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ISSUE BRIEF

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Review of the Hartley/Roberts Report, *Hawai'i's Electricity Future: Three Findings on Solar Reform, Enhanced Geothermal, and the JERA LNG Proposal*

I. Executive Summary

The Hartley/Roberts report should not be relied upon as a basis for major electricity-system planning decisions for O'ahu. Although the report presents a capacity-expansion analysis of Hawai'i's electricity future, its conclusions are not supported by the level of reliability, land-use, emissions, transmission, distribution, operational, and community-feasibility analysis required for an isolated island grid.

Hawai'i must accelerate clean energy deployment, including distributed solar and storage, responsibly sited utility-scale solar and storage, and energy efficiency, demand response, and other clean resources. However, the Hartley/Roberts report reaches broad conclusions that are not adequately supported by the analysis presented. In particular, the report overstates what capacity-expansion modeling can prove without corresponding resource adequacy, production cost, transmission, distribution, land-use, interconnection, and system-security analysis.

This Issue Brief does not comment on the geothermal or jobs sections of the Hartley/Roberts report.

The report's most serious flaws are:

1. **The land-use assumption is unrealistic.** The report's centerpiece assumption of installing more than 5,000 MW of utility-scale solar across O'ahu is not a minor modeling assumption; it would represent a massive land-use transformation of the island.
2. **The reliability analysis is inadequate.** The report relies on a limited set of sample days and does not fully test multi-day renewable droughts, storm conditions, generator outages, transmission contingencies, distribution constraints, or other emergency conditions that are central to island-grid reliability.

3. **The counterfactual is flawed.** The report appears to treat JERA LNG as additive to Waiau Repower in key scenarios, rather than fully testing whether JERA could replace Waiau Repower, reduce or eliminate reliance on the Kahe and Waiau powerplants, or accelerate retirement or allow fuel switching for older LSFO-burning units.
4. **The report underplays the problem of continued reliance on HECO's existing firm fleet.** A “no new thermal” case that depends on aging, inefficient, LSFO-burning units is not necessarily cleaner, cheaper, or more reliable in practice.
5. **Major emissions claims are insufficiently supported.** The report makes significant claims about emissions impacts without providing sufficient transparent dispatch, fuel, heat-rate, lifecycle-emissions, and retirement assumptions.
6. **The report overstates what wheeling and soft-cost reform can solve.** A PUC wheeling decision will not, by itself, resolve landowner willingness, permitting, community opposition, interconnection studies, project financing, litigation risk, or utility-scale RFP design.
7. **The report does not adequately address distributed energy resources as a central alternative.** A more equitable and resilient pathway should place greater emphasis on rooftop solar, parking canopy solar, distributed batteries, demand response, grid-interactive loads, community solar, virtual power plants, conservation, energy efficiency, and rate design.

Its conclusions regarding “no new combined-cycle beyond Pu‘uloa,” rejection of JERA LNG, and feasibility of a massive utility-scale solar buildout are not sufficiently supported by transparent assumptions and modeling, reliability studies, land-use analysis, dispatch data, and independent validation.

II. Land Use: The Central Solar Assumption Is Deeply Flawed

The Hartley/Roberts report's centerpiece assumption of installing 5,243 MW of utility-scale solar on 31,500 acres on O‘ahu is deeply flawed and raises questions about the feasibility, realism, and validity of the analysis. Merely identifying land as “developable” does not make it socially, environmentally, culturally, or politically available for utility-scale energy development.

Screened acreage is not the same as developable acreage. After landowner willingness, agricultural policy, cultural resources, habitat, drainage, slope, access roads, interconnection, substations, community acceptance, litigation risk, and permitting are accounted for, the usable acreage could be much lower. The Hartley/Roberts report

appears to treat the hardest constraint in Hawai‘i as though it were a secondary implementation issue.

Land use is not a minor implementation detail in Hawai‘i; it is often the central constraint. O‘ahu has limited land, competing needs for agriculture, housing, conservation, cultural resources, watershed protection, and community priorities, and a long history of uneven siting burdens. Any serious clean energy pathway needs to account for those realities.

The cancelled 15 MW Paeahu Solar project in South Maui illustrates that even much smaller solar-plus-storage projects can face serious siting, community, litigation, and implementation risks. Paeahu Solar was proposed with a 60 MWh battery system on approximately 200 acres leased from ‘Ulupalakua Ranch and was expected to serve approximately 6,900 Maui households, but Hawaiian Electric and Innergex ultimately cancelled the project after lengthy delays due to legal challenges and sustained opposition from some residents.

