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Making an Optimal Plan for 100% Renewable Power in Hawaii - Preliminary Results from the SWITCH Power System Planning Model

BY

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Introduction

In November 2015, the Hawaii Public Utilities Commission (PUC) requested that the HECO Companies file plans to revise their Power Supply Improvement Plans (PSIPs) by November 25. The PUC also requested that parties in the PSIP proceeding submit responses to the PSIPs, the PUC's observations and concerns, and the HECO Companies' revision plans by January 15, 2016.[1] I am submitting this white paper in partnership with Blue Planet Foundation in response to this request for comments.

The central purpose of the Power Supply Improvement Plan (PSIP) process, and before it the Integrated Resource Plan (IRP) process,[2] is to induce the HECO Companies to develop an optimal plan for meeting the State's energy needs and renewable energy goals over the coming decades.

The HECO Companies have made significant progress toward this goal, assembling and publishing data on the cost and capabilities of potential renewable and conventional energy projects.[3] Other data on HECO's existing power plants and potentially useful technologies are also available in the public domain.[4]

However, it appears that current planning efforts, such as those evidenced in the PSIPs, lack the tools needed to design an optimal generation portfolio for the Hawaiian islands based on this information. In this document I present a model designed for exactly this purpose – to identify an optimal portfolio of power system technologies in order to achieve policy goals, while maintaining a reliable supply of power, at the lowest cost. I also discuss the outlines of an optimal plan for reaching 100% renewable power on Oahu based on early work with this model, and identify several issues that will need particular attention in order to move efficiently toward the State's 100% renewable target. I also briefly address the question of how a tool like this could be used in the planning and regulatory process.

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[1] Order 33320 of docket 2014-0183, November 4, 2015.

[2] Dockets 2014-0183 and 2012-0036

[3] HECO, "Integrated Resource Plan Appendix K: Supply-Side Resource Assessment," Hawaii Energy Industries, Jun. 2013; HECO, "Hawaiian Electric Power Supply Improvement Plan," Hawaiian Electric Company, Honolulu, Hawaii, Aug. 2014; and Galway, "Integrated Resource Plan Appendix N: LNG Imports to Hawaii Study," Galway Advisors for Hawaii Energy Industries, Jun. 2013.

[4] e.g., GE Energy, "Hawaii Solar Integration Study: Final Technical Report for Oahu," Prepared for the National Renewable Energy Laboratory, Hawaii Natural Energy Institute, Hawaii Electric Company and Maui Electric Company, Apr. 2012; D. Corbus, M. Schuerger, L. Roose, J. Strickler, T. Surles, D. Manz, D. Burlingame, and D. Woodford, "Oahu Wind Integration and Transmission Study: Summary Report," National Renewable Energy Laboratory, Golden, Colorado, Nov. 2010; and EPRI, "Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits," Electric Power Research Institute, Palo Alto, Calif., 1020676, 2010.

This analysis yields several important findings:

- A 100% renewable energy target can be achieved using established technologies at a reasonable cost.
- EVs and other forms of flexible load will play a large role in grid optimization – much larger than reflected in the current PSIPs. These must become a core part of the sustainable utility business model. Integrating renewable power on a 100% scale will require sustained, intensive coordination between customers and operators of generation and storage (who may be other customers). This cannot be achieved via direct load control by the utility alone. The sustainable utility business model must move rapidly toward shifting load through economic incentives, so that customers can choose their own optimal plans based on dynamically varying system conditions, and in turn aid the system in adapting to these conditions.
- The HECO Companies should use a long-term optimal capacity model such as the open-source SWITCH model described here to select a least-cost portfolio to meet the state's needs. If the HECO Companies are not willing to do this, then I recommend that stakeholders work together to agree on assumptions, then use SWITCH to develop one or more "community plans", which HECO can use as a benchmark for their own plans.
- Even at current electrolysis and storage costs, hydrogen is a technology that should be closely evaluated for inclusion into the utility plans.

SWITCH Power System Planning Model for High-Renewable Power Systems

SWITCH is open-source software designed to choose optimal generation and transmission portfolios for high-renewable power systems over multi-decade periods. (SWITCH is a rough acronym for "solar, wind, hydroelectric and conventional generation and transmission model".)

SWITCH is a mixed-integer linear-programming model. Its objective is to minimize discounted, levelized costs of electricity production across the study period. The main decision variables (values chosen by the model) are the amount of capacity to add at various candidate project sites over the course of the study, and the amount of power to produce or store at each project site during each hour of the study. Constraints require that the power system provide adequate power and reserves during all hours, and also that it meet any exogenous policy goals such as a Renewable Portfolio Standard (RPS).

I wrote SWITCH as part of my Ph.D. research at the University of California, Berkeley, in 2005-08, and then released it as open-source software. It was first used to study the cost of achieving high renewable penetrations in California,[5] and it has subsequently been used by other researchers to model transitions toward renewable power in a number of regions, including the entire Western Electricity Coordinating Council (WECC) region,[6] Japan,[7] Chile[8] and Nicaragua.[9] In the past three years, my research group at the University of Hawaii, Manoa, has also begun using SWITCH to identify optimal paths toward 100% renewable power in Hawaii.[10] All source code for the SWITCH model and the Hawaii datasets are available to the public at http://www.switch-model.org. They are free of cost and users are invited to recommend changes to the model or data.

SWITCH can be thought of as a hybrid between two classes of model commonly used in electric utility planning: it contains a similar amount of operational detail to production cost models such as GE MAPS or Plexos; but it also optimizes decisions about

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[5] M. Fripp, "Switch: A Planning Tool for Power Systems with Large Shares of Intermittent Renewable Energy," *Environmental Science & Technology*, vol. 46, no. 11, pp. 6371–6378, Jun. 2012

[6] J. Nelson, J. Johnston, A. Mileva, M. Fripp, I. Hoffman, A. Petros-Good, C. Blanco, and D. M. Kammen, "High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures," *Energy Policy*, vol. 43, pp. 436–447, Apr. 2012.

