PSIP Update Revised Analytical Approach and Work Plan

7 September 2016




Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Preface

The Hawaiian Electric Companies respectfully submit this revised analytical approach and work plan for creating our revised 2016 Power Supply Improvement Plan (PSIP) Update Report to comply with Order No. 33877 issued by the Hawai'i Public Utilities Commission on August 16, 2016 in Docket No. 2014-0183.

Table of Contents

FIGURES

TABLES

1. Introduction

This *PSIP Update Revised Analytical Approach and Work Plan* describes the revised analytical approach employed to develop an updated PSIP and outlines in detail the necessary steps to further revise and finalize the updated PSIP.

The Companies' goal is "to produce final PSIPs that focus on near-term actions that the HECO Companies plan to take to advance the achievement of the State's 100% renewable energy goal, to stabilize and reduce customer rates, and to maintain safe and reliable service," which is consistent with the Commission's directive.[1]

As noted in our Motion for Clarification[2] filed on August 26, 2016, our interpretation of Order No. 33877 is that the revised PSIP should focus on near-term actions, particularly a five-year action plan, as that is consistent with the Commission's intent. In addition, we understand that the focus of our detailed analysis and modeling should be on the five-year action plan period and that long-term optimization can be fulfilled through capacity expansion modeling.

We will file our updated PSIP (entitled *PSIP Update Report: December 2016*) by December 1, 2016, as directed.

[1] Docket No. 2014-0183, Order No. 33877 at 2, filed August 16, 2016.

[2] Docket No. 2014-0183, Hawaiian Electric Companies' Motion for Clarification of Order No. 33877, filed August 26, 2016.

ABOUT THIS REVISED ANALYTICAL APPROACH AND WORK PLAN

As directed in Section IV. C. 6. of Order No. 33877, our work plan, enclosed herein, details the analytical approach for updating and finalizing our PSIP. Section 2: Work Plan follows this directive and explains how we are addressing Commission guidance by:

- Describing the development and anticipated revisions and further documentation of input assumptions, including fuel prices, resource costs, and distributed energy resources (DER) and DG-PV forecasts and revisions to input assumptions since our *PSIP Update Report: April 2016*.
- Providing a clear and detailed step-by-step explanation of how the resources in the analyses supporting the PSIP analyses will be considered, evaluated, and selected to create optimized resource mixes. This analysis includes identifying what models and calculations will be used and how the inputs and outputs of the models will be specified and utilized in each step, as well as describing any additional improvements in analytical methods.
- Describing how the Commission's guidance and any other changes in circumstances or development in interrelated dockets will be addressed.

Section 3: Work Flow and Timeline details our revised PSIP work flow and how our work plan complies with the procedural schedule outlined in Order No. 33877.

In our Motion for Clarification filed on August 26, 2016, the Companies respectfully suggested that the Commission provide feedback on this work plan, ideally by the end of September 2016, if the Commission determines that adjustments are necessary. We believe that Commission feedback before our completing substantive phases of the updated analysis, will help ensure that the updated PSIP is consistent with Order No. 33877 and the Commission's goals. Given the amount of work to be completed and short time frame, we are proceeding with the steps outlined in this *PSIP Update Revised Analytical Approach and Work Plan*.

2. Work Plan

This PSIP Work Plan describes how input assumptions were developed, and the modeling analysis that incorporates them toward creating our updated PSIP. We began developing these inputs starting with the December 17, 2015 stakeholder conference for the *PSIP Update Interim Status Report* (filed February 16, 2016), updated them for inclusion in our *PSIP Update Report: April 2016* (filed April 1, 2016), and most recently updated them in June 2016 for this work plan. These June 2016 input assumptions (which we provided to the Parties before the June 29, 2016 stakeholder conference) are the current basis for this work plan.

This PSIP Work Plan also describes how we are focusing our detailed analysis and modeling on the near-term action plan. Our Motion for Clarification noted that E3 will utilize their RESOLVE capacity expansion model to transparently develop and identify theoretical least-cost resource plans for O‘ahu, Maui, and Hawai‘i Island (and various interconnected cases). However, the Companies would like to note that while E3's capacity expansion model can optimize around generation resources and develop a theoretically lowest-cost resource plan, it does lack the granularity needed to properly evaluate hourly and sub-hourly variability of intermittent renewable resources and accounting for pricing sensitivity of customer adoption of DER and DR programs. To this end, validation of E3's results will be performed with Ascend Analytics' PowerSimm Planner gaining additional insight of hourly and sub-hourly operations. The Companies will also run Plexos to conduct hourly and sub-hourly production simulation modeling analysis. We will analyze various sensitivities to ensure and validate that E3's and Ascend's resource plans are optimal. We will also run the BCG DG-PV Adoption Model and Black and Veatch's Adaptive Planning for Production Simulation (as we did in our optimization process for developing our *PSIP Update Report: April 2016*) to determine DER and DR adoption. Because DER and DR resources cannot be dynamically analyzed within capacity expansion models, they will be added to the resource plans and production simulation modeling in Plexos to complete the process through the rates and bills analysis.

If the optimized resource plans with DR are not significantly different from the resource plans without DR included, we will use the results from the resource plans without DR to assess system security of the optimized resource plans. If the with and without DR resource differ significantly, a revised system security analysis of the optimized resource plans will be required.

INPUTS AND ASSUMPTIONS

Order No. 33877 states that "Clarity and transparency of the inputs and assumptions informing the Companies' PSIP analyses is critical to establishing confidence in the Companies' modeling and results." [3] The Companies concur.

Since the beginning of the process of updating our PSIP in 2015, we explained and distributed our inputs and assumptions, analyses, and progress a number of times. We:

- Held three stakeholder conferences—December 17, 2015; May 17, 2016; and June 29, 2016—to engage the Parties, share information, and obtain additional information.
- Explained our planned analytical approach and progress during two Commission-sponsored technical conferences—January 7, 2016 and March 8, 2016. In accordance with Order No. 33320, the Companies
- Filed our *PSIP Update Interim Status Report* on February 16, 2016 (complying with Order No. 33320) that explained the status of our planning and updating work at that time.
- Established an FTP (WebDAV) site to electronically share information with the Parties and to provide a means for the Parties to submit information to us.
- On that site, posted resource cost assumptions, fuel price forecasts, and Party submissions for review.
- Invited the Intervenors to attend our scheduled planning meetings (most of them regularly participated), then solicited and welcomed their suggestions in our discussions and to our decision-making. They participated in meetings throughout the development of our candidate plans, and the selection of our preferred resource plans.

We worked with consultants and other organizations to develop verifiable foundational input assumptions: resource costs, renewable generation potential, and fuel prices.

[3] *Ibid.*, at 19.

HD Baker and Company developed resource cost assumptions using publicly available information, which NREL reviewed and verified. NREL also analyzed and provided resource potentials and aggregated power time series for PV and wind resources. The Energy Information Administration (EIA) published an Annual Energy Outlook (AEO) Early Release report which provided the fuel price forecasts used in our analyses. We made all of this information available to the Parties through our WebDAV site.

The vast majority of input received throughout the development of the PSIP focused on our analytical approach; we received very little input to resource assumptions. Hawaiʻi Gas and Paniolo Power did provide partial information on LNG and wind/pumped storage hydro resources. To gain more complete information for our analysis, the Companies asked both organizations follow-up questions. Hawaiʻi Gas, however, did not reply. Paniolo Power stated they could not respond because of the risk of disclosing proprietary and competitive information. As a result, the Companies unfortunately could not incorporate any of this information into our analysis.

In addition, we have worked with Dr. Matthias Fripp (consultant for Ulupono and Blue Planet) and SunPower to compare data and assumptions. (See "Resource Cost Assumptions" for details.)

Fuel Price Forecasts

Chapter 9: Next Steps of the *PSIP Update Report: April 2016* stated that we would conduct additional analysis based on updated fuel price forecasts from the upcoming EIA AEO. Subsequently, we updated our fuel price forecasts when EIA published its AEO Early Release on May 17, 2016. We emailed these updated fuel price forecasts to the Parties on June 27, 2016[4] for input and discussion at the Stakeholder Conference on June 29, 2016, and posted the forecasts on our WebDAV site. (Appendix A: Fuel Price Forecasts contains these updated fuel price forecasts.)

Our Motion for Clarification noted that our five-year term action plans will not include LNG. We will, however, over the longer-term, continue to evaluate cleaner fuel alternatives, including LNG, to lower costs for our customers and better meet environmental mandates. We expect, then, to include LNG in our fuel price forecasts and resource plans with the assumption that LNG will not be available in the next five years.