Community opposition is not unusual for large land-intensive renewable energy projects in Hawai‘i, particularly where projects affect open space, agricultural lands, cultural resources, view planes, drainage, wildlife concerns, or communities that already feel overburdened by infrastructure siting. The proposal discussed in the Hartley/Roberts report would require utility-scale solar development on a vastly larger scale — more than 5,000 MW across 31,500 acres on O‘ahu — across essentially every area the authors identify as suitable for solar parcels, including Wai‘anae, the Central Plain, ‘Ewa, windward O‘ahu, and other parts of the island that appear, based on the report’s maps, to include certain beach parks, stream beds, and densely forested areas deep in the island’s valleys.

Consider that O‘ahu currently has about 357 MW of utility-scale solar compared with 2,984 MW of total installed capacity. Scaling to more than 5,000 MW of utility-scale solar would represent an enormous land-use transformation, not simply a technical substitution for fossil generation. Hawai‘i’s energy strategy recognizes and embraces the essential role for more solar, but it must transparently address the land-intensive nature of utility-scale solar, especially on O‘ahu.

The Hartley/Roberts report should also clarify whether the acreage calculation is based on MWdc or MWac. DC:AC ratio, fixed-tilt versus tracking design, capacity density, MWh output per acre, and interconnection capacity all materially affect the land requirement. A mismatch between MWac modeling and MWdc land-density assumptions could materially understate acreage.

III. Flawed Assumptions and Methods

A. Capacity expansion is not a substitute for integrated resource planning.

The Hartley/Roberts report overstates what its modeling can prove. Capacity-expansion modeling can identify potentially lower-cost portfolios under a defined set of assumptions. It cannot, standing alone, prove that a high-renewable island grid can operate reliably under real-world conditions.

For O‘ahu, the relevant question is not merely which resource mix minimizes modeled system cost. The question is whether the portfolio can maintain service during multi-day cloudy and low-wind periods, generator outages, transmission failures, distribution constraints, storm recovery, and emergency conditions.

O‘ahu cannot lean on neighboring balancing areas. Frequency response, contingency response, ramping, minimum generation, grid-forming capability, black start, storm recovery, and multi-day low-renewable events matter more than they do in large, interconnected electricity systems such as those on the continent.

The Hartley/Roberts reliability analysis is too narrow. It relies on a limited set of sample days and does not fully test week-long renewable droughts, storm conditions, fuel-supply disruptions, generator outages, or major transmission contingencies. That limitation goes directly to whether the report’s “no new combined-cycle beyond Pu‘uloa” conclusion is valid.

B. The report does not adequately evaluate reliability and resilience.

Another flaw is that reliability and resilience are not adequately evaluated in the Hartley/Roberts analysis. O‘ahu absolutely needs to accelerate clean energy deployment, including stronger policy and rate incentives for distributed solar, storage, demand response, and responsibly sited utility-scale solar. But the grid also needs resources that can maintain service during prolonged cloudy weather, storms, transmission or distribution outages, and other emergency conditions.

A clean energy transition that relies heavily on variable solar generation must still address the need for firm, flexible, and resilient resources that can support the system when solar output is low for extended periods. The Hartley/Roberts report does not sufficiently address the need for firm, flexible capacity during extended low-renewable periods, including periods when solar and wind output may be low for multiple consecutive days. Prior technical work by General Electric, HNEI, Hawaiian Electric, and others has emphasized that these conditions are material to Hawai‘i grid planning.

The report does not fully test multi-day climate stress, transmission constraints, local siting constraints, or detailed distribution hosting capacity. For O‘ahu, those are not academic sensitivities. They are core planning requirements.

C. The report uses the wrong counterfactual.

The Hartley/Roberts report appears to treat JERA LNG as an added resource layered on top of Waiau Repower in key scenarios. That is not the intent of the JERA plan. Relevant scenarios would test whether JERA’s 500 MW high-efficiency power plant fully replaces Waiau Repower, reduces reliance on or eliminates entirely Kahe and Waiau power plants, supports retirement of older LSFO units, and changes the timing and cost of firm-resource needs identified in Hawaiian Electric’s Integrated Grid Plan.

