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]

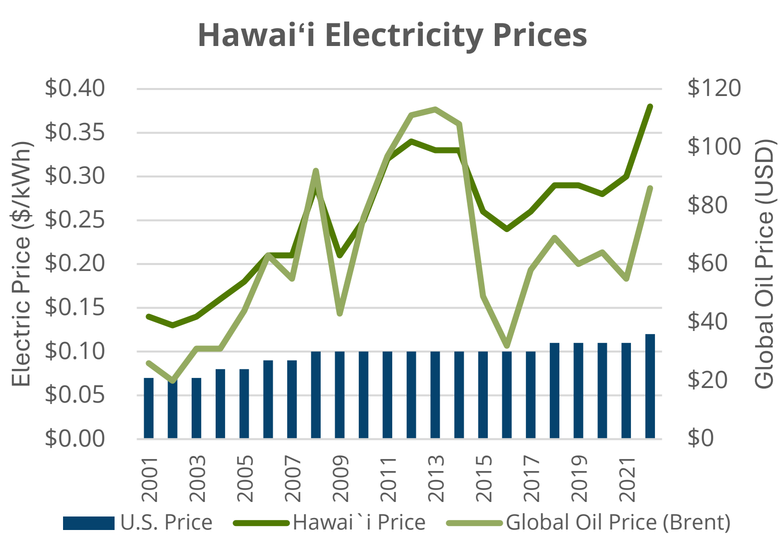

Figure 1. *Hawaiʻi Electricity Prices follow oil prices. Electricity prices from EIA; Brent oil prices from International Monetary Fund*

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

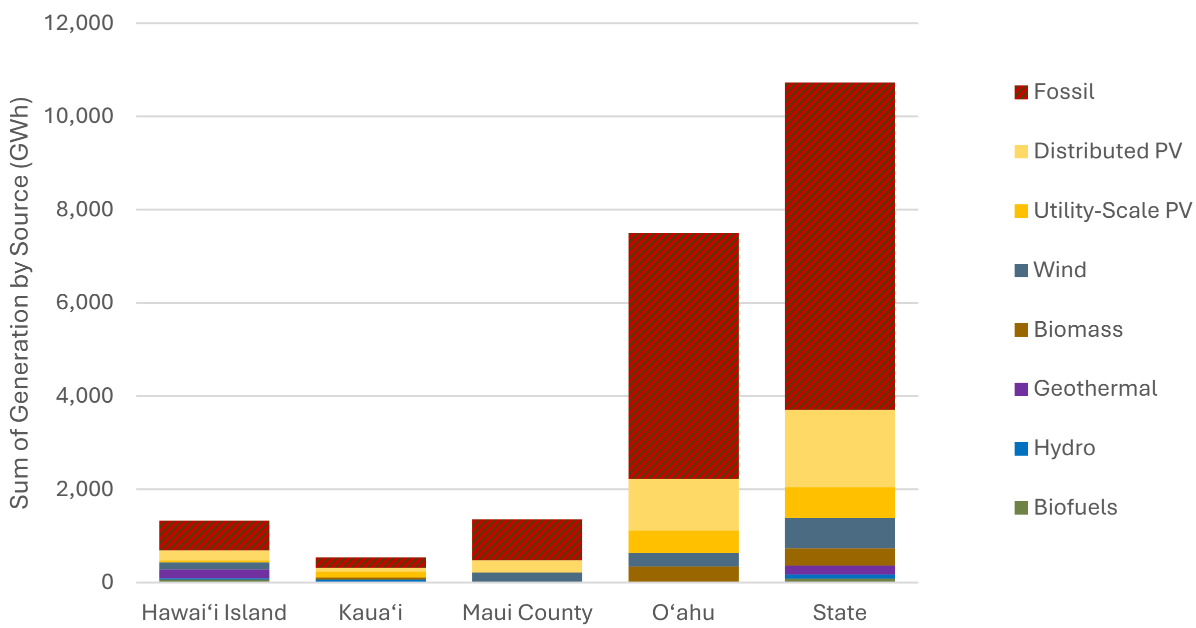

Figure 2. *County-specific generation by source (GWh). Data compiled by the Hawaiʻi State Energy Office (HSEO), Source Public Utilities Commission Docket 2007-0008. 2023 Renewable Portfolio Standards (RPS) Annual Status Reports.*

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.

[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.

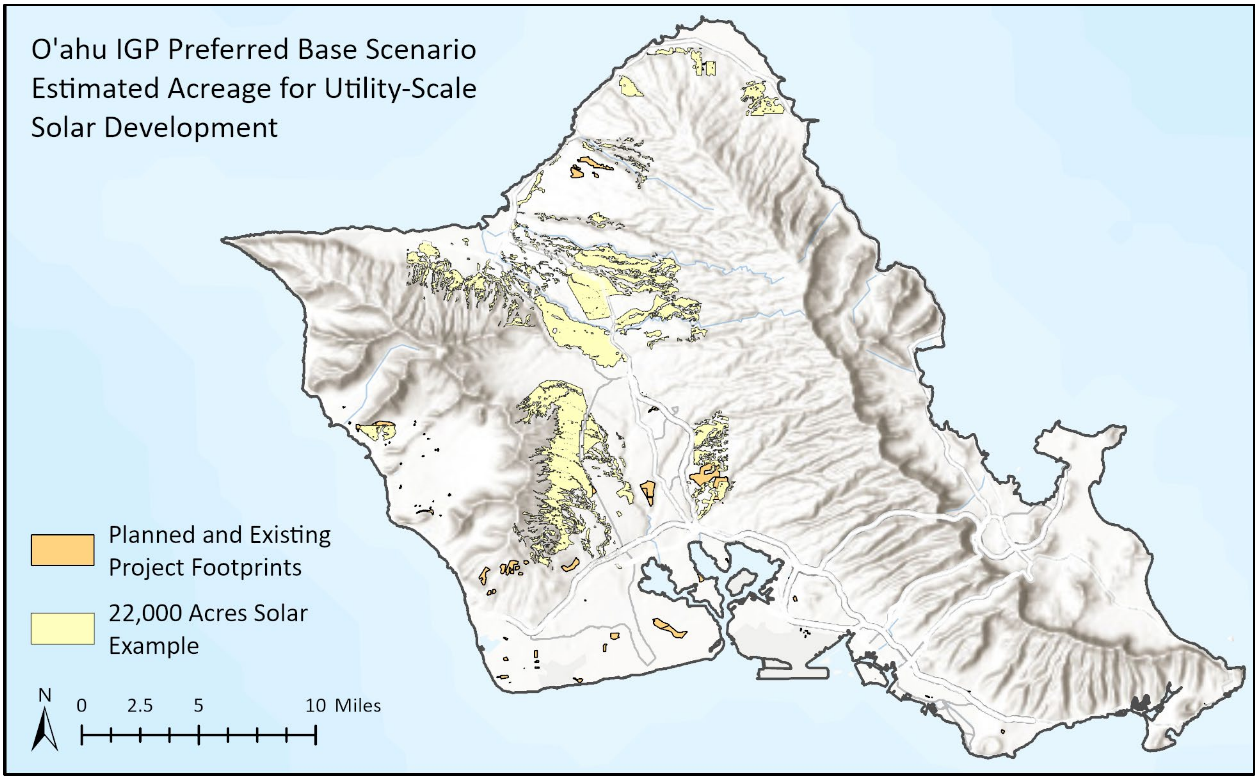

Figure 3 *Estimated acreage for utility-scale solar development. This figure illustrates the estimated acreage required to meet the projected 3,300 MW of utility-scale solar capacity. The area shaded yellow (22,000 acres) represents the estimated land area needed to meet the IGP preferred base scenario 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.

[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.