[4] Email from Todd Kanja on behalf of Colton Ching, Vice President of Energy Delivery, sent on June 27, 2016 at 7:42 PM, with the subject line "RE: Hawaiian Electric PSIP Stakeholder Conference".

Resource Cost Assumptions and Resource Potential

After filing the PSIP Update Report: April 2016, we re-evaluated and adjusted some resource costs

We emailed these updated resource costs to the Parties on June 24, 2016[5] for input and discussion at the Stakeholder Conference on June 29, 2016, then posted them on our WebDAV site. (Appendix B: Resource Cost Assumptions contains these updated resource cost assumptions.)

After our June 29, 2016 Stakeholder Conference, we have worked with Dr. Matthias Fripp (consultant for Ulupono and Blue Planet) and SunPower to compare data and assumptions. Based on multiple discussions and exchanges of information, we concluded that our PV and energy storage cost assumptions are consistent with data provided by SunPower and are reasonable for use in our PSIP update.[6]

We have, however, adjusted the resource potential screening criteria for utility-scale PV on O‘ahu, increasing from an up-to-5% developable slope to the aggressive up-to-10% developable slope, increasing the potential for grid-scale PV from 793 MW to 2,756 MW. We did not adjust the resource cost assumptions associated with an increase in the slope. No such adjustments were made for Maui or Hawai‘i Island as their PV potentials at a 5% slope are substantial enough to meet their energy needs. NREL, at our behest, reran their corresponding study using this increased slope, which resulted increased resource potential for utility-scale PV on O‘ahu. (Appendix C: NREL Resource Potential Study contains this updated study.)

The market DG-PV adoption model (developed by Boston Consulting Group) uses a levelized cost-of-energy utility-scale PV to determine export pricing for DG-PV. We updated this DG-PV adoption model to include the revised cost assumptions for utility-scale PV. We will also be developing a DG-PV plus storage forecast to represent the Customer Self-Supply option as a refinement to the DER and DR iteration analysis (described in the next section).

As the Commission observed in Order No. 33877, the Companies withdrew applications for approval of a LNG fuel supply agreement and a proposed Kahe combined cycle project to be fueled primarily with natural gas. Since both applications were contingent on the approval of the merger with NextEra Energy which has since been terminated, the Companies’ August 26, 2016 Motion for Clarification stated that the five-year near-term action plans will no longer include LNG or a 3-on-1 Kahe combined cycle project. However, as noted above, the Companies do intend on including LNG in its fuel price

[5] Email from Todd Kanja on behalf of Colton Ching, Vice President of Energy Delivery, sent on June 24, 2016 at 6:35 PM, with the subject line “Hawaiian Electric PSIP Stakeholder Conference”.

[6] Companies’ Motion for Clarification of Order No. 33877, filed August 26, 2016, at 14.

forecast and resource plans. Modernization of O‘ahu’s generation fleet will no longer include the 3-on-1 Kahe combined cycle project but will consider the smaller resources listed in Appendix B: Resource Cost Assumptions.

TRANSPARENCY OF OPTIMIZATION: ANALYTICAL APPROACH

Order No. 33877 emphasized the need for transparency when optimizing the PSIP, stating that “[i]n order for the commission to have a sufficient degree of confidence in the analysis and modeling results, the HECO Companies must demonstrate that the results are based on credible, transparent, and objective analysis.”[7] The Commission also observed that the Companies’ modeling approach “is not a transparent, well-defined and reproducible approach, such as the use of an optimizing capacity expansion model – which quantitatively determines an optimal resource portfolio according to standard, documented, and vetted methods.”[8]

We understand the concerns raised the Commission.

April 2016 PSIP Update Optimization Process

For our April 2016 filing, our planning engineers worked closely with consultants to develop an innovative process that was well-documented and transparent, optimized all resources including DER, DR, and utility-scale resources, and built on our completed DR work. The result is depicted in Figure 1. PSIP Optimization Process for DER, DR, and Utility-Scale Resources (and extensively described in Appendix C: Analysis Methodologies in our *PSIP Update Report: April 2016*).

[7] Docket No. 2014-0183, Order No. 33877 at 20.

[8] *Ibid.* at 22.

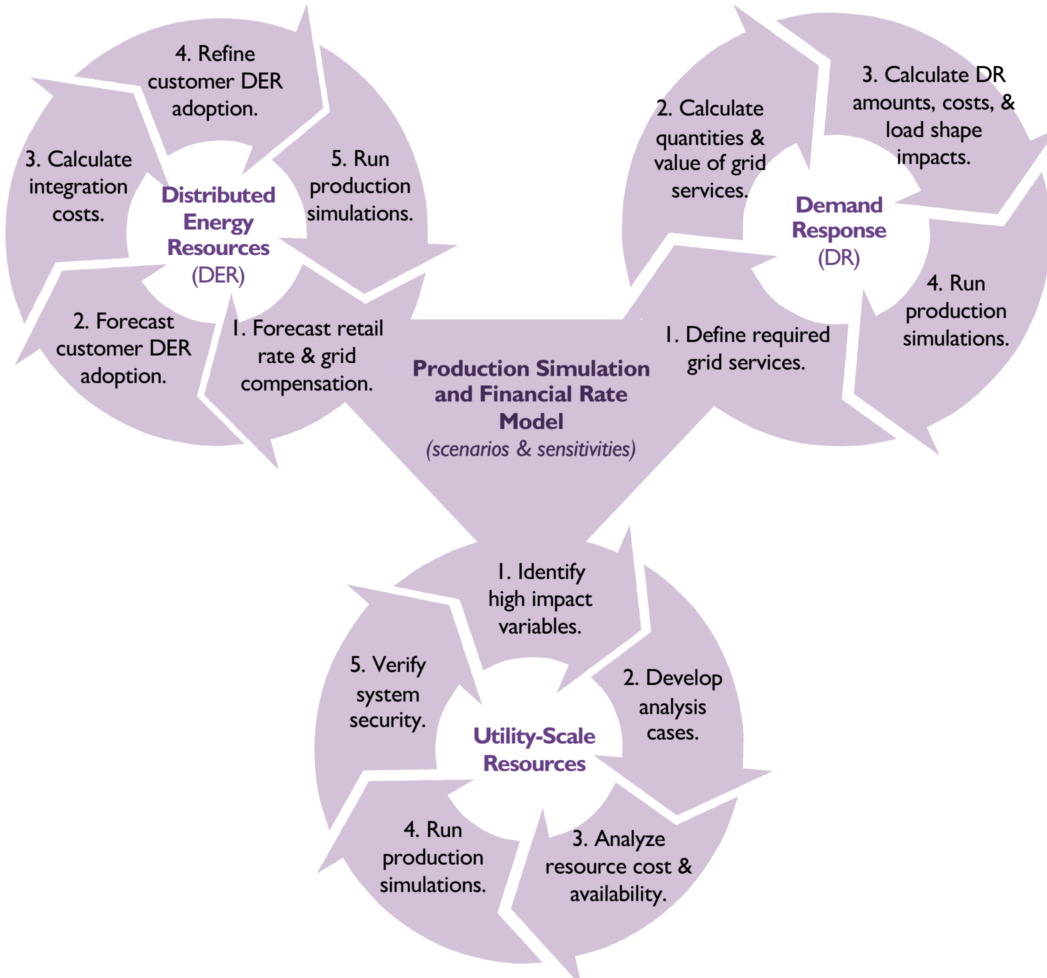


Figure 1. PSIP Optimization Process for DER, DR, and Utility-Scale Resources

The Companies understand that transparency is important. We attempted to demonstrate diversity by developing and documenting more than 200 candidate plan cases spread over three different themes. (Appendix K: Candidate Plan Data of the *PSIP Update Report: April 2016* contains resource plans for each case.) The Companies then down-selected plans using a Decision Matrix (described in Appendix C: Analysis Methodologies of the *PSIP Update Report: April 2016*). We believed that developing, documenting, and analyzing a vast array of cases would transparently demonstrate how the final and preferred plans were derived.

The Commission and Parties have raised the concern that resource plans were manually developed. Accordingly, the process could have inadvertently excluded certain cases that should have been considered and therefore lacks transparency. The Companies understand this concern.

