului	IFO	2,400,000
Māʻalaea	ULSD / Diesel	6,300,000
Hana Substation	ULSD	1,200

1. Based on 2022 eGRID Data

Power Needs Forecast

Over the next decade, the State's power demand is projected to rise, mainly due to the electrification of transportation. Energy demand drivers in various models from different studies include:

- Electrification of transportation
- Changes in total vehicle miles traveled
- Population growth
- Energy efficiency in buildings
- Technology updates
- Additional buildings (commercial and residential)

Hawaiʻi plans to meet much of this demand with renewable energy, but studies show that some thermal generation is necessary for grid stability, no matter the underlying power demand.[16] Without thermal power, the grid risks instability, blackouts, and failure to meet peak loads, especially during long periods of low renewable generation.

Scenario-based planning is used to model a range of possible futures, including conservative, moderate, and aggressive electrification pathways. This approach inherently produces a wide range of forecasts to account for different outcomes. Forecasts for generation needs are shown in Figure 8, with key assumptions driving the differing outcomes summarized in Table 7.

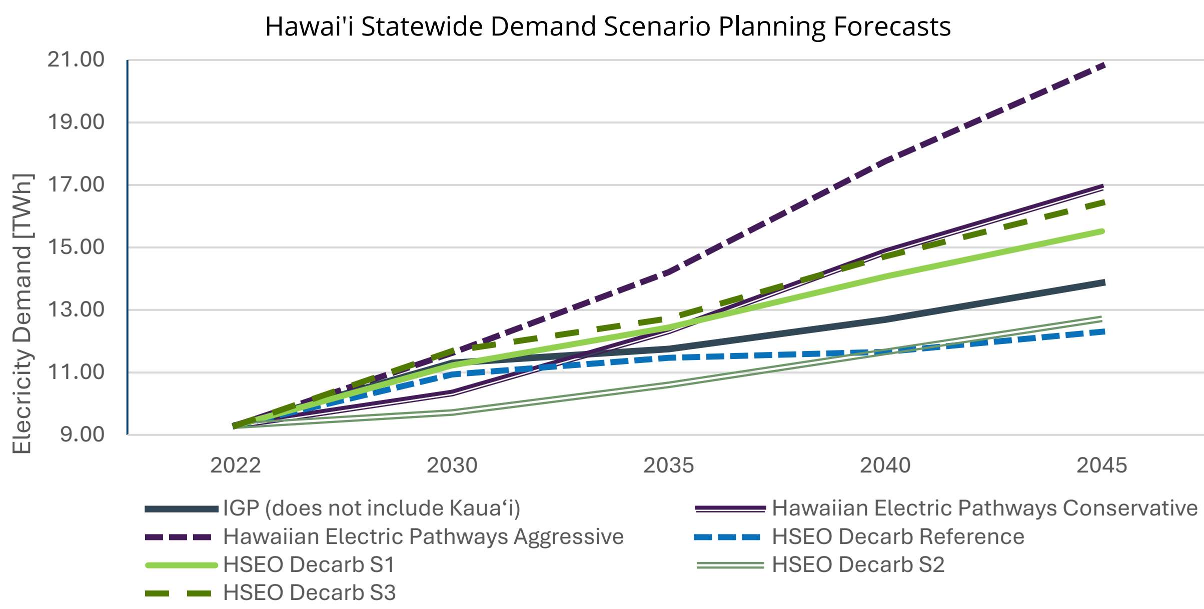

Figure 8. *Hawaiʻi generation forecasts developed by various reports.*

[16] See Table 3 – References included NREL Engage modeling, Hawaiian Electric, HSEO Act 238 Report, & others.

For details on assumptions applied to generation forecasts, see each referenced report.

Table 7. Key assumptions influencing power demands in various scenario planning forecasts

Scenario	Key Assumptions	Source for Full Documentation
Hawaiian Electric IGP*	Kaua'i not included Key assumptions outlined in the Hawaiian Electric IGP *Does not meet statewide decarbonization targets.	Hawaiian Electric IGP – Forecasts and Assumptions[17]
Hawaiian Electric Pathways - Aggressive	Light-duty vehicle: 100% zero emission vehicle sales by 2035, Direct Air Capture (Hawai'i Island only, not included in O'ahu forecast). Electrification of inter-island flights by 2045. "Achievable Potential – High" energy efficiency in buildings.	Hawaiian Electric Pathways to Net Zero[18]
Hawaiian Electric Pathways - Conservative	Light-duty vehicle: 100% zero emission vehicle sales by 2045; "Achievable Potential – High" energy efficiency in buildings.	
HSEO Decarb Reference	Business-as-usual future of energy demand and emissions, including all current state and federal policies (e.g. RPS achieved). Does not meet the 2030 or 2045 emissions targets. Light-duty vehicles: 52% zero-emission vehicle sales by 2030, 95% by 2045.	HSEO Decarb Strategy, Chapter Three[19]
HSEO Decarb S1	Widespread electrification of the transportation and buildings sectors, dramatically reducing fuel combustion. Light-duty vehicles: 100% zero-emission vehicle sales by 2035. More aggressive energy efficiency in buildings.	
HSEO Decarb S2	Focus on energy efficiency (EE) and conservation with aggressive EE in the buildings sector achieving "Economic Potential". Light-duty vehicles: 100% zero-emission vehicle sales by 2035. 20% statewide reduction in VMT.	
HSEO Decarb S3	Light-duty vehicles: 100% zero-emission vehicle sales by 2035, with buybacks for older ICE vehicles. Assumes that 30% of ICE vehicles on the road are replaced with EVs from 2025- 2030.	

[17] Hawaiian Electric Integrated Grid Plan (2023) Retrieved from https://hawaiipowered.com/igpreport/05_IGP-AppendixB_ForecastsandAssumptions.pdf

[18] Hawaiian Electric. (2023). *Hawai'i Pathways to Net Zero: An initial assessment of Decarbonization Scenarios.* Retrieved from https://www.hawaiianelectric.com/documents/about_us/our_vision_and_commitment/20230406_HECO_decarbonization_pathways_report.pdf

[19] Hawai'i State Energy Office. (2023). *Act 238: Decarbonization strategies for Hawai'i – Final report.* Retrieved from https://energy.hawaii.gov/wp-content/uploads/2022/10/Act-238_HSEO_Decarbonization_FinalReport_2023.pdf

Evaluation and Analysis of Alternative Fuels

Hawaiʻi's transition to a decarbonized energy system involves a variety of fuel options at different stages of development. To develop a pathway that meets policy targets while minimizing the impact on ratepayers, fuel options were reviewed relative to commercial viability, cost-effectiveness, and lifecycle carbon intensity (Table 8).

Based on the evaluation criteria, the four priority fuels are:

1. Imported Liquefied Natural Gas (LNG)
2. Imported Hydrogen (with Green Ammonia as a carrier)
3. Local Renewable Natural Gas (RNG)
4. Imported Biodiesel

See "Technical Appendix – Fuels Matrix" for the full documentation of the fuel evaluation.

Decision-Making Framework

A decision-making framework ranked fuels using a 1 to 5 scale for technological maturity and commercial viability (5 being most favorable) and inversely for cost-effectiveness and lifecycle carbon intensity (lower scores preferred).

Commercial Viability Score: Total score is based on a 1 to 5 scale with scores weighted using the percentages shown in table below.

Criteria	Weighting
TRL	30%
Transportation	15%
Fuel Availability	20%
Scalability (production)	35%

TRL: Evaluation of the maturity of the technologies in the fuel supply chain. This criterion indicates a technology risk where the technology has not reached maturity. The higher the TRL the lower the technology risk. The score is based on a 1 to 5 scale where 5 is the most mature technology and 1 is the least mature technology further defined in the table below.

Level	Description
1	Basic principles observed and reported
2	Proof of concept
3	Technology validated and early prototype demonstration
4	Technology operational at limited commercial scale
5	Proven at commercial scale, technology widely available and operational

Transportation Logistics: Evaluation of the maturity of the fuel transportation mechanisms. The score is based on a 1 to 5 scale where 5 is the most mature transportation mechanisms and 1 is the least mature transportation mechanisms further defined in the table below.

Level	Description
1	Innovation and investment required to transport and distribute fuel
2	Transportation logistics concept proven
3	Transportation logistics validated and early stage of implementation planning
4	Transportation logistics operational at prototype scale
5	Transportation logistics and infrastructure exists, operational and proven

Fuel Availability: Evaluation of current availability of the requisite volumes of the fuel. Evaluation is based on the supply of fuel relative to the demand. The score is based on a 1 to 5 scale where 5 is high volumes of fuel are commercially available and 1 is limited volumes commercially available as further defined in the table below.

Level	Description
1	Limited volumes available commercially
2	Small volumes available commercially
3	Moderate volumes available commercially
4	Large volumes available commercially
5	Abundant volumes available commercially with little or no constraints

Scalability: Evaluation of fuel capacity to meet energy demands. The score is based on a 1 to 5 scale where 5 can scale to meet the upper thresholds of power demands and 1 indicates no capacity to scale to meet energy demands.

Level	Description
1	No capacity to scale up, current fuel is at maximum capacity and availability, ability to produce volumes is severely constrained
2	Limited capacity to scale, produces limited volumes due to constraints (feedstock, space, etc.)
3	Moderate capacity to scale up
4	Capacity to scale up at large volumes with some risk
5	Capacity to scale up at large volumes with minimal constraints

Cost Effectiveness and Lifecycle Carbon Intensity: For cost-effectiveness and lifecycle carbon intensity, lower numbers are better. The avoided cost of carbon measures the effective cost of generation by technology to reduce one metric ton of CO_2 equivalent. Total lifecycle emissions measure cradle-to-outlet emissions of each fuel source.

Evaluation Matrix

Table 8. *Evaluation matrix of reviewed fuels relative to Technical Maturity, Commercial Viability, Cost Effectiveness, and Lifecycle Carbon Intensity*

	COMMERCIAL VIABILITY					**COST-EFFECTIVENESS**	**LIFECYCLE CARBON INTENSITY**
Fuel	**Commercial Viability Score**	*Scalability (Production) 35%*	*Technology Readiness Level (TRL) 30%*	*Fuel Availability 20%*	*Transportation Logistics 15%*	**Avoided Cost of Carbon (LCOE$/MTCO2e)**	**Total Lifecycle Emissions* (gCO2e/kWh)**
Methane/LNG – Imported	5.00	5	5	5	5	\$233 – \$594	630
Hydrogen using Ammonia as a carrier – Imported	3.15	4	3	2	3	N/A	350
Biomethane/RNG – Local	3.15	2	5	1	5	\$227 – \$578	--
Biodiesel/RD – Imported	3.00	1	5	2	5	\$91 – \$274	335-777
Biomethane/RNG – Imported	2.90	2	5	2	2	\$240 – \$611	--
Biodiesel/RD – Local	2.85	2	4	1	5	\$88 – \$266	200 - 410
E-Methane/SNG – Imported	2.65	1	5	1	4	–	–
Hydrogen – Local, electrolytic	2.60	2	3	2	4	N/A	40
E-Methane/SNG – Local	2.55	1	4	2	4	–	–
E-Ammonia – Imported	2.05	1	4	2	4	–	–
E-Diesel – Imported	2.05	2	1	3	3	–	–
E-Methanol – Local	1.90	1	4	1	2	–	–
E-Diesel – Local	1.75	1	2	1	4	–	–
E-Methanol – Imported	1.60	1	2	1	3	–	–
E-Ammonia – Local	1.30	1	1	1	3	–	–

*The lifecycle emissions intensity was determined using the GREET 2023 R&D Model using default and customized inputs when available. See lifecycle greenhouse gas documentation. The lifecycle carbon intensity of LSFO weighted average is ~1,137 gCO2e/kWh. The levelized cost estimates were determined using various resources.[20]

[20] U.S. Energy Information Administration, "Levelized Costs of New Generation Resources in the *Annual Energy Outlook 2023*", https://www.eia.gov/outlooks/aeo/electricity_generation/; Lazard, "Levelized Cost of Energy+", June 2024. https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf; International Renewable Energy Agency, "Renewable Power Generation Costs in 2022", August 2023. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2023/Aug/IRENA_Renewable_power_generation_costs_in_2022.pdf; National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity", October 2022. https://netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9

Power Plant Repowering and Replacement

Power plants across the State were analyzed for their appropriateness in adopting lower-carbon fuels. This desktop review provided an assessment of power plants on Oʻahu, Hawaiʻi Island, Maui, Molokaʻi, and Lānaʻi identifying potential alternatives for conversion to natural gas to support the State's shift toward a cleaner energy future.

Key considerations for conversion were:

- Age of the existing power plant
- Existing rated capacity
- Current fuel type
- Existing plans for upgrades to renewable fuel sources
- Location of the power plant regarding the potential cost of natural gas delivery

The assessment also considered the use of existing facility locations (such as Kalaeloa Partners and the Decommissioned Barbers Point Power Plant) to reuse existing infrastructure and to minimize community disruptions and the potential for land-use issues.

Oʻahu Power Plants

- **Kalaeloa Partners L.P. (KPLP) Power Plant:** KPLP is a combined cycle and cogeneration plant with two combustion turbine generators (CTG) and one steam turbine generator (STG) with a rated capacity of 208 MW. The plant is about 34 years old. KPLP's proximity to the potential FSRU gas pipeline terminal makes it a preferred candidate for conversion to natural gas. The CTGs could be retrofitted with new dual-fuel burners to fire natural gas with fuel oil as a backup along with the flexibility to transition to hydrogen in the future.
- **Campbell Industrial Park Generating Station (CIP):** CIP is a 129 MW single CTG used for addressing peak electricity loads on Oʻahu. The plant is 15 years old. CIP's proximity to the LNG infrastructure makes it a preferred candidate for conversion to natural gas. The CTG could be retrofitted with new dual-fuel burners to fire natural gas with fuel oil as a backup along with the flexibility to transition to hydrogen in the future.
- **Decommissioned Barbers Point Coal Plant:** The Barbers Point Coal Plant was decommissioned in 2022 and has undergone full demolition. The facility occupies an 8.5-acre plot in the industrial area of Kapolei. It has been identified as a preferred site for a new dual-fuel combined cycle power plant designed to burn natural gas, with the flexibility to transition to hydrogen. Its location in Campbell Industrial Park makes it well-suited for LNG infrastructure and provides proximity to a potential FSRU gas pipeline terminal.
- **Waiau Power Plant:** The Waiau power plant is a 474 MW power plant with six boilers and two combustion turbine generators. The boilers' ages range between 57 and 77 years old and the CTGs are 51 years old. The plant is in Pearl City which is approximately 13 miles east of the

Barbers Point LNG terminal. There is an ongoing Hawaiian Electric Stage 3 RFP project for refurbished electricity generation that Waiau, which requires consideration for switching fuel sources. The power plant is located along the existing Hawai'i Gas utility pipeline. Preliminary calculations and Hawai'i Gas responses to questions and information requests suggest that the existing pipeline may have the capacity to support an additional 140,000–150,000 therms per day. However, a detailed front-end engineering analysis would be required to confirm whether the pipeline could accommodate the volume needed to supply the power plant. If the existing pipeline is inadequate, additional natural gas piping would be required to deliver natural gas to the site.

Despite its challenges with potential infrastructure costs and the impact of Hawaiian Electric's Stage 3 RFP, Waiau may still be a preferred option to be considered with more evaluation and stakeholder engagement. Further, Hawaiian Electric's proposed Stage 3 repowering project includes dual-fuel combustion turbines that could be used with natural gas, despite being purposed for biodiesel.

- **Kahe Power Plant:** Kahe is the largest thermal generating station on the island of Oʻahu at a rated net capacity of 606 MW divided between six LSFO-fired boilers with steam turbine generators. The plant is located along the coast, approximately three miles north of Barbers Point. The plant operates at a relatively high-capacity factor of nearly 50% and has a net generation of approximately 2.5 million MWh. The boilers and steam turbines are between 48 and 61 years old.

  The Kahe site provides available space for expansion which would require approximately nine acres above tsunami evacuation zones, and the new plant could be built while the existing plant remains operational. However, a considerable amount of underground natural gas piping would be required to deliver natural gas to the site. This plant, or another of the current thermal fleet, could be used as a synchronous condenser in times of high solar production, and provide a ready diesel backup in case of disruptions to normal fuel supplies.
- **Schofield Generating Station:** Schofield Generating Station is a five-year-old peaking plant located in Schofield that consists of six reciprocating engines for a total capacity of 49 MW. The plant primarily runs on biodiesel and already meets RPS fuel requirements. The distance from the LNG terminal and the logistics of fuel delivery makes this plant not preferred for conversion. It would see continued use as a peaker plant using renewable fuels.
- **H-Power Plant:** H-Power is a 68.5 MW waste-to-energy plant that reduces landfill space by burning solid waste for electricity generation. This facility is not feasible for natural gas conversion due to its role in waste management, although the way it harvests electricity from waste could change and become more efficient and less polluting in the future.

Hawaiʻi Island Power Plants

- **Hill Power Plant:** The Hill Power Plant is a 34 MW plant that is expected to be decommissioned in 2029. This is a preferred plant for replacement with dual-fuel power generation equipment (natural gas with biodiesel/fuel oil backup) after decommissioning due to its location near the Hawaiʻi Island coast.

- **Kanoelehua Plant:** The Kanoelehua Plant, a 20 MW facility, is scheduled to have its combustion turbine generator (CTG) decommissioned in 2031. Similar to the Hill Power Plant, its coastal location on Hawaiʻi Island presents an opportunity for repurposing into a dual-fuel power generation facility capable of utilizing natural gas and biodiesel.
- **Keāhole Plant:** The Keāhole plant consists of a 50 MW combined cycle and four peaking units totaling 21 MW run on No. 2 Diesel and ULSD. The peaking units are between 35 and 40 years old, and the combined cycle is approximately 15 years old. The peaking units at this plant are a preferred candidate for natural gas replacement with new dual-fuel-fired power generation equipment. The combined cycle unit, being more efficient and only about 15 years old, is recommended to remain oil-fired to maintain fuel diversity on the island.
- **Puna Generating Station:** The Puna Generating Station consists of a CTG and a steam boiler totaling 35 MW located South of Hilo. The combustion turbine is 32 years old, and the steam unit is 54 years old. The steam unit is expected to be placed on standby in 2025. This plant is a preferred candidate for natural gas replacement due to the planned decommissioning and proximity to a potential LNG offloading located in Hilo Bay.
- **Waimea Generating Station:** The Waimea Plant consists of three boilers totaling 7.5 MW that are more than 51 years old and located further inland than the other plants on Hawaiʻi Island. This plant is not preferred for conversion due to the plant proximity and relatively small capacity compared to the other plants on the island.

Maui Power Plants

- **Māʻalaea Power Plant:** Maalaea Power Plant consists of a combined cycle capacity of 112 MW and simple cycle combustion turbine generator capacity of 80 MW. Although these units could potentially be converted to dual fuel with burner upgrades, the plant is not preferred for conversion due to its location in a tsunami evacuation zone with no areas outside of the zone. New technologies at this plant are likely to run into regulatory and public roadblocks due to the flooding risks.
- **Kahului Power Plant:** Kahului Power Plant consists of four boilers that are scheduled for retirement in 2028. The plant is not preferred for replacement due to its location in a tsunami evacuation zone with no areas outside of the zone. New technologies at this plant are likely to run into regulatory and public roadblocks due to the flooding risks.
- **Proposed Greenfield Plant:** A potential greenfield plant of 40-100MW capacity located outside tsunami evacuation zones, to use no- or low-carbon fuel.

Table 9. *Summary of power plants, potential alternatives, and fuels*

Power Plant	Status	Potential Alternative	Possible Fuels
O'ahu			
Kalaeloa Partners (KPLP)	Operational, repowering	Conversion to Dual-Fuel	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Campbell Industrial Park	Operational	Conversion to Dual-Fuel	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Barbers Point Coal Plant	Decommissioned	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Waiau Power Plant	Operational, repowering	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Kahe Power Plant	Operational	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Schofield Generating Station	Operational	Continue biodiesel usage	Biodiesel
H-Power Plant	Operational	Continue as Waste-to-Energy	Municipal Solid Waste
Hawai'i Island			
Hill Power Plant	Slated for decommissioning	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Kanoelehua Power Plant	Slated for decommissioning	New Dual-Fuel Plant	LNG, Biodiesel
Keāhole	Operational	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Puna Generating Station	Operational	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term), Oil/Biodiesel (Backup)
Waimea	Operational	Continue operation and decommission	
Maui Nui			
Mā'alaea Power Plant	Operational	Continue operation and decommission	Decommission
Kahului Power Plant	Operational	Decommission	Decommission
New Greenfield Plant	New Plant	New Dual-Fuel Plant	LNG (initial), Hydrogen (long-term)
Moloka'i and Lāna'i Power Plants	Small-scale	Continue operation	Biodiesel, RNG

Power Plant Upgrades

The first iteration of the natural gas conversion analysis involved converting or replacing select power plants on Oʻahu, Maui, and Hawaiʻi Island to run on natural gas, based on capacity targets from National Renewable Energy Lab (NREL) grid modeling. However, after an initial lifecycle cost analysis was completed, see *Economic Evaluation*, the results indicated that delivering gas to all islands would not benefit ratepayers, due to the increased costs of storage and interisland transport. Therefore, a decision was made to limit the use of LNG to Oʻahu only. Prioritizing the acceleration of intermittent renewable energy deployment and fuel switching to low-carbon alternatives on neighbor islands will be critical to ensure electric costs are stabilized, emissions are reduced, and grid reliability is ensured.

Table 10 provides a subjective evaluation of Oʻahu's existing power plants for potential natural gas conversion or replacement.

Table 10. *Oʻahu power plant natural gas conversion evaluation*

	Barbers Point Combined Cycle	Kalaeloa Partners	Campbell Industrial Park	Kahe	Waiau	H-Power	Schofield
Age of Generating Units *Older Units Preferred*	✓	✓	−	✓	✓	✓	✗
Total Rated Capacity (MW) *Higher Capacity Preferred*	✓	✓	✓	✓	✓	−	−
Generation Fuel Type *Higher Carbon Intensive Fuel Preferred*	✓	✓	−	✓	✓	✗	−
Existing Upgrade Plans *No Plans Preferred*	✓	−	✓	✓	−	✓	✓
Location *Closer Proximity to Natural Gas Infrastructure Preferred*	✓	✓	✓	−	−	✓	✗
Candidate for Natural Gas Generation	✓	✓	✓	✓	✓	✗	✗

✓ Preferred − Neutral ✗ Not Preferred

Oʻahu's decommissioned Barbers Point Coal Plant, KPLP, CIP, Kahe, and Waiau plants are all potential candidates for conversion to LNG as part of Hawaiʻi's energy transition strategy. Waiau was not modeled in this study because of extensive piping to deliver gas from Barbers Point, which may not be cost-effective, but future studies could consider this facility with more detailed evaluations of existing and new gas infrastructure to this site. In addition, the Waiau powerplant has existing plans for repowering.

Below is a summary of assumed capacity factors and the total electricity generation for the power plant conversions which were used in the later sizing of LNG infrastructure and economic evaluations. A capacity factor of 0.6 for base-loaded plants and 0.1 for peaking plants was chosen, with new plants achieving an average of 0.64 according to U.S. Energy Information Administration data. While higher than current Oʻahu power plant capacity factors, this is reasonable for a combined cycle power plant, which typically operates at higher capacity factors due to its use as a baseload combustion plant. Over time, renewable energy will displace significant amounts of this combustion, reducing overall capacity factors by 2045, even though the plants themselves can still achieve full output efficiently when needed, so there is no single correct capacity factor number for the entire study period; however, these capacity factor assumptions were necessary to inform economic analysis and estimate total generation. More detailed analysis will affect the exact capacity factors anticipated for baseload and peaking plants under a given set of assumptions.

Table 11. *Power plant modifications for LNG infrastructure and economic evaluations*

Site	Capacity Factor	Modifications	Total Capacity (MW)	Total Generation (TWh)	Year in Service
KPLP	0.6	Burner replacements with new gas infrastructure (compressor, gas skids, piping)	208	1.1	2030
Barbers Point Combined Cycle	0.6	New 2x1 CC power plant – Natural gas/ multifuel	156 (Baseload)	0.82 (Baseload)	2030
	0.1	Single simple cycle peaker	60 (Peaker)	0.06 (Peaker)	2030
Campbell Industrial Park (CIP)	0.1	New burners on single CTG	129	0.1	2035
Kahe Combined Cycle	0.6	New 3 x 1 CC – Natural gas infrastructure	358	1.9	2035
		Totals	**911**	**3.98**	

Preliminary Pathways to Integrate Alternative Fuels Into Hawaii's Energy Transition

Liquefied Natural Gas

LNG emerged as the only near-term fuel with the potential to cost-effectively reduce the State's greenhouse gas emissions during the renewable energy transition. LNG has been produced, stored, and transported globally for over 60 years and has an established safety record over this period. Its production technologies are mature, with key components of the supply chain having been widely implemented.

The international LNG supply chain is well-developed and has various fuel import options. It can be transported using ocean-going vessels delivering LNG directly to shore or a moored FSRU. These vessels transport LNG at cryogenic temperatures to reduce volume and transport effectively, and the availability of these vessels in the global market means little innovation is required to transport LNG to new locations.

There are several commercial avenues for LNG sourcing, with companies providing solutions that include sourcing, shipping, and providing an FSRU. Sufficient volumes of LNG can be sourced from Canada, Australia, Asia, Mexico, or the US to meet demand, providing scalability and availability. Domestic imports from US sources are limited by the Jones Act vessel availability.[21]

LNG distribution infrastructure can be designed to meet the specific demands of its destination. Storage volumes for LNG tankers and FSRUs can be adjusted to match local consumption, and vaporization equipment on the FSRU can provide variable natural gas flow rates through subsea pipelines. Given LNG's long history and adaptability, its distribution can meet various logistical challenges.

Siting considerations for LNG infrastructure include location-specific variables such as environmental impacts, logistical access, and proximity to energy demand centers. In the case of Hawaiʻi, siting considerations would need to include assessing the proximity of LNG infrastructure to existing infrastructure and populated areas, minimizing environmental disruption, and optimizing logistics for fuel delivery across islands.

See "Technical Appendix – LNG Import Evaluation" for more background on the relevant LNG storage, transportation, and regasification technologies.

Preferred Alternative LNG Supply Chain Summary

The supply chain process described below is the result of an iterative process where capital expenditure (CAPEX), timing, safety, equipment and skilled labor availability, and backup storage are considered. This preferred preliminary solution is split into two phases, Phase 1 is scheduled to be in

[21] See Facts Global Energy (FGE) *Economics of Accelerating Hawaiʻi's Energy Transition via LNG and other Alternative Fuels* prepared for the Hawaiʻi State Energy Office. August 2024.

service in 2030 with Phase 2 following in 2035. The phasing and sequencing of the project outlined represent a preliminary framework. These phases are subject to adjustments based on planned maintenance schedules and other logistical considerations. Advancing the timeline for repowering existing facilities may be beneficial while new power plants are under construction if this can be feasibly completed while maintaining resource adequacy, ensuring a faster transition, increased economic benefits, cost reduction, and enhanced system reliability.

The cost-effectiveness of the solution is heavily reliant on the island's cumulative natural gas demand. Table 12 and Table 14 show the estimated natural gas demand for the facilities to be introduced to O'ahu during each phase. Values were calculated based on each facility's generation capacity, expected facility efficiency, heat rate values, and facility capacity factors. Existing fuel oil storage will be left in place and used for longer-duration backup needs. Figure 9 summarizes the LNG supply chain, with a final in-service date of 2035.

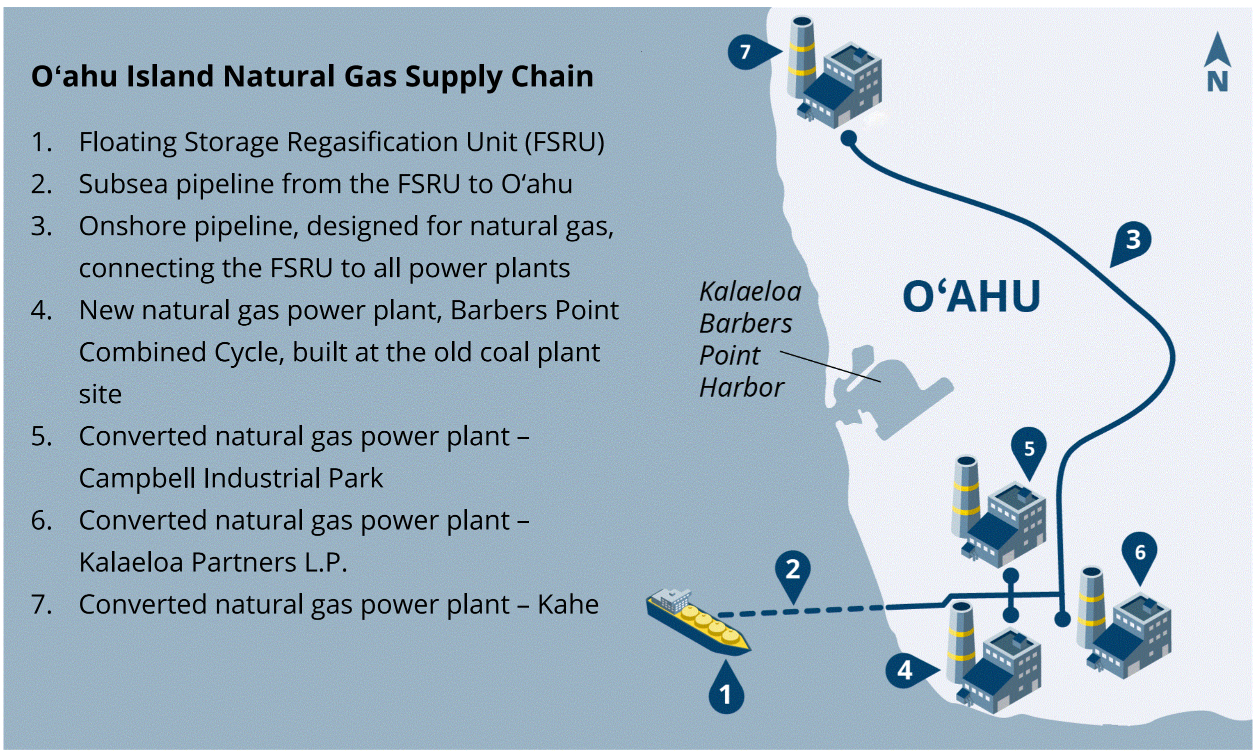

Figure 9. *LNG supply chain for O'ahu preferred alternative*

Phase 1

Phase 1 would introduce natural gas on a large scale to O'ahu. An FSRU with a storage volume of about 180,000 m^3 would be moored about two miles off Barbers Point. An advanced buoy system would be installed to verify safe operation. This vessel will be the island's main source of natural gas for power generation purposes.

The FSRU would be filled via LNG tankers at regular intervals to maintain the stored volume. A subsea pipeline will be built to connect the FSRU to the existing and new pipeline network on Oʻahu, and this pipeline will be sized to accommodate the design send-out flow rate from the FSRU.

During Phase 1, gas power plants would be modified and developed at two locations: the KPLP and Barbers Point Combined Cycle site (Decommissioned Coal Plant). KPLP currently operates a 208-megawatt (MW), combined-cycle cogeneration plant that combusts low-sulfur fuel oil (LSFO).[22] The facility would be modified with gas-burning infrastructure including burners, compressors, gas skids, piping, etc.

The decommissioned coal plant was previously a medium-sized, coal-fired electrical power station but was closed in September of 2022.[23] A 2 x 1 combined-cycle gas power plant with a simple cycle peaking unit will be built at this location. The plant has been fully decommissioned, leaving a brownfield site with some interconnection capacity. Table 12 provides power generation and gas demands for both power plants.

Table 12. *Phase 1 power plant data*

Location	Total Capacity (MW)	Required Flow Rate (million standard cubic feet per day [MMscfd])	LNG Volume (million gallons per year [MMgpy])	Total Generation (terawatt hours [TWh])
KPLP	208	22.2	97.6	1.1
Barbers Point Combined Cycle	156 60	13.6 1.2	59.9 5.3	0.82 0.06
Total	**424**	**37**	**162.8**	**1.98**

New pipeline installation would be necessary to connect both KPLP and the Barbers Point Combined Cycle locations to the existing natural gas transmission network, connecting both sites to the natural gas supply from the FSRU. Diesel or oil storage capacity will remain, and the diesel would provide an effective backup if normal fuel supplies face disruption. Gas and multifuel/dual fuel engines are available on the market today. These multifuel engines are capable of operating on natural gas as well as diesel fuel, when gas supply is unavailable for any reason, it is possible for plants to quickly switch over from gas to diesel or vice versa during continuous operation if necessary.[24] The FSRU

[22] Kalaeloa Partners (2024) *What we do.* Retrieved from https://www.kalaeloapartners.com/what-we-do

[23] AES Corporation. (2023, January 31). *AES marks retirement of Hawaii power plant while expanding renewable energy projects*. AES Hawaii. Retrieved from https://www.aes-hawaii.com/press-release/aes-marks-retirement-hawaii-power-plant-while-expanding-renewable-energy-projects

[24] Wartsila (2014) Gas and Multi-fuel Powerplants. Environmental Protection Agency (EPA) Archive Document. (2014). *STECS Red Gate and Wärtsilä Power Plant*. Retrieved from https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/stec-redgate-wartsila-power-plant.pdf

can also be moved into port to minimize downtime due to weather. To provide a conservative overall cost estimate, some contingency expense is incorporated into Table 13.

***Table 13**. Phase 1 LNG and Power Plant assets capital costs, undiscounted present value*

Description	CAPEX
FSRU, Buoy System, Subsea Pipeline	$412,000,000
Onshore pipeline connection to KPLP	$2,000,000
Onshore pipeline connection to Barbers Point Combined Cycle	$10,000,000
Transmission system upgrades	$20,000,000
KPLP Power Plant Conversion - Burner replacements with new gas infrastructure (compressor, gas skids, piping)	$20,000,000
Barbers Point Combined Cycle Power Plant	$570,000,000
Additional storage and additional contingency	$12,000,000
Phase 1 Total	**$1,046,000,000**

Phase 2

The second phase would supplement the new gas infrastructure introduced on Oʻahu during Phase 1. The FSRU and associated subsea pipeline installed during Phase 1 would be sized with the capacity to serve the demands of both phases. It would remain in place from its introduction in Phase 1 through the duration of gas usage on Oʻahu.

Phase 2 would introduce gas power generation to both the CIP and Kahe facilities. The CIP location would be modified to house new burners for a single-cycle gas turbine. The Kahe facility would incorporate a new 3 x 1 combined cycle gas power generation system. Table 14 provides additional information for the updated power plant.

A summary of the CAPEX for Phase 2 is shown in Table 15. These numbers are preliminary and need to be further refined during detailed design.

***Table 14.** Phase 2 power plant data*

Location	Total Capacity (MW)	Required Flow Rate (MMscfd)	LNG Volume (MMgpy)	Total Generation (TWh)
CIP	129	3.4	15.1	0.1
Kahe	358	34.2	150.6	1.9
Total	487	37.6	165.7	2.0

Table 15. *Phase 2 LNG assets capital costs, undiscounted present value.*

Description	CAPEX
Onshore pipeline connection to CIP	$2,000,000
Onshore pipeline connection to Kahe	$20,000,000
Campbell Industrial Park Power Plant Conversion - Burner replacement with new gas infrastructure (compressor, gas skid, piping)	$10,000,000
Kahe Combined Cycle Power Plant	$945,000,000
Transmission system upgrades	$44,000,000
Additional storage and additional contingency	$18,000,000
Phase 2 Total	$1,039,000,000

See Technical Appendix - Power Plant Repowering & Replacement for further details on the potential Supply Chain for LNG.

Renewable Natural Gas (RNG)

RNG is a low-carbon alternative to fossil fuels, as it recycles methane that would otherwise be released into the atmosphere from organic waste. RNG production can significantly reduce greenhouse gas emissions by capturing and using methane from landfills, wastewater treatment plants, and other waste sources. RNG has lower lifecycle greenhouse gas (GHG) emissions than fossil natural gas. While RNG is not scalable or widely available enough to meet Hawaiʻi's energy demands, it is a technically viable option and can be used to reduce lifecycle emissions when blended with natural gas. When produced with waste feedstocks, RNG can have substantial co-benefits. However, RNG may not always be cost-competitive in areas with lower feedstock availability. There are often additional costs associated with RNG production.

RNG can be blended with fossil-based natural gas by injecting it into the natural gas distribution pipelines, making it a viable substitute for fossil-based natural gas. Hawaiʻi Gas already blends a small amount of RNG into its utility gas lines, and the company has plans to expand RNG use further.[25] Inter-island transportation of RNG is a logistical challenge due to the geographical dispersion and the associated costs of moving gas among the islands.

RNG production facilities must be strategically located near feedstock sources to minimize transportation costs and maximize efficiency. For example, wastewater treatment plants (WWTPs) with anaerobic digesters or landfills with gas collection systems should be prioritized for upgrading facilities to RNG production. Dedicated energy crops should be sited on underutilized agricultural lands, particularly those with high Land Capability Classifications (LCC 1-4).

As with all energy-related fuels, safety is paramount in RNG production, especially in handling methane, a potent greenhouse gas and flammable substance. Gas collection systems at landfills and

[25] Hawaiʻi Gas 2023 Sustainability Report (2024). The Gas Company, LLC dba Hawaiʻi Gas

wastewater treatment plants must be properly managed to prevent leaks and enable safe operation. The integration of RNG into existing methane gas pipelines requires careful monitoring to maintain the compatibility and reliability of the gas network.

Livestock Manure

In areas with large numbers of confined animal feeding operations (CAFOs), livestock manure can be a valuable feedstock for RNG production. The US continent has seen dramatic increases in RNG production from dairies and hog farms in the last five years.[26] However, the Hawaiʻi Natural Energy Institute study reviewed the livestock populations in Hawaiʻi for cattle, chickens, and hogs and determined Hawaiʻi has insufficient number and size of animal feeding operations to justify biogas generation and RNG.[27]

Wastewater Treatment Plants

The State of Hawaiʻi has 12 WWTPs treating an average daily flow greater than 1.0 MMGAL per day (MGD).[28] Eight of these facilities already produce biogas through the anaerobic digestion of biosolids.

Table 16 summarizes the biogas production potential from wastewater treatment regardless of the use of anaerobic digestion as it could be added to the facilities that don't currently have that capability.

Table 16. Biogas production potential for wastewater treatment

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Sand Island	Honolulu	Yes	76.00	194,186	886,693	616
Honouliuli	Honolulu	Yes	25.70	65,674	299,879	208
Kailua	Honolulu	Yes	16.30	41,645	190,160	132
Waianae	Honolulu	Yes	3.80	9,719	44,381	31
East Honolulu	Honolulu	Yes	4.41	11,272	51,470	36
Schofield	Honolulu	Yes	2.40	6,142	28,046	19
Lāhainā	Maui	No	4.20	10,732	49,004	34
Wailuku-Kahului	Maui	No	3.91	9,989	45,614	32

[26] U.S. Environmental Protection Agency. (2024). *AgSTAR data and trends*. U.S. Environmental Protection Agency. Retrieved from https://www.epa.gov/agstar/agstar-data-and-trends

[27] Hawai'i Natural Energy Institute. (2021). *Resources for renewable natural gas production in Hawaii*. Retrieved from https://www.hnei.hawaii.edu/wp-content/uploads/Resources-for-Renewable-Natural-Gas-Production-in-Hawaii.pdf

[28] EPA 2022 Clean Water Needs Survey Report to Congress, 2022

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Kihei	Maui	No	3.59	9,179	41,915	29
Hilo	Hawaiʻi	Yes	4.20	10,732	49,004	34
Kealakehe	Hawaiʻi	No	1.69	4,320	19,725	14
Līhuʻe	Kauaʻi	Yes	1.11	2,835	12,944	9
TOTAL			**147**	**376,425**	**1,718,835**	**1,194**

Landfills

The State of Hawaiʻi has 15 municipal solid waste landfills, seven of which are closed and not receiving additional waste.[29] For effective landfill gas collection and RNG production, the study assumed candidate landfills have over 1.0 million tons of waste in place and have not been closed for more than 12 years. Table 17 summarizes the RNG production potential from landfill gas (LFG).

Table 17. *RNG production potential from landfill gas*

Landfill Name	Landfill Owner	Waste in Place (tons)	LFG Collection System in Place?	Current Project Status	Landfill Gas Produced (SCF/day)	Landfill Gas Produced (MMBtu/year)
Central Maui Landfill	Maui County	6,564,409	Yes	Planned	1,356,000	247,470
Kapaʻa and Kalāheo Sanitary Landfills	City & County of Honolulu	5,838,786	Yes	Shutdown	348,312	63,567
Kekaha Landfill/Phases I & II	County of Kauaʻi	3,113,967	Yes	Candidate	642,000	117,165
Palailai Landfill	Grace Pacific Company	2,845,215	Yes	Low Potential	70,000	12,775
South Hilo Sanitary Landfill (SHSL)	Hawaiʻi County	3,193,059	No	Candidate	640,000	116,800
Waimānalo Gulch Landfill & Ash Monofill	City and County of Honolulu	13,141,443	Yes	Candidate	1,121,000	204,583
West Hawaiʻi Landfill/Puʻuanahulu	Hawaiʻi County	3,404,076	Yes	Candidate	304,000	55,480
Total					**4,481,312**	**817,840**

[29] EPA Landfill Methane Outreach Program (LMOP), 2024

Food Waste

Food waste includes kitchen trimmings, plate waste, and uneaten prepared food from restaurants, cafeterias, and households as well as unsold and spoiled food from stores and distribution centers and loss and residues from food and beverage production and processing facilities. The City and County of Honolulu defines food waste as "all animal, vegetable, and beverage waste which attends or results from the storage, preparation, cooking, handling, selling or serving of food. The term shall not mean commercial cooking oil waste or commercial FOG waste."[30]

Food waste currently landfilled in Hawaiʻi could be converted to RNG with anaerobic digestion. Based on the assumptions listed below, current estimated food waste totals could support the production of about 326,000 MMBtu per year of methane production via anaerobic digestion (Table 18).

Table 18. *Potential RNG production from food waste via anaerobic digestion*[31]

Description	Units	Value
Municipal Solid Waste Landfilled	tons/year	617,408
Food Waste Landfilled	tons/year	92,893
Percent Recovery	%	50
Food Waste Diverted to Anaerobic Digestion	tons/year	46,447
Biogas Production	million cu ft/year	592
RNG Production	MMBtu/year	325,710

Total RNG and Electrical Production Potential from Wastes

Table 19 presents a summary of the estimated potential of RNG production from waste feedstocks produced within the State and the corresponding potential electrical power production. The electrical production potential estimates assume a generation efficiency of 40%. The 673,888 MWh/year of potential represents approximately 6% of the State's non-renewable electrical consumption[32] and roughly 74% of that production comes from the thermal conversion of urban fiber wastes. Without that feedstock, the total electrical production potential is only 178,132 MWh/year and less than 2% of the total for the State.

Table 19. *Total RNG and electrical production from waste*

Feedstock	RNG Potential	
	MMBTU/year	MWh/year
Livestock Manure	NA	NA

[30] City and County of Honolulu – Food Waste Tip Sheet, 2021

[31] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

[32] Hawaiʻi State Energy Office (2024) *Non renewable energy sources.* Retrieved from https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Feedstock	RNG Potential	
	MMBTU/year	MWh/year
WWTP	376,400	44,114
Food Waste	325,700	38,172
Landfill Gas	817,800	95,846
Urban Fiber Waste	4,230,000	495,756
Total	**5,749,900**	**673,888**

Dedicated Energy Crops

Based on previous studies, promising crops for RNG production on island include sugar cane, cane grass, or Bana grass, due to favorable yields in Hawaiʻi's climate. The market indicates that Bana grass could be a productive means of RNG feedstock, as a recent request for proposals for new RNG production led to Eurus Energy being selected to develop an RNG production facility that will use Bana grass as a feedstock.[33]

Assuming 1,500 therms/acre/year for converting Bana grass to RNG via thermal gasification[34] this equates to 150 MMBtu/acre per year of energy. Assuming that RNG was used in a power plant with an electrical efficiency of 40%, one acre of Bana grass crop would produce 17.6 MWh or 24 acres more land for the same 420 MWh of electricity generation.

From a land use efficiency perspective, solar is a much more preferred alternative for electric generation (Figure 10).

Hawaiʻi's potential RNG output from waste resources could displace a portion of the State's fossil fuel-based natural gas consumption, contributing to its overall emissions reduction goals. Dedicated energy crops for RNG also hold promise, provided that sustainable land-use practices are implemented to minimize environmental impacts from large-scale crop production. Considering land use and economic constraints, RNG may be put to higher use in harder-to-decarbonize sectors like transportation, including heavy-duty equipment at ports, airports, and other areas. Recognizing these scale limitations of local RNG, state policy can support the capture and productive use of this source of fuel, rather than let it go to waste.

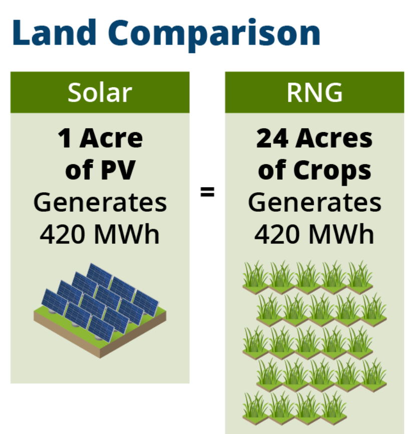

Figure 10. *Land use comparison between RNG and solar energy supply*

[33] Hawaiʻi Gas. (2023, January 12). *Eurus Energy America and BANA Pacific for hydrogen and renewable natural gas projects*. Retrieved from https://www.hawaiigas.com/posts/eurus-energy-america-and-bana-pacific-for-hydrogen-and-renewable-natural-gas-projects

[34] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

Biodiesel

Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. Various vegetable oils, such as soybean, rapeseed, sunflower, corn, and palm oil can be used. Biodiesel production is already established on the islands, and the capacity could be increased with a larger feedstock supply. This production technology is commercially available and proven.

Local Production

Hawaiʻi's biodiesel production is currently limited to one on-island refinery, Pacific Biodiesel has a nameplate production capacity of 5.5 million gallons per year (MMGAL/YR) from many feedstocks including waste oils and fats, supplemented by imports. In 2023, Pacific Biodiesel reached 6 million gallons of production, some of which is used for transportation, but a large portion was used for electric generation.

In a 2024 request for proposal, Hawaiian Electric is looking to increase biodiesel consumption to 12 MMGAL/YR for use at power plants.[35] However, these figures represent a very small portion (~2.4S%) of the 497 MMGAL/YR of total fossil fuel oil consumption for electric generation statewide (Table 20 and Table 21), if they can procure these fuels.

Table 20. *Fuel use for energy generation on the five islands served by Hawaiian Electric.*[36]

Fuel	2023 Consumption (barrels)	2023 Consumption (gallons)
LSFO	8,562,045	359,605,890
HSFO	630,292	26,472,264
Diesel	2,289,303	96,150,726
Naphtha	348,872	14,652,624
Fossil Fuel Total	**11,830,512**	**496,881,504**

Table 21. *Biodiesel use for energy generation on the five islands served by Hawaiian Electric versus Hawaiian Electric's 2024 RFP* [37,38]

Fuel	Consumption (barrels)	Consumption (gallons)
2023 Biodiesel Consumption	133,978	5,627,076
Hawaiian Electric's 2024 RFP for Biodiesel	285,000	11,970,000

[35] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

[36] Hawaiian Electric Companies Docket 2021-0024 – For Approval of Fuels Supply Contract with Par Hawaiʻ Refining LLC. Consolidated Annual Fuel Report. Submission to the Hawaiʻi Public Utilities Commission, January 31, 2024.

[37] Id.

[38] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

Expanding local biodiesel production by cultivating crops in Hawaiʻi requires increased land use for energy crops, but there is potential to utilize unused agricultural land or abandoned agricultural land to increase biofuel crop production. According to the *2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline,* the current amount of land used for agriculture is 886,211 acres with 120,632 acres in cropland and the remaining 765,579 acres used for pasture (Figure 11). [39] Biofuels such as camelina and sunflower can be rotated with other food crops to diversify agriculture, and potentially support food production.

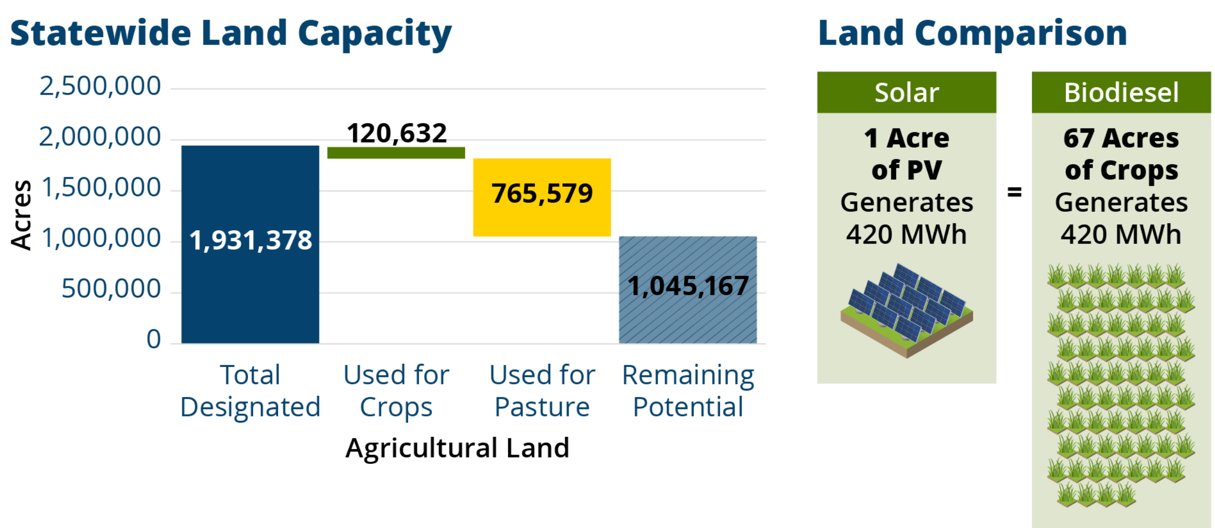

Figure 11. *Left: Land capacity statewide. Right: Acre comparison between palm oil biodiesel and solar*

From a land use efficiency perspective, however, solar is a more favorable option for electric generation (Figure 11). One acre of PV providing 420 MWh of electricity was calculated by assuming a solar capacity factor of 24% and a power density equivalent to 0.2 MWh/acre. Replacing 5% of Hawaiʻi's electricity consumption with biodiesel would require over 86,000 acres of new cropland under optimistic assumptions considering the use of the highest-yielding crop—palm oil. Palm oil on average exhibits yields (gal/acre) estimated to be approximately ten (10) times higher than camelina, five (5) times higher than rapeseed/canola, thirteen (13) times higher than soy, and about three (3) times higher than that of Jatropha.[40]

The energy security and economic development benefits of a robust low-carbon biofuels ecosystem should be pursued and supported by state policy. However, recognizing the overall scale limitations of local feedstock production will not offset the need for imported fuel.

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[39] 2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline (hawaii.gov)

[40] See Technical Appendix, Biodiesel and Renewable Diesel – Energy Production Capacity Calculations for assumptions and documentation for this estimate.

See Technical Appendix – Biodiesel and Renewable Diesel, Energy Production Capability

There are small pilot projects in Hawaiʻi to determine the viability of other alternative biofuel feedstocks including seeds of the *Pongamia* tree and seeds from *Camelina sativa,* a short-season flowering crop with high oil output. Additional research and plantings will need to demonstrate the commercial viability of dedicated energy crops within Hawaiʻi (e.g., palm, Pongamia, Camelina, or otherwise).

Imported Biodiesel

Hawaiʻi could import additional biodiesel or feedstock from Southeast Asia or sources in Europe and North America. Imported renewable diesel, largely sourced from a facility in Singapore, is also a viable option. This import reliance could address local limitations in feedstock supply and production scalability However, careful consideration of lifecycle greenhouse gas emissions is critical for imported fuels, and verification and regulatory vigilance of lifecycle assessment assumptions, as well as the implementation of these assumptions in practice, become more challenging for imported biofuels.[41] Ultimately, the choice of feedstock and production methods will heavily influence the overall lifecycle emissions of biodiesel.

See Lifecycle Greenhouse Gas Emissions Documentation for factors impacting lifecycle emissions of bioenergy.

Biodiesel presents logistical challenges for distribution infrastructure due to its chemical properties. It cannot be stored or transported using the same infrastructure as petroleum products, as it can degrade rubber in fuel lines and loosen or dissolve varnish and sediments. Instead, biodiesel must be transported via rail, vessel, barge, or truck. Existing infrastructure, such as the LSFO pipelines, may need modification or replacement to accommodate biodiesel.[42] For inter-island distribution, biodiesel transportation could follow similar methods for petroleum diesel and other liquid fuels.

Biodiesel production is reliable, but its high cost (typically two to three times that of LSFO) poses a serious economic challenge. Hawaiʻi currently has six power plants that can run on biofuels, which provide a pathway for integration into the State's energy mix. However, biodiesel's scalability depends on policy incentives and feedstock availability.

Biofuel Competing End Uses

There are also additional tradeoffs as Hawaiʻi looks to decarbonize the entire economy. Liquid biofuels can be used for electric generation, but they can also be used as low-carbon fuel in other sectors of the economy, particularly heavy-duty ground transportation, maritime transportation, and aviation. Competing demand for biodiesel, especially from sectors like aviation, could further

[41] Reuters. (2024, August 7). *U.S. EPA says it is auditing biofuel producers over used cooking oil supply*. Reuters. Retrieved from https://www.reuters.com/business/energy/us-epa-says-it-is-auditing-biofuel-producers-used-cooking-oil-supply-2024-08-07/

[42] U.S. Energy Information Administration. (2024). *Biodiesel: Renewable diesel, other biofuels, supply, and use*. Retrieved from https://www.eia.gov/energyexplained/biofuels/biodiesel-rd-other-use-supply.php

strain the supply and increase costs, as other sectors are more likely to be willing to pay a premium for the fuel or feedstock as they attempt to decarbonize driving increased prices.

Prioritizing biofuels for the most challenging sectors to decarbonize—such as aviation and maritime transport, where electrification is less practical and gains in combustion efficiency provide limited emissions reductions—is essential for achieving economy-wide decarbonization. Given the current costs of different fuels, competition for biofuel production may favor the aviation sector, which has a higher willingness to pay. Furthermore, directing biofuels to these sectors ensures cost-effective use of resources, helping to optimize their allocation and maximize overall emissions reductions.

Long-term Solutions Post-2045

The following section discusses the LNG to Ammonia or Hydrogen transition. It is important to note that this portion of the study represents an early-stage assessment, and significant advancements in technology and further planning will be necessary to refine its feasibility; however, the market for H_2 and NH_3 capable turbines is expected to fully develop in the next ten years.[43] Should these technologies not mature or realize cost-efficacy as anticipated, biodiesel and renewable diesel would remain potential options for firm generation in dual-fuel power plants.

Hydrogen

The potential of hydrogen (H_2) and green anhydrous ammonia (NH_3) as alternative energy carriers in Hawaiʻi's transition to a 100% renewable energy grid represents a promising yet nascent area of exploration. While both options offer significant emission reduction benefits and alignment with renewable portfolio standards (RPS), they remain in the early stages of technological and commercial development.

Significant advancements in cost reduction, scalability, and infrastructure are essential to make these clean energy solutions economically viable and operationally feasible. Programs such as the U.S. Department of Energy's Hydrogen Shot, launched to reduce clean hydrogen's cost by 80% within a decade, reflect the broader push to accelerate innovation and reduce costs in hydrogen production. However, much work remains to address challenges in storage, transportation, safety, and localized infrastructure.

As Hawaiʻi evaluates the integration of H_2 and NH_3 into its energy mix, careful consideration of economic, technological, and logistical factors will be required to ensure these solutions can be implemented cost-effectively and sustainably.

Hydrogen (H_2), using green anhydrous ammonia (NH_3) as a carrier, presents a potential alternative to replace natural gas, especially as Hawaiʻi moves towards a 100% renewable energy grid. Hydrogen can be produced through several methods, with electrolysis being a key technology.

Transitioning from LNG to H_2 or NH_3 offers substantial emissions benefits and compliance with RPS targets. H_2, when produced from electrolysis powered by renewable energy, can be classified as green H_2, leading to nearly zero emissions during power generation.

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[43] See Facts Global Energy 2024 Report for Hawaii State Energy Office. Available at: https://energy.hawaii.gov/alternative-fuels-repowering-and-energy-transition-study/

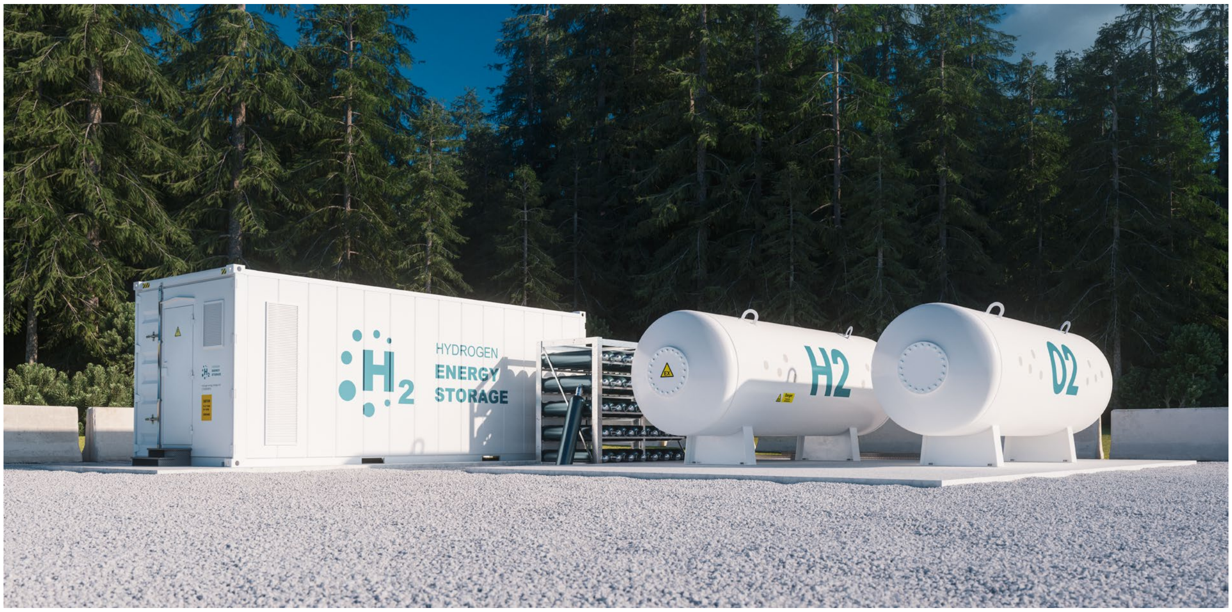

Figure 12. *Example hydrogen energy storage. Stock photo for illustrative purposes only.*

NH_3 can be produced using the Haber-Bosch process, which combines H_2 with nitrogen from atmospheric air. As an energy carrier, NH_3 can be thermally cracked to release the H_2 and reclaim the previously generated H_2 fuel molecules. Scaling up green NH_3 production, as proposed by US and international initiatives, will be essential for improving the commercial viability of this fuel. However, the traditional Haber-Bosch process is highly energy-intensive and heavily dependent on fossil fuels, significant advancements in cleaning up the Haber-Bosch process—and their widespread adoption— are crucial to achieving substantial lifecycle carbon intensity reductions for any imported NH_3.

Hawaiʻi would likely need to import H_2 or NH_3 via bulk tankers, since H_2 production, through electrolysis, is land and electricity intensive. The two major methods considered for H_2 import are liquid hydrogen (LH_2) and NH_3. NH_3 is significantly easier to transport compared to LH_2 due to its higher boiling temperature and lower vaporization energy requirement. Further, LH_2 transportation is still commercially underdeveloped, whereas NH_3 shipping infrastructure is already used for other industries, making it a more viable option for Hawaiʻi.

The siting of the NH_3 storage infrastructure will require careful consideration. To process NH_3 on-island, storage facilities near ports would need to be built to receive NH_3 shipments and handle its thermal cracking. Barbers Point Harbor is a potential location for receiving NH_3 and adjacent power plants can be adapted to use the resulting H_2.

H_2 and NH_3 each come with safety concerns. H_2, a highly flammable gas with low ignition energy, necessitates strict safety protocols, particularly in handling and storage. NH_3, while easier to store and transport, poses toxicity risks if leaked. Both fuels require dedicated infrastructure and safety regulations for their handling. The US Department of Transportation has established safety standards for H_2 pipelines (49 CFR 192.625), but NH_3 standards would need to be updated for large-scale energy use.

LNG to Ammonia and Hydrogen – Post-2045

Previous sections of this study detail a potential plan for LNG infrastructure and power plant conversions. By 2045, the plan contemplates hydrogen, biofuel, or another fully decarbonized will fulfill fuel needs while complying with RPS law. In general, most of the fuel receiving and processing equipment is not expected to be directly interchangeable between LNG and NH_3 or H_2. The LNG receiving method makes use of an FSRU for unloading and regasification of LNG – the plan assumes this infrastructure will be leased rather than owned to ensure it can easily be removed by 2045. Converting NH_3 to H_2 for use as a fuel to meet the expected electricity needs will require significant NH_3 storage and cracking infrastructure beyond what can be accommodated by a floating vessel. If pursued, NH_3 will need to be received and processed with new land-based infrastructure specifically dedicated to processing it.

On-shore pipelines, by contrast, could be designed for dual use, accommodating methane gas initially and later could be converted to H_2 use with modifications. While much of the fuel infrastructure might not be interchangeable, there is potential for most of the power generation equipment installed for methane gas to be adapted for future H_2 use.

Leading gas turbine manufacturers have begun to outline plans for transitioning their generation equipment to operate on H_2 and have demonstrated early successes with field tests using NH_3 as a fuel. However, these technologies are still in development, and the market for turbines capable of operating on H_2 or NH_3 is anticipated to mature significantly over the next decade. This evolving landscape underscores the preliminary nature of this plan and the need for continued monitoring of technological advancements.

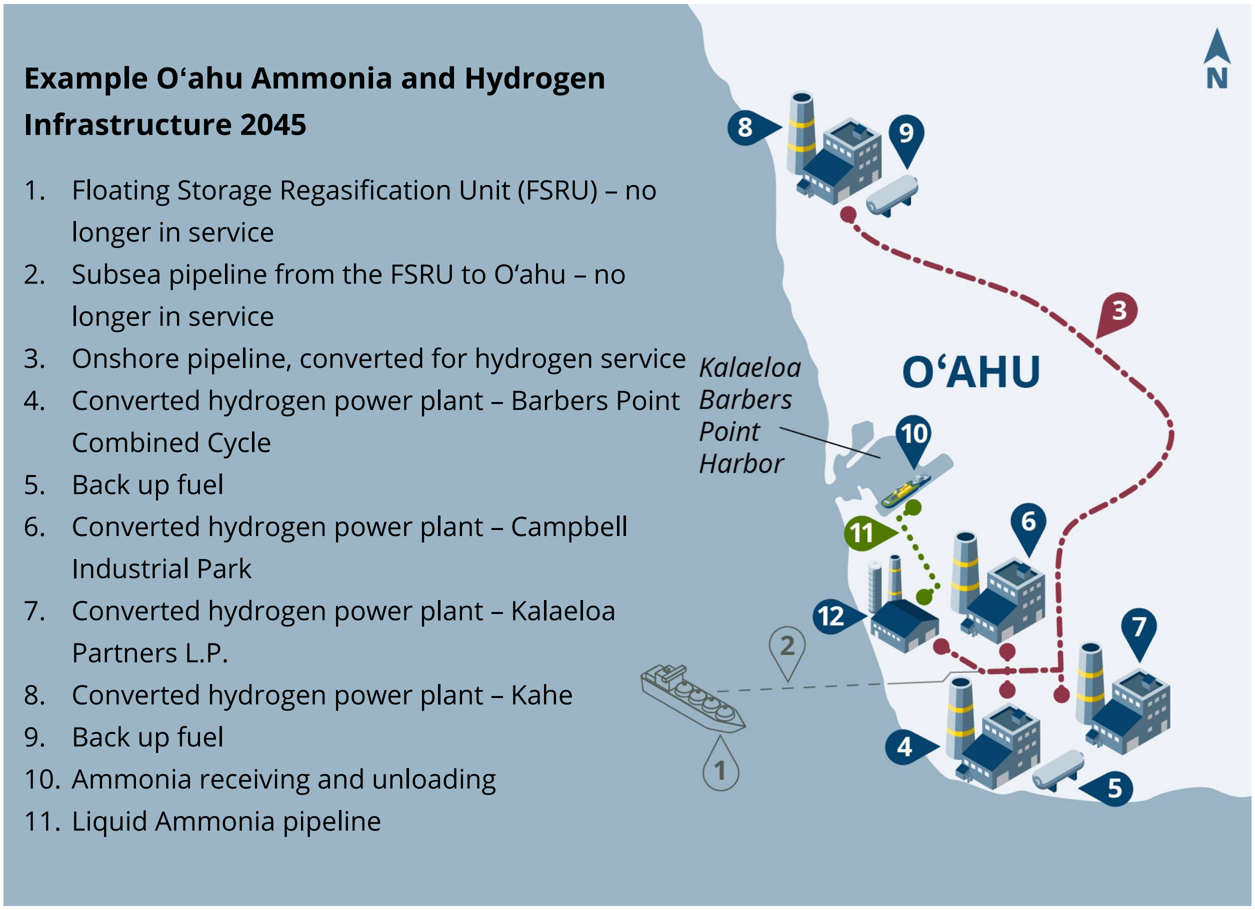

Figure 13. *Ammonia and hydrogen infrastructure on O‘ahu, in service 2045*

Economic Evaluation

The economic evaluation assessed alternative fuel transition pathways that could reduce reliance on carbon-intensive fuels with significant price volatility including LSFO and diesel fuel used for power generation, while also minimizing costs to ratepayers. While intermittent renewables technologies are a critical resource used to help reduce the reliance on LSFO, the focus of the analysis was on firm generation sources that could act as a bridging solution given the long lead times and expected build rates associated with the intermittent sources. Benefits of transitioning away from low sulfur fuel oil and diesel fuel include:

- Mitigating fuel price volatility
- Reducing greenhouse gas emissions
- Reducing economic risk to ratepayers and energy stakeholders

Statewide energy demand is expected to increase significantly in the future, driven by a combination of electrification and population growth. Based on current projections, Hawaiʻi's population is projected to experience an average growth rate of 0.24% per year between 2024 and 2050.[44] Significant electric grid investments are needed to meet the growing electric demand while maintaining a reliable network. Many existing power plants are over 50 years old, which will require greater and more frequent maintenance activities to keep them operational.

Initial Bookend Analysis

Given the uncertainty around future energy demand, fuel prices, and capital expenditure, the preliminary analysis considered a bookend approach to capture the upper and lower bounds of various energy demand cases (*See Power Needs Forecast*). Uncertainty was applied to key inputs in the analysis, primarily capital costs, fuel costs, and energy demand (Figure 14). The study employed a lifecycle cost analysis (LCCA)[45] to evaluate the defined low and high statewide bookends. The LCCA examined upfront capital costs, ongoing operating and maintenance costs, fuel costs, and interim RPS penalties, as applicable, for a base case and potential build case.

[44] State of Hawaiʻi, Department of Business, Economic Development, & Tourism – Research and Economic Analysis Division. (2024) *Population and Economic Projections for the State of Hawaiʻi to 2050.*

[45] LCCA is an economic analysis tool used to evaluate total costs for different project alternatives throughout a study period, leading to determination of the most cost-effective option.

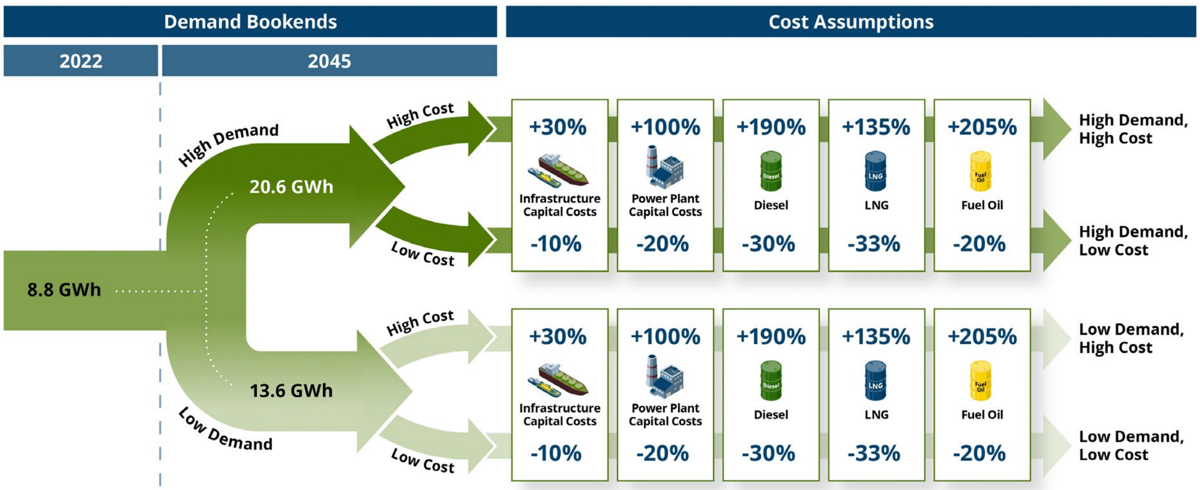

Figure 14 *Depiction of the bookend approach, capturing future uncertainty by introducing a range of demand and cost assumptions.*

The base case assumed there is no transition to methane gas, and firm generation continues to be met with LSFO. In the build case, gas infrastructure is built and LNG displaces LSFO generation.

Using the modeled energy mix from Engage for the high and low-demand scenarios, the initial analysis showed that certain use cases could result in cost savings relative to the base case, although the infrastructure would need to be sized to minimize costs and maximize benefits to ratepayers. After this initial analysis, the study explored the development of potential viable pathways that could result in cost savings while still adhering to RPS targets. An initial high-level financial impact to ratepayers was not performed until the viable pathway evaluation because the initial LCCA results highlighted the need for refinement to the use case to generate cost savings.

See Technical Appendix – Economic Analysis for full documentation of the bookend analysis.

The bookend analysis ultimately demonstrated the importance of right-sizing infrastructure, necessitated the removal of expensive interisland LNG transport from the final scenario, and demonstrated the need to ensure adequate demand to realize cost savings.

Viable Pathway Evaluation Methodology

After the bookend analysis was completed, it was clear certain assumptions would need to be modified to develop a viable pathway that achieved cost savings. The study specified the LNG volumes and infrastructure needed to generate fuel cost savings, while also adhering to the interim RPS targets.

Unlike the initial bookend analysis constrained by a modeled grid mix, this analysis relaxed the grid mix constraint and focused on the potential to displace LSFO until 2045, while maintaining the RPS mandates. A viable pathway must address multiple policy priorities:

- Reduce reliance on LSFO.
- Mitigate oil price volatility risk.
- Lower greenhouse gas emissions while continuing to meet RPS targets.
- Maximize cost savings to ratepayers.
- Build a more resilient grid.

In seeking a viable pathway, the analysis carefully considered power plants that could be candidates for conversion to meet the objectives while minimizing costs, as discussed in the power plant and repowering section.

There are several key assumptions underlying the analysis:

- Only O‘ahu is included.
- Combustion Turbines at new Barbers Point Combined Cycle and KPLP, are dual fuels (gas and diesel) in addition to being compatible with 100% hydrogen.
- Diesel, biodiesel, or another liquid fuel will be used for long-duration backup needs.
- Onshore pipelines are designed for methane gas and hydrogen service.
- Power plant conversion takes less than two years to construct.
- New power plants take three years to construct.
- LNG infrastructure is introduced only on O‘ahu and offsets generation from LSFO unless otherwise stated.
- Estimated future energy demand on O‘ahu is 12.4 TWh by 2045, and the energy demand is interpolated to estimate demand in the interim years.
- The energy mix not attributed to LSFO is generated by renewable sources.
- Weighted average heat rates based on current values, and where applicable, specifications assumed for newly constructed or converted plants, were used to convert fuel cost forecasts to a cost per MWh.
- Significant portions of LNG infrastructure can be re-used for hydrogen applications, minimizing stranded assets and preparing Hawai‘i for conversion to 100% renewable energy in 2045.
- Future costs and benefits were discounted to present value terms based on Hawaiian Electric’s required real rate of return.

Fuel projections are based on forecasts provided by FGE, under contract to HSEO. Cost estimates include relevant onshore and offshore infrastructure, and O&M cost savings are estimated based on efficiency improvements at new plants relative to existing older infrastructure. Actual maintenance costs may vary based on specific conditions and needs at each plant. The results include O&M cost savings, although many alternatives would yield cost savings even if these O&M cost savings were excluded.

With the grid mix assumption relaxed, the base case for all the alternatives outlined assumes that no LNG infrastructure is built, and a combination of primarily renewable intermittent and non-renewable firm generation sources meet the electricity demand on O‘ahu. There remains enough

LSFO generation to be offset completely by the gas generation in the build case. Without major capital investment in new combustion power plants, operating and maintenance costs are anticipated to increase to keep aging, existing diesel and LSFO generation plants online to maintain grid stability and reliability, while meeting increasing energy demand. The analysis assumes a reliance on non-renewable fuels until it is no longer feasible based on the RPS targets unless otherwise stated.

The build case assumes a transition to LNG. The specified existing aging power plants would be converted to using newer, more efficient gas turbines and will benefit from reduced O&M costs and improved heat rates which would result in the consumption of less fuel. The electricity demand is assumed to be the same as the base case, and LNG will displace other energy-generating sources, which are primarily assumed to be LSFO power plants.

The build case follows the phasing identified in the *Preferred Alternative LNG Supply Chain Summary*. To supply gas to KPLP and the new Barbers Point Combined Cycle Plant at the decommissioned coal plant site for an in-service date of 2030, the following infrastructure was considered and included in the price assumptions for the economic analysis:

- FSRU: moored 1.5 miles offshore of Barbers Point on the southwestern side of Oʻahu.
- Subsea pipeline: connecting the gas fuel supply from the FSRU to Oʻahu.
- Onshore pipelines to KPLP and the Barbers Point Combined Cycle Plant (tying in both facilities to fuel gas from the FSRU).
- Diesel storage kept at KPLP as a reserve fuel option.

To complete modifications to CIP and the new combined cycle Kahe plant for a 2035 in-service date, the following infrastructure would be installed:

- Onshore gas pipeline to Kahe from KPLP/Barbers Point Combined Cycle.
- Diesel storage is kept at Kahe as a reserve fuel option.

In addition to the major benefits of fuel cost savings and incremental O&M cost savings, the analysis also explored benefits from the re-use of LNG infrastructure for portions that can be repurposed for future firm generation from renewable energy sources, such as hydrogen. The analysis also compared cases where the infrastructure cannot be repurposed.

The introduction of LNG infrastructure on Oʻahu will help meet the island's growing electricity demand and stabilize its grid. The overall energy demand on Oʻahu is expected to increase, requiring careful balancing of LNG imports with the eventual integration of hydrogen as a long-term solution.

The energy transition plan will add new power plants resulting in increased overall on-island power capacity and offering greater flexibility and resilience. The additional capacity will allow for greater backup power during future major upgrades and conversions. The upgrades will also help modernize transmission infrastructure to converted plants, creating more resilient infrastructure and addressing transmission congestion.

The LCCA used Net Present Value (NPV) to compare the discounted benefits against the discounted costs through 2045. Positive NPVs indicate the benefits of implementing a transition outweigh the costs, and would result in savings to ratepayers, relative to no transition. Capital costs and potential incremental RPS penalties are included in the costs.

After performing the LCCA, the study investigated the incremental Levelized Cost of Electricity (LCOE) to estimate a high-level financial impact on ratepayers. The incremental LCOE was then compared against the existing cost per MWh faced by Hawaiʻi residents to generate an estimate of cost savings relative to the base case. Annual cost savings were calculated assuming electricity consumption of 500 kWh per month. Separate analysis is required to determine cost allocations and estimate the impacts to various ratepayer classes.

Sensitivity analyses were performed to evaluate the impact of reasonable changes in individual key variables to assess whether the conclusions reached under the baseline conditions would significantly change. These analyses only involve changing one variable at a time while all others remain constant, presenting a simplified view to understand the impact of each variable on the results. In practice, several variables would likely change at the same time, like LSFO prices and natural gas prices, which historically have demonstrated correlation. LSFO, LNG, and capital costs were key sensitivity analysis variables.

In summary, the economic evaluation compared the costs and benefits (cost savings) of implementing an LNG solution relative to a business-as-usual approach. The analysis accounts only for the incremental impacts attributable to the planned LNG infrastructure. When benefits exceed the costs, the analysis shows that ratepayers are better off than they would be without LNG infrastructure. In cases where costs exceed benefits, the analysis shows that ratepayers are worse off than they would be without LNG infrastructure.

Given the uncertainty around future conditions, the robustness of the analysis was tested by comparing how changes in key assumptions impact the overall findings.

Evaluated Alternatives

The evaluation considered several other assumptions, including whether LNG infrastructure could be re-used as part of a future renewable energy solution (such as hydrogen) and whether the projected significant increases in renewable energy generation were achievable (Figure 15). The evaluation incorporated a scenario analysis to explore results under different assumed base cases, primarily evaluating two distinct alternative futures, with three sub-alternatives each that led to a total of six potential solutions.

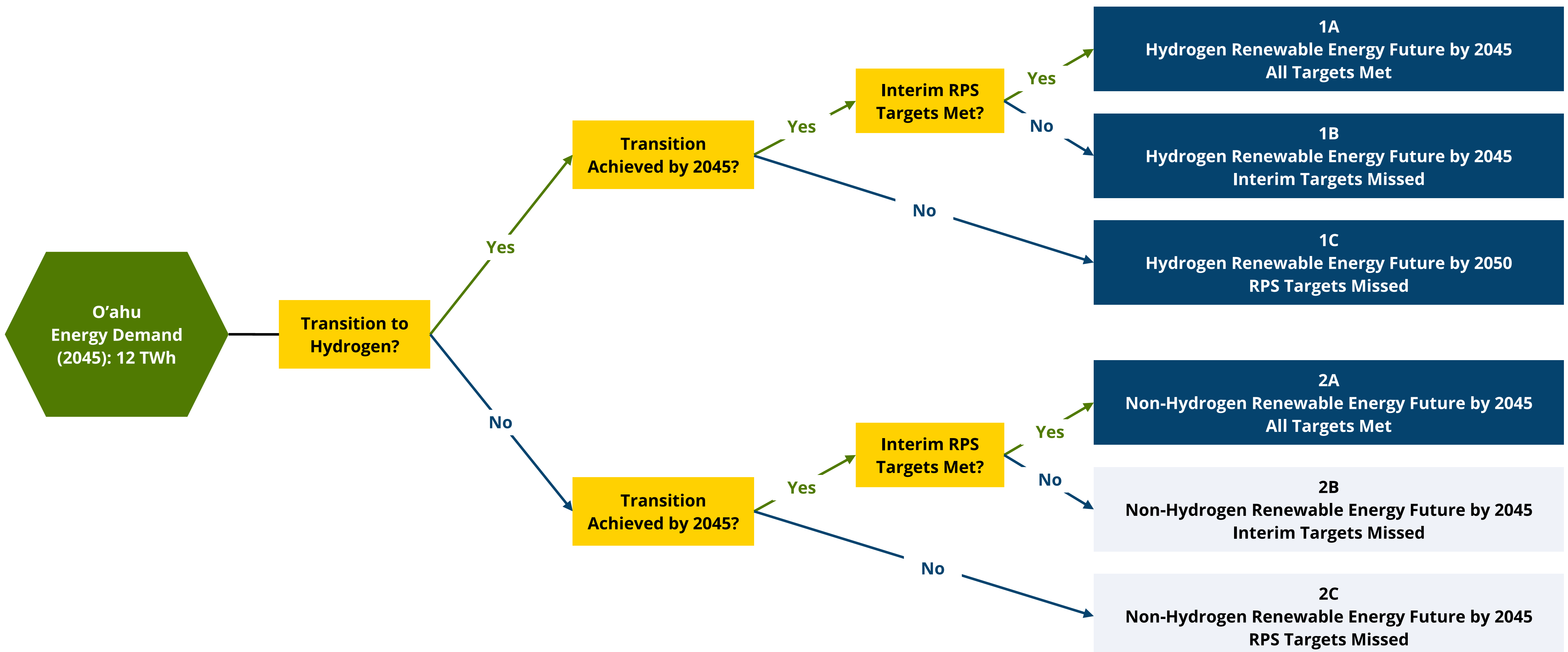

Figure 15. *Future possibilities considered for the final viable scenario.*

Not depicted – Alternative 3: Alternative 3A generally follows Alternative 1A and Alternative 3B follows 1B. Alternative 3 updates the fuel mix displaced.

Alternatives Summary

Alternative 1 assumes a transition to hydrogen as a firm source of renewable energy. With a future transition to hydrogen, significant portions of the initial capital investment in LNG infrastructure can be re-used for hydrogen when it becomes part of the energy mix. Under Alternative 1, the levelized cost of energy would likely decrease by $10.2/MWh to $17.8/MWh, resulting in an estimated 2.6% to 4.6% reduction in residential electricity costs (equivalent to $60 to $110 in ratepayer savings per year).

Alternative 2 explores a transition to an undefined non-hydrogen renewable fuel source that does not allow for the re-use of LNG infrastructure. Without the re-use of the LNG infrastructure, the benefits of primarily fuel cost savings alone are not enough to generate cost savings for ratepayers.

Alternatives 2B and 2C, which offer less stringent requirements and more favorable results than Alternative 2A, still did not result in cost savings for ratepayers. The study concluded that without the benefits of re-using the infrastructure, LNG will take significantly longer to break even and may not prove viable (assuming the fuel cost savings are driven only by the replacement of LSFO). Under Alternative 2, the levelized cost of energy would likely increase by $11.9/MWh to $24.6/MWh, resulting in an estimated 3.1% to 6.4% increase in residential electricity costs (equivalent to $70 to $150 in additional ratepayer costs per year).

After exploring Alternatives 1 and 2, a third alternative (Alternative 3) was developed as another sensitivity, based on changing the fuel mix LNG was assumed to offset. After evaluating the first two alternatives, capacity expansion modeling provided results that showed an evaluation with and without gas generation. The difference between the model with and without gas generation demonstrated that gas offset a mixture of biodiesel, solar, and LSFO.