[7] Japan Renewable Energy Foundation, *personal correspondence*

[8] D. M. Kammen, R. Shirley, J. P. Carvallo, and D. P. de L. Barido, "Switching to Sustainability," *Berkeley Review of Latin American Studies*, Spring 2014.

[9] D. P. de L. Barido, J. Johnston, M. V. Moncada, D. Callaway, and D. M. Kammen, "Evidence and future scenarios of a low-carbon energy transition in Central America: a case study in Nicaragua," *Environ. Res. Lett.*, vol. 10, no. 10, p. 104002, 2015.

[10] P. Das, D. Chermakani, and M. Fripp, "Development of SWITCH-Hawaii Model: Loads and Renewable Resources," University of Hawaii at Manoa, Honolulu, Hawaii, Dec. 2014.

long-term capacity expansion, similar to capacity planning models like Ventyx Strategist or PowerSimm Planner.

This combination of operational detail and capacity optimization is essential for developing optimal plans for power systems that include large shares of renewable power, storage and/or demand response. Commercial capacity planning models are inadequate for this task because they do not contain enough chronological, hourly detail to identify when renewables may need to be curtailed and how inter-hour load shifting or energy storage would be used to reduce curtailment. Commercial production cost models can be used to analyze these effects, but they can only be used with generation portfolios that are selected via some other method and "locked in" before running the model. In a high-renewable context, there are too many technology choices for planners to be able to systematically identify optimal or near-optimal capacity portfolios to test in this way. By providing the operational detail of a production cost model and the optimization capability of a capacity planning model, SWITCH provides the "best of both worlds," making it possible to choose optimal capacity expansion plans for high renewable power systems. We are not aware of any other commercial or open-source models that provide this ability.

The open-source nature of SWITCH may also make it especially useful for planning in a multi-stakeholder context such as the IRP/PSIP process. Since the analytical methods are transparent, stakeholders need only agree on the input assumptions; then SWITCH can be used to identify the best path forward based on those assumptions. Alternatively, if future conditions are uncertain or stakeholders disagree about the input assumptions, SWITCH can be used to identify capacity portfolios that will perform well under a variety of future conditions.

Preliminary Results from Using SWITCH for the Oahu Power System

My research group at the University of Hawaii has worked over the last three years to build a version of SWITCH with data for the Hawaiian power systems. We are nearing completion of this work, and this paper discusses preliminary results. The work summarized below focuses on achieving an adequate energy supply for Oahu. Additional work is currently in progress to consider reserve requirements, neighbor-island power systems and the possibility of inter-island cables. Studying Oahu on its own gives a conservative estimate of the cost and technical requirements to reach 100% renewable power. It will be important to treat reserves explicitly, but it is worth noting that the power system designs discussed below already include a large share of flexible resources (demand response, batteries, biofuel and/or hydrogen plants), which should be able to provide the necessary reserves without radically changing the system design or costs relative to the work presented here.

Assumptions

For this work, most generation project costs are based on technologies described in Appendix K of the HECO Companies' 2013 IRP report.[11] To be conservative, we assume that renewable and fossil project costs remain constant in the future, rather than following historical trends (generally downward for renewable power). The cost of rooftop solar projects in the IRP report appear to be outdated, so we use newer estimates. Properties for the main types of new power project are shown in Table 1.

Table 1. Cost and characteristics of power generation technologies

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/kWh)	Lifetime (years)	Full-Load Heat Rate (Btu/kWh)
Central Tracking PV	$3,472	$34.43	$0.00	25	.
Distributed PV	$4,000	$0.00	$0.00	25	.
Wind Turbines	$3,510	$79.52	$0.00	20	.
Reciprocating Engine	$2,702	$10.14	$11.74	30	8,443
Simple Cycle Combustion Turbine	$2,800	$22.01	$12.22	30	10,112
Combined Cycle Combustion Turbine	$3,510	$63.78	$10.39	30	7,643

[11] HECO, "Integrated Resource Plan Appendix K: Supply-Side Resource Assessment," Hawaii Energy Industries, Jun. 2013.

The HECO Companies' fossil fuel cost projections have varied over the years and are inconsistent between the IRP and PSIP reports. They also include some implausible assumptions, such as biodiesel becoming cheaper than petroleum diesel in later years (this is unlikely because biodiesel can be used in all the same markets as diesel, as well as in some that are willing to pay more). Consequently, we developed new, simplfiied forecasts based on the U.S. Energy Information Administration's 2015 forecasts for coal, oil and natural gas prices, indexed to Hawaii costs based on recent experience. These are shown in Figure 1.

Figure 1 also shows costs for containerized LNG as-delivered to Oahu and bulk LNG excluding regasification costs, both based on HECO's PSIP report.[12] We assume that a bulk LNG terminal could be built or leased at a cost of $76 million/year and provide enough gas to generate an average of 600 MW of electricity year-round (600 MWa). This is equivalent to the "Dockside Fullsize FSRU" described in Appendix N of HECO's 2013 Integrated Resource Plan.[13] If fully utilized, this would add $1.75/MMBtu to the "LNG, bulk" cost shown in Figure 1. If less LNG is used, e.g., enough to generate 200 MWa, the cost per Btu will be proportionately higher, as shown by the "Bulk LNG @200 MWa" trace in Figure 1.

It should be noted that the work presented in this paper uses a single forecast of fossil fuel prices; further analyses should consider the realistic possibility of higher or lower fossil fuel prices, and that natural gas prices would move up along with oil prices in the future (they are good substitutes for many applications, so it appears unlikely that a wide gap in prices could persist for many decades). We are also enhancing SWITCH with the ability to choose portfolios that have low expected costs and/or low risk across a wide range of future fossil fuel cost forecasts. For now, we note that fuel cost projections affect SWITCH's choice of resources and power costs prior to 2045, but have only a small effect on the 2045 portfolios, which are the focus of this paper.