The Commission also raised concerns about the clarity and transparency by which resource plans were down-selected. For the April 2016 PSIP update, the Companies developed a Decision Matrix as a means to evaluate and down-select the many cases. To ensure transparency of the process, the Companies requested Intervenors to attend all meetings where plans were evaluated and down-selected using the Decision Matrix.

Revised PSIP Optimization Process

We have listened to the need for additional transparency in the modeling and resource selection process. As such, we will employ E3's RESOLVE capacity expansion model to develop a theoretically lowest-cost resource plan. Use of the RESOLVE model will address the manual development of cases and down-selection process. While E3's capacity expansion model can optimize around generation resources and develop a theoretically lowest-cost resource plan, it lacks the granularity needed to evaluate hourly and sub-hourly variability of intermittent renewable resources and to account for pricing sensitivity of customer adoption of DER and DR programs. To this end, validation of E3's results will be performed with Ascend Analytics' PowerSimm Planner gaining additional insight of hourly and sub-hourly operations over the entire years under varying meteorology that contemporaneously determine renewable generation and load and simulated market fuel prices. PowerSimm Planner performs dynamic optimization to select the best resource plan overall future states with consideration for variability in weather and risks of market prices of fuel. The PowerSimm framework will also explicitly address the issue of "perfect foresight" in thermal generation dispatch and can optimally include this dimension into capacity expansion planning.

No single tool can fully and transparently develop a perfectly optimized resource plan. As stated earlier, the Companies believe that use of E3's RESOLVE and Ascend's PowerSimm Planner capacity expansion modeling in combination with the PSIP Optimization process (with hourly and sub-hourly production simulations) will address the concerns raised by the Commission; allow for proper modeling of variable intermittent generation; and optimize DER, DR, and utility-scale resources. For this update, the Companies propose to use E3's RESOLVE capacity expansion modeling to transparently develop and identify long-term theoretical least-cost plans for O‘ahu, Maui, and Hawai‘i Island (and various interconnected cases). Validation of E3's results will be performed with Ascend Analytics' PowerSimm Planner gaining additional insight of hourly and sub-hourly operations.

The Companies will also run Plexos to conduct hourly and sub-hourly production simulation modeling analysis to validate that: (1) all capacity planning criteria is satisfied in all years; (2) system energy costs are accounting for sub-hourly variability of generation and dynamic regulation requirements; and (3) costs for such granular production are appropriately captured for the rates and bills analysis. We will also analyze various sensitivities to ensure and validate that the plans developed by E3 and Ascend are optimal. Consistent with the April 2016 PSIP Optimization Process, the BCG DG-PV Adoption Model and Black and Veatch's Adaptive Planning for Production Simulation model will be utilized to determine DER and DR adoption. Because DER and DR resources cannot be dynamically analyzed within capacity expansion models, they will be added to the plans and production simulation modeling using Plexos to complete the process through the rates and bills analysis.

If the optimized resource plans with DR are not significantly different than the resource plans without DR, results of the system security analysis from the resource plans without DR will be used to assess system security of the optimized resource plans. If the plans differ significantly, however, a revised system security analysis of the optimized resource plans will be required. The production simulation hourly screening tool will be used to help make this determination. If system security requirements are found to be extremely costly, additional iterations may be necessary to find a lower cost alternative. Figure 2 depicts the revised analytical approach.

The Companies believe that the RESOLVE models inputs and outputs can be used to address many questions regarding the resources selected for both the five-year and long-term plans for each island we serve. To the extent that our recommended plans are driven not by the assumptions or the RESOLVE model, the Companies will identify the specific model that produced the recommendation and why the resource is needed.

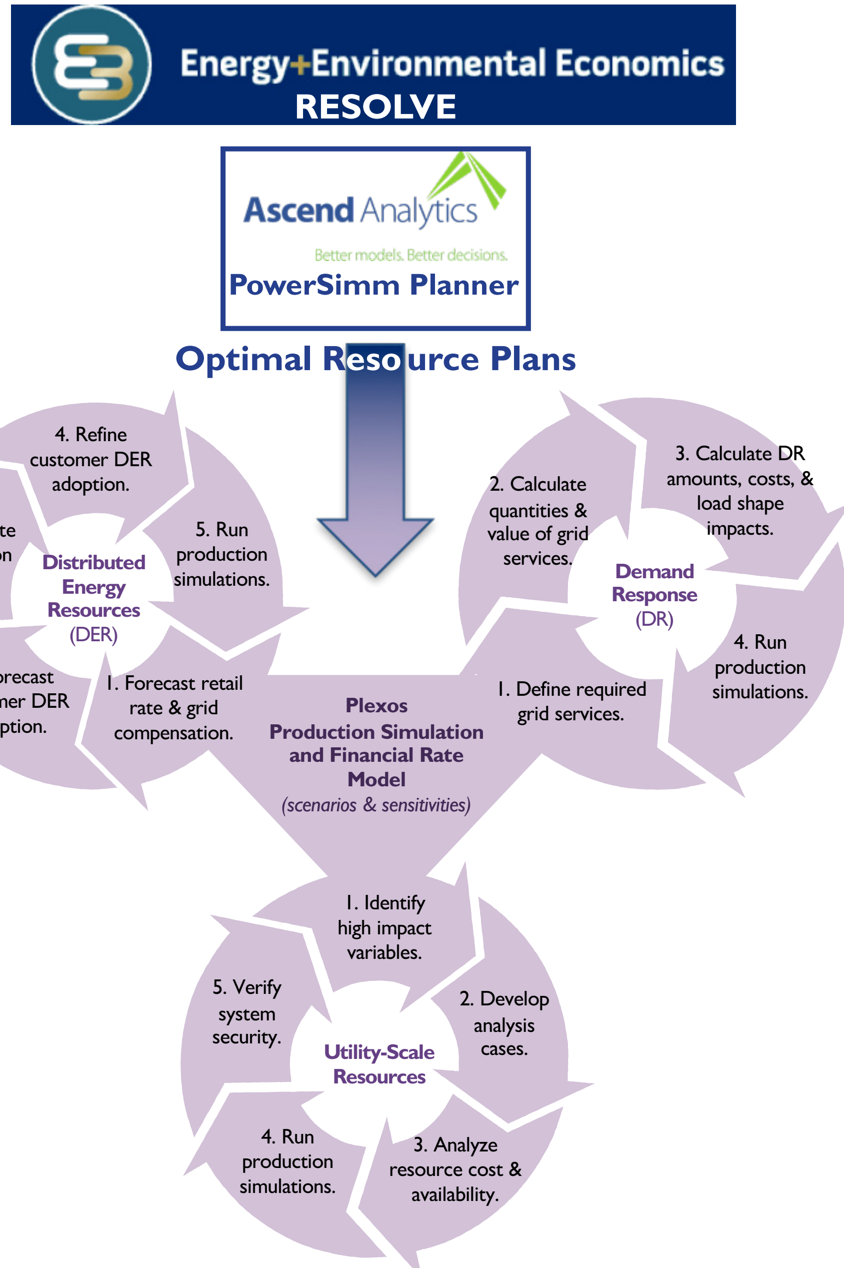


Figure 2. Revised PSIP Optimization Process

Assessing Risk and Validation of Results

The Companies identified minimizing risks as one of the objectives in the Decision Framework used in the April 2016 PSIP update.[9] Examples of risks that need to be considered are planning flexibility (preserving future optionality); resource technologies chosen and their related costs; fuel costs that are higher or lower than forecasted; project implementation risks including permitting and siting issues, and community acceptance; financing risks associated with availability and cost of capital investments and expenditures; risks associated with stranded costs, and the rate at which customers adopt renewable generation and provide grid services; and the risk of not achieving energy efficiency goals to the point of affecting demand forecasts.

To validate the resource plans determined through the process described above, the Companies plan to engage Ascend Analytics to independently analyze and develop optimal resource plans using its PowerSimm Planner tool.[10] PowerSimm Planner has the ability to quantify and monetize the risk into risk premiums (that is, incremental costs) by stochastically analyzing for uncertainties in key risk drivers including weather, load, renewable generation, renewable penetration rates, and market fuel prices. PowerSimm Planner also determines the amount of regulation and flexible reserves required with expanded renewable portfolios through minute analysis of renewables and load. Because portfolios with high renewable generation levels induce extreme variability in net load that can’t be anticipated in real-time generation dispatch, Ascend will also estimate the cost impact of perfect foresight in the planning process and the overall requirements for flexible generation.