The third alternative aligned the displaced fuel mix to match the capacity expansion modeling and explored the cost-effectiveness of LNG. Under Alternative 3, the levelized cost of energy would likely decrease by $23.9/MWh to $58.7/MWh, resulting in an estimated 6.2% to 15.2% decrease in residential energy costs (equivalent to $140 to $350 in ratepayer savings per year). As indicated by these results, the assumed fuel mix displaced by methane gas and the ability to reuse the infrastructure constructed for a methane gas transition strongly impacts the results of the economic evaluation.

See Technical Appendix C – Economic Analysis for Full Details on Economic Assumptions

Key Alternatives

Alternative 1A

The benefits of an interim transition to natural gas exceed the costs, with a net present value of about $150 million (Figure 16). The levelized cost savings from an LNG transition are $10.2/MWh. With the most stringent version of Alternative 1, an LNG transition is shown to generate benefits in excess of its costs, which can provide cost savings to ratepayers, relative to a base case where no

LNG infrastructure is constructed. With the planned re-use of LNG infrastructure for a hydrogen transition in 2045, under Alternative 1A the incremental LCOE will be reduced by roughly 2.6% while still meeting RPS targets (Figure 16).

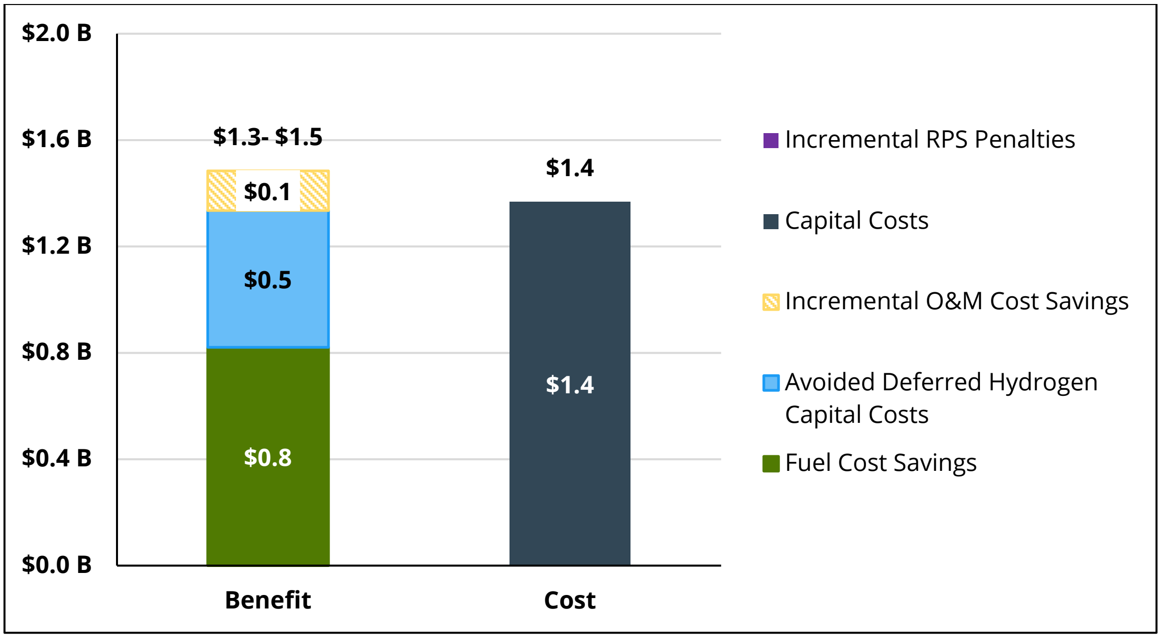

Figure 16. *Alternative 1A net present value of LNG transition*

The LNG transition in Alternative 1A can generate cost savings if LNG prices do not increase by more than 10%, LSFO prices do not decrease by more than 5%, or capital costs do not increase by more than 20% (Figure 17).

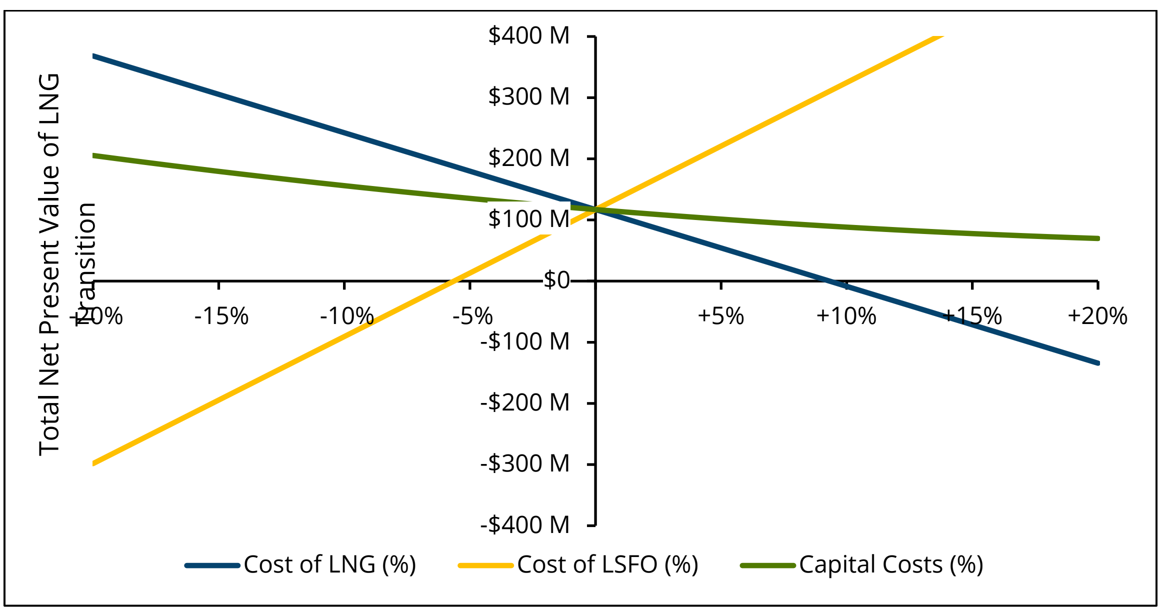

Figure 17. *Alternative 1A sensitivity analysis of the net present value of an LNG transition*

Alternative 3A

In Alternative 3A, a more optimistic future scenario where a transition to hydrogen results in the re-use of LNG infrastructure was explored, similar to Alternative 1A. Unlike Alternative 1A, where LNG displaces LSFO, capacity expansion energy modeling runs with and without LNG to change the incremental fuel displaced by LNG. The data indicated that with the introduction of LNG, the major fuels displaced included a mix of LSFO, utility-scale solar, and biodiesel, more closely following current Hawaiian Electric IGP plans. The weighted average fuel costs of this mix are substantially higher than the average fuel costs of just LSFO, resulting in significantly higher fuel cost savings when measuring against a transition to LNG. Additionally, there would likely be some avoided generation capacity costs as some of these newly constructed solar arrays or biodiesel plants could be avoided altogether, though this has been excluded from HDR's analysis.

Assuming in this solution that the RPS targets are met, LNG is fully phased out by 2045, and significant portions of LNG infrastructure are repurposed for hydrogen, this adjustment to the energy mix offset by LNG significantly increases the fuel cost savings, and when combined with avoided deferred hydrogen capital costs, approximately doubling the benefit.

With the adjusted fuel mix displaced by LNG, the benefits of an interim transition to LNG exceed the costs, with a net present value of about $867 million. The levelized cost savings from an LNG transition are $59/MWh, which equates to residential energy cost savings of about 15.2 percent (approximately $352 in cost savings per year). (Figure 18).

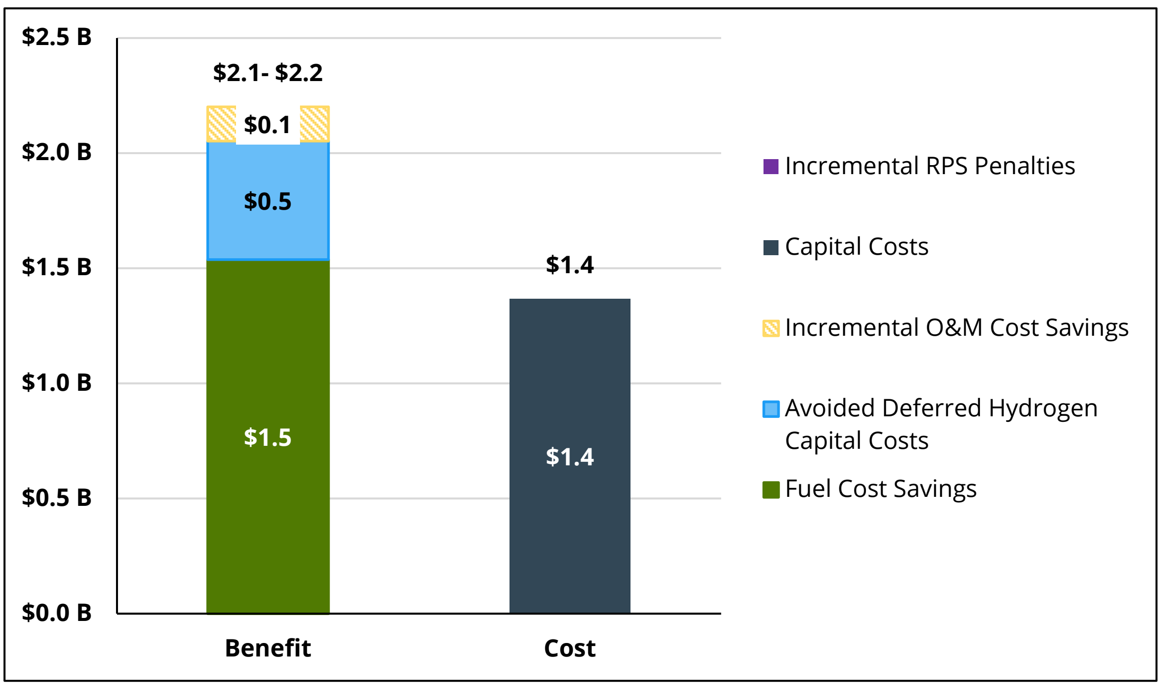

Figure 18. *Alternative 3A net present value of LNG transition*

Under a sensitivity analysis conducted, there is potential to see cost savings well above the initial $867 million. (Figure 19). By relaxing the RPS standards or assuming a potential 5-year delay in the transition to renewable energy (mirroring Alternatives 1B or 1C), the benefits of transitioning would be even greater than the results shown, and greater savings could be passed on to ratepayers.

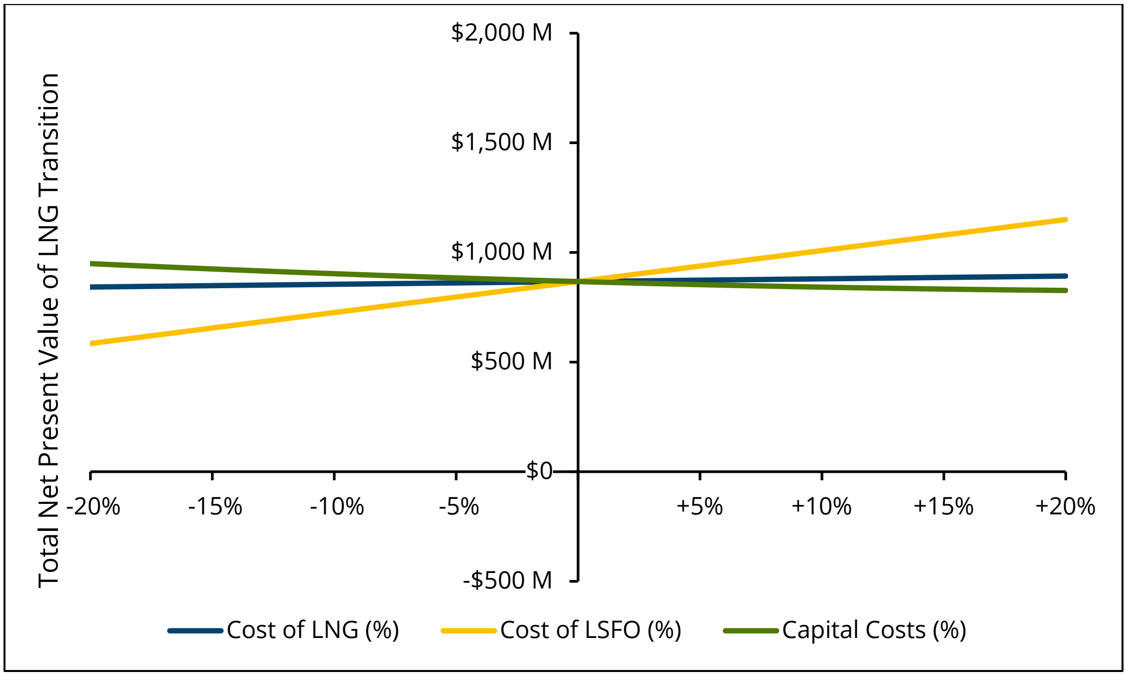

Figure 19. *Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3A*

See Technical Appendix – Economic Analysis for Full Details on Each Alternative

Viable Pathways Conclusions

The sensitivity analyses performed show results to be robust, with moderate changes in key variables still generating cost savings for ratepayers. LNG can add value by being a low-cost solution relative to the base case, while also acting as a potential hedge. In the event of increased reliance on firm generation, or if the transition to a fully renewable grid takes longer than expected, methane gas yields greater benefits to ratepayers while also reducing emissions before getting to a fully renewable grid. The new infrastructure built would offer network resilience and increased generation capacity, along with reduced volatility of fuel prices, which are important benefits of an LNG transition to consider that are not monetized in the economic analysis itself.

The analysis shows the potential to use LNG as a bridge fuel can result in savings to Hawaiʻi ratepayers, while still adhering to the RPS targets. A transition from LSFO to LNG would lead to fuel cost savings, and O&M savings associated with upgrading aging power plants, and assist with an easier transition to hydrogen by constructing some of the necessary infrastructure earlier.

Lifecycle Greenhouse Gas Emissions Evaluation

Act 54, Session Laws of Hawai‘i 2024, set forth an explicit requirement to analyze lifecycle emissions for combustion projects.[46] HRS §269-1, as amended, defines lifecycle greenhouse gas emissions assessment as “the evaluation of potential greenhouse gas emissions over the course of a product, program, or project’s lifetime or stages of production, construction, operations, and decommissioning, which includes but is not limited to, as applicable, upstream stages such as extraction and processing of materials, and transportation; operations stages such as the use of any fuels or feedstocks and the production of any materials; and downstream stages such as transportation, decommissioning, recycling, and the final disposal.” This discussion focuses on the extraction and production of fuels as well as the operations of power plants; construction activities and decommissioning were not included in this analysis.

LNG vs. LSFO

Based on a lifecycle analysis (well-to-outlet), completed by HSEO with a customized GREET model, LNG has the potential to reduce total lifecycle carbon intensity (emissions per kWh of electricity delivered) by an average of ~38% to ~44% when compared to imported LSFO in existing powerplants on a 20-year and 100-year Global Warming Potential (GWP), respectively.

Powerplant efficiency is a major factor impacting these estimates, and powerplant efficiency changes based on factors such as fuel type, plant design, age, maintenance practices, load conditions, and operational cycles. For the analysis, LSFO powerplant efficiency was assumed to be 32% based on the current HICC mix in GREET, while natural gas power plant efficiency was assumed to be 46%, based on modeled heat rates.

The lifecycle emissions estimates (Figure 20) represent average emissions for each supply chain stage from various source models, including GREET 2023, RMI/OCI+, and NOIA/EPA for both GWP of 100 years and 20 years.

Table 22 *Total lifecycle emissions estimates for low sulfur fuel oil and LNG*

	Weighted Total Lifecycle Carbon Intensity Estimate (g CO2e/kWh Elec)		
GWP	**Low Sulfur Fuel Oil**	**LNG**	**Percentage Change**
20	1224	753	38%
100	1137	634	44%

[46] Act 54, Session Laws of Hawai‘i 2024, Relating to Renewable Energy.

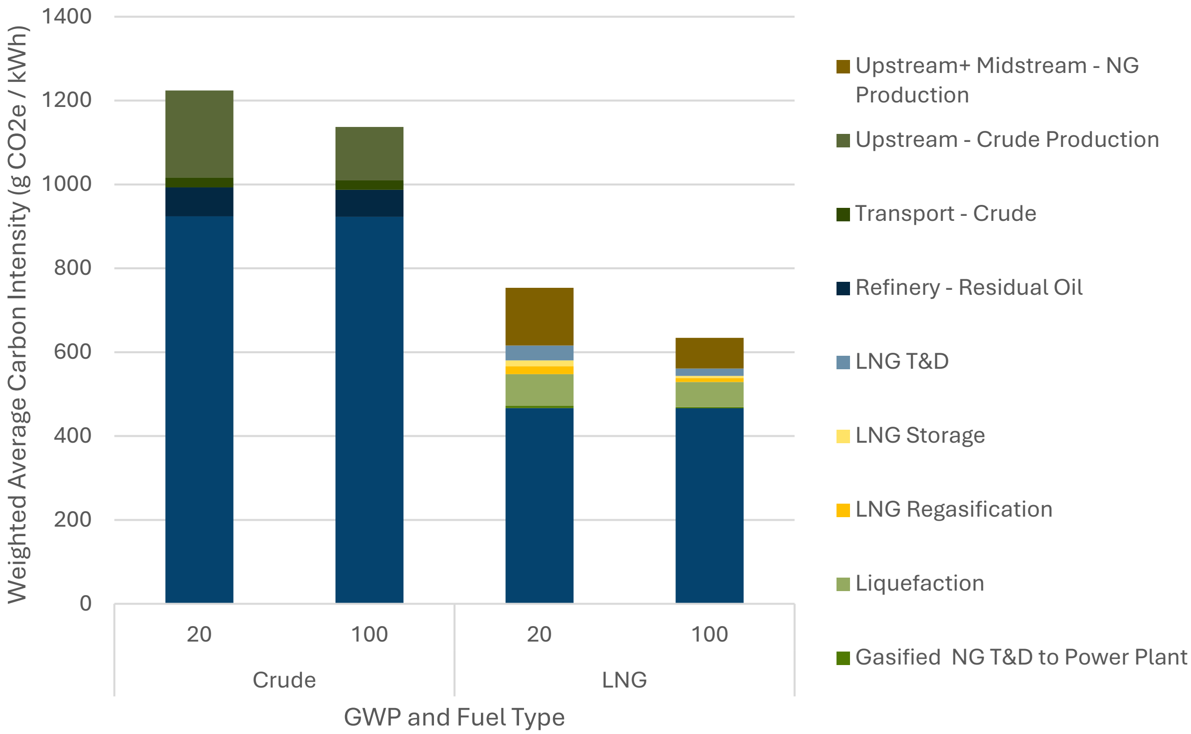

Figure 20. *Lifecycle emissions estimates for crude (LSFO) and LNG, evaluated over 20-year and 100-year Global Warming Potentials.*

LNG vs. Biofuels

The lifecycle carbon intensity of biofuels is one of the most difficult fuels to quantify. Emissions from biofuels, including biodiesel, renewable diesel, cellulosic diesel, ethanol (typically blended with other fuels), and renewable naphtha (more commonly used in industrial and transportation sectors but can be used for electrical generation) have substantial variation. Accounting methods for biofuels are challenging in accurately measuring emissions, especially for biofuels, due to complex land use changes, feedstock variability, and temporal carbon dynamics. Temporal dynamics, such as the lag between carbon release and ecosystem carbon sequestration, introduce uncertainties in determining whether biofuels are carbon-neutral over relevant policy timeframes.

Notably, many carbon accounting frameworks assume biogenic emissions to be entirely offset by future carbon uptake, often leading to an overestimation of emissions reductions. Empirical evidence highlights this issue, particularly in programs like the U.S. Renewable Fuel Standard (RFS), which has faced criticism for failing to fully account for the environmental impacts of feedstock production and associated land use change. Studies have also shown that reliance on the most commonly available first-generation biofuels, such as corn ethanol and palm oil, may result in higher lifecycle emissions than initially estimated, undermining the anticipated climate benefits. Inconsistencies in system boundaries, such as whether emissions from fertilizer production or livestock feedstocks are included, further exacerbate undercounting risks. These challenges necessitate the development of more robust, transparent, and adaptable frameworks to ensure biofuel emissions are accurately assessed and regulated.

See *Technical Documentation – Lifecycle Greenhouse Gas Emissions* for the components and assumptions included to generate these lifecycle carbon savings estimates.

The developed framework can be broadly applied and adapted to assess future fuel imports. However, for all fuels, verification and regulatory oversight are essential to ensure that the upstream and midstream assumptions used within the framework align with actual practices during production.

Local Impacts and Capital Considerations

Par Pacific

Par Pacific would be significantly impacted if it were to lose the current demand for its low-sulfur fuel oil (LSFO) supplied to Hawaiian Electric. This would also imply a loss of offtake for its naphtha supply to Hawaiʻi Gas, as there will be no more naphtha-based synthetic natural gas (SNG) production. In such a scenario, Par Pacific would face several options to continue its operations in Hawaiʻi, including:

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 where 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 biodiesel plant, running some of the hydrotreating units in that operation.
5) Mothball the refinery and convert the site into a storage terminal – like what was done to the former Island Energy Service (IES) plant.
6) Provide land to Hawaiian Electric or a third-party power producer for new power production discussed in this Study.

All of the above options come with caveats that depend on several factors to determine their financial and technical feasibility. In the event of the refinery closing (option 5), product imports need to increase by 45-50 thousand barrels (kb/d), more than double the current level of imports.

It is important to note that – relevant to option 1 above – generally freight economics do not favor refining operations that would import crude (from distant markets) and then must export products (back to distant markets) as well. Relevant to options 1 to 3 above – 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.

However, investment in fuel oil upgrading is not an inexpensive option, especially if the life of the asset is uncertain. On option 4, converting some of the refinery units into a biofuel facility may cost as much as $100 million (e.g. the case of Come-by-Chance refinery conversion in Canada) as well as potential issues sourcing the necessary feedstock for such an operation; not only the volume required but at an economically attractive price.

There would also be some financial investment required to turn the refinery into an efficient, low-cost import facility (i.e., option 5) as well, so it is important to note this is not a no-cost option. It is a more feasible option given that the State has already transitioned from a 150 kb/d refining throughput (when two Hawaiʻi refineries were operational) to a single plant running at around 82% utilization (in 2023) while importing some 40 kb/d of products, and all infrastructure is in place for storage tanks and jetties/moorings used for crude and product imports.

Hawaiʻi Gas

Hawaiʻi Gas 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 various purposes, including cooking, drying, hot water heating, and co-generation. The SNG is derived from naphtha that is provided locally by Par Pacific and then "cracked" at Hawaiʻi Gas' synthetic natural gas plant.

Assuming Par Pacific would no longer supply Hawaiian Electric with LSFO if LNG imports were to begin, it is highly unlikely Par would continue to provide Hawaiʻi Gas with naphtha for their SNG production. However, the naphtha would no longer be needed since the regasified LNG could also be sold to Hawaiʻi Gas and easily be placed in its existing gas reticulation system with some minor extensions.

Moreover, the imported LNG it would purchase would be expected to be less expensive than the SNG Hawaiʻi Gas current purchases, which would likely result in significant savings to Hawaiʻi Gas' regulated customers.

Hawaiʻi Gas 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 their 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.

As a natural gas utility, Hawaiʻi Gas is uniquely positioned to develop and invest in a decarbonized, clean-fuel system. Such utilities have delivered a mix of renewable natural gas and hydrogen to a subset of its customers already served via their existing infrastructure as well as supplying 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. Renewable natural gas does not have many technical limitations with Hawaiʻi Gas' existing infrastructure (see RNG Section), while hydrogen for existing pipelines is more challenging; gas pipelines can only handle about a 20% hydrogen blend before the pipes start corroding and degrading due to hydrogen embrittlement and hydrogen-induced cracking. Hydrogen currently comprises 10-15% of HG's SNG blend in their pipeline system and plans are to increase this up to 20% with some relatively minor improvements.[47] 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.

Because Hawaiʻi Gas' business is to build, own, and operate a natural gas pipeline system, its extensive knowledge would make it a candidate for transmission of natural gas to the Hawaiian Electric power plants. Hawaiʻi Gas could replace all its existing SNG pipeline gas with regasified LNG as it continues to play a leading role in the energy transition with biogas and hydrogen as it seeks solutions for renewable natural gas.

Attracting Capital

Post-Maui Wildfires, Hawaiian Electric has made significant progress in stabilizing its financial health, raising approximately $1.2 billion through several capital market activities and merger & acquisition (M&A) transactions. However, a significant amount of capital still needs to be raised by the utility over the next five years to achieve its energy goals and fulfill the objectives in this report. The confidence of any investor will be significantly influenced by the finalization of the Maui wildfire settlement agreements. To ensure progress on renewable energy power purchase agreements and other critical investments discussed in this study, continued work toward restoring investor confidence remains a priority. To ensure the lowest cost of capital and retain local control of critical decisions, any equity investments should be considered across a range of options; any large investments should be from entities that are completely aligned with Hawaiʻi's energy transition and decarbonization policy objectives. Suitable candidates among public utilities would include those in the United States and among strong U.S. allies with stated objectives to be fully decarbonized and fossil-free by 2050.

Other companies that invest in utilities and energy infrastructure across several states include NextEra and Sempra. Among these utility investors, a limited number own utility interests subject to mandatory decarbonization targets by 2045 or 2050, including Berkshire Hathaway Energy. Much more common is voluntary targets, with many utilities reporting a voluntary target including NextEra and American Electric Power.[48]

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[47] Hawaiʻi Gas 2023 Sustainability Report (2024). The Gas Company, LLC dba Hawaiʻi Gas

[48] Smart Electric Power Alliance (2023) *2023 Utility Transformation Profile*. Retrieved from https://sepapower.org/utility-transformation-challenge/profile/

In September of 2024, S&P Global reported that sixteen of the top 30 utilities by market cap in the United States have announced plans for a partial or complete net zero plan for greenhouse gas emissions by 2050. Of those, only three have announced and maintained a 2030 net-zero goal: Avangrid, Eversource Energy, and Public Service

JERA, Japan's largest power generation company has recently expressed interest in investing in Hawaiian Electric. JERA was founded in 2015 with the merger of the thermal power and fuel departments of Tokyo Electric Power Company and Chubu Electric Power Company.[49] JERA currently holds interest in 10 international renewable power generation projects, 23 international thermal power plants, and 28 thermal power plants in Japan, totaling roughly 100 GW of capacity. JERA has adopted a 2050 decarbonization target,[50] with interim targets in 2030 and 2035. JERA has access to LNG from British Columbia, Canada, which is among the lowest GHG emission supply chains in the world.[51] On top of its ability to invest, its experience with international utility operations and stated commitment to decarbonization may make it a viable candidate to support Hawai'i's energy transition.

To the extent Hawaiian Electric determines that a significant capital investment by an external strategic investor is reasonably justified and necessary, the company should explore all available options and follow a process designed to secure the lowest possible cost of capital. When it decided not to approve the NextEra merger,[52] the PUC identified six criteria in evaluating substantial outside investment: 1) ratepayer benefit; 2) mitigation of credit risk; 3) meeting the state's clean energy goals; 4) competition in independent power production; 5) commitment to local representation in company decision-making; and 6) metrics to demonstrate utility modernization. The foresight and judgment of the Commission Guidance in Appendix A of that Order remain clear and relevant now, ten years later.

Enterprise Group Inc (PSEG). PSEG, the former owner of Kalaeloa Partners, announced in November of 2023 that it was 100% carbon-free after it had sold all its fossil-fueled power plant assets, while still supplying power from fossil fuels to its customers.

[49] JERA Co., Inc. (2024) Retrieved from https://www.jera.co.jp/en/corporate/about/origin

[50] JERA Co., Inc. (n.d.). *Toward a world-leading zero-emission company*. Retrieved from https://www.jera.co.jp/en/corporate/about/zeroemission/world/

[51] See HSEO Lifecyle Greenhouse Gas Documentation

[52] PUC Order 33795, https://puc.hawaii.gov/news-release/puc-votes-to-not-approve-the-heco-companies-and-nextera-energys-joint-application-for-change-of-control/.

Policy and Regulatory Framework

Beyond the tragic loss of life, the Maui wildfires exposed the threats of a new normal engendered by climate change impacts; a threat that must be immediately addressed with mitigation plans to limit future risks to life and property. Since August 8, 2023, the Green Administration has shaped a policy to reduce electricity costs and carbon associated with power production under the premise that the current plans are no longer acceptable. The wildfires caused massive liability risk to our largest utility from damages associated with the wildfires, greatly limiting its access to, and cost of capital. This increases financing costs for all future projects by Hawaiian Electric, including power generation, grid improvements, and mitigation plans, much of which can be expected to be passed on to ratepayers. Some projects may not be able to move forward, putting necessary capital projects and the pace of Hawaiʻi's energy transition at risk.

Policies to improve the current plans should address three outstanding issues:

- Specific measures to accelerate the deployment of renewable energy, energy efficiency, and clean transportation.
- Fuel switching to mitigate oil price volatility, place downward pressure on electricity costs, and greatly reduce carbon emissions.
- Immediate reliability improvements that make it easier to integrate additional renewable energy through 2045.

The *Alternative Fuel, Repowering, and Energy Transition Study* is primarily focused on the second and third issues above. Fuels and power plant options have been evaluated with a preference for options that can achieve all the Governor's stated policy objectives – to lower costs and carbon in a manner to attract capital, improve grid reliability, and ensure that Hawaiʻi meets its energy transition targets. Energy affordability is enhanced by strategies that reduce the cost of producing electricity and oil price volatility while making meaningful reductions in lifecycle carbon emissions.

Clearly, switching to another fossil fuel does not satisfy our climate obligations. An alternative fossil fuel can make a significant reduction in near-term emissions but underscores how much more the state must do to meet the challenge of climate change. First, all state agencies must incorporate the reality of climate change into their day-to-day decisions. This includes reducing building energy use, switching to more efficient modes of transportation, relying on clean distributed energy resources to improve climate resilience, and acknowledging the ever-increasing risk of natural hazards to daily operations and new capital improvement projects. Agencies should prioritize programs that direct the majority of benefits to help low- and moderate-income residents avoid the risks of climate change, reduce their energy burden, and participate in the energy transition, for example through access to solar and job training.

Agencies should also consider the lifecycle emissions of their budget and procurement choices because the climate impacts of their decisions today can no longer be ignored or made to be someone else's responsibility.

Further, the PUC must require utilities to act with urgency in mitigating their climate risks, which include both aging grid infrastructure and a continued over-reliance on the dirtiest fossil fuel available. Working together, the state and private parties must identify modern rate structures and programs to ensure the widespread adoption of dispatchable clean distributed resources on all buildings, especially on land-constrained O‘ahu where distributed solar plays an irreplaceable role in the energy transition. This requires continued efforts on technical matters such as interconnection standards and the safe deployment of inverter-based grid controls, as well as a recognition that we have not done enough to help low-income residents benefit from solar subsidies in the past.

This analysis is complementary to the groundbreaking *Navahine F. v. Hawai'i State Department of Transportation* settlement of June 2024 and indicative of the Green Administration's perspective to go beyond the status quo and take tangible, substantive actions to create a more resilient and increasingly decarbonized economy. Decisions will be based on scientific data and proven technologies that best achieve the previously mentioned policy objectives to reduce carbon and costs while accelerating Hawai'i's energy transition. Consideration of lifecycle carbon emissions requires careful consideration of the location and circumstances under which energy is produced and shipped to Hawai‘i.

Regulatory and Permitting Requirements

Regulatory requirements for the options outlined herein generally fall into either discretionary or ministerial approval processes. Discretionary approval requires a regulatory agency to undergo a detailed process and evaluation to decide if a project should proceed (e.g., National Environmental Policy Act [NEPA], Hawai‘i Environmental Policy Act [HEPA], PUC regulatory approval). Ministerial permits are routinely granted when a project meets the requirements of the regulations and a permit or approval can be issued with limited review (e.g., building permits, grading permits, etc.).

This distinction is notable due to the in-depth evaluation and timeline required for discretionary processes. Often discretionary processes include multi-agency coordination and stakeholder involvement that provide additional inputs for consideration. As a result, these types of decisions are more often more intricate and subjective but streamlining permits and approvals that require similar analysis can reduce costs and condense timelines. The focus of the discussion below is on these approvals.

See Technical Appendix – Anticipated Permits and Approvals for a full list of approvals.

Critical Regulatory Approvals

The regulatory and permitting review completed under discretionary permits provides a framework to maintain compliance across federal, state, and local jurisdictions while addressing environmental, cultural, and operational considerations. Of the permits anticipated, several discretionary approvals are necessary. Completing these approvals promptly and streamlining permit efforts will be necessary.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) mandates that federal projects undergo environmental assessments (EA) or Environmental Impact Statements (EIS) to ensure all potential environmental impacts are thoroughly evaluated, fully disclosed, and carefully considered. There are several federal regulatory approvals needed for the activities in this study which would necessitate the completion of a full EIS. This process aims to ensure input from public agencies, promote active public participation, and foster transparency throughout the decision-making process. For a project such as the construction and operation of an LNG facility, NEPA would require extensive and comprehensive studies on a range of environmental factors, including air quality, water resources, wildlife habitats, greenhouse gas emissions, and potential socioeconomic impacts.

Additionally, the NEPA process would involve a public participation process, engaging federal, state, and local agencies in addition to local community groups, environmental organizations, and industry representatives. This public engagement is essential for ensuring that the diverse concerns of affected parties are heard and addressed.

Mitigation measures would likely be required to mitigate significant impacts identified in the EIS. These measures can include habitat restoration, pollution control technologies, or community benefits agreements. Such measures would be developed collaboratively with stakeholders and agencies to ensure that they adequately address the impacts while aligning with community needs and regulatory requirements.

Given the scale and scope of activities associated with LNG facilities multiple federal regulatory approvals would be required, including permits and approvals from the Federal Energy Regulatory Commission (FERC), the U.S. Army Corps of Engineers (USACE), the U.S. Environmental Protection Agency (EPA), and others. The complexity and potential impact of these activities would necessitate the completion of a full Environmental Impact Statement under NEPA, ensuring a comprehensive review and alignment with federal environmental and regulatory standards.

Hawaiʻi Environmental Policy Act

Chapter 343, Hawaiʻi Revised Statutes (HRS), colloquially known as "HEPA", establishes a system of environmental review at the state and county levels to "ensure that environmental concerns are given appropriate consideration in decision-making along with economic and technical considerations". HEPA parallels the NEPA for state approvals and projects. The purpose is to provide agencies and persons with procedures, specifications regarding the contents of exemption notices, environmental assessments (EAs), and environmental impact statements (EISs), and criteria and definitions of statewide applications.[53] Like NEPA, this process involves public participation and

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[53] Hawaiʻi Revised Statutes (HRS) Chapter 343 Environmental Impact Statements.
Hawaiʻi Administrative Rules (HAR) Title 11, Chapter 200.1 Environmental Impact Statement Rules.

stakeholder coordination. The processes can be completed jointly, or separately, typically at the discretion of the “accepting authority”.

HRS §343-5 establishes the applicability and requirements for various actions that require HEPA. For LNG-associated facilities, these applicability triggers include but may not be limited to: 1) Propose the use of state of county lands or the use of state or county funds (e.g. transportation right-of-ways); 2) Propose any use within a shoreline area as defined in section 205A-41, and 3) Propose any power generating facility. HRS 343-5 also states: “Whenever an action is subject to both the National Environmental Policy Act of 1969 (Public Law 91-190) and the requirements of this chapter, the office, and agencies shall cooperate with federal agencies to the fullest extent possible to reduce duplication between federal and state requirements. Such cooperation, to the fullest extent possible, shall include joint environmental impact statements with concurrent public review and processing at both levels of government. Where federal law has environmental impact statement requirements in addition to but not in conflict with this chapter, the office, and agencies shall cooperate in fulfilling these requirements so that one document shall comply with all applicable laws.”

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) is responsible for authorizing the siting and construction of onshore and nearshore LNG import or export facilities under Section 3 of the Natural Gas Act.[54] Typically, the FERC process requires NEPA.

Other Key Federal Approvals

The Clean Water Act (CWA) Section 404 regulates discharges into US waters, requiring permits from the Army Corps of Engineers for activities impacting water bodies including wetlands (referred to as Waters of the US [WOTUS]). This regulation would likely be triggered for any work on or impacting WOTUS. Depending on the activity occurring in WOTUS, the process could entail an Individual Permit that includes a public comment period as well as coordination with other agencies. Mitigation to offset impacts to WOTUS is anticipated and could be challenging in an area with limited options.

The Marine Mammals Protection Act (MMPA) and the Endangered Species Act (ESA) protect marine life and endangered species from harmful activities. Activities in the ocean would warrant a detailed evaluation of potential impacts to species including commitments to avoidance and mitigation measures. These two processes would be completed concurrently with the CWA or NEPA processes.

The Deepwater Port Act (DWPA) governs the operation and decommissioning of LNG ports, requiring coordination between federal and state authorities, with coastal governors holding veto power. This Act is not commonly engaged, having 30 applications of which only 11 have been

[54] Federal Energy Regulatory Commission (FERC). (2023). *Liquefied natural gas (LNG)*.Retrieved from: https://www.ferc.gov/natural-gas/lng

approved in the US. The Act would be required for options involving LNG imports. As part of the Act, the NEPA would be required.

Compliance with NHPA Section 106 ensures that federal projects assess and mitigate impacts on historic properties and archaeological resources. Engagement with Native Hawaiian Organizations will occur formally through this process but as a critical aspect of the project, engagement should occur throughout the project development and permitting processes.

While the various permits and approvals cover a range of environmental topics and resources, there are specific risks that have been notable in other projects in Hawaiʻi. Siting infrastructure in areas where energy infrastructure exists can minimize these impacts. All these issues as well as others would be identified early in the environmental processes for an appropriate level of analysis.

Regulatory Approval by the Hawaiʻi Public Utilities Commission

Hawaiʻi's Public Utilities Commission (PUC) regulates registered public utility companies in the state for activities such as rate changes, the procurement of new energy projects, and Power Purchase Agreements (PPAs). The utilities submit these requests through a "docket" system where interested parties can submit evidence and public comment. The PUC reviews the information presented and issues a decision. Adoption of the activities evaluated in this study would require PUC approval of Hawaiian Electric-owned facilities upgrading and switching to LNG in addition to changes to the Competitive Bidding Framework in the procurement process to accommodate both new facilities and the repowering of existing facilities.

Preliminary Permitting Timeline

The study team developed a timeline showing the sequencing and timing of the critical discretionary and a few ministerial permits and approvals associated with the alternative fuels in the energy transition (Figure 21). While the timeline shows only a few of the permits and approvals anticipated, a given project would require numerous permits for construction and operation.

Establishing a schedule that correlates each process to the engineering milestones is important for avoiding delays and continuing to develop the information necessary to complete each step in the permit process. The ability to complete permits in parallel or consolidate them into one document, as in the case of NEPA and HEPA, allows for schedule streamlining. While streamlining the process is key to meeting overall milestones for the implementation of the energy transition, it would be tempered with the need to thoroughly evaluate environmental impacts and incorporate stakeholder and public concerns into both the permit process as well as the engineering design.

To meet the projected operational timelines, the permit process, starting with preliminary engineering and baseline studies, would need to commence quickly to support the larger suite of permit processes and anticipated agency requirements.

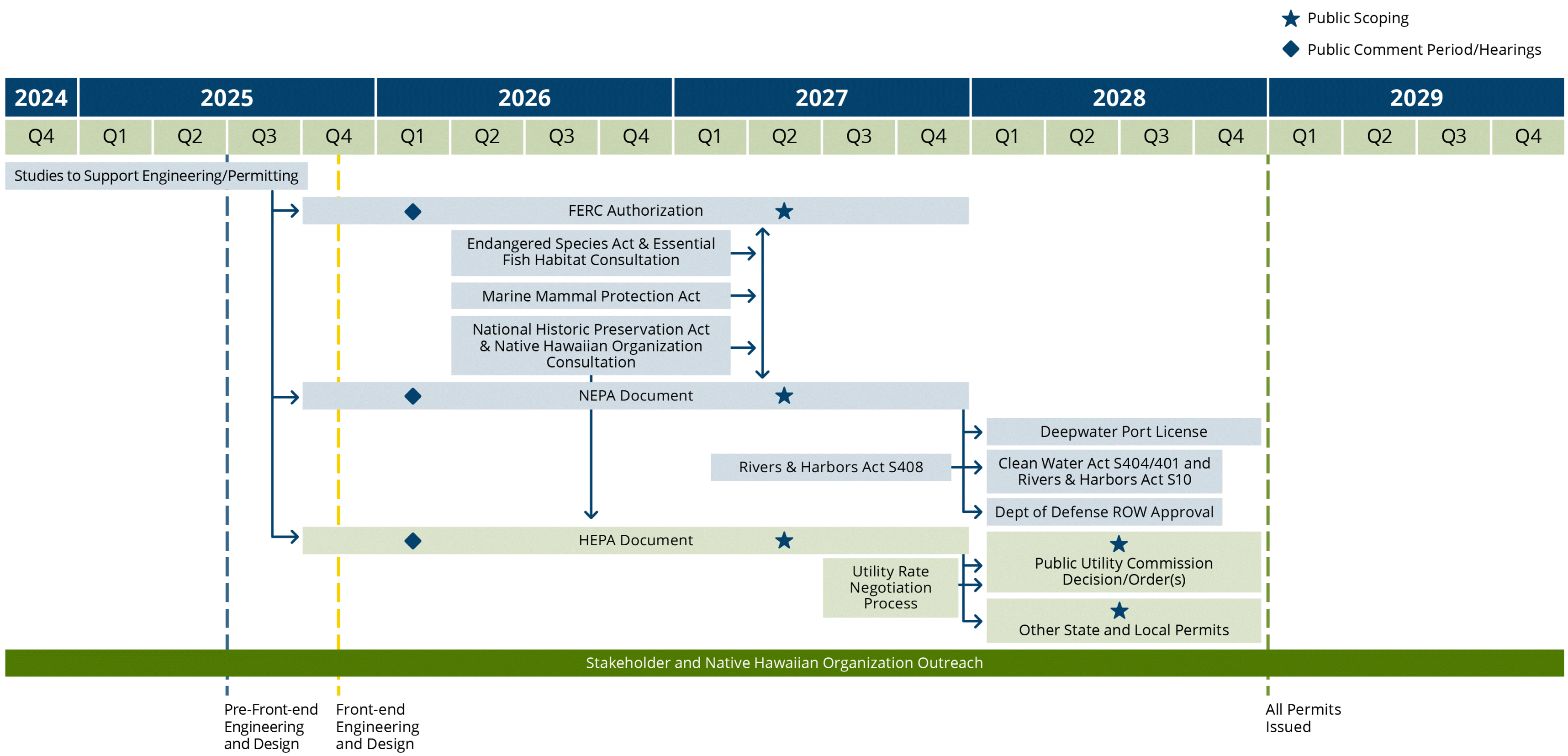

Figure 21. *Permitting timeline for major approvals with long lead times*

Policy Recommendations and Strategies to Enable a More Efficient Process

As energy development initiatives expand, aligning local policies and streamlining permitting processes to meet project timelines efficiently is essential. Early engagement with municipalities and coordinated efforts among agencies can minimize delays and provide smoother project approvals. Below is a list of key policy recommendations and strategies to optimize permitting workflows and secure stakeholder cooperation at the local, state, and federal levels.

- **Prioritize brownfield development and infrastructure reuse:** Emphasize repurposing brownfields and leveraging existing energy infrastructure to minimize environmental impact. Identify high-potential sites based on factors such as location, environmental conditions, and presence of existing infrastructure.
- **Implementing Permit Assistance Programs:** A permit assistance program led by HSEO in collaboration with the University of Hawai ʻi at Manoa, the counties, and other energy stakeholders, could assist agencies in improving permitting processes and would guide developers through the regulatory landscape, helping them navigate complex permitting processes and coordinate with multiple agencies. This program would provide technical and procedural support to minimize delays.
- **Dedicated Staff for Technical Assistance on Permit Processing:** Assigning dedicated staff at key state and county agencies to focus exclusively on necessary energy development permits to accelerate processing times, without bypassing necessary regulatory reviews or safeguards.
- **Develop Detailed Cost of Carbon Methodology:** A robust carbon accounting should be required to ensure that emissions reductions are being achieved. This accounting can be based on a portfolio comprised of tracking individual cargo and should incorporate the environmental stewardship of the source country. In addition to quantitative elements such as methane leakage estimates and the social cost of carbon, the stewardship framework can include qualitative elements regarding the source country's treatment of flaring, conventional versus fracked gas, participation in international emissions monitoring and reduction efforts, and similar concerns.

Risk Register

Acknowledging the significant risks of maintaining the current trajectory, the Hawai'i State Energy Office (HSEO) was tasked with developing a new energy strategy to address the firm energy requirements of the utility grid while reducing energy costs and carbon emissions in the electricity sector. Continuing with the status quo will fail to deliver affordable energy and attract the necessary investments to build a resilient and decarbonized energy system. Key risks and challenges associated with maintaining the status quo include::

- Hawai'i has the highest electricity costs and O'ahu has the highest average greenhouse gas emissions intensity.
- Continued reliance on LSFO and diesel has been a major contributor to the high costs of energy and the largest contributor to carbon emissions on the islands.
- Status quo would likely result in Hawaiian Electric's continued burning of liquid petroleum fuels until prohibited according to interim RPS mandates and total phase-out in 2045.
- The current Hawaiian Electric grid and development plans have unnecessarily high carbon emissions primarily due to substantial reliance on LSFO as well as powerplant inefficiency. Hawaiian Electric has historical practices of extending the life of its generation fleet well beyond its useful life and mostly deferring high-efficiency power plant replacements.
- With growing geopolitical risks within the USINDOPACOM area of responsibility (AOR), resilient, reliable, and affordable electricity is essential to fulfill US national security objectives and protect national interests.
- Land availability and other factors indicate that local energy supply will be insufficient to meet both current and forecasted demand, especially when considering demand from expected electrified transportation.
- Intermittent buildout of intermittent renewable energy technologies is optimistic when compared to historic build-out rates. Prioritizing the buildout of these intermittent resources is critical, but delays will likely extend the use of aging oil assets.

However, the proposed transition also presents risks that must be carefully managed and mitigated to ensure a successful transition. The study included facilitating a high-level risk discussion with key stakeholders related to items that could impact achieving the energy transition objectives outlined in the preferred pathway above. The stakeholders and study team documented risks related to several categories:

- Generation Resource Adequacy
- Power Delivery Capacity
- Construction
- Supply Chain
- Funding and Financing
- Power Demand
- Regulatory Approval
- Permitting

The high-level risks, related categories, and impacts to energy transition objectives are summarized in Table 23.

Table 23. *Identified risks*

Risk	Risk Categories							Impact on Energy Transition Objectives				
	Generation Resource Adequacy	Power Delivery Capacity	Construction	Supply Chain	Funding and Financing	Power Demand	Permitting	Increases Costs	Decreases Carbon Savings	Reduces Ability to Attract Capital	Reduces System Reliability	Delays Meeting 2045 RPS Schedule
Not able to build or repower sufficient power plants to use LNG fast enough	•		•				•		•			•
Campbell Industrial Park (CIP) plant: would need to run more than it runs now	•							•				
Hawai'i Gas pipeline capacity: concerns about sufficient capacity for the significant increase in gas flow; may need higher pressure with fuel gas compressor[55]	•							•				

[55] Preliminary calculations show that the pipelines have capacity for 140,000-150,000 additional therms per day. Based on an 8,500 btu/scf heat rate, and a 50% capacity factor, that equates to 140-150 MW. Based on Hawai'i Gas' responses to questions from HSEO.

Risk	Risk Categories							Impact on Energy Transition Objectives				
	Generation Resource Adequacy	Power Delivery Capacity	Construction	Supply Chain	Funding and Financing	Power Demand	Permitting	Increases Costs	Decreases Carbon Savings	Reduces Ability to Attract Capital	Reduces System Reliability	Delays Meeting 2045 RPS Schedule
Repowering Kahe: the ability to procure, permit, and construct on a rapid timeline	•		•				•					•
Biofuels: increasing demand from many sectors and parties internationally may lead to insufficient supply and will have higher prices. Imported first-generation biofuels and feedstocks readily available on the import market may not exhibit substantial lifecycle GHG savings.	•			•				•	•			
Transmission capacity / adding new generation to the grid: Kahe could be promising; CIP and KPLP would need transmission infrastructure upgrades		•						•				
N-1 and thermal capacity: could be limiting factors for power delivery		•									•	
Transmission line land and community opposition to building new lines		•	•									•
Section 111 of EPA carbon capture: no carveout for CTs; creates challenges for constructing new CTs; difficulties maintaining compliance with fuel blends; NG is difficult to comply with current guidelines.			•				•					•
The construction contractor community may not have the capacity.			•					•				•
Lead times for combustion turbines (CTs) could be two years.			•	•								•
LNG gas price variability related to global events and disruptions				•				•				
Waiau: changing plans could delay and potentially jeopardize financing; has existing stage 3					•		•			•		•
Hawaiian Electric's restricted access to capital; reduces the ability to debt fund projects.					•					•		
Intermittent energy projects may get delayed and cause more demand for firm energy; there would be sufficient time to transition to other fuels because of 45 days on island fuel storage.						•					•	
Uncertainty around power demand requirements; potential variability with EV adoption						•					•	
Power plant modifications would require air permits for fuel switching and running more.							•					•
FERC permitting driver for going down containerized solution; gas would require a FERC permit and may require a long time to gain permits for building the pipelines							•					•
Local activist opposition to new fossil fuels: NEPA/HEPA could push back timeline by five years							•					•
Permitting for building new transmission lines							•	•				•

Conclusion and Next Steps

HSEO was tasked with creating an energy portfolio that meets the State's RPS and decarbonization statutory targets, enhances grid stability, and rebuilds aging power plant infrastructure while minimizing the impact on ratepayers. This study is part of a broader effort to develop an energy transition strategy to support national security, safeguard energy infrastructure, increase energy affordability, and accelerate renewable adoption.

This desktop review provided an assessment of power plants on Oʻahu, Hawaiʻi Island, Maui, Molokaʻi, and Lānaʻi, identifying potential alternatives for conversion to methane gas to support the State's shift toward a cleaner energy future. Given the substantial energy needs of Oʻahu, the island served as the immediate focus for the statewide transition to renewables. Since the study was limited to in-depth desktop technical feasibility analyses, any action based on it should include appropriate outreach and engagement with key stakeholders, communities, and agencies involved in regulating and permitting energy infrastructure.

One of the largest challenges with creating an energy portfolio is projecting the anticipated increase in power demand. HSEO, with the use of capacity expansion modeling, anticipates a wide variety of energy sources to meet the increased power demand (Figure 22). Other major challenges include accurate price forecasting and anticipating technology development.

The preliminary pathway to meet the power demand for Oʻahu indicates LNG deserves careful consideration as a primary thermal generation source, using built-in fuel flexibility from current generation technology to accommodate lower-carbon, fossil-free alternatives as they mature and become more cost-effective. This pathway anticipates the maturation of hydrogen and ammonia technologies by 2045 will, based on current approaches, be built on methane infrastructure rather than oil. Additionally, this pathway anticipates that the U.S. EPA will regulate power sector emissions to require either methane with carbon capture or clean hydrogen as primary fuels in the future. Finally, this pathway minimizes stranded asset risks of necessary reliability investments by incorporating dual-fuel infrastructure that can adapt to technological and economic advancements.

This study shows that an interim transition to methane gas can yield meaningful cost savings while also reducing risk. Cost savings depend on infrastructure choices that must be based on more detailed study, as well as moving quickly to displace LSFO. The assumed fuel mix displaced by methane gas and the ability to re-use the infrastructure constructed for a methane gas transition strongly impacts the results of the economic evaluation (Alternative 1 vs. Alternative 2).

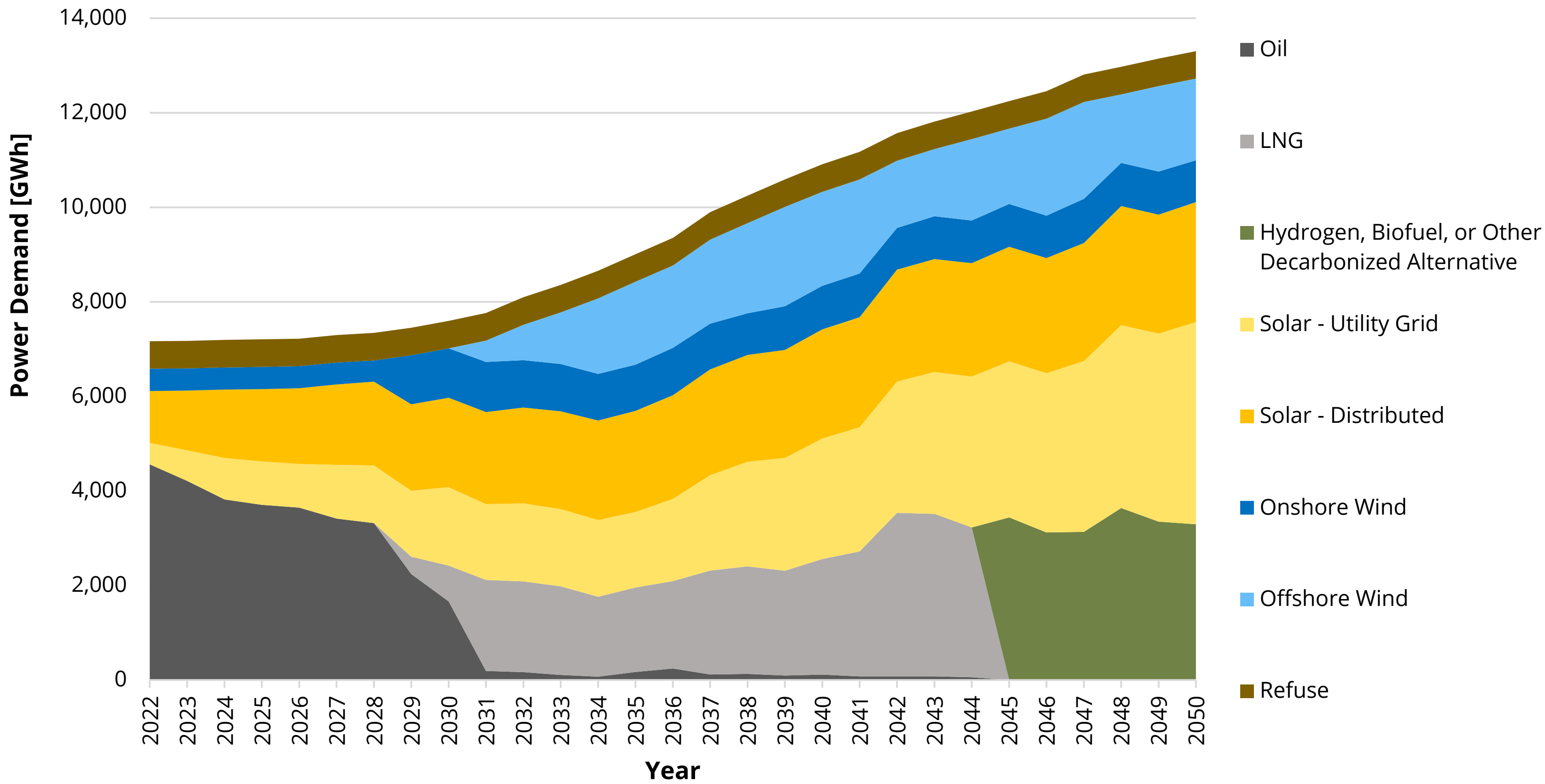

Figure 22. *Oʻahu future power demand by generation technology under a bridge fuel transition.*

The analysis found a significant potential for savings if the fuel mix displaced by LNG is more expensive than LSFO (Alternative 3). In any alternative scenario, immediate action is necessary to realize many of the cost savings presented, with delays in development resulting in reduced cost savings.

HSEO reasserts that under the status quo, many of the planned thermal projects (including Stage 3 and IGP RFP thermal projects), will result in one of two outcomes: either (1) higher electricity prices if biofuels are available and their costs are approved by the PUC – which was evaluated in Alternative 3, or (2) the continued reliance on liquid oil-based fossil fuels, such as Low Sulfur Fuel Oil or ultra-low sulfur diesel as evaluated under Alternative 1 and 2.

As energy development initiatives expand, aligning local policies and streamlining regulatory processes to meet project timelines efficiently is essential. Early engagement with municipalities and coordinated efforts among agencies can help minimize delays and provide smoother project approvals. While streamlining the permitting process is key to meeting overall milestones for the implementation of the energy transition, streamlining would be tempered with the need to thoroughly evaluate environmental impacts and incorporate stakeholder and public concerns into both the permit process as well as the engineering design. Of the permits anticipated, several discretionary approvals are critical for project success in terms of complexity and duration. To meet the projected operational timelines, the permit process, starting with preliminary engineering and baseline studies, would need to commence quickly to support the larger suite of permit processes and anticipated agency requirements.

Oil and gas production negatively impacts the health of neighboring communities,[56] and methane emissions must be significantly reduced across the globe to avoid the worst of climate change.[57] Public outreach, stakeholder engagement, and community feedback are critical for identifying other concerns. Also, integrating energy stakeholders such as Hawaiian Electric, Par, and Hawaiʻi Gas into the energy transition strategy will be necessary to maintain or increase the number of quality jobs for current residents.

Reducing fossil fuel use must remain a priority of the state to meet its constitutional responsibilities. If the pathways recommended in this study are accepted by the utility and are chosen to be pursued, further development of engineering through a Front-End Engineering Design is necessary, and immediate commencement of certain regulatory processes is critical. Additional laws and regulations must be established to ensure that these fossil fuels are permanently eliminated from the state's energy portfolio as quickly as possible.

[56] See, among others, *Human health and oil and gas development: A review of the peer-reviewed literature and assessment of applicability to the City of Los Angeles,* Seth B.C. Shonkoff, PhD, MPH , Lee Ann L. Hill, MPH (2019)
[57] Staniaszek, Z., Griffiths, P.T., Folberth, G.A. *et al.* The role of future anthropogenic methane emissions in air quality and climate. *Nature Clim Atmos Sci* **5**, 21 (2022). https://doi.org/10.1038/s41612-022-00247-5

Technical Appendices

Alternative Fuel, Repowering, and Energy Transition Study

Technical Appendix Contents

Appendix A - Fuels Evaluation

Criteria and Basis of Evaluation

This Technical Documentation presents the basis of fuel evaluation for the Alternative Fuel and Energy Transition Study starting with the identification of the fuel, whether it is imported or sourced locally, and then providing an overall evaluation score as well as individual scores for technology readiness levels (TRLs), transportation logistics, fuel geographic availability, and scalability. Ratings are explained in this section with fuels and their evaluations presented individually.

Fuel Name – Fuel Pathway: Name of Fuel – Imported or Local

Definition: Description of the fuel using references from HSEO, Hawaiian Electric Company, Inc. (HECO), and other reports.

Evaluation Score: Total score based on 1 to 5 scoring adjusted to weighting percentages shown in the following table.

Criteria	Weighting
TRL	30%
Transportation	15%
Fuel Availability	20%
Scalability (production)	35%

TRL: Evaluation of the maturity of the technologies in the fuel supply chain. This criterion indicates a technology risk where the technology has not reached maturity. The higher the TRL the lower the technology risk. HDR assigned values of 1 to 5 where 5 is the most mature technology and 1 is the least mature technology further outlined in the table below.

Level	Description
1	Basic principles observed and reported
2	Proof of concept
3	Technology validated and early prototype demonstration.
4	Technology operational at limited commercial scale
5	Proven at a commercial scale, technology is widely available and operational.

Transportation Logistics: Evaluation of the maturity of the fuel transportation mechanisms. HDR assigned values of 1 to 5 where 5 is the most mature transportation mechanism and 1 is the least mature transportation mechanism further outlined in the table below.

Level	Description
1	Innovation and investment required to transport and distribute fuel
2	Transportation logistics concept proven
3	Transportation logistics validated and early stage of implementation planning.
4	Transportation logistics operational at prototype scale
5	Transportation logistics and infrastructure exist, are operational and proven.

Fuel Availability: Evaluation of the current availability of the requisite volumes of fuel. Evaluation is based on the supply and demand of the fuel. HDR assigned values of 1 to 5 where 5 is high volumes of fuel are commercially available and 1 is limited volumes commercially available as further outlined in the table below.

Level	Description
1	Limited volumes available commercially
2	Small volumes available commercially
3	Moderate volumes available commercially
4	Large volumes available commercially
5	Abundant volumes available commercially with little or no constraints

Scalability: Evaluation of fuel capacity to meet energy demands. HDR assigned values of 1 to 5 where 5 can scale to meet the upper thresholds of power demands and 1 indicates no capacity to scale to meet energy demands.

Level	Description
1	No capacity to scale up, current fuel is at maximum capacity and availability, ability to produce volumes is severely constrained
2	Limited capacity to scale, and produce limited volumes due to constraints (feedstock, space, etc.)
3	Moderate capacity to scale up
4	Capacity to scale up at large volumes with some risk
5	Capacity to scale up at large volumes with minimal constraints

References: Links to reference information used in the evaluation.

Fuel Details

This section identifies and describes evaluation results for the fuels identified and studied in the Fuel Matrix, including various forms of methane, diesel, hydrogen, methanol, and ammonia.

Methane – Imported Liquefied Natural Gas (LNG)

Definition: Methane is the largest component of natural gas, a fossil fuel energy source. Natural gas is stored and transported in its liquid state (LNG) to increase the volumetric density.

Evaluation Score: 5.00

TRL: 5. LNG has a fully developed supply chain with production, shipping, and consumption technology readily available. For over 60 years, LNG has been produced, stored, and transported all over the world. The key components of the proposed LNG supply chain are the LNG container ship, floating storage regasification unit (FSRU), subsea pipeline, onshore pipelines, bullet tanks, and International Organization for Standardization (ISO) containers. This equipment has been implemented internationally in a similar manner successfully. Similarly, other associated technologies has been widely studied, developed, and utilized in many similar applications to meet the growing energy demand. With the long history of LNG comes a high level of maturity in both technology and supply chain feasibility.[1]

An example of a similar solution currently in operation is Northeast Gateway Deepwater Port, a project by the company Excelerate. This project was commissioned in 2008 and consists of an FSRU moored about 13 miles off Massachusetts Bay equipped with a subsea pipeline.[2] As with any project, there are location-specific variables and environmental considerations that need to be addressed.

Transportation Logistics: 5. LNG can be shipped on ocean-going vessels that deliver LNG directly to shore or a moored FSRU. LNG is shipped at cryogenic temperatures, and LNG vessels are widely available. Little innovation is required to transport LNG. Several commercial avenues exist currently in the market for turnkey LNG sourcing. Providers such as Excelerate would source, ship, and provide the FSRU in a turn-key arrangement.

Storage volumes for LNG container ships and FSRU can be optimized to meet the demand for the location they serve. Additionally, the vaporization technology can provide a range of flow rates for the natural gas via the subsea pipeline. Again, the long history of LNG transportation and flexibility provides multiple examples of logistical solutions meeting demands and confirming resilient and firm energy generation.

Fuel Geographic Availability: 5. LNG is not currently produced in Hawaiʻi, but could be sourced from Canada or Australia among other locations including the United States. Requisite volumes to meet the energy demand are available in both Canada and Australia with little constraints to volume production currently.

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[1] EIA. Natural gas explained. US EIA. https://www.eia.gov/energyexplained/natural-gas/liquefied-natural-gas.php

[2] Excelerate Energy. (2024). *Northeast Gateway Deepwater Port*. Retrieved from https://excelerateenergy.com/projects/northeast-gateway-deepwater-port/

If LNG is sourced from the United States, additional consideration to Jones Act compliance is necessary. As of today, there are no large-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 cargo to Hawaiʻi.[3]

Scalability: 5. LNG can be purchased and shipped. Natural gas is not currently used in Hawaiʻi at large volumes; however, synthesis gas (syngas) is. Natural gas could replace syngas or other gaseous fuel sources on the islands. The Institute for Energy Economics and Financial Analysis expects global LNG supply capacity to rise to 666.5 million tons per annum by the end of 2028, which exceeds International Energy Agency demand scenarios through 2050; therefore, there is adequate LNG capacity to meet Hawaiʻi's power needs.[4]

Diesel – Local Biodiesel and Renewable Diesel

Definition: Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil. Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.

Evaluation Score: 2.85

TRL: 5. Biodiesel is currently produced in Hawaiʻi and the production capacity could be increased with increased feedstock. The production technology is proven and commercially available in Hawaiʻi.

Transportation Logistics: 5. Pure biodiesel has limited direct-use applications and supply logistics challenges because of its physical properties and characteristics. Biodiesel is a good solvent, which means it can degrade rubber in fuel lines and loosen or dissolve varnish and sediments in petroleum diesel fuel tanks, pipelines, and engine fuel systems, which can clog engine fuel filters. Biodiesel turns into a gel at higher temperatures than petroleum diesel, which creates problems for its use in cold temperatures. So, certain biodiesels cannot be stored or transported in regular petroleum liquid tanks and pipelines—they must be transported by rail, vessel, and barge, or truck.[5]

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[3] Facts Global Energy (2024) Economics of Accelerating Hawaiʻi's Energy Transition via LNG and other Alternative Fuels. Prepared for the Hawaiʻi State Energy Office.

[4] The Institute for Energy Economics and Financial Analysis. (2024, November 25). Global LNG Outlook 2024-2028. Global LNG Outlook 2024-2028 | IEEFA

[5] EIA. (2024, February 1). Biofuels explained: Biodiesel, renewable diesel, and other biofuels. https://www.eia.gov/energyexplained/biofuels/biodiesel-rd-other-use-supply.php

Fuel Geographic Availability: 1. Currently, there is one refinery in Hawaiʻi that produces biodiesel: Pacific Biodiesel. This refinery has a nameplate capacity of 5.5 million gallons (MMGAL) per year, and in 2023, it produced 6 MMGAL. Most of the feedstock comes from waste oils and fats with local production supplemented by imported oils and fats (tallow). The most frequently used oils in Pacific Biodiesel's production are used cooking oil, tallow, yellow grease, poultry grease, cottonseed oil, and soybean oil. [6]

Scalability: 1. There are already six power plants across the island that can run on biofuel[7], but changing to biodiesel for fuel at these plants would require additional production of biodiesel in large quantities.

Based on previous studies, one of the highest-yielding crops for biodiesel and renewable diesel production in Hawaiʻi is palm oil, which also has had initial production testing. In the 2013 HNEI Biofuels Development crop assessment report initial production testing in Hawaiʻi showed palm oil yields of 620 to 650 gallons per acre.[8] On average exhibits yields (gal/acre) estimated to be approximately six to ten (6-10) times higher than camelina, approximately six (6) times higher than sunflower, five (5) times higher than rapeseed/canola, thirteen (13) times higher than soy, and about three (3) times higher than that of Jatropha.[9],[10] Noting annual yield is influenced by the number of harvests per year that can be reasonably completed. Palm oil only served as the most optimistic baseline to estimate scalability, when considering other crops, land use intensity would increase, further decreasing the overall scalability score.

There are also tradeoffs between economic sectors to consider as Hawaiʻi looks to decarbonize the entire economy. Liquid biofuels can be used for electric generation, but they can also be used as a low-carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels since hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there will likely be competing demands for biofuel production from other sectors that may be more likely and willing to pay a premium for the fuel or feedstock. The 2022 Inflation Reduction Act (IRA) provides substantial tax credits to support the domestic production of clean transportation fuels, including sustainable aviation fuel (SAF). These incentives are aimed at enhancing the cost-competitiveness of biofuels in the transportation sector, potentially leading to favored use in transportation instead of electricity generation.

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[6] Pacific Biodiesel Frequently Asked Questions. (n.d) Retrieved from biodiesel.com/faq/

[7] Hawaiian Electric Companies. (2024, January 31). Fuels Master Plan. Page 9 of 60.

[8] Hawaiʻi Natural Energy Institute (2013) Hawaiʻi Energy and Environmental Technologies Initiative, Alternative Biofuels Development: Crop Assessment.

[9] Id

[10] Pacific Biodiesel Technologies (2017). *Biofuel Crop Fact Sheet.* Retrieved from https://biodiesel.com/wp-content/uploads/2020/01/Biofuel-Crop-Fact-Sheet-2-24-17-FINAL.pdf

While locally produced biofuels cannot be scaled to meet Hawaiʻi's energy demand, they are still important to pursue in a balanced manner as they can provide substantial co-benefits for agriculture, have strong potential to reduce emissions if grown regeneratively, and can offset some of the state's fuel demand.

General Notes: From HECO's Fuels Master Plan, the cost of biodiesel is typically two to three times more than LSFO.[11]

Imported Biodiesel and Renewable Diesel

Definition: Biodiesel and renewable diesel can both be used as a combustion energy source though there are distinct differences in these "renewable" fuels. Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil.

Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.

Further supply of biodiesel to meet renewable energy and climate goals would either have to come through new supply sources or imports. Several previous studies have looked at biofuel production in Hawaiʻi with the most relevant and complete studies being a Black and Veatch study in 2010, *The Potential for Biofuels Production in Hawaiʻi,* and a Hawaiʻi Agricultural Research Center (HARC) study from 2006, *Biodiesel Crop Implementation in Hawaiʻi*. These studies provide a good fundamental understanding of the potential for biodiesel production within the state of Hawaiʻi as well as potential limitations.

Evaluation Score: 3.00

TRL: 5. Biodiesel and renewable diesel production has been steadily increasing since 2007. Commercially viable production pathways exist off-island.

Transportation Logistics: 5. Biodiesel could be shipped similarly to petroleum diesel and LSFO that the island currently uses. Infrastructure on the island exists with LSFO pipelines and feeds to power plants. Additional pipelines might be required.

Fuel Geographic Availability: 2. Renewable and biodiesel demand can also be met with imported fuels and feedstocks. Biodiesel production sources are typically geared toward specific markets with the bulk of the United States' current biodiesel production coming from soybean oil, Europe utilizing rapeseed oil, and southeast Asia favoring palm oil.

[11] Hawaiian Electric Companies. (2024, January 31). Fuels Master Plan. Page 5 of 60.

Indonesia and Malaysia dominate palm oil production accounting for greater than 80% of global production. This production also supports renewable diesel production abroad with almost all renewable diesel imported to the United States currently coming from a Neste facility in Singapore. The United States also receives smaller supplies of biodiesel from Canada, Germany, Spain, and Italy. Import options for Hawaiʻi are likely to be Southeast Asian due to proximity and cost.

Scalability: 1. The United States is a current net importer of biofuels and its current biodiesel production capacity sits at about 2,000 MMGAL[12]; however, US production capacity has been steadily decreasing since its peak capacity of 2,600 MMGAL in July 2019.[13] For comparison, Hawaiʻi consumed a combined 497 MMGAL per year of LSFO, high sulfur fuel oil, diesel, and naphtha fuels.[14] HECO's latest request for proposal for biodiesel imports to Hawaiʻi was for 285,000 barrels per year or about 12 MMGAL per year.[15] To replace a meaningful percentage of 497 MMGAL per year of fossil-based fuel oil, Hawaiʻi will have to compete for biofuels with states like California that have financial incentives to consume biofuels and midwestern states like Iowa, where customers would benefit from shorter shipping distances. Based on these challenges, Hawaiʻi is likely to source imported biofuels from southeast Asia due to proximity and cost.

Diesel – Local E-Diesel or Synthetic Diesel

Definition: E-diesel is a synthetic diesel fuel that can be produced from carbon dioxide, water, and electricity. E-diesel can also be synthesized from carbon-containing feedstocks, such as natural gas or coal.[16]

Evaluation Score: 1.75

TRL: 2. The production of e-diesel through the Fisher-Tropsch process has been around for about 100 years but is still only used by a few companies and is not available on island.

Transportation Logistics: 4. Existing infrastructure exists on island to transport e-diesel to power generation facilities. Minor upgrades to pipelines would be required to transport the volumes required.

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[12] US Biodiesel Plant Production Capacity. EIA. (2024, August 15). https://www.eia.gov/biofuels/biodiesel/capacity/

[13] EIA. (2024, September 10). Petroleum & Other Liquids. US biodiesel production capacity (MMGAL). https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M

[14] Data from Hawaiian Electric. (January 31, 2024). Consolidated Annual Fuel Report, DKT 2022-0014, Page 10 of 60. HDR calculations using assumption that 1 barrel is equivalent to 42 US gallons.

[15] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

[16] Majewski, A. (2023, August 1). Synthetic Diesel Fuel. Synthetic diesel fuel. https://dieselnet.com/tech/fuel_synthetic.php

Fuel Geographic Availability: 1. Feedstocks (natural gas or coal) are not readily available on the island. E-diesel production requires significant electricity, which is a resource that is already in high demand.

Scalability: 1. E-diesel can be used as a drop-in fuel for existing diesel engines; however, the process is expensive and requires large amounts of electricity and potentially carbon-containing feedstocks.

Diesel – Imported E-Diesel or Synthetic Diesel

Definition: E-diesel is a synthetic diesel fuel refined from crude oil produced from carbon dioxide, water, and electricity. E-diesel can also be synthesized from carbon-containing feedstocks, such as natural gas or coal.[17]

Evaluation Score: 2.05

TRL: 4. The production of e-diesel has been around for about 100 years but is still only used by a few companies and is not available on island.

Transportation Logistics: 2. E-diesel could be shipped similarly to other diesel fuels; however, it is not shipped in mass today.

Fuel Geographic Availability: 1. In the current market, the volumes of e-diesel that would be needed are not available.

Scalability: 1. E-diesel can be used as a drop-in fuel for existing diesel engines; however, the process is expensive and requires large amounts of electricity and potentially carbon-containing feedstocks.

Methane – Local Biomethane or Local Renewable Natural Gas (RNG)

Definition: RNG can be generated from various sources, including biogas obtained from wastewater plants, landfills, organic waste, and lignocellulosic materials. RNG can be used where the gas is created (landfills or wastewater plants) or it can be injected into natural gas transmission or distribution pipelines.

Evaluation Score: 3.15

TRL: 5. The technology used to manage methane produced in a landfill is relatively simple; however, it is very costly, and often cost-prohibitive particularly for established landfills unless the capture system is in place.[18]

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[17] Majewski, A. (2023, August 1). Synthetic Diesel Fuel. Synthetic diesel fuel. https://dieselnet.com/tech/fuel_synthetic.php

[18] Hawai‘i State Energy Office. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 125.

Transportation Logistics: 5. If locally produced, RNG could be integrated into existing infrastructure.

Fuel Geographic Availability: 1. Hawaiʻi Gas currently blends RNG in its utility gas line and is working to further expand this practice.[19] Notably, one of the incentives for RNG suppliers is the state's Renewable Fuels Production Tax Credit. Pursuant to Hawaiʻi Revised Statute §269-45, Hawaiʻi Gas is required to report the percentage of feedstock comprised of petroleum feedstock and the percent comprised of non-petroleum feedstock. In 2023, around 1.5% (329,269 therms) of Hawaiʻi Gas' feedstock was from recovered biogas at the Honouliuli wastewater treatment plant.[20]

To date, there are no landfill gas (LFG) waste-to-energy systems in Hawaiʻi – methane is either flared from LFG collection systems in place or slowly released into the atmosphere at landfills without LFG capture systems in place. Hawaiʻi has seven operating landfills to date, only three of which have LFG capture systems in place.[21]

The Honolulu Program of Waste Energy Recovery (H-POWER), owned by the City and County of Honolulu, already utilizes 3,000 tons per day (TPD) of garbage on Oʻahu for steam rather than RNG.

Scalability: 1. Hawaiʻi could expand the use of RNG for power production to a figure of 673,888 MWh/year which would be approximately 6 percent of the state's non-renewable electrical consumption[22] and roughly 74% of that production comes from the thermal conversion of urban fiber wastes. Without that feedstock, the total electrical production potential is only 178,132 MWh/year and less than 2% of the total for the state. Considering land use and economic constraints, RNG may be put to higher use in harder-to-decarbonize sectors like transportation, heavy-duty equipment at ports, airports, and other areas.

Methane – Imported Biomethane or RNG

Definition: RNG can be generated from various sources, including biogas obtained from wastewater plants, landfills, organic waste, and lignocellulosic materials.

Evaluation Score: 2.90

TRL: 5. RNG technology is a reliable technology but expensive to implement.

Transportation Logistics: 2. RNG could be shipped; however, RNG is not currently shipped at scale.

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[19] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 98.

[20] The Gas Company, LLC. Hawaiʻi Revised Statutes (HRS) §269-45, Gas Utility Companies Renewable Energy Report. (April 1, 2024). Retrieved from https://puc.hawaii.gov/reports/energy-reports/renewable-energy-annual-report-gas/

[21] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 126.

[22] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Fuel Geographic Availability: 2. The United States currently produces RNG as a supplement to a large NG demand domestically, but exportation of RNG internationally is becoming attractive and driven by regulatory initiatives in Europe.

Scalability: 2. Considering land use and economic constraints, RNG may be put to higher use in harder to decarbonize sectors like transportation, heavy duty equipment at ports, airports, and other areas. RNG can be used as a direct replacement to natural gas. EIA estimates in 2022 about 216 billion cubic feet (Bcf) of LFG was collected at 334 US landfills. LFG was burned to generate about 8.5 billion kilowatt-hours (kWh) of electricity or about 0.2% of total US utility-scale electricity generation in 2022. EIA estimates in 2022, 23 dairies and livestock operations with anaerobic digesters in the United States produced about 0.1 billion (121 million) kWh of electricity from biogas. RNG is typically consumed near the sites of production , or blended into utility gas lines. Based on current production levels, scaling up US production to a level where large scale liquefaction and shipping would be feasible is unlikely.[23]

Methane – Local E-Methane or Synthetic Natural Gas (SNG)

Definition: E-methane and SNG is a manufactured product chemically similar in most respects to natural gas. SNG results from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas. SNG can be synthesized using renewable energy.[24]

Evaluation Score: 2.55

TRL: 4. Utility gas service is already serviced by SNG.[25] However, Hawai‘i would be looking at renewable SNG and that technology is under development.

Transportation Logistics: 4. Utility gas service is only on O‘ahu, primarily in the urban core.[26]

Fuel Geographic Availability: 2. Hawai‘i Gas produces SNG from naphtha supplied by the Par Hawai‘i refinery.[27]

Scalability: 1. Hawai‘i Gas is seeking lower carbon alternatives to SNG.[28]

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[23] Biomass explained. Biogas-Renewable natural gas - US EIA. https://www.eia.gov/energyexplained/biomass/landfill-gas-and-biogas.php

[24] Alverà, M. (2024, January 9). Your guide to e-NG: The green natural gas alternative that could revolutionize the green transition. World Economic Forum. https://www.weforum.org/stories/2024/01/eng-synthetic-natural-gas-decarbonize-shipping/

[25] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238.

[26] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 97.

[27] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 97.

[28] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 98.

Methane – Imported E-Methane or SNG

Definition: E-methane and SNG is a manufactured product chemically similar in most respects to natural gas. SNG results from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas. E-methane is a version of SNG that can be produced from hydrogen.[29]

Evaluation Score: **2.65**

TRL: **5.** Producing SNG from carbon feedstock is a vetted technology. Producing green SNG from hydrogen and carbon dioxide is still at an advanced research and development level.

Transportation Logistics **4.** SNG can be liquified or compressed as a gas for transport.

Fuel Geographic Availability: **1.** Renewable SNG is not currently available for purchase in large quantities.

Scalability: **1.** Hawaiʻi Gas is seeking lower carbon alternatives to SNG.[30] The global SNG market demand was estimated at 230.05 million normal meter cubed per hour in 2023 and is expected to grow at a compound annual growth rate of 11.3% from 2024 to 2030.[31]

Hydrogen – Local Green Hydrogen

Definition: Green hydrogen is produced from the electrolysis of water with the electricity sourced from renewable energy.[32] It can also be produced via waste or biomass gasification or pyrolysis.[33]

Evaluation Score: **2.60**

TRL: **3.** Electrolysis at scale in Hawaiʻi is not yet cost efficient, but technology innovation is worth tracking over the next two decades.[34]

Transportation Logistics: **4.** For on-island hydrogen production existing transport systems are operational at prototype scale. Interisland transport of hydrogen (e.g. production on Hawaiʻi Island, where land availability is less constrained, for consumption on Oʻahu) presents logistical challenges, including the need for specialized shipping infrastructure such as high-pressure storage tanks or cryogenic systems to safely transport liquefied hydrogen. Additionally, the costs

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[29] Alverà, M. (2024, January 9). Your guide to e-NG: The green natural gas alternative that could revolutionize the green transition. World Economic Forum. https://www.weforum.org/stories/2024/01/eng-synthetic-natural-gas-decarbonize-shipping/

[30] HSEO. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 98.

[31] Grand View Research. Syngas Market Size & Trends. Syngas Market Size, Share, Growth & Trends Report, 2030. https://www.grandviewresearch.com/industry-analysis/syngas-market-report

[32] Department of Energy. (n.d.-a). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

[33] HSEO. (2023). Hawaiʻi Pathways to Decarbonization, Act 238.

[34] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238.

and energy requirements for compression or liquefaction, along with potential losses during transportation, add complexity to ensuring a reliable and efficient supply chain between islands.

Fuel Geographic Availability: 2. Feedstocks for hydrogen production would be electricity and water, two resources already in heavy demand. Hawaiʻi released a request for proposal for suppliers of renewable hydrogen.[35]

Scalability: 2.

Hydrogen would run on dedicated equipment and pipelines or be integrated into a natural gas blend. Scaling up green hydrogen in Hawaiʻi would also require a surplus of renewable energy to power electrolysis plants. Pipelines and equipment capable of accommodating 100% hydrogen are limited, as conventional infrastructure often lacks the materials needed to prevent hydrogen embrittlement and leakage, necessitating significant investments in upgrading or replacing existing systems to ensure safety and efficiency. These improvements and upgrades are anticipated to become more cost-effective in the near future.

Hydrogen – Using Ammonia as a carrier

Definition: Imported green hydrogen is produced from electrolysis powered by renewable energy. This hydrogen could be shipped as liquid hydrogen or liquid ammonia. Liquid ammonia would need catalytically cracked into hydrogen gas.

Evaluation Score: 3.15

TRL: 3. Green hydrogen is currently being studied with heavy federal investment. Ammonia technology has been identified as a hydrogen carrier with invested interest.[36]

Transportation Logistics: 3. There are no current vessels shipping liquid hydrogen at scale. There are vessels currently shipping ammonia. Shipping liquid hydrogen is challenging due to the extremely low boiling temperature and energy density.[37]

Fuel Geographic Availability: 2. There is investment in new-build hydrogen and ammonia facilities; however, green hydrogen and ammonia cracking facilities are relatively new.