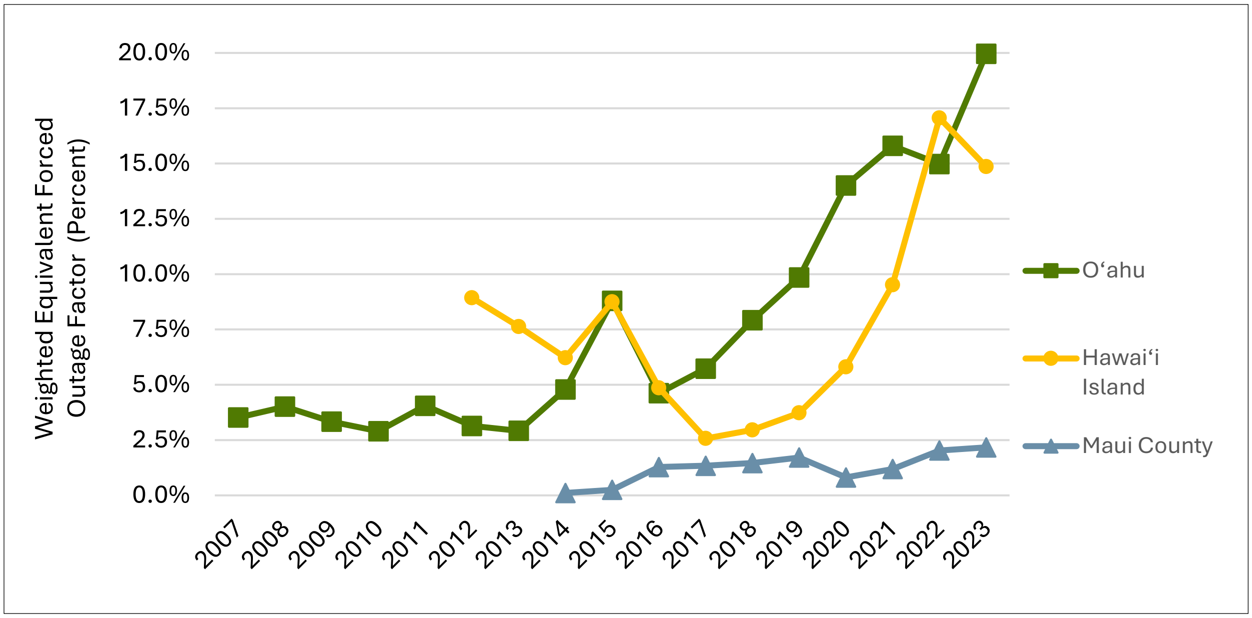

Figure 4 *Hawaiian Electric Territory Weighted Equivalent Forced Outage Factor (%), shows the increasing unavailability of HECO firm generators due to unplanned outages (Source: HNEI/Telos, Hawaiian Electric Power Supply and Generation Key Performance Metrics).*

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*	✓	✓	✓	⊖	⊖	✓	✗
Candidate for Natural Gas Generation	✓	✓	✓	✓	✓	✗	✗

✓ 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.

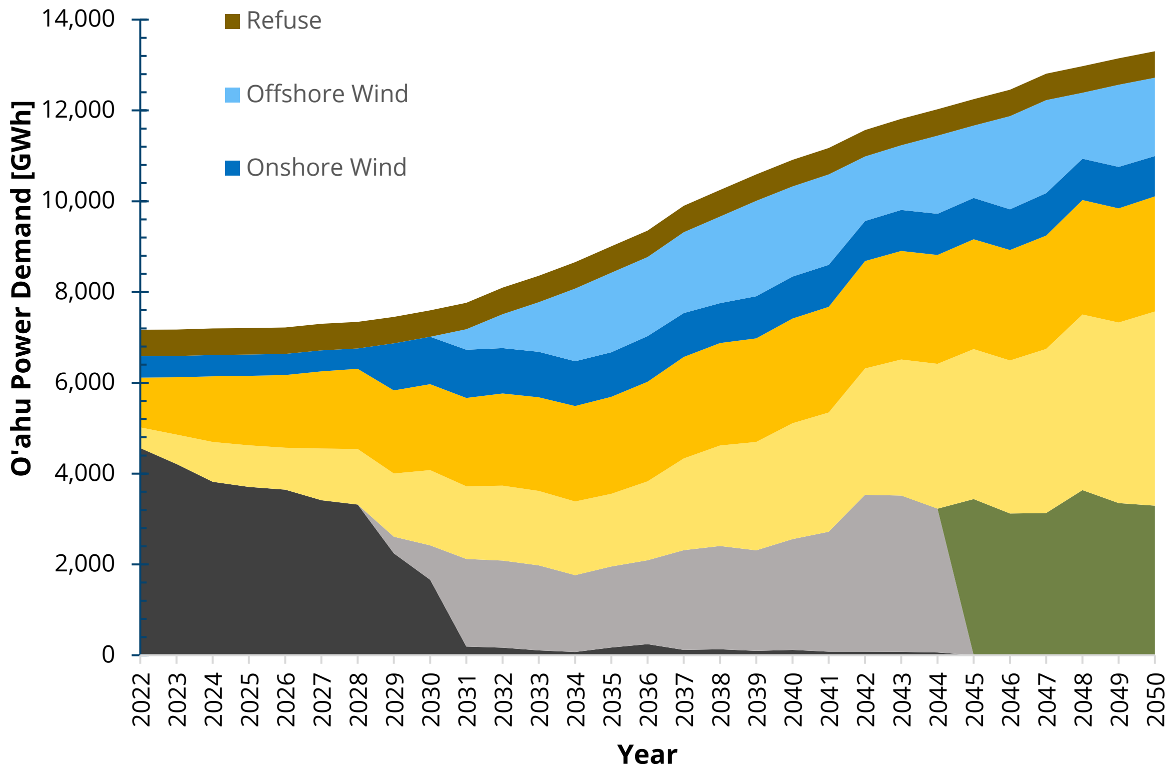

Figure 5. *Oʻahu forecasted future power demand and generation portfolio by technology type, based on conservative electrification forecast and capacity expansion modeling.*

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).

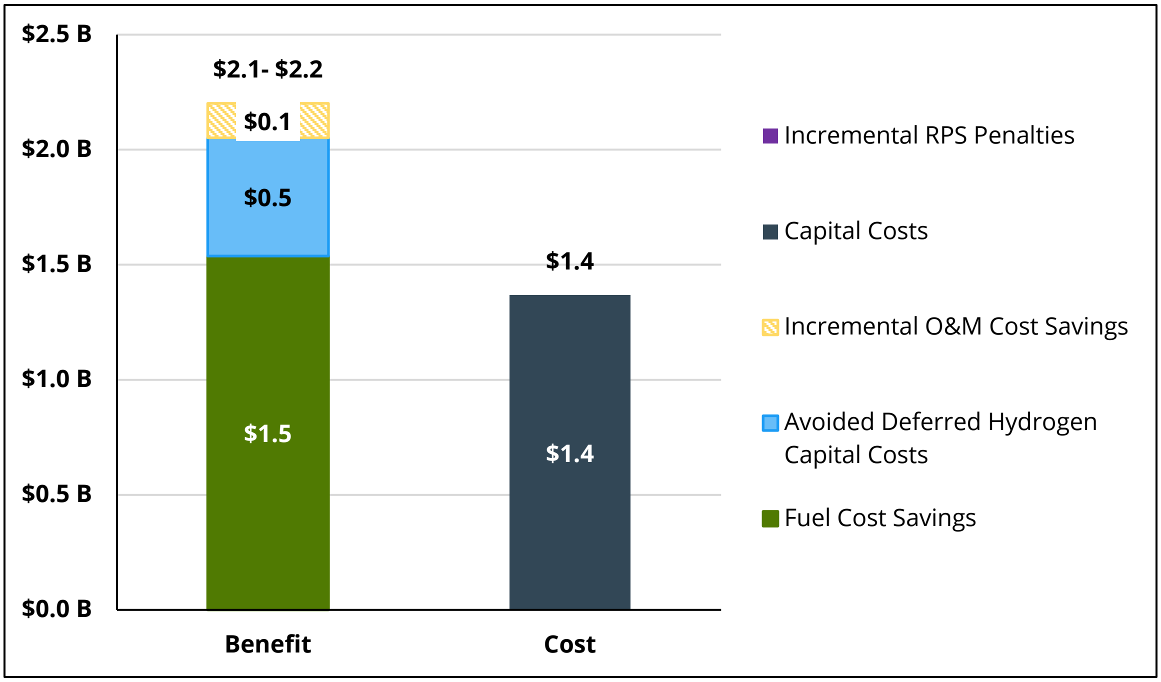

***Figure** 6. Alternative 3A net present value of LNG transition. Evaluation includes analysis of all fuel cost savings of biodiesel, some solar, and some LSFO.*

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 Hawaiʻi 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.