For the work reported here, we use the highest projection of EV adoption from the HECO Companies' 2013 IRP report, which assumes that the HECO Companies, policymakers and customers work together to achieve nearly universal EV adoption by 2045. We also use Hawaii's current RPS targets (30% by 2020, 40% by 2030, 70% by 2040 and 100% by 2045). Further, we assume that demand response measures can be used to reduce non-EV loads during any hour by 30%, and to reschedule that demand to some other hour of the same day (e.g., pre-chilling of ice-storage air conditioners or pre-heating of smart water heaters). Unless otherwise noted, we assume that all EV charging is scheduled for the best time of day. Weather in future years is represented by days sampled from 2007–08, using renewable resource data from the OWITS and HSIS studies and hourly load data from HECO's FERC Form 714 filings.

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[12] HECO, "Hawaiian Electric Power Supply Improvement Plan," Hawaiian Electric Company, Honolulu, Hawaii, Aug. 2014.

[13] Galway, "Integrated Resource Plan Appendix N: LNG Imports to Hawaii Study," Galway Advisors for Hawaii Energy Industries, Jun. 2013, p. N-65.

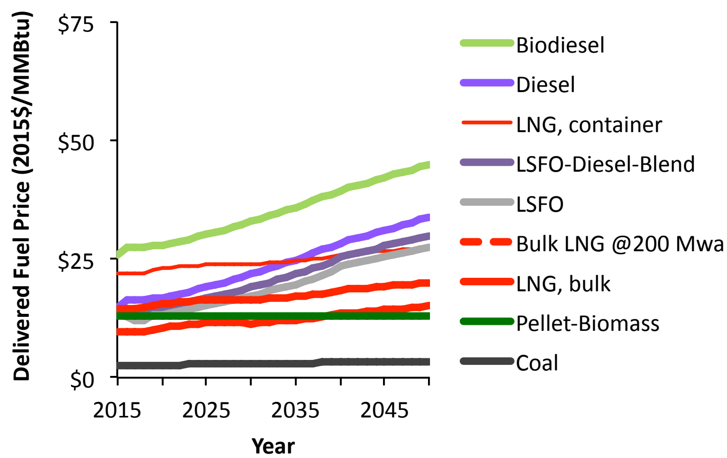


Figure 1. Reference fuel price forecasts for Oahu

All assumptions and forecasting methods are documented in the SWITCH repository at http://www.switch-model.org. We use these particular assumptions merely as a plausible starting point to help understand the issues that will be important in planning for a high-renewable future. We believe a stakeholder process can be used to refine, modify, and update assumptions to use for the HECO Companies' planning.

As currently configured for Hawaii, SWITCH produces optimal expansion plans for the Oahu power system for each of four investment periods (beginning in 2021, 2029, 2037 and 2045), as well as hourly operation of individual plants during sample days in each of these periods. In this white paper, we focus on the design and operation of the 100% renewable power system, as of 2045. In particular, we focus on the challenges of obtaining a satisfactory energy balance during all the hours of the day and all the seasons of the year.

Daily Energy Balance

Figure 2 shows hourly power production and consumption on Oahu during a typical day in 2045, with 100% renewable power. Some features of an optimal renewable plan are immediately apparent.

To obtain enough energy for the day, the least-cost portfolio found by SWITCH includes 1930 MW of solar resources and 440 MW of wind turbines, adding up to nearly double our current peak electricity demand. The solar resources in this scenario are primarily utility-scale, single-axis tracking PV systems, due to their assumed lower cost and better performance than rooftop solar power systems. Optimization models such as SWITCH tend to make "knife-edge" choices in favor of the cheapest technologies, even when multiple technologies are close in cost. As development potential, social acceptability, risk and siting difficulty of solar projects are considered further, it is possible that rooftop solar could emerge as a more attractive option, and the optimal plan could end up including a significant share of distributed solar instead of utility-scale solar. This may be more likely if the HECO Companies are unable to contract for utility-scale solar at a competitive price or if obstacles to distributed solar are relaxed and/or innovative financing mechanisms for distributed solar are available. Indeed, unrestricted power sales from distributed PV systems to the grid could serve as a valuable source of competition, driving HECO to obtain their own solar resources at a competitive cost or stand back and let customers provide the power. Since the timing and unit cost of rooftop solar production is similar to utility-scale solar production, such a shift would not be expected to have a radical effect on system costs or the rest of the portfolio design.

Although this scenario obtains only a small share of energy from wind power, this actually constitutes an ambitious wind build-out, with turbines placed on nearly all the windy sites on Oahu that are zoned for agricultural or country use. We anticipate that stakeholder discussions will be needed to judge the socially acceptable location and quantity of on-shore wind turbines. In addition, as information regarding potential offshore wind development becomes available, modeling assumptions will be updated, possibly shifting the optimal portfolio more in favor of off-shore wind.