ADDITIONAL IMPROVMENTS

Regulation/Ramping Requirements

High levels of variable, intermittent renewable distributed and utility-scale resources pose significant operational challenges. Weather variations will result in continual production variations and uncertainty in production capacity at any given point in time. Load changes are more predictable, but still dynamic. As the system transitions to higher levels of variable, intermittent renewable resources, balancing of capacity and load will be increasingly challenging. Regulation and ramping requirements will increasingly become more demanding.

---

9 Docket No. 2014-0183, *PSIP Update Report: April 1, 2016*, at C-3.

10 *Ibid.*, at H-24 to H-31.

The April 2016 PSIP update resources plans utilized regulating reserve assumptions as noted in Appendix J: Modeling Assumptions Data. As noted in Appendix L: EPRI Reserve Determination, the Companies are working with EPRI to investigate a new method for determining operating reserve requirements, but initial results are not expected until December 2016 or later.

For the December 2016 PSIP update, the Companies intend on using various methods to determine an estimated range of regulation and ramping requirements, as there are numerous approaches that could be used to define the requirements. One method is to perform sub-hourly modeling in Plexos to define regulation and ramping requirements. Another method is to analyze historical data to evaluate the magnitude of variability in the intermittent resources. In addition, Ascend Analytics has been conducting an independent analysis to determine regulation and ramping requirements using minutely level data. The Ascend model determines flexible resource requirements as a function of the renewable resource mix to determine requirements for regulation, ramps, and daily changes in gradient (changes in the slope of load following). As there is no industry standard for estimating regulation requirements for the high level of variable generation needed to achieve 100% renewable energy, the different methods described above will be used together to determine a reasonable amount of regulation and ramping requirements as a starting point for the December 2016 PSIP update.

Load Shifting Energy Storage

Since the April 2016 PSIP update, the Companies and Ascend Analytics have been evaluating the economics of load shifting energy storage (versus curtailment). We are finding that load shifting energy storage could be economical in the future. Cost effectiveness of energy storage is dependent upon the resource mix, cost of energy storage, and cost of energy resources on the system. The December 2016 PSIP update will incorporate these findings.

DR and DER Modeling

The Companies believe that additional granularity can be achieved by separating DER into the following components: NEM, customer self-supply, and future grid export. The customer self-supply will consist of residential, and small and medium commercial rate schedules with storage. Future grid supply will not include storage. The BCG DG-PV uptake model will be used to develop the Market DER forecast. The High DER forecast is not based on customer economics and represents a theoretical potential for all single family homes and some commercial customers (assumed to be 20 to 25% of commercial sales due to limitations of rooftop space) to be “net zero.”

In the April 2016 PSIP update, the production simulations of the final resource plans incorporated DR, however, there was not enough time to develop resource plans without DR to clearly show the impacts of DR. The Companies intend on completing this effort by developing plans without DR so that the system resources are identified before DR is included in the plans. DR will then be incorporated into the plans, and system resource changes will be identified to clearly show the impacts of DR.

Inter-Island Transmission

E3 will be conducting the interisland interconnection analyses using the updated assumptions. They will develop a theoretical least-cost plan for O‘ahu, Maui, and Hawai‘i Island without any interconnection. Then they will develop theoretical least-cost plans (that is, no transmission line restrictions) for interisland connections between (1) O‘ahu and Maui, (2) O‘ahu and Hawai‘i Island, and (3) O‘ahu, Maui, and Hawai’i Island. The difference between the theoretical least-cost plan cost and the combined cost of the theoretical least-cost plans of the individual islands will be the breakeven cost of the interconnection cable configuration.

SYSTEM SECURITY ANALYSIS

The Companies recognize that the system security analysis in its April 2016 PSIP update was not sufficiently complete. Sufficient time is necessary to complete the system security work described in Appendix O: System Security. The challenge is that a thorough system security analysis over the 30-year planning period requires extensive modeling, which will take several months to complete, and can only commence *after* the resource plans have been set. The Companies’ revised planning process requires the following steps: development of the resource plan (E3 RESOLVE), production simulation analyses with DER and DR optimization, validation, then system security analyses. As noted above, it is possible that additional iterations will be necessary if system security requirements are cost prohibitive and alternate plans may need to be developed and analyzed.

As noted in our Motion for Clarification, the Companies’ interpretation of Order No. 33877 is that the focus of the remaining phase of this docket should be on near-term actions, particularly a five-year action plan. In addition, detailed analysis and modeling should be on the near-term action plan period and that precise long-term optimization is of lesser emphasis.

To meet the Commission’s timeline, the Companies will perform voltage stability and frequency stability analyses using the Siemens PTI PSSE model on the resource plans without DR incorporated. Voltage stability analysis will be performed to determine

MVAR and short-circuit ratio requirements. The exact location of new resources has not been identified, so power flow analysis must be performed to determine if the existing transmission infrastructure can support resource plans. This will also have a bearing on voltage stability.

Frequency stability analysis will be performed on hourly data to define Fast Frequency Response 1 (FFR1), Fast Frequency Response 2 (FFR2), and Primary Frequency Response (PFR) requirements. This data can be used to develop DR programs and provide useful information on the E3 optimized plans. An assessment of the optimized plans will determine if a revised system security analysis is required.

Analyses of additional system security parameters such as rotor angle stability, under frequency load shedding, and system fault current will be performed and submitted with applications for projects and other Action Plan items that impact system security as appropriate.

ANCILLARY SERVICES

The Commission expressed concerns about our treatment of ancillary services. At the Commission's Technical Conference for DR in Docket No. 2015-0412 held on September 1, 2016,[11] the Companies clarified that while the April 2016 PSIP update does present DR as a resource under the FFR2 service category, this was intended to serve as an example of an FFR2 resource. The intent was not to preclude DR as a resource option for delivery other services such as FFR1 or PFR. The Companies will clarify this in the December 2016 PSIP update.

CUSTOMER AND IMPLEMENTATION RISKS

The Commission expressed concerns that the extensive capital investment strategies we proposed appears to entail risks that could ultimately be borne by its customers. As noted in our Motion for Clarification, we withdrew their applications for approval of an LNG fuel supply agreement and for approvals related to a proposed Kahe combined cycle project to be fueled primarily with natural gas. Consistent therewith, we made clear that the five-year near-term action plans that will be developed from the revised PSIPs will no longer include LNG or a 3-by-1 Kahe combined cycle project. Instead, resources will be selected as determined by the E3 RESOLVE capacity expansion analysis.

[11] Docket No. 2015-0412, For Approval of Demand Response Program Portfolio Tariff Structure, Reporting Schedule, and Cost Recovery of Program Costs through the Demand-Side Management Surcharge.

Over the longer term, we will continue to evaluate fuel alternatives to lower costs for customers, including considering LNG as a cleaner transition fuel towards the State's 100% renewable energy goal. Similar to other long-term options, LNG will be analyzed to determine its impact in stabilizing and lowering costs for customers and in lowering emissions while aiding in the effective integration of more renewable energy. This is consistent with the Commission's Inclinations.

The Commission also expressed concerns with customer exit. The Companies share these concerns: higher rates drives load defection, and increasing load defection decreases the customer base and revenue, thereby resulting in higher rates. Thus, maintaining reasonable rates is critically important as the transition to higher levels of renewable energy is achieved over time.

The Companies have considered the impact of a High DER forecast which represents a theoretical maximum potential for all single family homes and some commercial customers (assumed to be 20 to 25% of commercial sales due to limitations of rooftop space) to be "net zero". The Companies believe that since the PSIP contemplates market uptake that is correlated to plan-specific retail and export rates, the PSIP optimization process does account for load defection behavior and its impact to the resource plans and rates. For the December 2016 PSIP update, the Companies will provide an analysis of customer exit economics.

3. Work Flow and Timeline

WORK FLOW

The Companies and E3 will be simultaneously running production simulation models and developing candidate resource plans that incorporate the inputs and assumptions described in Section 2: Work Plan. After incorporating these updated inputs and assumptions into their RESOLVE model, E3 will provide us with a template of the data; the target date for this deliverable is September 9, 2016.

Using this template, E3 will develop theoretical, least-cost resource plans for O‘ahu, Maui, Hawai‘i Island; the target date for these preliminary results is September 20, 2016. If this target date is met, E3 will discuss these preliminary resource plans at the Commission’s scheduled Technical Conference #1 on September 21, 2016.