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[35] Hawaiʻi Gas. (2023, September 30). 2023 Request for Proposals. Hawaiʻi Gas

[36] US Department of Energy. (2006, February 1). Potential Roles of Ammonia in a Hydrogen Economy. Potential Roles of Ammonia in a Hydrogen Economy

[37] Qianqian Song, Rodrigo Rivera Tinoco, Haiping Yang, Qing Yang, Hao Jiang, Yingquan Chen, Hanping Chen, A comparative study on energy efficiency of the maritime supply chains for liquefied hydrogen, ammonia, methanol and natural gas, Carbon Capture Science & Technology, Volume 4, 2022, (https://www.sciencedirect.com/science/article/pii/S2772656822000276)

Scalability: 4. With the increased investment in research and development for hydrogen as a fuel, there is optimism for hydrogen use as a fuel. If programs like the US Department of Energy Hydrogen Shot succeed, prices for hydrogen will drop significantly.[38] Further, hydrogen could be integrated into existing natural gas infrastructure including piping and turbines.

Methanol – Local E-Methanol

Definition: E-methanol or renewable methanol can be produced using renewable energy and renewable feedstocks via two routes. Bio-methanol is produced from biomass. Green e-methanol is obtained by using carbon dioxide captured from renewable sources (i.e., bioenergy with carbon capture and storage and direct air capture) and green hydrogen (i.e., hydrogen produced with renewable electricity).[39]

Evaluation Score: 1.90

TRL: 2. The cost of renewable methanol production is currently high, and production volumes are low. With the right policies, renewable methanol could be cost-competitive by 2050 or earlier.[40]

Transportation Logistics: 5. Locally produced.

Fuel Geographic Availability: 1. Potential feedstocks would be forestry and agricultural waste and by-products; biogas from landfill, sewage, and municipal solid waste; and black liquor from the pulp and paper industry.

Scalability: 1. Feedstocks for local E-methanol are limited.

Methanol – Imported E-Methanol

Definition: E-methanol or renewable methanol can be produced using renewable energy and renewable feedstocks via two routes. Bio-methanol is produced from biomass. Green e-methanol is obtained by using carbon dioxide captured from renewable sources (i.e., bioenergy with carbon capture and storage and direct air capture) and green hydrogen (i.e., hydrogen produced with renewable electricity).[41]

Evaluation Score: 1.60

TRL: 2. The cost of renewable methanol production is currently high, and production volumes are low. With the right policies, renewable methanol could be cost-competitive by 2050 or earlier.[42]

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[38] Department of Energy. (n.d.). Hydrogen Shot. Hydrogen Shot | Department of Energy

[39] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - Renewable Methanol

[40] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[41] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[42] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

Transportation Logistics: 3. E-methanol is a liquid at atmospheric pressure and can be stored much like bunker fuel.[43]

Fuel Geographic Availability: 1. Less than 0.2 metric tons (Mt) of e-methanol is produced annually, mostly as bio-methanol. [44]

Scalability: 1. E-methanol is not currently produced at large scales.

Ammonia – Local E-Ammonia

Definition: E-Ammonia (Green or Renewable Ammonia) is produced from renewable hydrogen, which, in turn, is produced via water electrolysis using renewable electricity. This hydrogen is converted into ammonia using nitrogen that is separated from air.[45]

Evaluation Score: 1.30

TRL: 1. In the last decade, attempts to use ammonia in internal combustion engines and gas turbines have considerably increased. IHI, Mitsubishi, and GE have had successful field tests of liquid ammonia combustion turbines. Industrial production is shifting toward renewable ammonia. The annual manufacturing capacity of announced renewable ammonia plants is 15 Mt by 2030 (around 8% of the current ammonia market across 54 projects, notably in Australia; Mauritania, Africa; and Oman, West Asia). A pipeline of 71 Mt exists out to 2040, but investment decisions are still pending for most projects.[46]

Transportation Logistics: 3. Produced on island but would need hydrogen for production.

Fuel Geographic Availability: 1. Would be available depending on hydrogen sourcing. Hydrogen sourcing on island would be limited for use in creating e-ammonia.

Scalability: 1. Since e-ammonia relies on hydrogen as a feedstock and that hydrogen would need produced on-island from a renewable energy source. Local feedstock to scale up is not available.

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[43] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[44] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[45] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[46] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

Ammonia – Imported E-Ammonia

Definition: E-Ammonia (Green or Renewable Ammonia) is produced from renewable hydrogen, which, in turn, is produced via water electrolysis using renewable electricity. This hydrogen is converted into ammonia using nitrogen that is separated from air.[47]

Evaluation Score: 2.05

TRL: 1. In the last decade, the attempts to use ammonia in internal combustion engines and gas turbines have considerably increased. Industrial production is shifting toward e-ammonia.

Transportation Logistics: 3. Anhydrous ammonia is currently shipped in a similar method to LNG.

Fuel Geographic Availability: 3. Ammonia is produced mainly in Asia, which has more than half of the global ammonia production capacity.[48] There is some momentum to build new hydrogen-to-ammonia plants, especially in Australia.[49] However, it remains to be seen if these plants come to fruition and if they have any impact on e-ammonia fuel supply.

Scalability: 2. Ammonia for fuel consumption doesn't have the same funding and research and development compared to hydrogen. However, due to the transportation and storage challenges of hydrogen, e-ammonia may gain investment traction in the future.

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[47] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[48] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[49] Valentini, A. (2021). The market for Green Ammonia: Future potential and hurdles. Market for Green Ammonia

Appendix B - Power Plant Repowering & Replacement

Hawaiʻi currently relies on a mix of fuel sources for electricity generation. For firm capacity sources, the islands primarily rely on a combination of petroleum liquids including LSFO, Ultra Low Sulfur Diesel (ULSD), No. 2 Diesel Oil, and Industrial Fuel Oil (IFO) as well as biodiesel.

HDR performed a desktop review of the islands' power plants considering suitability of using natural gas as the primary fuel source. Key considerations for conversion were the age of the existing power plant, the existing rated capacity, the current fuel type, whether there are existing plans for upgrades to renewable fuel sources, and the location of the power plant pertaining to natural gas delivery.

A proposed option for receiving liquefied natural gas (LNG) to Hawaiʻi was to have a floating storage and regasification unit (FSRU) moored offshore at Barbers Point on the southwestern side of Oʻahu. A subsea pipeline would connect the FSRU and the new pipeline network on Oʻahu and deliver fuel to power plants via underground pipelines. See the LNG technical documentation and the Alternative Fuel, Repowering, and Energy Transition Study for more details.

Suitability of Existing Plants for Natural Gas Conversion

Oʻahu

Kahe

Kahe is the largest thermal generating station on the island of Oʻahu at a rated net capacity of 606 megawatts (MW) divided between six LSFO-fired boilers with steam turbine generators (STG). The plant is located along the coast, approximately three miles north of Barbers Point. The plant operates at a relatively high-capacity factor of near 0.5 compared to the other power plants on the island and has a net generation of approximate 2.5 million megawatts-hours (MWh)[50]. The boilers and steam turbines are between 48 and 61 years old and the heat rate of the existing units average around 10,300 British thermal units per kilowatt hour (Btu/kWh). According to Hawaiian Electric Company (HECO),[51] units 1 and 2 are planned for retirement in 2033 and units 3 and 4 in 2037. Units 5 and 6 are not planned for retirement until 2046.

According to available land parcel information and a review of previous studies for natural gas conversion[52], additional power generation equipment could be located on approximately 9 acres adjacent to the existing plant that would be above the tsunami evacuation zones according to

[50] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[51] Hawaiian Electric's Integrated Grid Plan 2023

[52] PUC Docket No. 2016-0137: Kahe Combined Generating Unit

publicly available geographic information system (GIS) data[53]. The ability to operate the existing Kahe boilers during construction of a new power plant would allow HECO to maintain reliability of the grid without shifting load to other plants.

Adding a new power plant at Kahe adjacent to the existing boilers is a potential option for natural gas replacement due to the available space for expansion, and the proximity to the LNG FSRU pipeline described in the introduction above.

Kalaeloa Partners (KPLP)

KPLP is a combined cycle and cogeneration plant with two combustion turbine generators (CTG) and one steam turbine generator (STG) that use heat recovery steam generators (HRSGs) to capture the heat from the CTG exhaust and generate steam for either the STG or for sending process steam to the fuel refinery nearby. The plant is located in the industrial section of Kapolei and there is limited space around the plant for expansion. The rated capacity of the plant is 208 MW and the heat rate is approximately 7,800 Btu/kWh. The plant operates at a relatively high-capacity factor of 0.5 compared to the other power plants on the island and has a net generation of approximately 1.2 million MWh.[54] The two CTGs are GE (formally ABB), model name 11NM each rated at 85 MW.

During discussions with plant staff, HDR determined converting the existing CTGs to run on natural gas using new dual fuel burners rather than replacing with new CTGs would be the preferred option, because the existing CTGs have had regular overhauls and are designed to operate with natural gas. To maintain plant power and steam output, a single CTG and HRSG could be taken offline and converted while the other continues operation during regular planned maintenance.

KPLP is a preferred potential option for natural gas conversion due to the plant having combustion turbine equipment that is capable of being converted with new burners. Additionally, the proximity to the LNG FSRU pipeline described in the introduction above would reduce costs for gas transmission.

Campbell Industrial Park (CIP)

CIP is a single, simple cycle CTG used for addressing the island's peak loads, and it typically runs at approximately a 0.1 annual capacity factor.[55] The plant was brought online approximately 15 years ago, and its rated capacity is 129 MW with an average heat rate around 11,500 Btu/kWh. The plant is in the industrial section of Kapolei, and there is limited space around it for expansion. The

[53] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

[54] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[55] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

CTG is a Siemens (formally Westinghouse) W501D5A designed to run on diesel and biodiesel. The W501D5A is likely able to be converted to run on natural gas with new combustors.

Due to the proximity of the decommissioned Barbers Point Coal Plant and KPLP, this unit is a preferred potential option for conversion; however, the total gas usage would not be significant if the plant remains a peaker.

Waiau

The Waiau power plant is a 474 MW power plant with six boilers with STGs and two CTGs. The boilers' ages range between 57 and 77 years old and the CTGs are 51 years old. The plant is located in Pearl City, which is approximately 13 miles east of Barbers Point. The average heat rate of the power plant is approximately 11,400 Btu/kWh, and the total generation of the plant is approximately 905,000 MWh annually.[56] Units 3 and 4 are expected to be retired in 2024, units 5 and 6 in 2029, and units 7 and 8 in 2031[57]. Units 9 and 10 are expected to remain in service throughout the analysis period.

An existing oil pipeline feeds Waiau from the Par Refinery, and a gas pipeline runs from the Par Refinery to neighboring towns and cities. The current gas pipeline is meant for home and business use, and the oil pipeline would need to be retained for backup fuel delivery in addition to not being designed for natural gas service. This existing gas pipeline may be able to supply partial capacity for the plant but would need to be further investigated. Adding another 13-mile pipeline adjacent to the existing pipelines could also be further investigated; however, this was not preferred and considered costly.

HECO's proposed Stage 3 repowering project includes dual fuel combustion turbines that could be used with natural gas, despite being purposed for biodiesel.

H-Power

H-Power is a 68.5 MW waste-to-energy plant that reduces landfill space by burning solid waste for electricity generation. This facility is not feasible for conversion due to its unique role in waste management.

Schofield Generating Station

Schofield Generating Station is a peaking plant located at the Schofield Army Barricks that consists of six reciprocating engines for a total capacity of 49 MW. This plant is approximately five years old and runs on biodiesel. This power plant is not recommended for conversion to natural gas due to the age of the plant, distance from the proposed LNG FSRU pipeline described in the introduction above, and use of biodiesel as a fuel, which meets RPS fuel requirements.

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[56] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[57] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

Decommissioned Barbers Point power plant

The Barbers Point Coal Plant was decommissioned in 2022 and is currently being fully demolished. The facility sits on an 8.5-acre plot of land in the industrial section of Kapolei near KPLP and CIP. The property is large enough for a new combined cycle power plant. Its location close to the coast makes it suitable to receive gas from the LNG infrastructure (e.g., FSRU and pipelines) planned at Barbers Point, and existing rights-of-way may be suitable for delivery. Discussions with HECO determined transmission and substation upgrades would be required if a power plant more than approximately 60 MW was built at this location.

Firm Capacity Stage 3 Request for Proposal (RFP) Projects

In 2021, HECO conducted an "all source" procurement process for capacity based on the grid requirements for Oʻahu. HECO awarded the projects described below for the Stage 3 RFP for firm, renewable electricity generation. This study considers the complexities of altering the plant requirements given in the existing proposal, as the projects are already progressing through the RFP process.

Puʻuloa Energy – Ameresco, Inc

HECO selected the Puʻuloa Energy project to provide 99 MW using 11 reciprocating engines operating on biodiesel. This plant will be located on the Pearl Harbor military base, which is about 13 miles east of the proposed LNG FSRU pipeline described in the introduction above. The project is expected to be in service in late 2027. Adding a pipeline could be further investigated; however, this was not preferred and was thought too costly. Future studies could investigate other means of transporting natural gas to this site including utilization of the existing gas line.

Waiau Repower

HECO selected the Waiau Repowering project to provide 253 MW using six CTGs operating on biodiesel. Each CTG is planned to be a 42 MW GE LM6000. The first two units are expected to be in service in 2029 with the next four expected to be in service by 2033[58]. These units are dual fuel and capable of additionally operating on natural gas or hydrogen. As described above, an existing gas pipeline may be able to supply partial capacity for the plant but would need to be further investigated.

KPLP

HECO selected KPLP as a repowering project that will allow the use of biodiesel, which the facility has previously demonstrated to successfully operate on. The units are currently planned to be converted and put into operation in 2033. Based on analysis of biodiesel production and sourcing[59] and discussions with KPLP staff and HECO, HDR decided to consider this site for switching to

[58] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

[59] See Alternative Fuel, Repowering, and Energy Transition Study

natural gas as its primary fuel. See the above section on KPLP for more information on natural gas operation.

Par Hawaiʻi Renewable Combined Heat and Power

HECO selected Par Refinery in the Stage 3 RFP to provide a 30 MW cogeneration facility powered by biodiesel for commercial operation by 2028. Since Par is the biodiesel source, it is not feasible to have this facility converted to natural gas. Since selection, this project has withdrawn from the Stage 3 Award group citing timeline challenges and delay in supply of combustion turbines.[60]

Hawaiʻi Island

Hill and Kanoelehua

The Hill and Kanoelehua plants are located near each other near Hilo Bay. Hill consists of two boilers running on oil with a capacity of 34 MW. Kanoelehua has 20 MW total with a mix of ULSD-fired boilers and one 10.3 MW, No. 2 diesel-fired CTG. Hill is planned for decommissioning in 2028 and the Kanoelehua Combustion Turbine 1 in 2031[61]. However, the existing 10 MW of Kanoelehua diesels are also more than 45 years old, but not scheduled for decommissioning.

These plants are preferred potential options for natural gas replacement due to the planned decommissioning and proximity to a potential LNG onshore transmission terminal. Additionally, the plant is not in a tsunami inundation zone, so future upgrades can be considered.

Keāhole

The Keāhole plant consists of a 50 MW combined cycle and four peaking units totaling 21 MW run on no. 2 diesel and ULSD. The peaking units are between 35 and 40 years old, and the combined cycle is approximately 15 years old. The combustion turbine (CT2) peaking unit is scheduled to be decommissioned in 2031.

The peaking units at this plant are a preferred potential option for natural gas replacement by replacing the units with new ones due to their old age. Since the combined cycle is more efficient and the units are relatively new, the combined cycle is recommended to remain as oil-fired to keep fuel diversity on the island. The plant is not in a tsunami evacuation zones according to publicly available GIS data[62], so future upgrades can be considered.

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[60] Hawaiian Electric Submission to the Hawaiʻi Public Utilities Commission, November 18, 2024. Docket No. 2017-0352 – To Institute a Proceeding Relating to a Competitive Bidding Process to Acquire Dispatchable and Renewable Generation Par Hawaiʻi Refining LLC Notice of Withdrawal.

[61] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

[62] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

Puna Generating Station

The Puna Generating Station, located south of Hilo, consists of a combustion turbine (CT3), which is a GE model LM2500, and a steam boiler totaling 35 MW. CT3 is 32 years old and the steam unit is 54 years old. The steam unit is expected to be placed in standby in 2025[63].

This plant is a preferred potential option for natural gas replacement due to the planned decommissioning and proximity to a potential LNG onshore transmission terminal. CT3 could have burners converted to dual fuel; however, additional discussions are required if this is preferred over procuring new turbines. The plant is not in a tsunami evacuation zones according to publicly available GIS data so future upgrades can be considered.

Waimea Generating Station

The Waimea plant consists of three ULSD-fired boilers totaling 7.5 MW that are more than 51 years old located further inland than the other plants. This plant is not preferred for conversion due to the plant proximity and the relatively small capacity.

Maui

Māʻalaea Power Plant

The Māʻalaea Power Plant consists of four combined cycle CTGs (GE LM2500s) that are 17 to 31 years old. These units are capable of combined cycle or simple cycle operation and are currently planned to remain operational through 2045. The total CTG capacity at the Māʼalaea Plant is approximately 80 MW with combined cycle output of about 112 MW.

Units 1 through 9 are diesel generators all over 45 years old, and decommissioning is planned for 2030.[64] Units 10 to 13 are diesel generators which total approximately 50 MW of capacity are planned for retirement in 2027 due to a lack of spare parts with the manufacturer. Additionally, there are two diesel generators that are not scheduled for retirement during the analysis period.

The power plant is currently in the tsunami evacuation zones according to publicly available GIS data meaning new technologies at this plant could run into regulatory and public roadblocks. Therefore, it was not preferred to convert this plant to natural gas.

Kahului Power Plant

The Kahului Power Plant consists of four boilers and steam turbines running on fuel oil. Units 1 through 4 have been scheduled for retirement by 2028 (32 MW), and units 3 and 4 will be converted to synchronous condensers (no power generation or fuel usage) to provide grid stability.[65]

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[63] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

[64] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

[65] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

The power plant is in the tsunami evacuation zones,[66] therefore new technologies at this plant are not feasible.

Scenario Selection for Potential Viable Pathway

The first iteration of the natural gas conversion analysis involved converting or replacing select power plants on Oʻahu, Maui, and Hawaiʻi Island to run on natural gas based on National Renewable Energy Lab (NREL) grid modeling. However, after an initial lifecycle cost analysis was completed by HDR, the results indicated that delivering gas to all of islands would not benefit the ratepayers, so the decision was made to have LNG delivered to the power plants on Oʻahu only.

A scenario with conversion of certain power plants on Oahu was developed including an estimate of LNG volumes needed. The capital and operating expenditures were modeled to develop the preliminary economics for LNG delivery to this island. As this is a preliminary analysis, future evaluations, including technical, environmental, regulatory, and detailed economics, would be needed to determine the configurations of these power plants.

The preliminary lifecycle cost analysis and cost of service analysis determined that maximizing the consumption of natural gas was economically advantageous, so the addition of new power plants in addition to conversions was preferred. HDR assumed that both the decommissioned Barbers Point Power Plant and Kahe Power Plant sites had sufficient space to build a new dual fuel combined cycle power plant. HDR chose the capacity of a new power plant on the Decommissioned Barbers Point Power Plant site by configuring CTG and steam turbine sizes to meet approximately 200 MW, which was close to the capacity of the previous coal power plant located at that site. For additional flexibility to help balance the increasing renewables planned for Oʻahu, a simple cycle CTG peaker plant was added to the former coal plant site in parallel to the combined cycle. This unit would only operate for peak loads and grid support through its fast-ramping capabilities.

HDR chose the new Kahe combined cycle power plant size to match the analysis included in the Kahe Combined Cycle PUC Application (HECO), which was approximately 350 MW[67]. This size aligned with the capacity to replace Kahe boilers 1 through 4 after those units are retired.

HDR developed a two-phase approach for natural gas conversions and new builds to allow for future analysis and design updates based on updated island energy demands, technological advancements, and actual renewable buildouts over the next decade.

All the proposed conversions consider that the power generation equipment will have dual-fuel burners capable of running on gas or oil with gas as the primary fuel and oil used as backup during longer gas outage durations. The new CTG technology will also be capable of operating on high

[66] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

[67] PUC Docket No. 2016-0137: Kahe Combined Generating Unit

percentages of hydrogen to help meet Hawaiʻi's RPS. Many CTG models are currently able to operate on high percentages of hydrogen with paths to 100% hydrogen in the next 5 to 10 years.

Below is the Phase 1 and 2 summaries along with the assumed capacity factors and total electricity generation for each conversion and new plant used in the economics evaluation. HDR used the capacity factors of 0.6 and 0.1 for base-loaded and peaking plants, respectively. A 0.6 capacity factor is slightly higher than historical operations at KPLP of 0.5 (see section on KPLP above), but from the economic analysis performed for this study, higher usage of LNG was preferred, so the capacity factor was increased to 0.6 which is reasonable for a combined cycle power plant.

Table 1. Phase 1 – In Service by 2030

Site	Capacity Factor	Modifications	Capacity	Electricity Generation
KPLP	0.6	Burner replacements with new gas infrastructure (compressor, gas skids, piping)	208 MW	0.6 x 208 MW = 1.1 TWh
Decommissioned Barbers Point Power Plant Site Combined Cycle (CC) and Simple Cycle (SC) Peaker	0.6 (CC) 0.1 (SC)	New 2 x 1 CC power plant with SC peaker - natural gas and fuel oil infrastructure	156 MW CC 60 MW SC	0.6 x 156 MW = 0.82 TWh 0.1 x 60 MW = 0.06 TWh
TOTAL			424 MW	1.98 TWh

Table 2. Phase 2 – In Service by 2035

Site	Capacity Factor	Modifications	Capacity	Electricity Generation
CIP	0.1	New burners on single CTG SC	129 MW	0.1 x 129 MW = 0.1 TWh
Kahe Combined Cycle	0.6	New 3 x 1 CC- natural gas and fuel oil infrastructure	358 MW	0.6 x 358 MW = 1.9 TWh
TOTAL			487 MW	2.0 TWh

Appendix C - Economic Analysis

Summary

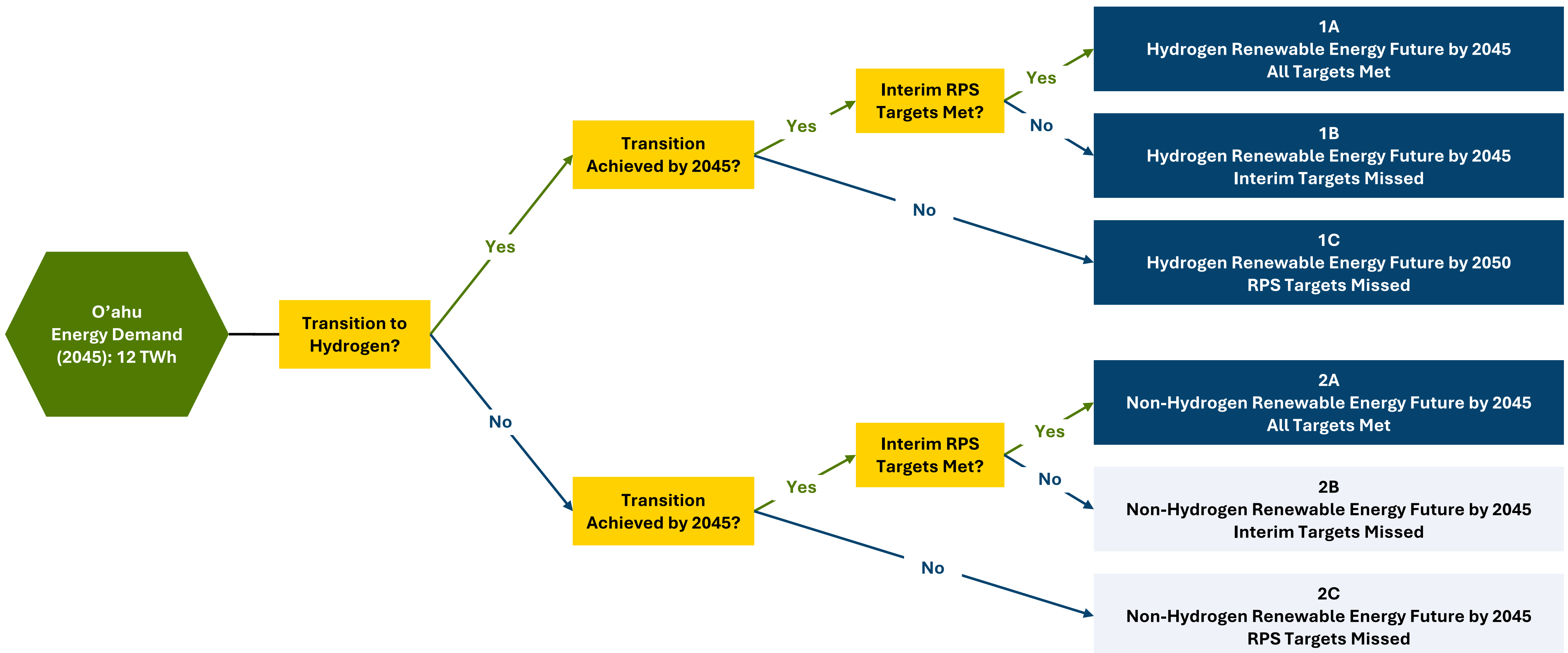
The goal of HDR's economic analysis involved determining the characteristics of a viable pathway that can yield cost savings for ratepayers by implementing a transition to HDR identified and evaluated potential solutions for importing LNG to the island of Oʻahu and implementing natural gas as a bridge fuel for Hawaiʻi's energy initiatives. HDR performed a lifecycle cost analysis to evaluate total costs including upfront capital costs, ongoing operating and maintenance costs, fuel costs, and interim RPS penalties, if applicable, for a base case and a potential build case.

By comparing the lifecycle cost of the base case to a build case, the analysis focuses on the incremental differences specifically attributable to the alternate fuel transition pathway. In cases where the build case results in lower costs than the base case, the results would indicate the cost savings relative to not transitioning to an alternate fuel.

The analysis performed involved an iterative process exploring the potential benefits of introducing LNG infrastructure and determining if the necessary infrastructure to achieve the generation required could be built at a cost less than the cost savings estimated. Based on the initial bookend analysis performed, a key underlying principle was that natural gas would not displace renewable energy. While a renewable energy evaluation was outside HDR's scope of work, the question arose as to whether the projected growth in renewable energy shown in NREL's modeling or Hawaiian Electric's Integrated Grid Plan (IGP), especially by 2030, was achievable. Given the heavy reliance on low sulfur fuel oil (LSFO) in the current grid mix, if there are delays in the construction of renewable energy, or if RPS targets are met just in time, it would be expected that there would be greater use of LSFO than initially projected. In a base case with greater use of LSFO to generate electricity, our analysis can allow for natural gas to displace more LSFO in a build case without impeding the growth of renewables.

HDR's analysis explores several variations in future renewable energy scenarios, each of which incorporates different implicit assumptions that may impact the results of an LNG transition. Under each of the future renewable energy scenarios, we define variations in the defined base case, which impacts how natural gas generation is assumed to operate. As shown in the diagram below, we evaluated two distinct alternative futures, with three sub-alternatives each that lead to a total of six potential solutions.

Figure 1: Future Possibilities Considered



Not depicted – Alternative 3: Alternative 3A generally follows Alternative 1A and Alternative 3B follows 1A. Alternative 3 updates the fuel mix displaced.

Description of Base Case

Across all evaluated alternatives, there are several key consistent assumptions used in the analysis:

- Estimated future energy demand on Oʻahu is 12.4 TWh by 2045[68], and the energy demand is interpolated to estimate demand in the interim years;
- Energy mix not attributed to LSFO is assumed to be generated by renewable sources;
- Weighted average heat rates based on current values, and where applicable, specifications assumed for newly constructed or converted plants, were used to convert fuel cost forecasts to a cost per MWh; and
- Fuel projections were based on forecasts provided by Facts Global Energy (FGE).

Possibilities included under Alternative 1 assume a transition to hydrogen as a firm source of renewable energy. Without any interim LNG infrastructure, significant capital costs to transition to hydrogen, including pipelines, plant conversions, and transmission upgrades, are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets).

Possibilities included in Alternative 2 assume a transition to an undefined non-hydrogen renewable fuel source. Significant capital costs to transition to this undefined renewable fuel source are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets).

Description of Build Case

Across all evaluated alternatives, there are several key consistent assumptions used in the analysis:

- Estimated future energy demand on Oʻahu is 12.4 TWh by 2045, and the energy demand is interpolated to estimate demand in the interim years;
- LNG infrastructure is introduced only on Oʻahu and only offsets generation from LSFO unless otherwise stated (e.g. Alternative 3);
- Weighted average heat rates based on current values, and where applicable, specifications assumed for newly constructed or converted plants, were used to convert fuel cost forecasts to a cost per MWh;
- Fuel projections were based on forecasts provided by FGE; and
- Significant portions of LNG infrastructure can be re-used for hydrogen applications, minimizing stranded assets and preparing Hawaiʻi for a conversion to 100 percent renewable energy for 2045.

[68] Based on Hawaiian Electric Pathways Conservative Load Forecast.

All scenarios rely on a consistent staggered deployment of LNG infrastructure contained in the LNG Import Study Technical Documentation. By 2030, 424 MW of capacity of natural gas is installed that can generate up to 2 TWh of electricity. By 2035, an additional 487 MW of capacity has been converted to natural gas, which can be used to generate another 2 TWh of electricity. It is assumed that LNG remains economically viable to be dispatched for a maximum of 4 TWh, unless constrained by RPS targets.

Possibilities included under Alternative 1 assumes a transition to hydrogen as a firm source of renewable energy. With a future transition to hydrogen, significant portions of the initial capital investment in LNG infrastructure can be re-used for hydrogen when it becomes part of the energy mix. The capital costs incurred in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets) are minimal relative to the base case.

Possibilities included in Alternative 2 explore a transition to an undefined non-hydrogen renewable fuel source, which does not allow for the re-use of LNG infrastructure. Significant capital costs to transition to this undefined renewable fuel source are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets), identical to the base case.

Overview of Evaluated Alternatives

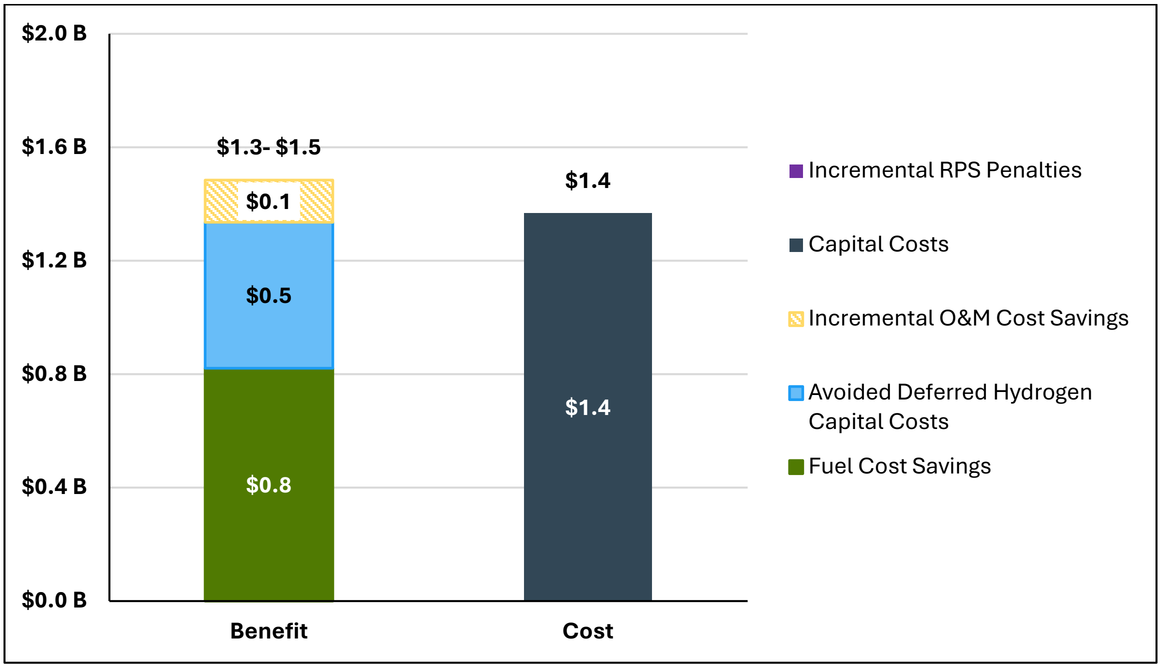
Alternative 1A: Transition to Hydrogen by 2045, All RPS Targets Met

In Alternative 1A, it is assumed that by 2045, Oʻahu has met all interim RPS targets and is utilizing hydrogen as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2040, LSFO generation is curtailed below 4 TWh due to increasingly stringent RPS targets, before being phased out in 2045.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2040, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2040, LNG is curtailed to comply with RPS standards, before being phased out in 2045. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2040 and 2045 are significantly reduced.

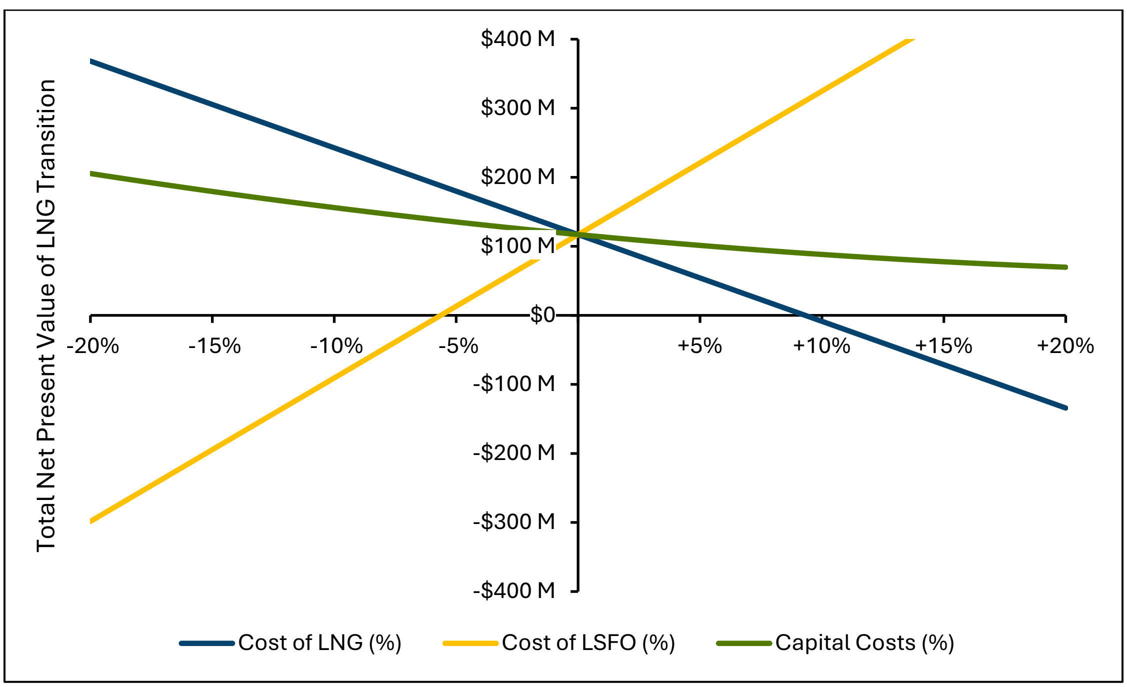
The benefits of an interim transition to natural gas exceed the costs, with a net present value of about $150 million, as shown in Figure 2. The levelized cost savings from an LNG transition are $10.2/MWh, which equates to residential energy cost savings of about 2.6 percent (approximately $61 in savings per year). With the most stringent version of Alternative 1, an LNG transition is shown to generate benefits more than its costs, which can provide cost savings to ratepayers, relative to a base case where no LNG infrastructure is constructed.

Figure 2: Net Present Value of LNG Transition Under Alternative 1A



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 10%, LSFO prices do not decrease by more than 5%, or capital costs do not increase by more than 20%. As can be seen in Figure 3, there is potential to see cost savings well more than the initial $150 million.

Figure 3: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1A



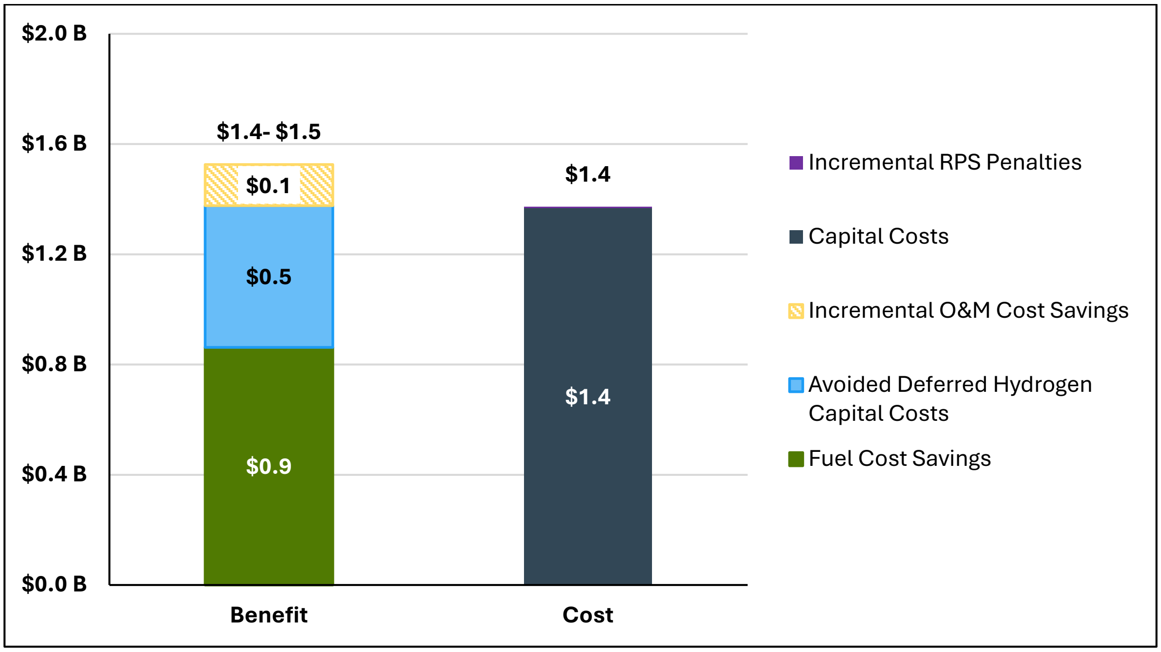
Alternative 1B: Transition to Hydrogen by 2045, Some RPS Targets Met

In Alternative 1B, it is assumed that by 2045, Oʻahu has met most interim RPS targets and is utilizing hydrogen as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2040, LSFO generation continues to account for 4 TWh due to either the delayed implementation of renewable generation, maintaining grid stability, or minimizing costs to ratepayers before being phased out in 2045. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2045, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2045, LNG is phased out in place of hydrogen. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2040 and 2045 are significantly reduced.

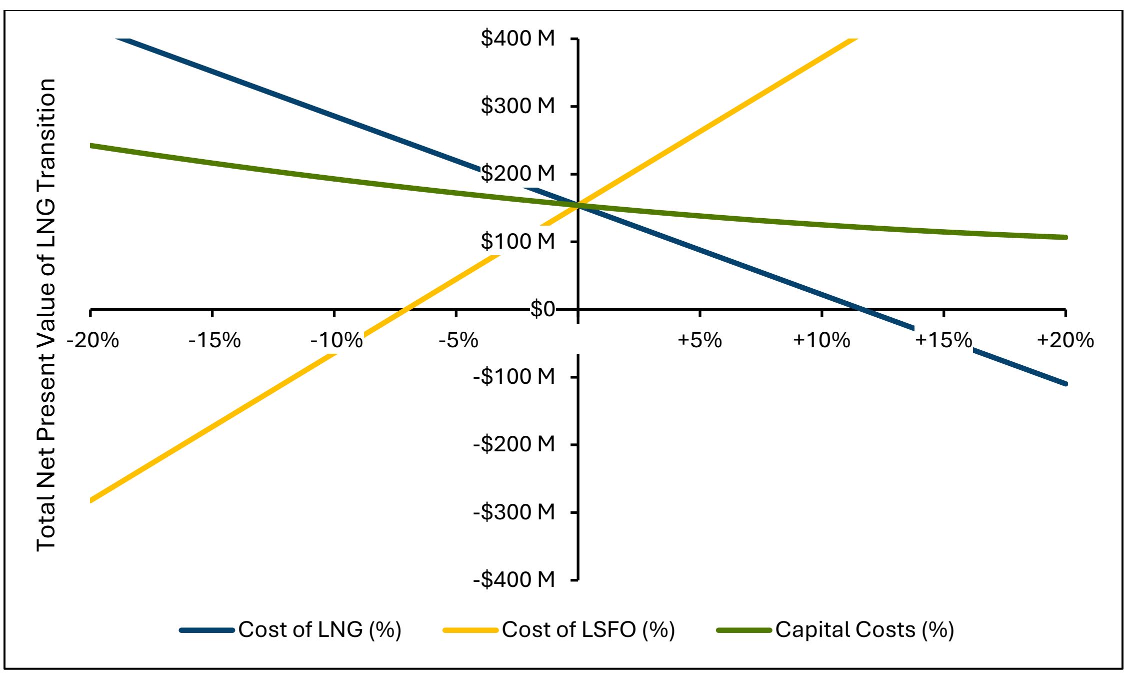
The additional fuel cost savings from increased non-renewable generation between 2040 and 2045 result in the net present value increasing to about $187 million, as shown in Figure 4. The levelized cost savings from an LNG transition are $12.2/MWh, which equates to residential energy cost savings of about 3.2 percent (approximately $73 in savings per year). If more non-renewable generation is required than allowed for under the RPS targets, a transition to natural gas generation will save ratepayers more than if LFSO were consumed instead.

Figure 4: Net Present Value of LNG Transition Under Alternative 1B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 12%, LSFO prices do not decrease by more than 7%, or capital costs do not increase by more than well over 20%. As can be seen in Figure 5, there is potential to see cost savings well over the initial $187 million.

Figure 5: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1B



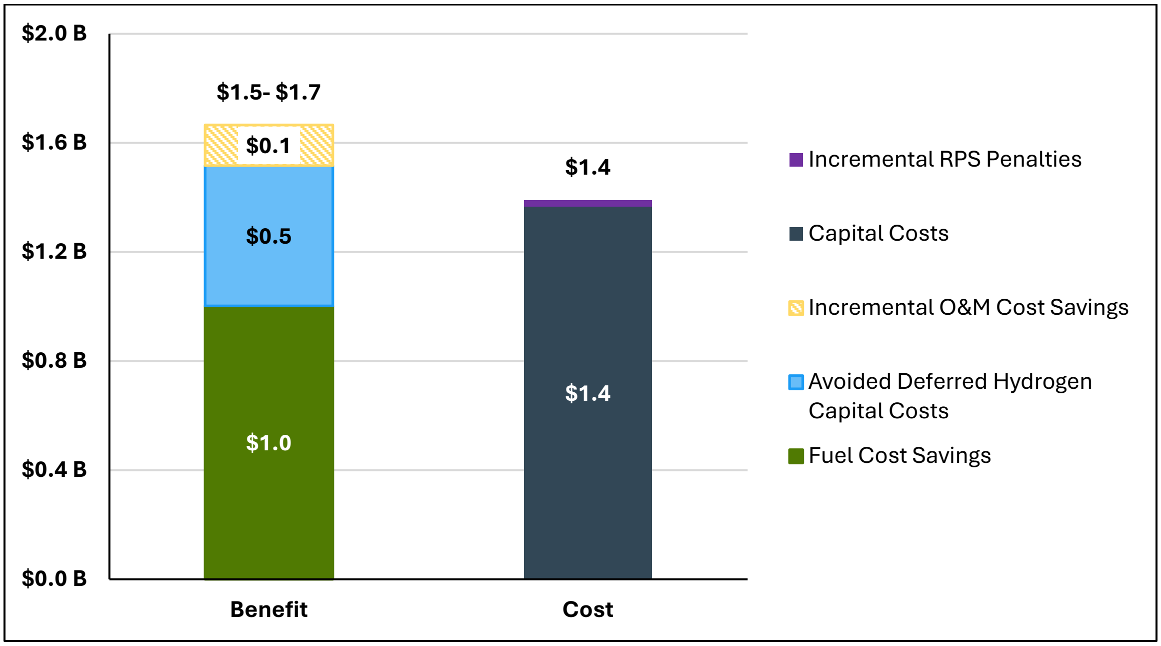
Alternative 1C: Transition to Hydrogen by 2050

In Alternative 1C, it is assumed that the transition to a 100% renewable electric grid has been delayed by 5 years. While interim RPS targets beyond 2040 are assumed to not be met, by 2050, hydrogen is utilized as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2045 and 2050 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2046, LSFO generation steps down to 2 TWh to account for the first phase of hydrogen generation being deployed, before being fully phased out in 2050. It is acknowledged that this scenario results in the RPS target in 2040 and 2045 not being met, and penalties are calculated accordingly. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2046, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2046, LNG is curtailed to 2 TWh to account for the first phase of hydrogen generation, before phased out entirely by 2050. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2045 and 2050 are significantly reduced.

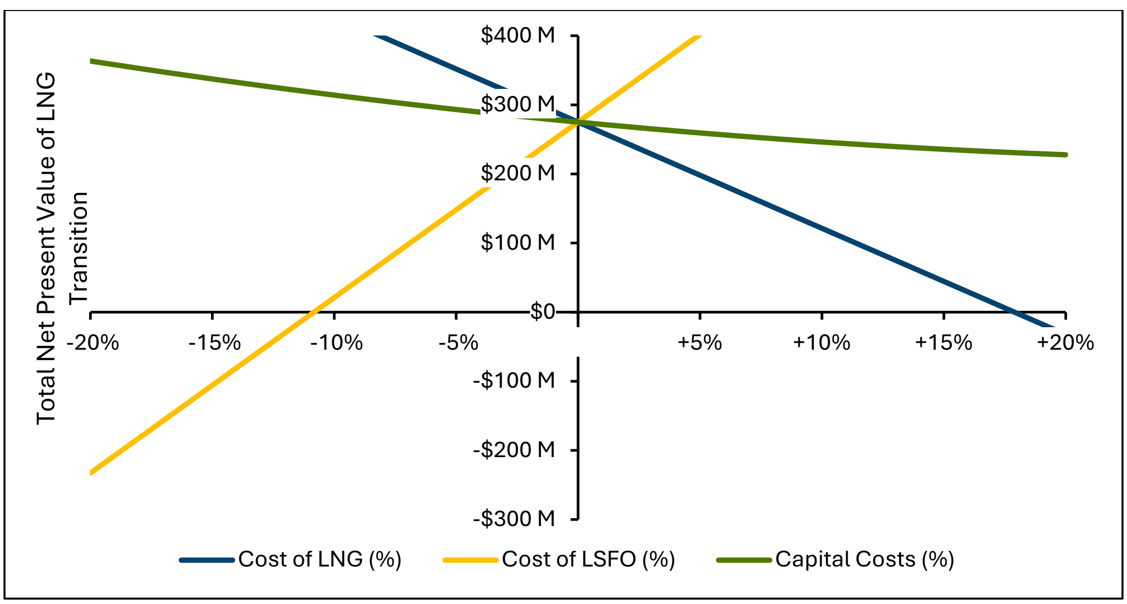
The additional fuel cost savings from increased non-renewable generation between 2040 and 2049 result in the net present value increasing to about $308 million (Figure 6). The levelized cost savings from an LNG transition are $17.8/MWh, which equates to residential energy cost savings of about 4.6 percent (approximately $107 in savings per year). If the implementation of a fully renewable energy grid is delayed, a transition to natural gas generation will save ratepayers more than if LFSO were burned instead.

Figure 6: Net Present Value of LNG Transition Under Alternative 1C



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 18%, LSFO prices do not decrease by more than 11%, or capital costs do not increase by more than well over 20%. As can be seen in Figure 7, there is potential to see cost savings well over the initial $308 million.

Figure 7: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1C



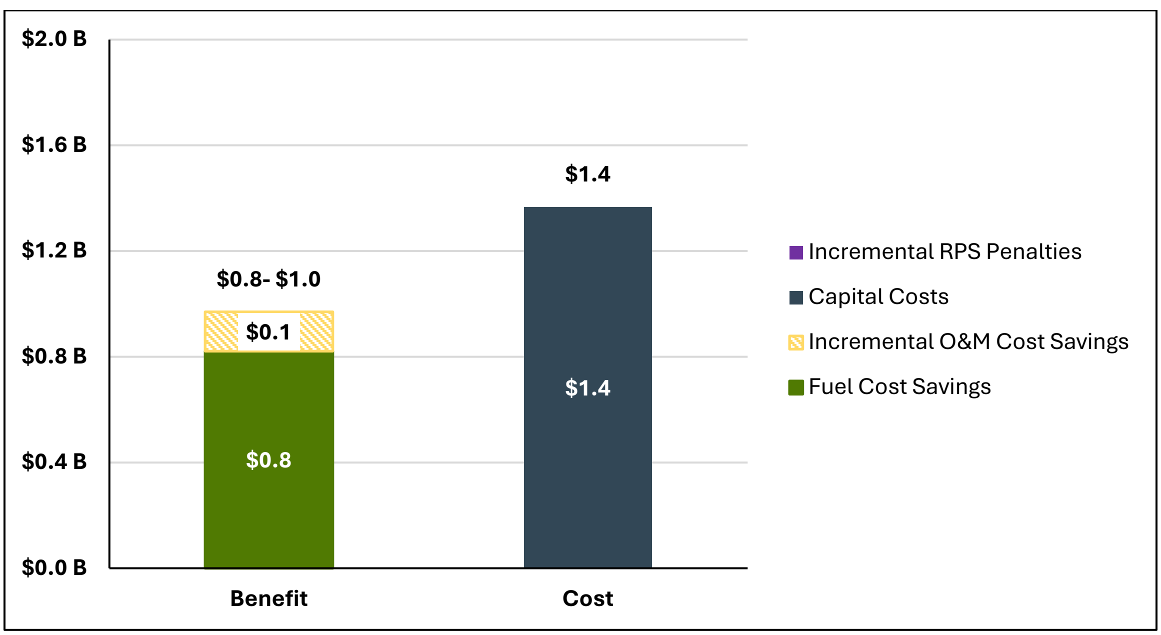
Alternative 2A: Transition to Non-Hydrogen Fuel by 2045, All RPS Targets Met

In Alternative 2A, it is assumed that by 2045, Oʻahu has met all interim RPS targets and is utilizing an undefined renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades to prepare for the implementation of a new renewable fuel. Beyond 2040, LSFO generation is curtailed below 4 TWh due to increasingly stringent RPS targets, before being phased out in 2045.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2040, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2040, LNG is curtailed to comply with RPS standards, before being phased out in 2045. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2040 and 2045.

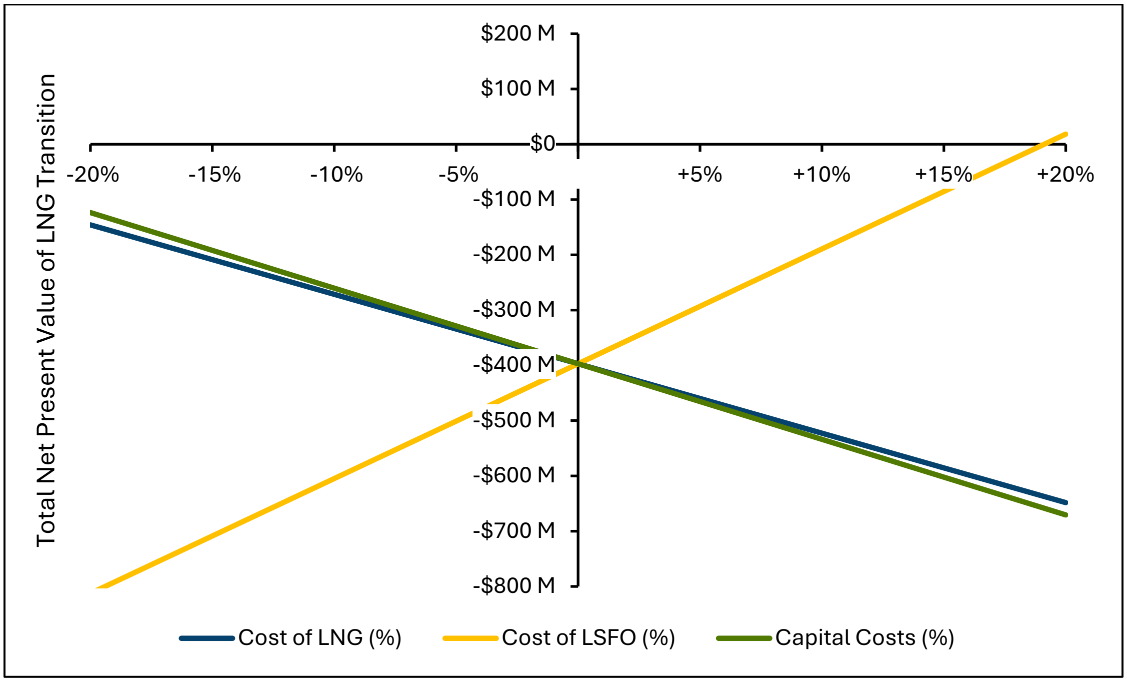
Without the benefit of re-using the LNG infrastructure, the benefits of an interim transition to natural gas do not exceed the costs, with a net present value of about -$364 million (Figure 8). The levelized cost increase from an LNG transition is $24.6/MWh, which equates to a residential energy cost increase of about 6.4 percent (approximately $148 in additional electricity costs per year). With the most stringent version of Alternative 2, an LNG transition is shown to generate costs above its benefits, which can result in negative impacts to ratepayers, relative to a base case where no LNG infrastructure is constructed.

Figure 8: Net Present Value of LNG Transition Under Alternative 2A



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. Significant changes to the base assumptions would be required in order for an LNG transition to generate cost savings without re-using the infrastructure for future renewable energy needs, as can be seen in Figure 9.

Figure 9: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2A



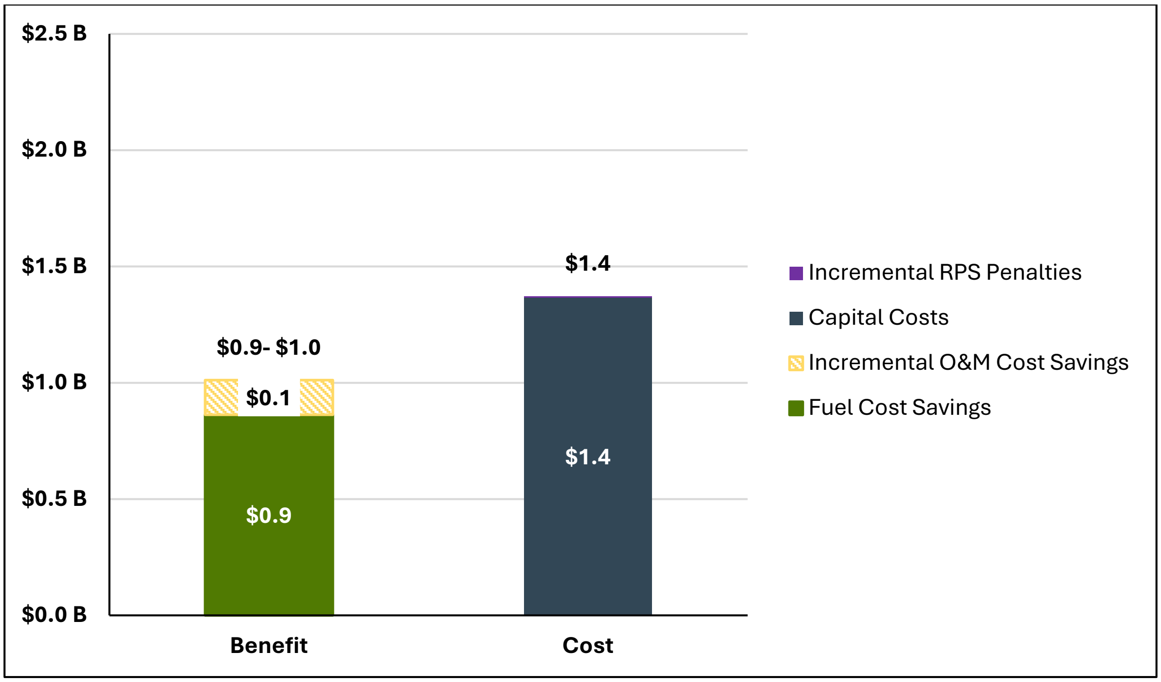
Alternative 2B: Transition to Non-Hydrogen by 2045, Some RPS Targets Met

In Alternative 2B, it is assumed that by 2045, Oʻahu has met most interim RPS targets and is utilizing an undefined renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to prepare for the implementation of a new renewable fuel. Beyond 2040, LSFO generation continues to account for 4 TWh due to either the delayed implementation of renewable generation, assisting to maintain grid stability, to minimize costs to ratepayers before being phased out in 2045. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2045, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2045, LNG is phased out in place of an undefined renewable firm fuel source. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2040 and 2045.

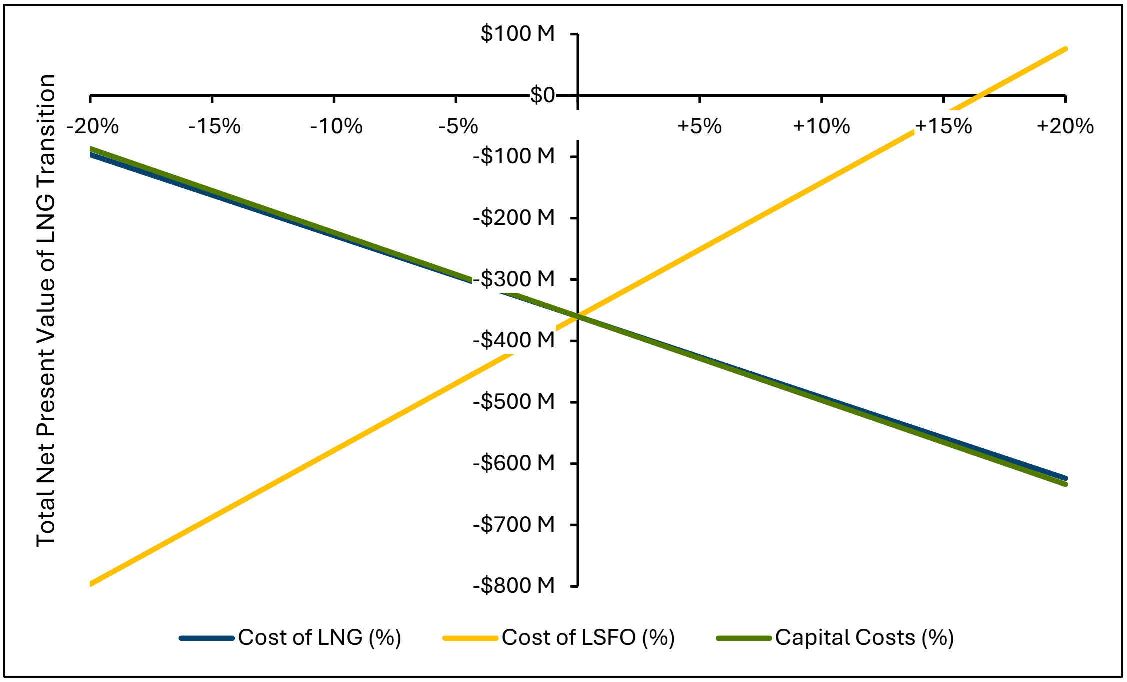
The additional fuel cost savings from increased non-renewable generation between 2040 and 2045 result in the net present value increasing, though still falling approximately $327 million short of covering the infrastructure costs, as shown in Figure 10. The levelized cost increase from an LNG transition is $21.2/MWh, which equates to an estimated residential energy cost increase of about 5.5 percent (approximately $127 in additional electricity costs per year).

Figure 10: Net Present Value of LNG Transition Under Alternative 2B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices or capital costs decrease by more than 20%, or LSFO prices increase by more than 17%. There are significant hurdles to show a transition being cost-effective if the LNG infrastructure cannot be re-used as part of a fully renewable energy solution (Figure 11).

Figure 11: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2B



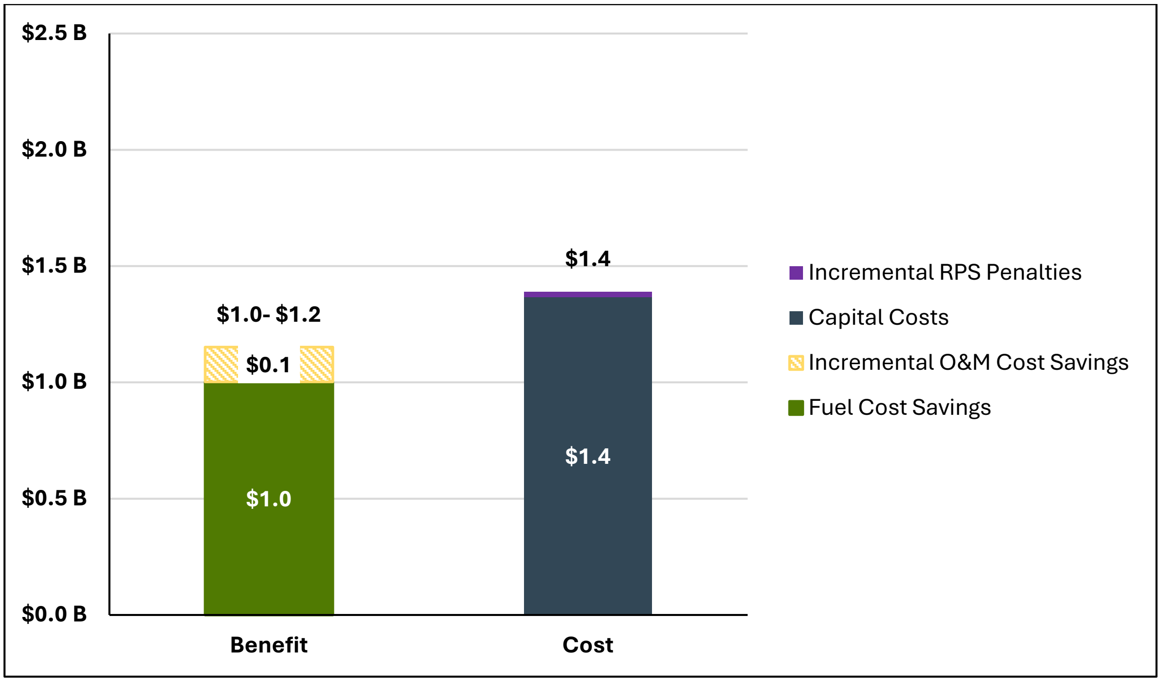
Alternative 2C: Transition to Non-Hydrogen by 2050

In Alternative 2C, it is assumed that the transition to a 100% renewable electric grid has been delayed by 5 years. While interim RPS targets beyond 2040 are assumed to not be met, by 2050, an undefined firm fuel source is utilized as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2045 and 2050 to prepare for the implementation of a new renewable fuel. Beyond 2046, LSFO generation steps down to 2 TWh to account for the first phase of a non-hydrogen renewable fuel generation being deployed, before LSFO is fully phased out in 2050. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2046, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2046, LNG is curtailed to 2 TWh to account for the first phase of an undefined renewable firm fuel source. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2045 and 2050.

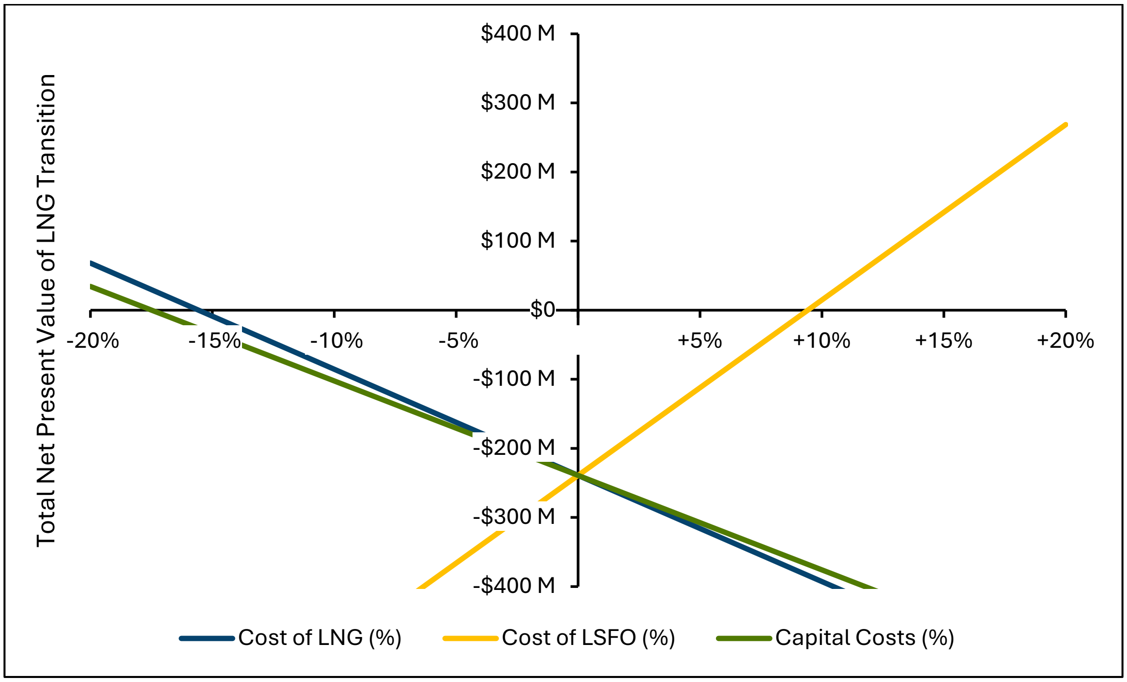
The additional fuel cost savings from increased non-renewable generation between 2040 and 2049 result in the net present value increasing, though still falling approximately $206 million short of covering the infrastructure costs, as shown in Figure 12. The levelized cost increase from an LNG transition is $11.9/MWh, which equates to a residential energy cost increase of about 3.1 percent (approximately $71 in additional electricity costs per year).

Figure 12: Net Present Value of LNG Transition Under Alternative 2C



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices decrease by more than 16%, capital costs decrease by more than 17%, or LSFO prices increase by more than 9%. Delays in implementing a fully renewable electric grid still is not enough to make LNG infrastructure cost-effective if the infrastructure cannot be re-used as part of a fully renewable energy solution (Figure 13).

Figure 13: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2C



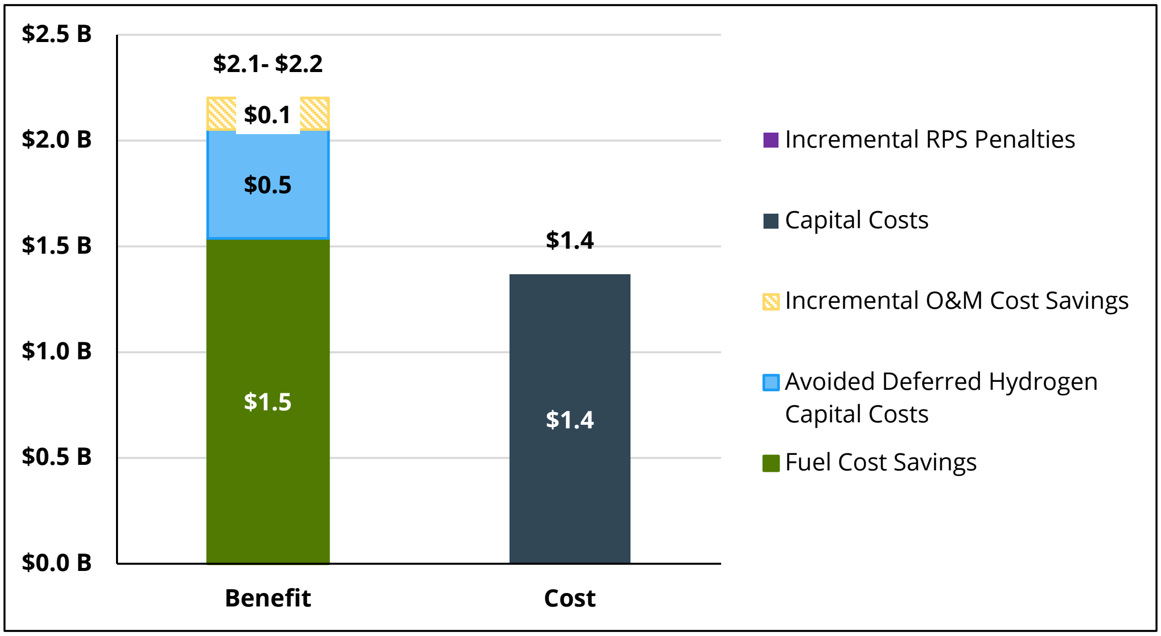
Alternative 3A: Transition to Hydrogen Fuel by 2045, All RPS Targets Met, Adjusted Displaced Fuels

In Alternative 3A, a more optimistic future scenario where a transition to hydrogen results in the re-use of LNG infrastructure, similar to Alternative 1A is explored. Unlike Alternative 1A, where LNG displaces LSFO, PLEXOS energy modeling runs with and without LNG. The data indicated that with the introduction of LNG, the major fuels displaced included a mix of LSFO, utility-scale solar, and biodiesel. The weighted average fuel costs of this mix are substantially higher than the average fuel costs of just LSFO, resulting in significantly higher fuel cost savings when measuring against a transition to LNG. Additionally, there would likely be some avoided generation capacity costs as some of these newly constructed solar arrays or biodiesel plants could be avoided altogether, though this has been excluded from HDR's analysis.

Assuming in this solution that the RPS targets are met, LNG is fully phased out by 2045, and significant portions of LNG infrastructure are repurposed for hydrogen, this adjustment to the energy mix offset by LNG significantly increases the fuel cost savings, and when combined with avoided deferred hydrogen capital costs, approximately doubling the benefit.

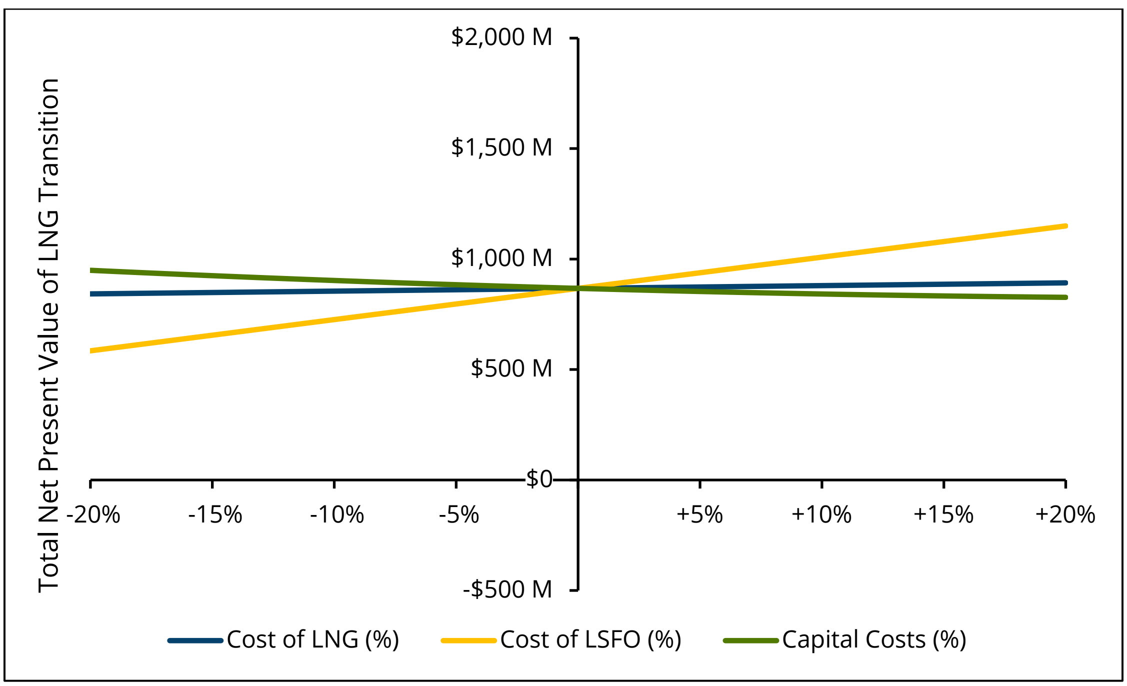
With the adjusted fuel mix displaced by natural gas, the benefits of an interim transition to natural gas exceed the costs, with a net present value of about $867 million. The levelized cost savings from an LNG transition are $59/MWh, which equates to residential energy cost savings of about 15.2 percent (approximately $352 in cost savings per year) (Figure 14).

Figure 14 Net Present Value of LNG Transition Under Alternative 3A



Under a sensitivity analysis conducted, there is potential to see cost savings more than the initial $867 million. With relaxing the RPS standards or assuming a potential 5-year delay in the transition to renewable energy (mirroring Alternatives 1B or 1C), the benefits of transitioning would be even greater than the results shown, and greater savings could be passed on to ratepayers (Figure 15).

Figure 15 Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3A



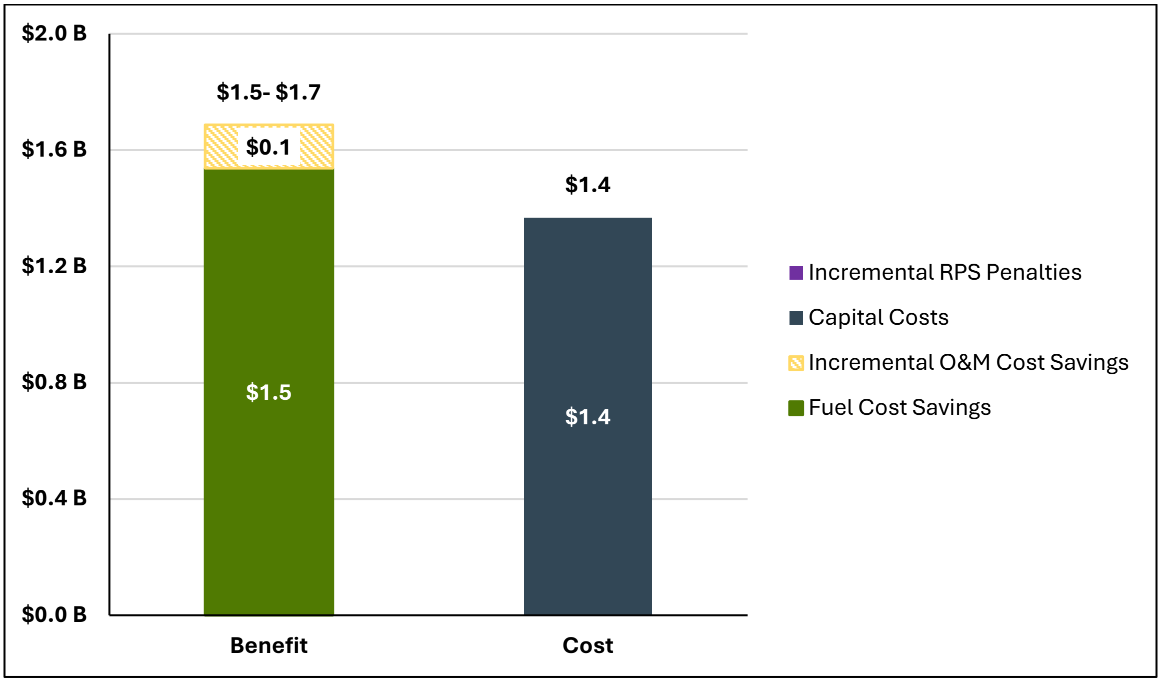
Alternative 3B: Transition to Non-Hydrogen Fuel by 2045, All RPS Targets Met, Adjusted Displaced Fuels

Alternative 2 established the need for infrastructure to be re-used to generate benefits for ratepayers because the fuel savings and operational efficiencies from displacing LSFO are not enough to cover the capital costs for the necessary LNG infrastructure. However, in Alternative 3A, we take Alternative 2A and make one key change to explore the impacts if the fuel mix displaced changes. Instead of assuming LNG displaces LSFO, we rely on PLEXOS energy modeling runs with and without LNG. The data indicated that with the introduction of LNG, the major fuels displaced included a mix of LSFO, utility-scale solar, and biodiesel. The weighted average fuel costs of this mix is substantially higher than the average fuel costs of just LSFO, resulting in significantly higher fuel cost savings when measuring against a transition to LNG. Additionally, there would likely be some avoided generation capacity costs as some of these newly constructed solar arrays or biodiesel plants could be avoided altogether, though this has been excluded from HDR’s analysis.

Assuming in this solution that the RPS targets are met, LNG is fully phased out by 2045, and significant portions of LNG infrastructure cannot be repurposed for a non-hydrogen fuel, this adjustment to the energy mix offset by LNG still significantly increases the fuel cost savings, approximately doubling the benefit, and indicating a positive net present value, unlike Alternative 2A.

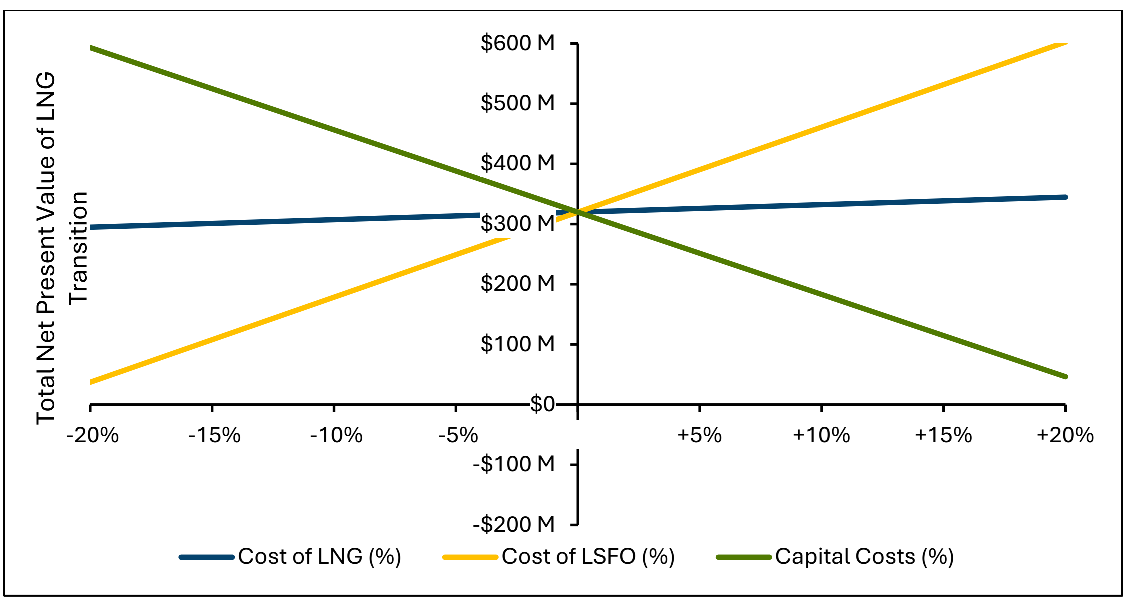
With the adjusted fuel mix displaced by natural gas, the benefits of an interim transition to natural gas exceed the costs, with a net present value of about $353 million (Figure 16). The levelized cost savings from an LNG transition are $23.9/MWh, which equates to residential energy cost savings of about 6.2 percent (approximately $143 in cost savings per year). If displacing more expensive fuels than LSFO, even without the re-use of LNG infrastructure as part of a future firm renewable generation source, the transition cost can yield cost savings to ratepayers.

Figure 16: Net Present Value of LNG Transition Under Alternative 3B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if variables do not change more than 20% from the initial base values (Figure 17), there is potential to see cost savings well above the initial $353 million. By relaxing the RPS standards or assuming a potential 5-year delay in the transition to renewable energy (mirroring Alternatives 2B or 2C), the benefits of transitioning would be even greater than the results shown, and greater savings could be passed on to ratepayers.

Figure 17: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3B



Economic Analysis - Conclusions

From the scenarios evaluated, key conclusions can be drawn. Viable pathways exist that allow for the staggered implementation of LNG that can result in cost savings to ratepayers while still adhering to RPS targets. Planned re-use of constructed infrastructure will both maximize cost savings and help prepare for a final transition to a fully renewable firm fuel. Another important consideration is the fuel that natural gas is assumed to be displacing. While displacing LSFO will reduce reliance on one volatile fuel source, some other renewable fuels, like biodiesel, are projected to be more costly than LSFO. The fuel mix displaced by natural gas drives cost savings, and as seen between Alternative 1A and 3A, can yield significant differences in cost savings. With the planned re-use of LNG infrastructure for a hydrogen transition in 2045, the incremental levelized cost of energy will be reduced by between 2.1 percent (Alternative 1A) and 14.6 percent (Alternative 3) under the baseline assumptions.

LNG can also act as a potential hedge to mitigate risk. In the event of increased reliance on firm generation, or if the transition to a fully renewable grid takes longer than expected, natural gas yields greater benefits to ratepayers while also reducing emissions prior to getting to a fully renewable grid. The new infrastructure built would offer network resiliency and increased generation capacity, along with reduced volatility of fuel prices, which are important benefits of an LNG transition to consider that are not monetized in the economic analysis itself.

Appendix D - LNG Import Evaluation

Summary

Included in this Technical Documentation is an overview of relevant LNG storage, transportation, and regasification technologies, which provides necessary background for this study. Additionally, HDR incorporated a summary of the engineering analysis that took place during this project to provide context into key decisions. This Technical Documentation culminates with a description of the proposed solution including LNG infrastructure, demand requirements, potential sourcing options, capital expenses, and other details relevant to establishing LNG as a fuel source on Oʻahu.

HDR identified and evaluated potential solutions for importing LNG to the island of Oʻahu and implementing natural gas as a bridge fuel for Hawaiʻi's energy initiatives. We assessed the technical feasibility of various LNG supply chain options and developed a phased approach for implementing LNG and natural gas infrastructure that can reduce emissions when compared to Oʻahu's current energy ecosystem and initiate Hawaiʻi's path to meeting its net-zero goal in 2045.