If the “no new combined-cycle” case depends on continued availability of old, inefficient thermal units with known maintenance, outage, minimum-load, and reliability constraints, then it may understate both cost and reliability risk. A proper integrated resource plan comparison should clearly show what units retire, what units remain available, what new resources are added, and how each portfolio meets reliability criteria.

This is a fundamental flaw. The Hartley/Roberts report strongly criticizes LNG as unnecessary, but its alternative may depend on preserving the existing LSFO fleet as a reliability backstop. That is not a clean or risk-free counterfactual.

D. The report underplays continued reliance on LSFO and HECO’s aging firm fleet.

The Hartley/Roberts “no new combined-cycle” case is not the same thing as a no-fossil or low-risk firm-capacity pathway. It appears to rely on HECO’s existing firm units remaining available in the background while solar and batteries expand. That matters because existing LSFO-burning units are aging, relatively inefficient, emissions-intensive, and subject to maintenance, outage, minimum-load, and operational constraints.

A planning analysis should not treat existing thermal capacity as a free or uncomplicated reliability bridge. It should disclose, by unit, the assumed retirement dates, availability, outage rates, heat rates, minimum generation levels, ramp rates, maintenance costs, fuel costs, emissions rates, and operating constraints. It should also test whether continued reliance on those units is consistent with reliability, emissions, cost, and statutory clean-energy objectives.

The Hartley/Roberts critique of LNG is incomplete unless it also confronts the weaknesses of the alternative on which it relies: continued use of LSFO-fired generation and existing firm resources. An outcome that avoids new thermal investment but keeps old LSFO units

available for reliability may look cheaper in a model while shifting risk to reliability, maintenance, emissions, and emergency operations.

E. The report relies on incorrect assumptions about JERA's cost and payback structure.

The Hartley/Roberts report appears to rely on incorrect or insufficiently documented assumptions regarding JERA's cost and payback structure. Based on information currently available to HSEO, the JERA capital cost is understood to be approximately \$2 billion with the power plant and gas import facilities included, not \$2.4 billion plus additional LNG import facilities. The Hartley/Roberts report should clearly document the cost basis it used. If the report assumes \$2.4 billion plus separate LNG import facilities, that could represent roughly a 30 percent overestimation and would materially bias the result against JERA.

The JERA 500 MW + LNG plan also should not be characterized as a 20-year payback for the entire infrastructure. The LNG-associated infrastructure appears to have a less-than-five-year payback, while the 20-year horizon applies to the majority of the plan — the 500 MW high-efficiency power plant — that could restore long-term system reliability to O'ahu and may be capable of running on biodiesel, renewable natural gas, or hydrogen to meet Hawai'i's RPS law.

The Hartley/Roberts report should not make definitive claims about JERA's economics unless the capital-cost stack, ownership structure, cost recovery, fuel contract, payback assumptions, and fuel-flexibility assumptions are clearly disclosed and tested.

F. Outdated Solar Procurement Data May Undermine the Report's Cost Conclusions

The report's total system cost results are highly sensitive to assumed solar and battery costs, which is a critical limitation given the central role those assumptions play in the analysis. The report itself states that, at its baseline cost basis, total 2027–2050 system cost is approximately \$24.7 billion, but rises to \$28.0 billion if solar and battery costs are 50 percent higher and \$28.8 billion if they are 70 percent higher. The report further states that each additional 10 percentage points of solar cost adds roughly \$700 million to total system cost between the baseline and 1.5x multiplier, and roughly \$400 million per 10 percentage points above that. In other words, the report's headline least-cost conclusions are not a minor function of solar and battery pricing assumptions; they are materially dependent on them. The report's own framing that solar and battery procurement reform is a roughly \$3.4 billion lever reinforces that the modeled results are highly exposed to whether the assumed solar and storage cost trajectory is realistic for O'ahu.