After the theoretical least-cost plans for the individual islands are developed, E3 will develop theoretical least-cost plans for interisland interconnected cable configurations. The difference between the cost of the theoretical least-cost interconnected plan and the combined cost of the theoretical least-cost plans of the individual islands will be the breakeven cost of the interconnection cable configuration. The target date for the theoretical least-cost interisland plans and breakeven cost analysis is September 30, 2016. If this target date is met, E3 will discuss these results and analysis at the Commission’s scheduled Technical Conference #2 on October 3, 2016.

After these E3 deliverables are complete, the Companies will use Plexos to run hourly and sub-hourly production simulations to optimize the E3 least-cost plans. Concurrent with this optimization, we will update the DER and DR portfolio, incorporating these portfolios into the production simulations for more complete assessment of the resource plan. In addition, we will perform sensitivity analyses to validate that the plans are reasonable. The target date for completing this analysis and optimization is the beginning of November, 2016.

While E3 is optimizing the long-range plan, the Companies will conduct system security analyses with a focus on the near-term action plan period that will likely not be significantly impacted by the E3 modeling. After the optimized least-cost plans are evaluated by production simulations, we will validate the system security analyses for the near-term action plan period, a few outer years that have significant system changes, and 2045 with 100% renewable energy attainment. We will incorporate the results of this system security analyses into the final resource plans filed in our December 2016 PSIP update.

While the Companies are running this modeling analysis, Ascend Analytics will be using their PowerSimm Planner model to evaluate E3's least-cost resource plans. Ascend Analytics will use PowerSimm's stochastic modeling capability to quantify the risk premium of the resource plans. This analysis will validate both the E3 modeling and the Companies' modeling in Plexos. If necessary, we will use the results from Ascend Analytics to refine the final resource plans filed in our December 2016 update.

Because of the short timeframes of a December 1 filing and the smaller size and smaller number of resource options, E3 will not be using their RESOLVE model to analyze the Moloka‘i and Lana‘i systems, nor include these two islands in the interisland interconnection analysis. Since the April 2016 PSIP update, however, the Companies have built Plexos models for Moloka‘i and Lana‘i and will use the Plexos models to develop the final plans for those islands, taking advantage of sub-hourly modeling of these islands.

A diagram of this work flow appears at the end of this report as Attachment A.

TIMELINE

The timeline for Commission-directed filings and events follows.

Milestone	Target Date
Work Plan Filing	September 7, 2016
Technical Conference 1	September 21, 2016
Technical Conference 2	October 3, 2016
Revised PSIP Filing	December 1, 2016

A. Fuel Price Forecasts

The Hawaiian Electric Companies are updating our PSIP based, in part, on the current state of the electric systems in Hawaiʻi; reasonable assumptions regarding technology readiness, availability, performance, applicability, and resource costs; and updated fuel price forecasts. We have documented and been fully transparent about these assumptions as well as our analytical methodologies.

The potential cost of producing electricity depends, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. The Companies use the following different types of fuels in our company-owned generators:

- Low Sulfur Fuel Oil (LSFO). A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- No.2 Diesel Oil
- Ultra-Low Sulfur Diesel (ULSD)
- Naphtha
- Medium Sulfur Fuel Oil (MSFO containing less than 2% sulfur; also called ISO-Industrial Fuel Oil)
- Biodiesel

Most fuel price forecasts are based on the EIA AEO Early Release report published in May 2016.

Hawaiian Electric Fuel Price Forecasts

$/MMBtu	Hawaiian Electric Fuel Price Forecasts					
	2016 EIA AEO Early Release					
Year	LSFO	No. 2 Diesel	ULSD	40% LSFO/ 60% ULSD	Biodiesel	LNG
2016	$6.85	$9.40	$10.32	$8.86	$29.87	n/a
2017	$9.13	$11.78	$12.76	$11.24	$32.31	n/a
2018	$11.04	$13.77	$14.82	$13.23	$34.41	n/a
2019	$13.85	$16.69	$17.81	$16.15	$37.30	n/a
2020	$15.45	$18.37	$19.55	$17.83	$39.20	n/a
2021	$16.77	$19.78	$21.01	$19.23	$40.93	$7.61
2022	$17.88	$20.97	$22.25	$20.42	$42.48	$7.77
2023	$18.76	$21.93	$23.24	$21.36	$43.76	$8.03
2024	$19.56	$22.79	$24.14	$22.22	$44.96	$8.43
2025	$20.48	$23.79	$25.17	$23.21	$46.28	$8.71
2026	$21.58	$24.96	$26.39	$24.37	$47.78	$8.31
2027	$22.60	$26.06	$27.53	$25.46	$49.23	$8.43
2028	$23.56	$27.10	$28.61	$26.50	$50.64	$8.64
2029	$24.75	$28.37	$29.93	$27.76	$52.28	$8.85
2030	$25.71	$29.42	$31.02	$28.79	$53.75	$9.03
2031	$27.09	$30.89	$32.55	$30.26	$55.62	$9.15
2032	$28.53	$32.44	$34.15	$31.80	$57.57	$9.36
2033	$30.05	$34.06	$35.83	$33.41	$59.60	$9.48
2034	$31.68	$35.80	$37.63	$35.14	$61.74	$9.64
2035	$33.02	$37.24	$39.13	$36.57	$63.66	$9.78
2036	$34.78	$39.12	$41.07	$38.43	$65.94	$9.96
2037	$36.19	$40.64	$42.65	$39.94	$67.95	$10.07
2038	$38.08	$42.64	$44.73	$41.94	$70.37	$10.19
2039	$39.77	$44.45	$46.60	$43.74	$72.63	$10.49
2040	$41.89	$46.70	$48.92	$45.97	$75.26	$10.71
2041	$43.62	$48.54	$50.83	$47.81	$77.54	$10.94
2042	$45.54	$50.59	$52.94	$49.84	$79.99	n/a
2043	$47.51	$52.67	$55.10	$51.92	$82.48	n/a
2044	$49.51	$54.80	$57.30	$54.04	$85.00	n/a
2045	$51.56	$56.97	$59.54	$56.20	$87.55	n/a

Table 1. Hawaiian Electric Fuel Price Forecasts (nominal dollars)

Maui Electric Fuel Price Forecasts

$/MMBtu	Maui Electric Fuel Price Forecasts						
	2016 EIA AEO Early Release						
Year	MSFO	No. 2 Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	Biodiesel	LNG
2016	$5.59	$9.52	$9.87	$11.09	$14.07	$29.87	n/a
2017	$7.55	$12.17	$12.58	$13.78	$16.79	$32.31	n/a
2018	$9.19	$14.40	$14.86	$16.05	$19.08	$34.41	n/a
2019	$11.60	$17.66	$18.20	$19.35	$22.39	$37.30	n/a
2020	$12.98	$19.53	$20.12	$21.27	$24.35	$39.20	n/a
2021	$14.10	$21.08	$21.71	$22.87	$26.00	$40.93	$9.98
2022	$15.06	$22.40	$23.06	$24.23	$27.42	$42.48	$10.18
2023	$15.81	$23.45	$24.14	$25.32	$28.56	$43.76	$10.48
2024	$16.49	$24.40	$25.12	$26.31	$29.60	$44.96	$10.92
2025	$17.28	$25.50	$26.24	$27.44	$30.79	$46.28	$11.24
2026	$18.21	$26.79	$27.57	$28.78	$32.18	$47.78	$10.89
2027	$19.09	$28.01	$28.81	$30.03	$33.49	$49.23	$11.05
2028	$19.91	$29.15	$29.98	$31.22	$34.73	$50.64	$11.30
2029	$20.92	$30.56	$31.43	$32.67	$36.24	$52.28	$11.57
2030	$21.74	$31.70	$32.60	$33.86	$37.50	$53.75	$11.79
2031	$22.92	$33.33	$34.27	$35.55	$39.25	$55.62	$11.96
2032	$24.16	$35.04	$36.02	$37.31	$41.07	$57.57	$12.22
2033	$25.45	$36.83	$37.86	$39.15	$42.99	$59.60	$12.39
2034	$26.85	$38.75	$39.83	$41.13	$45.03	$61.74	$12.60
2035	$27.99	$40.34	$41.46	$42.78	$46.76	$63.66	$12.79
2036	$29.50	$42.42	$43.59	$44.91	$48.96	$65.94	$13.02
2037	$30.70	$44.09	$45.30	$46.65	$50.77	$67.95	$13.19
2038	$32.32	$46.32	$47.58	$48.93	$53.12	$70.37	$13.36
2039	$33.77	$48.31	$49.63	$50.99	$55.25	$72.63	$13.72
2040	$35.59	$50.81	$52.18	$53.54	$57.88	$75.26	$14.00
2041	$37.07	$52.85	$54.27	$55.64	$60.05	$77.54	$14.29
2042	$38.71	$55.11	$56.59	$57.97	$62.44	$79.99	n/a
2043	$40.39	$57.42	$58.96	$60.34	$64.88	$82.48	n/a
2044	$42.11	$59.78	$61.37	$62.76	$67.37	$85.00	n/a
2045	$43.86	$62.18	$63.84	$65.23	$69.90	$87.55	n/a