At a high level, the solution proposes a floating storage and regasification unit (FSRU) moored off Barbers Point, Oʻahu; a subsea pipeline connecting the FSRU and Oʻahu and developing and converting new and existing power generation facilities to consume natural gas. HDR split the approach into two phases to provide a grace period between specific development milestones. This added flexibility allows Hawaiʻi to adapt in the future and confirm renewable portfolio standard (RPS) targets are met based on shifts in energy demand, technological advancements, and performance of intermittent fuel sources compared to today's projections. Additionally, this approach nearly eliminates stranded assets without compromising consumer energy costs, grid reliability, or resiliency. Table 1 below summarizes the proposed LNG approach.

Table 1. Phase Approach Summary

Title	Construction Period	Key LNG Infrastructure
Phase 1	2027 to 2030	FSRU and Buoy System Subsea Pipeline Onshore Pipeline to Barbers Point Combined Cycle and Kalaeloa Partners LP (KPLP) Locations
Phase 2	2031 to 2035	Onshore Pipeline to Kahe Power Plant (Kahe) and Campbell Industrial Park (CIP) Locations

Summary of LNG Infrastructure

Subsea Pipeline

- A pipeline that is laid on the seabed or below it inside a trench.

- FSRU comes equipped with Submerged Turret Loading (or similar technology) for gas transfer to a subsea pipeline.

International Organization for Standardization (ISO) Containers

- Vacuum-insulated, cryogenic tanks encased in a standard, container-type box frame and approved for truck transport and shipping by container vessel.
- Shipped like cargo from the mainland and transported from the port to an onshore storage location via trucks.
- ISO containers typically hold up to 10,000 gallons of LNG.

Onshore Storage Vessels

- Storage tank engineered to keep LNG below its vaporization temperature.
- Storage volumes and configurations can vary widely depending on need.

Overview of LNG Technologies

FSRU

An FSRU has the capacity to act similarly to a land-based terminal with the added benefit of minimizing the footprint on land. These units can receive, store, and vaporize LNG and distribute natural gas to facilities and pipelines on shore[69]. They are highly customizable to meet a variety of parameters including flow rate, storage volume, mooring, etc. Table 2 provides examples of FSRU vessels put into service. Storage capacity of FSRUs ranges from 125,000 m^3 to 170,000 m^3.

Table 2. FSRU Examples

Ship Name	Excelsior	Excellence	Excelerate	Explorer
Year Built	January 2005	May 2005	October 2006	March 2008
Cargo Capacity (100%)	138,000 cubic meters (m^3)	138,000 m^3	138,000 m^3	150,900 m^3
Length (meters)	277.00	277.00	277.00	291.00
Beam (meters)	43.4	43.4	43.4	43.4
Draft (meters)	12.32	12.32	12.32	12.4
Deadweight Tonnage (metric ton [mt])	77,288	77,288	77,288	82,000
Gross Tonnage (mt)	93,719	93,719	93,719	108,000
Service Speed (knots)	19.1	19.1	19.1	19.1

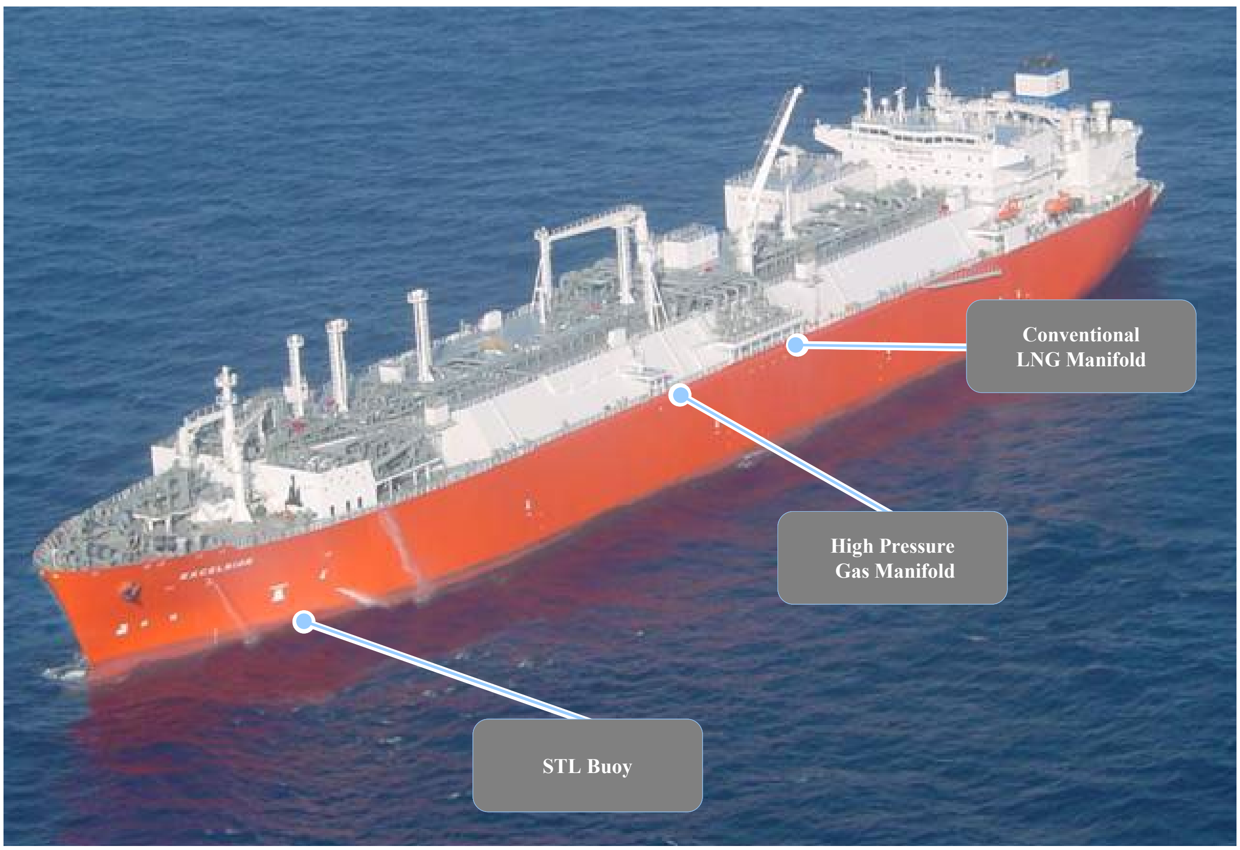
[69] FSRU - Excelerate Energy

A typical FSRU stores about 138,000 m^3 of LNG, which converts to approximately 2.8 billion cubic feet of natural gas. Discharge pressure is up to 1,000 pounds per square inch gauge (psig) at a temperature of 40 degrees Fahrenheit (°F).

Figure 18 depicts the "Excelsior" LNG FSRU showing:

- The compartment for the submerged turret loading (STL) buoy for gas transfer to onshore via a subsea pipeline.
- The high-pressure manifold for transfer of gas on a dockside application.
- A conventional LNG manifold for LNG ship-to-ship transfer via flexible hoses.

Figure 18. Overview of Gas Transfer Connections



LNG Transfer

Since 2006, composite hoses have been used for the transfer of LNG from ship to ship in benign environments for small and medium-scale LNG services.

Figure 19. Ship-to-Ship Transfer via Flexible Hoses

Loading and unloading of LNG carrier (LNGC) vessels in an offshore location is challenging and includes several risks. Due to dynamic motion inherently associated with the LNGC and FSRU while connecting, disconnecting, and transferring LNG, accidents can happen through a marine transfer hose during any of the operational phases. Operational issues related to the high-dynamic motions involved in offshore LNG transfer are an important safety concern, which should be investigated in detail. It is critical to review the terminal site's weather data and historical events thoroughly to assess the effects of waves, wind, and tide and identify the required design features for the selected marine transfer system.

LNGC Vessels

An LNGC vessel, otherwise known as an LNG tanker, carrier, or ship, is designed to transport LNG from one location to another. They vary from typical cargo ships in many ways owing to the necessary equipment to load and unload, store, and handle a cryogenic fluid. These vessels maintain an incredible safety record. Over the more than 50-year history of delivering LNG across the world via ship, vessels have traveled over 150 million miles without major incident[70]. Pictured in Figure 20 is an example of an LNGC.

Figure 20. LNGC – "Marvel Pelican"[71]

Summary of Work

This section summarizes the work that ultimately led to the final solution proposed in the following Final Supply Chain Summary section of this report, providing a greater context into the various considerations throughout the evaluation.

The initial driver for the required LNG infrastructure was the natural gas demand for the State. This included multiple factors such as onshore storage volume and technique, pipeline size, FSRU size, etc. HDR was provided with previously compiled reference documentation to begin the analysis. After noting discrepancies in the documentation, the team endeavored to establish its own natural gas demand estimations for the state to create "bookends" to design toward. These bookends were the foundation for the scenario design moving forward.

The team began with Oʻahu. It was apparent an FSRU would be ideally suited to serve the island's natural gas storage needs. Excelerate Energy, experts in floating storage and regasification, were consulted to aid in cost estimation, proper sizing, and applications of the FSRU.

Initially, the teams plan for Oʻahu included:

[70] 2015, 06-30 LNG Safety

[71] MARVEL PELICAN, LNG Tanker – Details and current position – IMO 9759252 – VesselFinder

- An FSRU moored off Barbers Point, including a subsea pipeline to connect the FSRU to the island.
- An onshore LNG import terminal with a field-erected storage tank and vaporization equipment at Pier 9 in Barbers Point Harbor.
- New and repowered natural gas power generation facilities on Oʻahu.
- New onshore underground natural gas pipelines creating a network between the subsea line, the import terminal, and natural gas power generation facilities.

Concerns regarding a single point of failure at any one power generation facility and the increased permitting and community challenges associated with a large onshore storage tank were discussed. This, along with further analysis of neighboring islands and other variables resulted in an amended approach. This phased design incorporated the following.

Phase 1 – Oʻahu:

- An FSRU moored off Barbers Point, including a subsea pipeline to connect the FSRU to the island.
- A new natural gas power generation facility.
- New onshore underground pipeline connecting the subsea line to the natural gas power generation facility.

Phase 2A – Oʻahu:

- An articulated tug barge (ATB) route from the FSRU to a new ATB/LNG import terminal.
  - ATB would transfer LNG to ISO containers for transport
- New natural gas power generation facility
- New onshore underground pipeline connecting the new power generation facility to the natural gas supply pipeline network.

Following feedback from HSEO, the neighboring islands were removed from consideration and the final phased approach outlined in the following Final Supply Chain Summary section was developed. Many additional items were removed from consideration to avoid over buildout of infrastructure and to save capital costs.

Final Supply Chain Summary

The final supply chain process described below is the result of an iterative process described earlier in the Summary of Work section. The final solution was split into two phases, Phase 1 is scheduled to be in-service in 2030 with Phase 2 following in 2035. HDR developed the phased approach to allow for additional flexibility for updated energy demands, technological advancements, and other driving information as it becomes available over the next decade. The effectiveness of the solution is heavily reliant on the island's cumulative natural gas demand. Below Table 3 and Table 5 show the estimated natural gas demand for the facilities to be introduced to Oʻahu during each phase. HDR calculated these values based on proposed facilities generation capacity, expected facility efficiency, heat rate values, facility capacity factors, etc.

Existing fuel oil storage will be left in place and utilized for fuel backup needs and new engines would all be dual fuel engines able to switch between gas and diesel or biodiesel if necessary for backup. Keeping in mind the overarching goal set in the RPS, natural gas turbines and other infrastructure will be compatible with hydrogen service for a future conversion to hydrogen-based power generation. Pipelines may be

Phase 1

Phase 1 introduces natural gas on a large scale to the island of Oʻahu. An FSRU with a storage volume of about 180,000 m^3 will be moored about two miles off Barbers Point. An advanced buoy system will be installed to verify safe operation. In detailed design, HDR will further analyze the waters in which the FSRU will be moored. This vessel will be the island's main source of natural gas for power generation purposes. Detailed specifications of the FSRU will be determined during detailed design. The FSRU will be filled via LNGC at regular intervals to maintain the stored volume. The product will be sourced most likely from Canada or Mexico due to Jones Act requirements. A subsea pipeline will be built to connect the FSRU to the existing and new pipeline network on Oʻahu, and this pipeline will be sized to accommodate the design send-out flow rate from the FSRU. Based on preliminary calculations shown below in Table 3 and Table 5 the pipeline will have a diameter of 16 inches, and these calculations will need refined and confirmed during detailed design.

During Phase 1, natural gas power plants will be modified and developed at two locations: the KPLP and Barbers Point Combined Cycle site (De-commissioned Coal Plant). KPLP currently operates a 208 megawatt (MW), combined-cycle co-generation plant that combusts low sulfur fuel oil (LSFO)[72]. The facility will be modified with natural gas-burning infrastructure including burners, compressors, gas skids, piping, etc. The De-commissioned coal plant was previously a medium-sized, coal-fired electrical power station but was closed in September of 2022[73]. A 2 x 1 combined-cycle natural gas power plant with a simple cycle peaking unit will be built at this location. Table 3 provides power generation and gas demands for both proposed power plants.

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[72] What We Do | Kalaeloa Partners Lp

[73] AES Marks the Retirement of Hawaiʻi Power Plant While Expanding with Renewable Energy Projects Statewide | AES Hawaiʻi

Table 3. Phase 1 Power Plant Data

Location	Total Capacity (MW)	Required Flow Rate (million standard cubic feet per day [MMscfd])	LNG Volume (million gallons per year [MMgpy])	Total Generation (terawatt hours [TWh])
KPLP	208	22.2	97.6	1.1
Barbers Point Combined Cycle	156 60	13.6 1.2	59.9 5.3	0.82 0.06
Total	**424**	**37**	**162.8**	**1.98**

A new pipeline will be installed to connect both KPLP and the Barbers Point Combined Cycle locations to the existing natural gas transmission network, connecting both sites to the natural gas supply from the FSRU.

A summary of the capital expense (CAPEX) for Phase 1 is shown in Table 4. These numbers are considered preliminary and will need further refining during detailed design and engineering.

Table 4. Phase 1 LNG Assets Capital Costs, undiscounted present value.

Description	CAPEX
FSRU, Buoy System, Subsea Pipeline	$412,000,000
Onshore pipeline connection to KPLP	$2,000,000
Onshore pipeline connection to Barbers Point Combined Cycle	$10,000,000
Transmission system upgrades	$20,000,000
KPLP Power Plant Conversion - Burner replacements with new gas infrastructure (compressor, gas skids, piping)	$20,000,000
Barbers Point Combined Cycle Power Plant	$570,000,000
Additional storage and additional contingency	$12,000,000
Phase 1 Total	**$1,046,000,000**

Phase 2

The second phase will supplement the new natural gas infrastructure introduced to O'ahu during Phase 1. The FSRU and associated subsea pipeline installed during Phase 1 will be sized with the capacity to serve the demands of both phases. So, it will remain in place from its introduction in Phase 1 through the lifecycle of natural gas usage on O'ahu.

Phase 2 will introduce natural gas power generation to both the CIP and Kahe facilities. The CIP location will be modified to house new burners for a single-cycle gas turbine. The Kahe facility will incorporate a new 3 x 1 combined cycle natural gas power generation system. Table 5 provides additional information on the updated power plant. A pipeline will be built to connect the CIP and Kahe facilities to the existing natural gas pipeline network and the FSRU's gas supply. A summary of the capital expense for Phase 2 is shown in Table 6. These numbers are considered preliminary and will need further refined during detailed design

Table 5. Phase 2 Power Plant Data

Location	Total Capacity (MW)	Required Flow Rate (MMscfd)	LNG Volume (MMgpy)	Total Generation (TWh)
CIP	129	3.4	15.1	0.1
Kahe	358	34.2	150.6	1.9
Total	**487**	**37.6**	**165.7**	**2.0**

Table 6. Phase 2 LNG Assets Capital Costs, Undiscounted Present Value

Description	CAPEX
Onshore pipeline connection to CIP	$2,000,000
Onshore pipeline connection to Kahe	$20,000,000
Campbell Industrial Park Power Plant Conversion - Burner replacement with new gas infrastructure (compressor, gas skid, piping)	$10,000,000
Kahe Combined Cycle Power Plant	$945,000,000
Transmission system upgrades	$44,000,000
Additional storage and additional contingency	$18,000,000
Phase 2 Total	$1,039,000,000

Conclusion

The phased approach outlined in the Final Supply Chain Summary section provides a conservative, viable path forward for the implementation of a lower cost and carbon power generation alternative to residual fuel powered generation on Oʻahu. Natural gas is the only viable bridge fuel to replaced low sulfur fuel oil as Hawaiʻi stives towards its RPS targets. By removing oil price volatility, this approach lessens the overall burden on the ratepayer, provides a resilient and reliable source of energy, while reducing greenhouse gas emissions when compared to current power generation techniques. It also provides the necessary and prudent fuel flexibility required when planning an energy future for a state over an extended period. Table 7 provides the cumulative natural gas demands, LNG volumes, CAPEX, etc. for both phases outlined in the Final Supply Chain Summary section.

Table 7. Cumulative Phase 1 and 2 Information

Description	CAPEX
Total Capacity (MW)	911
Total Required Flow Rate from FSRU (MMscfd)	74.6
Total LNG Volume Demand (MMgpy [million tons per annum {MPTA}])	328.5 [0.53]
Total Power Generation (TWh)	3.98
Total CAPEX ($)	**$500,000,000**

Appendix E - Biodiesel and Renewable Diesel

Summary

This Technical Documentation introduces biodiesel and renewable diesel as fuels that could be used for electric generation in Hawaiʻi. Currently, Pacific Biodiesel produces 5.5 to 6 million gallons per year (MMGAL/YR) of biodiesel in Hawaiʻi from both local and imported feedstock. In a 2024 request for proposal, Hawaiian Electric (HECO) is looking to increase biodiesel consumption to 12 MMGAL/YR for use at plants statewide.[74] However, these figures are relatively small compared to the 497 MMGAL/YR of total fossil fuel oil consumption for electric generation statewide.

As part of examining future options for low-carbon electricity, HDR looked at potential biodiesel feedstocks and land availability for local production. About half of the current designated agriculture land is not currently being utilized for crops or pasture and could theoretically be utilized for biofuel feedstock production. For calculating relative land use intensity, palm oil was chosen as a high-yield proxy for feedstock production, and a tabletop calculation showed 420-megawatt hours (MWh) of energy generation could be attained with 67 acres of palm oil or 1 acre of photovoltaic (PV) solar. Other feedstocks could theoretically be used in Hawaiʻi but likely with smaller energy yields per acre of land.

The import market to Hawaiʻi was also considered. The United States is currently a net importer of biodiesel, which is driven by regulatory initiatives like California's low carbon fuel standard. Hawaiʻi will need to look for additional supply options, which could include import options from Asia. Pricing of oil feedstocks and biodiesel tends to be linked to petroleum markets due to substitutability.

Considering land use and economic constraints, biodiesel (and other biofuels) may be put to higher use in harder-to-decarbonize sectors like heavy-duty ground transportation, heavy-duty equipment at ports, and aviation.

Introduction

Biodiesel and renewable diesel can both be used as a combustion energy source, though there are distinct differences in these "renewable" fuels. Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil.

The US Energy Information Administration, explains further, "Pure biodiesel has limited direct-use applications and has supply logistics challenges because of its physical properties and characteristics. Biodiesel is a good solvent, which means it can degrade rubber in fuel lines and

[74] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

loosen or dissolve varnish and sediments in petroleum diesel fuel tanks, pipelines, and in engine fuel systems (which can clog engine fuel filters). Biodiesel turns into a gel at higher temperatures than petroleum diesel, which creates problems for its use in cold temperatures. So, biodiesel cannot be stored or transported in regular petroleum liquids tanks and pipelines—it must be transported by rail, vessel and barge, or truck."[75]

Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.[76]

Demand for biodiesel and renewable diesel continues to grow globally largely as a function of public policy support for replacing petroleum products in the transport sector driven by both climate change mitigation and energy independence goals. Policy support can come either from subsidies for fuel production or mandates governing the carbon content of fuels or specific fuel sources. Ethanol, renewable diesel, and biodiesel are the three main options for drop-in blending or fueling of the transport sector, which is a large source of biodiesel demand.[77]

As biofuel consumption is largely driven by transportation demand, the supply and pricing of biodiesel and renewable diesel are driven as a function of both petroleum pricing and policies that support the use of renewable or low-carbon fuels. As such, biofuel use and consumption tend to be mostly focused on domestic or local markets, but other factors, such as fuel policies that produce demand exceeding local supply, also support a growing export market for biofuels.

Hawaiʻi and Biodiesel

Currently, there is one refinery in Hawaiʻi that produces biodiesel: Pacific Biodiesel. This refinery has a nameplate capacity of 5.5 MMGAL/YR. In 2023, Pacific Biodiesel produced 6 MMGAL. Most of the feedstock comes from waste oils and fats, with domestic production supplemented by imported oils and fats.[78] Therefore, further supply of biodiesel to meet renewable energy and/or climate goals would either have to come through new on-island biofuel feedstocks or imports of biofuel feedstock and/or biodiesel.

Several previous studies have looked at biofuel production in Hawaiʻi with the most relevant and complete studies including a Black and Veatch study in 2010, *The Potential for Biofuels Production in Hawaiʻi* and a Hawaiʻi Agricultural Research Center (HARC) study from 2006, *Biodiesel Crop*

[75] Biofuels explained - use and supply - U.S. Energy Information Administration (EIA)

[76] Biofuels explained - Biodiesel, renewable diesel, and other biofuels - U.S. Energy Information Administration (EIA)

[77] Transport biofuels – Renewables 2023 – Analysis - IEA

[78] Pacific Biodiesel

Implementation in Hawaiʻi. These studies provide a good fundamental understanding of the potential for biodiesel production within the state of Hawaiʻi and potential limitations.[79,80]

Hawaiʻi Agriculture and Land Use

As biodiesel production is typically rooted in agricultural activity for feedstock crops, it is important to discuss future biodiesel opportunities in the context of current agricultural practices. Hawaiʻi's agricultural industry supports both local markets and export markets. Traditional food crops and pasture lands are used to meet local dietary needs and offset the need for costly imports, which represent 90% of current consumption. The main agricultural exports include pineapple, macadamia nuts, and coffee.

As of December 2022, there were 1,931,378 acres (781,934 hectares) of land classified as "agricultural" by the State Land Use Commission.[81] However, in practice, much less of that land is used for actual agricultural practices due to topological, soil, climate, geographic, and economic constraints.

According to the *2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline,* the current amount of land used for agriculture is 886,211 acres with 120,632 acres in crop land and the remaining 765,579 acres used for pasture.[82]

Production of new energy crops for biodiesel would typically be viewed as most applicable to lands suited for crop production due to topological, soil, and water requirements.

Energy Production Capability

Based on previous studies, one of the highest-yielding crops for biodiesel and renewable diesel production is likely palm oil. Other biodiesel feedstocks are discussed later in this document. It is important to note that the production of palm oil is a controversial pathway to produce biofuels and can have extremely negative environmental impacts due to deforestation and land-use changes associated with its cultivation; however, given high-yield it was used for the basis of the analysis. Emissions from palm oil-based biodiesel are higher if forests or peatlands are cleared for plantations, releasing significant amounts of stored carbon into the atmosphere, a particular concern for imported palm oil. However, some of the environmental concerns surrounding palm oil could be alleviated by utilizing palm oil on lands previously used for agriculture.

For desktop calculation purposes, palm oil was selected because it is the most optimistic and high oil-yielding means of biofuel feedstock per unit of land area with production of approximately 600

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[79] Microsoft Word - Hawaii_DBEDT_--_Final_HI_biofuels_Report_rev7.doc

[80] Microsoft Word - biodiesel report.doc (hawaii.gov)

[81] section06.pdf (hawaii.gov)

[82] 2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline (hawaii.gov)

gallons per acre/per year. This is supported by initial production testing in Hawai‘i showing rates of 620 to 650 gallons per acre.[83] Palm oil would require several years for oil production to ramp up.

Converting palm oil to biodiesel via esterification results in a yield of approximately 87% by volume. The biodiesel energy content is 119,550 British thermal units per gallon (btu/gal) for biodiesel and 123,710 btu/gal for renewable diesel.[84] Therefore, assuming the conversion factors above, converting palm oil to biodiesel via esterification would equate to 62.4 metric million Btu per acre (MMBtu/acre) per year of energy. Assuming the biodiesel was used in a power plant with a heat rate of 10 MMBtu/MWh, one acre of palm oil crop would produce 6.24 MWh or 67 times more land for the same 420 MWh of electricity generation.

Palm oil on average exhibits yields (gal/acre) estimated to be approximately ten (10) times higher than camelina, five (5) times higher than rapeseed/canola, thirteen (13) times higher than soy, and about three (3) times higher than that of Jatropha.[85] Utilizing these crops would increase the land use requirements for growth.

Converting palm oil to biodiesel via esterification results in a yield of approximately 87% by volume. The biodiesel energy content is 119,550 British thermal units per gallon (btu/gal) for biodiesel and 123,710 btu/gal for renewable diesel.[86] Therefore, assuming the conversion factors above converting palm oil to biodiesel via esterification would equate to 62.4 metric million Btu per acre (MMBtu/acre) per year of energy.

$$600\ \left[\frac{gal - oil}{year}\right] \cdot 0.87\ \cdot 119{,}550\ \left[\frac{Btu}{gal}\right] \cdot \frac{1}{1{,}000{,}000}\ \left[\frac{MMBtu}{Btu}\right] = \mathbf{62.4}\ \left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre - year}}\right] \tag{1}$$

Assuming the biodiesel was used in a power plant with a heat rate of 10 MMBtu/MWh, 1 acre of palm oil crop would produce 6.24 MWh.

$$62.4\ \left[\frac{MMBtu}{acre - year}\right] \cdot \frac{1}{10}\ \left[\frac{Btu}{MMBtu}\right] = \mathbf{6.24}\ \left[\frac{\boldsymbol{MWh}}{\boldsymbol{year}}\right] \tag{2}$$

[83] About Us (hawaiioilseedproducers.com)

[84] Alternative Fuels Data Center: Fuel Properties Comparison (energy.gov)

[85] Hawaii Natural Energy Institute. (2013). *Biofuels crop assessment*. University of Hawai‘i Hawai‘i Energy and Environmental Technologies Initiative. Retrieved from https://www.hnei.hawaii.edu/wp-content/uploads/Biofuels-Crop-Assessment.pdf

[86] Alternative Fuels Data Center: Fuel Properties Comparison (energy.gov)

6.24 MWh roughly equates to the annual electric use of one residential customer per acre of palm oil production.

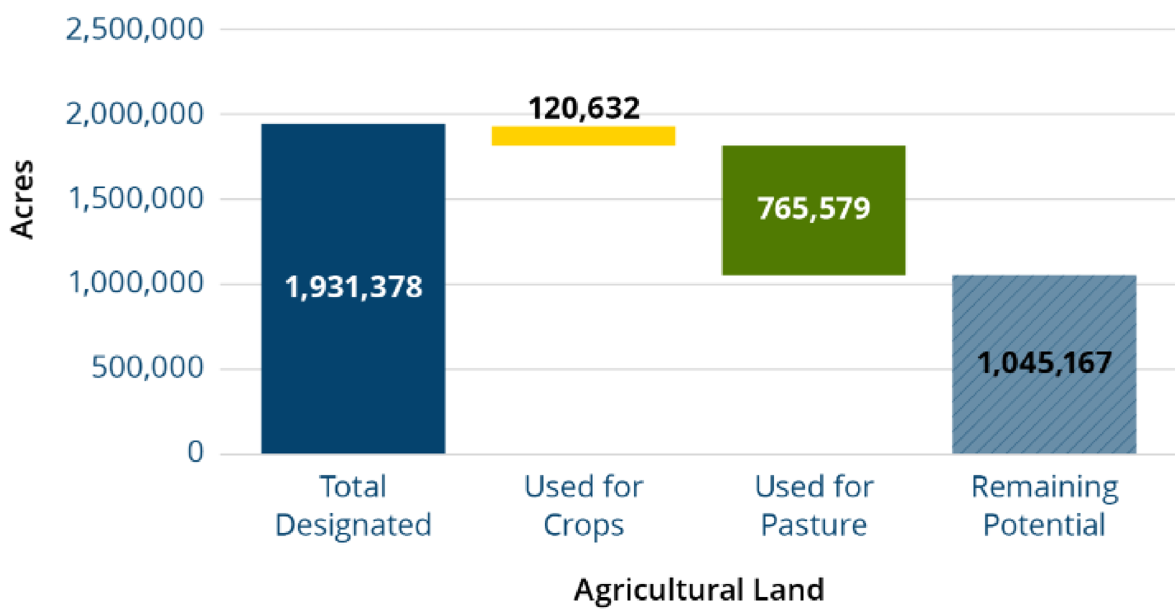
To contrast with respect to total Hawaiʻi electricity consumption and land use, Hawaiʻi consumes 10,819 gigawatt hours (GWh) of gross electricity per year.[87]

Therefore, to replace just 5% of total energy consumption with biodiesel would require 86,691 acres of new crop land.

$$0.05 \cdot 10{,}819\,[GWh] \cdot 1{,}000\left[\frac{MWh}{GWh}\right] \cdot \frac{1}{6.24}\left[\frac{acre - year}{MWh}\right] = \mathbf{86,691}\,[\boldsymbol{acres}] \tag{3}$$

Hawaiʻi currently has 120,632 acres in farmland, see Figure 1.

Figure 1. Land capacity use statewide



The new acreage required solely for bioenergy through palm oil production would result in a 72% increase in crop land.

$$\frac{86{,}691\,[acres]}{120{,}632[acres]} = \boldsymbol{72\%\ increase\ in\ crop\ land} \tag{4}$$

[87] ElectricityTrendsReport2023.pdf (hawaii.gov)

Increasing biofuel production in Hawaiʻi would require substantial public policy, regulatory, and economic decisions to incentivize demand. However, this demand would also place economic pressure on the existing agriculture industry as land prices would increase in response to a new demand for crop production. This would result in shifts in the agriculture output, which would likely result in higher prices for non-biofuel agricultural products.

There are also additional tradeoffs to consider as Hawaiʻi looks to decarbonize the entire economy. Liquid biofuels can be used for electric generation, but they can also be used as a low carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels since hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there might be competing demands for biofuel production from other sectors that would be willing to pay a premium for the fuel or feedstock as they attempt to decarbonize.

Solar Comparison to Biodiesel

Since land use in Hawaiʻi is subject to competing interests in balancing urban development, industry, agriculture, tourism, recreation, biologic preservation, and agriculture, it can be useful to compare land requirements between substitute activities. In the case of biofuel production for electricity, PV solar energy is a competing energy source.

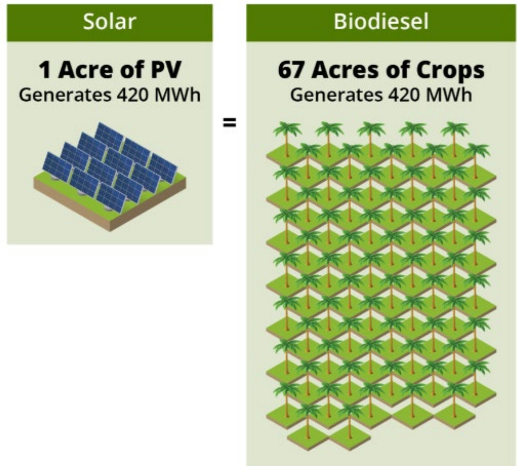
Assuming a solar PV capacity factor of 24% and a power density of 0.2 megawatt alternating current (MWac) per acre, one acre of a PV installation can produce 420 MWh per year.

$$0.2\ \left[\frac{MWh}{acre}\right] \cdot 0.24 \cdot 8{,}760\ \left[\frac{hours}{year}\right] = \mathbf{420}\ \left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre - year}}\right] \quad (5)$$

This means the equivalent electrical output from the same amount of land is approximately 67 times greater for solar PV than from biofuel production.

$$\frac{420\ \left[\frac{MMBtu}{acre - year}\right]}{6.24\left[\frac{MMBtu}{acre - year}\right]} = \mathbf{67} \quad (6)$$

Figure 2. Land comparison, solar versus biodiesel



Other Biodiesel Feedstocks

For evaluating potential land use impacts of domestic biofuel production, palm oil was chosen due to its wide-spread cultivation in climates similar to Hawaiʻi, high relative productivity per acre, and prevalent commercial use as a biofuel feedstock. Past work by Black & Veatch and the University of Hawaiʻi[88] as well as HARC[89] have previously examined other potential sources of biofuel feedstock for production in Hawaiʻi.

Many different feedstocks are used for biodiesel production worldwide with soybean, rapeseed, and corn oils as major bio-oil-based feedstocks (other than palm oil) used in global biodiesel production.[90] However, these crops are typically produced in more temperate climates than Hawaiʻi and typically have smaller oil yields than what has been demonstrated with palm oil. As with any biofuel feedstock or biofuel, import could be an option, though market conditions will dictate pricing, and as a petroleum substitute, biofuel pricing is linked to crude oil pricing.

Small pilot projects with other alternative biofuel feedstocks have begun to emerge in recent years in Hawaiʻi to further investigate the viability of local commercial production. One such feedstock is from the beans of the Pongamia tree, which is native to southeast Asia, Australia, and western pacific islands. The Terviva company is looking to develop these trees as a biofuel feedstock and is currently growing Pongamia trees on former pineapple and sugar plantations in Hawaiʻi.[91] While research is ongoing, it is hopeful the oil yields could approach those of palm oil with these trees growing in less productive soils.[92]

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88 https://energy.hawaii.gov/wp-content/uploads/2011/10/Hawaii-Biofuels-Assessment-Report.pdf

89 https://hdoa.hawaii.gov/wp-content/uploads/2013/01/biodieselreportrevised.pdf

90 Total biofuel production by feedstock, main case, 2021-2027 – Charts – Data & Statistics - IEA

91 https://terviva.com/

92 https://www.fastcompany.com/90871132/these-supertrees-grow-a-climate-friendly-alternative-to-palm-oil

Another biofuel feedstock emerging for potential use in Hawaiʻi is camelina, or false flax, which is an annual plant producing oil-rich seeds. Pono Pacific and Par Hawaiʻi are currently exploring development of camelina in local production of sustainable aviation fuel. The hope is to use camelina as a rotational cover crop to complement existing agricultural activities.[93] Based on research by HARC on similar crops, camelina yields on Hawaiʻi would likely be significantly less than could be provided by palm oil; hence, its investigation as a rotational crop to supplement other crops.

Additional research and plantings will need to demonstrate the commercial viability of dedicated energy crops within Hawaiʻi (palm, Pongamia, camelina, or otherwise). Each biofuel feedstock will have certain characteristics that govern its productivity, cost, and utilization. As such, commercial production may utilize several different oil sources.

Renewable and Biodiesel Imports

Renewable and biodiesel demand can also be met with imported fuels and feedstocks. Biodiesel production sources are typically geared toward specific markets with the bulk of the United States' current biodiesel production coming from soybean oil, Europe utilizing rapeseed oil, and southeast Asia favoring palm oil.

Indonesia and Malaysia dominate palm oil production accounting for greater than 80% of global production. This production also supports renewable diesel production abroad with almost all renewable diesel imported to the United States currently coming from a Neste facility in Singapore. The United States also receives smaller supplies of biodiesel from Canada, Germany, Spain, and Italy.

The United States is a current net importer of biofuels, and its current biodiesel production capacity sits at about 2,000 MMGAL[94]; however, US production capacity has been steadily decreasing since its peak capacity of 2,600 MMGAL in July 2019.[95]

For comparison, Hawaiʻi consumed a combined 497 MMGAL/YR of low sulfur fuel oil (LSFO), high sulfur fuel oil (HSFO), diesel, and naphtha fuels.[96] HECO's latest request for proposal for biodiesel

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[93] https://www.khon2.com/local-news/a-new-initiative-in-hawai%CA%BBi-could-change-our-carbon-footprint/

[94] US Biodiesel Plant Production Capacity. EIA. (2024, August 15). https://www.eia.gov/biofuels/biodiesel/capacity/

[95] EIA. (2024, September 10). Petroleum & Other Liquids. US biodiesel production capacity (million gallons). https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M

[96] Data from Hawaiian Electric. (January 31, 2024). Consolidated Annual Fuel Report, DKT 2022-0014, Page 10 of 60. HDR calculations using assumption that 1 barrel is equivalent to 42 US gallons.

imports to Hawaiʻi was for 285,000 barrels per year or about 12 MMGAL/YR.[97] Table 8 and Table 9 below summarize these figures.

Table 8 Fuel use for energy generation on the five islands served by HECO[22]

Fuel	2023 Consumption (barrels)	2023 Consumption (gallons)
LSFO	8,562,045	359,605,890
HSFO	630,292	26,472,264
Diesel	2,289,303	96,150,726
Naphtha	348,872	14,652,624
FOSSIL FUEL TOTAL	11,830,512	496,881,504

Table 9 Biodiesel use for energy generation on the five islands served by HECO versus HECO's 2024 RFP[21,22]

Fuel	Consumption (barrels)	Consumption (gallons)
2023 Biodiesel Consumption	133,978	5,627,076
HECO's 2024 RFP for Biodiesel	285,000	11,970,000

To replace a meaningful percentage of 497 MMGAL/YR of fossil-based fuel oil, Hawaiʻi will have to significantly increase its import quantities requested in its current proposals. This increase would come at a significant cost because of competition from states like California that have financial incentives to consume biofuels and midwestern states like Iowa, where customers would benefit from shorter shipping distances.

[97] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

Appendix F - Biogas and RNG

Summary

This Technical Documentation summarizes biogas and renewable natural gas (RNG) as fuels that could be used for electric power generation in Hawaiʻi. Currently, Hawaiʻi produces wastewater biogas, landfill gas, and syngas that supplement imported fossil natural gas (NG). However, Hawaiʻi's use of natural gas is very small and makes up less than 2% of its overall energy portfolio.[98]

The Honouliuli Wastewater Treatment Plant located on Oʻahu produces 800,000 therms of RNG from municipal biosolids. Hawaiʻi is striving to become net zero by 2045 and looking to increase RNG production for use at power plants as well as supplement other energy uses statewide. The current RNG production figures are relatively small compared to the 497 million gallons per year (MMGAL/YR) of total fossil fuel oil consumption for electric generation statewide.

As part of examining future options for low-carbon electricity, HDR looked at potential RNG production from various feedstocks and land availability for local production. About half of the current designated agriculture land is not currently being utilized for crops or pasture and could theoretically be utilized for energy crop feedstock production. For calculating relative land use intensity, HDR chose Bana grass, or cane grass, as a high-yield proxy for feedstock production. A tabletop calculation showed 420 megawatt hours (MWh) of energy generation could be attained with 24 acres of Bana grass or 1 acre of photovoltaic (PV) solar. Other feedstocks could theoretically be used in Hawaiʻi but likely with smaller energy yields per acre of land.

HDR also considered the import market to Hawaiʻi. The United States currently produces RNG as a supplement to a large NG demand domestically, but the exportation of RNG internationally is becoming attractive and driven by regulatory initiatives in Europe.

Considering land use and economic constraints, RNG may be put to higher use in harder-to-decarbonize sectors like transportation, heavy-duty equipment at ports, airports, and other areas.

Hawaiʻi and RNG

Currently, there is one facility in Hawaiʻi that produces RNG: the Honouliuli Wastewater Treatment Plant (WWTP) on Oʻahu. This facility treats an average daily wastewater flow of 26 MMGAL per day and can produce 800,000 therms per year of RNG. In its first full year of operation (2020), the Honouliuli WWTP produced 382,000 therms of RNG, which was injected into a Hawaiʻi Gas Pipeline. The feedstock for the RNG production comes from the anaerobic digestion of biosolids produced during treatment.

[98] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Several previous studies have looked at RNG production in Hawaiʻi with the most relevant and complete study being a Hawaiʻi Natural Energy Institute of the University of Hawaiʻi 2021, *Resources for Renewable Natural Gas Production in Hawaiʻi*. This study provides a good fundamental understanding of the potential for RNG production within the state of Hawaiʻi and potential limitations.[99]

RNG Production from Wastes

RNG is composed primarily of methane produced from either biological or elal conversion of organic feedstocks. RNG has lower life cycle greenhouse gas (GHG) emissions than fossil NG and has become an attractive method of reducing the carbon emissions of communities globally. RNG from biological or thermal conversion can both be used as a combustion energy source as a NG replacement for heating or vehicle fuel or to produce electrical power with internal combustion engines or turbines. The end use of RNG will dictate the quality required and the levels of contaminant removal. Many RNG production facilities recycle the gas for on-site power generation and heat recovery.

For on-site electrical production, a low British thermal unit (Btu) (500 to 650 Btu per cubic feet [cu ft]) RNG can be utilized with minimal gas conditioning for removal of hydrogen sulfide, moisture, and siloxane removal. End uses requiring transportation via trucks or a pipeline for NG replacement or vehicle fuels will require additional gas conditioning to remove the CO2 and other contaminants and produce a high Btu (900 to 1,010 Btu/cu ft) RNG of NG quality.

For the US mainland, high-Btu RNG has unlimited direct-use applications and minimal supply logistic challenges because of its nearly identical physical properties and characteristics to fossil NG. In Hawaiʻi, RNG direct-use applications may be limited by the overall lower NG volumes used in comparison to other energy sources like wind, solar, and non-NG, petroleum-based fuels.

Demand for RNG continues to grow globally largely as a function of public policy support for replacing petroleum products in the transport sector driven by both climate change mitigation and energy independence goals. Policy support can come either from subsidies for fuel production or from mandates governing the carbon content of fuels or specific fuel sources.

As RNG consumption is largely driven by transportation demand, the supply and pricing of RNG is driven as a function of both petroleum pricing and policies that support the use of renewable or low carbon fuels. As such, RNG use and consumption tend to be mostly focused on domestic or local markets, but other factors, such as fuel policies that produce demand exceeding local supply, also support a growing export market for RNG.

The potential additional RNG production in Hawaiʻi for this study is based on the availability of organic feedstocks already produced within the state or those that could be produced with a

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[99] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

change in land use. HDR assumes it would not be financially feasible, or practical, to import feedstocks to produce RNG locally. Importing RNG as LNG or NG from the mainland or other sources is covered in other HDR Technical Memorandums. To estimate the additional RNG production potential in Hawaiʻi, HDR evaluated the available quantities of the various feedstocks for either biological or thermal conversion to RNG. Feedstocks for biological conversion include livestock manure, municipal biosolids from WWTPs, food wastes diverted from municipal solid waste, and municipal solid waste that produces landfill gas. Feedstocks evaluated for the thermal conversion to RNG include urban fiber sources, agricultural residues, and energy crops. The Hawaiʻi Natural Energy Institute study on potential RNG production was a key reference for most of these feedstocks with information supplemented from other publicly available sources.

Livestock Manure

In areas with large numbers of confined animal feeding operations (CAFOs), livestock manure can be a valuable feedstock for RNG production. The mainland United States has seen dramatic increases in RNG production from dairies and hog farms in the last five years.[100] However, the Hawaiʻi Natural Energy Institute study reviewed the livestock populations in Hawaiʻi for cattle, chickens, and hogs and determined Hawaiʻi has insufficient number and size of animal feeding operations to justify biogas generation and RNG.

WWTPs

The State of Hawaiʻi has 12 WWTPs treating an average daily flow greater than 1.0 MMGAL per day (MGD).[101] Eight of these facilities already produce biogas through the anaerobic digestion of biosolids. Table 10 summarizes the biogas production potential from wastewater treatment regardless of the use of anaerobic digestion as it could be added to the facilities that don't currently have that capability.

Table 10. Biogas Production Potential of Wastewater Treatment

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Sand Island	Honolulu	Yes	76.00	194,186	886,693	616
Honouliuli	Honolulu	Yes	25.70	65,674	299,879	208
Kailua	Honolulu	Yes	16.30	41,645	190,160	132
Waianae	Honolulu	Yes	3.80	9,719	44,381	31
East Honolulu	Honolulu	Yes	4.41	11,272	51,470	36

[100] https://www.epa.gov/agstar/agstar-data-and-trends

[101] EPA 2022 Clean Water Needs Survey Report to Congress, 2022

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Schofield	Honolulu	Yes	2.40	6,142	28,046	19
Lāhainā	Maui	No	4.20	10,732	49,004	34
Wailuku-Kahului	Maui	No	3.91	9,989	45,614	32
Kihei	Maui	No	3.59	9,179	41,915	29
Hilo	Hawaiʻi	Yes	4.20	10,732	49,004	34
Kealakehe	Hawaiʻi	No	1.69	4,320	19,725	14
Līhuʻe	Kauaʻi	Yes	1.11	2,835	12,944	9
TOTAL			**147**	**376,425**	**1,718,835**	**1,194**

Food Waste

Food waste includes kitchen trimmings, plate waste, and uneaten prepared food from restaurants, cafeterias, and households as well as unsold and spoiled food from stores and distribution centers and loss and residues from food and beverage production and processing facilities (USEPA, 2020). The City and County of Honolulu defines food waste as "all animal, vegetable, and beverage waste which attends or results from the storage, preparation, cooking, handling, selling or serving of food. The term shall not mean commercial cooking oil waste or commercial fats, oils and grease (FOG) waste."[102]

Food waste currently landfilled in Hawaiʻi could be converted to RNG with anaerobic digestion. Based on the assumptions listed below, currently disposed of food waste totals could support the production of about 326,000 MMBtu per year of methane production via anaerobic digestion (Table 11).

Table 11. Potential RNG Production from Food Waste via Anaerobic Digestion[103]

Description	Units	Value
Municipal Solid Waste Landfilled	tons/year	617,408
Food Waste Landfilled	tons/year	92,893
Percent Recovery	%	50
Food Waste Diverted to Anaerobic Digestion	tons/year	46,447
Biogas Production	million cu ft/year	592

[102] City and County of Honolulu – Food Waste Tip Sheet, 2021

[103] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

Description	Units	Value
RNG Production	MMBtu/year	325,710

Landfill Gas

The State of Hawaiʻi has 15 municipal solid waste landfills, seven of which are closed and not receiving additional waste.[104] For effective landfill gas collection and RNG production, HDR assumed candidate landfills have over 1.0 million tons of waste in place and have not been closed for more than 12 years. Table 12 summarizes the RNG production potential from landfill gas.

Table 12. RNG Production Potential from Landfill Gas

Landfill Name	Landfill Owner Organization(s)	Waste in Place (tons)	LFG Collection System in Place?	Current Project Status	Landfill Gas Produced (SCF/day)	Landfill Gas Produced (MMBtu/year)
Central Maui Landfill	Maui County, HI	6,564,409	Yes	Planned	1,356,000	247,470
Kapaʻa and Kalaheo Sanitary Landfills	City and County of Honolulu, HI	5,838,786	Yes	Shutdown	348,312	63,567
Kekaha Landfill/Phases I & II	County of Kauai, HI	3,113,967	Yes	Candidate	642,000	117,165
Palailai Landfill	Grace Pacific Company	2,845,215	Yes	Low Potential	70,000	12,775
South Hilo Sanitary Landfill (SHSL)	Hawaiʻi County, HI	3,193,059	No	Candidate	640,000	116,800
Waimānalo Gulch Landfill & Ash Monofill	City and County of Honolulu, HI	13,141,443	Yes	Candidate	1,121,000	204,583
West Hawaiʻi Landfill/Puʻuanahulu	Hawaiʻi County, HI	3,404,076	Yes	Candidate	304,000	55,480
Total					**4,481,312**	**817,840**

Urban Fiber Sources

Urban waste fiber resources for RNG production include the fibrous and/or combustible portion of materials disposed of as municipal solid waste (MSW) and construction and demolition waste

[104] EPA Landfill Methane Outreach Program (LMOP), 2024

(CDW). These include the drier, non-food biomass components of the waste stream (paper, cardboard, woody material, and green waste), textiles, and some plastics.

Based on the same data for solid waste composition and disposal amounts used in the food waste discussion earlier, disposal and RNG potential from the fibrous/combustible portion of the MSW stream is shown for the State in Table 4. RNG potential from this resource is approximately 4,230,000 MMBTU per year.

Table 13. Potential RNG Production from Urban Fiber Waste via Thermal Conversion[105]

Description	Units	Value
Municipal Solid Waste Landfilled	tons/year	617,408
Urban Fiber Wastes (Non-Food and Plastics	tons/year	385,766
Percent Recovery	%	90
Thermal Conversion Efficiency	%	60
RNG Production	MMBtu/year	4,230,000

Total RNG and Electrical Production Potential from Wastes

Table 5 below presents a summary of the potential RNG production potential from waste feedstocks produced within the State and the corresponding potential electrical power production. The electrical production shown assumes a generation efficiency of 40 percent. The 673,888 MWh/year of potential would be approximately 6 percent of the state's non-renewable electrical consumption[106] and roughly 74% of that production comes from the thermal conversion of urban fiber wastes. Without that feedstock, the total electrical production potential is only 178,132 MWh/year and less than 2% of the total for the state.

Table 14. Total RNG and Electrical Production from Waste

Feedstock	RNG Potential	
	MMBTU/year	MWh/year
Livestock Manure	NA	NA
WWTP	376,400	44,114
Food Waste	325,700	38,172

[105] Resources for renewable natural gas production in Hawai‘i, Hawai‘i Natural Energy Institute, May 2021

[106] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Landfill Gas	817,800	95,846
Urban Fiber Waste	4,230,000	495,756
Total	**5,749,900**	**673,888**

RNG Production from Energy Crops

Hawaiʻi Agriculture and Land Use

As RNG production is typically rooted in the conversion of wastes, thermal conversion of dedicated energy feedstock crops also has potential and it is important to discuss future RNG opportunities in the context of current agricultural practices. Hawaiʻi's agricultural industry supports both local markets and export markets. Traditional food crops and pasture lands are used to meet local dietary needs and offset the need for costly imports which represent 90% of current consumption. The main agricultural exports include pineapple, macadamia nuts, and coffee.

As of December 2022, there were 1,931,378 acres (781,934 hectares) of land classified as 'Agricultural' by the State Land Use Commission.[107] However, in practice, much less of that land is used for actual agricultural practices due to topological, soil, climate, geographic, and economic constraints.

According to the *2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline,* the current amount of land currently used for agriculture is 886,211 acres, with 120,632 acres in cropland and the remainder, 765,579 acres used for pasture.[108]

Production of new energy crops for RNG would typically be viewed as the most applicable lands suited for crop production due to topological, soil, and water requirements.

Energy Production Capability

Based on previous studies, one of the promising crops for RNG production on island is likely sugar cane, cane grass, or Bana grass due to favorable yields in Hawaiʻi's climate. The market indicates that Bana grass could be a productive means of RNG feedstock per unit of land area, as a recent request for proposals for new RNG production led to Eurus Energy being selected to develop an RNG production facility that will utilize Bana grass as a feedstock.[109]

[107] section06.pdf (hawaii.gov)

[108] 2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline (hawaii.gov)

[109] https://www.hawaiigas.com/posts/eurus-energy-america-and-bana-pacific-for-hydrogen-and-renewable-natural-gas-projects

Therefore, assuming 1,500 therms/acre/year for converting Bana grass to RNG via thermal gasification would equate to 150 MMBtu/acre per year of energy.[110]

Assuming that the RNG was used in a power plant with an electrical efficiency of 40 percent, 1 acre of Bana grass crop would produce 17.6 MWh.

$$15\ \left[\frac{MMBtu}{acre - year}\right] \cdot 0.293 \left[\frac{MWh}{MMBtu}\right] \cdot 0.4 = \mathbf{17.6} \left[\frac{\boldsymbol{MWh}}{\boldsymbol{year}}\right] \tag{1}$$

17.6 MWh roughly equates to the annual electric use of 3 residential customer per acre of Bana grass production.

In contrast with respect to total Hawaiʻi electricity consumption and land use, Hawaiʻi consumes 10,819 GWh of gross electricity per year.[111]

Therefore, replacing just 5% of total energy consumption with RNG would require 30,736 acres of new cropland.

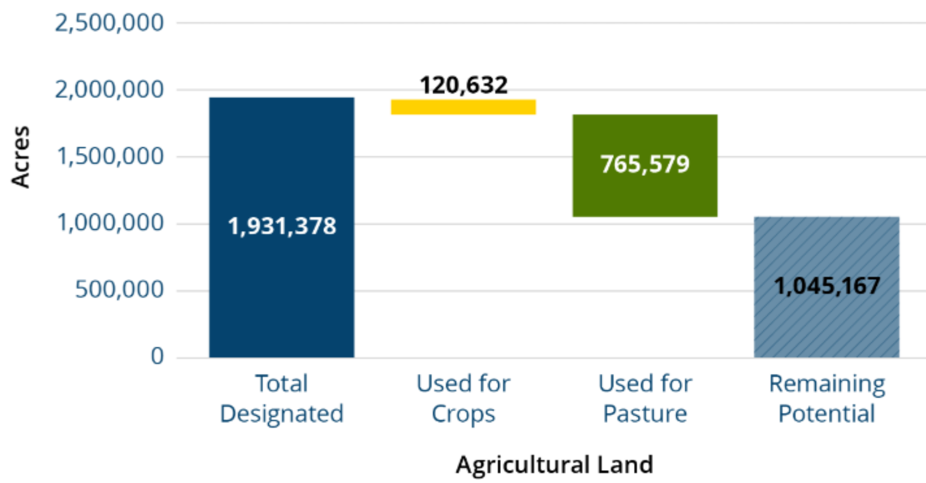
$$0.5 \cdot 10{,}819\ [GWh] \cdot 1{,}000 \left[\frac{MWh}{GWh}\right] \cdot \frac{1}{17.6}\left[\frac{acre - year}{MWh}\right] = \mathbf{30{,}736}[\boldsymbol{acres}] \tag{2}$$

As Hawaiʻi currently has 120,632 acres of farmland, see Figure 1.

Figure 1. Land Capacity Use on Hawaiʻi.

[110] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

[111] ElectricityTrendsReport2023.pdf (hawaii.gov)



The new acreage required solely for bioenergy through palm oil production would result in a 25% increase in crop land.

$$\frac{30{,}736\ [acres]}{120{,}632[acres]} = \mathbf{25\%\ \textit{increase in crop land}} \tag{3}$$

Increasing biofuel production in Hawaiʻi would require substantial public policy, regulatory and economic decisions to incentivize demand. However, this demand would also place economic pressure on the existing agriculture industry as land prices would increase in response to a new demand for crop production. This would result in shifts in the agriculture output which would likely result in higher prices for non-biofuel agricultural products.

There are also additional tradeoffs to consider as Hawaiʻi looks to decarbonize the entire economy, while liquid biofuels can be used for electric generation, they can also be used as a low-carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels as hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there might be competing demands for biofuel production from other sectors that would be willing to pay a premium for the fuel or feedstock as they attempt to decarbonize.

Solar Comparison to RNG:

As land use in Hawaiʻi is subject to competing interests in balancing urban development, industry, agriculture, tourism, recreation, biologic preservation, and agriculture, it can be useful to compare land requirements between substitute activities. In the case of RNG production for electricity, PV solar energy is a competing energy source.

Assuming a solar PV capacity factor of 24% and a power density of 0.2 MWac/acre, one acre of a PV installation can produce 420 MWh/yr.

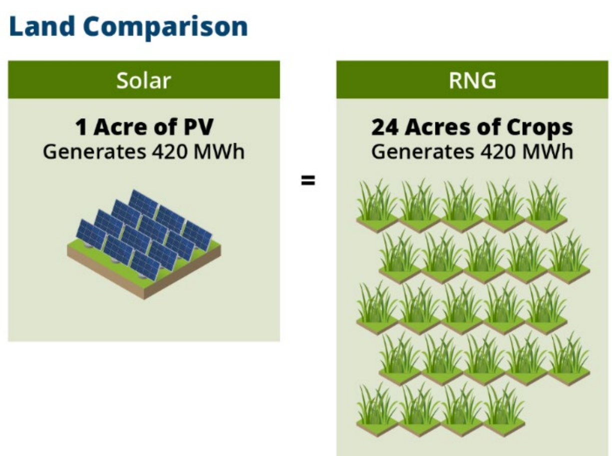
** 0.2 MWac/acre *24% * 8760 hr./yr = 420 MWh

$$0.02\left[\frac{MWh}{acre}\right]\cdot 0.24\cdot 8{,}760\left[\frac{hours}{year}\right] = \mathbf{420}\left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre-year}}\right] \tag{4}$$

This means that the equivalent electrical output from the same amount of land is approximately 23.9 greater for solar PV than for RNG production.

$$\frac{420\left[\dfrac{MMBtu}{acre-year}\right]}{17.6\left[\dfrac{MMBtu}{acre-year}\right]} = \mathbf{23.9} \tag{5}$$

Figure 2. Land Comparison, solar versus RNG.



RNG Imports

RNG demand can also be met with imported RNG and feedstocks. RNG production sources are typically focused on specific markets with the bulk of the United States' current RNG production coming from landfill gas and biogas from anaerobic digestion.

Appendix G – Hydrogen & Ammonia Concept Summary

Liquified Natural Gas to Ammonia and Hydrogen

As the Hawaiʻi State Energy Office looks to make a transition plan from low-sulfur fuel oil to 100% renewable energy, the state currently faces significant challenges. To decrease the dependence on low-sulfur fuel oil and reduce greenhouse gas emissions, HDR has recommended adopting liquefied natural gas (LNG) into Hawaiʻi's current energy portfolio and converting natural gas (NG) assets to clean ammonia (NH3) and/or hydrogen (H2) in the future.

Fuel Needs for Expected Loads

For Hawaiʻi to achieve its Renewable Portfolio Standards[112], the use of NG must be phased out before 2045 in favor of low-carbon alternative fuels. H2 is one fuel that may be an appropriate replacement for NG, especially in power generation applications. There are substantial efforts to increase the H2 production capacity in the United States through programs like the Department of Energy's Hydrogen Shot, which seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade.[113] If these programs are successful, the amount of H2 available on the US mainland is expected to greatly increase.

Before utilizing an expanded US and international H2 production market, Hawaiʻi needs to act to ensure grid stability while reducing greenhouse gas emissions. In HDR's proposed final path, the following capacity and generation are either built or converted to NG assets over Phases 1 and 2, see Table 1.

Table 1. Expected Electricity Needs on Oʻahu

Phase	Year	Total Capacity Converted (megawatt [MW])	Total Generation Estimate (terawatt [TWh])
1	2030	424	1.98
2	2035	487	2
	Total	911	3.98

112 Public Utilities Commission | Hawaii's Renewable Energy and Energy Efficiency Policies

113 Hydrogen Shot | Department of Energy

Generating the approximately 4,000,000 megawatt-hours (MWh) of electrical energy, as outlined in Table 1 above, using H2 fuel, would require approximately 265,000 metric tons of H2 per year.

For reference, the current US production of H2 is approximately 10 million metric tons per year and the Department of Energy Clean H2 Strategy indicates a potential for this to grow to 50 million metric tons by 2050.[114]

Hydrogen Delivery Pathways

Considering the main intent of H2 use in Hawaiʻi would be for power generation, on-island production of H2 is likely not feasible. A typical onsite production scenario would include H2 generation from electrolysis, onsite storage of H2 in tanks, and combustion of the H2 for power generation. The typical round-trip efficiency of this process is less than 30%, meaning 3 kilowatt-hours (kWh) of electrical energy input to H2 production is required to produce 1 kWh from combusted H2. Successful deployment of this type of system requires extensive build-out of renewable electricity generation assets like wind and solar. Installation of renewable assets at this scale would likely exceed land availability constraints on the islands.

To meet H2 demands of over 265,000 metric tons per year, Hawaiʻi will likely need to consider fuel delivery via bulk tanker in a similar configuration to LNG deliveries. The tables below provide comparisons of two developing methods for delivering H2 molecules for fueling purposes. These are compared to LNG delivery to demonstrate the scale associated with each pathway. In general, the two pathways are:

1. **Liquid Hydrogen –** Gaseous H2 fuel is cryogenically cooled below its boiling point. Liquefying the gas increases the volumetric energy density, which makes transporting the fuel more economical. Upon receipt, the liquid H2 must be re-gasified for use with power generation equipment.
2. **Anhydrous Ammonia –** Gaseous H2 is generated via conventional processes. A Haber-Bosch process is then employed to combine H2 with nitrogen molecules from atmospheric air to synthesize NH3 molecules. NH3 can then be transported in a liquid form with high density. Upon receipt, NH3 must be thermally cracked to release combustion-ready H2.[115]

There are many design differences for infrastructure in terms of LNG, NG, NH3, and H2. Table 2 below shows the property difference between the fuels.

Table 2. Fuel Properties

[114] U.S. National Clean Hydrogen Strategy and Roadmap

[115] Note, there are R&D efforts by major turbine manufacturers to directly combust liquid NH3, which would remove the need for cracking.

Fuel	State	Gross Heating Value (Btu/lb)	Net Heating Value (Btu/lb)	Density (lb./ft^3)	Energy Density HHV (Btu/ft^3)	Energy Density LHV (Btu/ft^3)	Boiling Point at 1 atm (°F)	Heat of Vaporization (Btu/lb)
NG (US market)	Gas	22,453	20,267	0.0485	1,089	983	-259 (methane)	N/A
LNG	Liquid	23,734	20,908	26.73	634,496	558,943	-259 (methane)	239
Anhydrous NH3	Liquid	9,551	8,001	42.57	406,586	340,302	-28	593
H2	Gas	61,127	51,682	0.00562	343	290	-423	N/A
H2	Liquid	60,964	51,621	4.42	269,447	228,155	-423	192

A few key takeaways from this comparison of chemical properties shown in Table 2 above include:

- LNG has the highest energy density as a fuel for transportation. NH3 contains roughly 60% of the energy per volume compared to LNG while liquid H2 contains only 40%.
- Current technology for liquefying H2 below the boiling temperature of -423°F is highly energy intensive and the potential for boil-off loss is increased during transit due to the lower storage temperature.
- Anhydrous NH3 has a high boiling temperature compared to LNG and liquid H2, which makes liquefaction more economical. However, the process of converting H2 to NH3 and NH3 back into H2 requires additional energy input (cracking) and reduces the overall efficiency of the fuel transportation.

As shown in Table 3 below, receiving bulk liquid H2 deliveries via ship at the scale needed to provide the expected power generation demands would result in a large increase in the number of deliveries required. Since shipments from the mainland to Hawaiʻi may take weeks, this method of H2 delivery also incurs significant losses from boil-off gas, which is significantly increased by the low storage temperature of the cryogenic liquid H2.

Table 3. Delivery Pathway Summary

Description	Units	LNG	LH2	NH3
Energy Delivered	Million British Thermal Unit (MMBTU) per year	28,238,900	28,238,900	28,239,900
Gallons Required	Gallons per year	328,500,000	925,357,000	721,794,000

Tankers Required	Ships per year[116]	4-6	12-14	9-11
Transport Temp	Fahrenheit [°F]	-259	-423	-28
Boil-off Loss	% per day	0.1%-0.25%[117]	2%-2.5%[118]	0.015% to 0.03%[119]

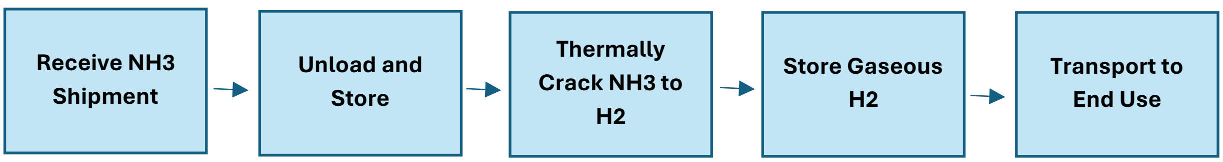
Additionally, the commercial availability of liquid H2 transport via ship is relatively underdeveloped in the current market; whereas NH3 is commonly transported in support of the fertilizer industry.

For these reasons, HDR considered anhydrous NH3 to be a more appropriate pathway for transporting H2 molecules to Hawaiʻi to meet the proposed renewable power generation requirements.

Proposed Ammonia Concept

In general, delivery of NH3 for conversion to gaseous H2 fuel will involve a significantly different set of processes as compared to the receipt of LNG. The diagram below loosely demonstrates the process needed.

Figure 1. Process for Ammonia Use as an Energy Carrier



To date, the concept of receiving bulk NH3 delivery as an energy carrier for the import of green H2 has not been implemented. However, this concept has been proposed and evaluated by multiple entities throughout the world. Below are a few examples of proposed projects that intend to use this method for green H2 energy import:

- Germany floating NH3 import terminal[120].
- Port of Rotterdam NH3 terminal[121].

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[116] Approximately 70,000 [GAL] per ship

[117] ON THE BOIL OFF RATE OF LIQUEFIED CARGO OF GAS CARRIER DURING A PARTIALLY LOADED VOYAGE (trb.org)

[118] A comparative study on energy efficiency of the maritime supply chains for liquefied hydrogen, ammonia, methanol and natural gas - ScienceDirect

[119] Ammonia as fuel for ships | Bureau Veritas

[120] First Floating Import Terminal with a Hydrogen Cracker Planned for Germany

[121] Large-scale ammonia cracker to enable 1 million tonnes of hydrogen imports via port of Rotterdam | Port of Rotterdam

- Daeson, South Korea NH3 import[122].

While the full NH3-H2 supply chain described above has not yet been implemented, the key processes required to transport NH3 and to decompose it into H2 are commercially available and implemented in other industries. Anhydrous NH3 is frequently shipped as feedstock to the fertilizer industry. Both land and sea-based infrastructure exists and is available.

Multiple vendors exist with commercial offerings for thermal NH3 cracking plants. A few of these include KBR, Topsoe, Thyssenkrupp, Johnson Matthey, Duiker, Casale, and H2Site.

Additionally, large-scale NH3 cracking facilities like the size needed to meet the expected H2 demands are currently in operation. One example of this is a facility provided by Topsoe in Arroyito, Argentina. While not specifically aimed at the production of H2 fuel, this facility does demonstrate a capability to process and crack 4,800 metric tons of NH3 per day, which is comparable to the approximately 3,900 metric tons per day expected to meet Hawaiʻi's energy demands.

Figure 2. Image of Ammonia Processing Facility[123]

Since the use of NH3 as energy carrier is rapidly evolving, potential configuration created at this stage should be considered as a conceptual-level arrangement only.

[122] KBR to provide cracking tech for new South Korean project - Ammonia Energy Association

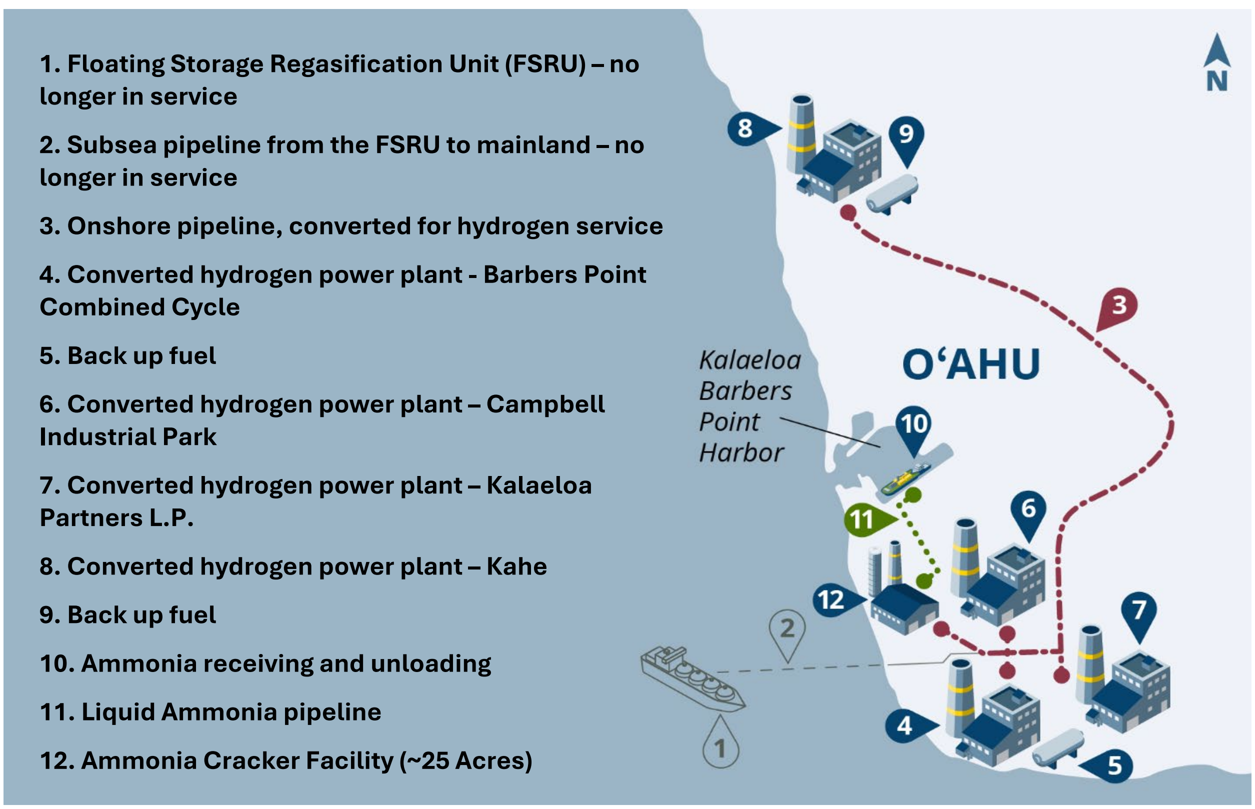
[123] Argentina recupera la Planta Industrial de Agua Pesada de Arroyito

If NH3 were employed as an energy carrier for transporting green H2 to Hawaiʻi at some time in the future, the state of technology at that time would need to be re-evaluated to confirm newly developed best practices are incorporated.[124]

In developing this concept, HDR considered proposed configurations of announced NH3 projects as well as the potential footprint of the NH3 cracking facilities described above. In general, the large throughput of NH3 processing expected to be required seems to favor a land-based NH3 cracking facility. While floating NH3 cracking facilities have been proposed, the throughput of these facilities does not seem to be large enough to accommodate the H2 needs forecasted for Hawaiʻi.

The concept shown in Figure 3 below for the island of Oʻahu would mirror operation of the existing oil refinery. NH3 could be received at the Barber's Point Harber and then transported via pipeline to new NH3 processing equipment. H2 produced by the NH3 cracking could then be transported via pipeline to the adjacent power plants.

Figure 3. Ammonia Energy Concept for Oʻahu



[124] As of 2024, turbine manufactures GE Vernova, Mitsubishi, and IHI have successfully conducted field tests of combusting liquid NH3 in their turbines. As these turbines improve and if further tests are validated, Hawaiʻi may choose to implement a system that combusts NH3 rather than H2. This would remove the need for the energy intensive cracking process.

LNG Infrastructure Reuse

As described elsewhere, HDR proposes Hawaiʻi adopt LNG as a near-term energy source to bridge the gap between current oil-based power generation and the goal of fully carbon neutral energy use on Oʻahu. The proposed LNG infrastructure is fully described in other HDR Technical Documentation. Since LNG is being considered as an intermediate fueling solution with the long-term goal of utilizing carbon neutral H2, consideration is needed regarding the ability to convert LNG and NG-based infrastructure to the proposed NH3-H2 delivery concept outlined in this document.

In general, the majority of the fuel receiving and processing equipment is not expected to be interchangeable between the two fuels. The proposed LNG receiving method makes use of a floating storage regasification unit (FSRU) for unloading and regasification of LNG. Converting NH3 to H2 for use as a fuel to meet the expected electricity needs will require significant NH3 storage and cracking infrastructure beyond what can be accommodated by a floating vessel. NH3 will need to be received and processed with new land-based infrastructure specifically dedicated to processing this NH3.

While the fuel infrastructure may not be interchangeable, much of the power generation equipment proposed to be fueled by NG supplied as LNG could be installed to provide the capability to operate on H2 in the future. Many of the prominent gas turbine suppliers have published clear plans to transition their generation equipment to operation on H2 as a fuel. Some turbines can be supplied today with full H2 capability but, in general, the market for H2-capable gas turbines is expected to fully develop in the next 10 years.

Converting a natural gas power plant to H2 would require modification of the fuel system to accommodate the large volumetric flows associated with H2, however, most of the steam and power systems within the plant could continue to operate as designed regardless of the fuel used.

Additionally, pipelines installed on the island for the transportation of NG could be converted for the transport of gaseous H2 fuel.

Ammonia Supply

An additional consideration for implementing the proposed NH3-H2-based fueling system outlined in this document is the ability to source bulk low-carbon NH3. Based on US Geological Survey data, the United States produced close to 14 million metric tons of NH3 in 2023[125]. 88% of this NH3 was used for agriculture purposes with the remainder serving other chemical and industrial processes. The majority of this was used within the United States with only 1 million metric tons being exported. This NH3 was produced from 36 different plants throughout the country operating at approximately 90% of rated capacity.

[125] Nitrogen Statistics and Information | U.S. Geological Survey

The current US NH3 production is spoken for and would not be available as fuel supply to Hawaiʻi. Additionally, the level of electrical generation proposed is expected to require 1.5 million metric tons of NH3 per year, which is 11% of the 2023 nationwide production. NH3 production in the United States would need to be significantly increased to meet this demand.

Recently, multiple announcements have been made indicating the potential expansion of the US NH3 generation capabilities. Most of these projects are aimed at providing low-carbon NH3 as a fuel source. A few of these are noted below. Development of these projects and other low-carbon NH3 production facilities should be carefully evaluated before committing to an NH3-H2 energy supply strategy for Hawaiʻi.

- Ascension Clean Energy - Louisiana[126]
- CF Industries Blue Point Complex - Louisiana[127]
- SIP St Charles Project - Louisiana[128]
- Adams Fork Clean Energy – West Virginia[129]
- Gulf Coast Ammonia - Texas[130]
- Nutrien - Louisiana[131]

Outside of the United States, NH3 for fuel markets in Australia and Southeast Asia should also be considered as Hawaiʻi looks to make the fuel transition.

[126] The Ace Project

[127] CF Industries and JERA Announce JDA to Develop Greenfield Low-Carbon Ammonia Production Capacity in U.S. | CF Industries

[128] St. Charles

[129] AdamsForkEnergy

[130] Gulf Coast Ammonia – Meeting domestic & global demands for agricultural fertilizers

[131] Nutrien Announces Intention to Build World’s Largest Clean Ammonia Production Facility | Nutrien

Appendix H - Anticipated Permits and Approvals

The tables below include the anticipated permits that may be applicable.

- Table 15 includes the Federal permits and approvals
- Table 16 includes the State permits and approvals
- Table 17 includes the Oʻahu permits and approvals

Table 15. Federal Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
National Historic Preservation Act (NHPA) Section 106 Review and Compliance	Advisory Council on Historic Preservation / State Historic Preservation Division	D	Will the project require federal assistance, including federal funding, permits, or approvals, and have the potential to affect historic properties?
National Environmental Policy Act (NEPA)	Council on Environmental Quality, Lead Agency Depends on Federal Action	D	Will the project require a federal action (including federal funding, permits, or approvals) or be located on federal land triggering the National Environmental Policy Act (NEPA)?
Department of Defense Consultation	Department of Defense	D	Will the project have potential to affect Department of Defense (DOD) installations or training activities in Hawaiʻi?
Marine Mammal Protection Act (MMPA) Incidental Harassment Authorization or Letter of Authorization	National Oceanic and Atmospheric Administration, National Marine Fisheries Service	D	Will the project have potential to affect marine mammals protected by the Marine Mammal Protection Act (MMPA)?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Essential Fish Habitat Consultation, Magnuson-Stevens Fishery Conservation and Management Act (MSA)	National Oceanic and Atmospheric Administration, National Marine Fisheries Service	D	Will the project require federal funds, permit, or activities that may adversely affect essential fish habitats (EFH) under the Magnuson-Stevens Fishery Conservation and Management Act (MSA)?
Endangered Species Act (ESA) Section 7 Consultation and Compliance (National Oceanic and Atmospheric Administration [NOAA], U.S. Fish and Wildlife Service [USFWS]) Incidental Take Permit, Section 10 (NOAA, USFWS)	National Oceanic and Atmospheric Administration, National Marine Fisheries Service, US Fish and Wildlife Service, Pacific Islands Fish and Wildlife Field Office	D	Will the project have potential to incidentally or unintentionally harm threatened or endangered species or designated critical habitats listed under the Endangered Species Act (ESA)?
Clean Water Act (CWA) Section 404 Permit (Department of Army Permit, Individual or Nationwide Permit)	US Army Corps of Engineers (USACE), Regulatory Branch	D	Will the project require any work in, under, or over Waters of the United States or the discharge (e.g., dump, place, deposit) of dredged or fill material in Waters of the United States (including navigable waters and wetlands)?
Marine and Harbor Activities Notice	US Coast Guard, Department of Homeland Security	M	Will the project require activities within navigable Waters of the United States that may affect marine vessel or harbor activities?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Spill Prevention, Control, and Countermeasure (SPCC) Plan	US Environmental Protection Agency	M	Will the project include bulk above ground storage tanks with a total oil capacity of over 1,320 gallons in containers of 55 gallons or larger or total buried storage capacity over 42,000 gallons?
Deepwater Ports	Maritime Administration	D	A licensing system for ownership, construction, operation, and decommissioning of deepwater port structures located beyond the U.S. territorial sea for the import and export of oil and natural gas
Authorization for Liquefied Natural Gas Terminal Facilities, Onshore or in State Waters	FERC	D	Application for the siting, construction, expansion, or operation of an LNG terminal filed pursuant to section 3 of the Natural Gas Act
Section 10 of the Rivers and Harbors Act of 1899	USACE	D	Placement of structures affecting course, location, condition, or capacity of navigable waters of U.S. (includes offshore wind within 3 miles of coast); exemptions exist)
USCG Letter of Recommendation for Marine Operations	USCG	D	An owner or operator seeking approval from FERC to build and operate or expand an LNG facility, as defined in 33 CFR Part 127

* Permit Type is defined as 1) D = Discretionary or 2) M = Ministerial

Table 16. State Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Hawaiʻi State Environmental Policy Act (HEPA)	Office of Planning and Sustainable Development, Environmental Review Program	D	Will the project require a state action (including federal funding, permits, or approvals) or be located on federal land triggering the National Environmental Policy Act (NEPA)?
Lease, Easement, or Right-of-Entry	Department of Hawaiian Home Lands, Hawaiian Homes Commission	M	Will the project use lands owned, managed, or controlled by the Department of Hawaiian Home Lands (DHHL)?
Air Pollution Control Permit, Covered Source Permit or Noncovered Source Permit	Department of Health, Clean Air Branch	M	Will the project construct, reconstruct, modify, or operate a stationary air pollution source?
National Pollutant Discharge Elimination System Permit (Individual and General Construction Activities)	Department of Health, Clean Water Branch	M	Will the project disturb one or more acres of land?
National Pollutant Discharge Elimination System Permit (Dewatering Permit)	Department of Health, Clean Water Branch	M	Will project's construction require the removal or temporary relocation of groundwater or surface water from the site?
National Pollutant Discharge Elimination System Permit (Individual and General Industrial Activities)	Department of Health, Clean Water Branch	M	Will the project be considered an industrial facility that is regulated under HAR Section 11-55, Appendix B?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Section 401 Water Quality Certification	Department of Health, Clean Water Branch	M	Is there potential for the project to discharge pollutants into waters of the State and/or require a Section 404 Individual Permit?
Community Noise Permit / Noise Variance	Department of Health, Indoor and Radiological Health Branch	M	Will the project conduct any construction activity or install stationary equipment that will exceed the maximum allowable noise limits set by HAR Section 11-46-3?
Comprehensive Environmental Response, Compensation, and Liability Act Compliance	Department of Health, Office of Hazard Evaluation and Emergency Response (delegated by US Environmental Protection Agency	M	Does the project site contain confirmed or potential soil contaminated by hazardous waste or materials?
Hazardous Waste Treatment, Storage, and Disposal Permit Hazardous Materials Permit (FHAZ)	Department of Health, Solid and Hazardous Waste Branch	M	Will the project require the storage, disposal, or treatment of any hazardous waste that meets the definition of hazardous waste under HAR Section 11-261.1?
Elevator and Kindred Equipment Permit	Department of Labor and Industrial Relations, Hawaiʻi Occupational Safety and Health	M	Will the project install or alter elevators, dumbwaiters, escalators, moving walks, stage lifts, personnel hoists, or other mechanized equipment to convey people in place?
Incidental Take License and Habitat Conservation Plan	Department of Land and Natural Resources, Division of Forestry and Wildlife, Wildlife Section	D	Will the project "take" a Hawaiʻi-listed threatened or endangered species?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Submerged Land Lease	Department of Land and Natural Resources, Land Division	D	Will the project require a lease for an area within the state marine waters or submerged lands?
Lease, Easement, or Right-of-Entry	Department of Land and Natural Resources, Land Division	D	Will the project require one or more of the following: access, use, or other easements to public lands; the purchase of remnant public lands; direct land lease; and/or a land license?
Historic Preservation Review and Compliance (HRS 6E)	Department of Land and Natural Resources, State Historic Preservation Division	D	Will the project affect cultural, archeological, or historic resources or sites or require state approvals or funding?
Ocean Waters of the State Work Permit	Department of Transportation, Harbors Division	M	Will the project perform any dredging, filling, installation of buoys, or erection of any construction within commercial harbors or entrance channels belonging to or controlled by the state?
Permit for the Occupancy and Use of State Highway Right-of-Way	Department of Transportation, Highways Division	M	Will the project require equipment or infrastructure located within the state highway right-of-way?
Coastal Zone Management Federal Consistency Certification	Office of Planning and Sustainable Development	M	Will the project involve a federal agency action (such as needing to obtain a federal permit, receive federal funding, or be constructed on federal land) and affect any coastal use or resource?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Certificate of Public Convenience and Necessity	Public Utilities Commission	D	Will the project provide, sell, or transmit power directly to the public or end users other than a public utility?
Power Purchase Agreement or Fuel Purchase Agreement	Public Utilities Commission	D	Will the project sell power, fuel, or gas to one of Hawaiʻi's regulated public utilities (KIUC, HECO, MECO, HELCO, or Hawaiʻi Gas)?
Transmission Line Approval	Public Utilities Commission	D	Will the project interconnect to the existing electric grid and require a new transmission line?