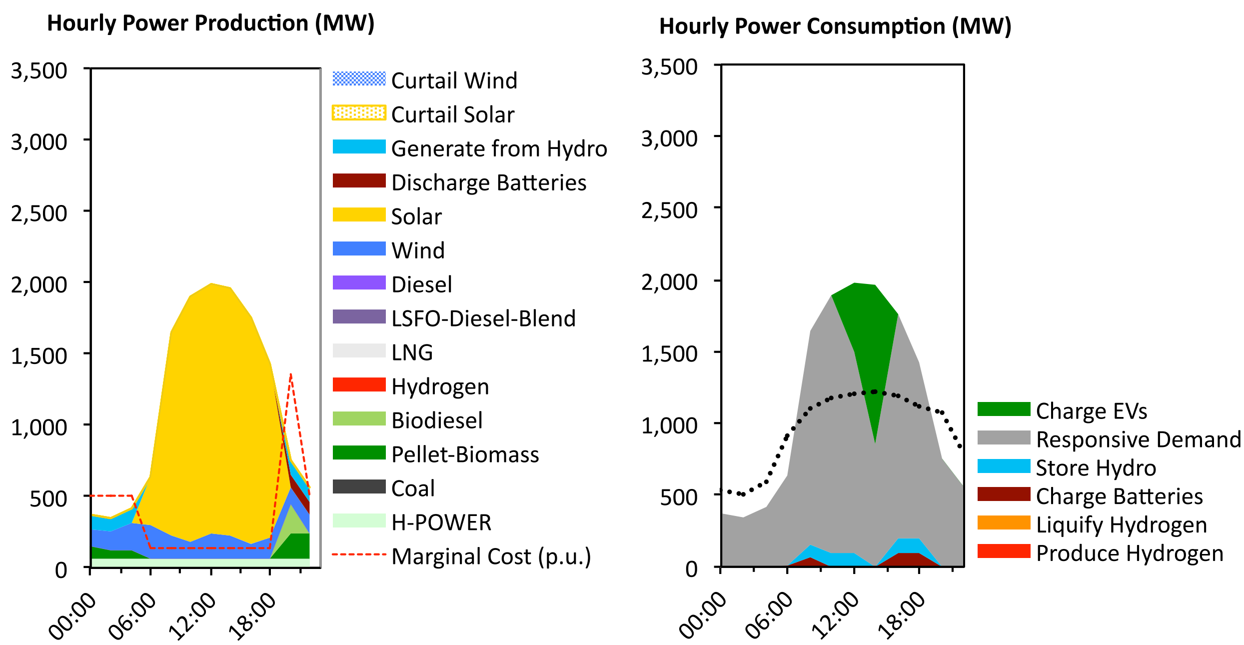


Figure 2. Hourly power production and consumption on Oahu during an April day in 2045, with 100% renewable power

It can be seen from Figure 2 that there is a significant mismatch between the timing of renewable production and the traditional electricity demand (dotted line on the "consumption" side of Figure 2). In this scenario, three key measures are used to achieve a satisfactory energy balance throughout the day:

(1) Electric vehicle (EV) charging and as much non-EV electricity demand as possible are rescheduled to the middle of the day (green and gray bands on

"consumption" side of Figure 2).[14] This creates a load profile that nearly matches the renewable production profile.

We anticipate that this load shifting can be achieved by setting hourly prices for power based on the marginal cost of production each hour, shown schematically as a dotted red line on the "production" side of Figure 2. We also note that customers could sell unrestricted quantities of power from distributed renewable or storage systems at these prices without creating a cross-subsidy. This would resolve most of the economic problems associated with net electricity metering.[15]

Compared to the scenarios included in this report, we found that electricity costs in 2045 will be about 20% higher if there is no demand response and electric vehicles are charged as a baseload (flat around-the-clock) instead of during sunny hours. Costs will be even higher if EVs charge primarily during the evening peak (a plausible business-as-usual assumption).

(2) Biofuels and the H-POWER facility are used during non-sunny hours to provide several hundred MW of additional power. (Note that the use of hydrogen instead of biofuels is evaluated below).

(3) About 200 MW of batteries and/or pumped storage hydro are charged during the day and then used to provide extra power during the evening and night.

Seasonal Energy Balance

Figure 3 shows the same information as Figure 2, but presents twelve different sample days in 2045 instead of just one. Obtaining enough renewable energy in each season of the year may be a greater challenge than obtaining enough in each hour of the day. In particular, there are days in the fall (October–December) with poor sunlight. For this analysis, we assumed that demand response, batteries and pumped storage hydro could only be used to shift energy within the same day. Consequently enough energy must be produced on each day to satisfy the total demand on that day. (This is a somewhat conservative assumption, but not completely unrealistic since, at current energy storage costs, we are unlikely to build many days' worth of batteries, and many demand response technologies will be unable to wait more than one day for service.) In this scenario, the energy shortfall on fall days is resolved by burning biofuel on a large

[14] In Figure 2, consumption alternates randomly between EVs and responsive demand during the day; this is because there are many possible ways to schedule loads during the day to achieve the desired overall profile, and SWITCH currently treats all of them as equally good. In practice, we would expect to see a smoother, more even split between EVs and non-EV demand response.

[15] M. Coffman, M. Fripp, M. J. Roberts, and N. Tarui, "Efficient Design of Net Metering Agreements in Hawaii and Beyond," University of Hawaii Economic Research Organization (UHERO), Aug. 2015.

– possibly unacceptable large – scale. (In a scenario below we consider the use of hydrogen instead.)