Table 2. Maui Electric Fuel Price Forecasts (nominal dollars)

Hawai‘i Electric Light Fuel Price Forecasts

$/MMBtu	Hawai‘i Electric Light Fuel Price Forecasts					
	2016 EIA AEO Early Release					
Year	MSFO	No. 2 Diesel	ULSD	Naphtha	Biodiesel	LNG
2016	$5.90	$9.98	$10.25	$11.96	$29.87	n/a
2017	$7.88	$12.55	$12.88	$14.40	$32.31	n/a
2018	$9.54	$14.70	$15.09	$16.46	$34.41	n/a
2019	$11.98	$17.86	$18.31	$19.44	$37.30	n/a
2020	$13.37	$19.68	$20.17	$21.19	$39.20	n/a
2021	$14.51	$21.19	$21.72	$22.67	$40.93	$10.20
2022	$15.48	$22.48	$23.05	$23.93	$42.48	$10.41
2023	$16.24	$23.51	$24.10	$24.94	$43.76	$10.71
2024	$16.93	$24.44	$25.05	$25.87	$44.96	$11.16
2025	$17.73	$25.51	$26.15	$26.92	$46.28	$11.48
2026	$18.68	$26.78	$27.45	$28.16	$47.78	$11.14
2027	$19.57	$27.97	$28.66	$29.33	$49.23	$11.30
2028	$20.40	$29.09	$29.81	$30.44	$50.64	$11.56
2029	$21.43	$30.46	$31.21	$31.78	$52.28	$11.83
2030	$22.26	$31.59	$32.36	$32.90	$53.75	$12.05
2031	$23.46	$33.18	$33.99	$34.45	$55.62	$12.23
2032	$24.71	$34.85	$35.70	$36.08	$57.57	$12.50
2033	$26.03	$36.60	$37.49	$37.79	$59.60	$12.67
2034	$27.44	$38.47	$39.41	$39.62	$61.74	$12.89
2035	$28.60	$40.03	$41.00	$41.15	$63.66	$13.09
2036	$30.13	$42.05	$43.07	$43.12	$65.94	$13.32
2037	$31.35	$43.69	$44.75	$44.73	$67.95	$13.49
2038	$32.99	$45.86	$46.97	$46.83	$70.37	$13.68
2039	$34.46	$47.80	$48.96	$48.73	$72.63	$14.04
2040	$36.30	$50.23	$51.45	$51.08	$75.26	$14.32
2041	$37.80	$52.22	$53.48	$53.01	$77.54	$14.62
2042	$39.47	$54.43	$55.74	$55.15	$79.99	n/a
2043	$41.17	$56.68	$58.04	$57.33	$82.48	n/a
2044	$42.91	$58.97	$60.39	$59.56	$85.00	n/a
2045	$44.69	$61.31	$62.79	$61.82	$87.55	n/a

Table 3. Hawai‘i Electric Light Fuel Price Forecasts (nominal dollars)

LNG Total Cost Price Forecasts

2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas

$/MMBtu	2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$14.76	$17.09	$17.31
2022	$15.01	$17.38	$17.61
2023	$15.35	$17.76	$17.99
2024	$15.83	$18.28	$18.52
2025	$16.20	$18.69	$18.93
2026	$15.88	$18.42	$18.67
2027	$16.09	$18.67	$18.92
2028	$16.39	$19.02	$19.27
2029	$16.70	$19.37	$19.63
2030	$16.96	$19.68	$19.95
2031	$17.18	$19.95	$20.22
2032	$17.49	$20.31	$20.59
2033	$17.71	$20.57	$20.86
2034	$17.97	$20.89	$21.18
2035	$18.22	$21.19	$21.48
2036	$18.50	$21.52	$21.82
2037	$18.72	$21.80	$22.10
2038	$18.95	$22.08	$22.39
2039	$19.36	$22.55	$22.86
2040	$19.69	$22.94	$23.26
2041	$20.05	$23.35	$23.68

Table 4. 2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas (reference case—nominal dollars)