* Permit Type is defined as 1) D = Discretionary or 2) M = Ministerial

Table 17. Oʻahu Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
State Special Use Permit (Oʻahu)	Department of Planning and Permitting, Planning Division	D	Will the project require non-permissible uses (i.e., “unusual and reasonable” uses) within the agricultural and/or rural land use districts? Only required for parcels located in the State Agricultural District.
Conditional Use Permit (CUP) (Major or Minor) (Oʻahu)	Department of Planning and Permitting, Planning Division	D	Will the project conform to the land uses permitted in the parcel's county zoning designation?
Shoreline Setback Variance	Department of Planning and Permitting	D	Will the project include structures, facilities, construction, or any activities prohibited within the shoreline setback area?
Minor Shoreline Structure Permit	Department of Planning and Permitting	D	Will the project include minor structures within the shoreline setback area?
Special Management Area Assessment (Oʻahu)	Department of Planning and Permitting (DPP), Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA)?
Special Management Area Use Permit Major (Oʻahu)	Department of Planning and Permitting, Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA) that will exceed $500,000 (or $125,000 in Maui County) or is expected to have a substantial adverse environmental or ecological effect to coastal areas?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Special Management Area Permit Minor (Oʻahu)	Department of Planning and Permitting, Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA) that does not exceed $500,000 (or $125,000 in Maui County) and which has no substantial adverse environmental or ecological impact on coastal areas?
Flood Determination Approval + Flood Hazard District Variance (Oʻahu)	Department of Planning and Permitting, Building Division	M	Will the project be located in a flood zone?
Building Permit	Department of Planning and Permitting, Building Division	M	Will the project construct, alter, move, demolish, repair, or use any building or structure or require electrical or plumbing work?
Tank Installation Permit	Honolulu Fire Department	M	Will the project install or operate equipment in connection with the storage, handling, use, or sale of flammable or combustible liquids regulated under Chapter 66 of the National Fire Protection Association?
Sewer Connection Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require a connection to the county wastewater system?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Grading Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require excavation or filling with earth materials (e.g., rock, coral, gravel, soil, recycled asphalt pavement) that are taller than 3 feet high or greater than 50 cubic yards in volume, or redirect existing surface run-off patterns with respect to adjacent properties?
Grubbing Permit	Department of Planning and Permitting, Site Development Division	M	Will the project uproot or dislodge vegetation from the ground surface across an area larger than 15,000 square feet?
Stockpiling Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require the temporary open storage of earth materials in excess of 100 cubic yards?
Trenching Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project trench (i.e., dig, break, disturb, or undermine) any public highway, street, thoroughfare, alley, or sidewalk or any other similar public space?
Erosion and Sediment Control Plans for Small Construction Projects	Department of Planning and Permitting	M	Is the project a residential or commercial project less than 1 acre in size within the City and County of Honolulu (CCH) that requires a Building Permit, but does not require a Grading, Grubbing, or Stockpiling permit?
Construction Dewatering Permit	Department of Planning and Permitting	M	Will the water from the construction site discharge into the city-owned municipal storm sewer system?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Industrial Wastewater Discharge Permit (IWDP)	Department of Planning and Permitting, Site Development Division, Wastewater Branch	M	Will the project require a building permit and have a sewer connection for the discharge of water into the county sanitary sewer?
Storm Drain Connection License	Department of Planning and Permitting, Site Development Division	M	Will the proposed project require a private drainage-system connection to the city municipal separate storm sewer system (MS4)?
Driveway Variance	Department of Planning and Permitting, Site Development Division	M	Will the project require a driveway approach that deviates from City and County of Hawaiʻi (CCH) standards?
Sign Permit	Department of Planning and Permitting, Site Development Division	M	Will the project require the installation or modification of any fixed, permanent signs?
Authorization of Surface Encroachment	Department of Planning and Permitting, Site Development Division	M	Will the project require placement of landscaping, objects, or structures on city sidewalk areas that deviate from city standards?
Demolition Permit	Department of Planning and Permitting, Site Development Division	M	Will the project require demolition of any building?

* Permit Type is defined as 1) D = Discretionary or 2) M = Ministerial

HAWAIʻI STATE ENERGY OFFICE

Lifecycle Greenhouse Gas Emissions – Technical Documentation

Alternative Fuel, Repowering, and Energy Transition Study

Contents

Background

The State of Hawaiʻi is one of only seven states to set a statutory target to fully decarbonize, and one of only two to commit to it by 2045. Achieving economy-wide carbon reductions will require ambitious GHG reductions in the electric sector.

In 2023, the Hawaiʻi Supreme Court ruled on the critical importance of lifecycle emission accounting in its decision regarding the *Application of Hawaiʻi Electric Light Company For Approval of a Power Purchase Agreement for Renewable Dispatchable Firm Energy and Capacity.*[1] In its decision, the court affirmed the Public Utilities Commission's (PUC's) authority to carry out its public interest mission by addressing the court's remand instructions to consider the reasonableness of the proposed project in light of its greenhouse gas emissions and project costs.[2] At the core of this decision was a biomass project's lifecycle analysis presented to the PUC, which showed that the project's associated lifecycle emissions were substantial and could not be appropriately mitigated through the prescribed offsets.[3]

The State Legislature further upheld the precedent set forth by the Hawaiʻi Supreme Court and added additional language to Hawaiʻi Revised Statutes (HRS) to ensure lifecycle accounting is incorporated into PUC decision-making by passing Act 54, Session Laws of Hawaii 2024. Act 54 set forth an explicit requirement to analyze lifecycle emissions for combustion projects.[4] HRS §269-1, as amended, defines lifecycle greenhouse gas emissions assessment as "*the evaluation of potential greenhouse gas emissions over the course of a product, program, or project's lifetime or stages of production, construction, operations, and decommissioning, which includes but is not limited to, as applicable, upstream stages such as extraction and processing of materials, and transportation; operations stages such as the use of any fuels or feedstocks and the production of any materials; and downstream stages such as transportation, decommissioning, recycling, and the final disposal*." This discussion focuses on the extraction and production of fuels as well as the operations of power plants; construction activities and decommissioning were not included in this analysis.

As of 2023, 65% of Hawaiʻi's grids are powered with low-sulfur fuel oil (LSFO) or diesel, making Hawaiʻi the last state in the country to provide the bulk of its electricity in this manner. On Oʻahu, just 33% of the total generation on the island was from renewables—the remaining 67% is powered by *bottom-of-the-barrel* LSFO, a type of residual fuel oil (RFO). On outer islands, the fossil fuel used is diesel, categorized as distillate fuel oil (DFO).[5] The term, *bottom-of-the-barrel* is

[1] Supreme Court of Hawaiʻi. (2023). *In re: the Application of Hawaiʻi Electric Light Company, Inc. for approval of a power purchase agreement for renewable dispatchable firm energy and capacity* (SCOT-22-0000418). Decided March 13, 2023.
[2] *Id*.
[3] Before the Public Utilities Commission in the Matter of the Application of Hawaiʻi Electric Light Company Inc. Docket No. 2017-0122. For Approval of a Power Purchase Agreement for Renewable Dispatchable Firm Energy and Capacity. Decision and Order No. 38395
[4] Act 54, Session Laws of Hawaiʻi 2024, Relating to Renewable Energy.
[5] Data Compiled by the Hawai'i State Energy Office, Source PUC Docket 2007-0008, Hawai'i Renewable Portfolio Standard Status Reports

used to describe these fuels because RFO is the heavier, leftover residue of crude oil after lighter hydrocarbons and distillates are removed during the refining process, these lighter distillates are most used in ground transportation and aviation. Outer islands primarily use diesel, a heavier distillate oil.

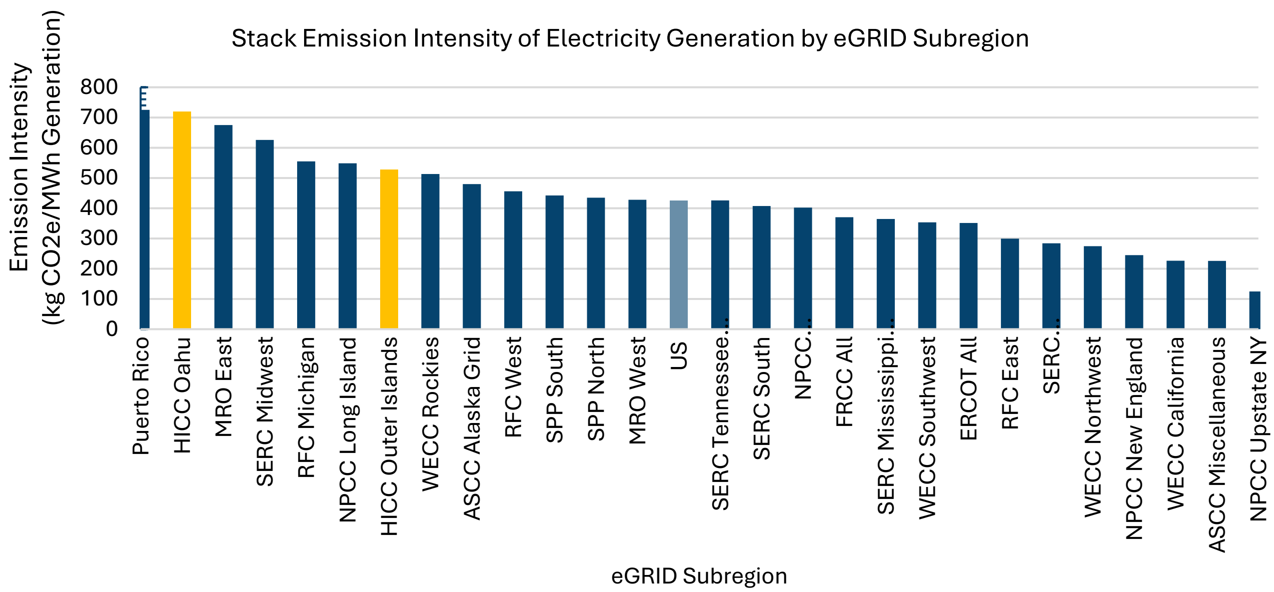


Figure 1 Stack emission intensities for US eGRID Subregions. Source EPA eGRID 2022 Data.

The consequences of burning LSFO for the majority of Hawai'i's generation has resulted in the island of O'ahu having the highest emission intensity in the country, or the highest carbon emissions, per unit of electricity produced when compared to other electric grid subregions (Figure 1), with only Puerto Rico having a higher emission intensity, also known as carbon intensity (CI). While these statistics represent emissions at the stack, or emissions released during combustion; when accounting for the full lifecycle emissions for electrical generation from "well-to-outlet" oil-fired generation comparatively has the highest carbon emissions intensity, on average, compared to other cost-competitive conventional options, with only coal exceeding oil emissions on a lifecycle accounting basis.[6]

[6] National Renewable Energy Laboratory (2021), *Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update.* Office of Energy Efficiency and Renewable Energy Operated by the Alliance for Sustainable Energy, LLC https://www.nrel.gov/docs/fy21osti/80580.pdf

* Top-down approaches derive emissions estimates from direct measurements such as those obtained from remote sensing (satellite or flyover) and imaging spectroscopy. Bottom-up estimation approaches derive emission estimates from known emission factors and system component leakage estimates. This analysis uses a hybrid approach.

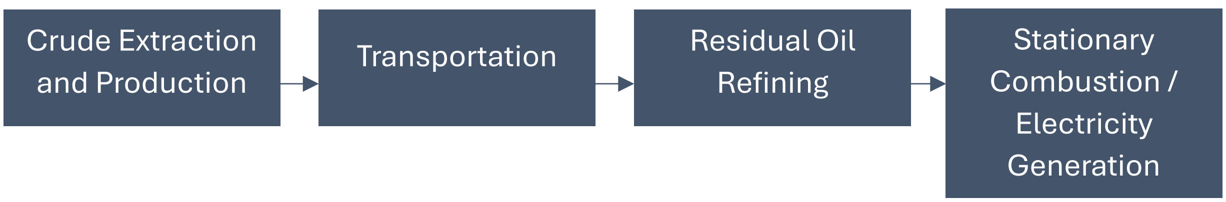
Applicability for the Various Fuel Types Evaluated in the Alternative Fuels Study

For this study, all alternative fuel options were considered, and emissions were compared on a lifecycle carbon intensity (CI) basis.[7] The fuel lifecycle varies by fuel type. Emissions estimates can also differ based on assumptions, methodology—e.g. top-down or bottom-up approaches*, emission factors assumed, system boundaries, and applied global warming potentials (GWP).[8] For this reason, this analysis and comparative literature review strived to use various data sources and emission factors.

Lifecycle Stages by Fuel Type

The key lifecycle stages for differing fuel types are unique. Stages of differing fuel types are summarized below.

Lifecycle of Oil for Electricity Generation



1. Extraction and production (Upstream)

Emissions from extraction and production occur during the different processes required to extract oil from source wells. These emissions may result from gas flaring and venting practices (which can vary widely depending on the source country or basin) and from fugitive methane leakage, which occurs in both natural gas and oil extraction.

In addition, greenhouse gases are emitted from the energy used to operate drilling rigs, pumps, and other processing equipment, also accounted for at this stage.

2. Crude and Final Product Transport (Transportation)

Emissions at this stage are from the transport of crude oil products to where they will be refined, typically via ship or pipeline. In Hawai‘i’s case, crude oil is transported via ship most frequently from Northern and Western Africa as well as South America. These distances were incorporated into the weighted GHG analysis presented.

[7] Carbon intensity (CI) refers to the amount of carbon dioxide equivalent (CO_2e) emissions produced per unit of output or activity. In this analysis, CI units are CO2e per MMBtu.
[8] Global Warming Potential (GWP) is a measure of the relative radiative effect of a greenhouse gas compared to carbon dioxide over a chosen time horizon. GWPs used herein are from the IPCC Sixth Assessment Report (AR6). See Section A-4.

Emissions from the transport of fuel, mostly through pipelines, after refining takes place are also incorporated into this stage.

3. Refining (Midstream)

Emissions from refining are typically released from stationary fuel combustion units but may also be released from cracking and coking units, blowdown systems, storage tanks, and general equipment leaks.

Note, the refining of some fuels may occur before transport to Hawaiʻi. If refined out of state, refining emissions are still incorporated into the lifecycle estimates. Since Par Hawaiʻi is the current supplier of most of Hawaiian Electric's fuels, the refining stage is placed after crude transport in this analysis.

4. Stationary Combustion / Electricity production (Downstream)

Emissions from stationary combustion are produced at power plants during the combustion of fuel to generate electricity. These emissions can be categorized as input emissions and output emissions. Input emission intensities are determined by dividing total emissions by the total heat input from combustion. Output emission intensities, on the other hand, are calculated as the total emissions released per unit of electricity generated. For this stage, output emission intensities should be utilized to accurately reflect electricity generation, with the energy conversion efficiency of the plant considered throughout the entire lifecycle to account for heat loss.

See *Hawaiʻi Power Plant Combustion Input and Output Emissions and Calculated Conversion Efficiencies* for the input and output emissions rates of existing power plants in Hawaiʻi as well as the calculated energy conversion efficiencies. Energy conversion efficiencies, also known as heat rates (more commonly presented in units of btu/kWh), are calculated using the following equation:

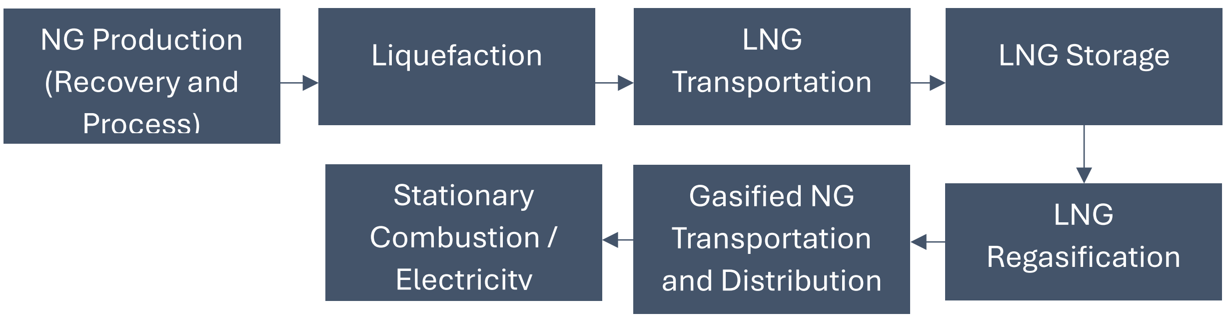
$$\frac{\left(\frac{kgCO2e}{mmbtu\ electricity\ generated}\right)}{\left(\frac{kgCO2e}{mmbtu\ fuel\ combusted}\right)} = energy\ conversion\ efficiency\ \left(\frac{mmbtu\ fuel\ combusted}{mmbtu\ electricity\ generated}\right)$$

The powerplant efficiency ultimately determines how much energy is consumed in the combustion process per unit of energy generated. When deriving carbon intensities, the energy conversion efficiency of the power plant is applied to all points in the lifecycle, because the power plant efficiency ultimately dictates the amount of fuel required to generate electricity. While the heat rates fluctuate based on a variety of factors including load variations and plant cycling, fuel quality, and plant age, it is important to include some metric of heat loss across all lifecycle stages because power plants convert only a portion of the energy in the fuel into electricity, with the rest lost as heat.

The efficiency multiplier captures this conversion loss. This is a standard practice in the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model.

Lifecycle of Liquefied Natural Gas for Electricity Generation

There are many parallels between the lifecycle of natural gas and the lifecycle of oil and liquid petroleum fuels. Often, natural gas is extracted at the same location as oil, with many production wells producing both.[9] There are more steps in the natural gas fuel lifecycle than in oil systems due, in part, to the liquefaction and regasification needs, only applicable to locations that require import. Because methane (CH_4) is a gas at normal temperatures and pressures, it must be cooled and stored at high pressures to be transported long distances efficiently without occupying substantial space. These additional lifecycle stages add risk for additional operational and fugitive releases and should be carefully accounted for in the lifecycle analysis.



1. Production – Recovery/Extraction and Processing

Emissions from the extraction of natural gas are very similar to that of crude oil and result from fugitive methane leakage and gas flaring and venting practices, which can vary widely depending on the source country as well as the geological hydrocarbon basin (e.g. the Permian Basin vs. the Marcellus Basin), where the gas is extracted.

In addition, emissions arise in this stage from the energy used to operate drilling rigs, pumps, and other processing equipment. Additionally, natural gas undergoes processing to separate natural gas liquids and remove impurities such as carbon dioxide, hydrogen sulfide, or sulfur dioxide.

2. Liquefaction

Most of the emissions are carbon dioxide from either fuel combustion for refrigeration compressors or generator turbines. Carbon dioxide emissions occur during flare combustion which is used to destroy high global warming potential waste gases, mostly methane, which may need to be released for maintenance or for a short duration during emergencies. Methane (CH_4)

[9] https://www.eia.gov/petroleum/wells/

emissions from incomplete flaring and leaks may also occur; however, these emissions are much smaller in amount when compared to the production/extraction stage.[10]

3. LNG Transportation and Distribution

Emissions from the LNG transportation and distribution stage occur during the transportation of the LNG. For Hawai‘i, transport emissions include fuel used for shipping, as well as energy used for LNG handling (primarily cooling). Emissions from transport may include methane fugitives (unintentional leaks, typically from seals or equipment connections) and venting emissions (intentional emissions via dedicated outlets to the atmosphere, primarily for safety) from the onboard LNG and vapor handling plant.[11] The LNG tanker type impacts the emission rates.

4. LNG Storage

Emissions from LNG storage primarily arise from boil-off and leaks.

Boil-off refers to the small amount of liquefied natural gas (LNG) that naturally evaporates during storage, loading, transport, and unloading due to heat ingress. LNG is stored at cryogenic temperatures in insulated tanks, but some heat transfer is inevitable, causing vaporization and necessitating pressure management. Strategies to mitigate evaporation during LNG storage and transportation include utilizing the evaporated gas efficiently, heat ingress may be reduced with more advanced tank design.

Leaks are unintended releases of LNG or vapor, sources of leaks include compromised tank, valve, or seal integrity and leaks during transfer operations. Regular inspections, maintenance, adherence to safety guidelines, and installation of vapor recovery systems can reduce leaks and fugitive emissions from LNG storage.

5. LNG Regasification

The main sources of methane emissions from LNG export/import terminals include fugitive leaks from equipment, incomplete combustion of fuel from power-generating equipment, and incomplete combustion from flare and boil-off systems. Carbon dioxide emissions arise from flaring systems as well as general energy use.

6. Stationary Combustion for Electricity Generation

After regasification, natural gas is combusted in stationary sources such as gas turbines or boilers to produce electricity or heat. Emissions from this stage are the result of burning or combusting the fuel to generate electricity in stationary sources such as gas turbines or boilers to produce electricity or heat. The combustion process primarily releases CO_2, but emissions can contain small amounts of CH_4 and N_2O. Ultimately, the efficiency of the combustion technology (i.e.

[10] Zheng et al., 2023. Measuring carbon dioxide emissions from liquefied natural gas (LNG) terminals with Imagin spectroscopy https://agupubs.onlinelibrary.wiley.com/doi/pdf/10.1029/2023GL105755

[11] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC9261184/

powerplant heat rate) and the combustion conditions determine the quantity and chemical makeup of emissions.

The **energy conversion efficiency of the power plant is considered at all points in the lifecycle.** This is because power plant efficiency ultimately dictates the amount of fuel required to generate electricity, which is critical if an intensity value is derived.

Efficiency for typical natural gas power plants ranges from 43% to as high as 58%, for combined cycle power plants. The energy conversion efficiency is essentially the inverse of a plant's heat rate. Choosing an average 51% efficiency conversion factor equates to a multiplier of 1.9 MMBtu of fuel per 1 MMBtu of electricity produced.[12] This multiplier must be applied to all points in the lifecycle to account for energy loss. However, 58% efficiency may not be attainable if there is frequent plant cycling.

For the natural gas and oil comparison, this efficiency factor is a large driver of emissions reduction, as shown in the *Comparative Analysis Section*.

Accounting Methods and Challenges in Oil and Natural Gas

Estimating emissions from the oil and gas industry is done using two primary methods: top-down and bottom-up. Top-down calculations are typically derived from site or field measurements, which may include emissions recorded during flyovers, measuring stations, drive-by detection, or satellites. Bottom-up emission estimates are derived from equipment specifications and component-specific leak factors.[13]

Recent studies have demonstrated that national emission inventories, which use bottom-up accounting, underestimate methane emissions compared to top-down measurements.[14] However, new bottom-up methods are being developed to better incorporate top-down measurement-informed data.[15]

Given the variability of emission estimates across differing methods, HSEO developed a scenario approach to evaluate emission estimates from different sources, inclusive of bottom-up and, at the stages available, top-down estimates. A hybrid approach was used when certain stages in the supply chain were not part of a published dataset. For example, Rocky Mountain Institute's (RMI) Oil Climate Index plus Gas (OCI+) model, a hybrid top-down and bottom-up emissions dataset, did not include emission estimates from liquefaction, therefore RMI estimates were used for upstream estimates and added the ANL (Argonne National Laboratory) GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) tool for midstream and downstream estimates.

[12] GREET, 2023.

[13] Oil Climate Index plus Gas (rmi.org)

[14] Zhu, Y., Allen, D., & Ravikumar, A. (2024). Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains. DOI: 10.26434/chemrxiv-2024-9v8dw

[15] Oil Climate Index plus Gas (rmi.org)

For the LNG supply chain in particular, the main determinants of methane emissions are facility design, age, and operational and management procedures. Facilities designed with an emphasis on emissions can achieve very low emissions during normal operations and can strive to reduce emissions during maintenance. These facility designs, practices, and procedures are often impacted by the environmental regulations in place for source countries, thus resulting in geographic differences in upstream emissions. The underlying geology and shale composition can also impact emissions estimates, resulting in basin-specific and geographic differences.[16]

Further discussion on the analysis conducted is presented in the *Comparative Analysis*.

Lifecycle of Biofuels for Electricity Production

Lifecycle analysis for biofuels can generally be broken into the following stages: 1) feedstock production and collection, which includes emissions from land use change, farming inputs, and energy inputs; 2) farm-input manufacturing; 3) the production of the fuel itself (i.e. feedstock processing and refining); and 4) the combustion of the fuel and, as applicable, electricity production.

Empirical limitations are significant for bioenergy and are discussed by lifecycle stage below.

1. Land Use Change and Soil Carbon Flux

Land use change (LUC) is defined as the shift in land use and land cover that accompanies feedstock or fuel crop production. Emissions estimates from various biofuel lifecycle analysis documentation stem from both economic modeling of market-mediated effects as well as biophysical modeling of soil carbon and other biological systems and processes.[17] The LUC stage in lifecycle analysis incorporates estimates of emissions from activities such as cultivating new land for feedstocks including deforestation (applicable for fuels such as palm oil, and indirectly applicable for tallow feedstocks), soil carbon flux from soil disturbances, and other elements such as temporality; however, these stages are highly variable and region- or farm-specific, thus can be challenging to summarize in “average”, or general terms.

LUC often results in nonlinear feedback effects, which are challenging to account for empirically. When ecosystems change—such as deforestation, reforestation, or shifts to agricultural use—these alterations can trigger complex interactions among carbon, water, and nutrient cycles within both the aboveground biomass and within the soil. Such nonlinear responses are influenced by a variety of factors, including soil health, biodiversity, and climate, and their impact on GHG emissions may not be immediately observable. Variability arises from a multitude of interacting factors that influence the carbon absorption and storage capacities of ecosystems.

[16] Zhu, Y., Allen, D., & Ravikumar, A. (2024). Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains.
[17] Wang, M., Elgowainy, A., Lee, D., & Bafana, A. (2021). *Cradle-to-Grave Lifecycle Analysis of U.S. Light Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current and Future Technologies* (No. ANL/ESD-21/30). Argonne National Laboratory. https://publications.anl.gov/anlpubs/2021/10/171711.pdf

For example, water availability, which can be affected by local climate and seasonal drought conditions, directly impacts plant growth rates and, consequently, the carbon sequestration potential of a given area. Similarly, temperature fluctuations can either stimulate or suppress plant growth, depending on the species and ecosystem, thereby affecting carbon dynamics. Soil conditions, including soil organic matter, nutrient availability, and structure, also play a critical role in supporting plant growth and carbon retention. Soils with high organic content and rich nutrient levels can enhance plant productivity and carbon sequestration. Conversely, degraded soils may inhibit these processes, limiting the ecosystem's ability to offset GHG emissions.

Carbon accounting for biogenic, or biologically derived energy sources, is particularly challenging because it must consider the timing of both carbon release and sequestration in biological systems, also known as temporality. Like fossil fuels, which release carbon immediately at each stage of their lifecycle, biogenic emissions from biofuels are also released immediately during combustion but are not necessarily accounted for in the same way because the carbon balance of biogenic emissions is often evaluated differently. This is due to assumptions about carbon neutrality, which considers the potential for biogenic carbon to be reabsorbed by the ecosystem through natural processes like photosynthesis, thereby offsetting the emissions over time. However, the overall *neutrality* of biofuels depends on the payback period, which is influenced by the variable processes of plant growth and decomposition. These processes occur over months, years, or even decades, creating a time lag between carbon uptake during plant growth and carbon release upon biomass combustion, conversion, or decay. This temporal aspect introduces significant challenges for accurate accounting, as the carbon balance for biogenic energy sources is dynamic and fluctuates based on factors like seasonal growth rates, harvest cycles, and land management practices. This feedback adds layers of complexity to carbon accounting model which must be considered both in this lifecycle stage, as well as in the final combustion stage.

To improve the accuracy of emissions estimation for biofuels, the Argonne National Laboratory's GREET model incorporates the Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB). CCLUB attempts to estimate emissions from land use changes (LUC) related to biofuel production, factoring in land management practices and temporal aspects. Specifically, CCLUB aims to provide a better approximation of carbon fluxes by incorporating delayed sequestration and emissions tied to land use. Within the Renewable Fuel Standard (RFS) program, CCLUB is utilized to help address these temporal accounting complexities in the LUC stage, thereby enhancing the accuracy of lifecycle GHG assessments for biofuels.

A notable critique of the RFS program is its inability to fully capture the timeframe required to offset emissions initially released by biofuels.[18] When biofuels are produced and burned, the

[18] Lark, T. J., Hendricks, N. P., Smith, A., Gibbs, H. K., & Marshall, E. (2022). Environmental outcomes of the US Renewable Fuel Standard. *Proceedings of the National Academy of Sciences, 119*(9), e2101084119. https://doi.org/10.1073/pnas.2101084119

immediate release of carbon dioxide (CO_2) may not be effectively balanced by carbon sequestration through new plant growth or reforestation within a relevant policy timeframe. Consequently, there is a time gap before the displaced fossil fuel emissions, intended as an environmental benefit of biofuels, are counterbalanced by the carbon uptake of regrowing biomass. This time lag has raised concerns among researchers and policymakers who argue that without accounting for these temporal dynamics in carbon sequestration, biofuel emissions reductions may be overstated in the short term.

Further, LUC emissions exhibit significant variability across regions and feedstocks, making it difficult to establish a one-size-fits-all approach to carbon accounting in the global fuel market.

2. Feedstock Production and Collection

This stage includes growing, harvesting, or collecting the raw materials needed for renewable fuel production. Emissions associated with feedstock production can be further broken down into a) agricultural inputs and b) agricultural energy inputs.

a. Agricultural Inputs

This stage includes emissions associated with key inputs for crop or feedstock production. Dominant emitting inputs include fertilizers, pesticides, and herbicides, but emissions from water extraction processes used for irrigation may also play a significant role. The definition of system boundaries at this step is critical. For example, if a lifecycle analysis (LCA) includes only emissions from fertilizer application (e.g., N2O, Nox, and SOx) and excludes emissions from fertilizer production (CO2, CH4, N2O), this may lead to underestimating total upstream emissions.

Thus, a major question is: how far upstream in the supply chain should emissions be accounted for?

For feedstocks derived from animal byproducts (e.g., beef tallow), the question arises of whether and how to account for indirect emissions associated with the primary production of the animal product. Should the emissions from raising livestock, including methane from enteric fermentation and manure management, be allocated to the feedstock? Such decisions are pivotal in determining the overall CI of renewable fuel.

b. Agricultural energy inputs

Agricultural energy inputs include emissions associated with the energy required for field operations (e.g., planting, harvesting, and tilling), transportation of raw materials, and the use of machinery and equipment. This category also encompasses energy used for post-harvest processes, such as drying or initial processing of feedstocks, which may vary significantly depending on the type of crop or byproduct. The energy source for these operations also influences the carbon intensity of agricultural energy inputs.

For the land use change and soil carbon flux emissions estimates, each of these factors results in a highly localized nature of LUC and feedstock production emissions, underscoring the importance of understanding the specific climate and ecological context of the feedstock source for accurate carbon flux accounting. However, in the global fuel market, such granular accounting is arguably impractical. This challenge is especially relevant in Hawaiʻi, where local feedstock production faces constraints due to limited land availability and the prohibitive costs of shipping domestic products imposed by the Jones Act.

3. Feedstock & Co Product Transport

Emissions in this stage are from transporting feedstocks and other inputs to the sites where they will be processed. For example, if renewable fuels are refined in Hawaiʻi utilizing imported feedstocks (e.g. imported tallow), the emissions from shipping the input feedstocks to Hawaiʻi refineries would be accounted for in this stage. Emissions from shipping are highly impacted by ship/barge fuel efficiency. For imported as well as locally produced feedstock, this stage would also account for any trucking emissions associated with moving feedstock to refineries (e.g. transporting used oil from various restaurants in heavy-duty vehicles).

4. Fuel Production

Per the EPA's RFS program and the GREET model, the fuel production stage includes "GHG emissions associated with a specific type of fuel production technology, including all the energy and material inputs used in the fuel production process and the impacts of any co-products. This includes energy and material input used for handling, processing, and storing the feedstocks, co-products, intermediate products, and resulting fuel. The GHG emissions are calculated using emissions factors for all the process energy (e.g., natural gas, coal) and electricity used for fuel production operations. These factors include the upstream emissions associated with extraction, transport, and distribution of the energy, and are generally determined on an average basis (e.g., grid average electricity in the United States). The upstream emissions associated with significant material inputs used to produce the renewable fuel, such as methanol for biodiesel production, are also included."[19]

5. Fuel Distribution

Emissions in this stage are from transporting refined fuel from the source location. For example, if fuels are imported as refined products to Hawaiʻi, emissions from shipping would be accounted for in this stage. Distribution of fuels is typically more significant in the transportation sector due to the need to transport/truck refined fuels to fueling locations. For electricity generation, most on-island distribution of refined products would likely occur via pipeline, reducing emissions from trucking.

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[19] https://www.epa.gov/renewable-fuel-standard-program/lifecycle-analysis-greenhouse-gas-emissions-under-renewable-fuel

6. Stationary Combustion for Electricity Generation

Emissions in this stage are the same as those described in the oil and natural gas final stationary combustion stage. However, because emissions are considered "biogenic" many accounting standards consider these emissions to be carbon neutral because, in theory, the carbon had once been captured from the atmosphere through photosynthesis. However, as discussed in Chapter 5 of the Hawaiʻi Pathways to Decarbonization Report, scientific consensus generally recognizes this assumption as flawed.[20]

The final use stage of the GHG analysis must be customized to account for the energy conversion efficiencies unique to each power plant(s) burning the biofuel, and the electricity conversion efficiency must be applied to all upstream stages when calculating intensity.

Challenges with Lifecycle Accounting for Biofuels

Land use change involves emissions from activities such as deforestation, reforestation, or soil disturbances that are influenced by site-specific factors like biodiversity, soil composition, and climate. These elements often interact in nonlinear and regionally distinct ways, making it challenging to generalize emissions estimates. The temporal lag between ecosystem alterations and observable effects on greenhouse gas (GHG) fluxes further complicates accurate accounting.

Further, the production and collection of feedstocks involve numerous inputs like fertilizers, pesticides, and water, as well as the energy needed for field operations. Defining system boundaries is critical; for example, whether emissions from fertilizer manufacturing should be included affects lifecycle estimates, and is a critical item to measure, but the inputs to account for these emissions estimates are not always disclosed. Additionally, indirect emissions for animal-based feedstocks, such as those arising from livestock production, highlight the complexity of allocating responsibility in upstream processes.

Given these challenges, developing a holistic and adaptable framework for regulatory decisions in Hawaiʻi is important, but will require adequate regulatory resources. Given Hawaiʻi's reliance on international sources for fuel and feedstock imports, accountability for upstream emissions is complex given the diverse environmental policies, economic drivers, and agricultural practices in different countries. Developing a comprehensive, adaptable regulatory framework is essential to address these complexities. This framework should account for regional variations in LUC emissions, consider the temporality of the feedstock, emphasize supply chain transparency, and include international monitoring and verification mechanisms, as appropriate.

Local sourcing dramatically reduces uncertainties tied to international land use changes and their variable impacts. Monitoring local soil carbon flux, biodiversity, and ecosystem shifts becomes more feasible, allowing for region-specific data collection that improves the accuracy of

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[20] Liu, W., Zhang, Z., Xie, X., Yu, Z., Von Gadow, K., Xu, J., ... & Yang, Y. (2017). Analysis of the global warming potential of biogenic CO2 emission in life cycle assessments. *Scientific Reports*, *7*(1), 39857. Doi: 10.1038/srep39857

emissions estimates. Local context also helps address temporal and nonlinear feedback; however, regulatory and land management agencies will need to enforce land management practices to mitigate emissions from soil disturbances, fertilizer application, and land conversions.

Comparative Analysis

The various data sources for this comparative analysis used to determine the lifecycle emissions of fuels are listed and cited below. A full copy of the weighted analysis is available for download at: https://energy.hawaii.gov/alternative-fuels-repowering-and-energy-transition-study/

- Argonne National Laboratory. (2023). *GREET model: The greenhouse gases, regulated emissions, and energy use in technologies model*. Argonne National Laboratory. https://greet.anl.gov/; DOI: 10.11578/GREET-Excel-2023/dc.20230907.1

  General/default and customizable spreadsheets were used to conduct the analysis. The R&D GREET spreadsheet served as the primary harmonization tool for incorporating emission intensities at different lifecycle stages from other sources.

- RMI/OCI+ (2024) https://ociplus.rmi.org/

  The RMI/OCI+ dataset includes a hybrid approach to emission accounting incorporating both top-down emissions estimates and bottom-up emissions estimates.

- National Ocean Industries Association (NOIA). (2020). *GHG emission intensity of crude oil and condensate production*. https://www.noia.org/noia-report-ghg-emission-intensity-of-crude-oil-and-condensate-production/

- U.S. Environmental Protection Agency. (2023). Inventory of U.S. greenhouse gas emissions and sinks. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

To allow for comparative analysis, the functional unit for carbon intensity, or greenhouse gas emissions intensity, is kg CO_2e / mmBtu. For all analyses, 20-year and 100-year global warming potentials (GWP) were applied. GWPs from the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) were used.[21]

Current Generation Mix

Hawaiʻi's current generation mix consists of 65% fossil generation – with fossil fuels comprised of *bottom-of-the-barrel* LSFO primarily on Oʻahu (making up 67% of generation) and diesel primarily

[21] Intergovernmental Panel on Climate Change (IPCC). (2021). *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (V. Masson-Delmotte et al., Eds.). Cambridge University Press. https://doi.org/10.1017/9781009157896

serving units on the Maui, Hawaiʻi Island, Kaua'i, Molokaʻi, and Lānaʻi. For this analysis, fossil fuel generation was the focus of comparison.

Natural Gas v. Oil

Natural gas upstream—recovery and extraction—emissions vary dramatically by source country. The first part of the analysis involved an evaluation of likely source countries for natural gas, see *C-3: Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index*. HSEO identified likely source countries for LNG were British Columbia, Canada, and Australia. The next step was to use a scenario approach to estimate lifecycle emissions using various data sources. Scenarios are defined below.

Fuel	Scenario	Description
Oil	ANL GREET Default	CIs are directly from GREET default, with HICC as local grid generation mix.
	RMI/OCI+	All CIs are directly from RMI/OCI+.
	RMI/OCI+ and GREET Hybrid	Upstream CIs are from the RMI/OCI+ database (2022), while CIs of crude transport, refinery, and combustion are from ANL GREET Default.
	NOIA Report and GREET Hybrid	Upstream CIs are from the NOIA report, while CIs of crude transport, refinery, and combustion are from ANL GREET Default.
LNG	ANL GREET Default	CIs are directly from GREET default.
	RMI/OCI+ (AUS) and GREET Hybrid	Upstream and midstream CIs are from RMI/OCI+ estimates from Australia and all the other stages are from ANL GREET Default.
	RMI/OCI+ (CAN - Montney BC) and GREET Hybrid	Upstream and midstream CIs are from RMI/OCI+ estimates from British Columbia, Canada, and all the other stages are from ANL GREET Default.
	EPA Report and Customized GREET	ANL GREET inputs are customized based on EPA GHGI.

See *Multiple Source Analysis Results* for emissions estimates for each scenario, because the scenario analysis did not reveal any significant outliers, averages across scenarios were used to estimate LNG and LSFO lifecycle CI. Average CIs are presented in Table 1, where the fuel input CI and total output electricity carbon intensities are shown for liquified natural gas and oil.

Table 1 Weighted average carbon intensity estimates for Low Sulfur Fuel Oil and LNG using 20-year and 100-year GWPs for fuel inputs (right) and electricity output (left). Electricity output calculation assumed the current HICC powerplant efficiency of 32% (Source eGRID 2022), and LNG used a modeled powerplant efficiency of 46%. Transmission and distribution loss was assumed at 5.4%.

Fuel and Lifecycle Stage	Weighted Carbon Intensity (kg Co2e/MMBtu fuel input) 20-year GWP	100-year GWP	Weighted Carbon Intensity (kg CO2e/MMBtu electricity output) 20-year GWP	100-year GWP
LSFO				
Upstream - Production	18.6	11.4	60.9	37.3
Transport - Crude	2.1	2.0	6.9	6.6
Refinery - Residual Oil	6.2	5.8	20.1	18.9
LSFO - Combustion	82.8	82.6	270.9	270.4
TOTAL	109.7	101.8	358.8	333.2
LNG				
Upstream+ Midstream - NG Production	17.6	9.3	40.3	21.4
Liquefaction	9.6	7.6	22.0	17.5
LNG T&D	4.5	2.2	10.3	5.1
LNG Storage	1.8	0.7	4.1	1.5
LNG Regasification	2.4	1.2	5.5	2.8
Gasified NG T&D to Power Plant	0.7	0.4	1.6	0.8
NG - Combustion	59.6	59.5	136.9	136.7
TOTAL	96.1	80.9	220.8	185.8

Natural gas power plants are generally more efficient at cycling than oil-fired generation due to the faster response times and better load-following capabilities of natural gas turbines. Natural gas plants can ramp up or down quickly, adjusting their output in response to fluctuations in renewable energy generation or grid demand. In contrast, oil-fired plants are typically slower to adjust and less flexible, which makes them less efficient when frequently cycling. This efficiency advantage allows natural gas plants to better accommodate grid fluctuations, providing more reliable backup power with less fuel consumption compared to oil-fired plants.

The comparison between Natural Gas and Oil-Fired Generation shows a weighted average 38-44% savings over 20-year and 100-year GWPs respectively, when accounting for improved power plant efficiencies. Current powerplant efficiencies: Crude oil current powerplant efficiency of 32%, Natural gas combined cycle and simple cycle weighted powerplant efficiency were estimated from capacity expansion modeling averages from 2030-2045 of 46%.

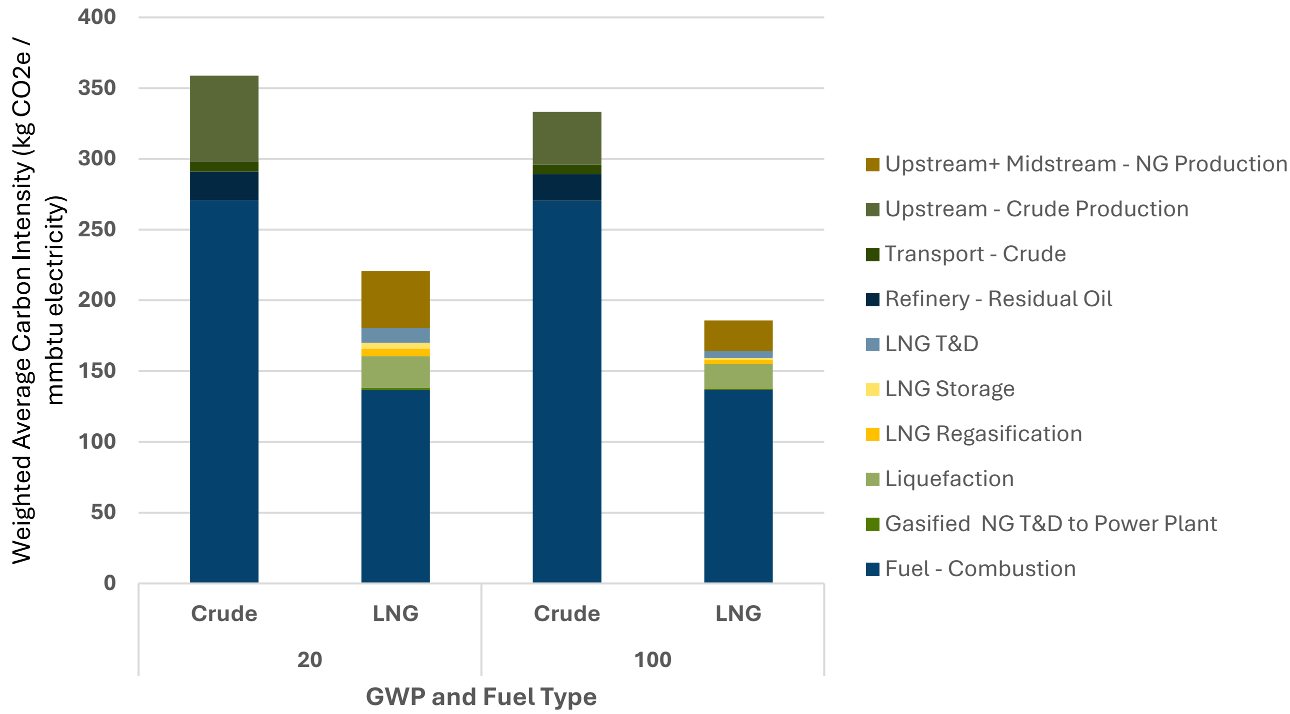


Figure 2 Comparative analysis of natural gas lifecycle emissions vs. current petroleum generation.

Table 2 Total lifecycle emissions estimates for low sulfur fuel oil and LNG

Weighted Total Lifecycle Carbon Intensity Estimate (kg CO2e/MMBtu Elec)			
GWP	**Low Sulfur Fuel Oil**	**LNG**	**Percentage Change**
20	358.8	220.8	38%
100	333.2	185.8	44%

Lifecycle of Biofuels

The lifecycle carbon intensity of biofuels one of the most difficult fuels to quantify. Emissions from biofuels, including biodiesel, renewable diesel, cellulosic diesel, ethanol (typically blended with other fuels), and renewable naphtha (more commonly used in industrial and transportation sectors but can be used for electrical generation) have substantial variation.

The US Renewable Fuel Standard (RFS) is the world's largest existing biofuel program. The program requires empirical lifecycle assessment of greenhouse gas emissions to determine if fuel pathways can qualify, there are many frameworks available to account for lifecycle emissions from bio-based sources.

The RFS is referenced in this comparison due to the availability of data from EPA-evaluated fuel pathways and published numerical GHG results.[22] With the continental U.S. producing nearly 47% of the global output of renewable liquid fuels over the last decade, the RFS has been a driving policy incentivizing biofuel production. The RFS program is designed to compare renewable fuels against common transportation fuels (gasoline and diesel). The upstream and midstream estimates can be applied to inform lifecycle emissions from stationary combustion for electricity generation and adjusted appropriately based on powerplant efficiencies.[23] The EPA's RFS program has approved certain pathways for various feedstocks and fuel types. Figure 3 and Figure 4 show estimated emissions from proposed fuel pathways. While the RFS program applies to U.S. production, the program includes feedstocks grown outside the US, and therefore is also applicable to Hawaiʻi imports. The EPA has not approved pathways with palm oil feedstocks.

The biofuel lifecycle CI presented in Figure 3 and Figure 4 are unadjusted values submitted to and reviewed by the EPA for the RFS program.

- U.S. Environmental Protection Agency. (2023). *Lifecycle greenhouse gas results*. Renewable Fuel Standards (RFS) Program summary data. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

Figure 3 shows the variability across lifecycle stages of different feedstock types using the average CI for each lifecycle stage. The figure demonstrates the variability of CI for different biofuels, using average CIs reported to the RFS program. Figure 4 shows the variability by feedstock type.

The values presented are "fuel inputs" and do not account for the conversion of fuel to electricity, which is dependent on the power plant configuration. For locally produced feedstocks land use change estimates would also need to be adjusted; however, there is limited data availability for this to be incorporated.

[22] U.S. Environmental Protection Agency. (May 2023). *Lifecycle greenhouse gas results*. U.S. Environmental Protection Agency Fuels Registration, Reporting, and Compliance. Retrieved from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

[23] "Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis" (EPA-420-R-10-006).

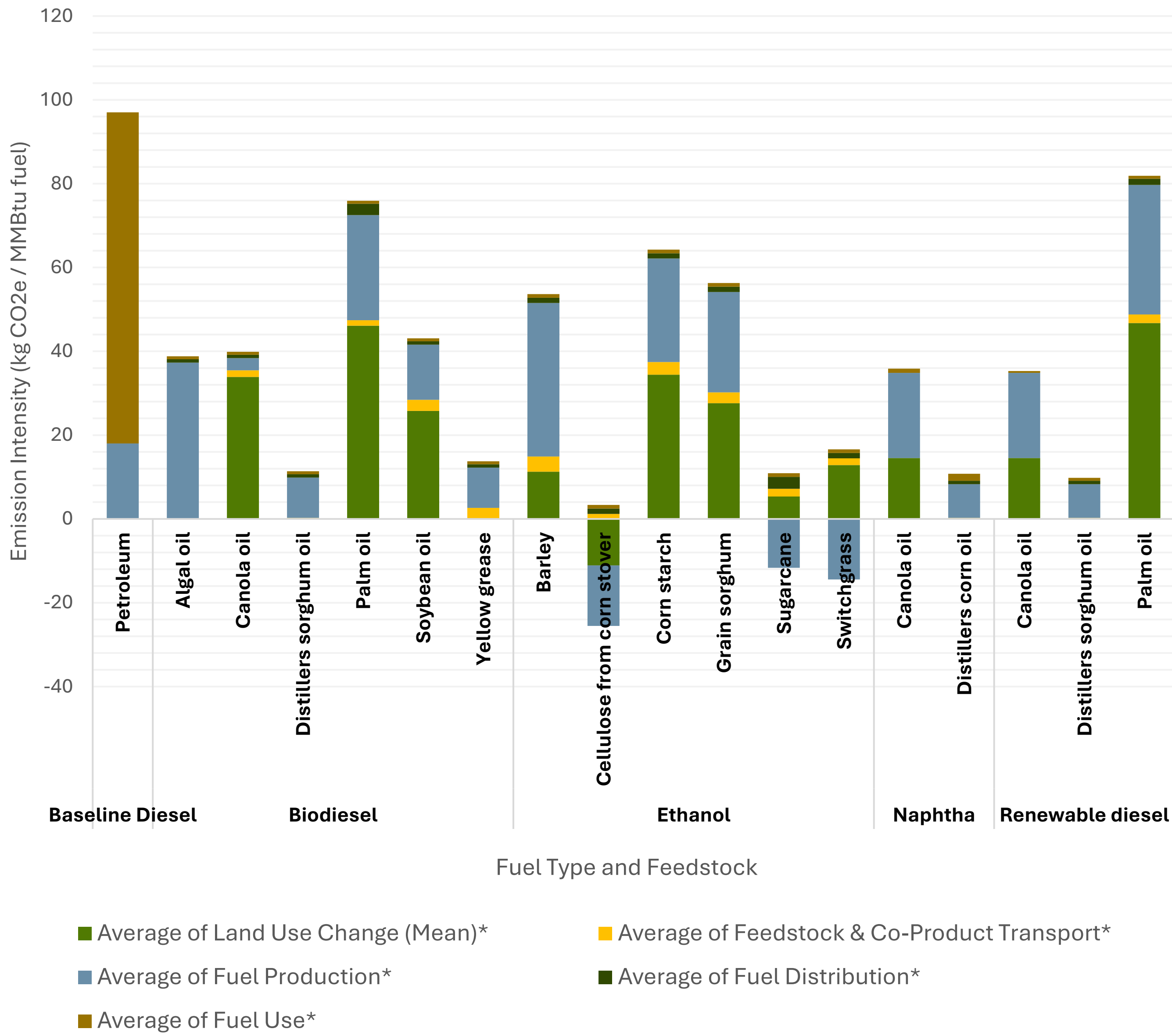
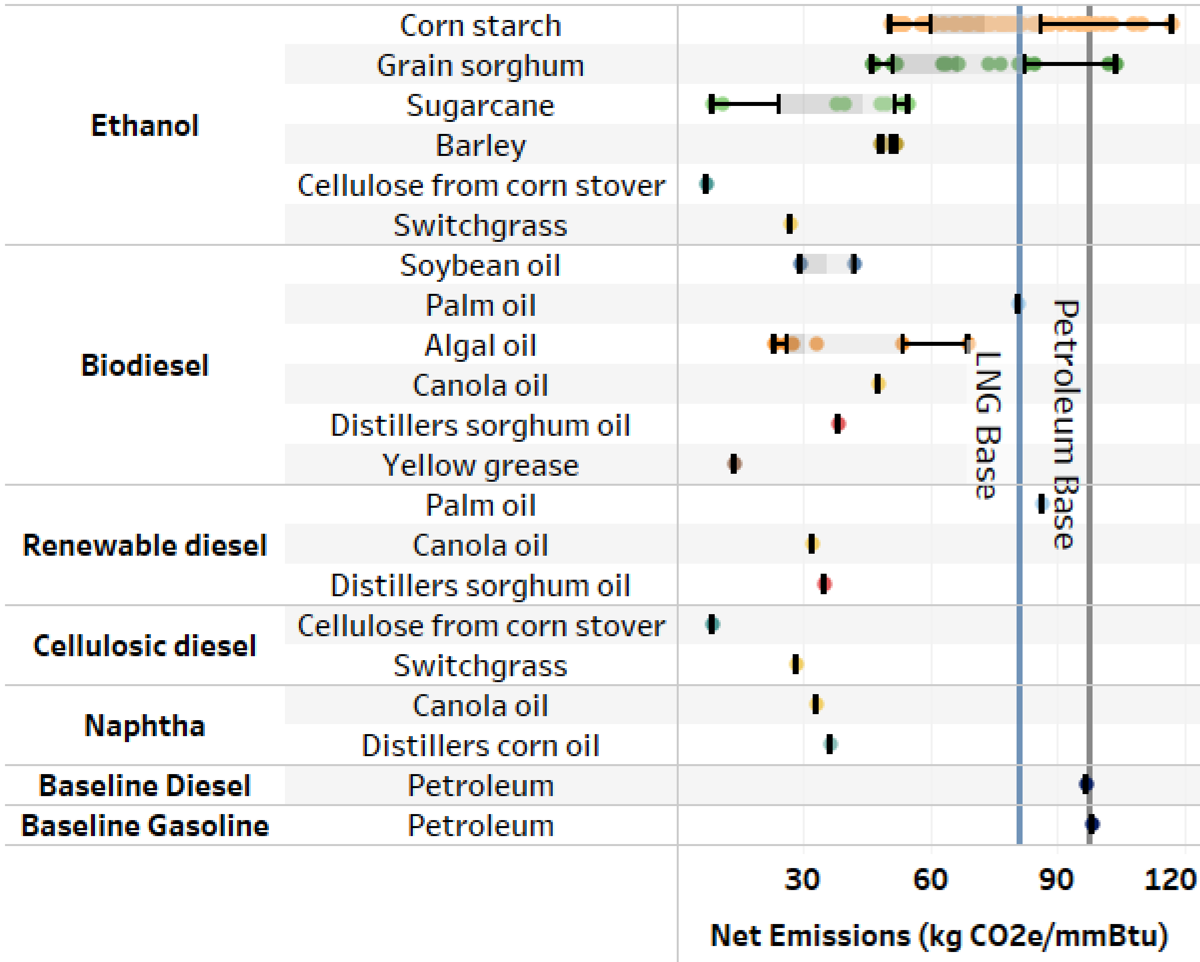


Figure 3 Unadjusted average lifecycle CI fuel input by feedstock and fuel type from submitted fuel pathways with full LCAs submitted. Colors demonstrate various lifecycles

Figure 4 shows the wide ranging variability of total lifecycle net emissions from various feedstocks and fuels.



Whiskers extend to 1.5 times the Interquartile Range (IQR). Boxes extend from 25th to 75th percentile with the median indicated in between.

Figure 4 EPA Renewable Fuels Program, unadjusted average emission intensities for various fuel types and feedstocks. Values do not incorporate powerplant efficiencies and should be considered "fuel inputs". Source: EPA Completed Pathways Assessments Lifecycle Analysis. https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel. LNG Base is the "fuel input CI" from the weighted hybrid comparative analysis.

Not shown or included in the data set, includes lifecycle emissions from fuels produced with livestock tallow. For beef tallow-based fuels, GHG emission estimates are also dependent on whether the emissions from meat production are incorporated, or if the tallow is treated as a byproduct or waste product. The United States Department of Agriculture (USDA) Economic Research Service and the DOE report that animal fats, waste oils, and greases accounted for 37% of feedstocks used in U.S. biomass-based diesel production in 2023, up from 17% in 2020. This shift has reduced the reliance on vegetable oils like soybean, canola, and corn. Increased use of these alternative feedstocks, particularly used cooking oil, has driven U.S. import demand, with used cooking oil imports rising from 0.9 billion pounds in 2022 to over 3 billion pounds in 2023.[24]

Studies have demonstrated that the RFS program has inadvertently caused unintended consequences like increased fertilizer use, reduced conservation land, and expanded cropland. These factors elevated GHG emissions and undermined the RFS program's intended climate benefits. Empirical evidence indicates biofuels *may* have a higher overall impact than natural gas, particularly when land use change (LUC) and other upstream emissions are included, particularly when considering the bulk of fuels on the market are first-generation fuels, derived from corn, soy, and palm feedstocks.[25] To date, approximately 87% of the RFS mandate has been met using conventional renewable fuels, primarily corn ethanol.[26] This heavy reliance on corn ethanol has limited the realization of the anticipated benefits associated with the program's more advanced fuel requirements, such as those for cellulosic biofuels and biomass-based diesel; for certain corn-based ethanol lifecycle CI can be 24% higher than that of gasoline.

Comparison with Regulatory Filings

A copy of the spreadsheet used to compare HSEO estimates with past reports and filings is available at: https://energy.hawaii.gov/alternative-fuels-repowering-and-energy-transition-study/

Fuel Contract LCA for Hawaiian Electric

A lifecycle assessment was completed for the existing fuels contract with Par Hawaiʻi, Pacific Biodiesel, and Vitol and submitted to the Hawaii Public Utilities Commission by Hawaiian Electric for Approval of Fuels Supply Contact in Docket 2022-0014, as a part of the application, a lifecycle analysis was completed and submitted.[27] The resulting emissions from these contracts are summarized below. To allow for comparison HSEO converted all units to "kg CO2e per mmBtu" using the conversions listed in Section C-4.

Par Hawaiʻi – Liquid fuels derived from imported crude

HSEO's weighted carbon intensity estimates are consistent with the emission estimates submitted by Hawaiian Electric if the system boundaries are appropriately adjusted to account for power plant energy conversion efficiency.

[24] U.S. Department of Agriculture, Economic Research Service. (n.d.). *Chart detail: Major feedstocks for biomass-based diesel*. Retrieved from https://ers.usda.gov/data-products/chart-gallery/gallery/chart-detail/?chartId=109680

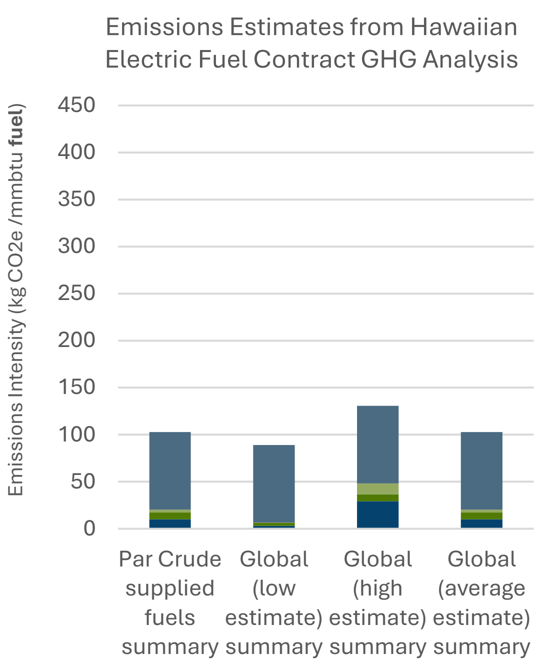
[25] Lark, T. J., Hendricks, N. P., Smith, A., Gibbs, H. K., & Marshall, E. (2022). Environmental outcomes of the US Renewable Fuel Standard. *Proceedings of the National Academy of Sciences, 119*(9), e2101084119. https://doi.org/10.1073/pnas.2101084119

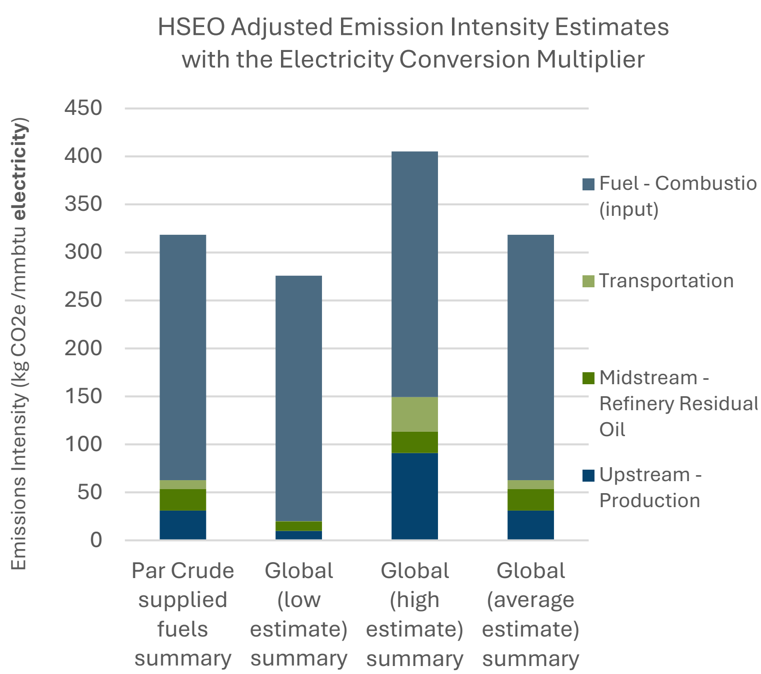
[26] Id

[27] Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., & Maui Electric Company, Limited. (2022). *Application for approval of fuels supply contract with Par Hawaii Refining, LLC, the Biodiesel Supply Contract with Pacific Biodiesel Technologies, LLC, and the Backup Fuels Supply Contract with Vitol, Inc. (Docket No.2022-0014).* Submitted to the Public Utilities Commission of the State of Hawai'i.

The lifecycle assessment for Par Hawai‘i presented in docket 2022-0014 as a part of the Hawaiian Electric fuel contract did not account for the conversion of fuel to electricity when determining lifecycle intensity values. Assuming power plant energy conversion efficiency of 32.3%[28] it takes approximately 3.1 MMBtu of fuel to produce 1 MMBtu of electrical energy.[29] This conversion factor is also known as power plant heat rate, more commonly expressed in Btu/kWh. This conversion factor must be applied upstream to account for energy loss across the entire fuel lifecycle. Consequently, the Hawaiian Electric analysis accounted for all input emissions, but did not account for energy loss during electrical generation; therefore, it underestimated lifecycle emission intensity from oil combustion by a factor of ~3.1 for all stages in the fuel's lifecycle. In other words, the analysis instead incorporates lifecycle emissions from well-to-powerplant, rather than well-to-outlet.

HSEO's fuel analysis is consistent with the analysis completed for Par Hawai‘i if carbon intensity values are compared based on input fuel combustion, rather than electricity production. See *Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index* for the energy conversion efficiencies of various power plants.





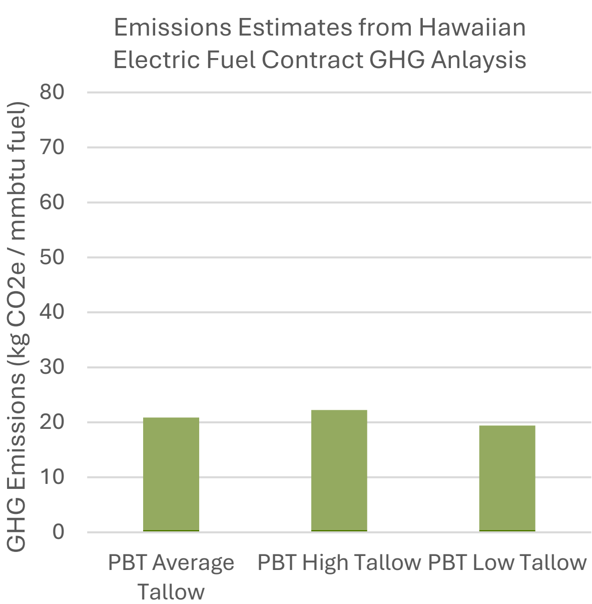
When accounting for the energy conversion factors (right), average emission intensity estimates for Par Hawai‘i-supplied liquid fuels are consistent with the estimates presented in the comparative analysis presented above, with total emission intensity for Par-supplied fuels:

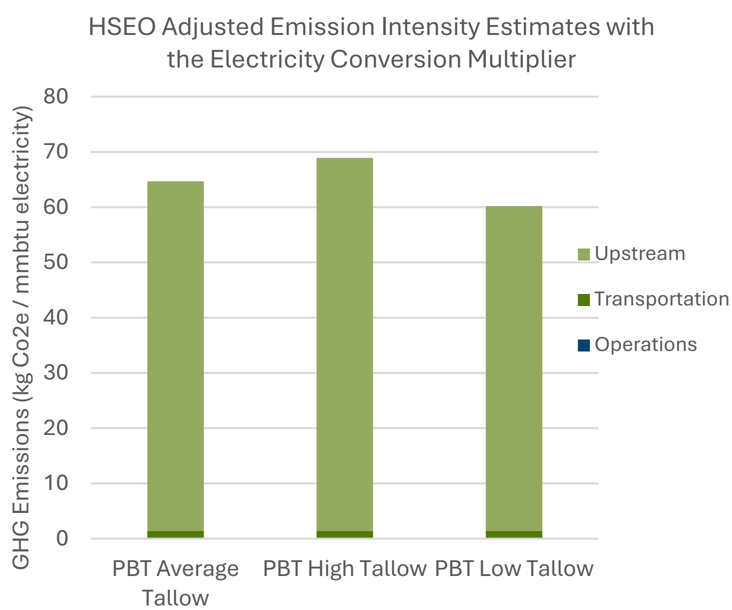
[28] GREET and eGRID estimates for HICC mix (ANL GREET 2023 Workbook).
[29] GREET 2023

- Total emissions Par Hawaiʻi supplied fuels: 317 kg CO2e / MMBtu electricity (assuming 100-year GWP)
- Total emissions from average estimate HSEO weighted analysis: 333 kg CO2e / MMBtu electricity (assuming 100-year GWP) (Figure 2)

Pacific Biodiesel – Liquid biofuels derived from locally sourced used cooking oil and imported feedstock tallow

As a part of Hawaiian Electric's fuel contract with Pacific Biodiesel (PBT), Hawaiian Electric submitted a lifecycle GHG analysis in accordance with HRS 269-6(b).[30] According to the January 2022 submission to the PUC in Docket 2022-0014, PBT has historically sourced tallow from the continental US, shipping it in from California and Washington. Used cooking oil is collected from local restaurants in Hawaiʻi by truck. The tallow-oil mix varies based on availability and cost, with tallow typically representing 66-87% of the feedstock. The analysis assumed carbon neutrality for biogenic emissions.





It is unclear if the analysis incorporated power plants' energy conversion efficiencies (fuel to electricity) at all stages in the lifecycle analysis. **However, because the lifecycle analysis presented the GHG intensities in units of kgCO$_2$e/gal, HSEO believes conversion efficiencies were not incorporated into the analysis.** The total emissions estimates (as opposed to the intensity estimates) are accurate because PBT included annual consumption figures.

[30] Pacific Biodiesel Technologies (PBT) Biodiesel Contract GHG Analysis. January 2022. Hawaiian Electric submission to PUC Docket 2022-0014.

With a conservative emission factor applied (multiplier of ~3.1MMBtu of electricity/ MMBtu fuel), PBT-supplied fuels offer carbon savings under the applied system boundary assumptions, with high-tallow estimates providing approximately 79% lifecycle carbon savings. Carbon savings increase if biofuel is burned in more efficient power plants.

- Emission intensity fuel (high tallow): 22.23 kg CO2e / MMBtu fuel
- Emission intensity electricity generated: 68.93 kg CO2e / MMBtu electricity
- Petroleum fuel HSEO weighted analysis: 331 kgCO2e / MMBtu electricity

Notably, while it is standard practice to assume beef tallow as a byproduct or waste product in GHG accounting, it is worth acknowledging for this study tallow is assumed to be a waste product of meat production. GHG emissions associated with meat production were not included in the emission estimate, a common system boundary assumption. Rendering emissions were accounted for.

The submitted analysis for PBT is slightly higher than, but consistent with, the average CI for the EPA's RFS "Yellow Grease" average of 13.76 kg CO2e / MMBtu fuel.[31]

Comparison with Literature and Published Studies

The weighted analysis presented above is generally consistent with published scientific literature. Comparisons are presented in Table 3. Certain studies only evaluate specific stages in fuel lifecycles and may not account for energy conversion efficiencies, the "unit" column indicates whether a conversion efficiency was applied (i.e. units with *MMBtu electricity* indicate a conversion was applied, units of *MMBTU fuel* indicated no conversion efficiency was applied. Further research is needed to determine the underlying causes for differences; however, based on initial research, it is likely due to geographic distinctions and/or operational assumptions. Estimates shown in Table 3 compare HSEO estimates with other source estimates where supply-chain point divisions were distinct.

Table 3 Published emissions estimates compared to HSEO's weighted hybrid analysis averages. All intensities were converted to kg CO2e / MMBtu using conversion factors. All shaded cells indicate estimates where HSEO estimates are less than published estimates.

Sources	Unit	Supply Chain Point	Fuel Type	GWP	CI From Literature Cited	HSEO Average CI from Weighted Analysis for Comparison
NREL Harmonization (average)	kg CO2e/MMBtu electricity	Total	Oil	100	246.19	333
NREL Harmonization (average)	kg CO2e/MMBtu electricity	Total	LNG	100	142.44	185
NREL Harmonization (high)	kg CO2e/MMBtu electricity	Total	LNG	100	158.26	185

[31] U.S. Environmental Protection Agency. (2023) *Lifecycle greenhouse gas results*. Retrieved from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

Sources	Unit	Supply Chain Point	Fuel Type	GWP	CI From Literature Cited	HSEO Average CI from Weighted Analysis for Comparison
NREL Harmonization (low)	kg CO2e/MMBtu electricity	Total	LNG	100	123.09	185
NREL High EF	kg CO2e/MMBtu electricity	Total	Oil	100	342.91	333
NREL Low EF	kg CO2e/MMBtu electricity	Total	Oil	100	149.47	333
NREL Mid EF	kg CO2e/MMBtu electricity	Total	Oil	100	246.19	333
Abrahams et al. 2015	kg CO2e/MMBtu electricity	Total	LNG	100	192.0	185.8
Abrahams et al. 2015	kg CO2e/MMBtu electricity	Total	LNG	20	263.8	220.8
Howarth, 2024	kg CO2e/MMBtu electricity	Total	LNG	20	168.80	186
Howarth, 2024	kg CO2e/MMBtu electricity	Total	Coal	20	126.60	range 197-495 (100 year)
Howarth, 2024	kg CO2e/MMBtu electricity	Upstream + midstream	LNG	20	79.76	40.3
Howarth, 2024	kg CO2e/MMBtu electricity	Liquefaction	LNG	20	14.98	17.5
Howarth, 2024	kg CO2e/MMBtu electricity	"Combustion by final consumer"	Diesel	20	79.13	74.2
Howarth, 2024	kg CO2e/MMBtu electricity	"Combustion by final consumer"	LNG	20	58.03	59.6
Zhang et al, 2023	kg CO2e/MMBtu fuel	liquefaction	LNG	100	3.31	7.6
Zhang et al, 2023	kg CO2e/MMBtu fuel	liquefaction	LNG	100	7.65	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction (low estimate)	LNG	100	4.75	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction	LNG	100	4.96	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction	LNG	100	6.22	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction (high estimate)	LNG	100	6.54	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Permian-UK)	LNG	100	20.47	9.3
Zhu, Allen, Ravikumar, 2025	kg CO2e/MMBtu fuel	Upstream + midstream (Permian-China)	LNG	100	21.42	9.3
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Marcellus-UK)	LNG	100	7.70	9.3
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Marcellus-UK)	LNG	100	8.02	9.3

National Renewable Energy Lab Harmonization Study

To compare the various intensities published across the literature, the National Renewable Energy Laboratory (NREL) completed a harmonization report titled *Life Cycle Greenhouse Gas Emissions from Electricity Generation*. This work is valuable for comparing fossil fuel sources to other electrical energy generation technologies and further illustrates why natural gas is a bridge fuel rather than a long-term solution, as intermittent technologies demonstrate substantially lower carbon intensities (CI). As shown in Figure 4, the weighted estimates presented here are generally consistent with and fall within the ranges provided in the harmonization report. One critical assumption to note: the biopower estimates below assume carbon neutrality for all biogenic emissions, skewing the results toward the lower end.

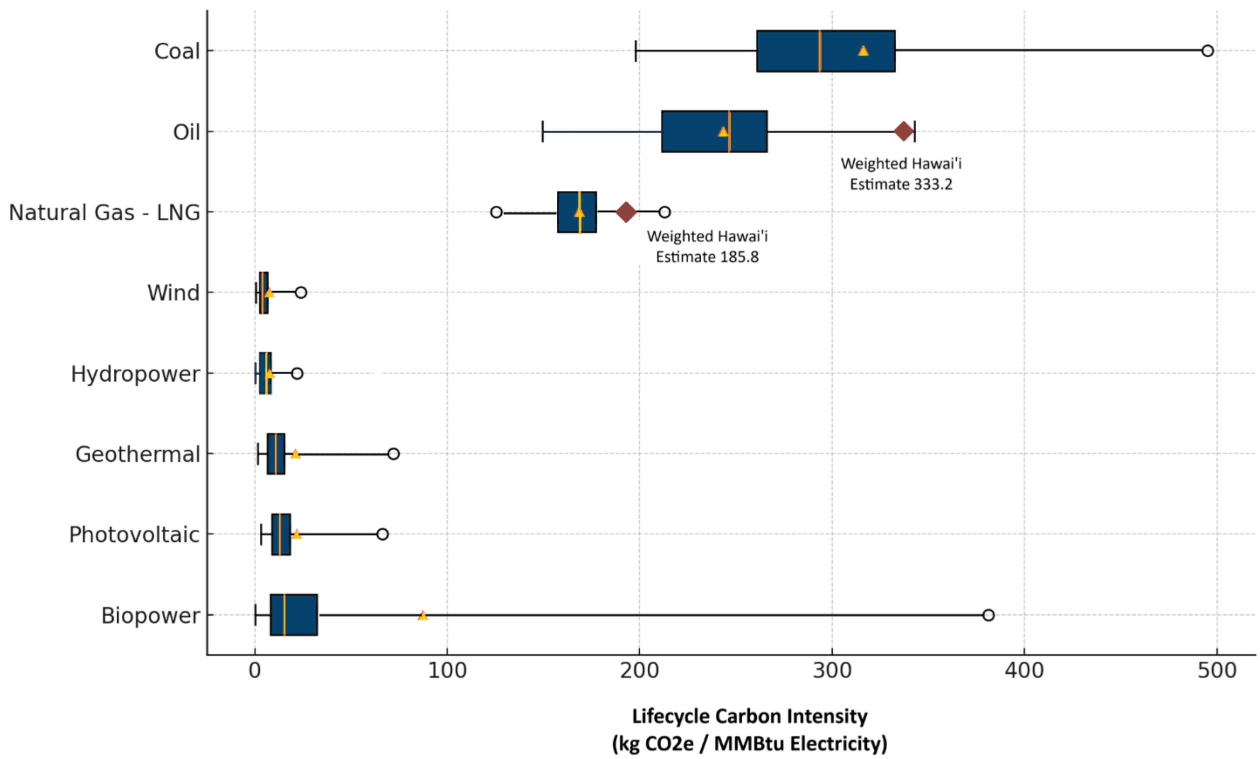


Figure 5 Lifecycle greenhouse gas emission intensities from NREL Harmonization Study for electricity generation technologies. Source: National Renewable Energy Laboratory, Life Cycle Greenhouse Gas Emissions from Electricity Generation Update. Data retrieved from https://www.nrel.gov/docs/fy21osti/80580.pdf Weighted estimates from HSEO analysis indicated by diamonds, both within the upper end of the published ranges of the NREL Harmonization work.

All analysis demonstrates the need to eventually phase out natural gas and only use it as a bridge fuel. While LNG offers a more immediate opportunity to reduce emissions while achieving cost savings in the near term, the prolonged use of LNG is not consistent with international, national, and state GHG targets.

Hawaiʻi Power Plant Combustion Input and Output Emissions and Calculated Conversion Efficiencies

Data Year	Plant name	Island	Plant primary fuel	Plant capacity factor	Plant nameplate capacity (MW)	Plant annual CO2 equivalent input emission rate (kg/MMBtu)	Plant annual CO2 equivalent total output emission rate (kg CO_2e/MMBtu electricity)	Conversion Efficiency / Heat Rate (MMBtu fuel/MMBtu electricity)	Efficiency
2022	Kahe Generating Station	Oʻahu	RFO	0.4692	609.7	74.256	233.309	3.142	32%
2022	Waiau Generating Station	Oʻahu	RFO	0.2176	474.6	74.261	253.067	3.408	29%
2022	Kalaeloa Cogen Plant	Oʻahu	RFO	0.4652	299.4	74.257	166.3	2.24	45%
2022	Māʻalaea	Maui	DFO	0.3336	229.8	74.324	202.743	2.728	37%
2022	Campbell Industrial Park	Oʻahu	DFO	0.1036	113	74.324	358.836	4.828	21%
2022	Port Allen	Kauaʻi	DFO	0.0534	89.5	74.324	215.414	2.898	35%
2022	Keāhole	Hawaiʻi	DFO	0.3656	89.1	74.324	221.23	2.977	34%
2022	Hāmākua Energy Plant,	Hawaiʻi	WO, OBL	0.3762	66	62.899	162.555	2.584	39%
2022	Schofield Generating Station	Oʻahu	OBL	0.0338	50.4	0.268	0.74	2.766	36%
2022	Kapaia Power Station	Kauaʻi	WO	0.4923	39.1	78.63	217.345	2.764	36%
2022	Puna	Hawaiʻi	DFO	0.1807	39.1	74.324	280.37	3.772	27%
2022	W H Hill	Hawaiʻi	RFO	0.5232	37.1	74.256	291.685	3.928	25%
2022	Kahului	Maui	RFO	0.5339	34	74.256	325.817	4.388	23%
2022	Kanoelehua	Hawaiʻi	DFO	0.016	21	74.324	570.574	7.677	13%
2022	Palaau Power Hybrid	Molokaʻi	DFO	0.2118	17.1	74.324	219.502	2.953	34%
2022	Miki Basin	Lānaʻi	DFO	0.3971	10.4	74.324	220.284	2.964	34%
2022	HNL Emergency Power Facility	Oʻahu	OBL	0.0154	10	0.268	0.741	2.769	36%
2022	Waimea	Hawaiʻi	DFO	0.0325	7.5	74.324	230.559	3.102	32%
2022	Hana Substation	Maui	DFO	0.0059	2	74.324	242.153	3.258	31%

Source: US EPA eGRID 2022. https://www.epa.gov/egrid

$$\frac{\left(\frac{kgCO2e}{mmbtu\ electricity\ generated}\right)}{\left(\frac{kgCO2e}{mmbtu\ fuel\ combusted}\right)} = energy\ conversion\ efficiency\ \left(\frac{mmbtu\ fuel}{mmbtu\ electricity}\right)$$

Multiple Source Analysis Results

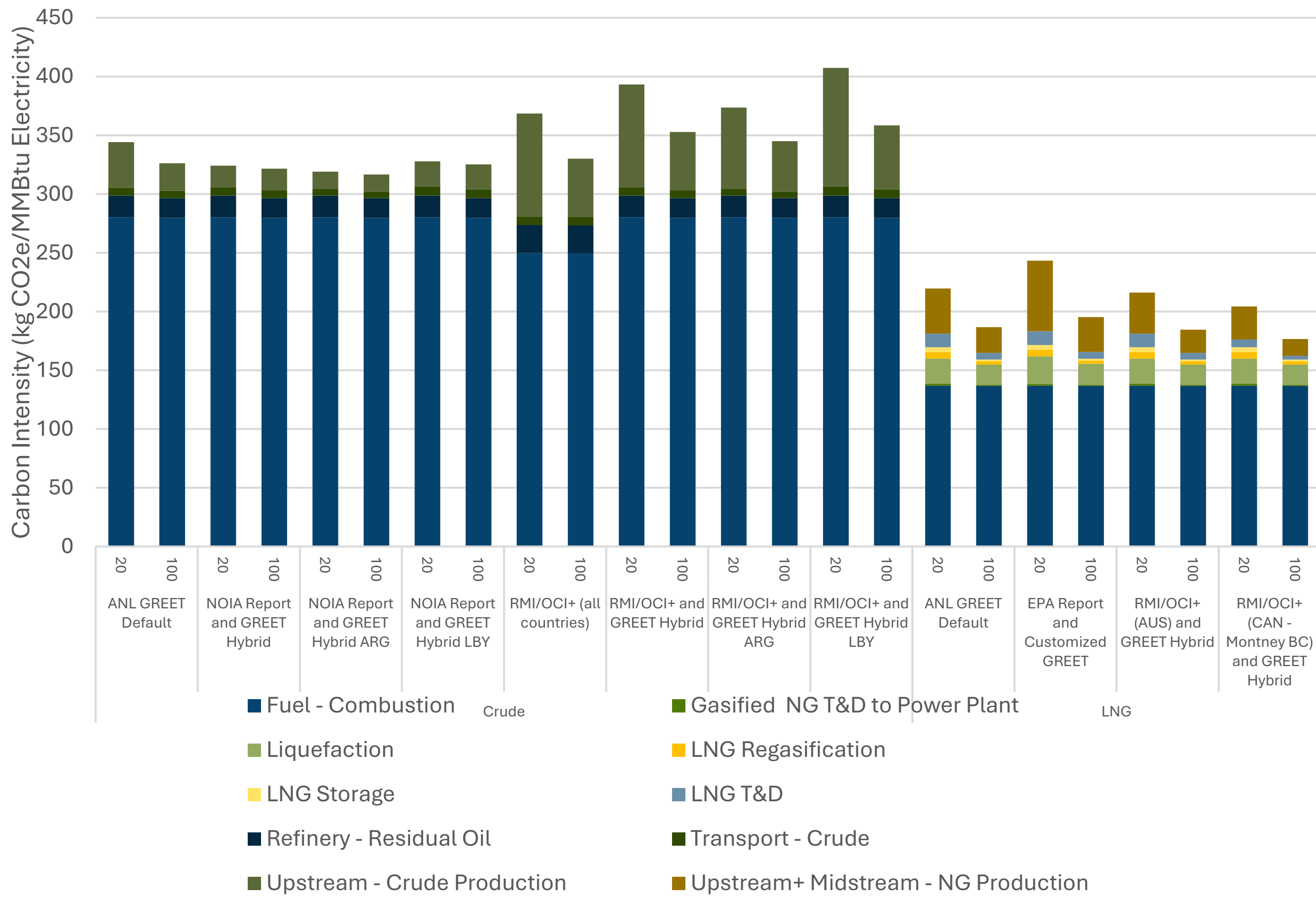


Figure 6 Lifecycle emissions intensities for natural gas and oil scenarios. Values presented are inclusive of powerplant energy conversion efficiency.