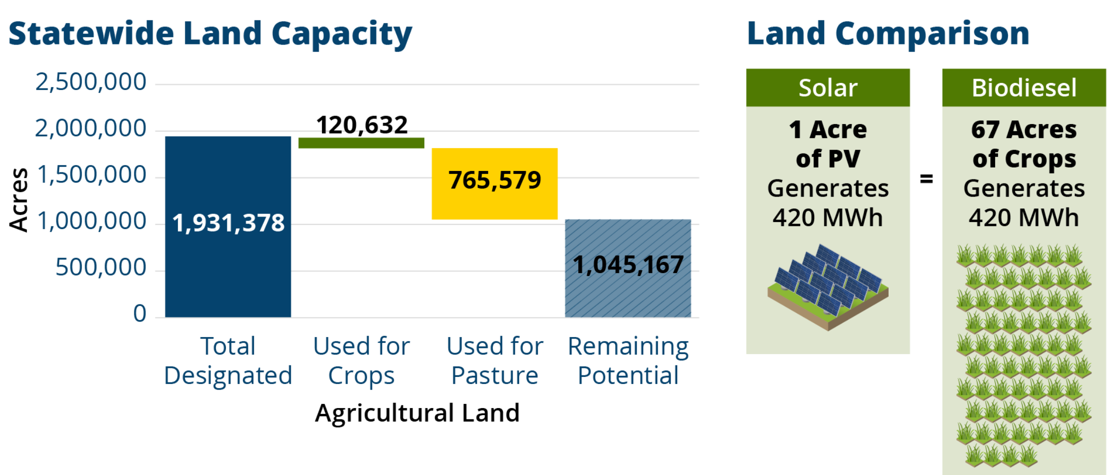

Figure 7. *Left: Hawai'i statewide agricultural land capacity by current use.[14] Right: Graphic depiction showing overall land-use efficiency of two energy-generating technologies. See the Biodiesel section for an explanation of the comparison. Estimates vary by feedstock, soil, microclimate, and other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

Hawai'i 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.

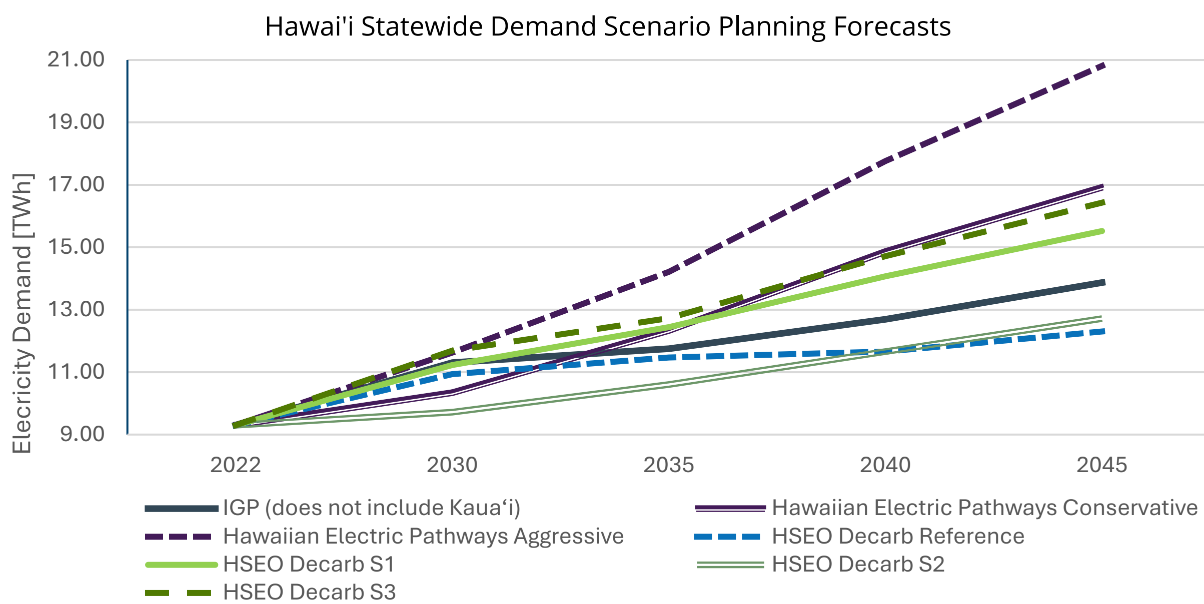

Figure 8. *Hawai'i generation forecasts developed by various reports.*

[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 O‘ahu, Hawai‘i Island, Maui, Moloka‘i, and Lāna‘i 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.

O‘ahu 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 O‘ahu. 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*	Preferred	Preferred	Neutral	Preferred	Preferred	Preferred	Not Preferred
Total Rated Capacity (MW) *Higher Capacity Preferred*	Preferred	Preferred	Preferred	Preferred	Preferred	Neutral	Neutral
Generation Fuel Type *Higher Carbon Intensive Fuel Preferred*	Preferred	Preferred	Neutral	Preferred	Preferred	Not Preferred	Neutral
Existing Upgrade Plans *No Plans Preferred*	Preferred	Neutral	Preferred	Preferred	Neutral	Preferred	Preferred
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

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 Oʻahu 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.