A. Fuel Price Forecasts

Hawaiian Electric Fuel Price Forecast Trends

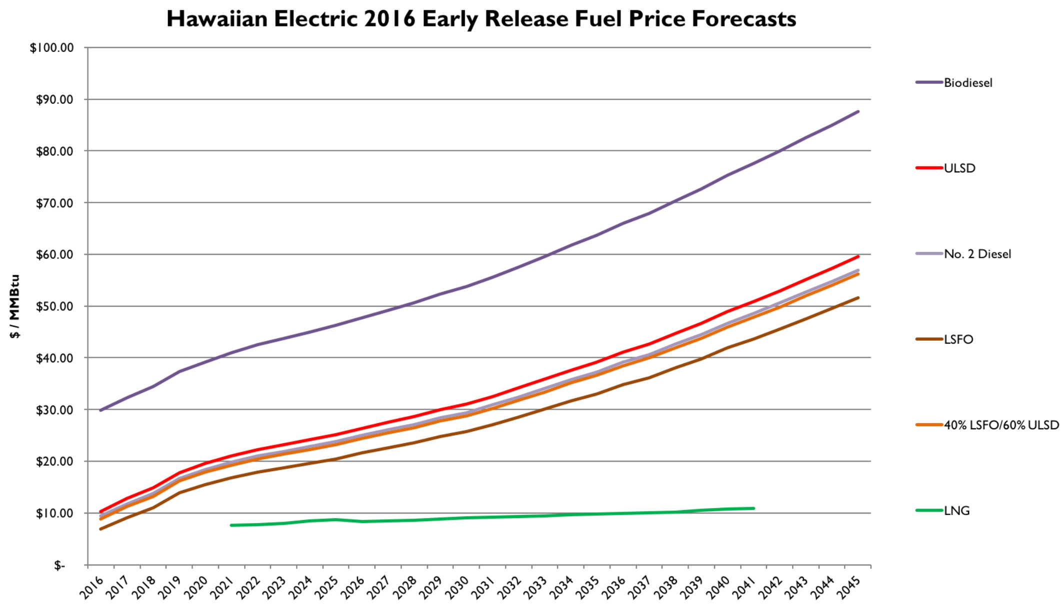


Figure 3. Hawaiian Electric Fuel Price Forecast Trends

Maui Electric Fuel Price Forecast Trends

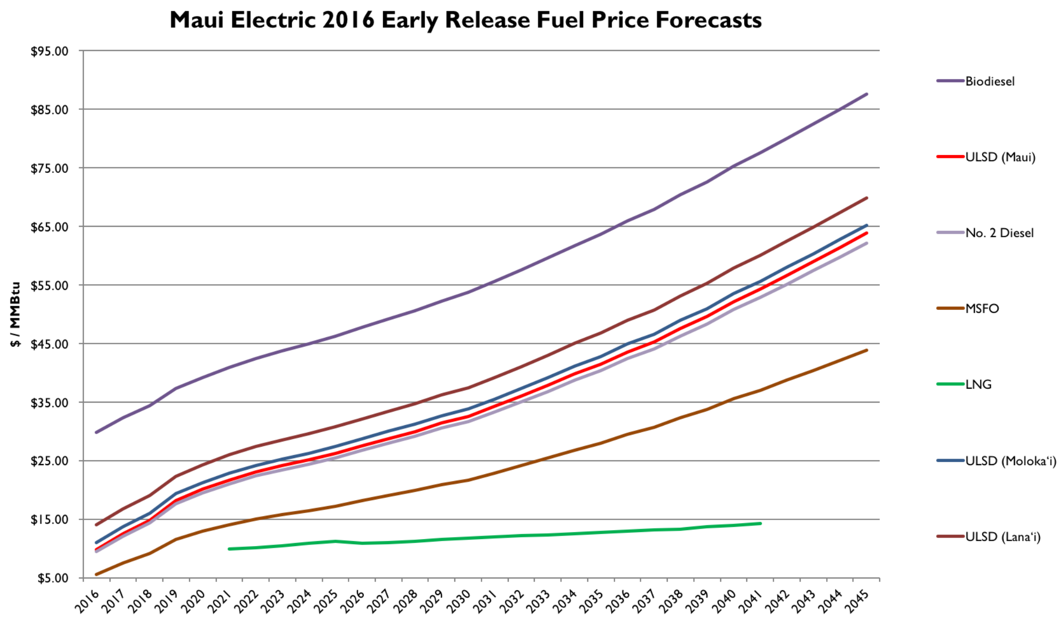


Figure 4.Maui Electric Fuel Price Forecast Trends

A. Fuel Price Forecasts

Hawai'i Electric Light Fuel Price Forecast Trends

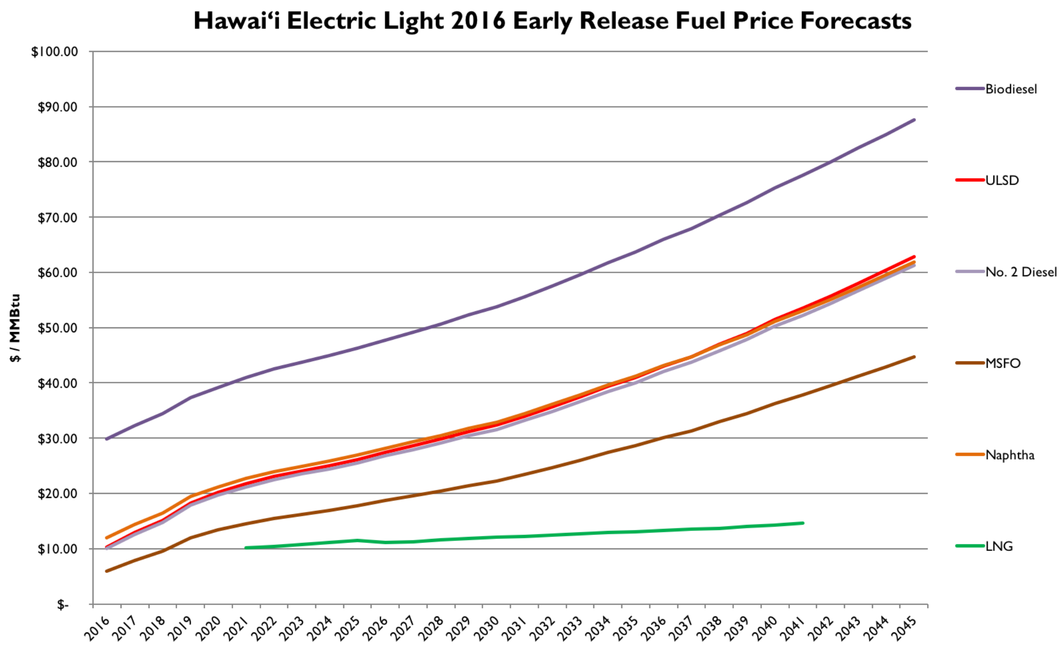


Figure 5.Hawai'i Electric Light Fuel Price Forecast Trends

B. Resource Cost Assumptions

Resource costs and potential are key foundational assumptions for developing the PSIP. We have re-evaluated our resource costs since filing our *PSIP Update Report: April 2016*. This appendix contains those marginally updated resource costs.

New Resource Cost Assumptions: O‘ahu

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$,[12] without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	DG-PV	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2016	$2,215	$6,340	n/a	n/a	$2,293	$3,945	$12,304
2017	$2,254	$6,255	n/a	n/a	$2,127	$3,716	$12,525
2018	$2,193	$6,165	n/a	n/a	$2,047	$3,573	$11,681
2019	$2,178	$6,070	n/a	n/a	$1,984	$3,457	$10,781
2020	$2,230	$5,969	$4,847	$4,322	$1,932	$3,360	$9,848
2021	$2,520	$5,880	$5,207	$4,672	$1,892	$3,285	$8,874
2022	$2,586	$5,720	$5,324	$4,778	$2,099	$3,218	$7,867
2023	$2,644	$5,553	$5,456	$4,899	$2,064	$3,160	$7,813
2024	$2,691	$5,571	$5,560	$4,992	$2,035	$3,111	$7,756
2025	$2,722	$5,587	$5,664	$5,085	$2,012	$3,068	$7,694
2026	$2,753	$5,602	$5,758	$5,166	$1,995	$3,034	$7,627
2027	$2,773	$5,616	$5,851	$5,248	$1,980	$3,004	$7,555
2028	$2,805	$5,629	$5,948	$5,333	$1,966	$2,976	$7,478
2029	$2,830	$5,640	$6,049	$5,422	$1,955	$2,952	$7,396
2030	$2,867	$5,650	$6,154	$5,514	$1,946	$2,933	$7,309

* = Amounts have been reduced by the $500,000 state tax credit cap

Table 5. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (1a of 2)

[12] Solar PV costs are typically quoted based on the price per kW of Direct Current (DC) output (that is, the total capacity of the PV panels). These utility-scale solar PV costs has been converted to the price per kW of Alternating Current (AC) output supplied to the grid using a DC to AC ratio of 1.5:1 for this conversion.

New Resource Cost Assumptions: O‘ahu (1b of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2031	$2,891	$5,705	$6,257	$5,604	$1,937	$2,925	$7,216
2032	$2,925	$5,760	$6,362	$5,696	$1,928	$2,917	$7,117
2033	$2,949	$5,815	$6,468	$5,789	$1,920	$2,910	$7,245
2034	$2,984	$5,871	$6,577	$5,884	$1,910	$2,902	$7,375
2035	$3,010	$5,926	$6,688	$5,981	$1,902	$2,894	$7,508
2036	$3,045	$5,982	$6,800	$6,079	$1,893	$2,887	$7,643
2037	$3,071	$6,037	$6,915	$6,179	$1,884	$2,879	$7,781
2038	$3,107	$6,093	$7,031	$6,281	$1,875	$2,872	$7,921
2039	$3,134	$6,149	$7,150	$6,385	$1,867	$2,864	$8,064
2040	$3,171	$6,205	$7,270	$6,490	$1,857	$2,856	$8,209
2041	$3,199	$6,266	$7,393	$6,598	$1,849	$2,849	$8,356
2042	$3,237	$6,328	$7,518	$6,707	$1,839	$2,841	$8,507
2043	$3,265	$6,390	$7,646	$6,818	$1,831	$2,834	$8,660
2044	$3,303	$6,452	$7,775	$6,931	$1,821	$2,827	$8,816
2045	$3,333	$6,514	$7,907	$7,046	$1,813	$2,819	$8,975

* = Amounts have been reduced by the $500,000 state tax credit cap

Table 6. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (1b of 2)

New Resource Cost Assumptions: O‘ahu (2a of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O‘ahu	O‘ahu	O‘ahu	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu
2016	$1,758	$1,660	$1,237	$6,296	$3,177	$2,493	$1,323
2017	$1,783	$1,683	$1,253	$6,092	$3,219	$2,526	$1,347
2018	$1,797	$1,697	$1,261	$6,178	$3,238	$2,541	$1,371
2019	$1,822	$1,720	$1,277	$6,269	$3,280	$2,574	$1,396
2020	$1,845	$1,742	$1,292	$6,354	$3,319	$2,604	$1,421
2021	$1,870	$1,766	$1,309	$6,446	$3,362	$2,638	$1,447
2022	$1,896	$1,790	$1,326	$6,541	$3,406	$2,672	$1,473
2023	$1,921	$1,813	$1,342	$6,633	$3,448	$2,705	$1,499
2024	$1,944	$1,836	$1,358	$6,725	$3,487	$2,736	$1,526
2025	$1,969	$1,859	$1,373	$6,826	$3,527	$2,768	$1,554
2026	$1,992	$1,881	$1,388	$6,918	$3,564	$2,797	$1,582
2027	$2,021	$1,909	$1,408	$7,019	$3,617	$2,838	$1,610
2028	$2,051	$1,937	$1,428	$7,121	$3,668	$2,878	$1,639
2029	$2,079	$1,963	$1,447	$7,222	$3,716	$2,916	$1,669
2030	$2,108	$1,991	$1,466	$7,323	$3,766	$2,955	$1,699

Table 7. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (2a of 2)

New Resource Cost Assumptions: O'ahu (2b of 2)