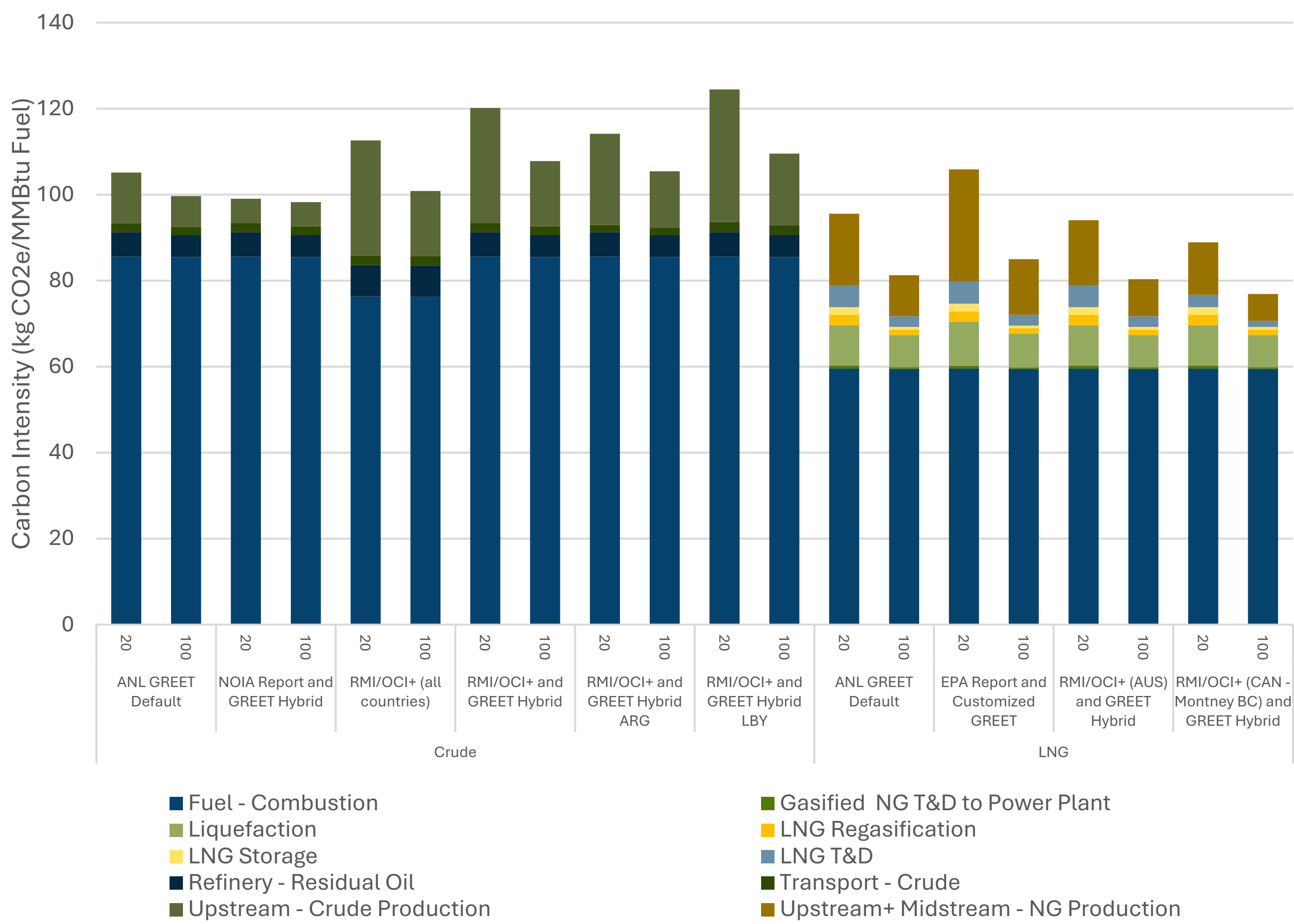
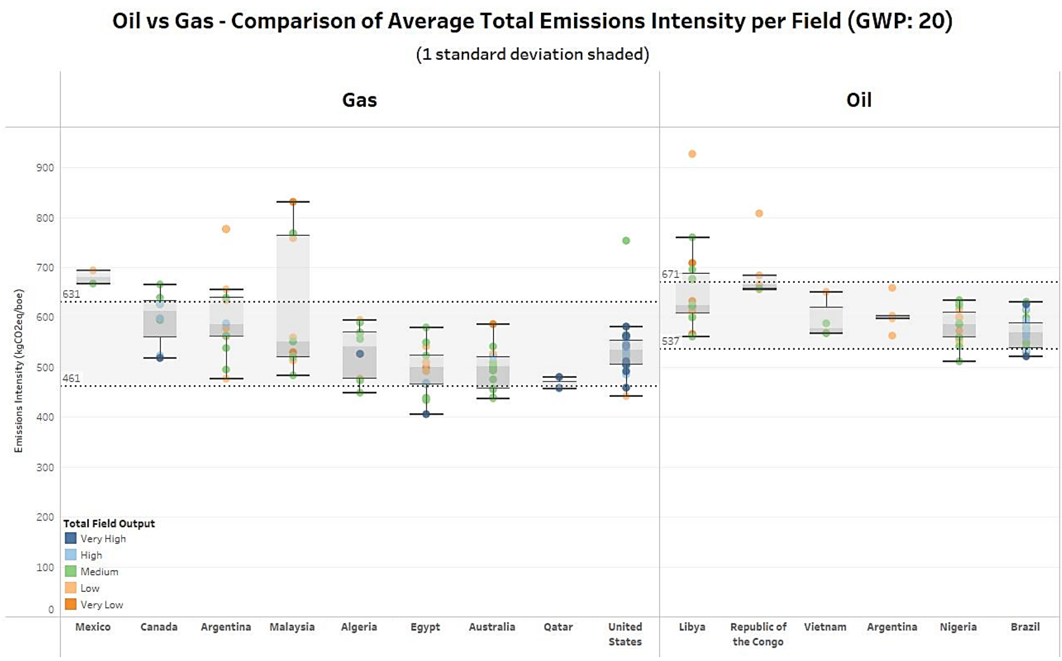


Figure 7 emissions intensities for natural gas and oil scenarios for input fuels. Values presented are not inclusive of powerplant energy conversion efficiency. Values demonstrate the importance of incorporating power plant efficiency into GHG analysis as the GHG savings are less substantial without this conversion applied.

Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index.

Note: units are unadjusted and presented in kgCO2e / barrel of oil equivalent (boe).



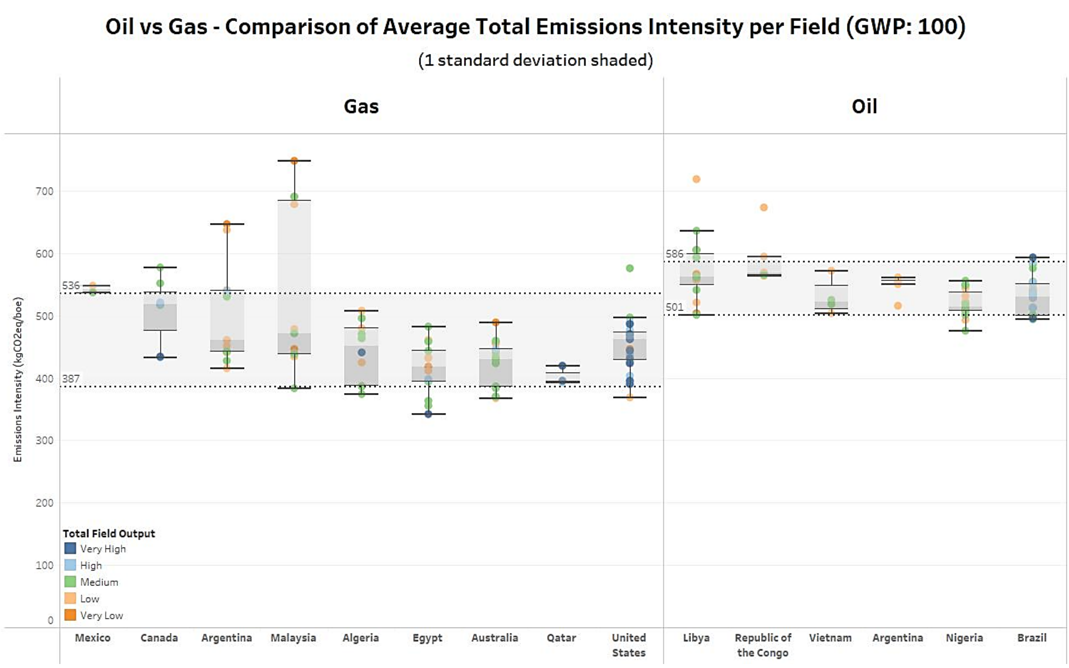


Figure 8 Oil and gas comparison of emission intensities from various possible source countries for gas and countries that have supplied Hawai'i's crude since 2015. Emissions estimates use RMI's OCI+. While Hawai'i has imported crude oil from Australia, no oil emission intensity values are reported in the OCI+ database. The top figure presents emissions derived using GWP 20, bottom uses GWP 100. ***Note emissions presented in this figure are unadjusted for powerplant efficiency.***

Each data point is an average of all reported annual emissions values for a given production field in RMI's OCI+ database from 2015-2022. Emissions do not account for liquefaction and LNG transport stages and should be considered averages used only as a comparison between different source countries. Based on these emissions, Mexico and Malaysia are not ideal source countries, and Hawai‘i should strive to ensure fuel suppliers do not source from these countries unless current environmental and operational venting and flaring practices are changed.

For Canadian natural gas, an ideal source country, upstream emissions are highly dependent on the oil field. Thus, the next step of the analysis was to narrow down upstream emissions from source countries by oil fields. Canadian natural gas from British Columbia, the likely source for Hawai‘i and the Pacific, exhibits lower emissions than emissions from eastern Canadian oil fields.

Figure 8 shows upstream emissions from likely source countries, compared to the dominant crude suppliers for Hawai‘i.

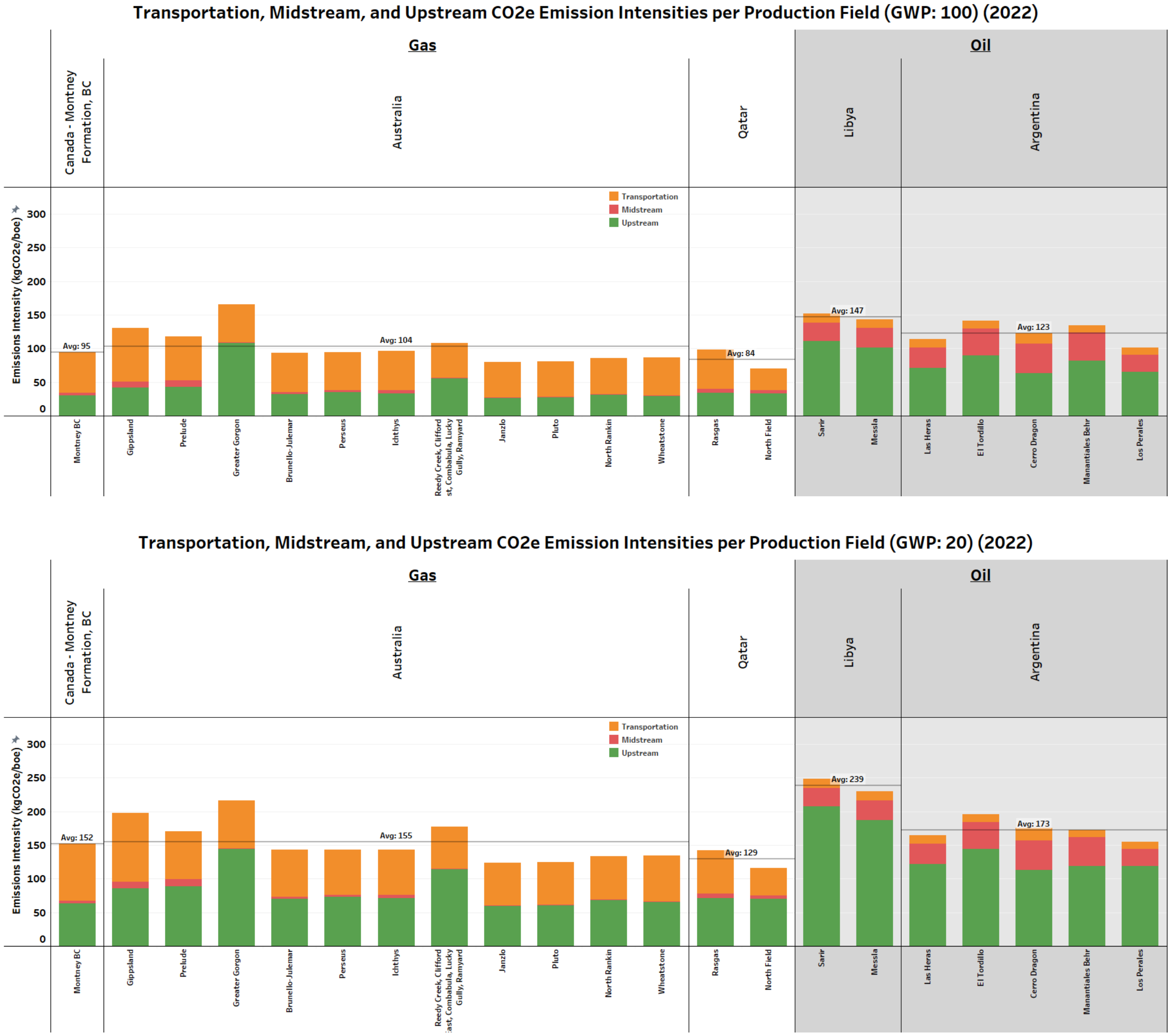


Figure 9 Upstream emissions from likely source countries by production field. Transportation emissions in the OCI index are not inclusive of liquefaction and LNG transport but do include average distance to end-use locations which may include liquefaction terminals. Estimates shown do not include powerplant efficiency gains.

Note: For RMI/OCI+ data, upstream refers to production (well to refinery gate), midstream refers to refining and petrochemical processing, and transportation refers to delivering the resource to refining and/or distribution locations other than end uses.

Downstream emissions are not shown in this figure.

Conversion Factors and GWPs

Conversion Factors

Value	Conversion
1,055	MJ per MMBtu
1,000	kg per MT
5,684,000	Btu per bbl.
5.68	MMBtu per bbl.
5,996.94	MJ per bbl.
0.0001706	MJ per boe
5.8	MMBtu per boe
3,412.14	kWh per Btu
0.003412	kWh per MMBtu
293.07	MMBtu per kWh
3.099	MMBtu fuel per MMBtu electricity for oil-fired generation (HICC mix)
1.938	MMBtu fuel per MMBtu electricity for natural gas-fired generation

Global Warming Potentials

AR Edition/Type Time Horizon (YR)	AR6/GWP 100-year	AR6/GWP 20-year
CO_2	1	1
CH_4	29.8	82.5
N_2O	273	273

Stable Final Data – All Scenarios

Available on the Tableau Dashboard

Purpose of Analysis and Overall Approach

The analysis associated with this report builds upon the work presented in Chapters 3-4 of HSEO's Hawaiʻi Pathways to Decarbonization Report Decarbonization Report, specifically the electric sector analysis. The scope of the analysis includes many of the same assumptions discussed in depth on pages 155-169 of the Decarbonization Report .[1] The electric sector modeling effort, completed in Engage,[2] identified the most cost-effective portfolios of generation and storage. As a new analysis component, the models were used to determine the least-cost resource portfolio when liquified natural gas is included as an option for electrical generation. Engage analysis determines the most cost-effective generation resource portfolio to meet energy demands based on assumptions about future electricity demand (e.g. load shapes), fuel prices, technology availability, technology costs and performance, and user-defined constraints such as those determined by policy and regulation.

HSEO worked closely with NREL staff to ensure conservative cost assumptions were applied widely for natural gas technologies given the need to eventually retire all natural gas resources and avoid abandoned and costly assets. The analysis is not intended to prescribe capacities, but rather the capacity expansion analysis is intended to inform decision-making on the cost-effectiveness of various resource portfolio options. The next steps of the analysis include adjustment of capacities based on interconnection feasibility and technical constraints, full production cost models, input cost refinement based on the selected preferred pathway, and capital costs refinement as determined by more detailed engineering and lifecycle cost analysis.

Scenario Assumptions

Underlying.Electrical.Demand

To determine the impact of electrical load on resource selection, a total of three (3) different underlying electricity demands were applied to two (2) different price scenarios (high-cost / low-cost NG), across three (3) separate island grids – Oʻahu, Hawaiʻi Island, and Maui. The various scenarios and model adjustments demonstrated substantial resource selection sensitivity. In other words, the resources chosen by the model and the amount of build-out of certain new resources were highly dependent upon and sensitive to the built-in technology assumptions.

Table 1 below shows the underlying demands applied across scenarios. While Maui and Hawaiʻi were initially evaluated, HSEO did not proceed with further analysis for these islands.

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[1] https://energy.hawaii.gov/wp-content/uploads/2022/10/Act-238_HSEO_Decarbonization_FinalReport_2023.pdf

[2] Engage is a free, publicly available modeling tool built around Calliope (2023) an open-source modeling framework for cross-sectoral energy system modeling and planning. Engage is a least-cost optimization model, meaning the model assesses the most cost-effective way to meet demand in each year.

Table 1: Underlying Demands Cases Applied Across Scenarios				
Model	**Scenario**	**Total Modeled Demand in 2045**	**Source / Justification for Underlying Demand Assumptions***	**Total Cumulative Demand (2021-2050)**
Oʻahu	Reference	~ 10.2 TWh	Hawaiian Electric Pathways	247,009.8 GWh
Oʻahu	Conservative	~ 12.3 TWh	Hawaiian Electric Pathways	274,521.2 GWh
Oʻahu	Aggressive	~ 14.7 TWh	Hawaiian Electric Pathways	313,852.4 GWh
Hawaiʻi	Reference	~ 1.6TWh	Hawaiian Electric Pathways	38,140.6 GWh
Hawaiʻi	Conservative	~ 2.3 TWh	Hawaiian Electric Pathways	48,174.7 GWh
Hawaiʻi	Aggressive	~ 2.9 TWh	Hawaiian Electric Pathways	56,666.9 GWh
Maui	Reference	~3 TWh	Hawaiian Electric Pathways	40,834.31 GWh
Maui	Conservative	~2.1 TWh	Hawaiian Electric Pathways	45,460.42 GWh
Maui	Aggressive	~ 1.8 TWh	Hawaiian Electric Pathways	55,167.55 GWh

*Raw.data.courtesy.of.Hawaiian.Electric¡.The.same.processing.described.in.the.Hawai›i.Decarbonization. Report.was.applied.to.all.underlying.demand.scenarios¡.Hawai›i.and.Maui.were.not.pursued.beyond.the. bookend.analysis¡

Note: A low natural gas and high natural gas cost was applied to all of the scenarios above. The "NG High Cost" runs assume the FSRU is less utilized resulting in higher costs for natural gas. The "NG Low Cost" runs assume the FSRU is more utilized resulting in lower costs for natural gas. In addition, all scenarios were modeled with and without the inclusion of offshore wind.

Infrastructure & capital costs assumed

Hawai›i.Cost.Premium

A Hawaiʻi cost multiplier of 2.154 was calculated by comparing recently completed PV projects in Hawaiʻi to continental US prices for utility-scale PV. It was applied to all capacity expansion technologies besides the FSRU itself. The decision to include the premium on the NG technologies was to explore the most conservative scenario for the economic viability of natural gas. A higher multiplier does not necessarily result in a less immediate transition in favor of the status quo; however, one thing that could change with a reduced multiplier would be the speed at which the new generation is built instead of using older legacy generators. The rollout of renewable energy in all model runs is primarily driven by the RPS, so the effect of a lower multiplier is limited.

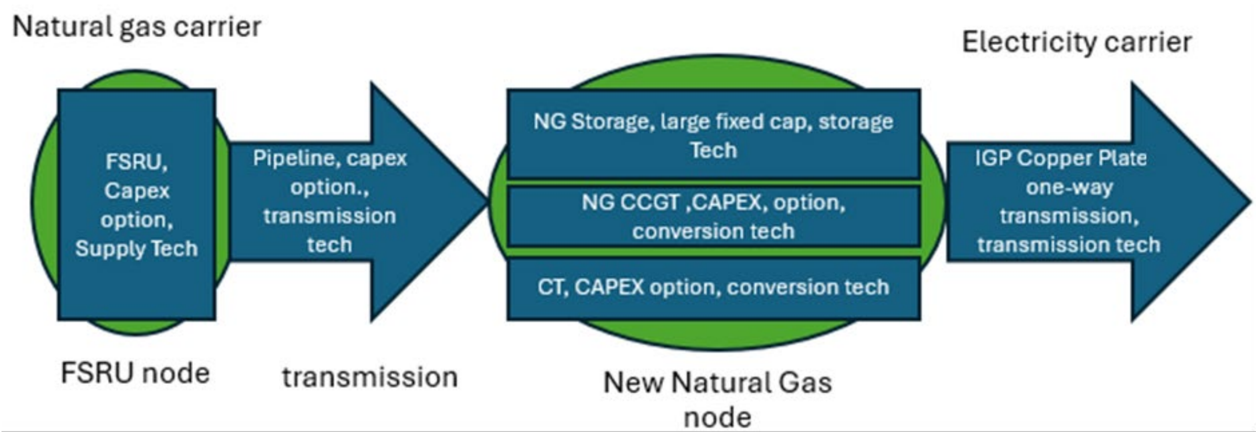
Interest.Rates.™.Amortization.Assumptions

As a part of the analysis, costs were largely driven by the assumed amortization, or payback period for the installed infrastructure. For fossil fuel infrastructure, a shorter amortization period was assumed to ensure actions would not economically prolong the utilization of natural gas. All PPAs were priced with an assumed ROA of 7%. The default lifetime for most technologies was 20 years. Shorter lifetimes were assumed for natural gas and other fossil fuel infrastructure that could not be used, or retrofitted, for renewable hydrogen operations beyond the required RPS retirement dates.

Assumptions.by.Generation.Resource

Natural Gas

Engage.natural.gas.system.representation.- .costs.were.estimated.for.each.part.of.the.resource.supply. chain¡



Two iterations of this analysis were completed. The first iteration utilized assumptions and price configurations for natural gas, and the second iteration used more conservative independently derived figures (i.e., higher storage costs), described in detail below. The second iteration included model runs with hydrogen technology available in the later years, and two (2) different resource availability scenarios one with offshore wind and the second with no offshore wind. Floating storage regasification unit (FSRU) costs were independently verified by HDR and FGE (under contract with HSEO). The FSRU costs were assumed to include the infrastructure needed to transport natural gas from the FSRU and onto the island. On-island natural gas storage, the pipeline, and the turbines were all individually priced and expanded separately in the models. Each island had separate on-island natural gas infrastructure sized to meet the needs of that island. The non-Oahu models had increased FSRU costs to represent the transport of natural gas from Oʻahu.

<u>1st Iteration "Alternative Fuels Study 2024 (first draft)"</u>

The first iteration represents the baseline, lowest-capital-cost scenario. This uses the capital and operational costs (CAPEX and OPEX, respectively) from the preliminary analysis and assumes H2-capable gas turbines (both CCGT as well as CT). The amortization period for the FSRU and pipeline ends in 2045 (i.e., a length of 2045 – build year), which assumes that the plant is no longer needed once the State's decarbonization is achieved.

Fuels Costs – The LNG fuel costs are costs from the JKM PLATTS East Asia Spot. These costs are converted to kWh and real 2018$ (assuming the nominal values were calculated with a 2.5% inflation rate from 2024 onward, the PPI index used to convert values from 2018-2023). These costs are incurred as the 'carrier production cost' ($/kWh) constraint in the FSRU technology.

FSRU – The report assumes a capital cost of $200 million for the FSRU (regasification/storage component construction or conversion) + $200 million for the terminal – total costs of $400,000 million, with different utilization resulting in different costs to build and use the FSRU. These costs were then put through the PPA process to obtain annual costs for leasing the FSRU. The FSRU costs were spot-checked with other estimates and it was decided that the 2.154 premium (see Hawaiʻi Cost Premium, above) was not applicable for the FSRU.[3] Finally, the fixed O&M is calculated as 2% of the total costs and accounts for a yearly production of 2,000,000 tons per year.

Pipeline and Transmission – The preliminary analysis assumed a unit cost of $20 million per mile of pipeline. To connect a pipeline from the Honolulu port to the Waiau generation plant is approximately 9.6 miles via HI-99. The upper bound for pipelines similar to the volume needed on Oʻahu (150 mmcfd) is equivalent to an energy throughput of 1,901,299 kW, resulting in a "cost of production capacity" (i.e., transportation cost) of approximately 101 $/kW. The amortization period, interest rate, and ROA are assumed to be the same as the other fossil technologies (up to 2045, 4%, and 7%, respectively).

Onshore Storage - Natural gas storage works differently than water or diesel storage because natural gas (after regasification) can be compressed within a storage unit or a pipeline. The physical natural gas storage is modeled at the same node as an infinite Engage storage technology. An infinite storage capacity was applied, which assumes that storage capacity would not be a limiting factor on the system. The storage unit can only store the natural gas carrier and then supply it to the CCGT or CT turbines if built into the model. Note: All FSRU storage costs are included in the FSRU facility costs.

Powerplants – Natural gas capacity expansion technology options modeled consisted of Combined Cycle Gas Turbines (CCGTs) and Combustion Turbines (CTs), also called Gas Turbines (GTs). While these units are capable of running on diesel, biodiesel, renewable natural gas, or other future renewable fuels, in the current model, they are assumed to run off natural gas.

The CCGT technology has a higher efficiency and higher capital cost, while the CT technology has a lower technology cost and lower efficiency. The technology heat rates (called conversion efficiencies in Engage) are sourced from the NREL 2023 ATB[4], and adjusted by the heat rate multipliers used in the ReEDS model. The multipliers are applied to the ideal technology heat rates reported by the ATB to account for the model not running always running the generator at the optimal heat rate.

Table 8. Multipliers Applied to Full-Load Heat Rates to Approximate Heat Rates for Part-Load Operation

Technology	Adjustment Factor
Coal (all)	1.0674
Gas-CC	1.0545
Gas-CT	1.1502
OGS	1.1704

[3] The FSRU costs were spot-checked against other industry estimates, including recent project data and market benchmarks, to ensure consistency and accuracy. The 2.154 multiplier was not applied because the specific capital costs for FSRU construction and terminal development were considered directly comparable to global estimates without requiring an adjustment for Hawaiʻi-specific cost premiums.
[4] https://atb.nrel.gov/electricity/2023/fossil_energy_technologies

Table 8 reproduced from Regional.Energy.Deployment.System.(ReEDS).Model.Documentation¿Version. 8686, Jonathan Ho et al., https://www.nrel.gov/docs/fy21osti/78195.pdf.

Engage operates on an hourly time series, and these technologies can ramp up to 100% of capacity within an hour, so no ramp rates are configured. Additionally, no minimum operating parameters or min up/down times are enforced to reduce model complexity. No minimum or maximum capacity constraints are enforced, meaning the model can optimize the desired CT/CCGT capacity. The carrier production costs for both CCGT and CT technologies are from RESOLVE input workbooks from Hawaiian Electric's IGP.[5]

2nd Iteration "Alternative Fuels Study 2024"

The second iteration included adjusted assumptions for high storage costs and other infrastructure cost adjustments beyond the 1st iteration.

FSRU – Same capital cost as 1st iteration, except that the fixed O&M cost and cost of production capacity are derated for a 600MW output, thus raising their respective costs. The fixed O&M cost and cost of production capacity rise from 3.22 $/kW and 161 $/kW in the 1st iteration to 13.33 $/kW and 666 $/kW in the 2nd iteration, respectively.

Pipeline and Transmission – The amortization period, interest rate, and ROA are the same as the 1st iteration. As with the FSRU, the cost of production capacity is derated for a 600MW output, raising it from ~101 $/kW to 320 $/kW.

Storage, Fuel Costs, Powerplant(s) – Same as 1st iteration.

Biofuels

Biomass – The capital costs reflect the ATB/EIA cost projections for biopower, which represents costs for a dedicated biomass plant. Both CAPEX and OPEX are scaled using the 2.154 Hawaii cost multiplier, with the current biomass fuel/variable cost at 60.9 $/MWh of production.

Biodiesel – Similar to biomass, the capital cost assumptions reflect the ATB/EIA cost projections for biopower, with additional diesel turbine costs applied.

Fossil

Planned retirement dates from the IGP are assumed. No economic retirements are included in the analysis.

Hydrogen Combustion Turbine (CT)

The H2 infrastructure (CAPEX/OPEX) costs are derived from the ATB and scaled for Hawaii using the 2.154 cost multiplier. Costs for appropriate turbine technologies from the ATB are applied, escalated to account for hydrogen-capable turbines, and adjusted prior to the PPA process. Costs were generated for electrolyzers, CTs, and H2 storage across all years, but hydrogen is only included in 2045. Import costs

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[5] Hawaiian Electric IGP Workbooks. Available at https://www.hawaiianelectric.com/a/10684

include transportation to the islands and delivery to storage or turbine locations. Hydrogen pricing incorporates all IRA incentives.

Distributed Generation PV

Assumptions for distributed generation PV remain the same as in the Decarbonization Report.

Utility-Scale PV

Third-party PPA costs are updated using the 2023 ATB with the NREL PPA model. Technology assumptions remain consistent with the Decarbonization Report.

Onshore Wind

PPA costs are updated with the 2023 ATB, scaled using the 2.154 Hawaii cost multiplier, and supplemented with independent power producer unit costs. Technology assumptions align with the Decarbonization Report.

Offshore Wind

PPA costs are updated with the 2023 ATB, following assumptions from the Decarbonization Report. In this analysis, technical potential (maximum resource capacity) is capped at 400 MW.

Waste-to-Energy

The existing H-Power waste-to-energy plant is modeled as-is for this analysis. No additional capacity is included.

\.In.the.Decarbonization.Report?for.Oʻahu?Hawaiʻi.Island?and.Maui.solar.and.land_based.wind.resource. technical.potential.are.sourced.from.8689.Hawaiian.Electric.IGP.Base.scenario.assumptions¡.The.8689. Hawaiian.Electric.IGP.Base.scenario.uses.the.Alt_7.land.exclusions.outlined.in.the.8687.update.of.the. NREL.technical.potential.report¡[6].The.capacity.expansion.analysis.used.representative.weather.year. technical.potential.profiles.published.in.the.Hawaiian.Electric.IGP.workbooks¡[7].Cost.assumptions.are. discussed.in.detail.on.pages.7❷❷_7❷❺¡[8].

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[6] Grue, N., Waechter, K., Williams, T., & Lockshin, J. (2021). Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company. National Renewable Energy Laboratory.

[7] The solar and wind technical potential profiles used in this study are provided in Excel workbooks at this website: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/power-supply-improvement-plan. For Oʻahu, Hawaiʻi Island, Maui, Molokaʻi, and Lānaʻi, Hawaiian Electric published four workbooks with inputs to their IRP processes under the heading "March 31, 2022 – Hawaiian Electric Response to Order No. 38253 Approving Inputs and Assumptions with Modifications (PDF)." The solar and wind technical potential profiles are sourced from the workbooks associated with each island entitled "Workbook 2."

[8] https://energy.hawaii.gov/wp-content/uploads/2022/10/Act-238_HSEO_Decarbonization_FinalReport_2023.pdf

Model constraints and resource selection drivers

A key constraint within the model was the attainment of the Renewable Portfolio Standard (RPS). To ensure the selected technologies did not backslide on current laws, the following RPS constraints were included in the model. The selected generation resources were required to meet these renewable targets:

- 39% by 2029
- 40% by 2030
- 55% by 2035
- 70% by 2040
- 100% by 2045

RPS constraints were unchanged from the decarbonization study and compliant with Hawaiʻi Revised Statutes §269-91(definitions) and §269-92 (generation requirements). The RPS is a major driver of buildout as expected and was one of the most heavily-binding constraints in the model. The incremental capacity increases throughout the years are primarily driven by the need to increase the amount of RE generation.

Power.Plant.Retirements

Power plant retirements were preprogrammed into the model based on the published retirement dates in Hawaiian Electric's IGP. Economic retirements were not considered in this analysis.

Other.Major.Assumptions?Constraints?and.Resource.Selection.Influences

Demand scenarios were pulled from the Hawaiian Electric Pathways report because the Decarbonization Report had extremely aggressive energy efficiency (EE) assumptions, sourced from the 2020 State of Hawaiʻi Market Potential Study.[9] incorporated into the scenarios. While energy efficiency is a critical component of Hawaiʻi's energy plan, the adoption of the EE measures to the scale described in the Decarbonization Report will be challenging and may not be practical without substantial resources. Therefore, for more conservative estimates with less aggressive demand reductions, forecasts from Hawaiian Electric were applied.

The different prices due to FSRU utilization play a major role in whether natural gas is built across the islands, especially on Oʻahu. This can be seen by comparing the modeled natural gas capacities between high and low-pricing scenarios in the Appendices, where no natural gas capacity is added in the high-pricing scenarios across all islands.

The model preferred offshore wind over other resources and imposed offshore wind constraints (400 MW or 0MW) have a noticeable impact on results. Without offshore wind, the additional capacity of natural gas is most substantial in 2035, when offshore wind was assumed to become available.

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[9] https://puc.hawaii.gov/wp-content/uploads/2021/02/Hawaii-2020-Market-Potential-Study-Final-Report.pdf

Appendix 1 – O‘ahu Results Tables (with and without offshore wind)

Appendix 1.1 – O‘ahu Aggressive Electrification High Costs Scenarios

Oahu Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Aggressive High Costs with Offshore Wind	Generation	Biofuels	8	8	314	492	0	4	1,926	2,217	0	2	460	492
		Hydrogen CT	0	0	0	559	0	0	0	2,295	0	0	0	166
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	400	400	400	0	2,061	2,112	2,109	0	203	204	203
		Onshore Wind	286	286	286	286	1,073	993	976	995	142	121	64	64
		Petroleum	1,095	722	550	0	2,698	2,204	1,134	0	440	483	246	0
		Solar DGPV	1,467	1,729	2,550	2,605	2,755	3,162	4,683	4,879	125	154	249	251
		Solar PV	943	943	915	915	1,919	1,862	1,853	1,862	135	123	103	93
		Waste-to-Energy	68	68	68	68	402	348	392	436	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	324	324	0	0	631	540	0	0	126	125
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	188	299	318	288	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,260	1,454	1,380	1,180	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	204
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	21	21	21
Aggressive High Costs without Offshore Wind	Generation	Biofuels	8	91	365	543	0	571	2,452	2,724	0	135	570	596
		Hydrogen CT	0	0	0	591	0	0	0	2,631	0	0	0	175
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	286	286	286	1,070	1,008	983	994	142	121	64	64
		Petroleum	1,095	722	550	0	2,698	2,539	1,603	0	440	558	343	0
		Solar DGPV	1,467	2,325	3,130	3,312	2,715	4,318	5,833	6,193	125	230	324	340
		Solar PV	943	943	915	915	1,934	1,873	1,842	1,871	135	123	103	93
		Waste-to-Energy	68	68	68	68	402	375	407	442	15	14	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	213	506	506	0	410	1,020	920	0	77	191	191
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	302	151	267	284	277	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,085	1,350	1,277	1,179	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	234
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

Appendix 1.2 – O‘ahu Aggressive Electrification Low Costs Scenarios

Oahu Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW) 2030	Capacity (MW) 2035	Capacity (MW) 2040	Capacity (MW) 2045	Generation (GWh) 2030	Generation (GWh) 2035	Generation (GWh) 2040	Generation (GWh) 2045	Cost (million USD) 2030	Cost (million USD) 2035	Cost (million USD) 2040	Cost (million USD) 2045
Aggressive Low Costs with Offshore Wind	Generation	Biofuels	8	8	8	186	0	0	3	30	0	0	1	21
		Hydrogen CT	0	0	0	970	0	0	0	4,847	0	0	0	315
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	130	195	449	0	941	1,131	2,379	0	54	78	172	0
		Offshore Wind	0	400	400	400	0	2,062	2,073	2,095	0	203	204	203
		Onshore Wind	286	256	286	286	1,075	970	925	969	142	112	63	63
		Petroleum	1,095	722	550	0	1,875	1,160	1,149	0	306	252	247	0
		Solar DGPV	1,366	1,663	2,382	2,424	2,586	2,978	4,327	4,515	107	140	224	224
		Solar PV	943	943	915	915	1,932	1,903	1,774	1,834	135	123	103	93
		Waste-to-Energy	68	68	68	68	431	364	350	404	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	172	181	368	301	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,216	1,073	1,395	1,083	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	11
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	431
		Natural Gas Distribution	-	-	-	-	-	-	-	-	23	27	93	93
		Natural Gas Supply	-	-	-	-	-	-	-	-	76	95	236	38
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	21	21	21
Aggressive Low Costs without Offshore Wind	Generation	Biofuels	8	8	139	317	0	0	893	1,034	0	0	208	228
		Hydrogen CT	0	0	0	989	0	0	0	5,101	0	0	0	314
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	130	432	457	0	941	2,503	2,563	0	54	170	179	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	256	286	286	1,076	975	990	992	142	112	63	63
		Petroleum	1,095	722	550	0	1,875	1,107	1,349	0	306	239	285	0
		Solar DGPV	1,366	2,027	2,741	2,827	2,562	3,765	4,951	5,286	107	187	270	275
		Solar PV	943	943	915	915	1,939	1,874	1,881	1,863	135	123	103	93
		Waste-to-Energy	68	68	68	68	431	378	383	428	15	14	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	63	63	0	0	118	75	0	0	24	24
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	302	153	248	381	267	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,111	1,246	1,443	1,092	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	7
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	453
		Natural Gas Distribution	-	-	-	-	-	-	-	-	23	67	67	67
		Natural Gas Supply	-	-	-	-	-	-	-	-	76	233	238	28
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

Appendix 1.3 – Oʻahu Conservative Electrification High Costs Scenarios

Oahu Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Conservative High Costs with Offshore Wind	Generation	Biofuels	8	8	192	370	0	0	1,216	1,408	0	0	289	317
		Hydrogen CT	0	0	0	509	0	0	0	2,051	0	0	0	151
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	400	400	400	0	1,984	2,088	2,100	0	203	204	203
		Onshore Wind	286	256	286	286	1,073	977	960	990	142	112	63	63
		Petroleum	1,095	722	550	0	2,096	1,437	1,166	0	339	310	252	0
		Solar DGPV	1,201	1,364	1,835	1,876	2,274	2,503	3,431	3,541	83	99	152	152
		Solar PV	943	943	915	915	1,929	1,915	1,834	1,863	135	123	103	93
		Waste-to-Energy	68	68	68	68	406	342	384	424	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	96	96	0	0	168	131	0	0	36	36
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	181	253	323	291	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,259	1,319	1,388	1,166	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	182
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	21	21	21
Conservative High Costs without Offshore Wind	Generation	Biofuels	8	19	256	434	0	78	1,692	1,911	0	19	395	418
		Hydrogen CT	0	0	0	549	0	0	0	2,531	0	0	0	163
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	286	286	286	1,071	1,046	986	1,001	142	121	64	64
		Petroleum	1,095	722	550	0	2,096	2,562	1,726	0	339	562	370	0
		Solar DGPV	1,201	1,766	2,389	2,481	2,248	3,248	4,439	4,655	83	150	222	228
		Solar PV	943	943	915	915	1,929	1,874	1,868	1,875	135	123	103	93
		Waste-to-Energy	68	68	68	68	406	359	398	441	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	19	240	240	0	35	463	384	0	7	90	90
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	302	151	274	287	272	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,080	1,324	1,274	1,162	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	225
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

Appendix 1.4 – Oʻahu Conservative Electrification Low Costs Scenarios

Oahu Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Conservative Low Costs with Offshore Wind	Generation	Biofuels	8	8	8	186	0	0	3	28	0	0	1	19
		Hydrogen CT	0	0	0	723	0	0	0	3,381	0	0	0	229
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	57	72	225	0	418	415	1,187	0	24	29	86	0
		Offshore Wind	0	400	400	400	0	2,058	2,096	2,106	0	203	204	203
		Onshore Wind	286	256	286	286	1,075	973	946	962	142	112	63	63
		Petroleum	1,095	722	550	0	1,734	1,050	1,229	0	281	229	264	0
		Solar DGPV	1,151	1,324	1,918	1,960	2,169	2,456	3,427	3,672	74	91	160	160
		Solar PV	943	943	915	915	1,933	1,878	1,834	1,815	135	123	103	93
		Waste-to-Energy	68	68	68	68	423	351	345	396	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	151	287	365	327	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,094	1,462	1,464	1,155	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	6
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	300
		Natural Gas Distribution	-	-	-	-	-	-	-	-	10	10	51	51
		Natural Gas Supply	-	-	-	-	-	-	-	-	34	35	121	20
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	21	21	21
Conservative Low Costs without Offshore Wind	Generation	Biofuels	8	8	75	253	0	0	458	531	0	0	108	123
		Hydrogen CT	0	0	0	838	0	0	0	4,293	0	0	0	263
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	57	290	312	0	418	1,668	1,738	0	24	113	122	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	256	286	286	1,074	1,002	973	992	142	112	63	63
		Petroleum	1,095	722	550	0	1,734	1,076	1,596	0	281	232	335	0
		Solar DGPV	1,151	1,699	2,225	2,267	2,168	3,072	4,082	4,229	74	140	200	200
		Solar PV	943	943	915	915	1,934	1,937	1,853	1,870	135	123	103	93
		Waste-to-Energy	68	68	68	68	423	373	381	419	15	14	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	151	207	402	272	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,094	1,148	1,526	1,018	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	6
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	381
		Natural Gas Distribution	-	-	-	-	-	-	-	-	10	47	47	47
		Natural Gas Supply	-	-	-	-	-	-	-	-	34	160	167	20
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

Appendix 1.5 – Oʻahu Reference High Costs Scenarios

Oahu Alternative Fuels Study - Scenario Results

			Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Reference High Costs with Offshore Wind	Generation	Biofuels	8	8	24	202	0	0	103	138	0	0	26	43
		Hydrogen CT	0	0	0	486	0	0	0	1,971	0	0	0	144
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	364	400	400	0	1,884	2,041	2,085	0	185	205	204
		Onshore Wind	286	256	286	286	1,078	958	947	970	142	112	63	63
		Petroleum	1,095	722	550	0	2,126	1,040	1,307	0	344	227	281	0
		Solar DGPV	1,212	1,290	1,465	1,507	2,292	2,392	2,700	2,820	85	90	107	108
		Solar PV	943	943	915	915	1,926	1,805	1,828	1,843	135	123	103	93
		Waste-to-Energy	68	68	68	68	406	313	334	387	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	182	330	370	341	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,247	1,615	1,503	1,226	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	175
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	21	21	21
Reference High Costs without Offshore Wind	Generation	Biofuels	8	8	152	330	0	0	988	1,113	0	0	231	248
		Hydrogen CT	0	0	0	512	0	0	0	2,422	0	0	0	152
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	286	286	286	1,070	1,025	994	1,004	142	121	64	64
		Petroleum	1,095	722	550	0	2,126	2,207	1,752	0	344	478	372	0
		Solar DGPV	1,212	1,547	1,732	1,774	2,269	2,801	3,221	3,344	85	123	142	142
		Solar PV	943	943	915	915	1,930	1,915	1,877	1,879	135	123	103	93
		Waste-to-Energy	68	68	68	68	406	356	392	434	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	36	36	0	0	64	49	0	0	14	14
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	151	183	282	271	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,079	1,089	1,256	1,097	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	215
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

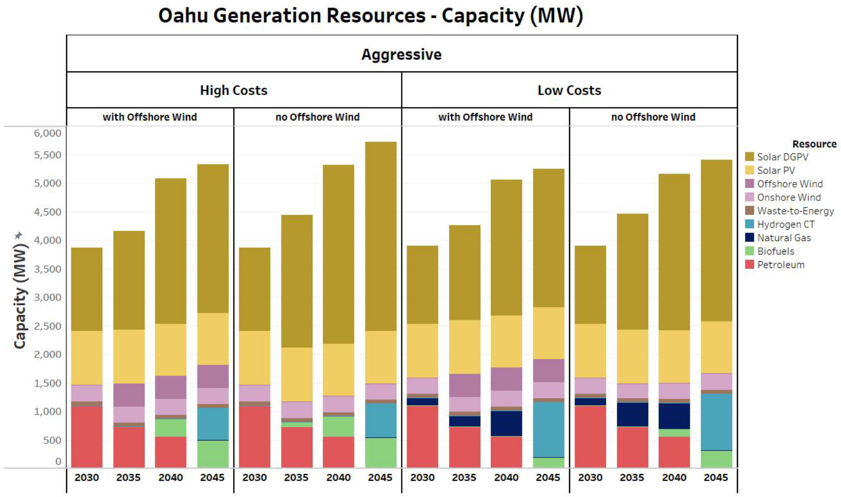
Appendix 1.6 – O‘ahu Reference Low Costs Scenarios

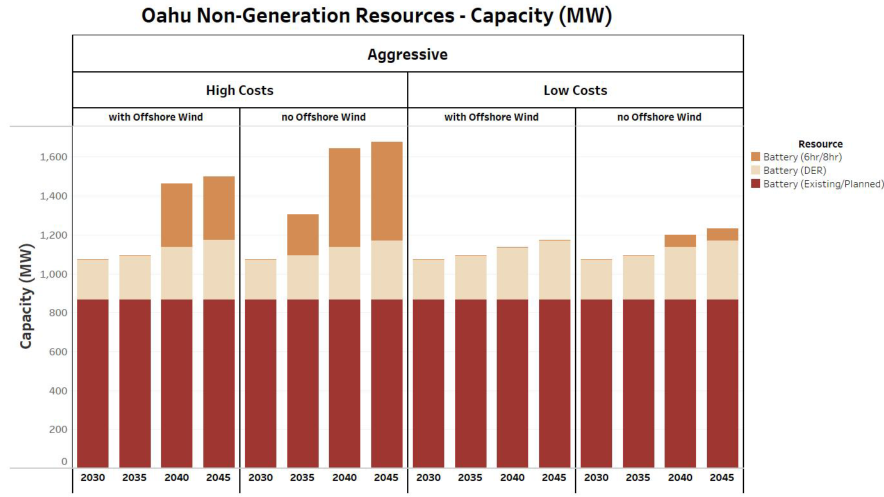
Oahu Alternative Fuels Study - Scenario Results

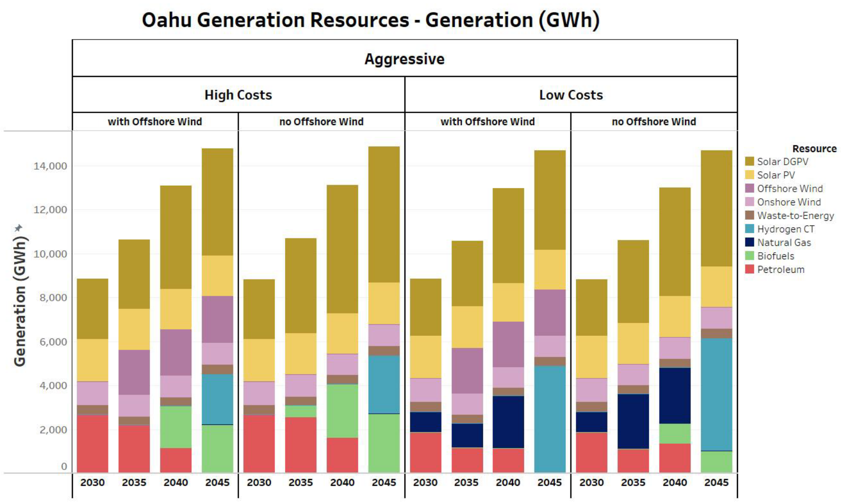
Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Reference Low Costs with Offshore Wind	Generation	Biofuels	8	8	8	186	0	0	1	27	0	0	1	19
		Hydrogen CT	0	0	0	520	0	0	0	2,242	0	0	0	158
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	65	82	94	0	481	457	510	0	27	33	37	0
		Offshore Wind	0	321	400	400	0	1,670	2,067	2,081	0	163	207	206
		Onshore Wind	286	256	163	163	1,075	952	770	784	142	112	31	31
		Petroleum	1,095	722	550	0	1,704	740	1,037	0	277	166	222	0
		Solar DGPV	1,161	1,239	1,472	1,514	2,207	2,278	2,717	2,852	76	81	105	106
		Solar PV	943	943	915	915	1,933	1,865	1,807	1,829	135	123	103	93
		Waste-to-Energy	68	68	68	68	424	340	345	394	15	13	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	306	174	182	356	323	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,220	1,078	1,477	1,195	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	2
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	199
		Natural Gas Distribution	-	-	-	-	-	-	-	-	12	12	12	12
		Natural Gas Supply	-	-	-	-	-	-	-	-	39	39	42	5
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	20	21	21
Reference Low Costs without Offshore Wind	Generation	Biofuels	8	8	8	186	0	0	3	23	0	0	1	14
		Hydrogen CT	0	0	0	667	0	0	0	3,468	0	0	0	207
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	65	206	218	0	481	1,187	1,231	0	27	81	86	0
		Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	286	256	201	201	1,075	1,001	831	839	142	112	41	41
		Petroleum	1,095	722	550	0	1,704	1,082	1,556	0	277	233	325	0
		Solar DGPV	1,161	1,510	1,860	1,902	2,187	2,763	3,433	3,588	76	116	154	155
		Solar PV	943	943	915	915	1,934	1,930	1,849	1,860	135	123	103	93
		Waste-to-Energy	68	68	68	68	424	370	356	413	15	14	12	11
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (10hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	206	225	270	302	151	245	375	286	8	11	13	14
		Battery (Existing/Planned)	868	868	868	868	1,096	1,251	1,497	1,105	51	45	40	36
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	4
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	308
		Natural Gas Distribution	-	-	-	-	-	-	-	-	12	32	32	32
		Natural Gas Supply	-	-	-	-	-	-	-	-	39	110	114	13
		Transmission/Distribution	-	-	-	-	-	-	-	-	14	14	14	14

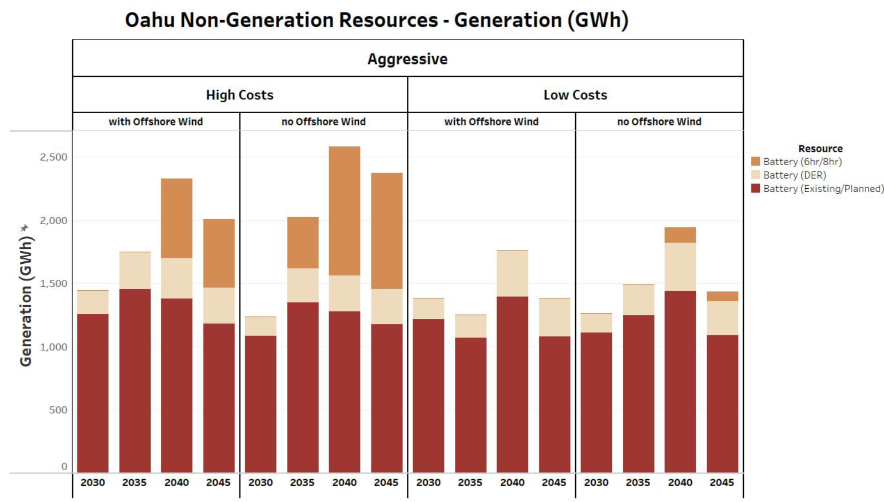
Appendix 2 - Oʻahu Results Charts

Appendix 2.1 - Oʻahu Aggressive Electrification Scenarios

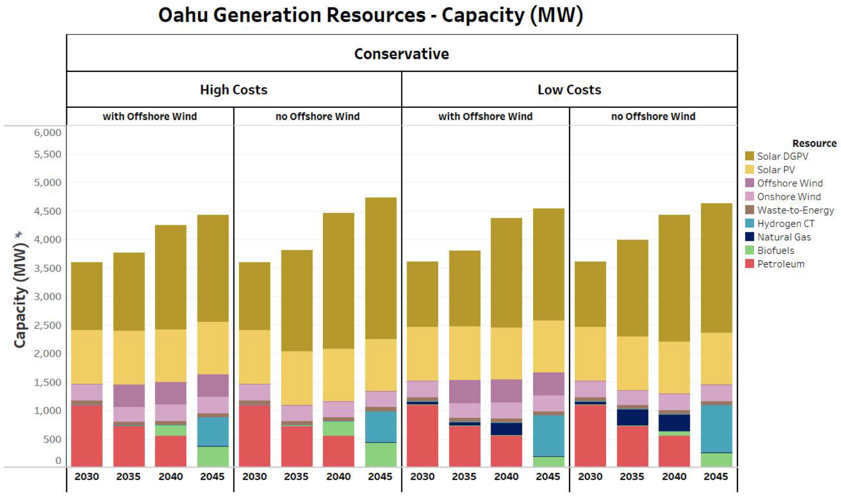


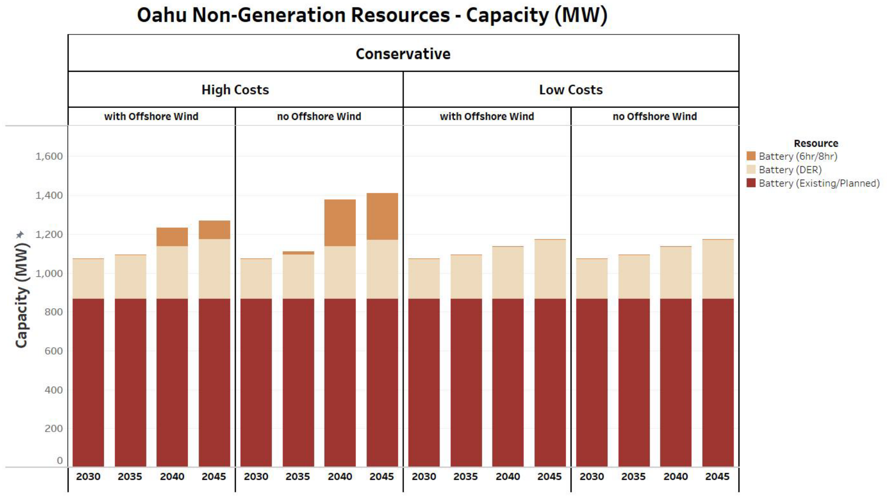


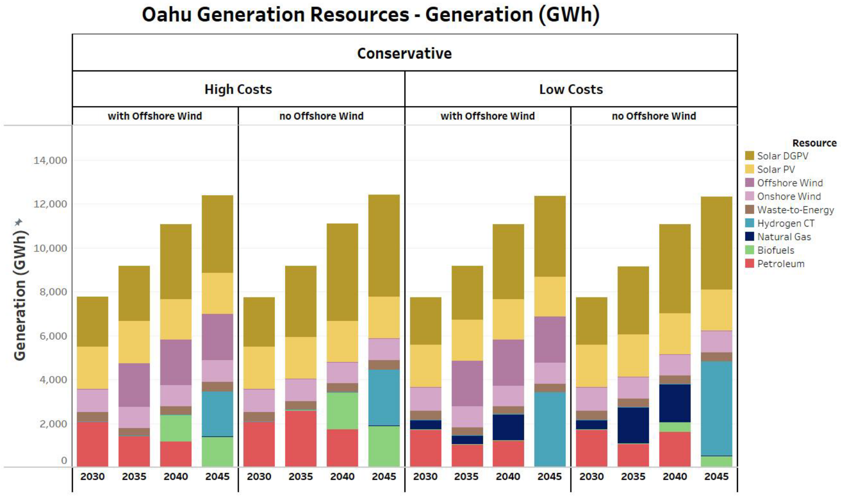


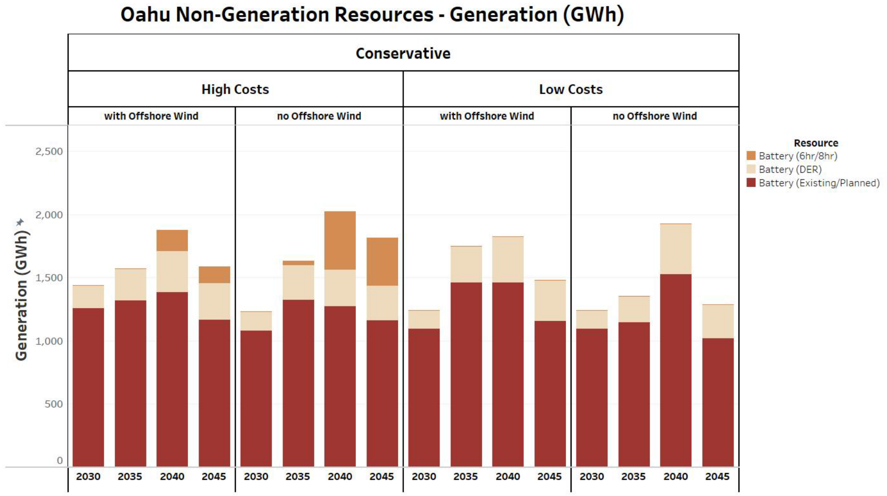


Appendix 2.2 - O‘ahu Conservative Electrification Scenarios

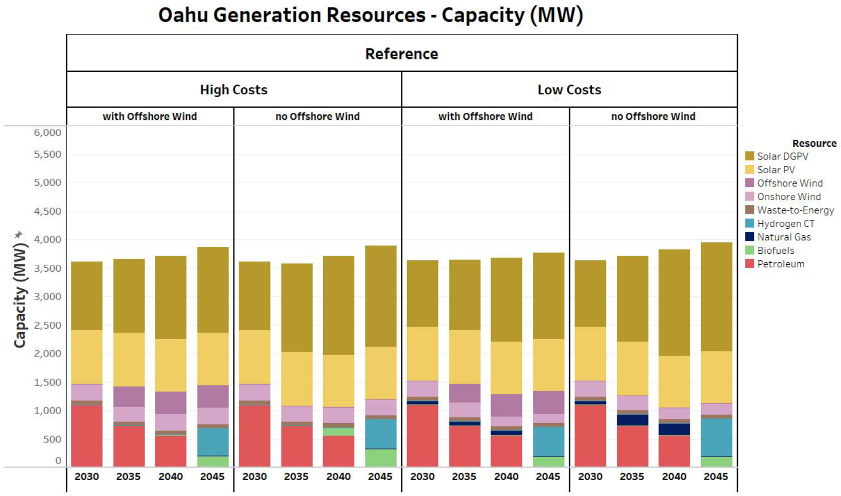


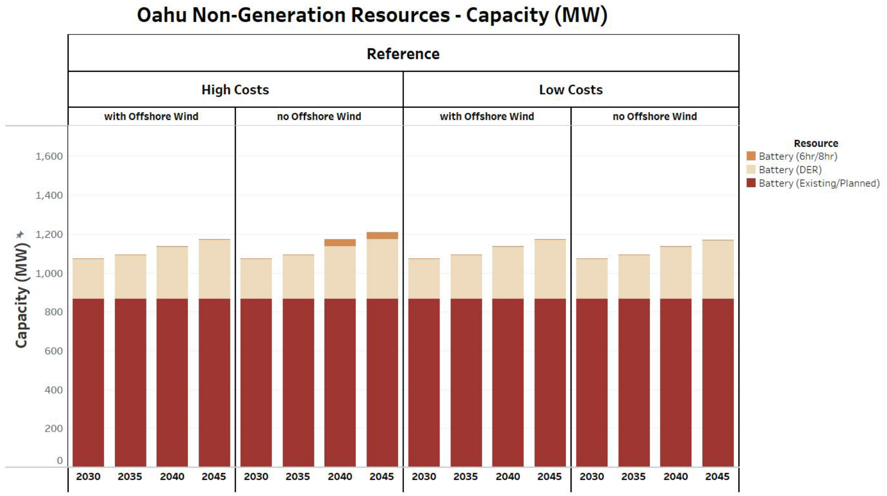


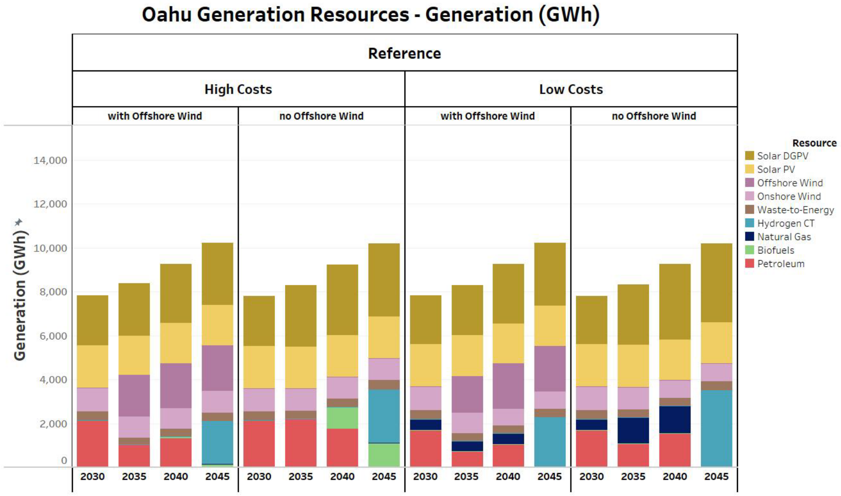


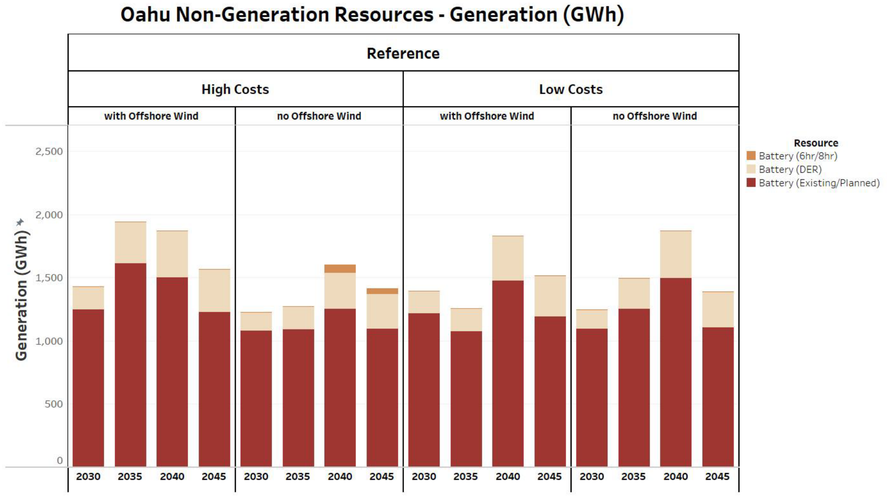


Appendix 2.3 - O‘ahu Reference Electrification Scenarios









Appendix 3 – Maui Results Tables

Appendix B.1 – Maui Aggressive Electrification Scenarios

Maui Alternative Fuels Study - Scenario Results

			Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Aggressive High Costs with Offshore Wind	Generation	Biofuels	0	0	0	309	0	0	0	359	0	0	0	131
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	72	96	171	270	297	399	708	1,049	50	21	41	66
		Petroleum	155	155	155	0	89	201	354	0	22	37	61	0
		Solar DGPV	181	202	355	556	343	390	621	895	0	0	17	38
		Solar PV	352	352	346	346	664	749	725	704	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	91	100	166	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	356	473	482	715	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	3	9	15	24
Aggressive Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	309	0	0	0	359	0	0	0	131
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	72	96	171	270	296	398	713	1,025	50	21	41	66
		Petroleum	155	155	155	0	89	201	354	0	22	37	61	0
		Solar DGPV	181	202	355	556	344	390	626	850	0	0	17	38
		Solar PV	352	352	346	346	666	749	724	728	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	91	112	101	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	358	465	533	491	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	3	9	15	24

Appendix B.2 – Maui Conservative Electrification Scenarios

Maui Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Conservative High Costs with Offshore Wind	Generation	Biofuels	0	0	0	224	0	0	0	190	0	0	0	72
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	53	71	106	147	221	289	427	563	46	16	25	36
		Petroleum	155	155	155	0	83	165	235	0	21	32	43	0
		Solar DGPV	181	202	259	416	343	390	475	686	0	0	5	22
		Solar PV	352	352	346	346	664	746	721	722	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	87	71	159	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	368	476	342	715	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	1	6	10	13
Conservative Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	224	0	0	0	190	0	0	0	72
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	53	71	106	147	221	274	426	557	46	16	25	36
		Petroleum	155	155	155	0	83	165	235	0	21	32	43	0
		Solar DGPV	181	202	259	416	342	386	475	683	0	0	5	22
		Solar PV	352	352	346	346	666	741	721	724	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	60	72	152	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	368	353	342	681	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	1	6	10	13

Appendix B.3 – Maui Reference Scenarios

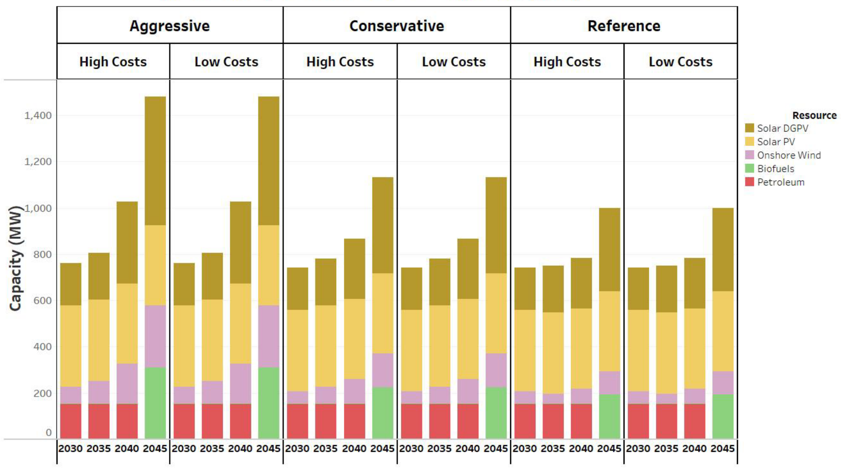
Maui Alternative Fuels Study - Scenario Results

Scenario	Category	Resource	Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Reference High Costs with Offshore Wind	Generation	Biofuels	0	0	0	194	0	0	0	119	0	0	0	48
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	53	42	63	100	223	163	255	361	46	9	15	24
		Petroleum	155	155	155	0	84	130	176	0	21	27	34	0
		Solar DGPV	181	202	218	358	344	384	417	594	0	0	0	15
		Solar PV	352	352	346	346	663	732	715	705	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	60	71	113	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	367	375	352	567	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	1	4	6	9
Reference Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	194	0	0	0	119	0	0	0	48
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	53	42	63	100	219	164	255	362	46	9	15	24
		Petroleum	155	155	155	0	84	130	176	0	21	27	34	0
		Solar DGPV	181	202	218	358	340	384	417	597	0	0	0	15
		Solar PV	352	352	346	346	672	731	716	725	58	54	49	45
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	57	72	85	96	45	60	71	154	0	0	0	0
		Battery (Existing/Planned)	371	371	371	371	368	375	352	676	58	57	56	60
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	1	4	6	9

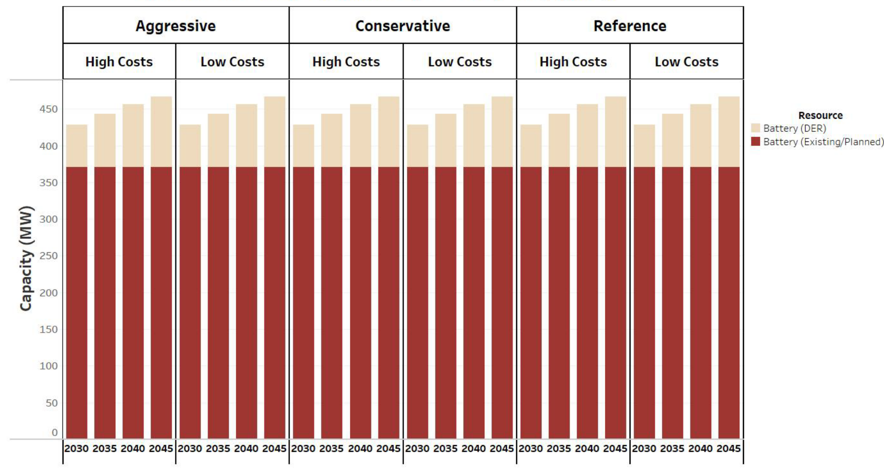
Appendix 4 – Maui Results Charts

Appendix 4.1 - Maui All Scenarios

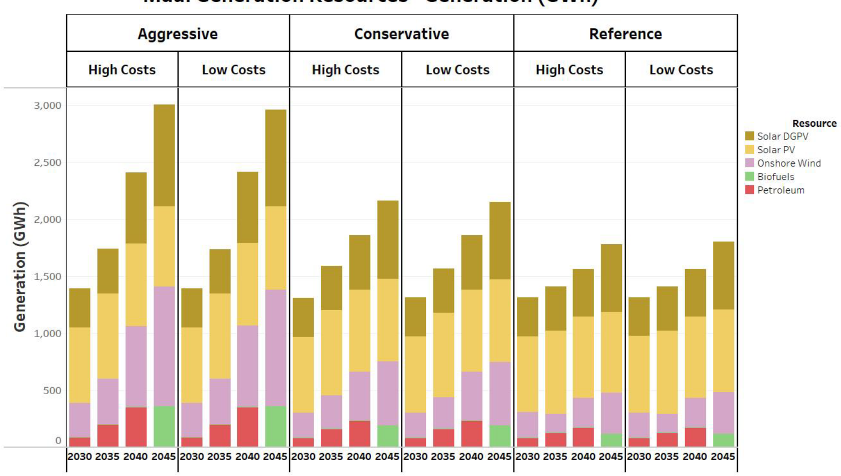
Maui Generation Resources - Capacity (MW)



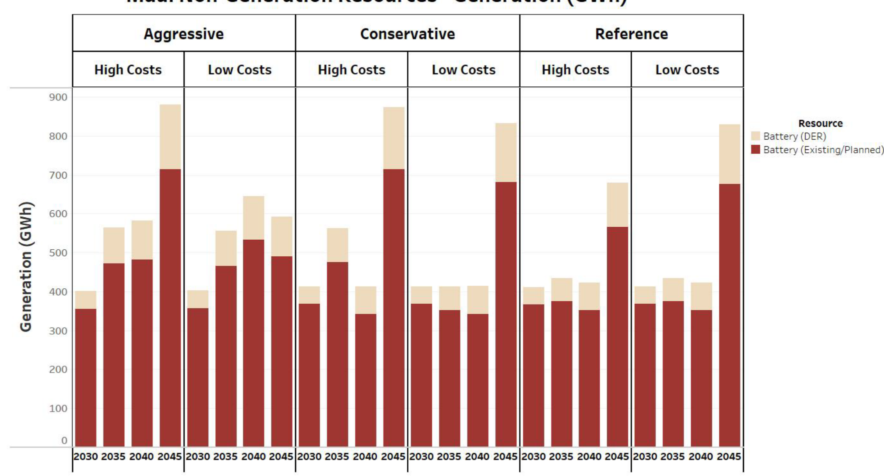
Maui Non-Generation Resources - Capacity (MW)



Maui Generation Resources - Generation (GWh)



Maui Non-Generation Resources - Generation (GWh)



Appendix 5 – Hawai‘i Island Results Tables

Appendix 5.1 – Hawai‘i Island Aggressive Electrification Scenarios

Hawaii Island Alternative Fuels Study - Scenario Results

			Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Aggressive High Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	79	0	0	0	37
		Geothermal	46	46	81	146	258	259	575	1,053	81	76	122	199
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	49	115	145	145	208	504	617	594	11	26	33	33
		Petroleum	182	124	124	0	31	124	176	0	31	39	54	0
		Solar DGPV	162	184	212	227	296	336	388	410	0	0	2	2
		Solar PV	243	244	284	346	578	582	660	741	47	42	53	60
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	74	30	43	55	64	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	259	228	226	256	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	5	14	18	18
Aggressive Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	86	0	0	0	40
		Geothermal	46	46	81	151	258	259	576	1,078	81	76	122	205
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	49	115	145	145	209	506	616	618	11	26	33	33
		Petroleum	182	124	124	0	31	124	176	0	31	39	54	0
		Solar DGPV	162	184	212	227	296	336	387	411	0	0	2	2
		Solar PV	243	244	284	316	577	580	660	681	47	42	53	55
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	76	30	43	55	67	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	259	227	226	242	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	5	14	18	18

Appendix 5.2 – Hawai‘i Island Conservative Electrification Scenarios

Hawaii Island Alternative Fuels Study - Scenario Results

			Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Conservative High Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	81	0	0	0	37
		Geothermal	46	46	46	90	248	267	275	561	80	77	76	127
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	26	81	127	127	107	351	551	555	6	18	31	30
		Petroleum	182	124	124	0	15	74	158	0	27	28	48	0
		Solar DGPV	162	184	202	217	296	336	371	397	0	0	0	0
		Solar PV	243	243	259	292	576	579	614	647	47	42	48	50
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	76	32	43	55	76	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	278	247	231	285	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	2	9	15	15
Conservative Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	81	0	0	0	37
		Geothermal	46	46	46	90	248	267	275	566	80	77	76	127
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	26	81	127	127	106	351	552	542	6	18	31	30
		Petroleum	182	124	124	0	15	74	158	0	27	28	48	0
		Solar DGPV	162	184	202	217	295	336	371	397	0	0	0	0
		Solar PV	243	243	259	292	576	579	614	659	47	42	48	50
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	76	30	43	55	78	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	268	247	231	307	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	2	9	15	15

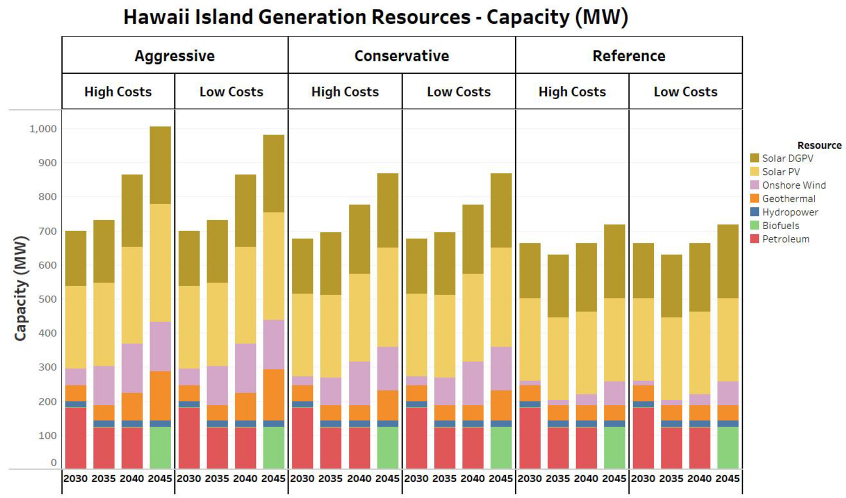
Appendix 5.3 – Hawai‘i Island Reference Scenarios

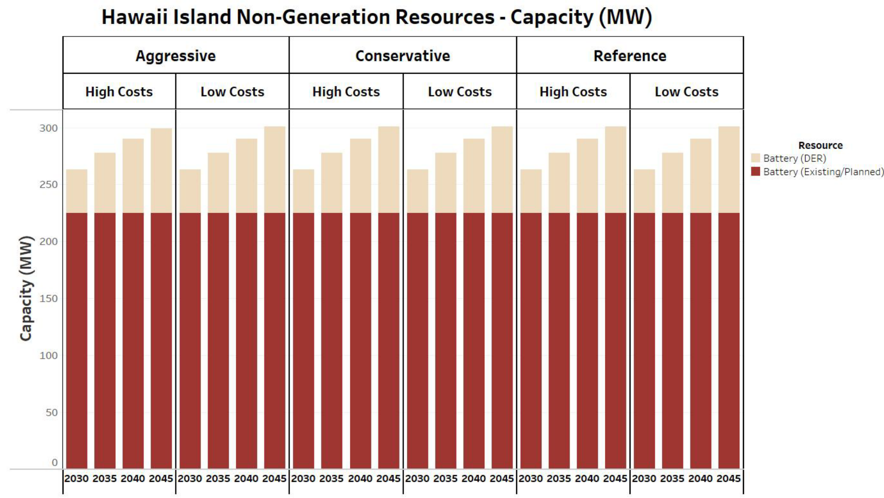
Hawaii Island Alternative Fuels Study - Scenario Results

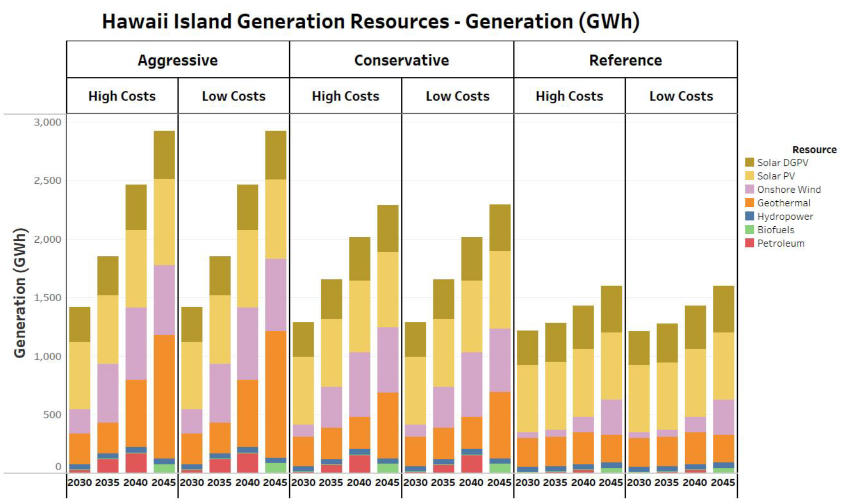
			Capacity (MW)				Generation (GWh)				Cost (million USD)			
			2030	2035	2040	2045	2030	2035	2040	2045	2030	2035	2040	2045
Reference High Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	45	0	0	0	23
		Geothermal	46	46	46	46	242	252	274	237	80	76	76	73
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	13	15	31	70	51	60	130	297	4	4	8	17
		Petroleum	182	124	124	0	10	15	31	0	26	15	18	0
		Solar DGPV	162	184	202	217	295	336	370	397	0	0	0	0
		Solar PV	243	243	243	243	573	576	578	577	47	42	45	41
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	76	33	54	55	68	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	291	304	273	272	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	0
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	0	1	3	8
Reference Low Costs with Offshore Wind	Generation	Biofuels	0	0	0	124	0	0	0	45	0	0	0	23
		Geothermal	46	46	46	46	242	252	274	237	80	76	76	73
		Hydrogen CT	0	0	0	0	0	0	0	0	0	0	0	0
		Hydrogen Electrolyzer	0	0	0	0	0	0	0	0	0	0	0	0
		Hydropower	18	18	18	18	47	47	47	47	3	3	3	3
		Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0
		Onshore Wind	13	15	31	70	51	60	130	298	4	4	8	17
		Petroleum	182	124	124	0	10	15	31	0	26	15	18	0
		Solar DGPV	162	184	202	217	294	334	370	397	0	0	0	0
		Solar PV	243	243	243	243	571	572	578	576	47	42	45	41
	Non-Generation	Battery (2hr/4hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (6hr/8hr)	0	0	0	0	0	0	0	0	0	0	0	0
		Battery (DER)	38	53	65	76	30	43	55	69	0	0	0	0
		Battery (Existing/Planned)	225	225	225	225	272	275	273	270	52	56	59	54
		Hydrogen Storage	-	-	-	-	-	-	-	-	0	0	0	46,816
		Hydrogen Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Distribution	-	-	-	-	-	-	-	-	0	0	0	0
		Natural Gas Supply	-	-	-	-	-	-	-	-	0	0	0	0
		Transmission/Distribution	-	-	-	-	-	-	-	-	0	1	3	8

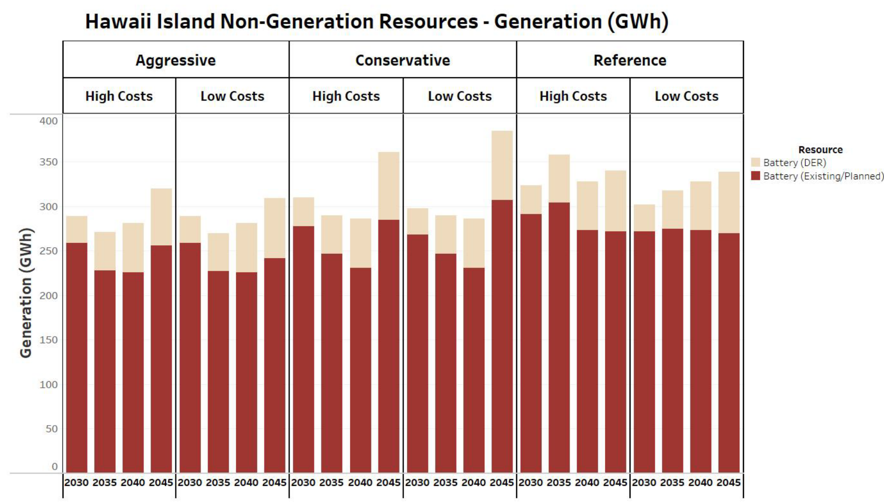
Appendix 6 – Hawai‘i Island Results Charts

Appendix 6.1 - Hawai‘i Island All Scenarios









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

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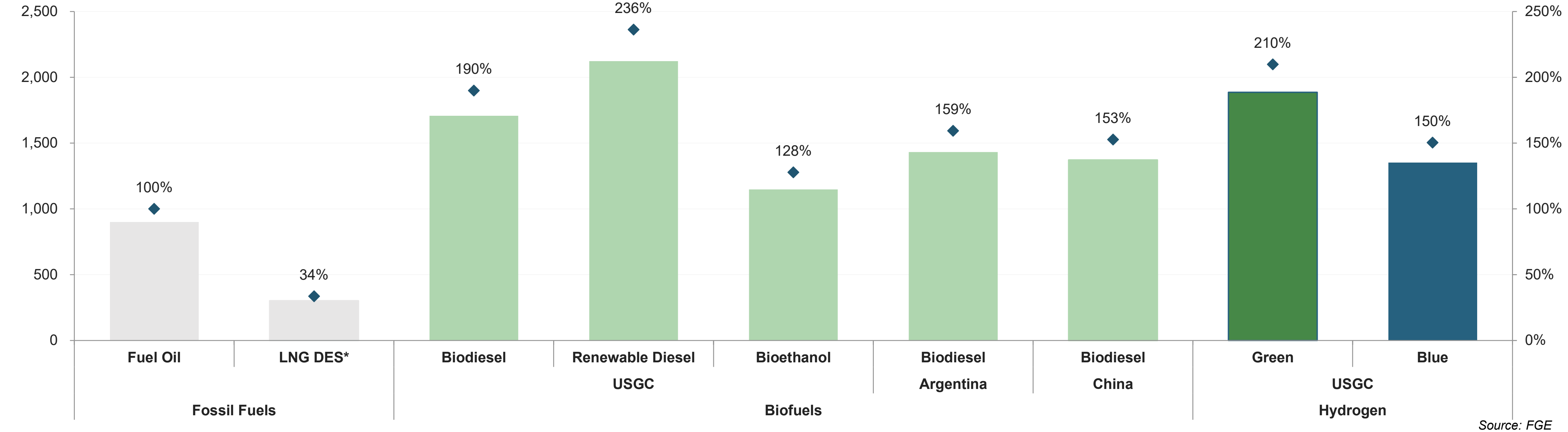
1. Executive Summary

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

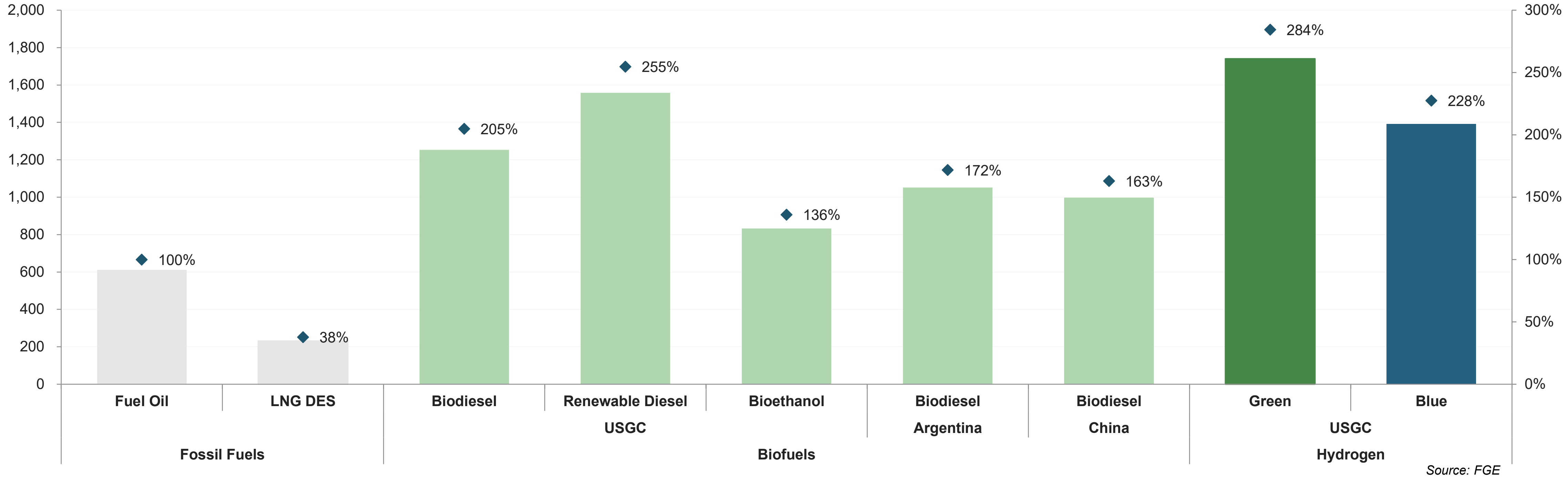
Source: FGE and DBEDT
**Assumes 1 mtpa under FSRU charter*

- 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

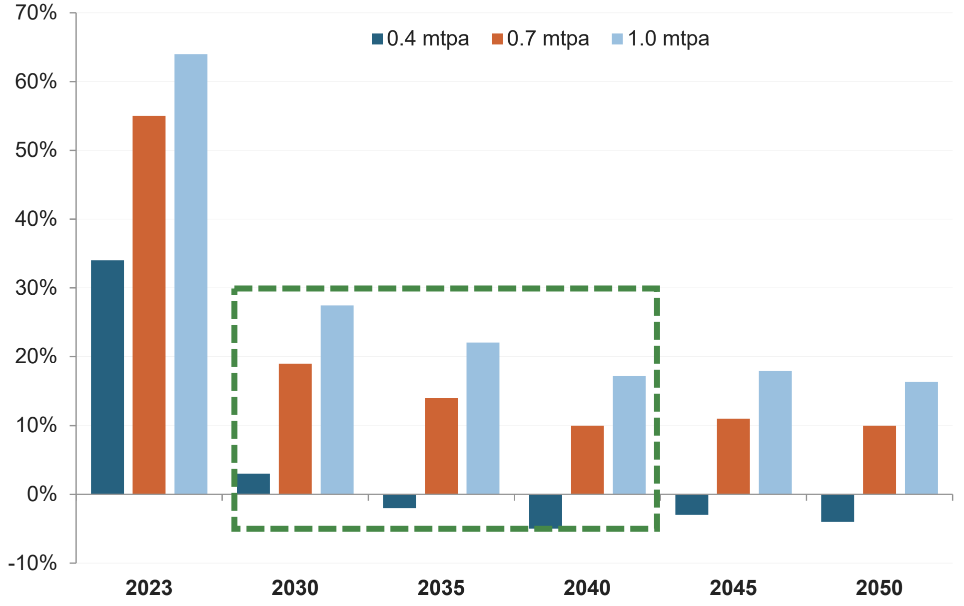
LNG Imports at US$700 million Base Case Investment Scenario (mtpa)	Regas Tariff (US$/MMBtu)	Average Annual Savings vs LSFO*
0.2	7.67	-19%
0.4	3.93	4%
0.6	2.68	15%
0.8	2.06	21%
1.0	1.68	25%
1.2	1.43	28%
1.4	1.26	30%
1.6	1.12	32%
1.8	1.02	33%

Source: FGE
** 2030-2040*

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

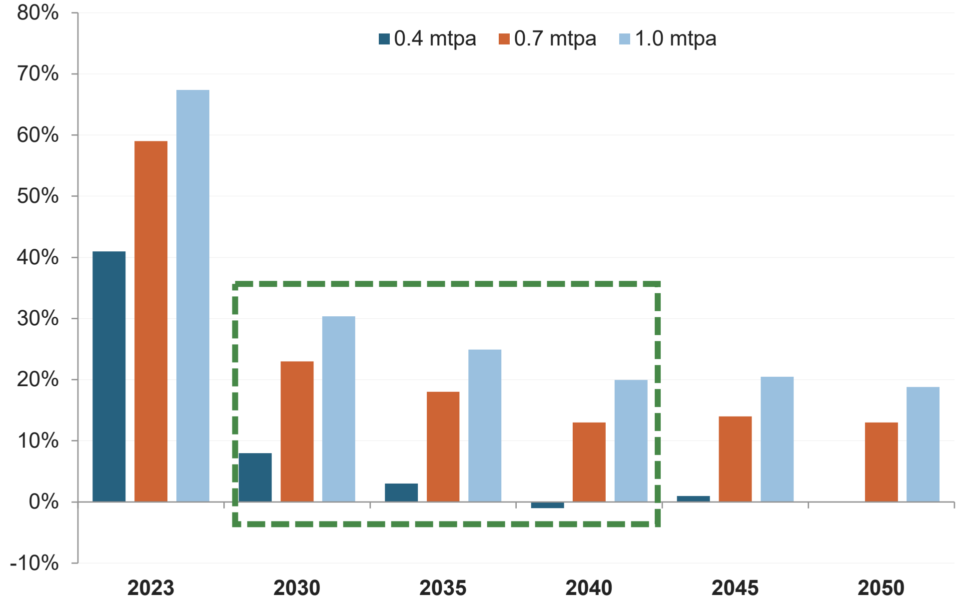
Higher LNG imports bring down FSRU costs as economies of scale are critical

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



Source: FGE

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

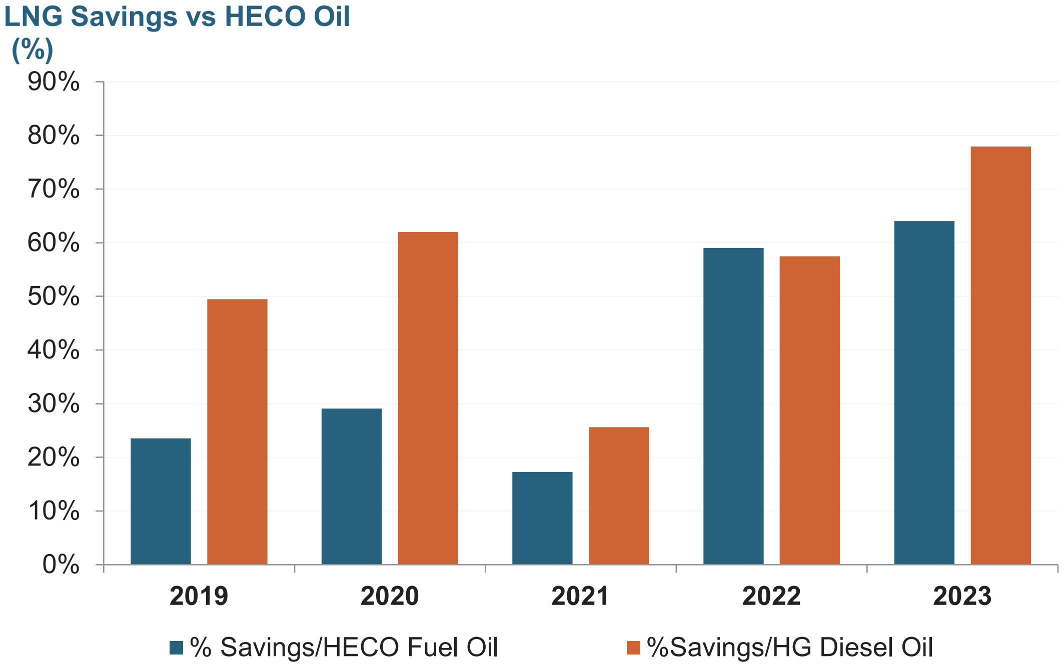


Source: FGE

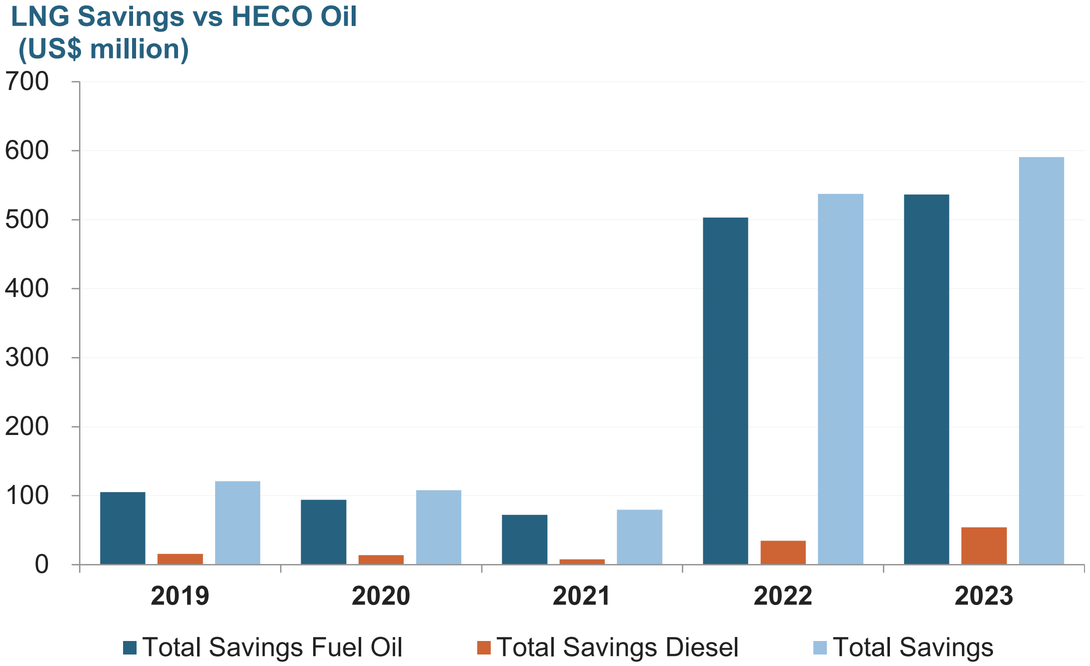
- LNG imports at 0.4 mtpa provide environmental benefits compared to LSFO but zero savings under the FSRU charter scenario. There are minimal savings under the FSRU purchase scenario at this volume.
- LNG imports at 0.7 mtpa provide environmental benefits compared to LSFO and noteworthy economic savings 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

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.