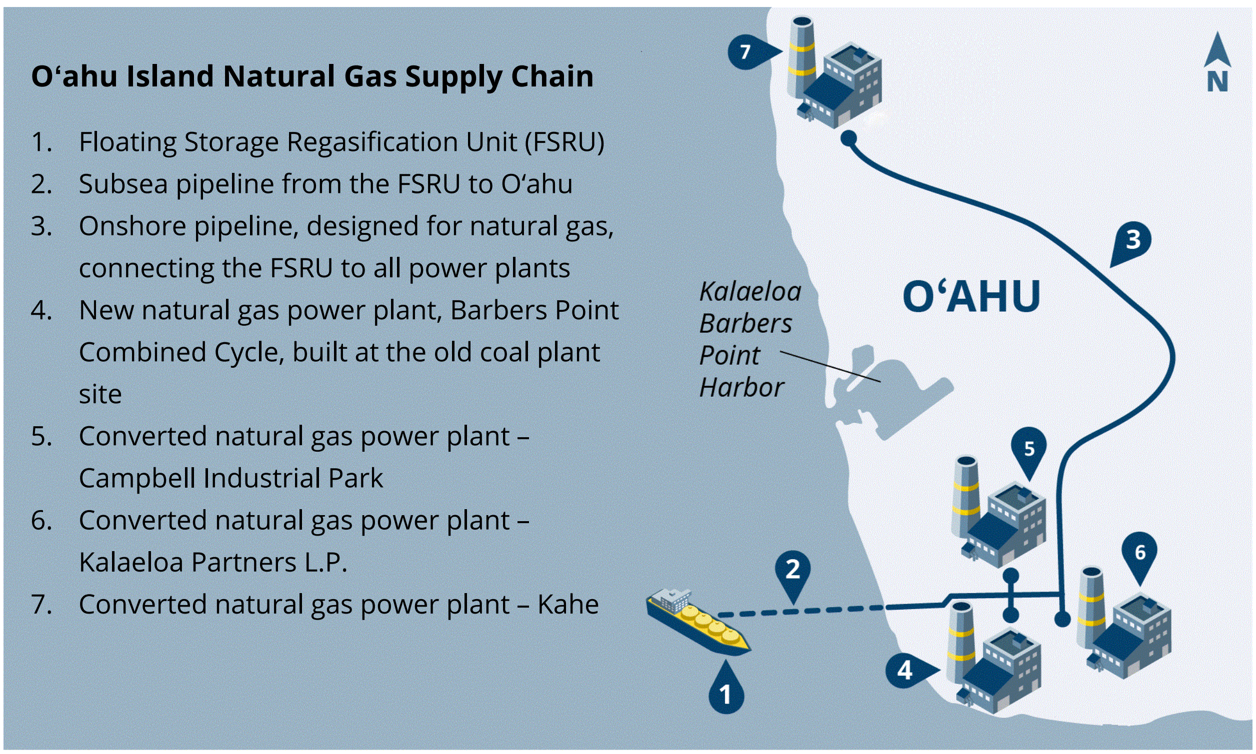

Figure 9. *LNG supply chain for Oʻahu preferred alternative*

Phase 1

Phase 1 would introduce natural gas on a large scale to Oʻahu. 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 Hawai'i Natural Energy Institute study reviewed the livestock populations in Hawai'i for cattle, chickens, and hogs and determined Hawai'i has insufficient number and size of animal feeding operations to justify biogas generation and RNG.[27]

Wastewater Treatment Plants

The State of Hawai'i 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	Hawai'i	Yes	4.20	10,732	49,004	34
Kealakehe	Hawai'i	No	1.69	4,320	19,725	14
Līhu'e	Kaua'i	Yes	1.11	2,835	12,944	9
TOTAL			**147**	**376,425**	**1,718,835**	**1,194**

Landfills

The State of Hawai'i 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
Kapa'a and Kalāheo Sanitary Landfills	City & County of Honolulu	5,838,786	Yes	Shutdown	348,312	63,567
Kekaha Landfill/Phases I & II	County of Kaua'i	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)	Hawai'i 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 Hawai'i Landfill/Pu'uanahulu	Hawai'i 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 Hawai'i'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).

Hawai'i'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.

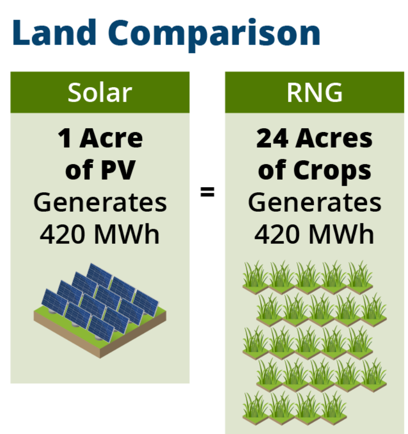

Figure 10. *Land use comparison between RNG and solar energy supply*

[33] Hawai'i 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 Hawai'i, Hawai'i 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.

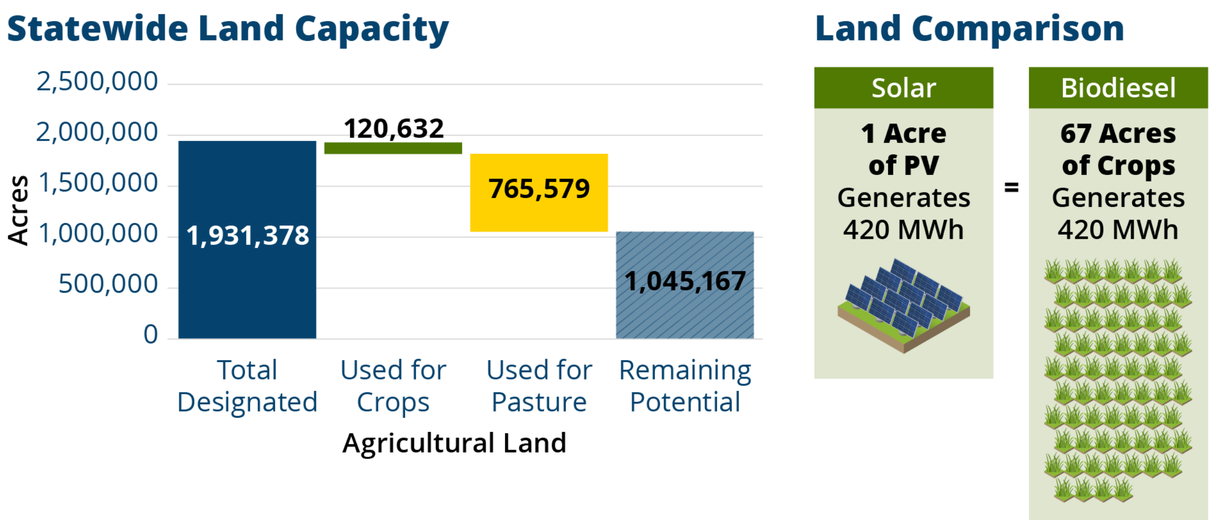

Figure 11. *Left: Land capacity statewide. Right: Acre comparison between palm oil biodiesel and solar*

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.

[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/

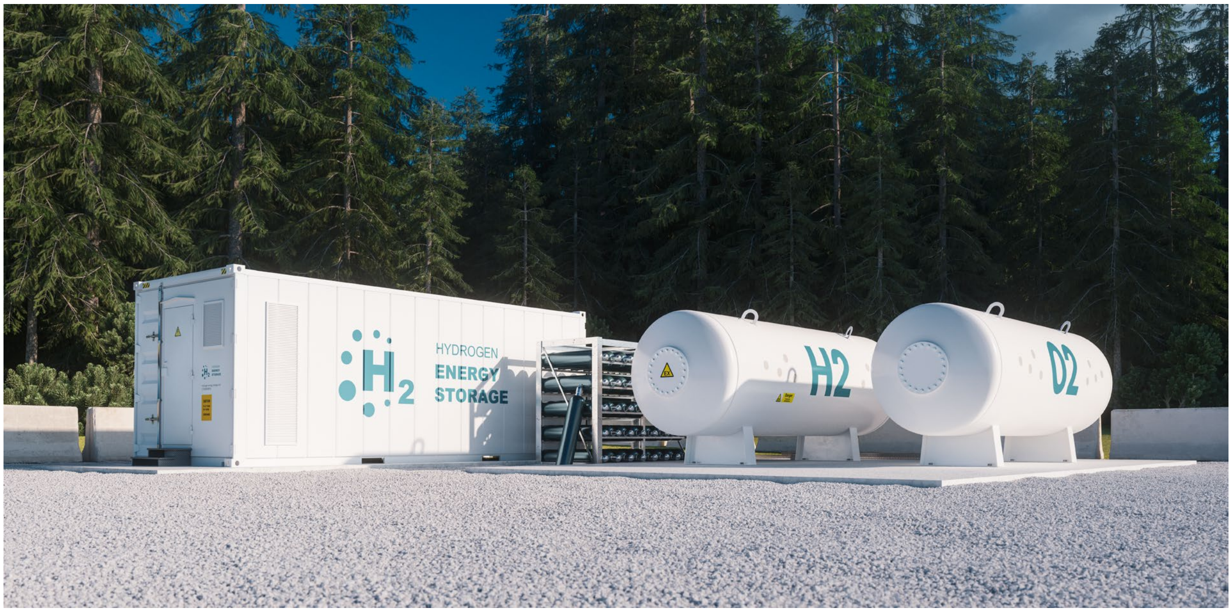

Figure 12. *Example hydrogen energy storage. Stock photo for illustrative purposes only.*

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.