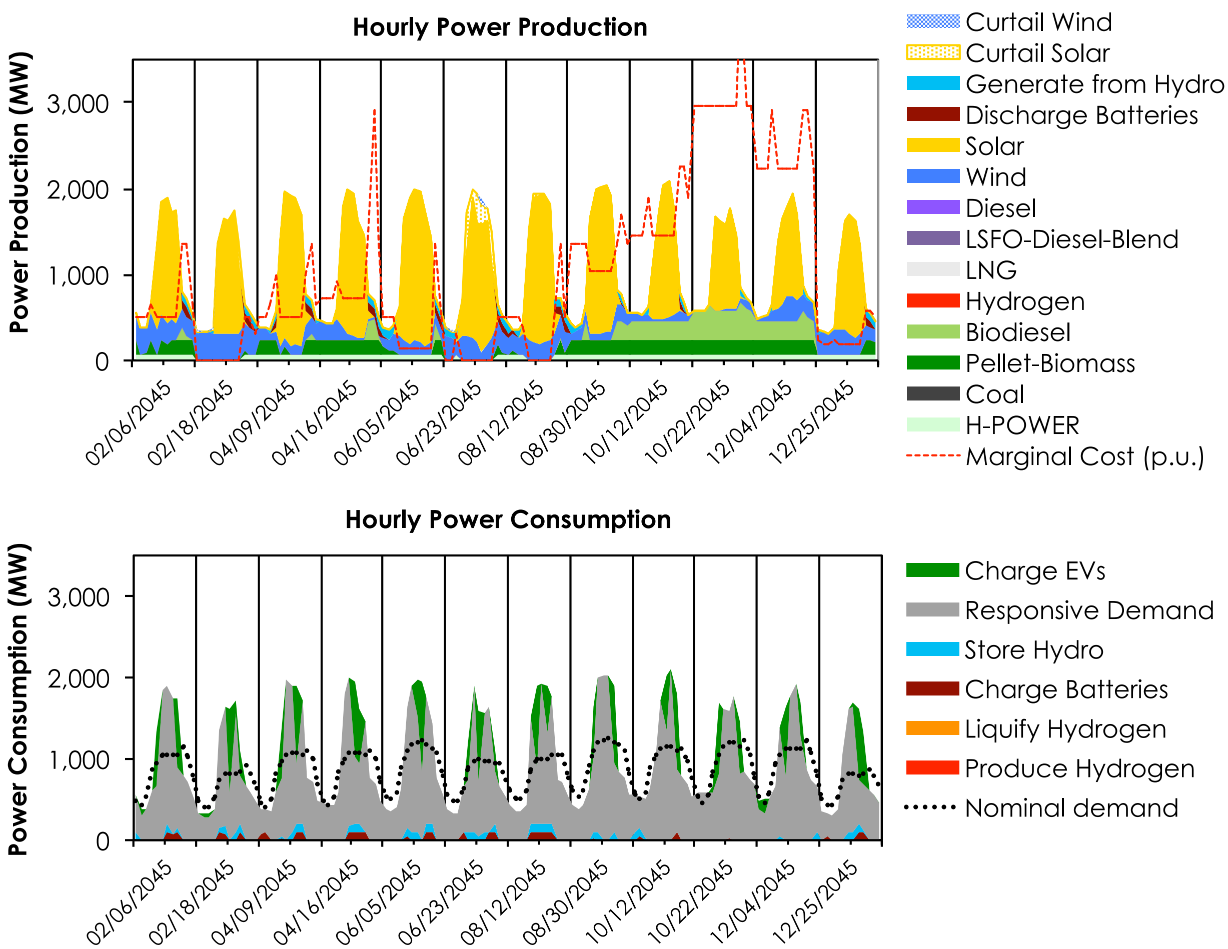


Figure 3. Hourly power production and consumption on Oahu during 12 sample days in 2045, with 100% renewable power

Figure 3 suggests several important considerations about the resources that may be needed to achieve 100% renewable power.

(1) This work demonstrates for the first time that 100% renewable power can be achieved using established technologies at a reasonable cost. In this system, components are scaled carefully to minimize costs: curtailment of renewable power is almost completely avoided; capital-intensive batteries are developed only up to a scale where they will be used intensively on most days of the year; low-capital-cost models of thermal power plant are selected, since they will be used for only part of the year; biofuels (or hydrogen) are then used to fill in on the days when there is insufficient sun or storage capacity.

(2) This system uses less electricity storage – batteries or pumped storage hydro – than many observers might expect. Instead it relies primarily on demand response to achieve the necessary energy balance throughout the day. In this

scenario, we treated demand response as a free service provided by economically rational, cost-minimizing consumers. In future work we will include the cost of maximizing this flexibility (e.g., adding smart controllers or storage to air conditioners, water heaters, water pumps, etc.). Preliminary research indicates that these services will have much lower capital and O&M costs than batteries.[16] Indeed, over the course of the next 30 years, this type of functionality is likely to become a standard part of many energy-consuming devices. Consequently, it will be important to develop good estimates of the amount of inter-hour demand response that is possible in Hawaii's power systems, and the strategies for exploiting it.

(3) This system contains just enough schedulable resources to meet peak nominal loads of 1222 MW. For this particular model run, these resources include 238 MW of new reciprocating plants, 215 MW of existing plants converted to biodiesel, the 180 MW AES plant converted to pellet-biomass, 198 MW of batteries and pumped storage hydro, and 367 MW of demand response. Table 2 summarizes the optimal generation capacities selected in this scenario and in the two additional scenarios discussed later in this paper. More work is needed to identify the best retirement dates for existing plants; however, even if all existing plants are retired by 2045, we don't expect a large change in costs, because capital recovery on existing plants will be replaced by capital recovery on new plants.[17]

(4) In this system, thermal power plants and batteries are often shut down or pegged to their upper limits, so that the system energy balance is maintained by demand response or renewable energy curtailment. This is a system which often has no spinning machines on the margin. This is a feasible and cost-effective approach, but it will require the HECO Companies to take on a new core function as an integrator of supply and demand, rather than focusing on the supply side.

[16] For example, scheduling and "spinning reserve" capabilities can be added to EV chargers or water heaters at a cost of $100 or less. These devices can then reschedule around 5 kWh of load per day. This equates to around $0.01 per kWh shifted, less than 10% of the cost of batteries.
[17] We note that if the AES plant is no longer in service in 2045, it will probably be impossible to use pellet biomass as a fuel; burning biodiesel in reciprocating plants instead would raise costs slightly.

Table 2. Generation capacity installed by 2045 in the scenarios reported in this paper

Technology	17.9% biofuel, no hydrogen	5% biofuel, no hydrogen	5% biofuel, hydrogen storage
Solar PV	1933 MW	2885 MW	2260 MW
Wind	441 MW	481 MW	522 MW
New reciprocating plants	238 MW	14 MW	14 MW
Existing thermal plants (using biodiesel)	215 MW	215 MW	215 MW
AES plant (pellet biomass)	180 MW	180 MW	180 MW
Batteries and pumped hydro	198 MW	581 MW	181 MW
Hydrogen electrolyzers	0 MW	0 MW	250 MW
Hydrogen fuel cells	0 MW	0 MW	259 MW