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^{o} 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 →

Transportation

Pipeline Transportation →

US$4-US$6 billion investment

(typically for 2 Bscf/d of gas conventional production)

Liquefaction

Pre-treatment ↓

Liquefaction ↓

Storage ↓

Loading →

Shipping

Shipping →

Cost of modern LNG vessel:

US$250-US$260 million

US$6-US$12 billion Investment

(for a typical liquefaction facility with 10 mtpa capacity)

Regasification

Unloading ↑

Storage ↑

Regasification →

Distribution

Transport to End-Users

Cost of a typical land-based LNG regas terminal:

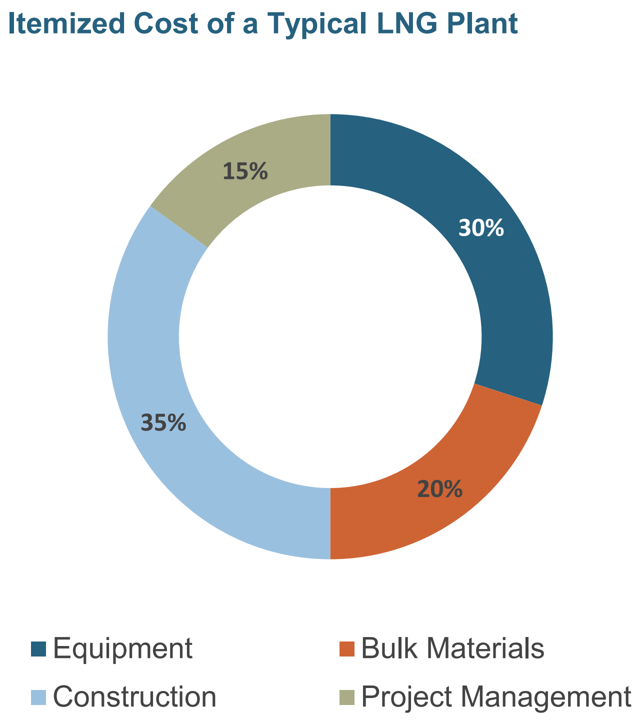
US$1-US$2 billion

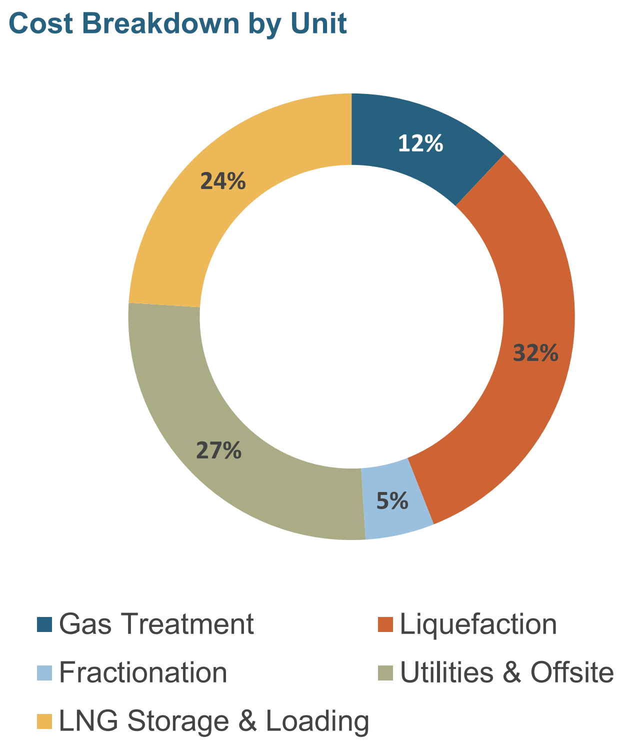
Value of a modern FSRU:

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

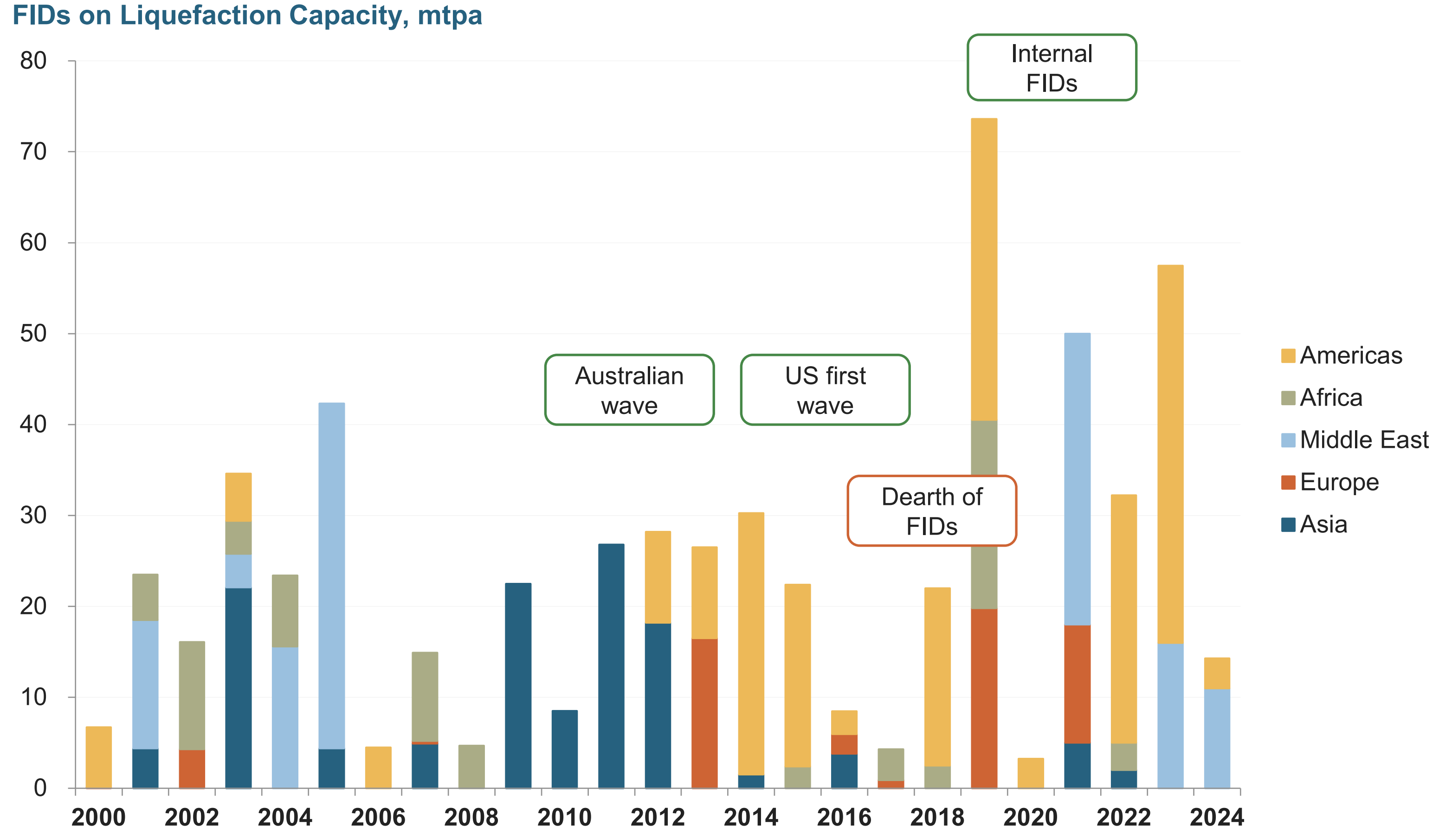




- The above charts are indicative and actual cost breakdown varies project to project, depending on many factors such as location, gas quality and project technical designs, etc.

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



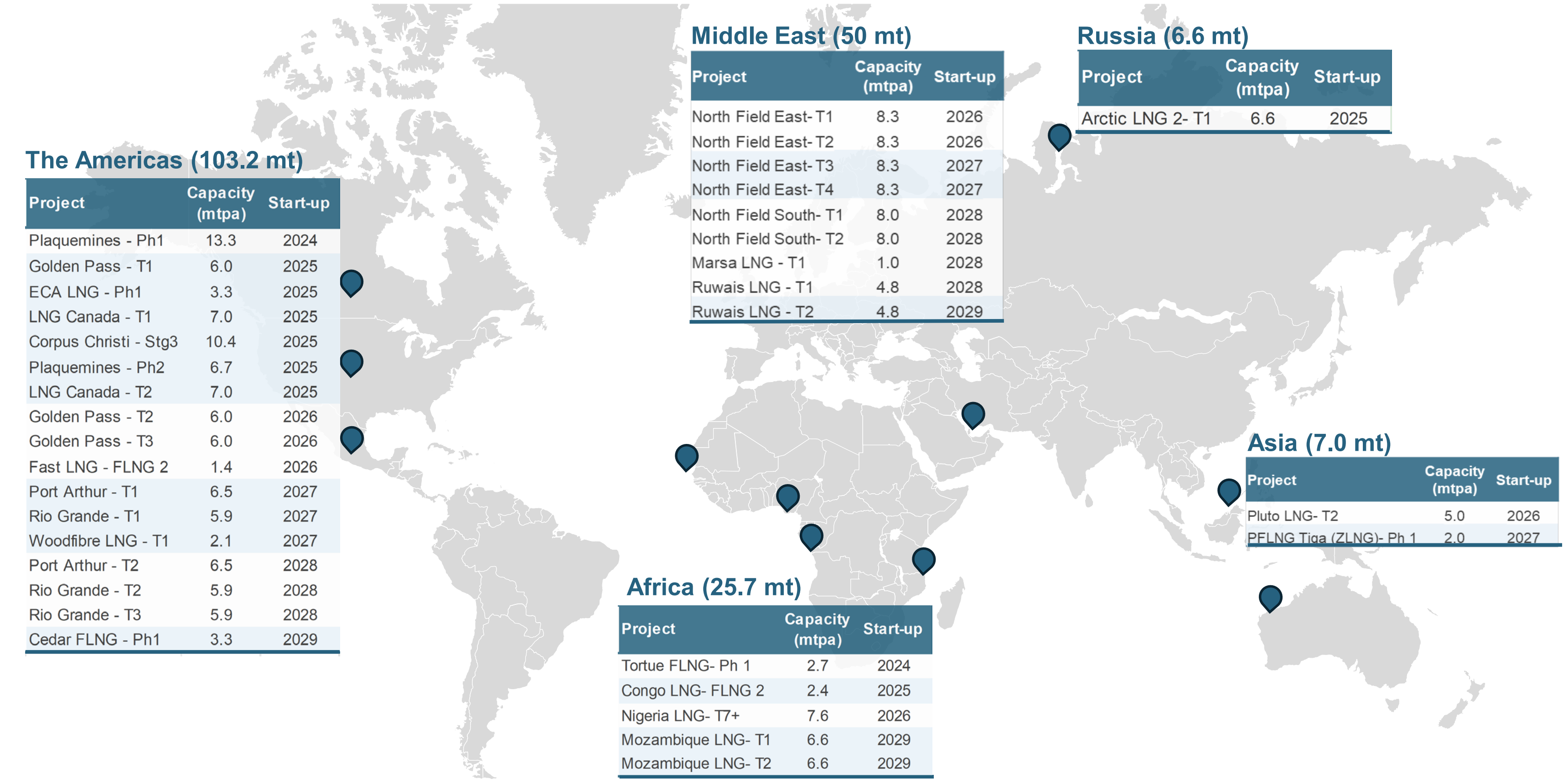
Only includes new liquefaction capacity, excludes backfill projects
Source: FGE LNG ODS

- 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

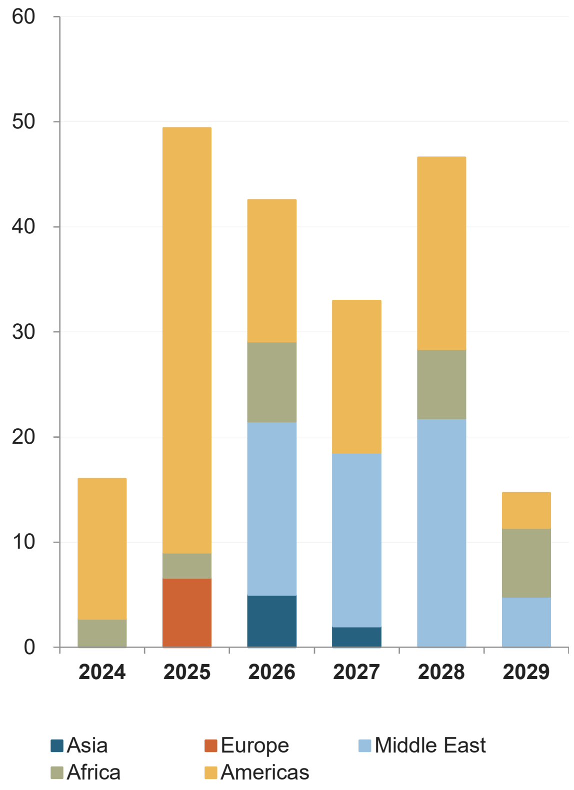
Africa (25.7 mt)

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

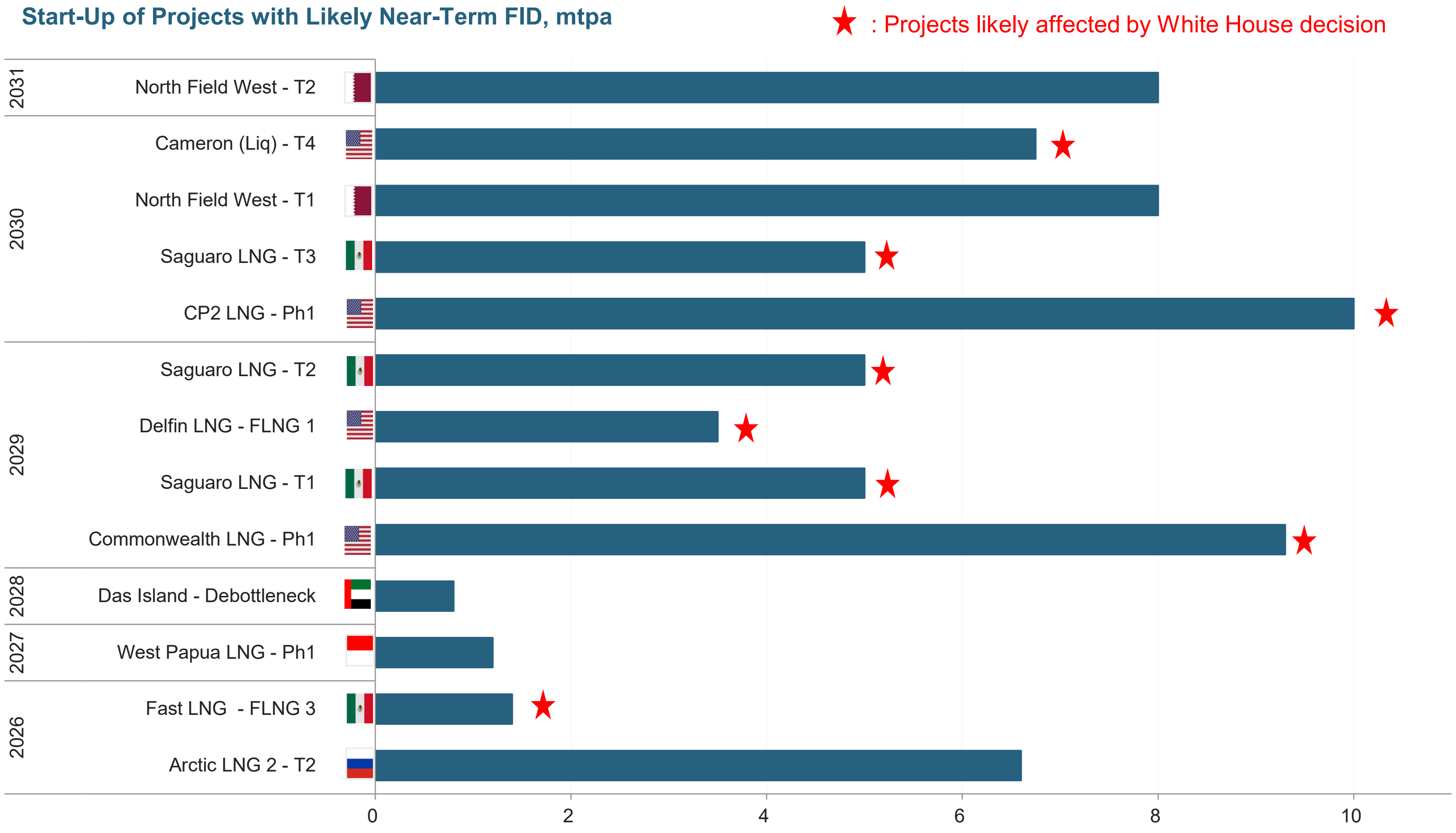
Under Construction LNG Supply by Start-Up Year, mt



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

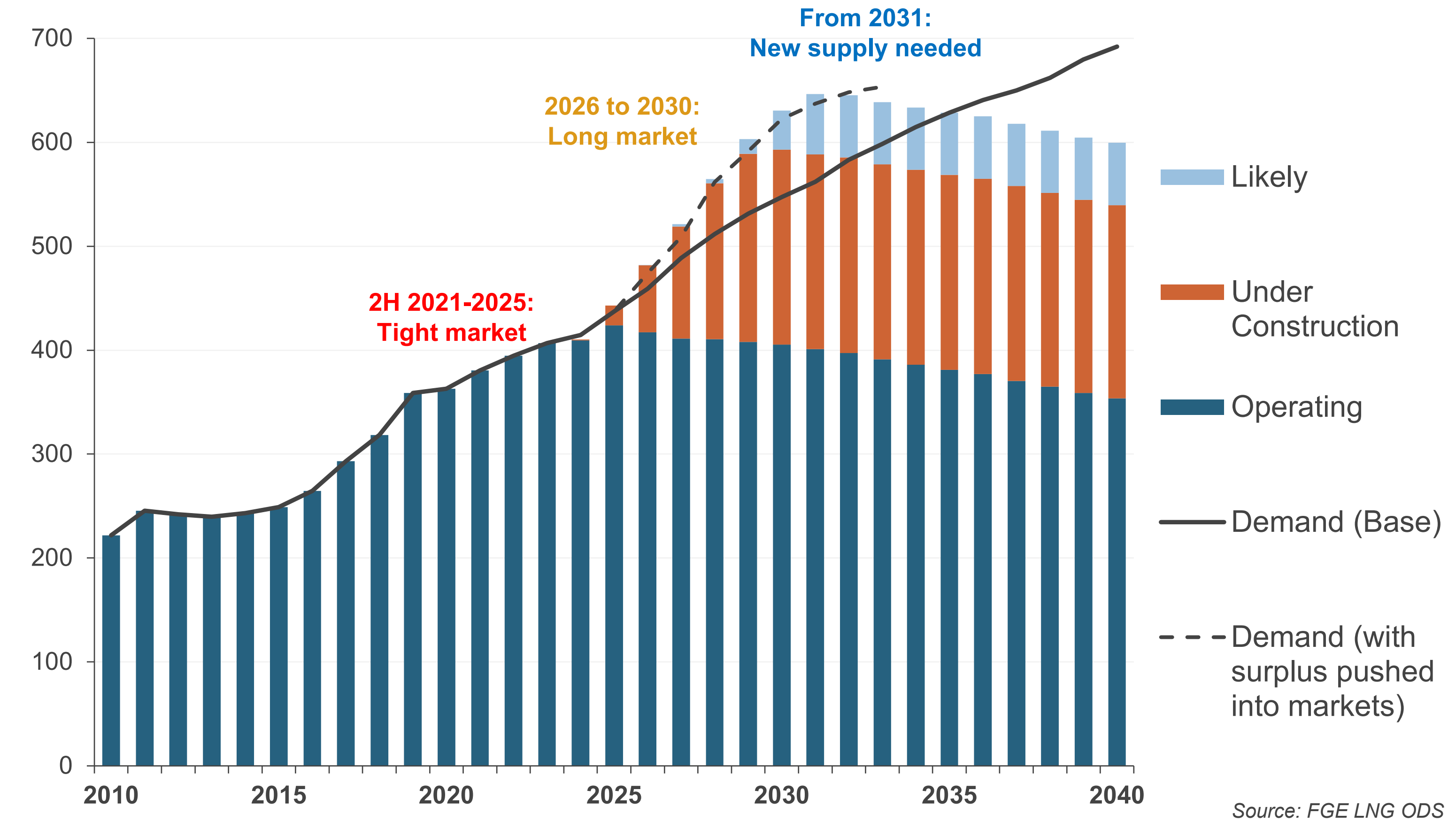


- In January 2024, the Biden Administration initiated a pause on new LNG projects in the United States that did not have a non-FTA license in place. Non-FTA licenses, issued by the US Department of Energy, are key to sanctioning FIDs for LNG projects as it allows the LNG to go to any country in the world.
- 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

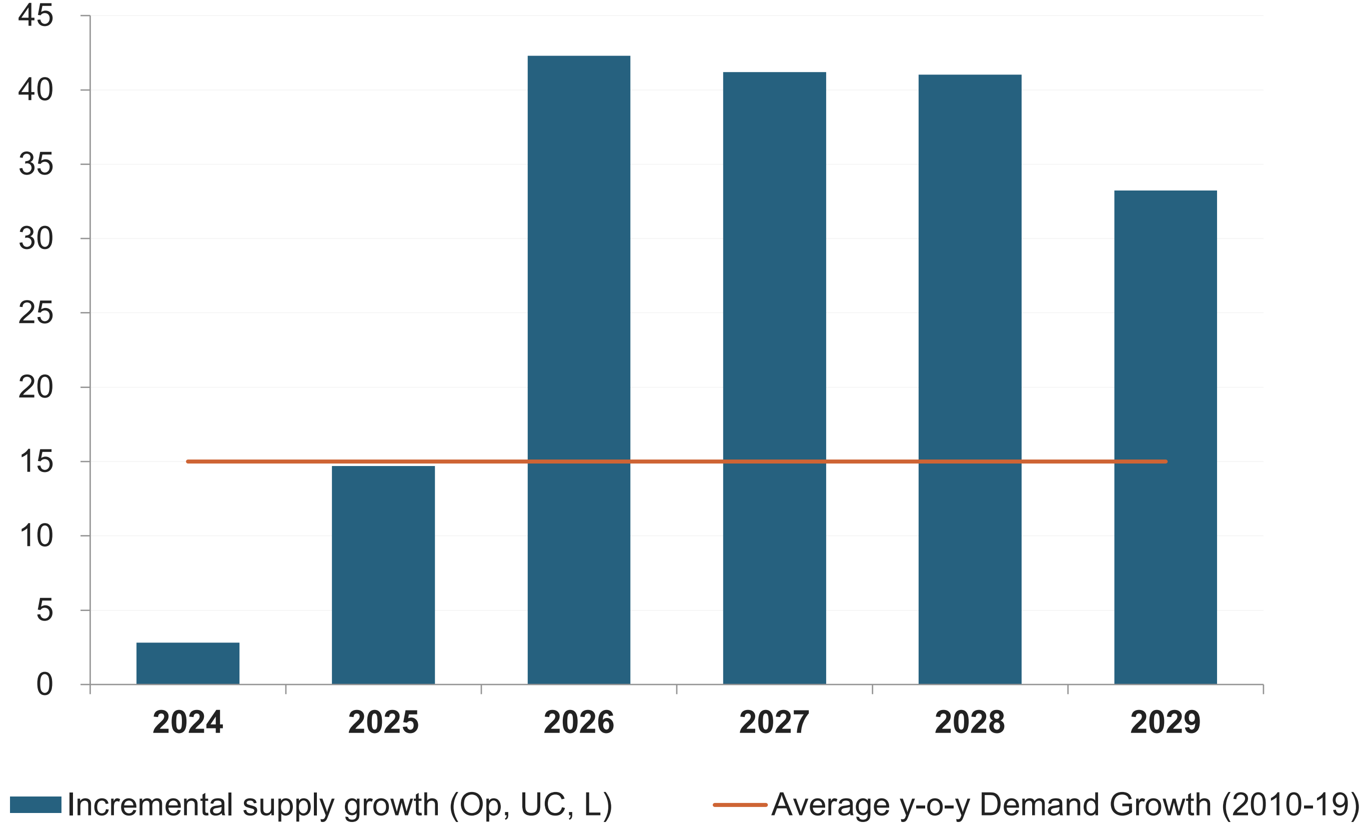


Source: FGE LNG ODS

- **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

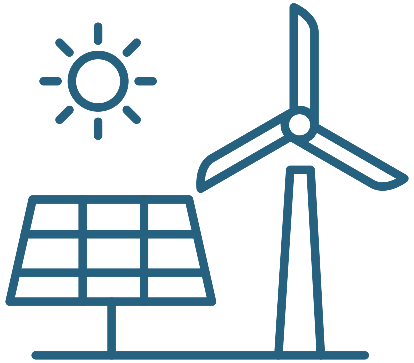
- The next supply wave will add volumes of unprecedented levels to the LNG market over 2026-30.
- Prompt LNG prices will soften significantly to encourage a push into Asian and European markets. Low prices are also necessary to shut in some US LNG, especially in 2026 and 2027.
- Buyers should be mindful 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

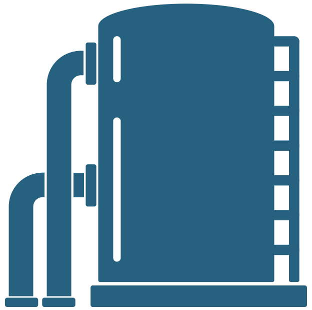
Hydrogen storage & power generation value chain

The value chain is formed of three key components

Hydrogen Production



Hydrogen Storage



Power Generation

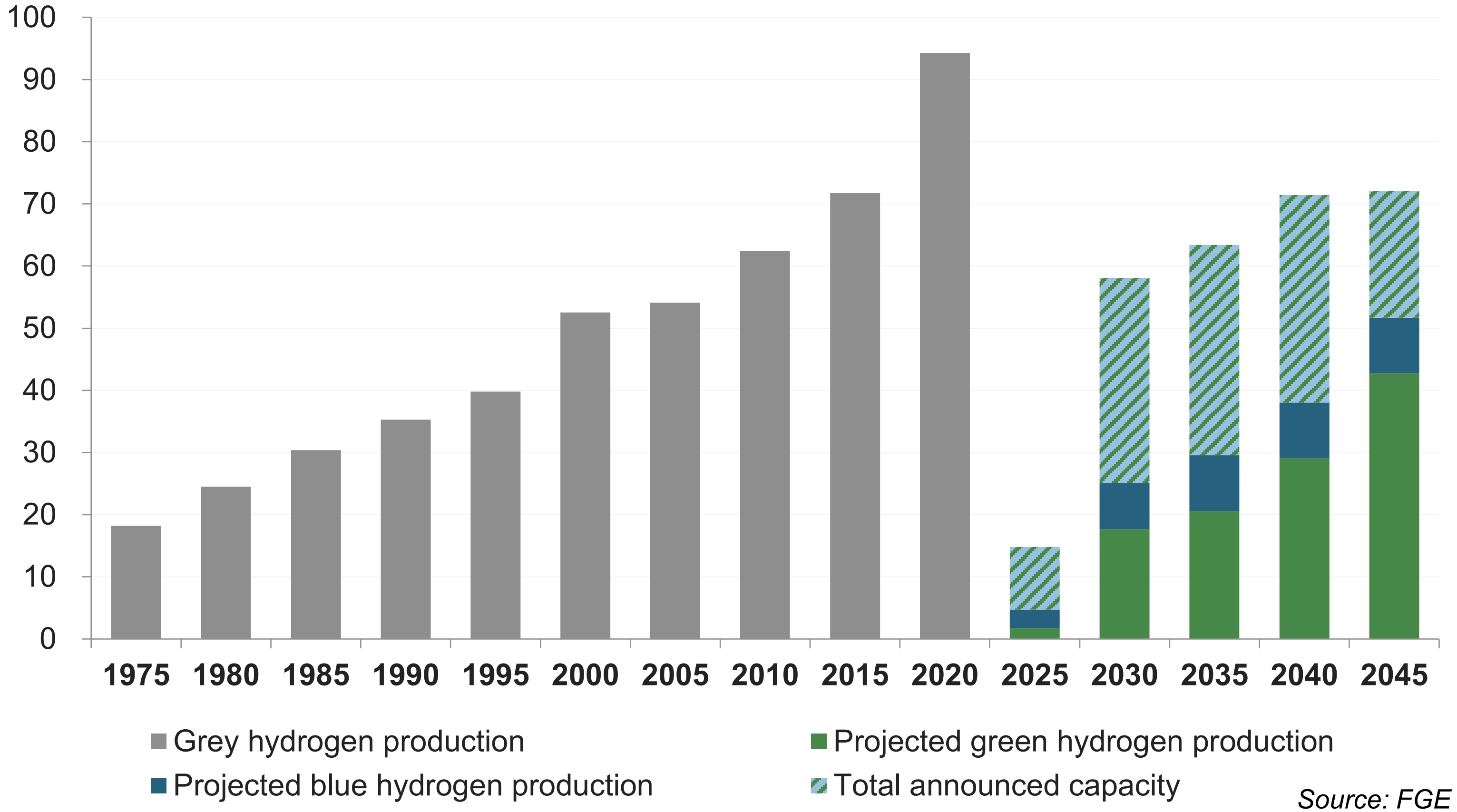
- Low-carbon hydrogen production can be ‘**green hydrogen**’, produced with renewable electricity and water, or ‘**blue hydrogen**’, produced from natural gas using carbon capture.
- Both can be used for power generation, but **green hydrogen** is used for storing excess renewable power.

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

- 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

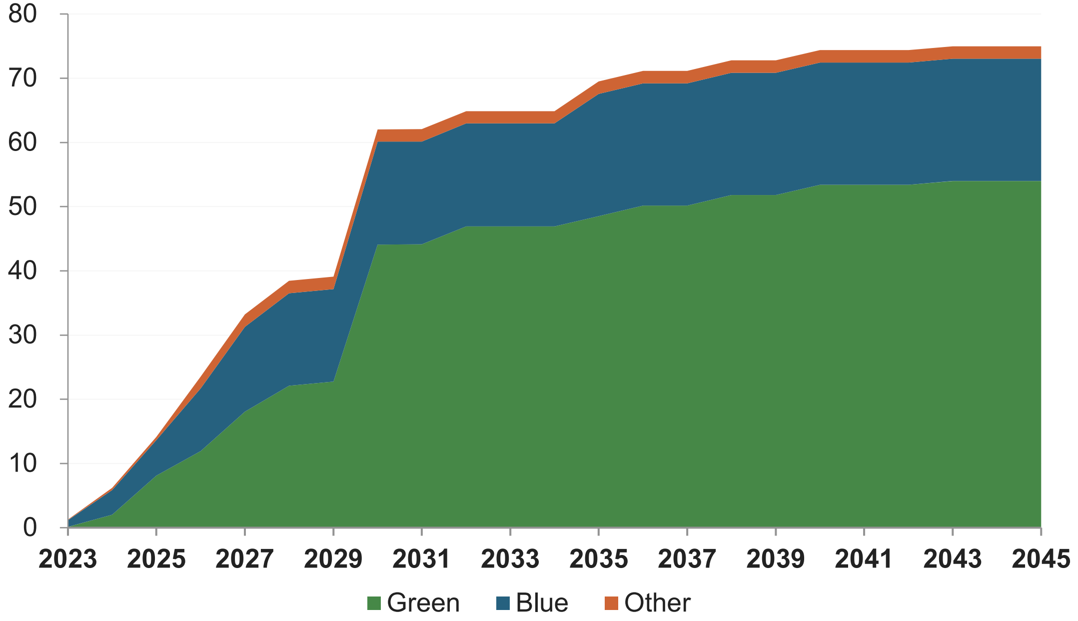


Source: FGE

- 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

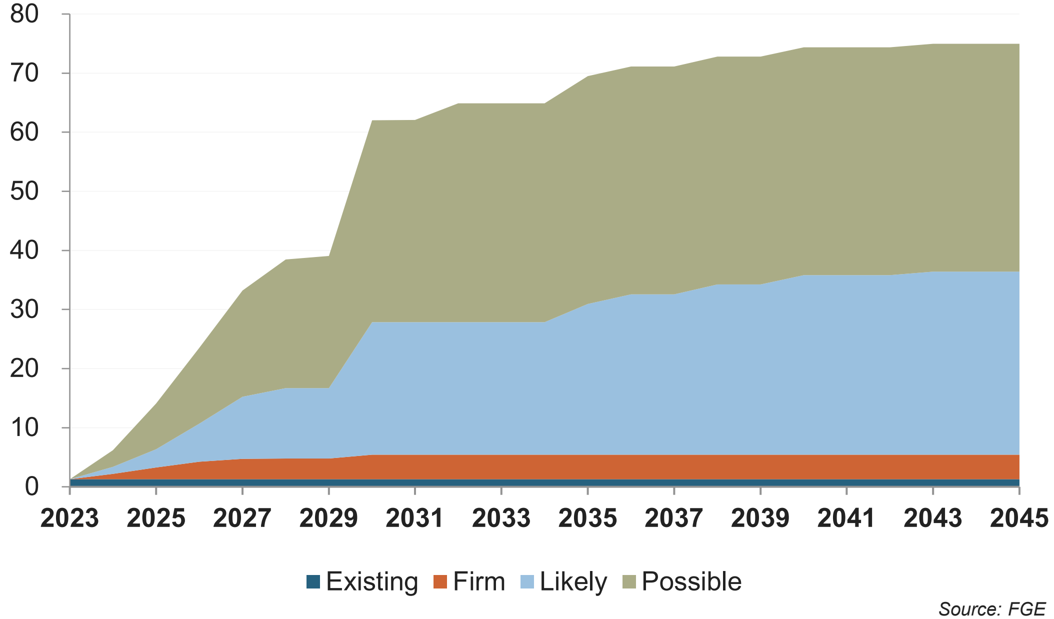
Global Clean Hydrogen Production, mtpa



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

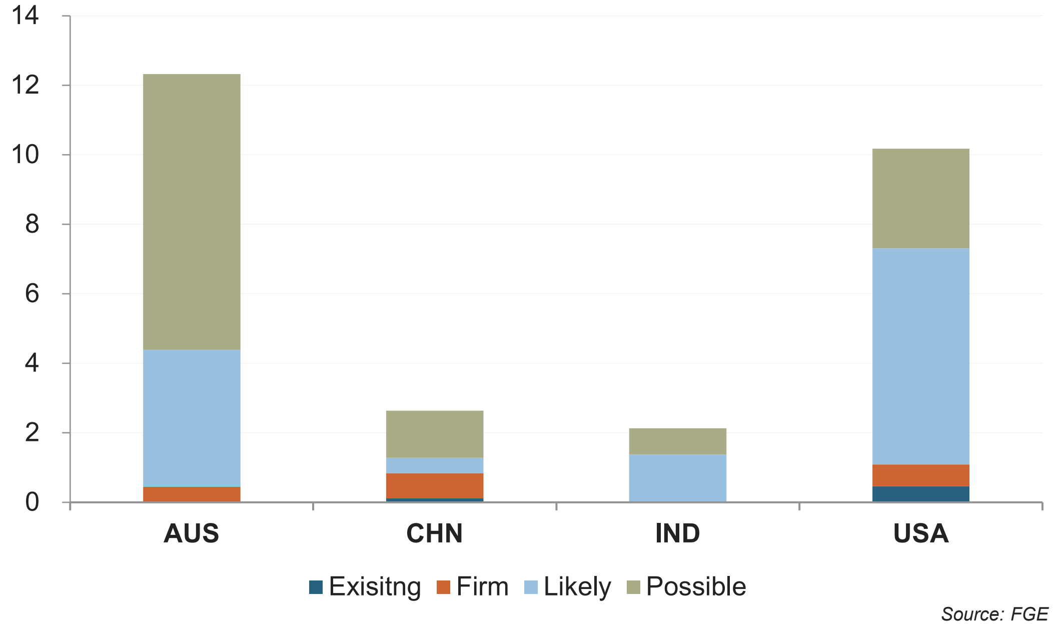


Source: FGE

- 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%)

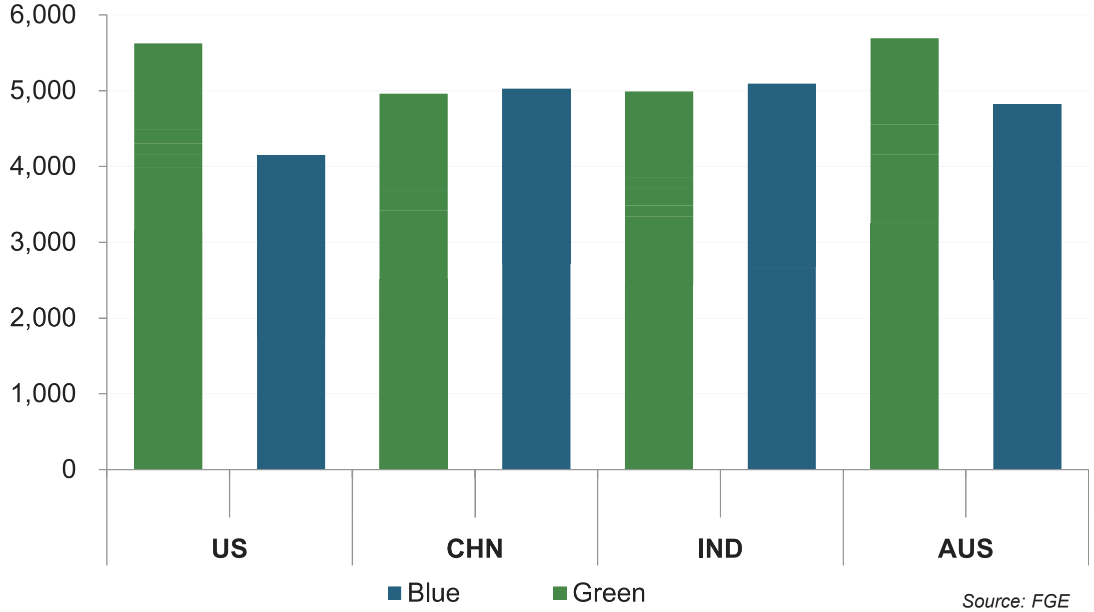
Where will Hawai‘i be able to get its hydrogen from?

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



Source: FGE

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



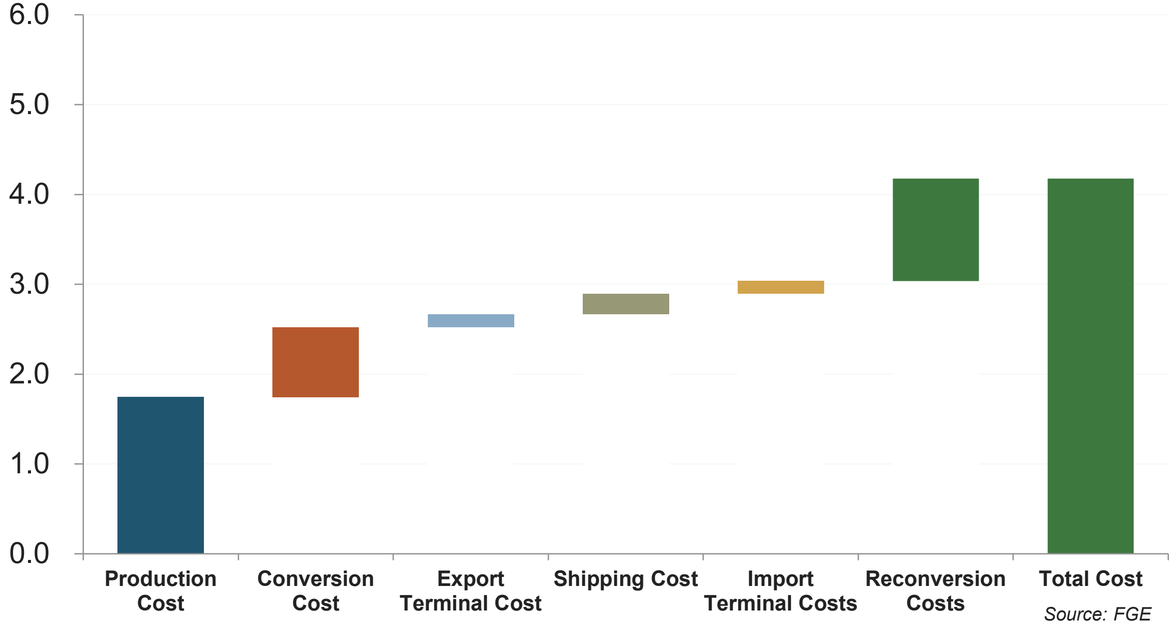
Source: FGE

- 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

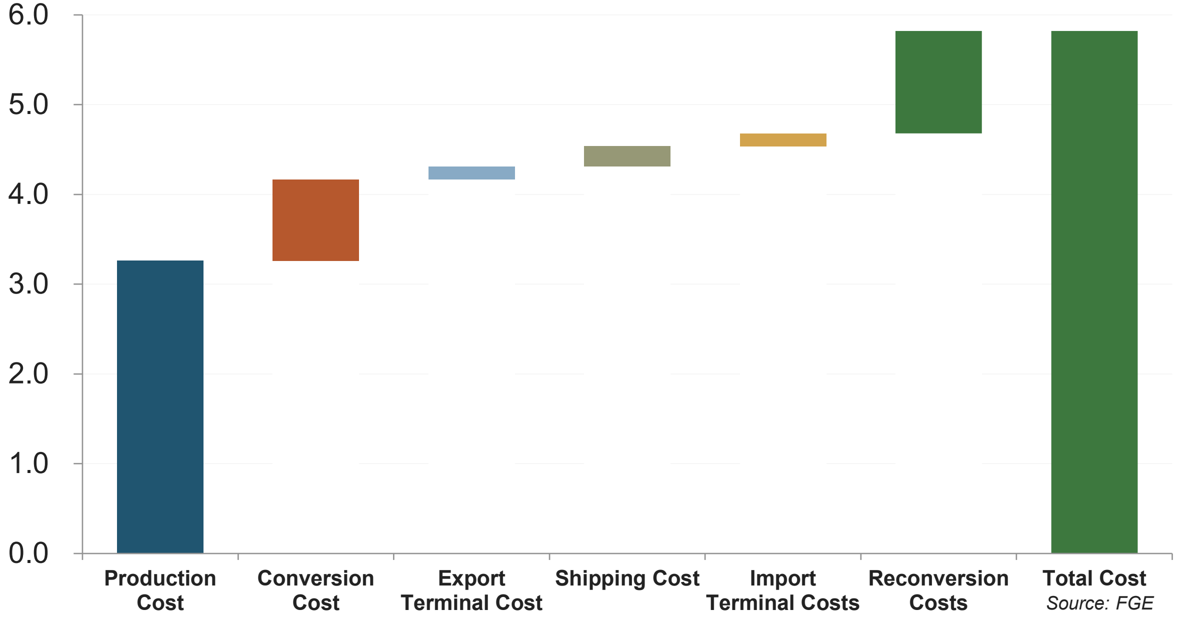
These levelized cost models utilize the US' solar power electricity and natural gas prices, while the hydrogen carrier selected has been ammonia

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



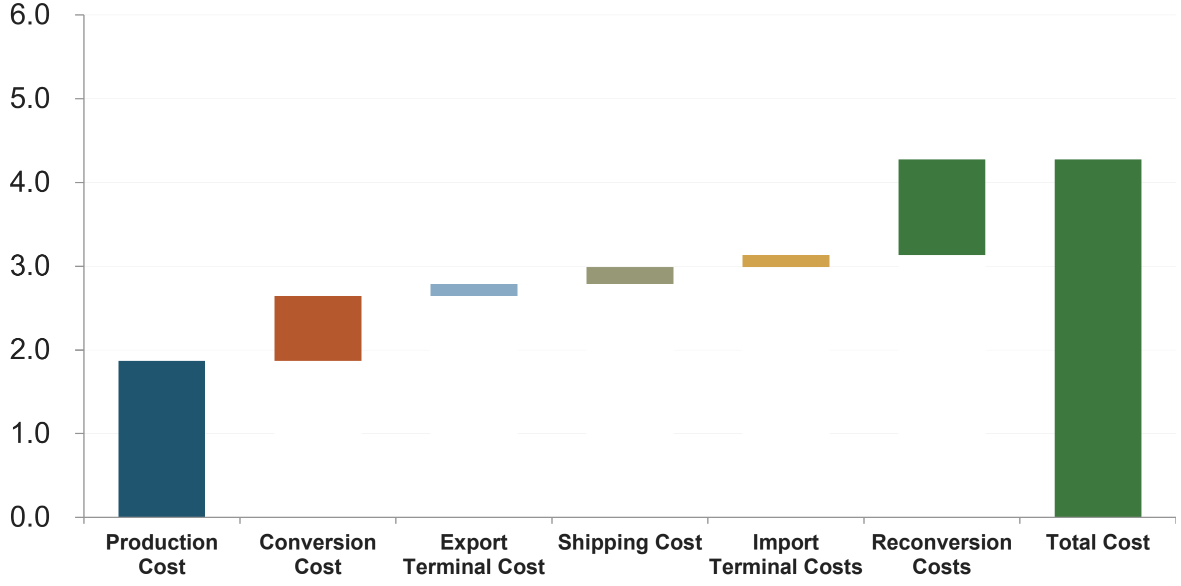
Source: FGE

- 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

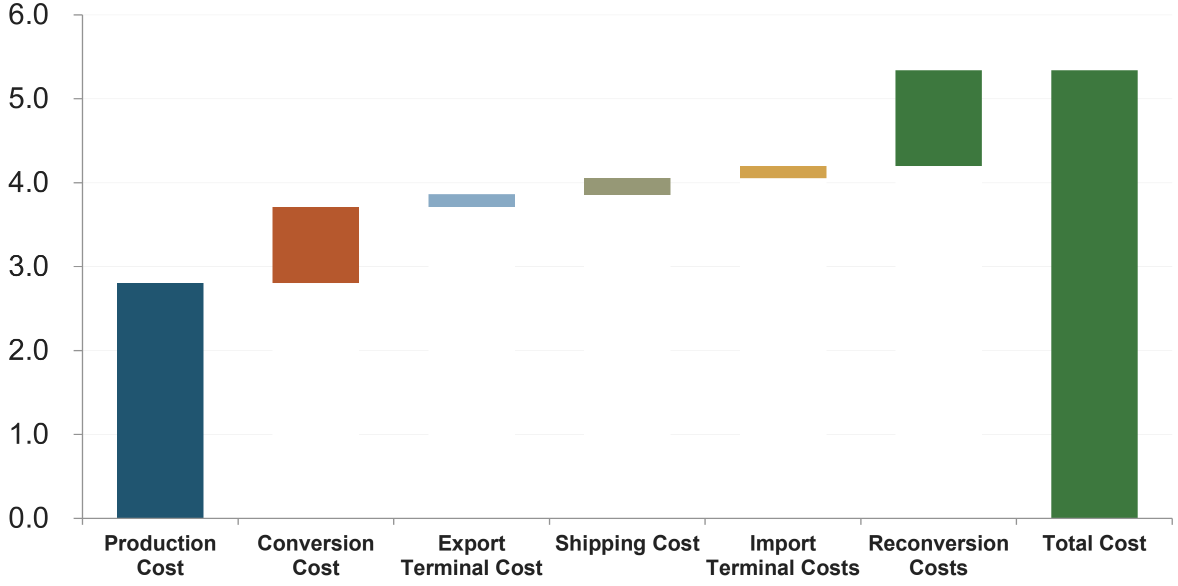
These levelised cost models utilize the US' solar power electricity and natural gas prices, while the hydrogen carrier selected has been ammonia

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



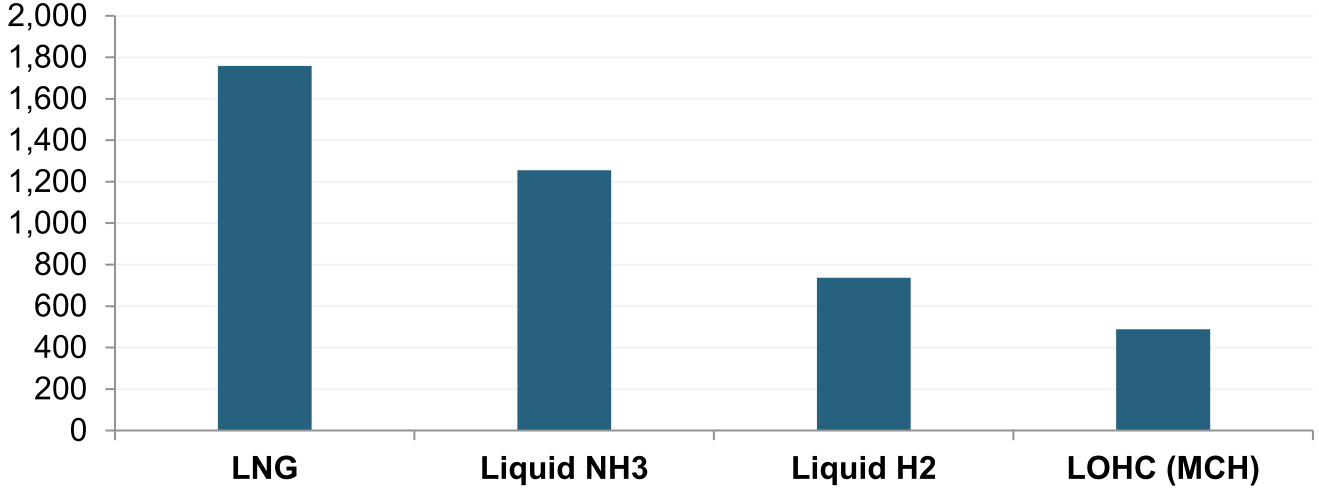
Source: FGE

- 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)

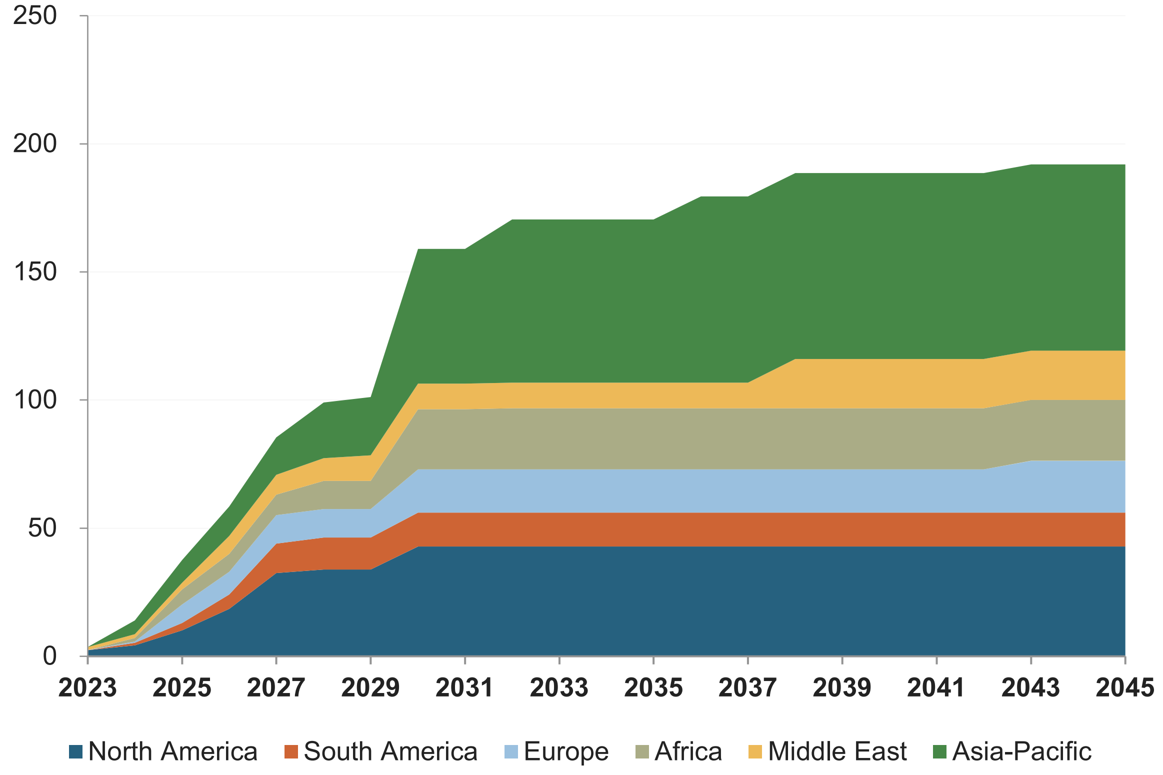
Transported in One Q-Max LNG Carrier Equivalent, GWh



- 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

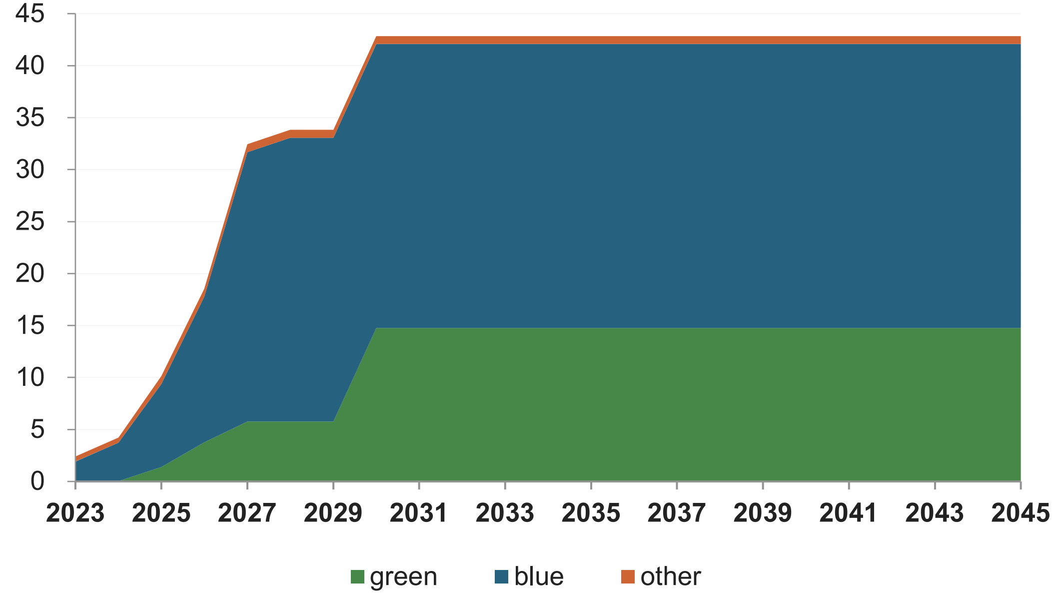


Source: FGE

- 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.

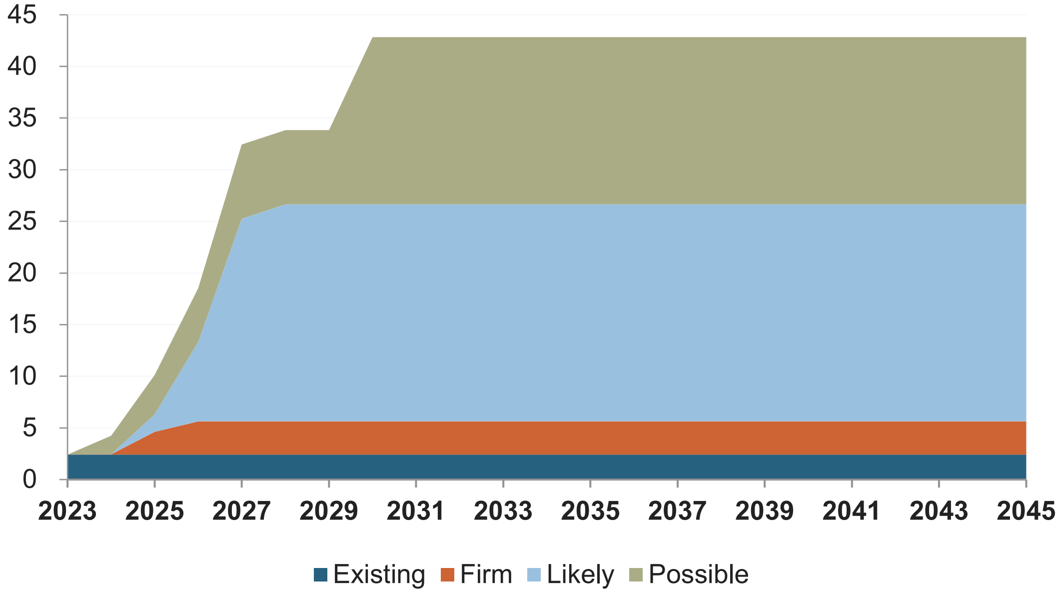
North American clean ammonia production based on proposed projects

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

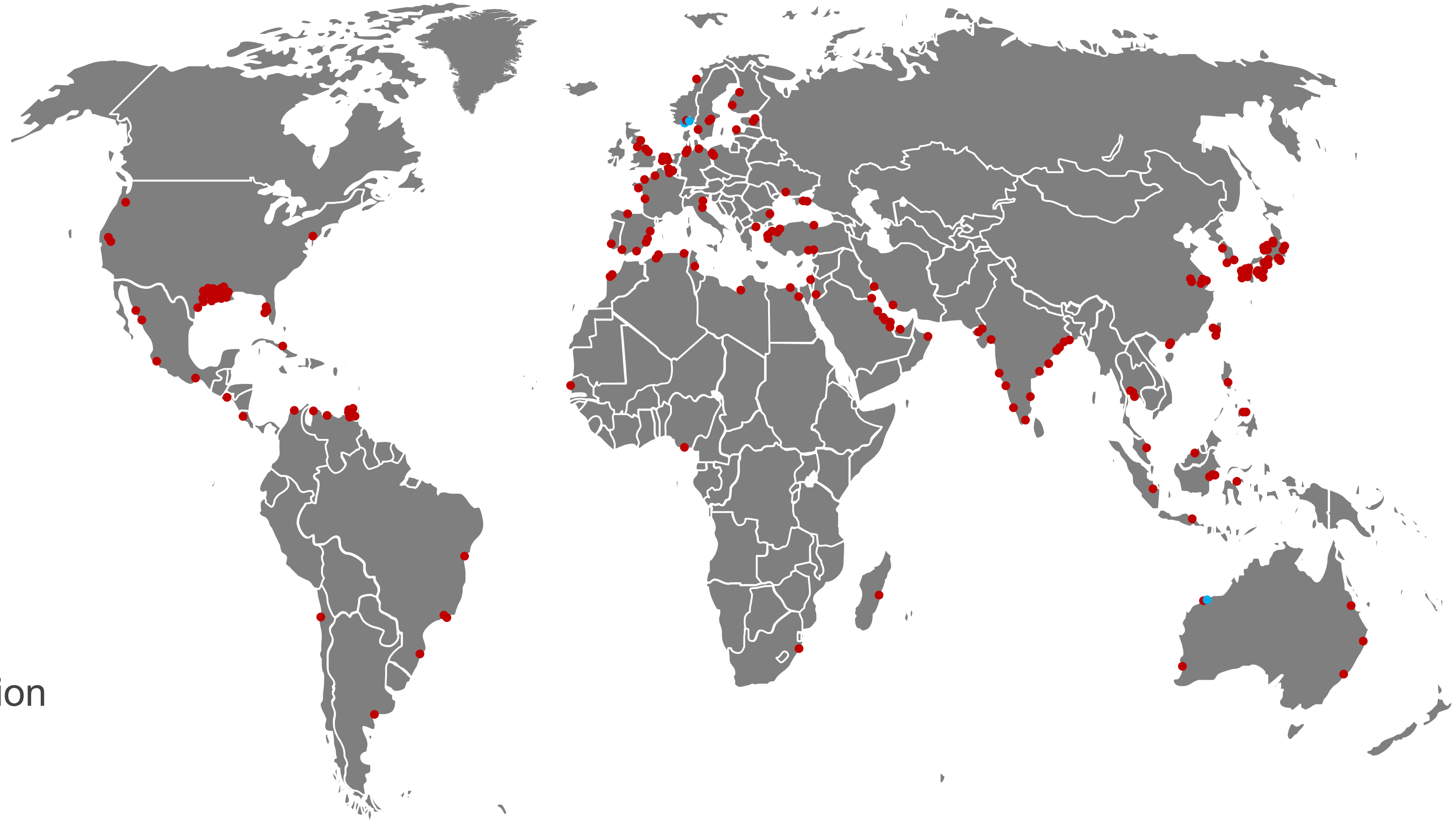
Source: FGE

- 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

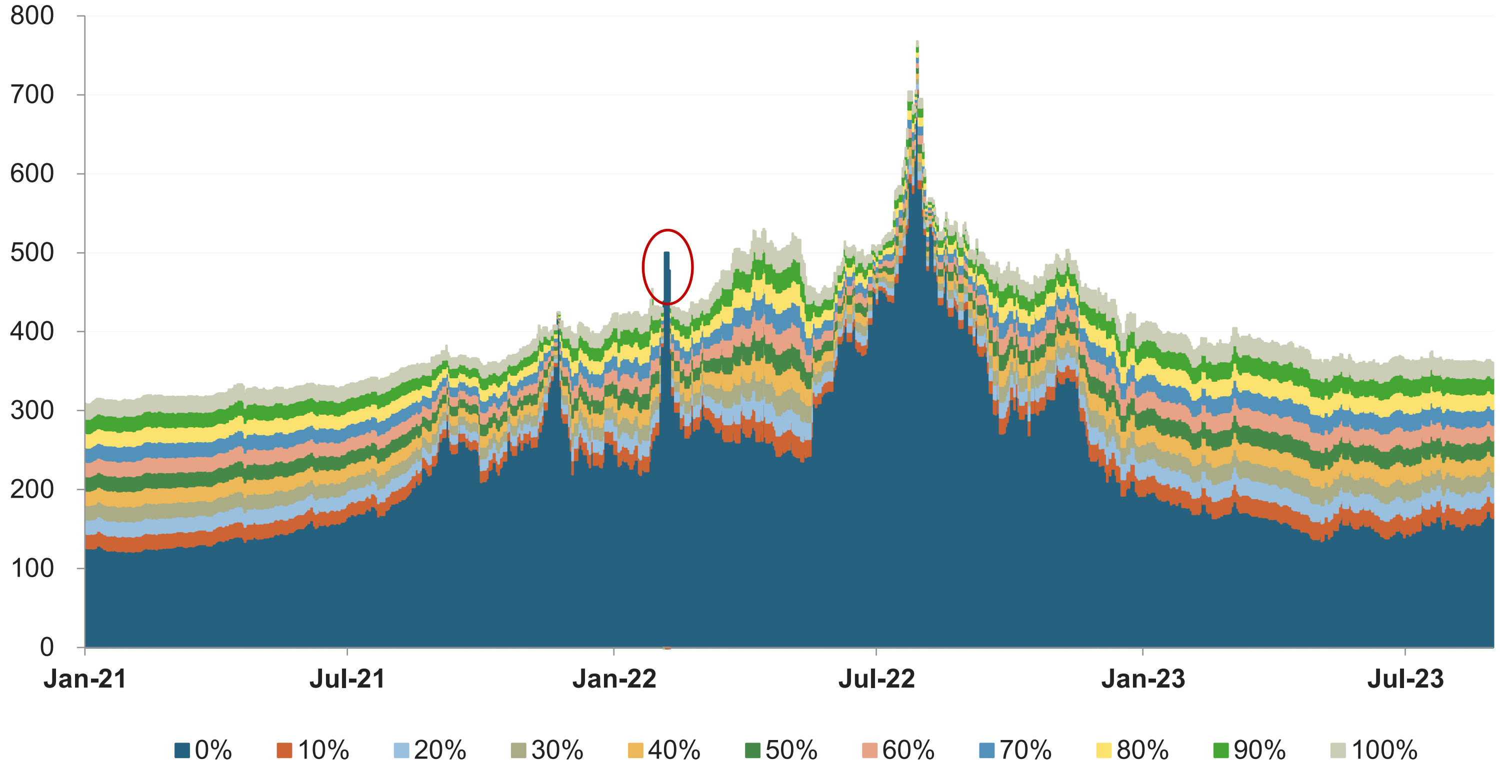


Key:
- operational
- under discussion

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



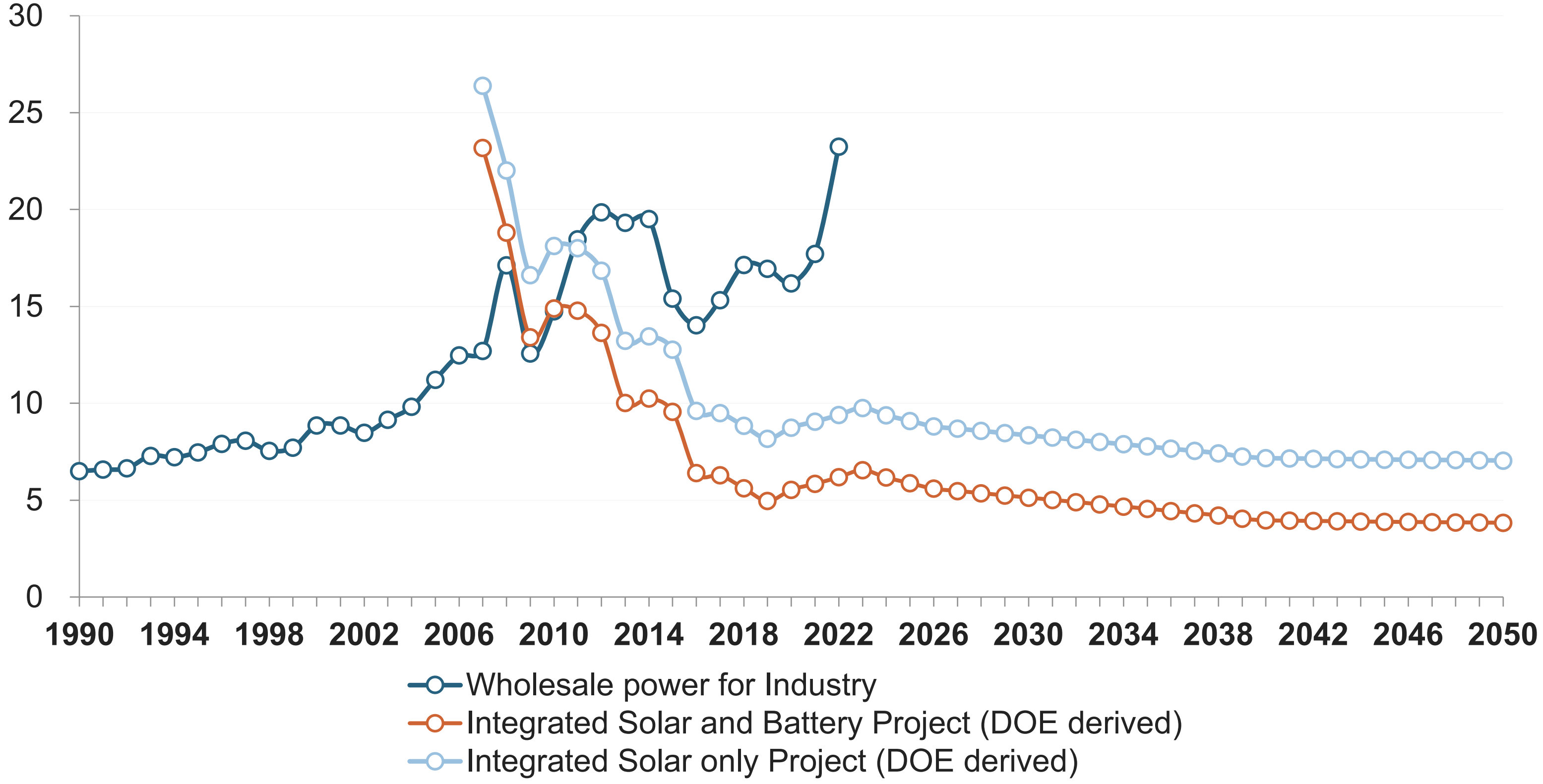
Source: FGE

- 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

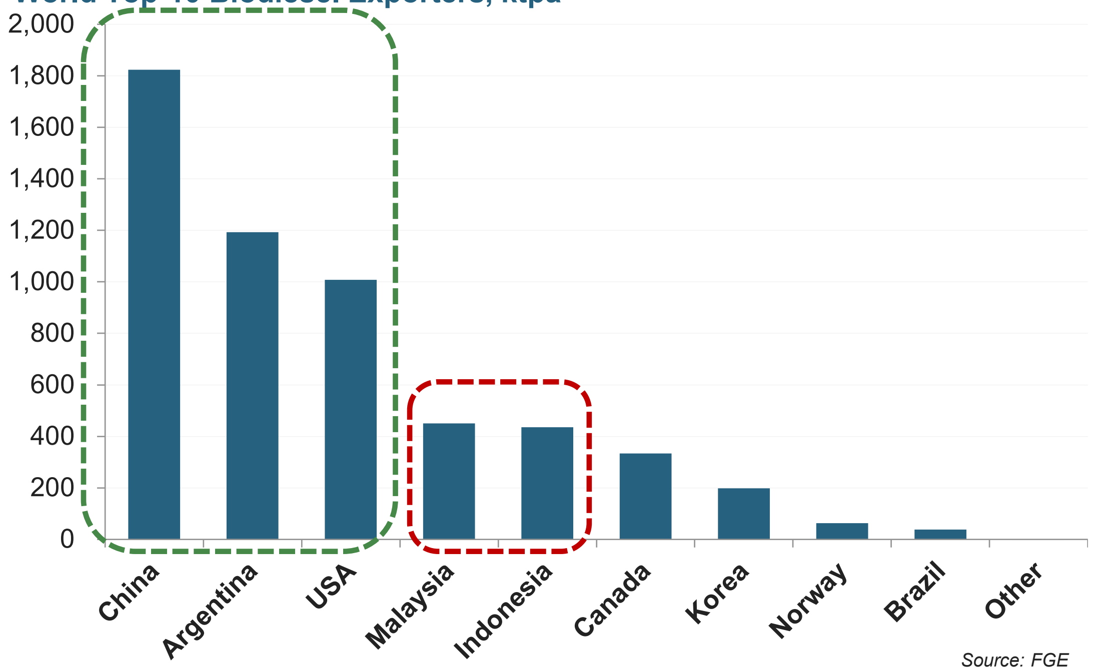
- Due to the high price and carbon intensity of grid electricity in Hawai'i the cost of producing electrolytic hydrogen from this method is prohibitive and not environmentally friendly.
- Using solar power for green hydrogen production should deliver significantly lower costs.
- However, in Hawaii it 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?