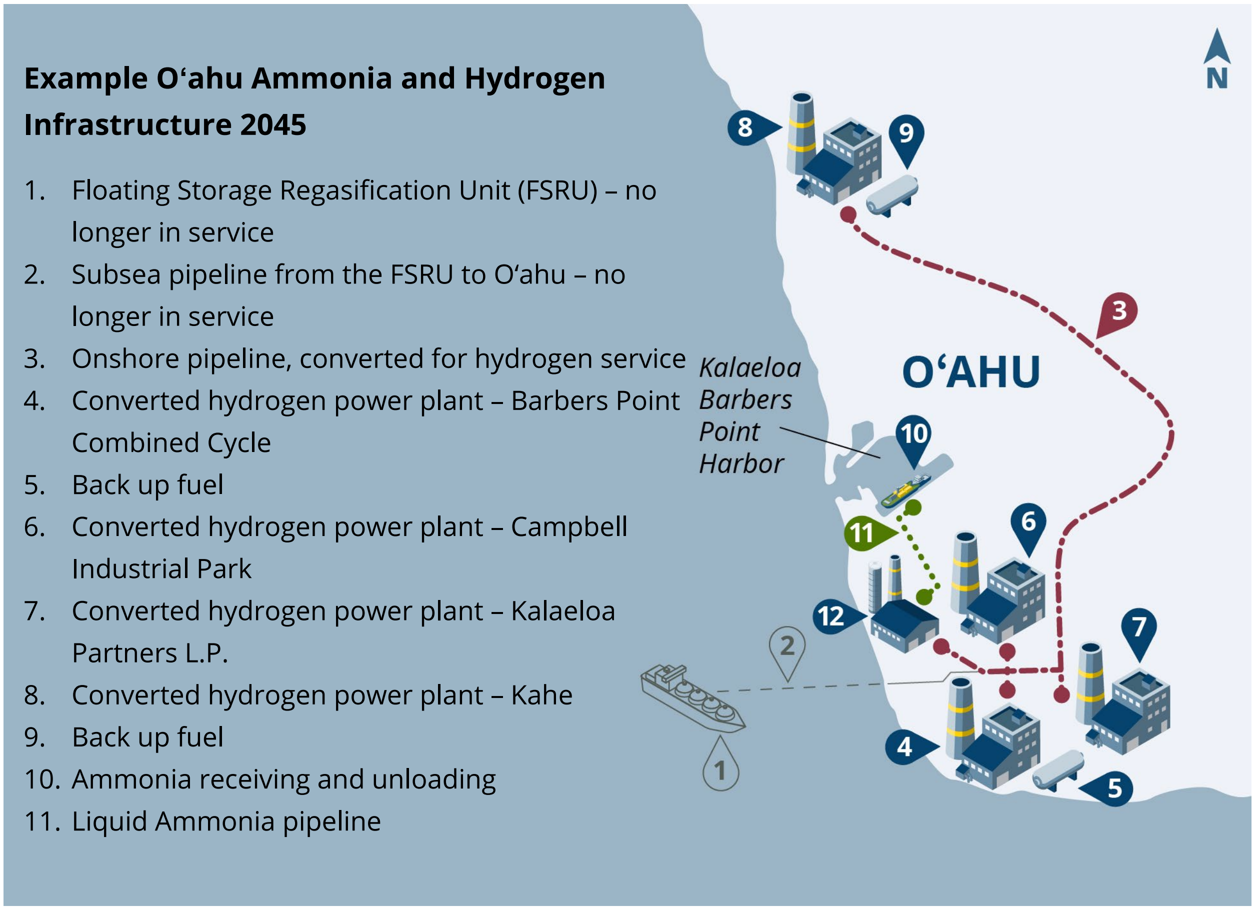

Figure 13. *Ammonia and hydrogen infrastructure on O‘ahu, in service 2045*

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.

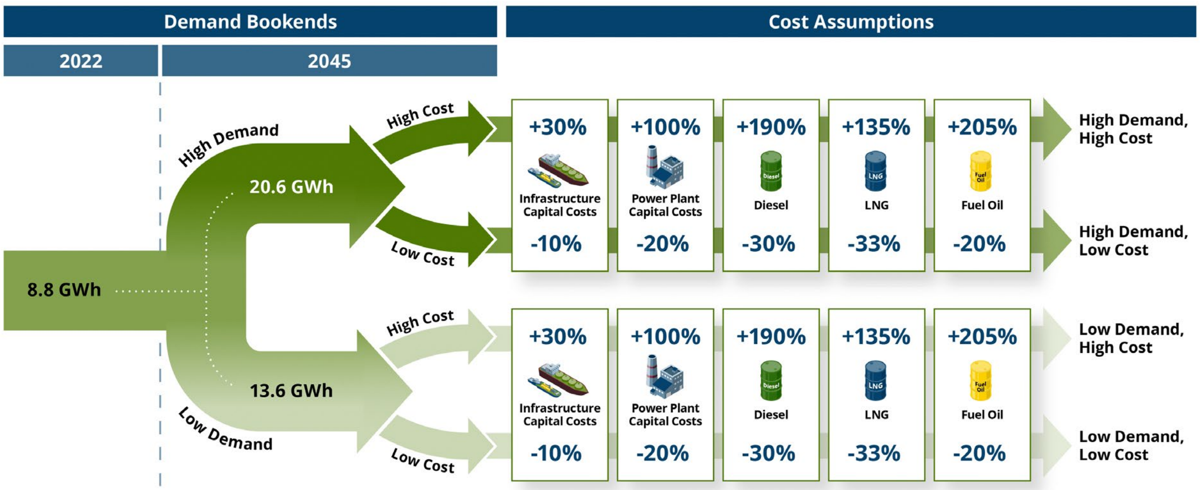

Figure 14 *Depiction of the bookend approach, capturing future uncertainty by introducing a range of demand and cost assumptions.*

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 Oʻahu 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 Oʻahu and offsets generation from LSFO unless otherwise stated.
- 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.
- 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 Hawaiʻi 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 Oʻahu. 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.