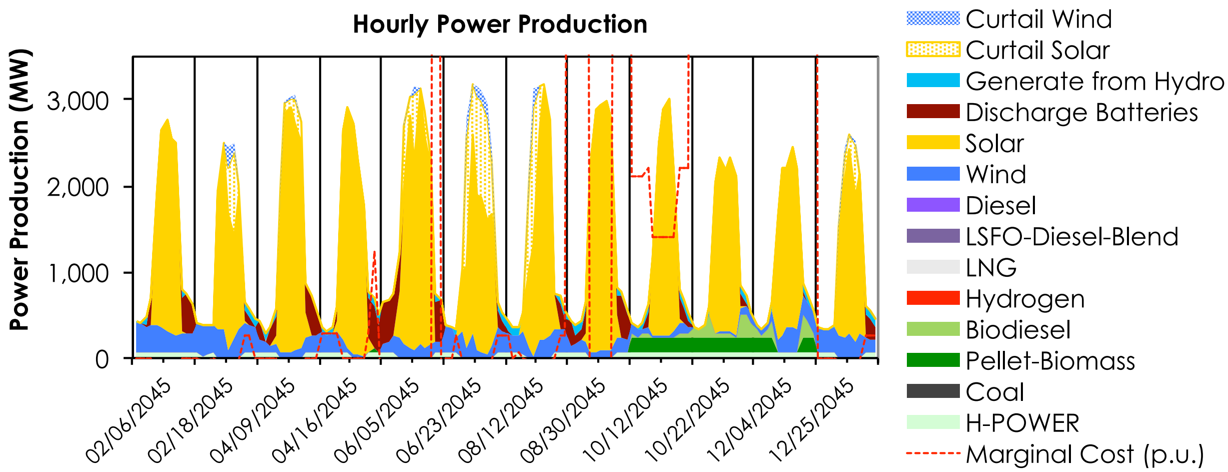
Biofuel Limits

For the scenario shown in Figure 3, we assumed that unlimited amounts of biofuels (pellet biomass and biodiesel) could be used on Oahu. In this case, the least-cost power system design uses 18.9% biofuel in 2045, and the levelized cost of power in 2045 is $0.162/kWh (in 2015 dollars)[18]. Growing this much biofuel on Oahu or elsewhere in the State would place a significant burden on the available land, possibly displacing use for agriculture or wildlife habitat. On the other hand, importing biofuel would run counter to House Bill 1286 (2015), which aims for the "elimination of Hawaii's dependence on imported fuels for electrical generation and ground transportation." To address these concerns, we ran several additional scenarios in which biofuels were limited to 5% of Oahu's electricity production.

Figure 4 shows a least-cost scenario similar to Figure 3, but with only 5% of electricity derived from biofuels. Under this constraint, we would need to build significantly more solar capacity in order to have enough energy available to get through the low-sun days in the fall. This results in greater curtailment during higher-sun days at other times of year. This system also requires significantly more battery storage to get through non-sunny times of day. These changes raise the average cost of production by about 10%, to $0.178/kWh.

[18] This cost includes fuel, operation & maintenance (O&M), amortization of new power plants, and a rough estimate of amortization for transmission, distribution and existing power plants. It does not include other costs, such as meter reading, billing and administration.

Given this tradeoff between land use and cost, the HECO Companies' plans will need to give careful consideration to the amount of land that should be devoted to energy production. Land use could be limited in SWITCH scenarios using a hard cap (e.g., the 5% limit on biofuels, but extended to include land used for solar and/or wind equipment as well), or a soft cap (e.g., an economic adder per acre of land used, reflecting the environmental harm caused by using land for energy production). This kind of customized modeling capability is one of the benefits of using open-source optimization software such as SWITCH, rather than the proprietary tools currently in use in the PSIP process.



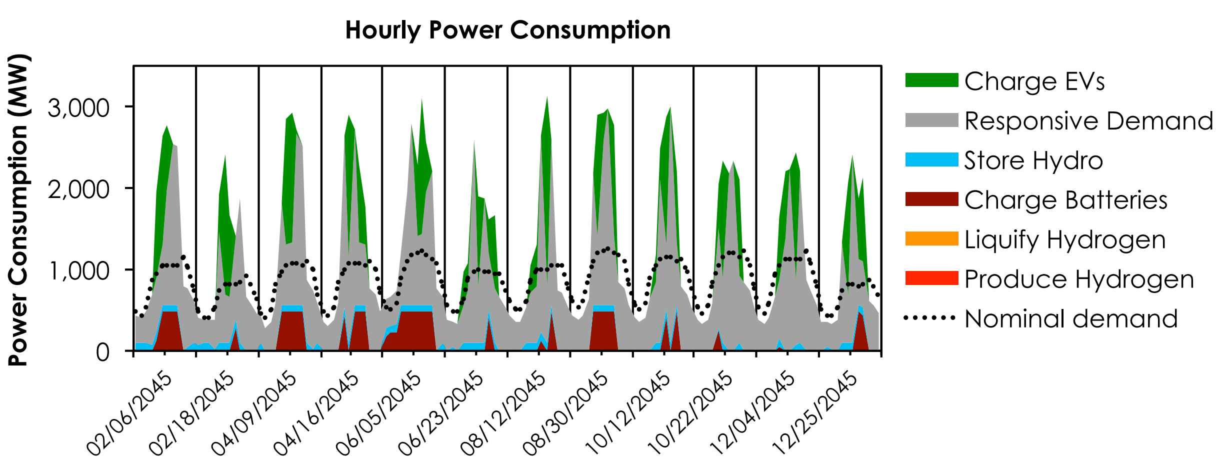


Figure 4. Hourly power production and consumption on Oahu with 100% renewable power and biofuels limited to 5% of production

Hydrogen Energy Storage

In the scenarios discussed above, biofuel is used on a large scale to maintain the seasonal energy balance for Oahu. As a "fuel," biofuels are an energy source that can be readily stored for multiple days or months, in order to get through low-solar-energy periods late in the year. Biofuels are in fact one of very few fuels that people are currently able to make from renewable sources on a commercial scale. Hawaii may, however, benefit from considering another fuel that can be synthesized directly from renewable electricity: hydrogen.

As a preliminary step toward considering the role of hydrogen in Oahu's power system, we developed a simplified model of a liquefied hydrogen energy storage facility. Costs and capabilities for this facility are modeled based on existing technologies: electrolyzers use electricity to split water into hydrogen and oxygen[19]; hydrogen is stored at low pressure for use later in the day, or chilled into liquid form and stored in large, well-insulated tanks[20]; then fuel cells are used to convert hydrogen back to electricity[21]. This process has a low round-trip efficiency, around 37%, but it may be worthwhile if it uses renewable power that would otherwise be curtailed. With large tank sizes, it is possible to store liquefied hydrogen for several months with minimal losses.

Figure 5 shows a least-cost plan for Oahu's power system in 2045, with a 5% cap on biofuel production, but with the opportunity to build a hydrogen energy storage facility. In this case, the optimal plan includes 250 MW of electrolyzer capacity, 259 MW of fuel cell capacity, and approximately 10 million kg of storage (enough hydrogen for about 180 GWh of electricity production). This storage volume is about 20% of the size of PAR Petroleum's oil storage tanks or the Red Hill underground fuel storage facility.