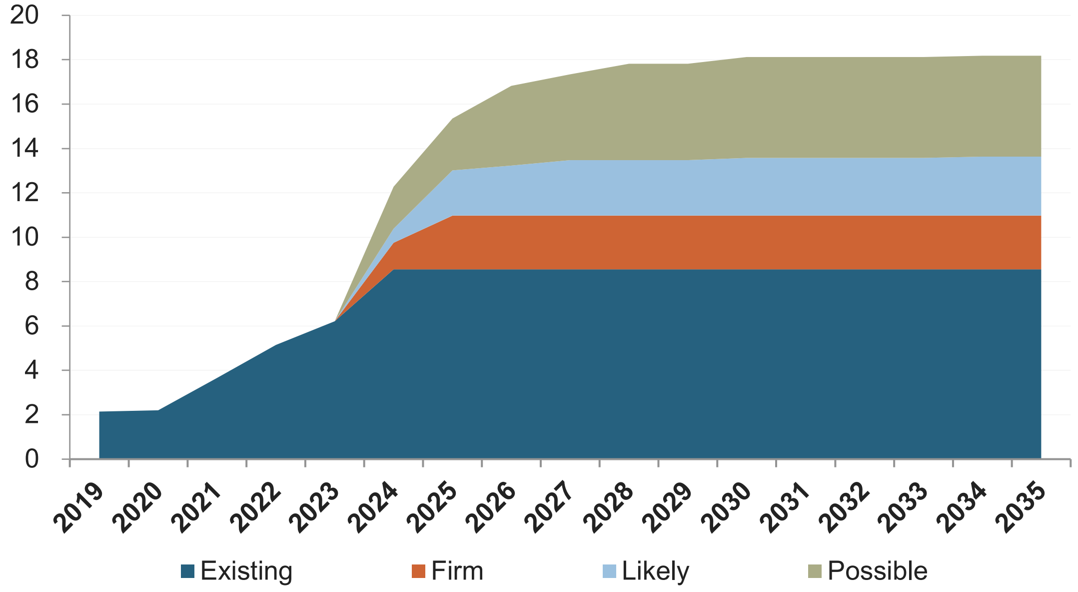
The US and future biofuels from Par will likely provide the bulk of Hawai‘i's biofuel supply due to regulations restricting palm oil biofuels from S.E. Asia

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.

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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

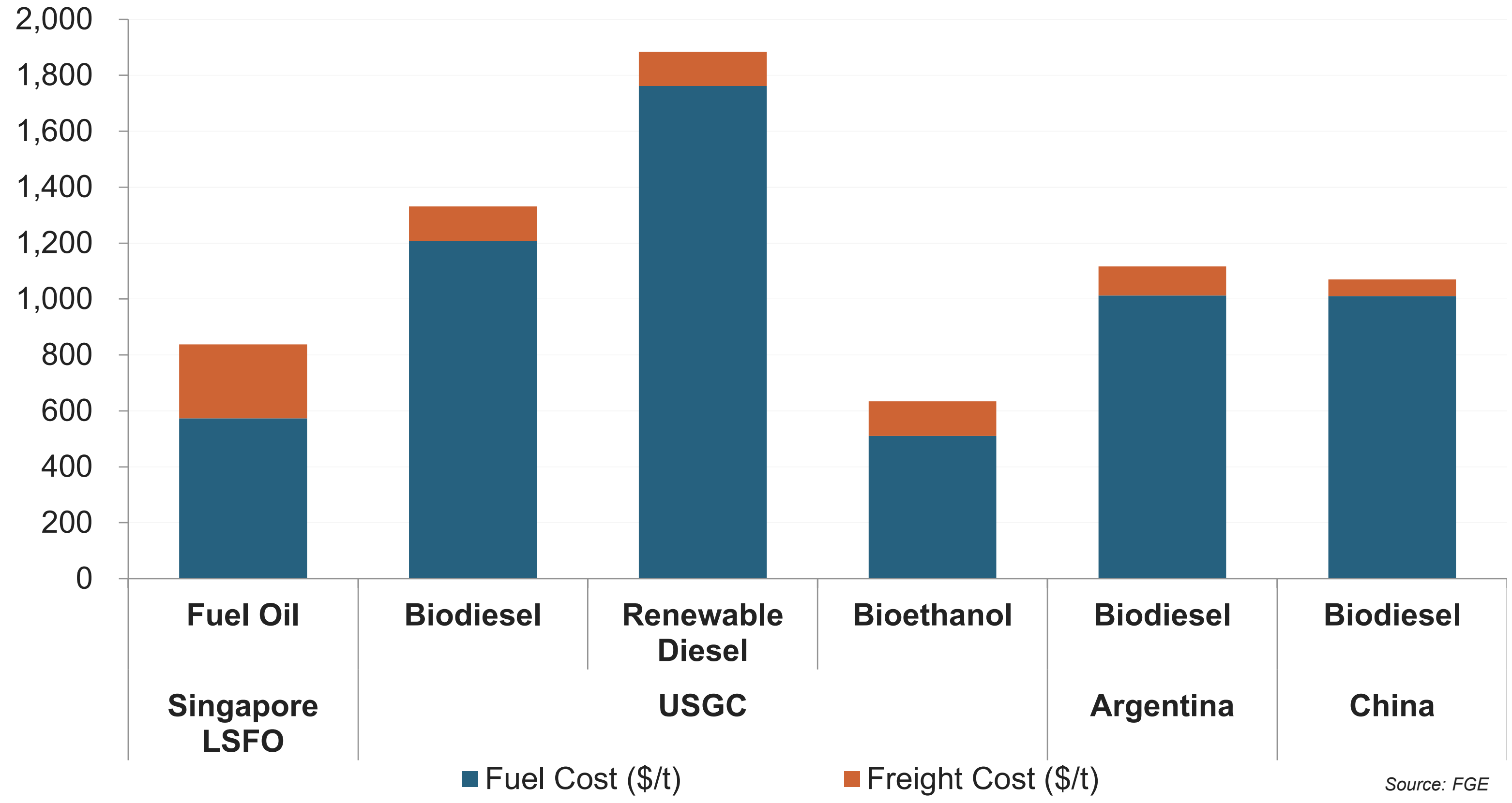
Source: US EPA
https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

- 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 Hawai‘i

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

Hawai‘i 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 Hawai‘i 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.

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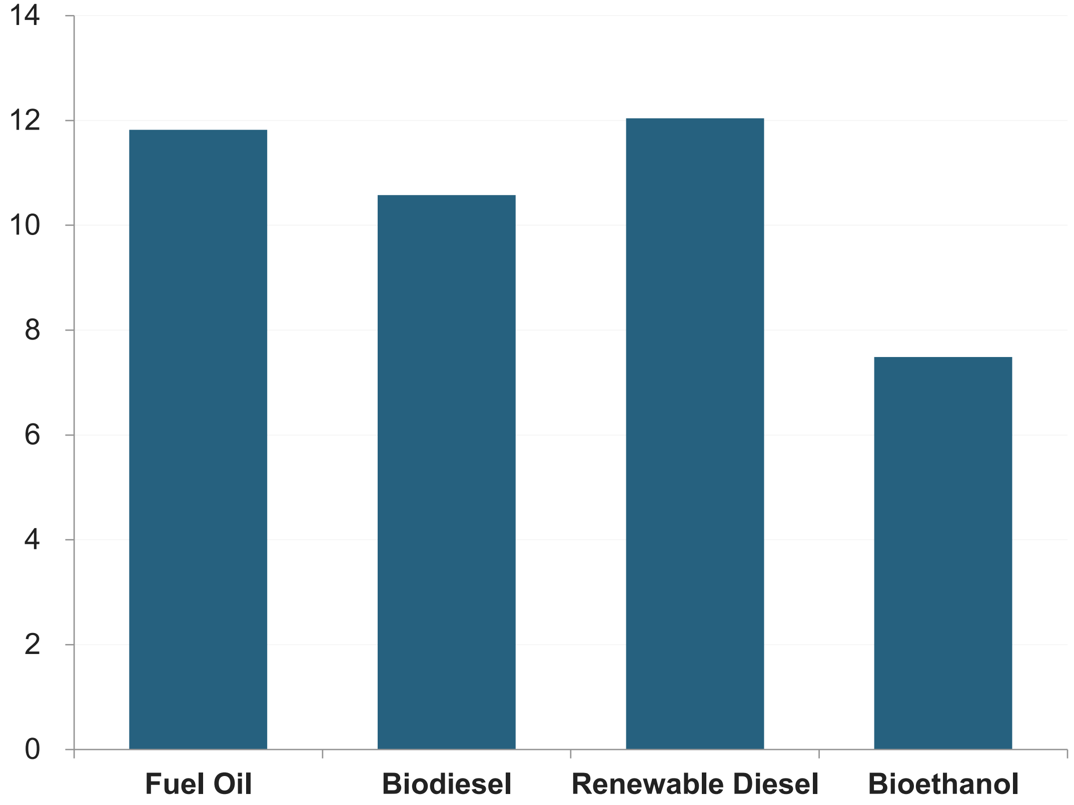
Specific fuel emission comparison at the stack

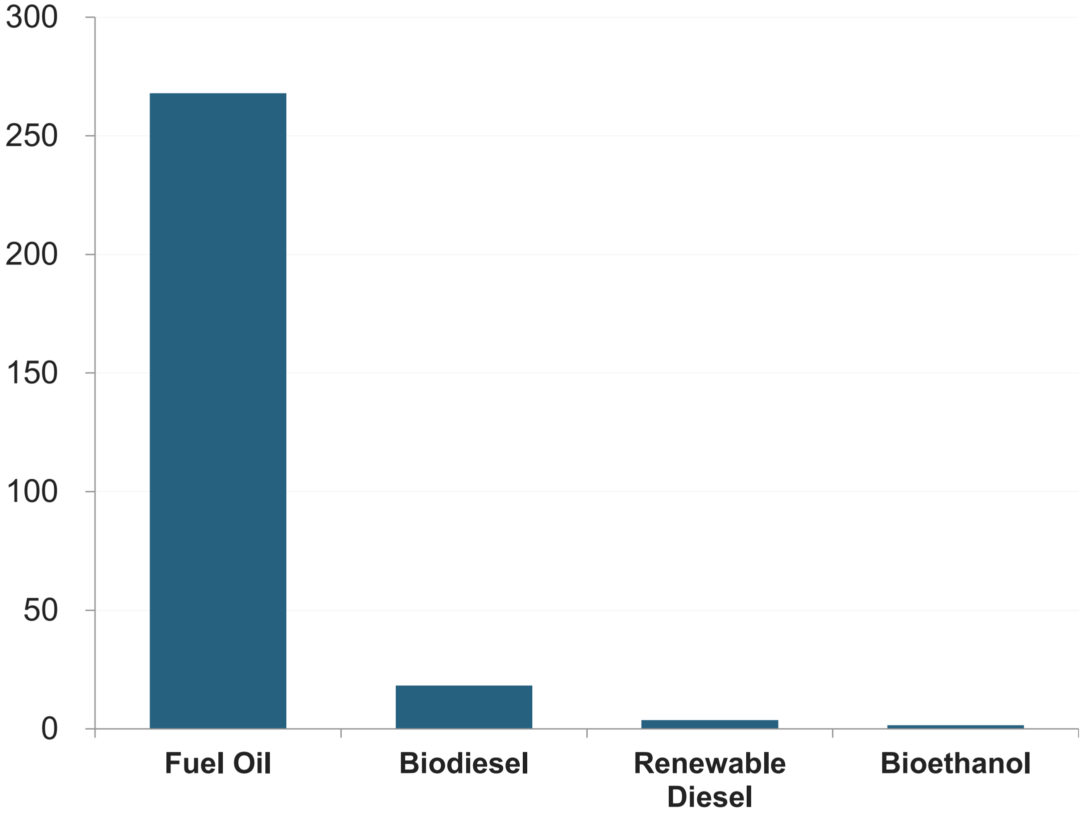
While fuel oil and biofuels have approximately the same specific energy densities, significant emissions reduction in power generation can be achieved by replacing fuel oil with biofuels.

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



Source: FGE

CO2 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 Hawaiʻi 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

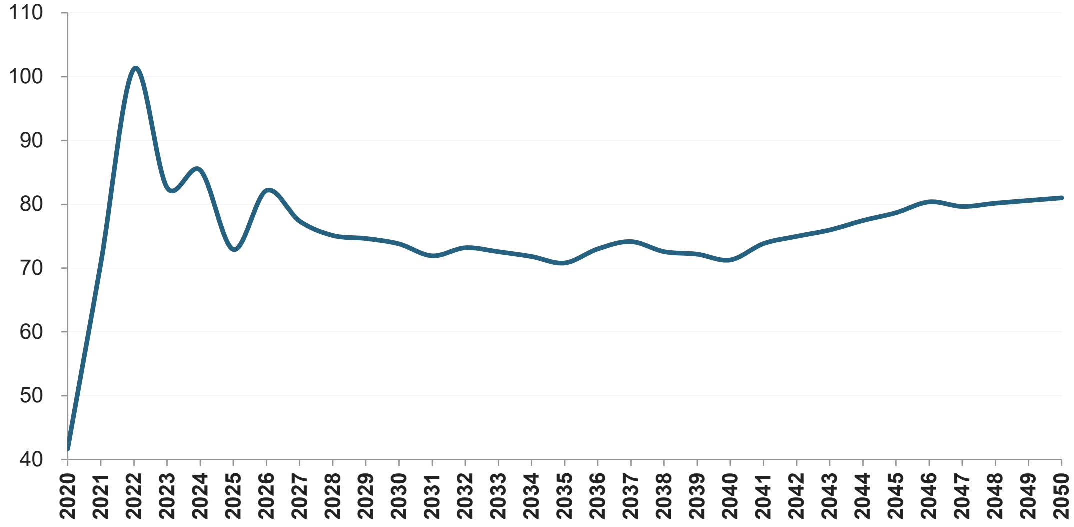
- FGE is confident that Hawaiʻi could get a delivered LNG price with a slope of around 11.8% Brent plus a constant for volumes of at least 0.4 million mtpa over 10 years, commencing in 2030. This is assuming a standard "vanilla" LNG supply contract. Similar deals have been signed for LNG buyers for delivery 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 Hawaiʻi 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 Hawaiʻi 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 Waiʻau power plants as well as Kalaeloa Partners.

Background and Assumptions (4)

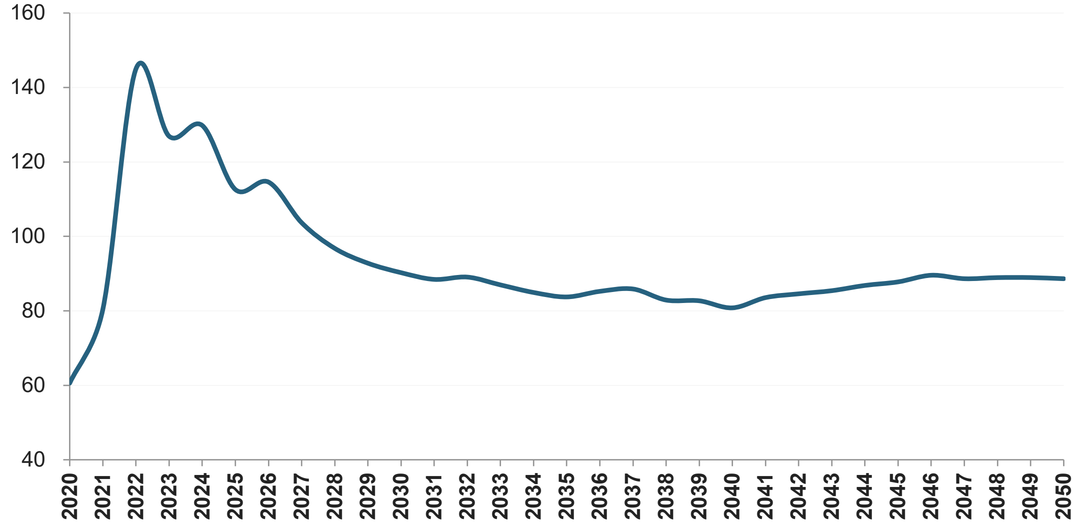
FGE’s Brent long-term forecast drives our LSFO price forecast

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



Source: FGE, Forecast 2024 onwards

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



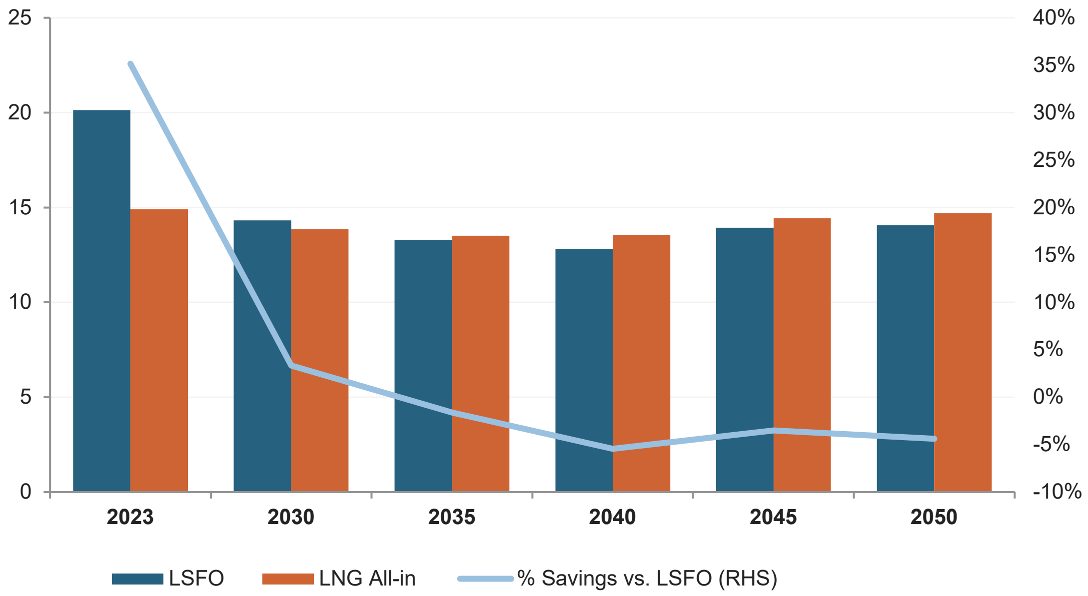
Source: FGE, Forecast 2024 onwards

- 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

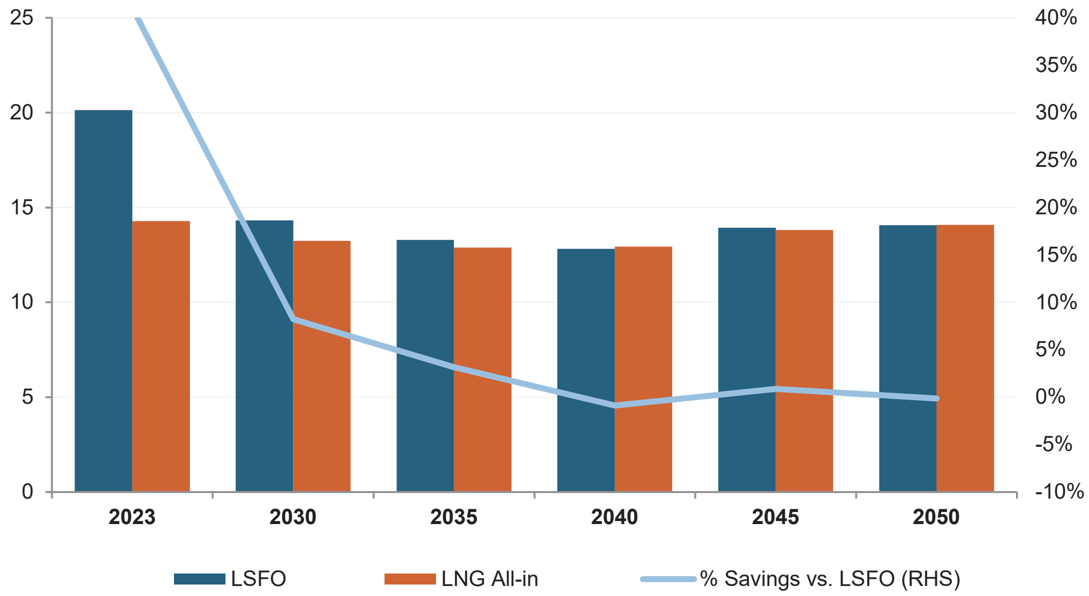
LNG imports at this volume provides environmental benefits compared to LSFO but zero savings under the FSRU charter scenario and minimal savings under the FSRU purchase scenario

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



Source: FGE

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



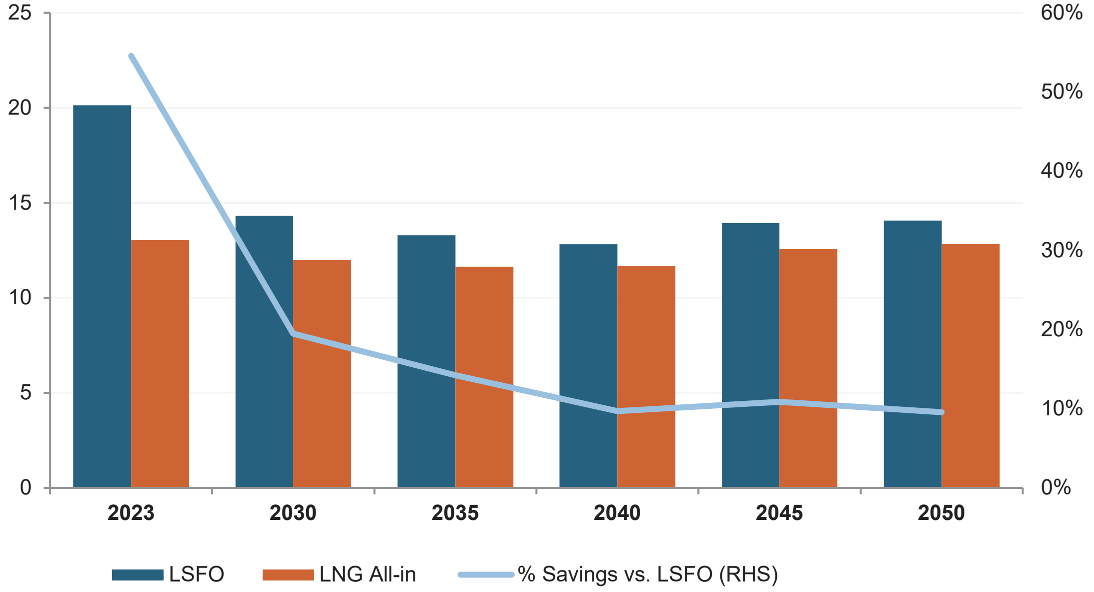
Source: FGE

- 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

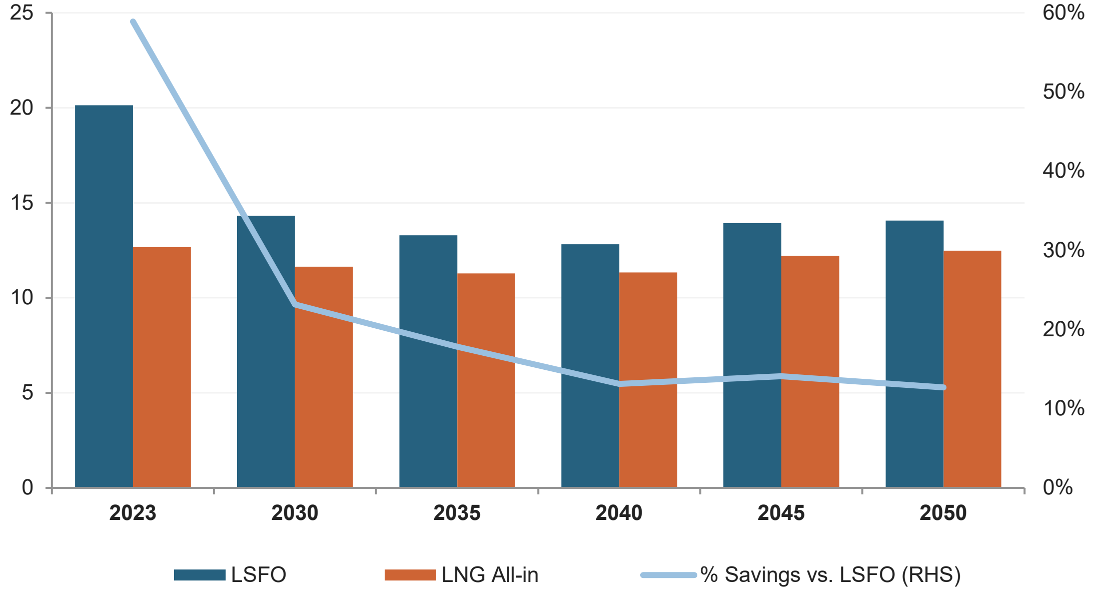
LNG imports at this volume provides environmental benefits compared to LSFO and noteworthy economic savings

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



Source: FGE

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



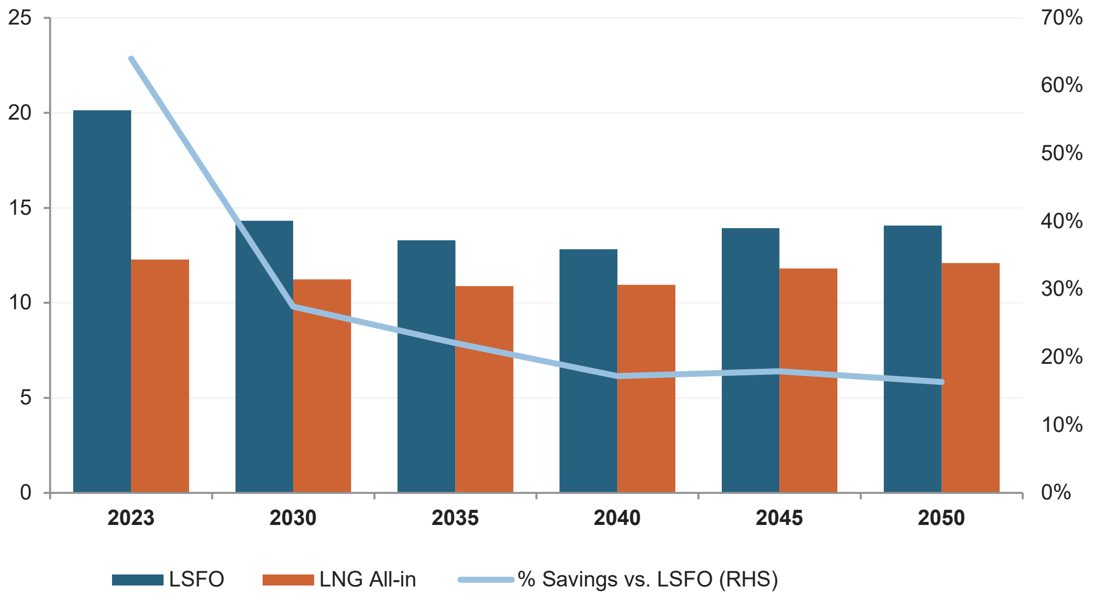
Source: FGE

- 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

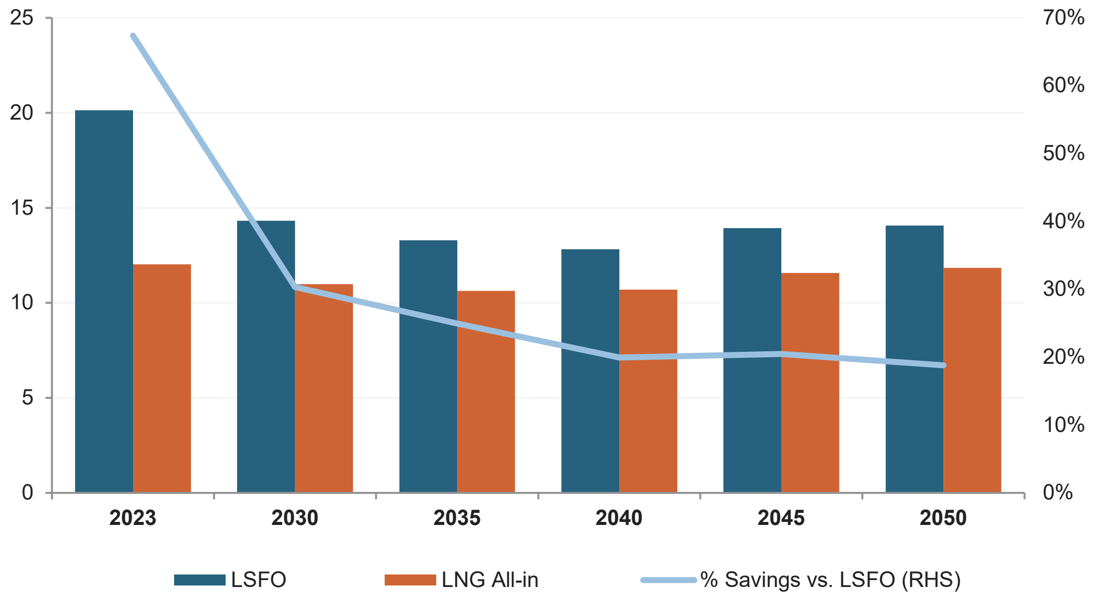
LNG imports at this volume provides environmental benefits compared to LSFO and significant economic savings

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



Source: FGE

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



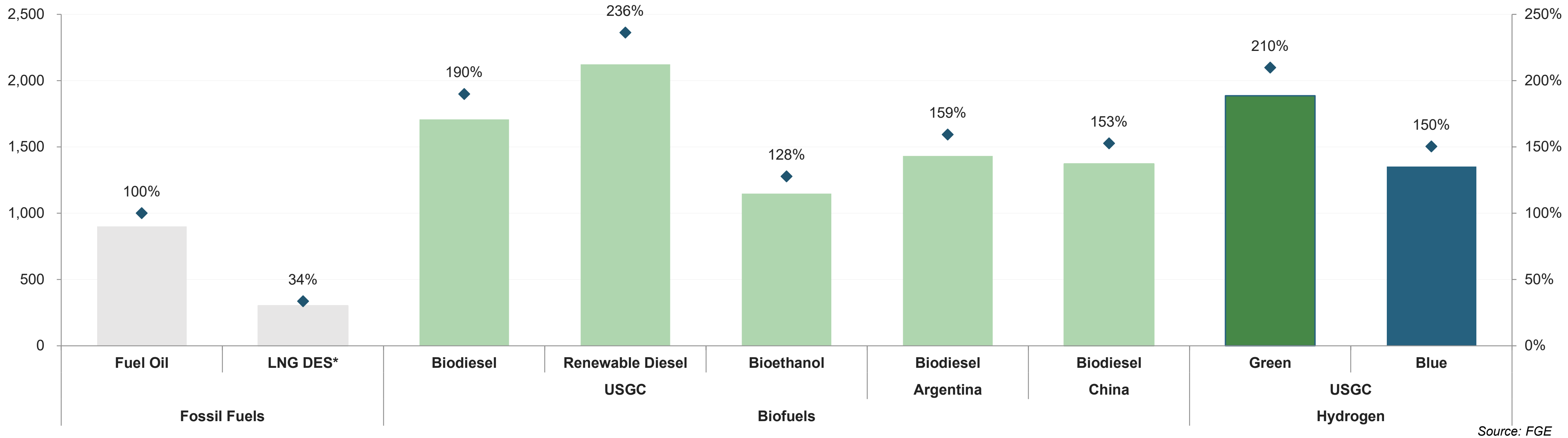
Source: FGE

- 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%.

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



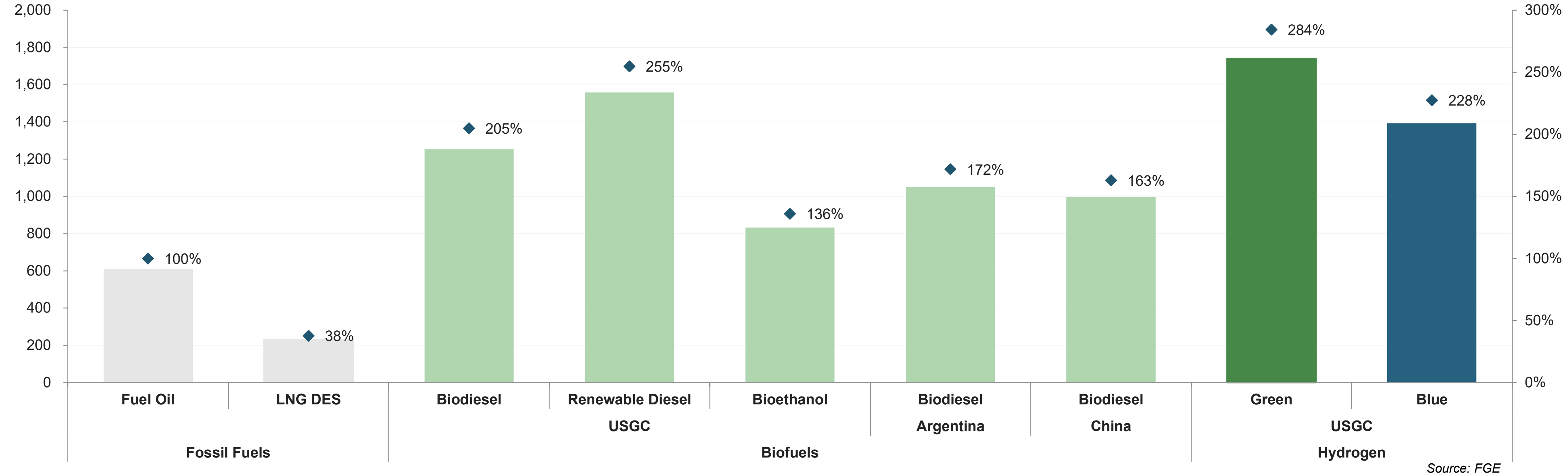
Source: FGE and DBEDT
**Assumes 1 mtpa under FSRU charter*

- 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

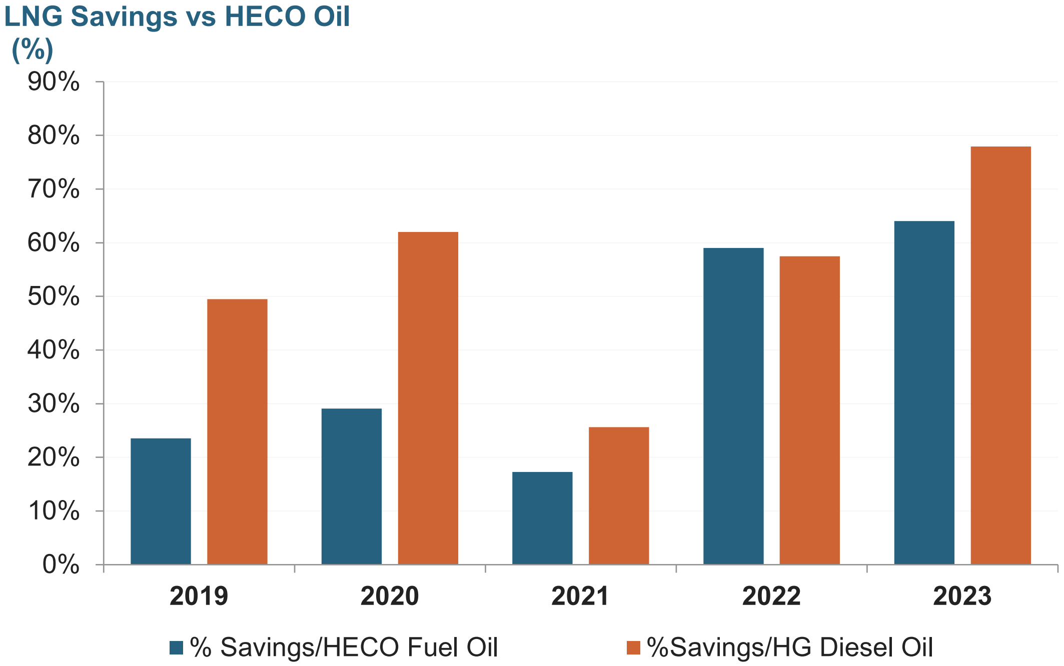


Source: FGE
**Assumes 1 mtpa under FSRU charter*

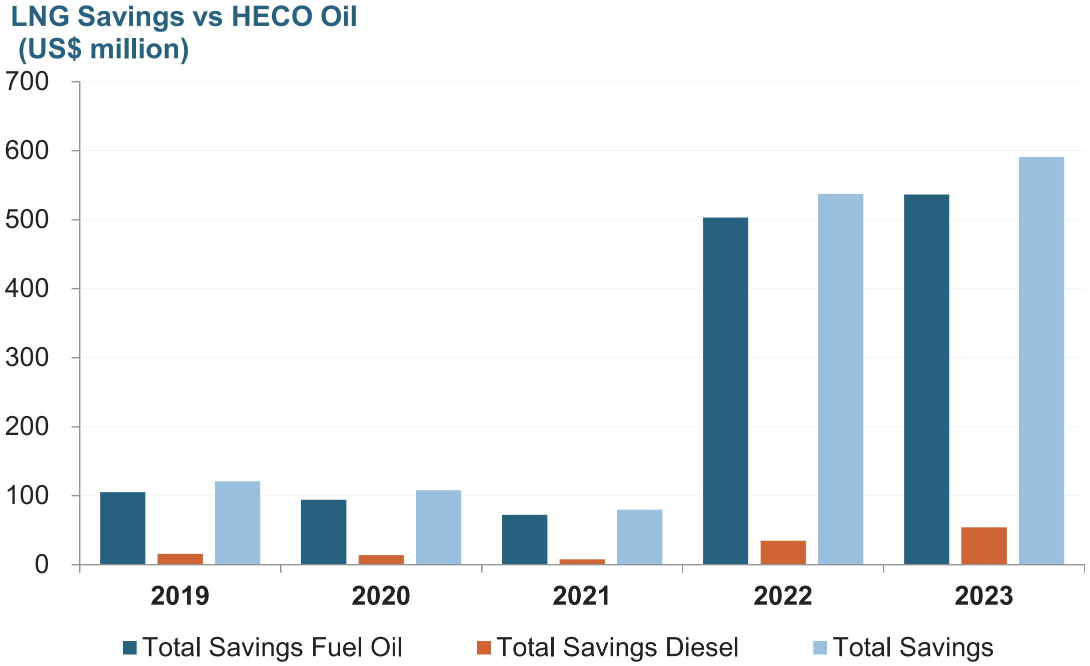
- Looking forward to 2040, LNG is still by far the most cost competitive fuel option. In this analysis we assume LNG will be running in a new CCGT with efficiency at 60%. We assume the same efficiency rates for petroleum products and biofuels as the previous slide.
- Most other alternative fuels such 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).

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 Hawaiʻi 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

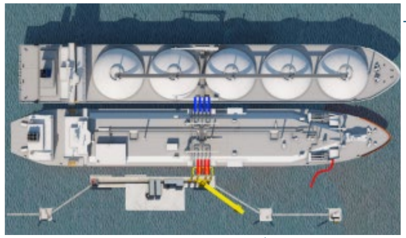
Pros

- 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.

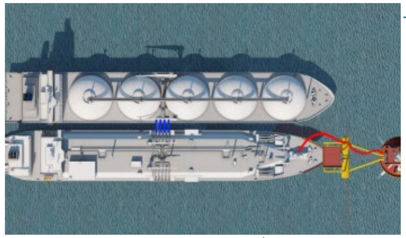
Cons

- 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.

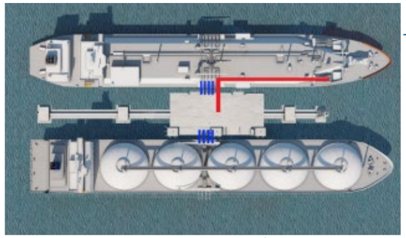
Common FSU/FSRU Configurations



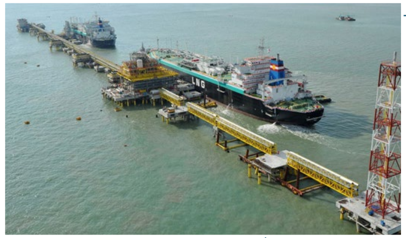
Single berth FSRUs, for instance in Nusantara Regas Satu, Salvador Brazil, Dubai. LNG ships can moor alongside the FSRU and offload LNG for regasification. This low-cost option works best in protected harbors or near-shore with water depths of 15-30 meters and mild weather conditions.



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.

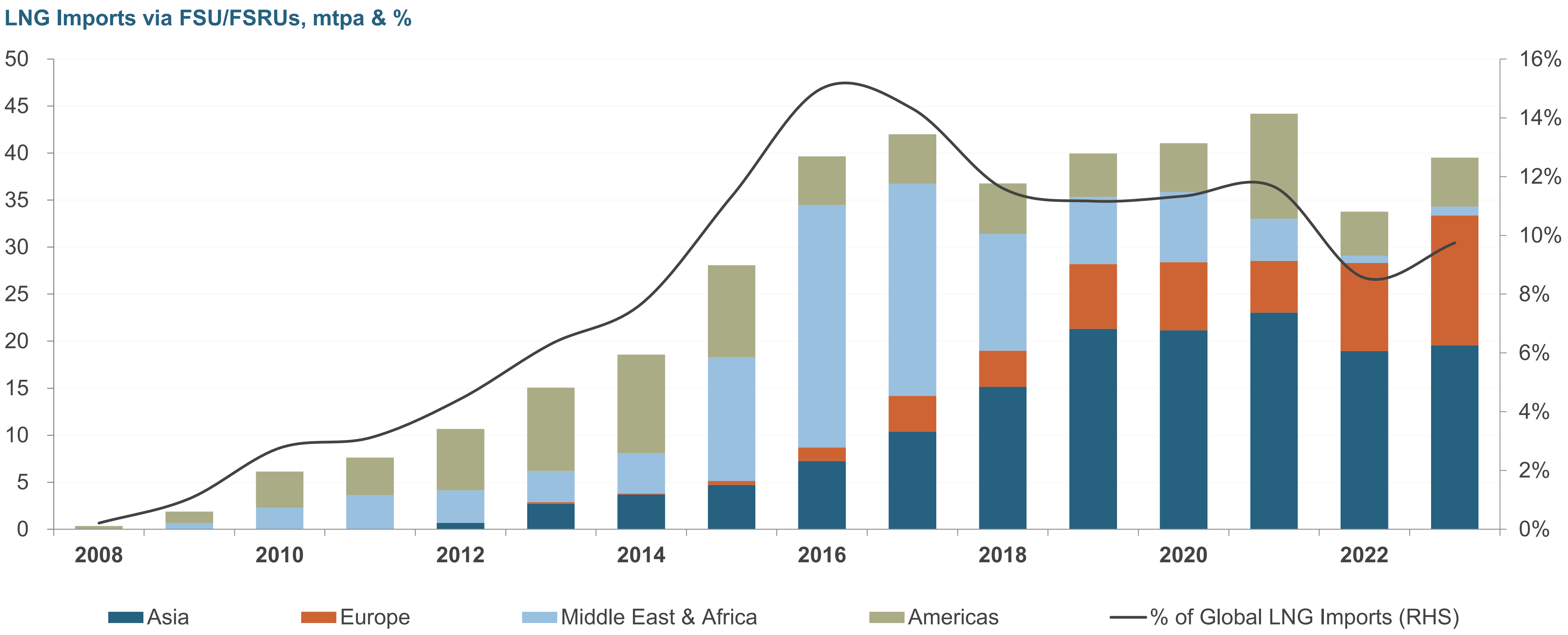


The regasification unit can be installed on jetty while the storage units can be FSUs. There may be a similar design that utilizes an onshore regasification unit connected to an FSU. Malaysia, Malta, and Bahrain are some examples using FSU in their LNG import terminal design.

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.

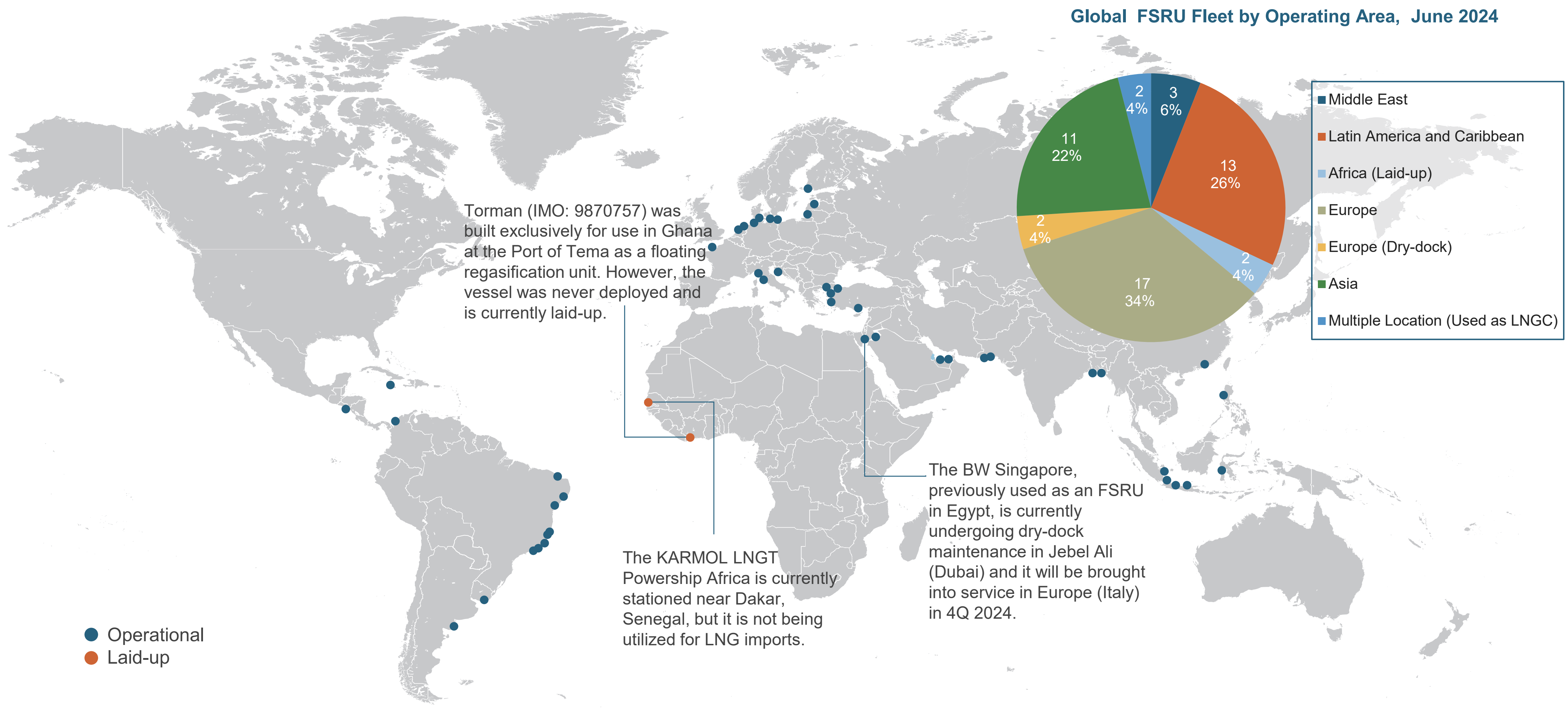
Source: ExxonMobil, FGE

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



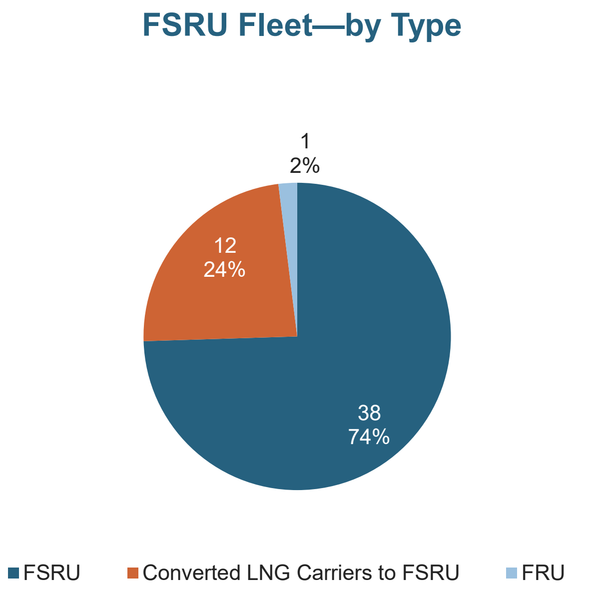
Source: FGE

FSRUs in service for LNG imports

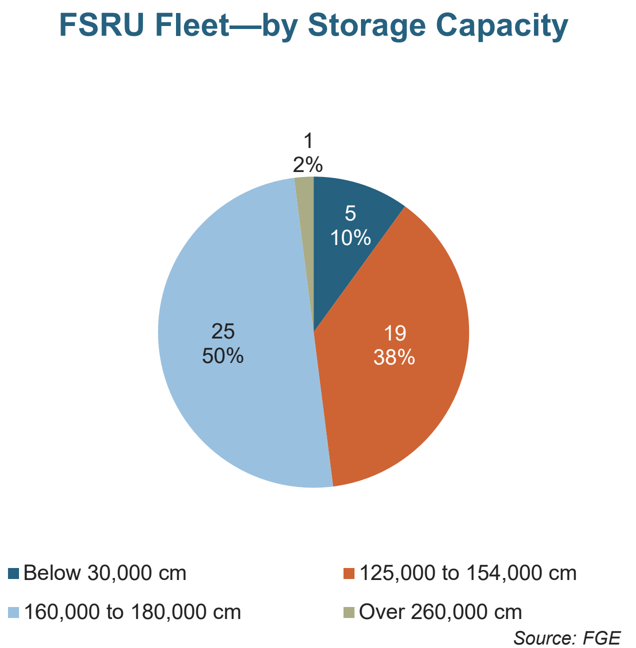


Source: FGE

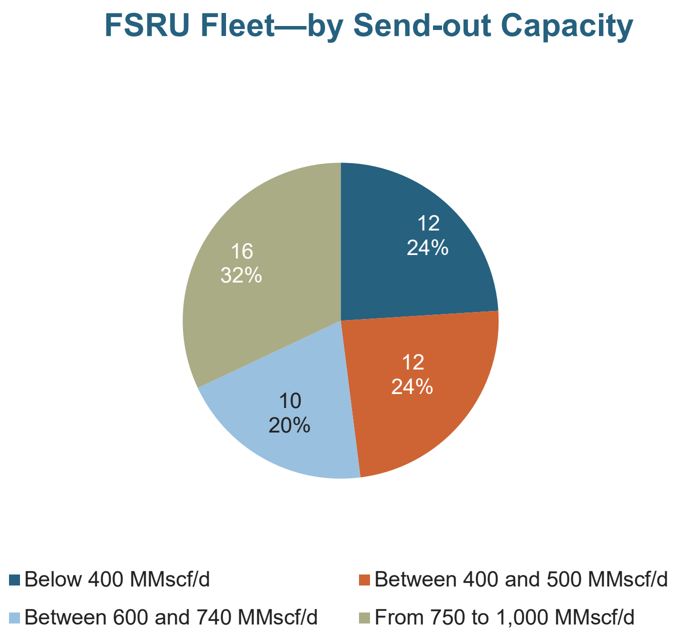
Global FSRU fleet snapshot (as of June 2024)



Source: FGE



Source: FGE

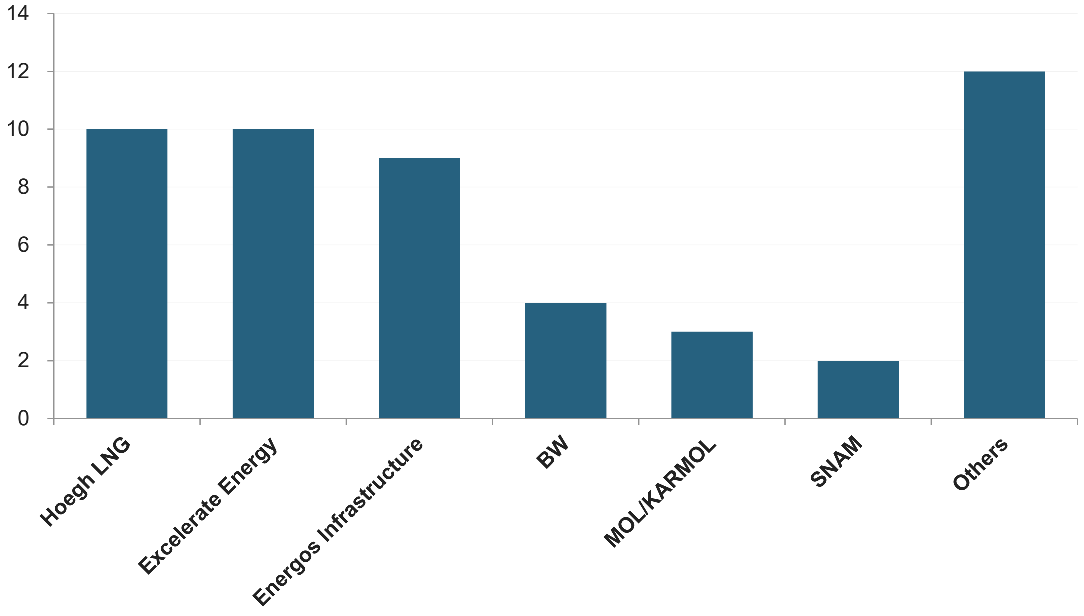


Source: FGE

- 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

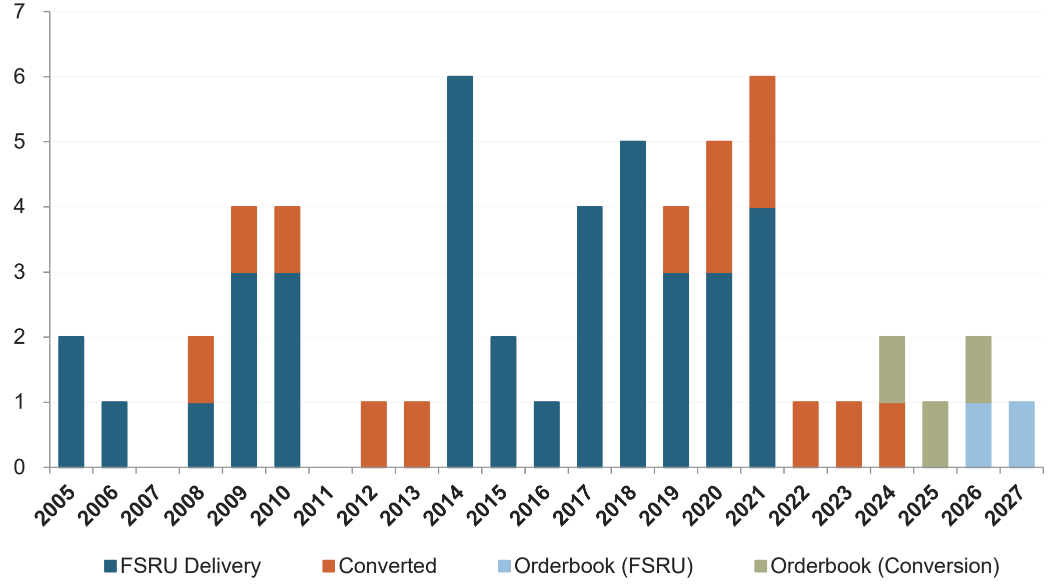
FSRU Fleet Chartering Status, June 2024



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.

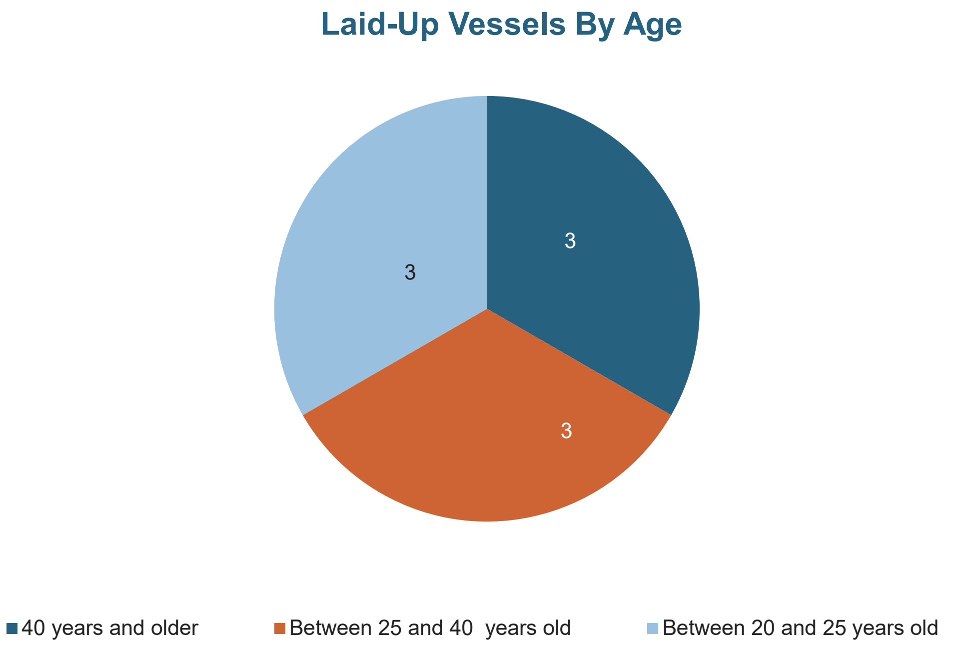
FSRUs provided a swift solution to Europe's gas supply crisis and are expected to continue playing a crucial role in the near term

- 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)

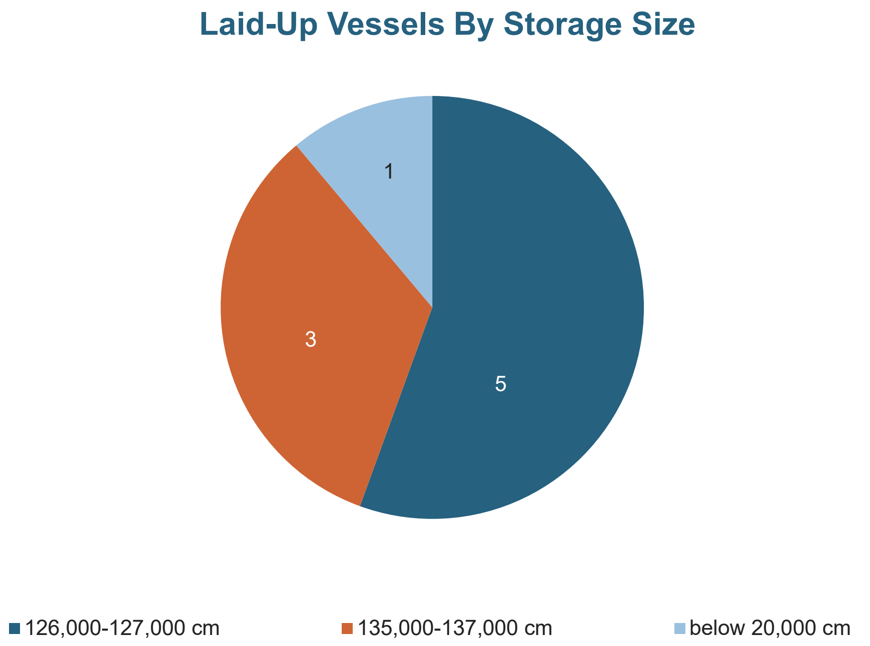
The choice between purchasing, ordering, converting, or chartering depends on the project technical specifics, desired capacity, budget, and timeline

- 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



Source: FGE



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

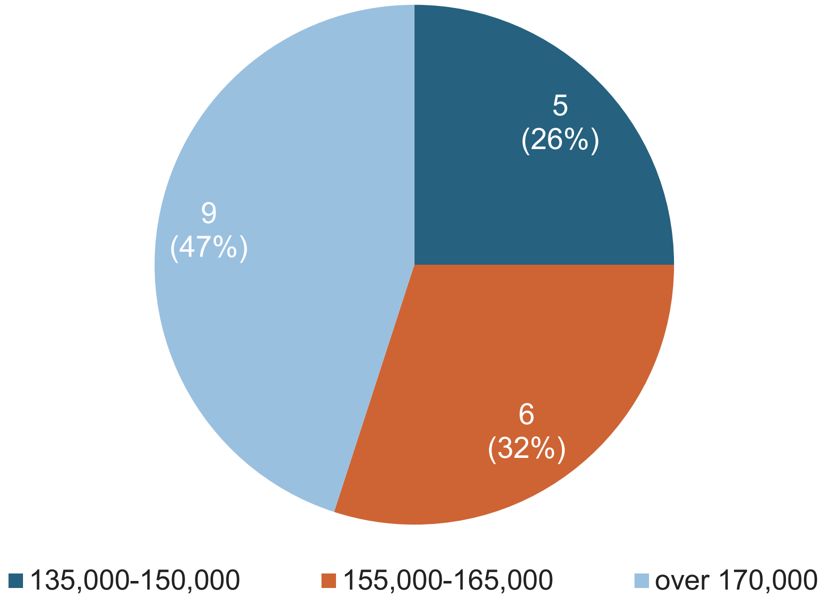
19 Vessels that JERA owns and controls (as of June 2024)

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

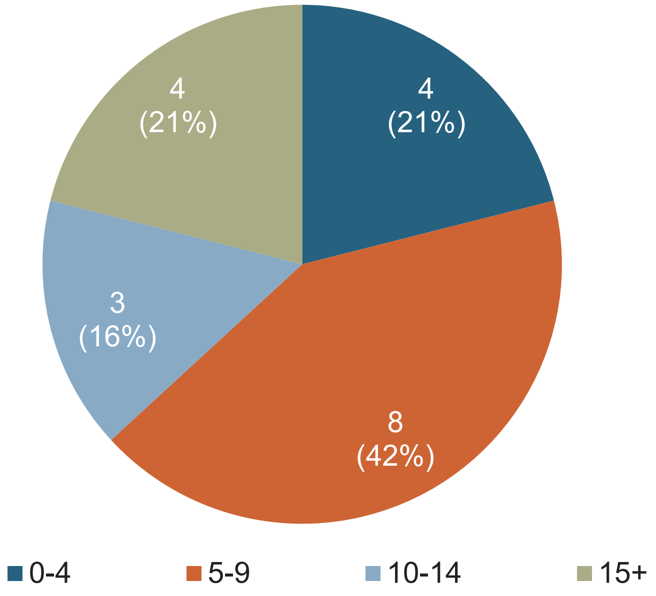
Specifications of JERA controlled vessels

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

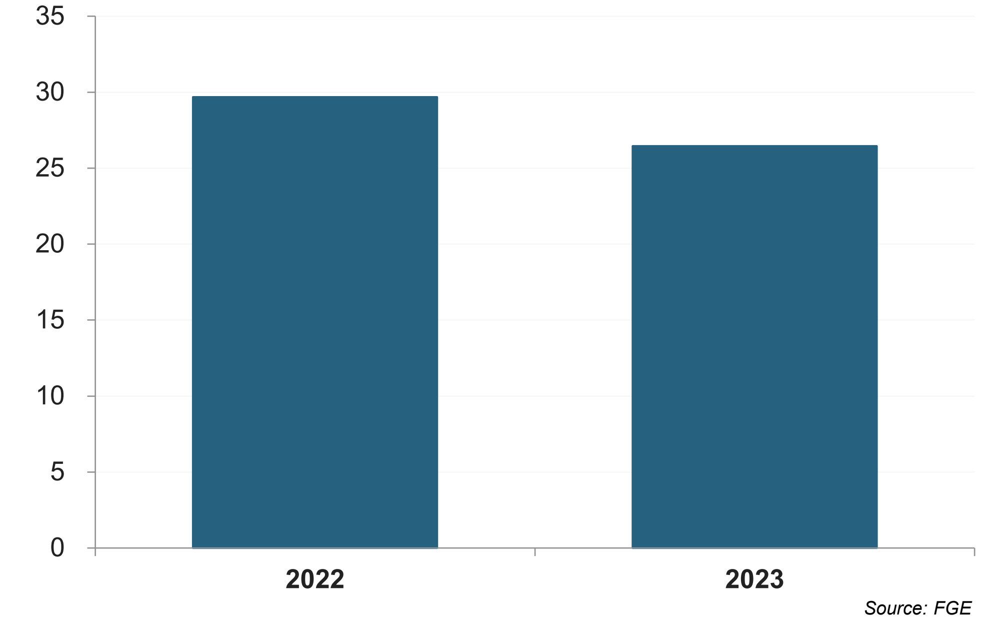
- JERA’s most recent consolidated financial results are for fiscal year (FY) 2022.
  - FY2022 denotes the period from April 1, 2022 to March 31, 2023.
  - FY2023 consolidated financial results are expected to be available by the end of April 2024.
- JERA’s equity was JPY2,039.7 billion as of March 31,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

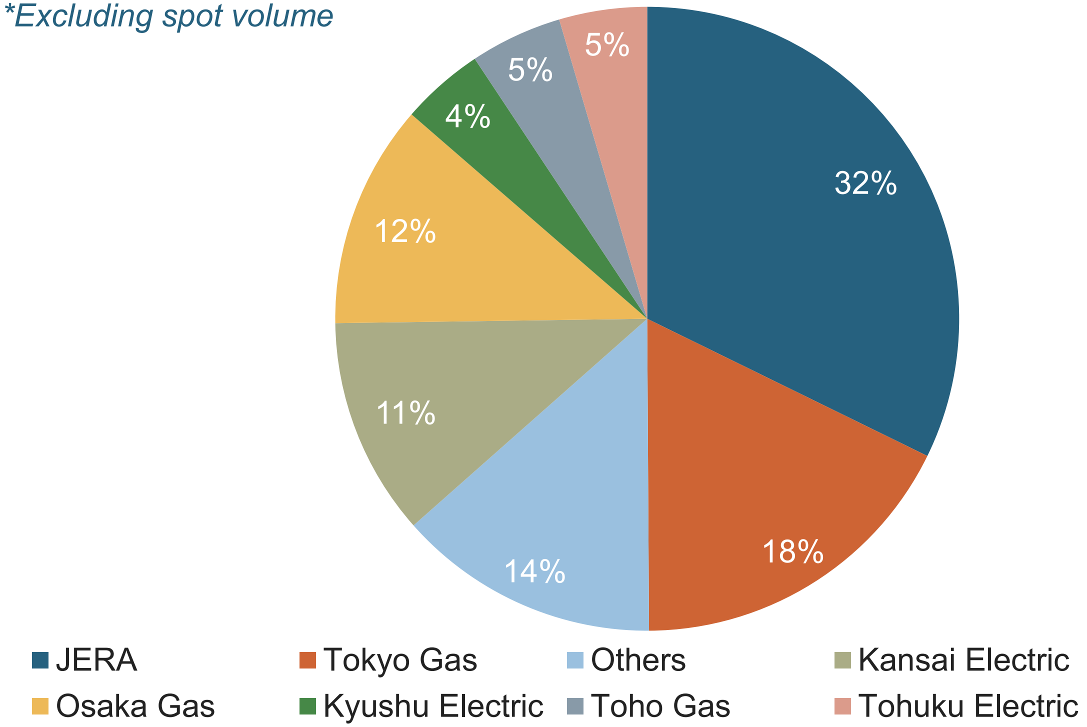
JERA's LNG Imports, mt



Source: FGE

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

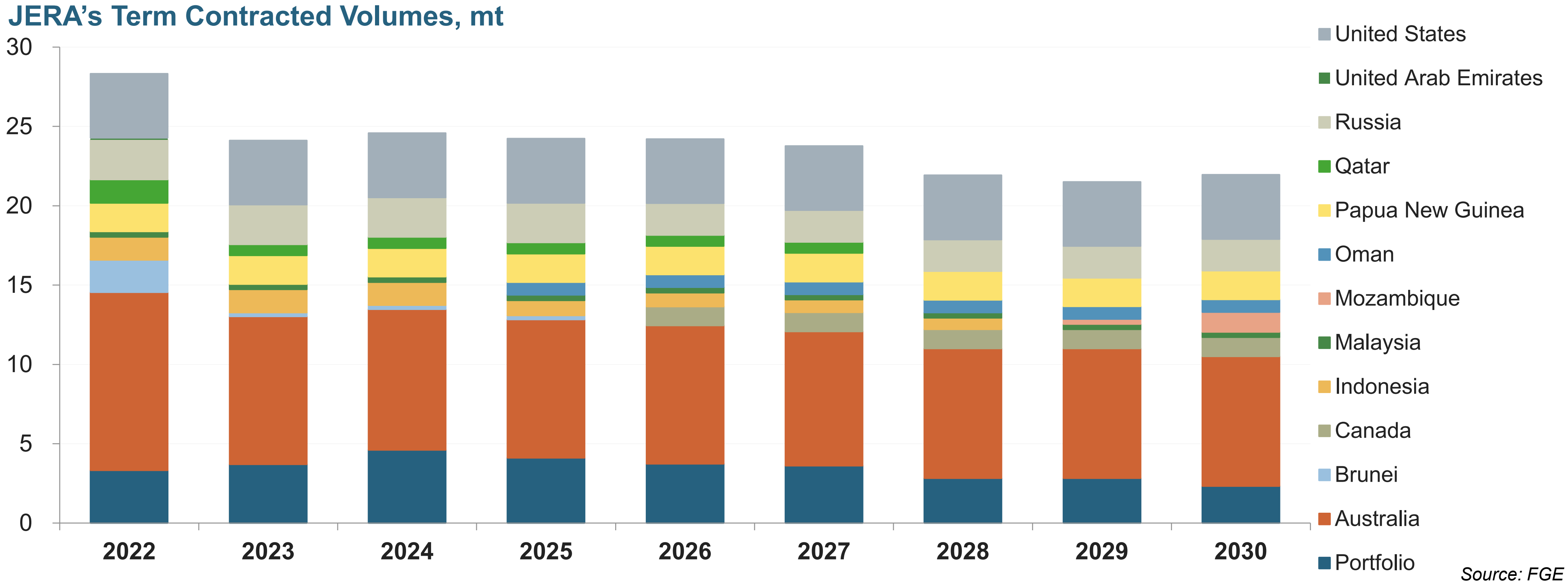
**Excluding spot volume*



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

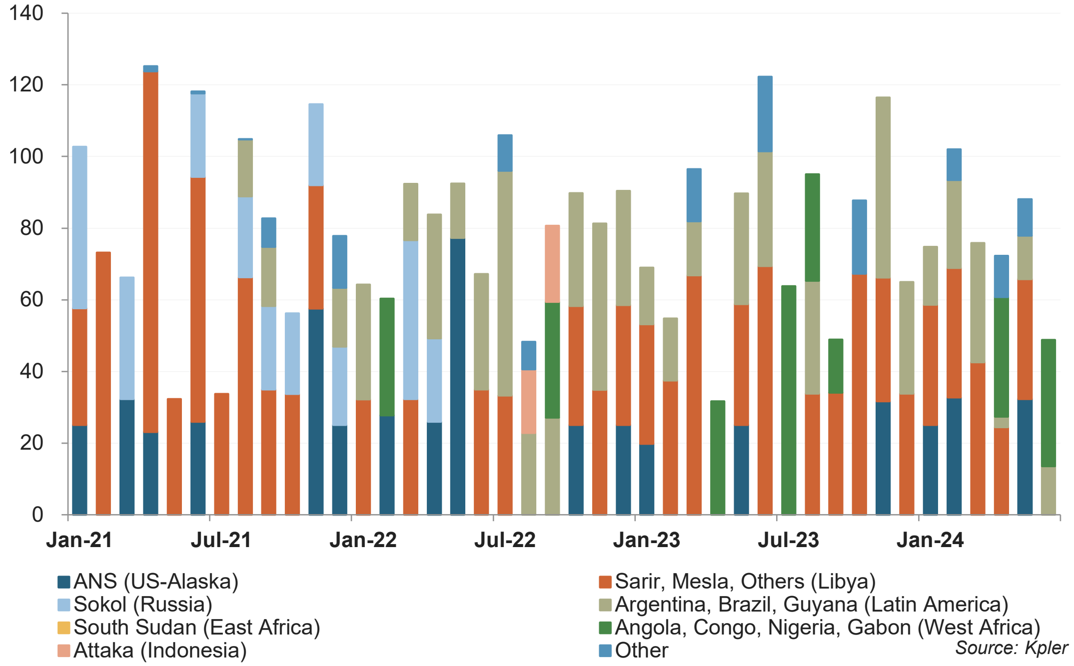
The most likely outcome if Par loses the LSFO contract with HECO is a combination of partial conversion of the refinery to small-to-medium-sized bio-refinery, as well as converting the remaining tank storage and logistics into an import terminal

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).

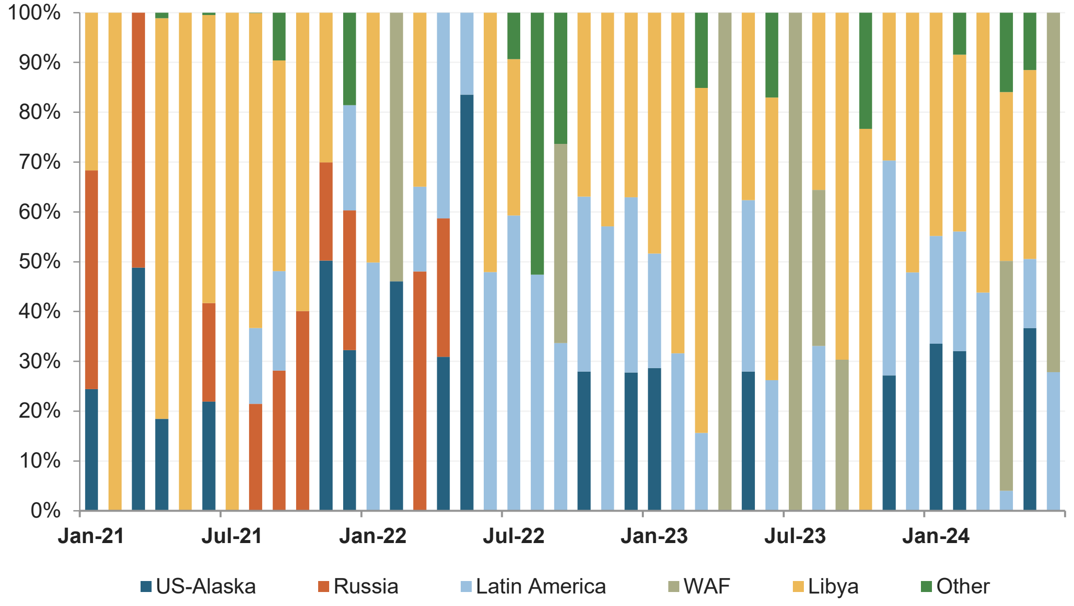
Par Petroleum’s crude imports

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



Source: Kpler

Hawai’i: Crude Oil Imports by Origin, %

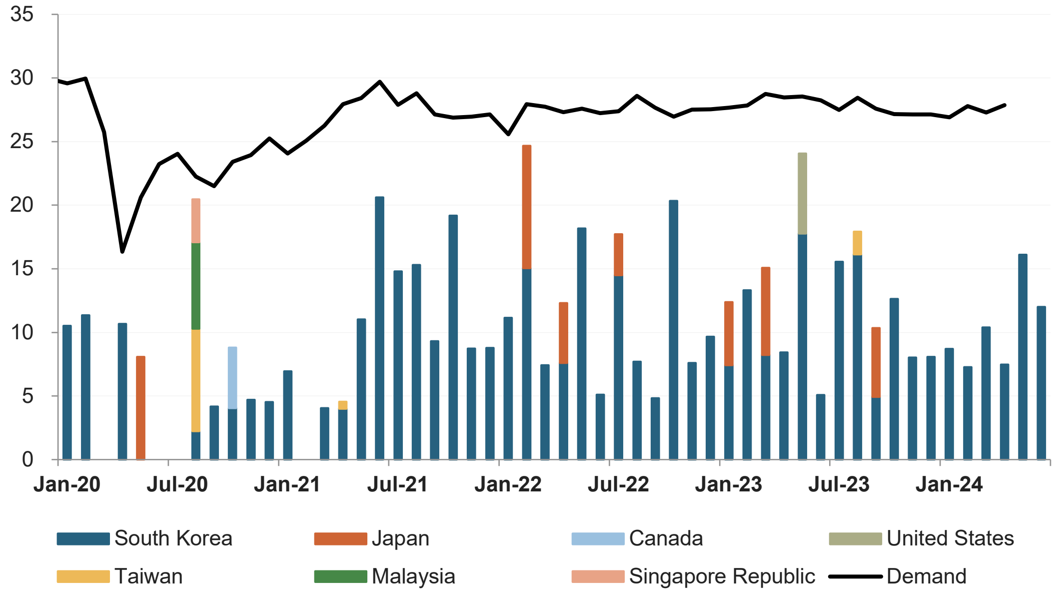


Source: Kpler

- 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).

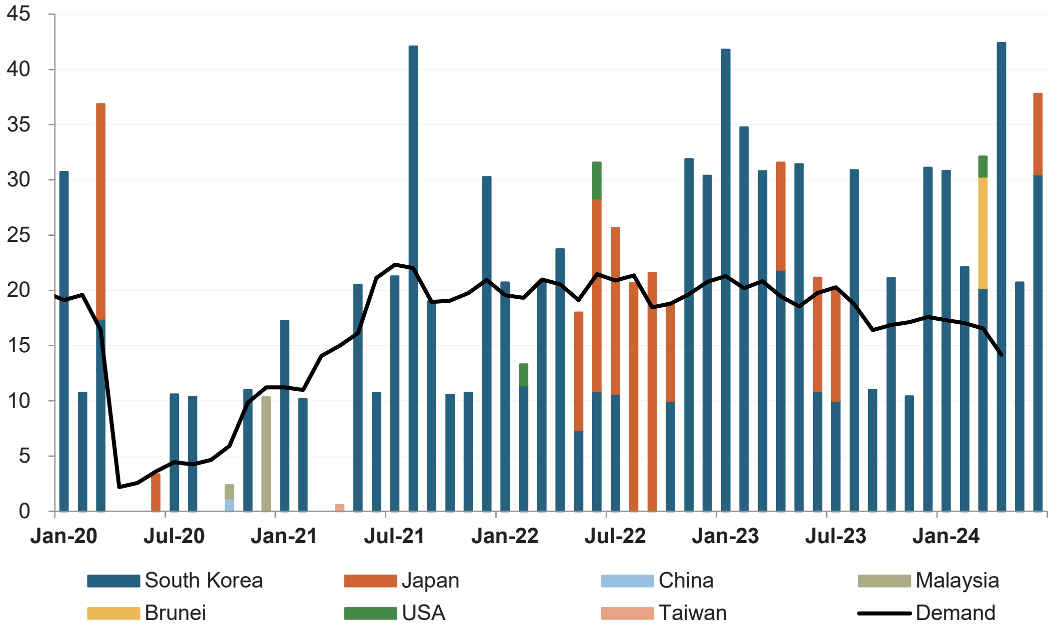
South Korea: The primary supplier of products to Hawai’i

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!

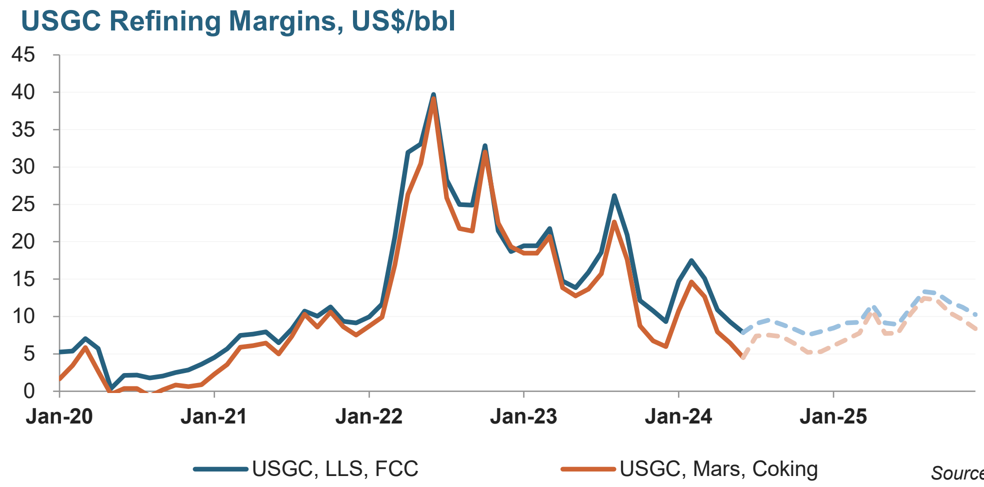
	2018	2019	2020	2021	2022	2023	1Q-23	1Q-24
Ref Throughput, Par Hawaii (kb/d)	**116**	**109**	**73**	**82**	**82**	**81**	**76**	**79**
Adjusted Gross Margin ($/bbl)	5.37	3.30	-1.63	4.56	13.99	15.25	19.11	14.00
Production costs per bbl ($/bbl)	3.65	3.25	4.03	3.98	4.86	4.57	4.54	4.89
DD&A ($/bbl)	0.66	0.40	0.55	0.66	0.67	0.65	0.73	0.60
Ref Throughput, Wyoming (kb/d)	**16**	**17**	**12**	**17**	**17**	**18**	**17**	**17**
Adjusted Gross Margin ($/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

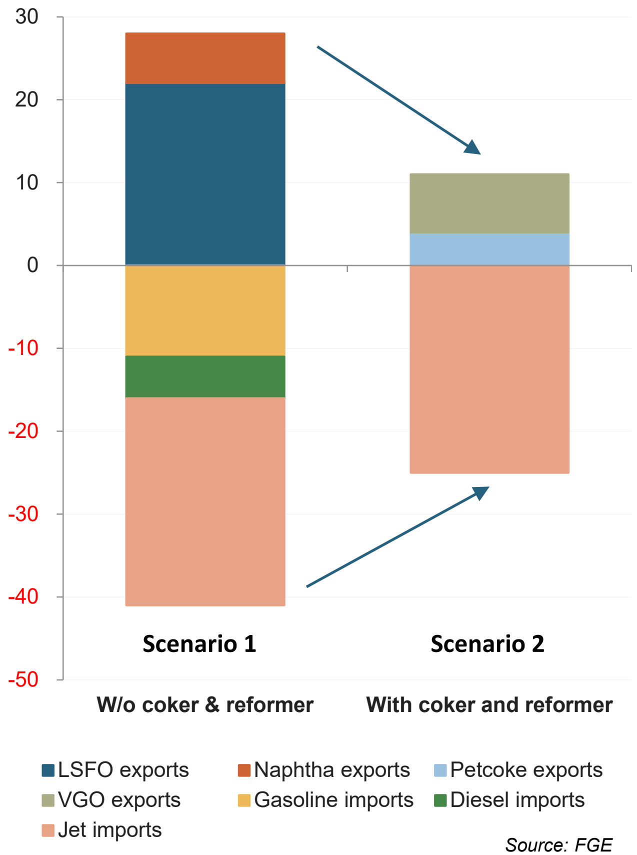
- If Par Pacific loses demand for its LSFO (due to HECO switching to LNG as a fuel), it would also imply a loss of offtake for its naphtha supply to Hawai‘i Gas, as there will be no more naphtha-based SNG production.
- In that case, Par Pacific would face several scenarios:
    1. Continue running at 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

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.