This sensitivity is especially concerning because the report appears to rely, at least in part, on stale cost evidence from Hawaiian Electric’s Stage 1 RFP projects rather than treating more recent Stage 3 procurement results as the operative benchmark for current market conditions. The report acknowledges that the \$0.08 to \$0.12/kWh pricing range reflects Stage 1 awards from 2018–2019, while Stage 3 O’ahu solar-plus-storage awards approved in 2024–2025 came in at approximately \$0.21 to \$0.23/kWh for predominantly four-hour configurations—roughly two to nearly three times the Stage 1 range. Although the report characterizes this escalation as evidence of soft-cost inflation rather than a change in underlying fundamentals, the practical effect is that current delivered project costs in Hawai‘i are far above the low-cost assumptions that drive the report’s modeled savings. A least-cost plan for O’ahu should not treat outdated Stage 1 pricing as representative of deployable near-term resources without a more rigorous demonstration that procurement, interconnection, permitting, financing, and siting reforms can actually bring Stage 3-era costs down to the assumed levels within the modeled timeframe.

G. Limited Land-Cost Evidence Does Not Support Systemwide Conclusions

The report’s reliance on a small number of University of Hawai‘i solar RFPs and confidential lease agreements is not a sufficient basis for concluding that land costs are immaterial to utility-scale solar deployment on O’ahu. Those examples may show that certain public or institutionally controlled parcels can be leased at competitive ground-rent rates, but they do not establish that similar terms would be available across the thousands of acres and hundreds of privately and publicly controlled parcels needed to support the report’s modeled utility-scale buildout. Ground rent on a few selected parcels is not the same as the full marginal cost of acquiring, permitting, interconnecting, and socially licensing tens of thousands of acres of solar development.

This distinction matters because the report’s own land-use discussion acknowledges that practical constraints include landowner willingness, community acceptance, cultural and environmental review, agricultural-land policy, transmission proximity, distribution-level hosting capacity, and litigation risk. Those constraints can affect project cost even if nominal ground rent appears low. A credible land-cost analysis would need to evaluate parcel-specific ownership, lease terms, agricultural opportunity costs, community-benefit or mitigation costs, interconnection and transmission costs, permitting risk, and the likelihood that landowners will demand higher compensation as the buildout approaches the limits of available developable land. A few UH RFPs do not provide that systemwide evidence.

H. The report overstates wheeling as a solution to solar costs.

The Hartley/Roberts report implies that retail wheeling could address much of Hawai'i's solar cost premium. That claim is weak. A PUC wheeling decision would not, by itself, solve permitting delays, landowner willingness, community opposition, HECO interconnection studies, utility-scale RFP design, project financing, customer-acquisition costs, litigation risk, or site control.

Many of the causes the report identifies for high solar costs occur outside the PUC wheeling docket. The report therefore appears to assign too much causal weight to wheeling while underweighting the actual institutional, land-use, permitting, interconnection, and community-acceptance barriers that delay or prevent projects.

IV. Lack of Supporting Data and Analysis for Major Claims

A. The emissions claims are not adequately supported.

The Hartley/Roberts report makes major emissions claims without sufficient transparent support. It claims JERA LNG would increase cumulative power-sector emissions by about 34 percent, displace about 430 MW of solar and 6,500 MWh of battery storage, and reduce 2050 renewable generation from 87 percent to 75 percent. The report should disclose the calculations and assumptions in far greater detail to demonstrate that such consequential conclusions are supported by fact.

The report should account for the wide range of lifecycle emissions associated with biofuels. Biofuels are not uniformly low-carbon simply because they are labeled “renewable”; emissions vary significantly based on feedstock, fertilizer use, land-use change, processing energy, transportation, methane and nitrous oxide emissions, and whether the fuel is waste-derived or crop-based.

This matters because the report's conclusions about future thermal resources may depend on assumed use of renewable fuels or biodiesel. For example, a waste-oil-based fuel could have very different lifecycle emissions than a crop-based fuel imported to Hawai'i. Any finding that continued operation of firm thermal units on renewable fuel is compatible with deep decarbonization should therefore be supported by fuel-specific lifecycle emissions assumptions, including feedstock source, carbon intensity, supply chain, land-use-change treatment, and high- and low-emissions sensitivity cases.

At minimum, the report should provide:

- annual dispatch by generator, fuel, and scenario;
- heat rates by unit and year;
- cumulative CO₂ and CO₂e emissions by scenario;

- lifecycle emissions for LNG, LSFO, biodiesel, renewable diesel, hydrogen, biomass, and H-Power
 - Note: The report falsely reports that H-power is “zero carbon baseload.” In 2023, H-Power had 378,136 tons of CO2 equivalent emissions according to [EPA eGrid data](#).
- methane leakage assumptions;
- upstream production and shipping emissions;
- liquefaction and regasification emissions;
- post-2045 fuel assumptions;
- assumed retirement dates for Kahe, Waiau, and other firm units;
- the dispatch volumes driving the 34 percent emissions claim.