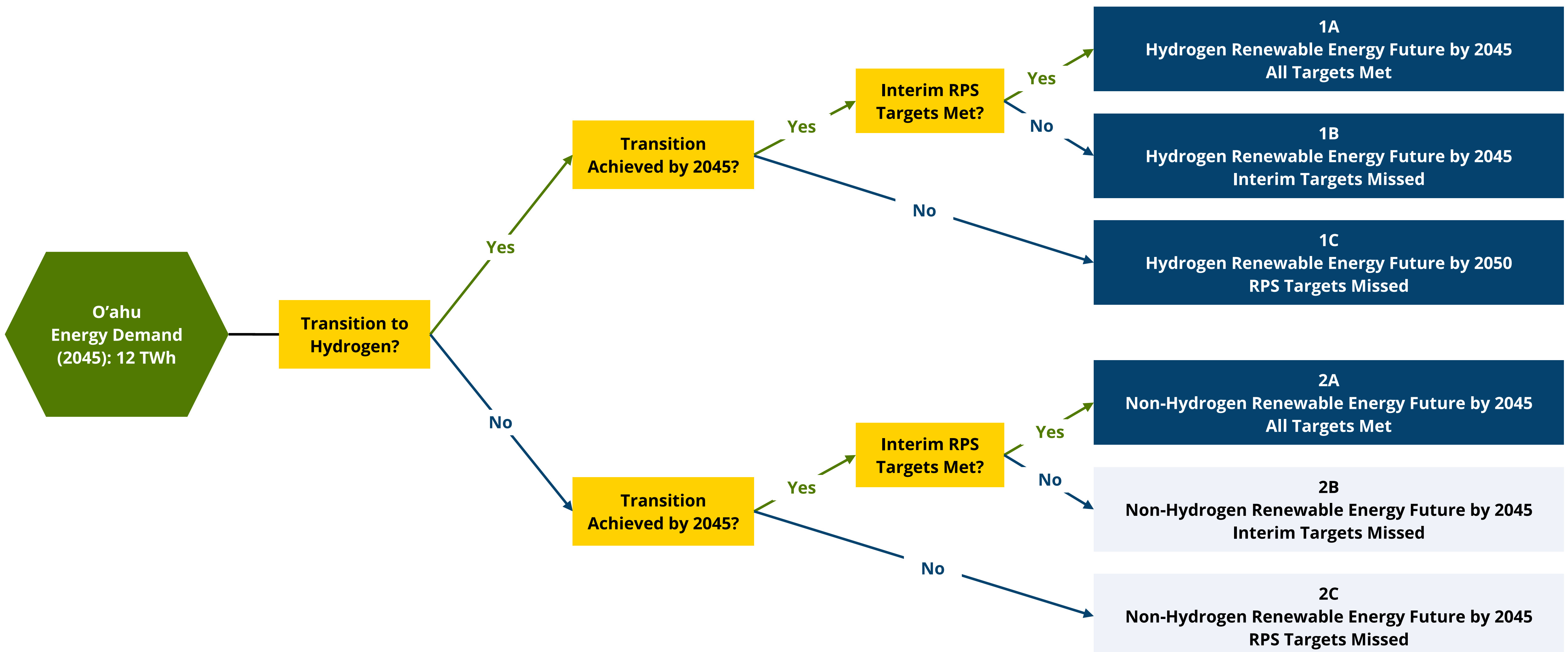

Figure 15. *Future possibilities considered for the final viable scenario.*

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).

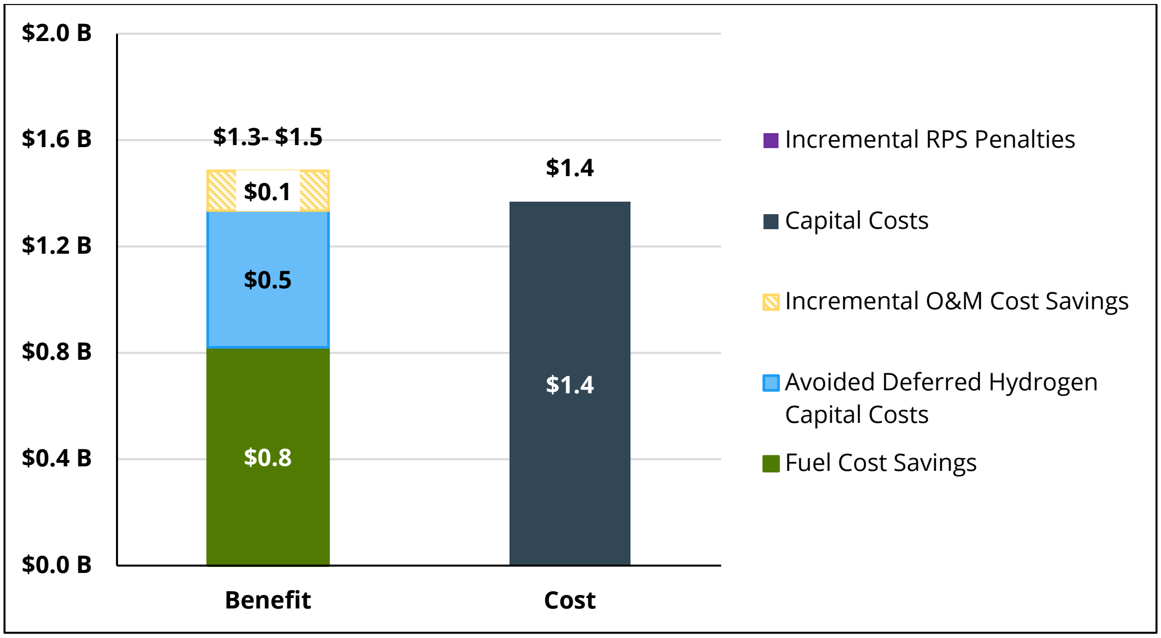

Figure 16. *Alternative 1A net present value of LNG transition*

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).

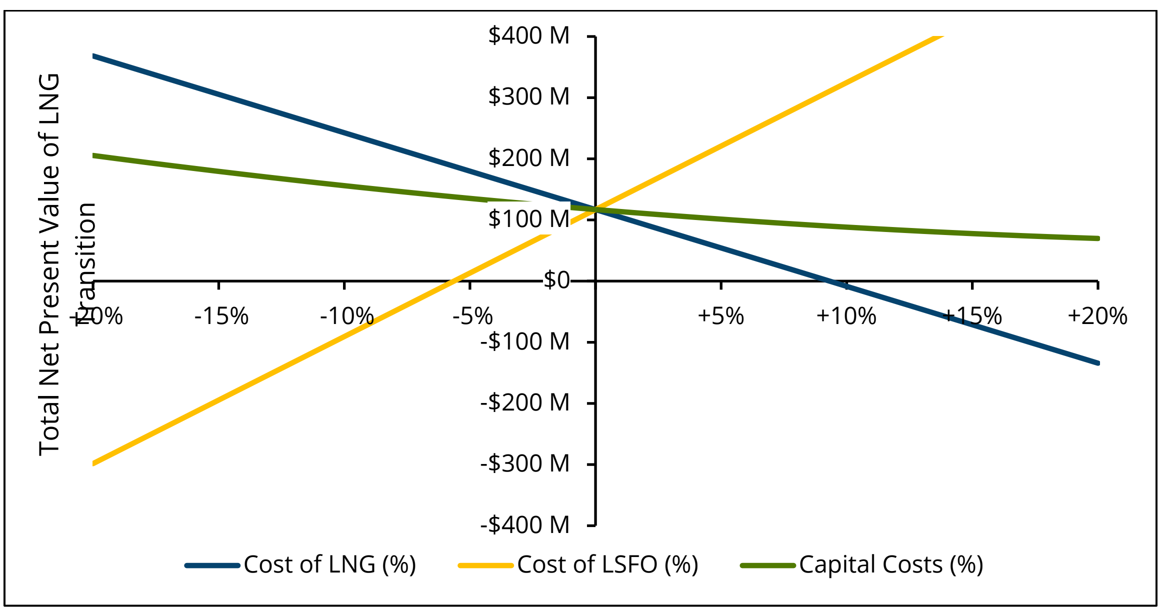

Figure 17. *Alternative 1A sensitivity analysis of the net present value of an LNG transition*

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).