In this scenario, the hydrogen facility is used to serve dual purposes of short-term and long-term storage. The hydrogen facility displaces most battery capacity from the system and also reduces the need to build excess solar capacity in order to provide enough energy during the fall months. The system shown in Figure 4 has an average production cost of $0.163/kWh in 2045. Comparing this scenario to the 5% biofuel scenario presented above, we see that hydrogen storage may reduce the cost of the 5% biofuel scenario by about 8.5%. The scenario with hydrogen energy storage and a 5% biofuel cap costs nearly the same as the first scenario presented, with no hydrogen and 18.9% biofuel.

The cost data used for hydrogen storage in this scenario are preliminary, and we have not addressed the safety, security and reliability implications of large-scale hydrogen storage. However this work suggests that using hydrogen for electricity deserves further investigation. A hydrogen facility may also be of additional benefit as a source of fuel for hydrogen vehicles, currently under development by several major manufacturers.

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[19] US DOE, "Production Case Studies," U.S. Department of Energy, Hydrogen and Fuel Cells Program. https://www.hydrogen.energy.gov/h2a_prod_studies.html. "Current Central Hydrogen Production from Solid Oxide Electrolysis version 3.1"

[20] W. A. Amos, "Costs of storing and transporting hydrogen," National Renewable Energy Laboratory, Golden, Colo. NREL/TP-570-25106, November 1998.

[21] D. Steward, G. Saur, M. Penev, and T. Ramsden, "Lifecycle cost analysis of hydrogen versus other technologies for electrical energy storage," National Renewable Energy Laboratory, Golden, Colo. NREL/TP-560-46719, Nov. 2009.

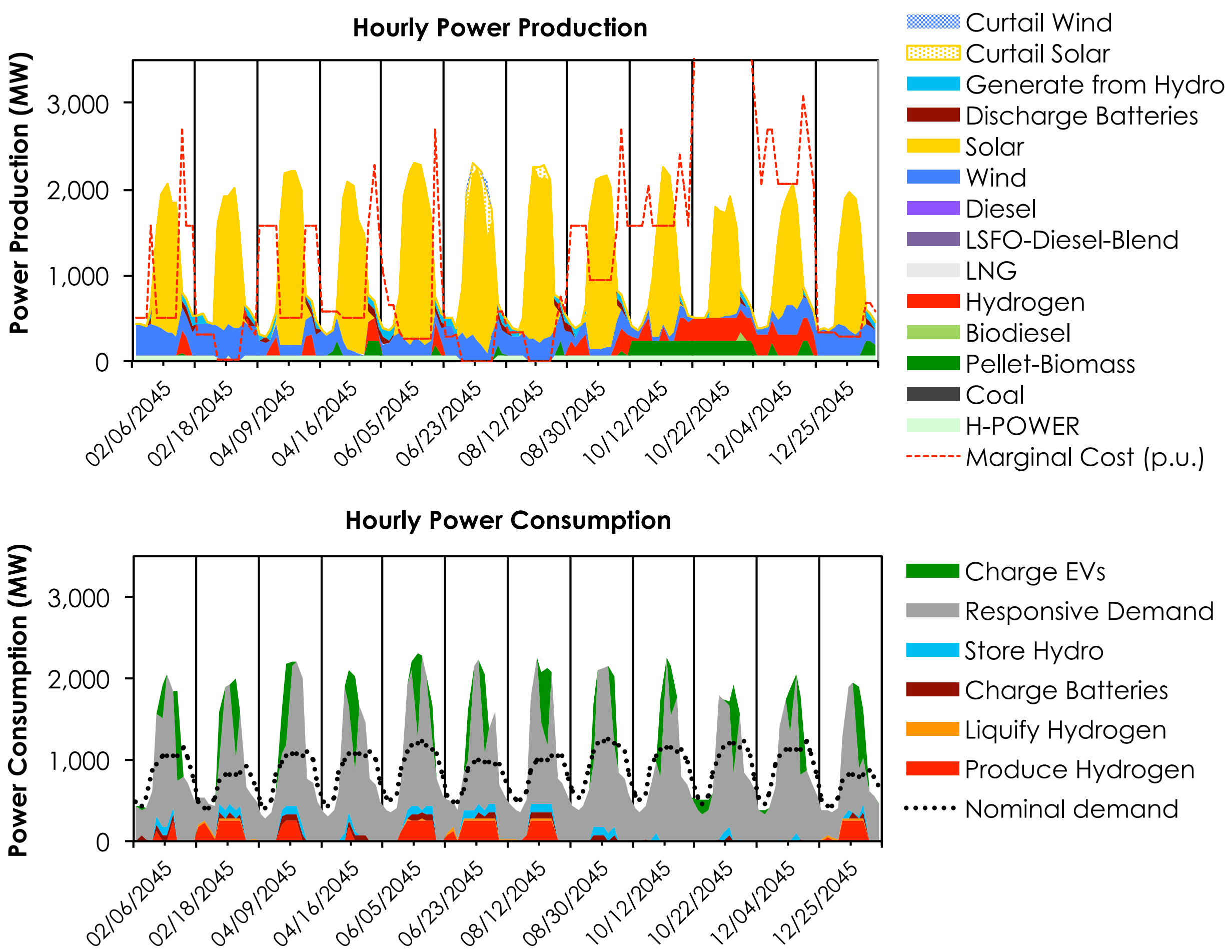

Figure 5. Hourly power production and consumption on Oahu with 100% renewable power, biofuels limited to 5% of production, and an option for hydrogen energy storage

Using SWITCH in the Regulatory Energy Planning Process

SWITCH or a similar long-term optimization model (if one exists) could play a useful and perhaps essential role in the regulatory energy planning process.