Without that information, the emissions conclusion should be treated as unsupported. The report should not compare LNG against a modeled solar-heavy counterfactual while ignoring whether LNG could replace older LSFO resources, enable earlier retirement, or reduce dispatch from more polluting units.

B. LNG should not be evaluated only as a fuel switch against static LSFO generation.

LNG should not be evaluated only as a fuel switch against static LSFO generation. It should be evaluated as part of a portfolio that may retire older oil units such as Waiau and Kahe, reduce or increase fossil dispatch, interact with renewable buildout, and potentially support broader energy-system uses.

If LNG is modeled as additive to existing firm resources and subject to take-or-pay dispatch, it will predictably look worse. But that does not answer the more relevant planning question: whether a modern, high-efficiency, fuel-flexible plant with LNG infrastructure could replace or reduce reliance on older, dirtier, less reliable LSFO units while supporting a higher-DER, more resilient grid.

C. Solar and battery lifecycle costs need more scrutiny.

The Hartley/Roberts report relies heavily on solar plus storage, but it does not clearly address solar degradation, inverter replacement, battery degradation, battery augmentation, battery replacement, usable versus nameplate capacity, or end-of-life costs.

That matters because a portfolio with thousands of MW of solar and thousands of MWh of batteries through 2050 will have major lifecycle replacement and augmentation needs. If batteries are modeled as remaining fully available without degradation or replacement

costs, the model may understate the lifecycle cost of the solar-plus-storage pathway relative to firm generation alternatives.

V. The Report Underweights DER and More Equitable Alternatives

The Hartley/Roberts report under develops a key solution under review by HSEO to expand distributed energy resources, as highlighted in Governor Green's Executive Order 25-01. The State is looking to solutions that are more equitable, reliable, resilient, and acceptable to affected communities.

A more credible clean-energy pathway for O'ahu should place greater emphasis on:

- conservation
- energy efficiency
- advanced dynamic rate design
- rooftop solar
- parking canopy solar
- distributed batteries
- grid-interactive water heating
- managed EV charging
- demand response
- virtual power plants
- community solar
- public facility solar and storage
- resilience hubs
- responsible utility-scale solar outside of tsunami zones and where land-use conflicts are manageable.

The report's visual and modeling emphasis on very large amounts of land-based utility-scale solar risks presenting a pathway that is politically, culturally, and physically unrealistic on O'ahu.

VI. Questions for Further Review

Land use and solar feasibility

1. Is the 31,500-acre estimate based on MWac or MWdc?
2. What DC:AC ratio was assumed for utility-scale solar?
3. What capacity density was used for fixed-tilt versus tracking systems?
4. How much land would be required if O'ahu-specific MWdc-per-acre assumptions are used?

5. How much of the screened acreage is actually developable after landowner willingness, cultural resources, habitat, agricultural policy, slope, drainage, access roads, interconnection, permitting, and litigation risk?
6. How many individual parcels would be needed to reach 5,243 MW of utility-scale solar?
7. How many separate land leases, permits, community processes, and interconnection studies would that require?
8. How much of the mapped acreage overlaps with gulches, stream corridors, steep slopes, high ridges, drainage areas, agricultural lands, or culturally sensitive areas?
9. How would the results change if available utility-scale solar land were reduced by 25 percent, 50 percent, or 75 percent?
10. How would the preferred portfolio change with much higher reliance on rooftop solar, parking canopy solar, distributed storage, and VPPs?

Reliability and resilience

11. Why are 13 sample days from 2007–2008 sufficient for O‘ahu reliability planning?
12. Has the portfolio been tested against a week-long low-solar/low-wind event?
13. Has the portfolio been tested against Kona lows, storm conditions, wildfire events, fuel-supply disruptions, or simultaneous generator/transmission contingencies?
14. What probabilistic resource adequacy standard was applied?
15. What are the LOLE, EUE, and ELCC assumptions?
16. What forced-outage rates were assumed for existing thermal units?
17. Does the model include N-1 transmission contingency performance?
18. Does the model include black start, grid-forming inverters, fault current, voltage support, inertia or synthetic inertia, and fast frequency response?
19. What storage durations are assumed, and are batteries modeled as nameplate or usable capacity?