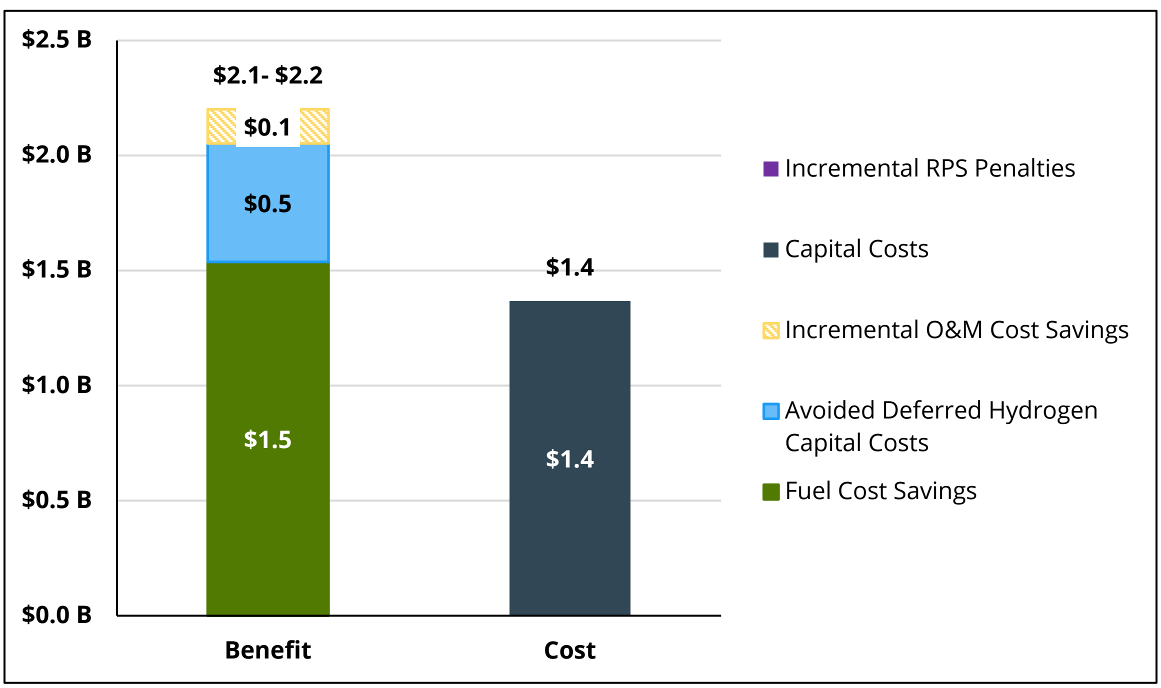

Figure 18. *Alternative 3A net present value of LNG transition*

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.

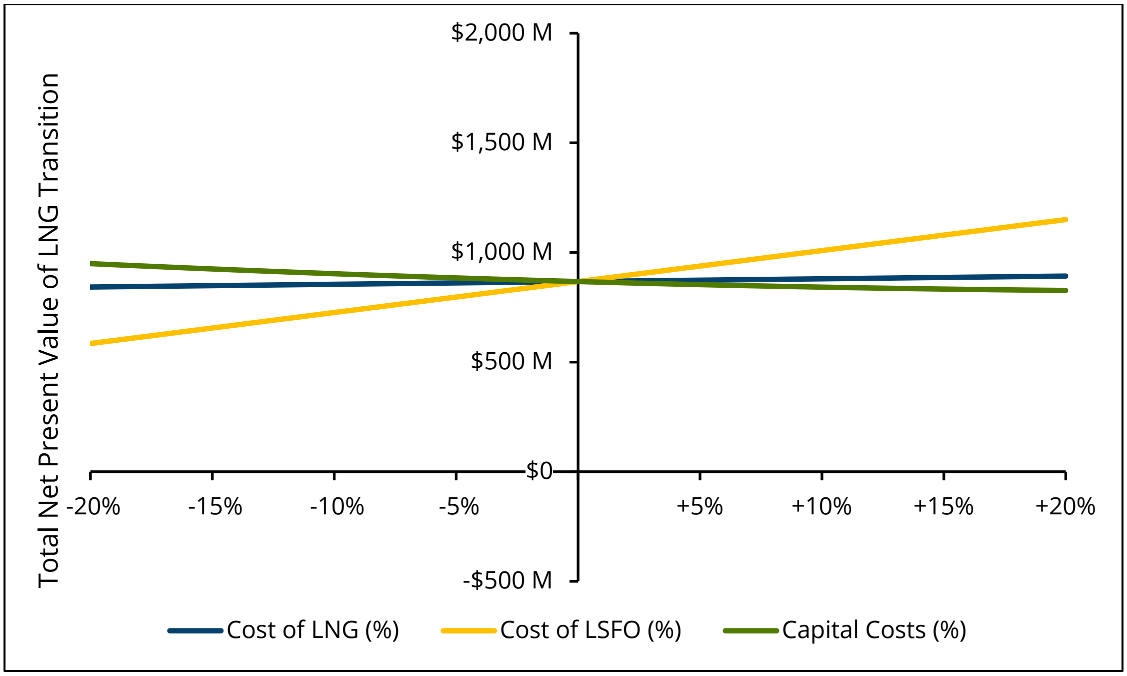

Figure 19. *Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3A*

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.

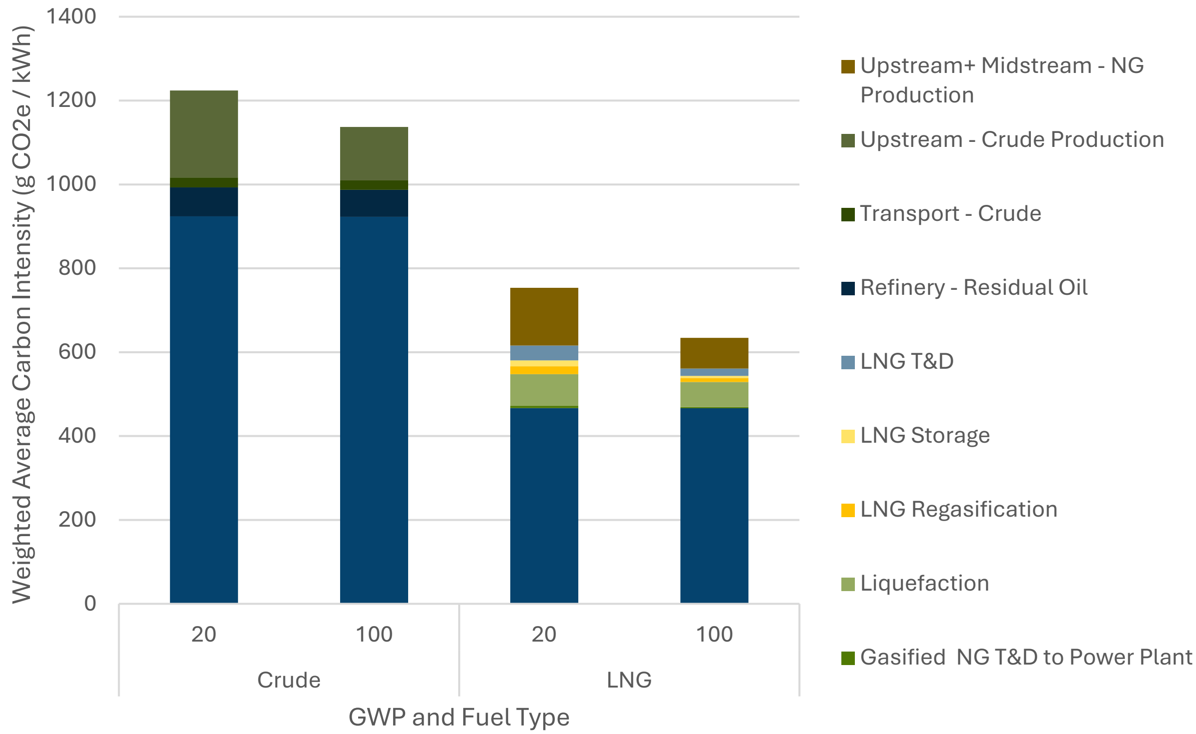

Figure 20. *Lifecycle emissions estimates for crude (LSFO) and LNG, evaluated over 20-year and 100-year Global Warming Potentials.*

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 Hawai'i 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 Hawai'i, 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 Hawai'i 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.

Hawai'i Gas

Hawai'i Gas 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 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 Hawai'i 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 Hawai'i Gas with naphtha for their SNG production. However, the naphtha would no longer be needed since the regasified LNG could also be sold to Hawai'i 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 Hawai'i Gas current purchases, which would likely result in significant savings to Hawai'i Gas' regulated customers.

Hawai'i Gas 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 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, Hawai'i 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 Hawai'i 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]

[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 Oʻahu 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 Hawaiʻi.

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], Hawaiʻi 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

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[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.