First, SWITCH can be used to help identify an optimal capacity plan in the IRP/PSIP process, based on starting assumptions mutually agreed among the HECO Companies and stakeholders. In this process, the HECO Companies and other parties could propose candidate generation portfolios that meet the State's policy objectives, developed via SWITCH and possibly via other methods. Then the HECO Companies could use standard production cost software to evaluate the performance of the SWITCH portfolio in more detail and/or to compare it to other candidate portfolios. The HECO Companies are free to run SWITCH themselves as part of this process, or we are happy to work with other stakeholders to develop "community plans" which the HECO Companies can compare to their own plans. Since SWITCH is an optimization model, it should provide an excellent benchmark to evaluate the quality of other proposals against. Conversely, without a transparent model like SWITCH, there is no easy way to judge the cost-effectiveness of the HECO Companies' long-term plans.

SWITCH can also play a useful role in prudence reviews for individual project investments. Hawaii is just beginning to accelerate toward a clean energy future, so the plans developed during the IRP/PSIP process will necessarily be based on uncertain assumptions about existing and new technologies and strategies. As the HECO Companies move ahead with implementing these plans, they will obtain more information on the cost and capabilities of projects, technologies, and strategies. This could make it necessary to regularly and systematically re-optimize the plans to rule out technologies that have higher cost or worse performance than originally thought, or to incorporate new technologies with lower costs or better performance. In this case, the new information can be incorporated into the shared dataset of assumptions and then SWITCH (or a similar model) can be run again, to assess how the plan should be changed (i.e., which technologies should now be ruled out or in). At that point, any project that makes it into an optimal plan at its realistic final cost can be deemed a good choice.[22] Projects that are not selected by the optimization model when their final costs and capabilities are known can be deemed imprudent on a planning basis. A more flexible version of this test is also possible: a candidate project can be forced into or out of the plan proposed by SWITCH; if average production costs are at least as low with the project included as without it, then the project can be deemed worthwhile.

In other words, the plan developed during the IRP/PSIP process does not need to be "set in stone." With automated tools like SWITCH that can quickly find an optimal plan based on any set of assumptions, it is possible to revise the plan whenever new

[22] We note that this is a test for planning prudence, i.e., whether a project is a good choice relative to other options that are available. However, other tests will still be needed to ensure that specific projects are developed prudently.

information (e.g., PPA bids) becomes available. Then the optimal plan can provide up-to-date indications of which generation projects are worth developing and which are not.

Incentives for the HECO Companies to Create and Implement an Optimal Plan

In this document, we have shown techniques for evaluating resource plans and defining optimal generation plans to meet the State's policy objectives while maintaining a reliable supply of power. We have also suggested ways that the HECO Companies could incorporate these techniques into the IRP/PSIP planning process.

However, we are concerned that at present there are weak or negative incentives for the HECO Companies to follow this path. Under the State's Competitive Bidding Framework, the HECO Companies cannot necessarily expect to build the new generation capacity needed in the future and add it to the rate base. Instead, there is a good chance that new generation will be obtained via power purchase agreements with independent power producers or via purchases from customers. Consequently, the HECO Companies' profit may be the same whether or not they make a good plan and sign good PPAs.

This is arguably better than their previous incentives, where the HECO Companies' profits increase if they build excess capacity and/or build at a high cost. However, when an optimal generation plan is developed and implemented, a parallel step will be to retire existing generation plants that are no longer needed and remove them from the HECO Companies' rate base. Consequently, the HECO Companies' profits may actually be reduced if they make a good plan and follow through on it. Thus, their most profitable option at present may be to continue to stretch out the process, oppose distributed generation and negotiate unattractive power purchase agreements. To achieve more rapid progress, we recommend that the Commission, HECO Companies and stakeholders make significant changes to the incentive system, to better align the utilities' incentives with ratepayers' interests.

Put simply, the HECO Companies should benefit from making and implementing an optimal plan, whether they own the generating assets or not, and should be penalized if they do not make and implement an optimal plan. HECO's incentives should not be based primarily on owning capital assets.

Conclusion

This paper introduces tools and techniques for creating an optimal plan to meet Hawaii's energy goals. The findings are preliminary and are expected to be updated over the next few months as a community consensus emerges on the assumptions to make about available options. However, even at this preliminary stage, several conclusions can be drawn from this work.

(1) The HECO Companies should use a long-term optimal capacity model such as SWITCH to select a least-cost portfolio to meet the state's needs. If the HECO Companies are not willing to do this, then we recommend that stakeholders work together to agree on assumptions, then use SWITCH to develop a "community plan", which HECO can use as a benchmark for their own plans.

(2) An optimal planning model can also be used to test the prudence of individual investments. This can be done by updating the assumptions with the latest information (including individual project bids) and then seeing whether the proposed project increases or decreases long-term costs compared to the optimal plan without it.

(3) Using the SWITCH planning model, we have found that it is possible to achieve 100% renewable power at moderate costs, using existing technologies. To some extent, planning can be organized around the questions of how best to balance supply and demand on a diurnal and seasonal basis. The seasonal balance may in fact be more difficult to achieve, since there are few options for long-term energy storage. Active, engaged demand response may play a key role on both of these timescales.

(4) As part of this ongoing planning and optimization process, it will be important to refine and agree upon the assumptions that define the planning environment we face. The work presented here has identified some topics that are especially important to investigate, since they are currently poorly understood and could significantly affect the cost of reaching 100% renewable power. These include

    a. the potential for demand response to shift loads to sunny hours and provide regulating and contingency reserves;

    b. the desirability of using land in the state for producing biofuels, solar or wind power; and

    c. the potential for using hydrogen as a medium to store solar power during sunny times of year and produce power during less sunny times.

(5) The portfolio optimization reported here portrays a different kind of utility than has ever existed before. Strategies such as demand response, EVs, dynamic energy pricing, alternative fuels, energy storage and balancing, and renewable integration will become core utility functions. This business may be more or less

capital-intensive than in the past, relying either on utility-scale projects or on distributed, customer-sited renewable power and storage. To effectively implement this business model revolution, the utility revenue model and incentives must also evolve. Thus, we believe that the updated PSIP resource plans must be accompanied by a plan and timeline to quickly implement a performance-based revenue model. Rather than rewarding capital investment (and only capital investment), that revenue model must incentivize the utility as directly as possible to design and build an optimized resource portfolio, and penalize strategies that are not consistent with that portfolio.