Existing firm fleet and LSFO reliance

20. Which Kahe and Waiau units remain online in each scenario?
21. What retirement dates are assumed for Kahe, Waiau, CIP, and other firm resources?
22. How much LSFO is burned each year in each scenario?
23. What minimum generation constraints are assumed for the existing firm fleet?
24. What maintenance and outage risks are assumed for aging LSFO-fired units?
25. How would results change if Kahe retired earlier?
26. How would results change if older Waiau units retired earlier?
27. How would results change if existing firm units had lower availability or higher maintenance costs?

JERA and Waiau counterfactuals

28. What happens if JERA replaces Waiau Repower rather than being added to it?
29. What happens if JERA enables earlier retirement of Kahe and Waiau units?
30. What happens if JERA is modeled as a fuel-flexible power plant capable of biodiesel, renewable natural gas, or hydrogen operation?
31. What capital cost did the Hartley/Roberts report assume for the JERA plant?
32. Did the report assume \$2.4 billion plus additional LNG import facilities, or approximately \$2 billion including the plant and import facilities?
33. What payback assumption was used for LNG-associated infrastructure?
34. What payback assumption was used for the power plant portion?
35. How would correcting the JERA capital-cost assumption affect the system-cost comparison?

Emissions and lifecycle analysis

36. What dispatch volumes drive the 34 percent cumulative emissions increase claim?
37. Are the emissions estimates power-sector CO₂ only, or lifecycle CO₂e?
38. How are methane leakage, liquefaction, regasification, and shipping emissions modeled for LNG?
39. How are upstream, refining, shipping, and combustion emissions modeled for LSFO?
40. How are biodiesel, renewable diesel, hydrogen, biomass, and H-Power emissions modeled?
41. What post-2045 fuels are assumed for each firm resource?
42. Does the report count H-Power as renewable or zero-carbon, and if so, why?
43. How would emissions change if LNG enabled earlier LSFO unit retirements?

Customer bills, affordability, and rate impacts

44. What are the estimated residential, commercial, industrial, and government-customer bill impacts under each scenario?
45. Are cost impacts evaluated on a total-system-cost basis, revenue-requirement basis, customer-rate basis, or all three?
46. How are stranded costs, accelerated retirements, fuel-price risk, and new transmission and distribution investments reflected in customer bills?
47. How are low- and moderate-income customers affected under each modeled pathway?
48. Does the report evaluate whether the solar-heavy pathway shifts costs between customers with DER access and customers without DER access?

Cost, wheeling, and data transparency

49. Is the 20 percent Hawai'i premium applied uniformly across all technologies?
50. What O'ahu-specific evidence supports the assumed utility-scale solar premium?
51. What exact reforms are assumed to reduce solar costs?
52. Which of those reforms are actually within the PUC wheeling docket?
53. What wheeling compensation structure and project-size assumptions are used?
54. Were T&D upgrades quantified, and if so, how much do they cost by scenario?
55. When will the full model files, inputs, assumptions, and dispatch outputs be released?
56. Can reviewers verify scenario tags, forced builds, retirements, fuel constraints, emissions factors, and output tables?

VII. Conclusion

The Hartley/Roberts report is not sufficiently reliable to support its strongest conclusions. It uses a simplified modeling framework to make broad claims about O'ahu's electricity future while failing to fully account for land-use constraints, island-grid reliability, continued dependence on LSFO-fired units, transmission and distribution deliverability, community acceptance, lifecycle emissions, and customer-bill impacts.

The report's most problematic conclusion is that O'ahu can avoid new firm thermal capacity beyond Pu'uoloa while relying on a massive buildout of utility-scale solar and batteries. That conclusion may be true only within the model's assumptions. It is not proven under real-world O'ahu conditions unless validated through resource adequacy, production-cost, transmission, distribution, system-security, land-use, and community-feasibility analysis.

HSEO concludes that Hawai'i is better served by accelerating clean energy deployment consistent with current policies, executive orders and strategies, not through an unrealistic land-intensive pathway or an under-tested reliability framework as proposed in the Hartley-Roberts report. A serious plan should prioritize DER, conservation, efficiency, rooftop and parking canopy solar, distributed storage, demand response, responsible utility-scale solar, and firm low-carbon resources that reduce dependence on aging LSFO units while maintaining reliability during the conditions that matter most.