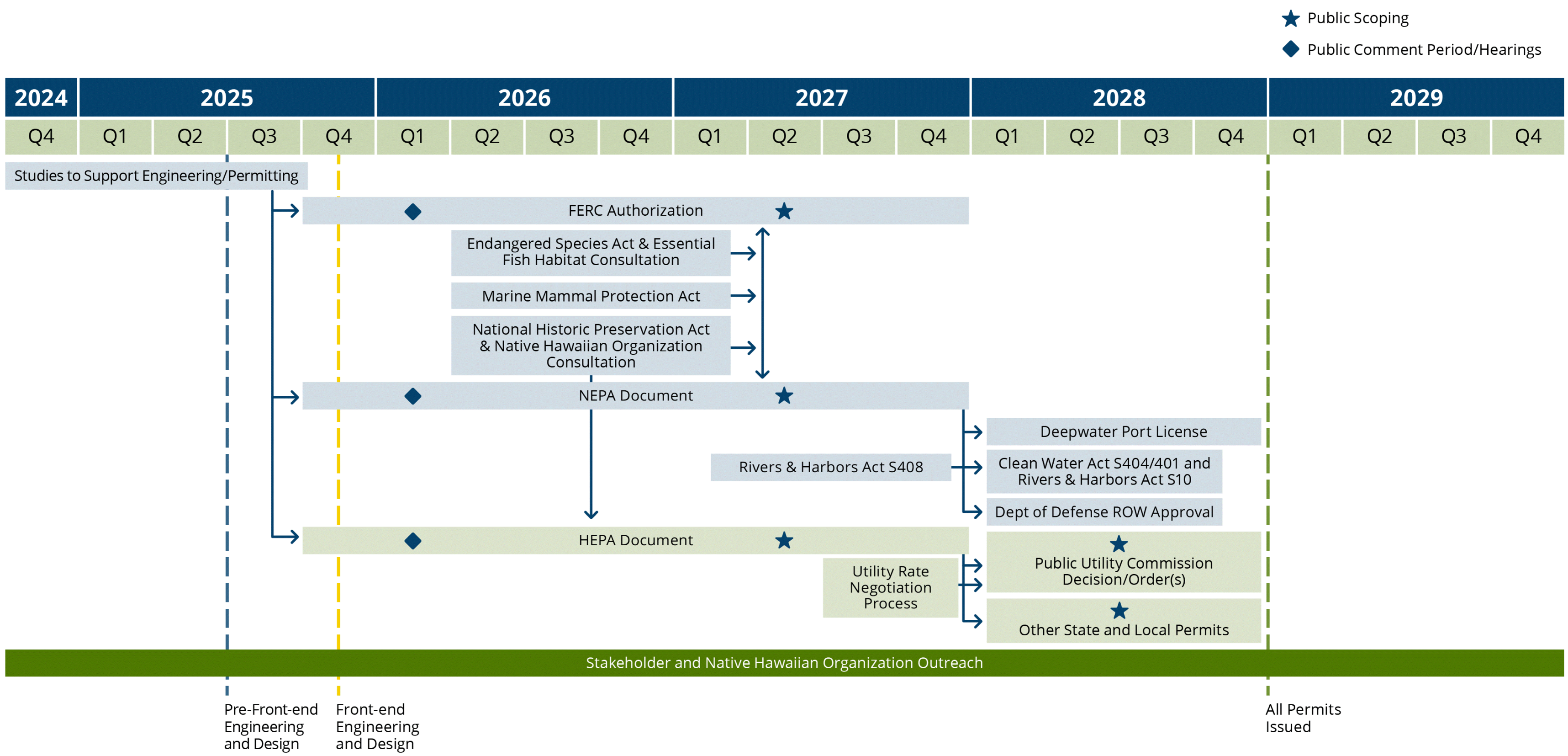

Figure 21. *Permitting timeline for major approvals with long lead times*

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 ‘i 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).

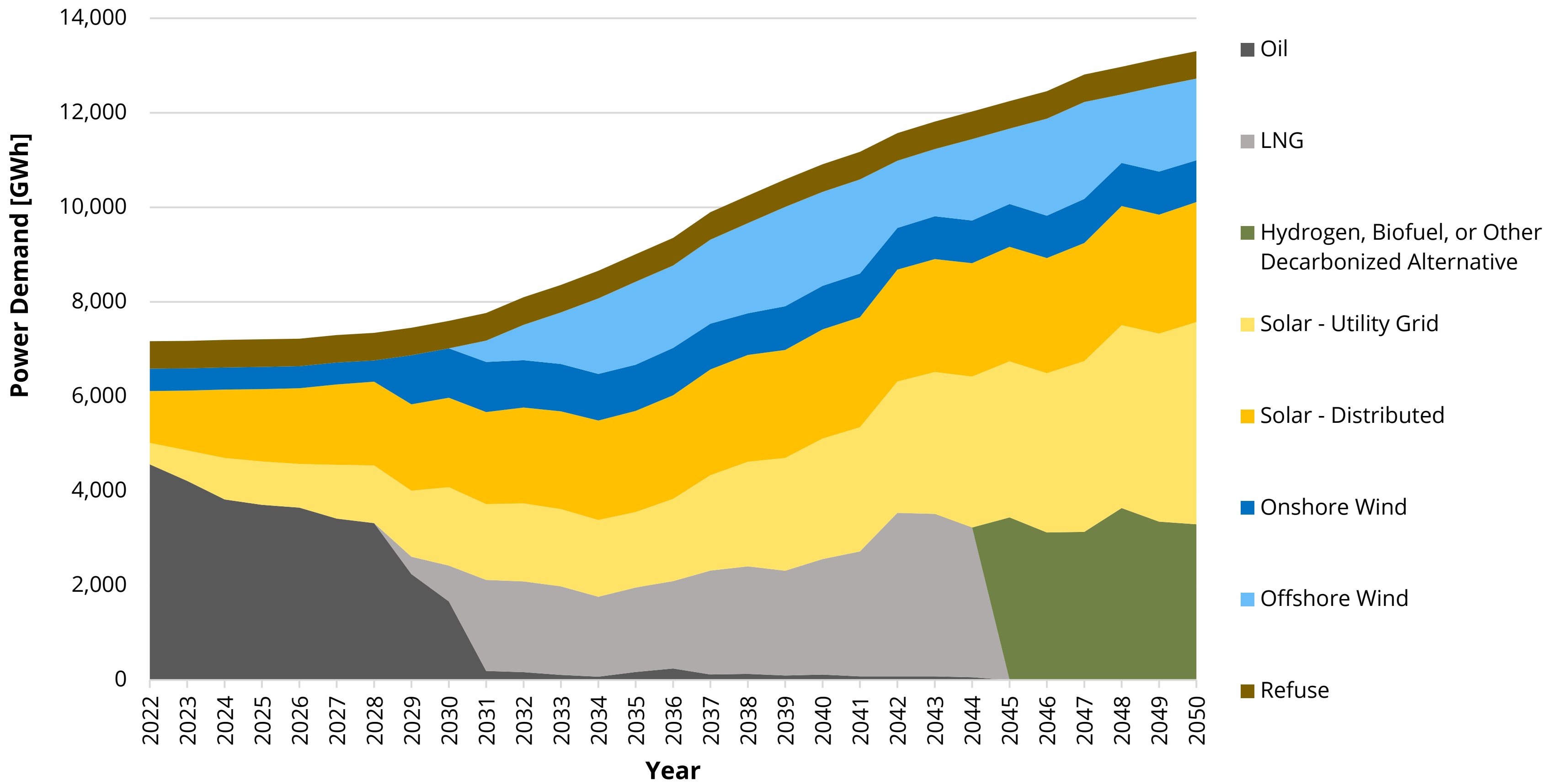

Figure 22. *Oʻahu future power demand by generation technology under a bridge fuel transition.*

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