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O'ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O'ahu	O'ahu	O'ahu	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu
2031	$2,139	$2,019	$1,487	$7,425	$3,819	$2,997	$1,729
2032	$2,169	$2,048	$1,507	$7,528	$3,872	$3,038	$1,761
2033	$2,202	$2,079	$1,530	$7,638	$3,930	$3,083	$1,792
2034	$2,234	$2,110	$1,552	$7,743	$3,986	$3,127	$1,825
2035	$2,270	$2,143	$1,577	$7,850	$4,050	$3,178	$1,857
2036	$2,304	$2,176	$1,601	$7,952	$4,112	$3,226	$1,891
2037	$2,342	$2,211	$1,627	$8,062	$4,179	$3,279	$1,925
2038	$2,379	$2,246	$1,653	$8,166	$4,246	$3,331	$1,959
2039	$2,419	$2,284	$1,681	$8,267	$4,317	$3,387	$1,995
2040	$2,455	$2,318	$1,706	$8,361	$4,382	$3,439	$2,031
2041	$2,499	$2,360	$1,737	$8,512	$4,461	$3,501	$2,067
2042	$2,544	$2,403	$1,768	$8,665	$4,542	$3,564	$2,104
2043	$2,590	$2,446	$1,800	$8,821	$4,623	$3,628	$2,142
2044	$2,637	$2,490	$1,832	$8,979	$4,707	$3,693	$2,181
2045	$2,684	$2,535	$1,865	$9,141	$4,791	$3,760	$2,220

Table 8. Replacement Resource Capital Cost Assumptions w/o AFUDC: O'ahu 2031–2045 (2b of 2)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui	Lana'i Moloka'i	Lana'i Moloka'i	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui
2016	$3,921	$2,718	$2,215	$3,510	$3,523	$2,762	$2,349	$2,074
2017	$3,987	$2,765	$2,254	$3,603	$3,283	$2,568	$2,180	$1,921
2018	$3,884	$2,691	$2,193	$4,111	$3,169	$2,476	$2,099	$1,848
2019	$3,858	$2,673	$2,178	$4,380	$3,077	$2,401	$2,034	$1,789
2020	$3,948	$2,737	$2,230	$4,803	$3,003	$2,341	$1,981	$1,741
2021	$4,266	$3,035	$2,520	$5,588	$2,946	$2,295	$1,941	$1,705
2022	$4,377	$3,114	$2,586	$5,734	$3,056	$2,414	$2,066	$1,833
2023	$4,475	$3,184	$2,644	$5,916	$3,018	$2,384	$2,040	$1,810
2024	$4,553	$3,240	$2,691	$6,020	$2,987	$2,360	$2,019	$1,792
2025	$4,606	$3,277	$2,722	$6,122	$2,961	$2,340	$2,002	$1,776
2026	$4,659	$3,315	$2,753	$6,192	$2,943	$2,325	$1,989	$1,765
2027	$4,693	$3,339	$2,773	$6,258	$2,926	$2,312	$1,978	$1,755
2028	$4,747	$3,377	$2,805	$6,330	$2,913	$2,301	$1,969	$1,747
2029	$4,789	$3,407	$2,830	$6,410	$2,902	$2,292	$1,961	$1,740
2030	$4,853	$3,453	$2,867	$6,495	$2,894	$2,286	$1,956	$1,736

* = Amounts have been reduced by the $500,000 state tax credit cap

Table 9. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (1a of 2)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (1b of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2031	$4,892	$3,481	$2,891	$6,571	$2,886	$2,280	$1,951	$1,731
2032	$4,950	$3,522	$2,925	$6,649	$2,879	$2,274	$1,946	$1,727
2033	$4,992	$3,552	$2,949	$6,727	$2,871	$2,268	$1,941	$1,722
2034	$5,051	$3,594	$2,984	$6,807	$2,864	$2,262	$1,936	$1,718
2035	$5,093	$3,624	$3,010	$6,887	$2,856	$2,256	$1,931	$1,713
2036	$5,154	$3,667	$3,045	$6,968	$2,849	$2,250	$1,925	$1,709
2037	$5,198	$3,698	$3,071	$7,051	$2,841	$2,244	$1,920	$1,704
2038	$5,259	$3,742	$3,107	$7,134	$2,834	$2,239	$1,915	$1,700
2039	$5,304	$3,774	$3,134	$7,218	$2,826	$2,233	$1,910	$1,695
2040	$5,367	$3,819	$3,171	$7,303	$2,819	$2,227	$1,905	$1,691
2041	$5,414	$3,852	$3,199	$7,389	$2,811	$2,221	$1,900	$1,686
2042	$5,478	$3,897	$3,237	$7,477	$2,804	$2,215	$1,895	$1,682
2043	$5,525	$3,931	$3,265	$7,565	$2,796	$2,209	$1,890	$1,677
2044	$5,591	$3,978	$3,303	$7,654	$2,789	$2,203	$1,885	$1,673
2045	$5,640	$4,013	$3,333	$7,744	$2,782	$2,198	$1,880	$1,669

* = Amounts have been reduced by the $500,000 state tax credit cap

Table 10. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2031–2045 (1b of 2)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island (2a of 2)

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2016	$3,985	$3,586	$8,334	$6,296	$8,804	$10,394	$5,407
2017	$3,753	$3,634	$8,064	$6,092	$8,963	$10,532	$5,479
2018	$3,609	$3,655	$8,179	$6,178	$9,124	$10,593	$5,510
2019	$3,492	$3,702	$8,298	$6,269	$9,289	$10,731	$5,582
2020	$3,394	$3,747	$8,411	$6,354	$9,456	$10,859	$5,649
2021	$3,318	$3,795	$8,533	$6,446	$9,626	$11,000	$5,722
2022	$3,251	$3,844	$8,659	$6,541	$9,799	$11,142	$5,796
2023	$3,192	$3,892	$8,781	$6,633	$9,976	$11,280	$5,868
2024	$3,142	$3,936	$8,902	$6,725	$10,155	$11,408	$5,935
2025	$3,100	$3,981	$9,036	$6,826	$10,338	$11,540	$6,003
2026	$3,065	$4,023	$9,158	$6,918	$10,524	$11,661	$6,066
2027	$3,034	$4,082	$9,291	$7,019	$10,713	$11,832	$6,155
2028	$3,007	$4,140	$9,427	$7,121	$10,906	$12,000	$6,243
2029	$2,982	$4,194	$9,560	$7,222	$11,103	$12,157	$6,324
2030	$2,962	$4,251	$9,694	$7,323	$11,302	$12,322	$6,410

Table 11. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (2a of 2)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island (2b of 2)

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2031	$2,955	$4,311	$9,829	$7,425	$11,506	$12,494	$6,500
2032	$2,947	$4,371	$9,966	$7,528	$11,713	$12,668	$6,590
2033	$2,939	$4,436	$10,111	$7,638	$11,924	$12,856	$6,688
2034	$2,931	$4,499	$10,250	$7,743	$12,138	$13,040	$6,783
2035	$2,924	$4,571	$10,391	$7,850	$12,357	$13,250	$6,893
2036	$2,916	$4,641	$10,527	$7,952	$12,579	$13,453	$6,998
2037	$2,908	$4,717	$10,673	$8,062	$12,806	$13,672	$7,112
2038	$2,901	$4,792	$10,810	$8,166	$13,036	$13,890	$7,226
2039	$2,893	$4,873	$10,944	$8,267	$13,271	$14,123	$7,347
2040	$2,885	$4,947	$11,068	$8,361	$13,510	$14,338	$7,459
2041	$2,878	$5,036	$11,267	$8,512	$13,753	$14,596	$7,593
2042	$2,870	$5,126	$11,470	$8,665	$14,001	$14,859	$7,730
2043	$2,863	$5,219	$11,677	$8,821	$14,253	$15,126	$7,869
2044	$2,855	$5,313	$11,887	$8,979	$14,509	$15,398	$8,010
2045	$2,848	$5,408	$12,101	$9,141	$14,770	$15,676	$8,154

Table 12. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2031–2045 (2b of 2)

Replacement Resource Construction Expenditure Profiles: O‘ahu

	Replacement Resource Construction Expenditure Profiles: O‘ahu						
Years Before Commercial Operation Date	Onshore Wind	Offshore Wind Floating Platform	Onshore Wind + Cable	Onshore Wind + Cable	Utility-Scale Solar PV	DG-PV	Solar CSP w/ 10 Hours Storage
–5	00%	00%	00%	00%	00%	n/a	00%
–4	00%	00%	00%	00%	00%	n/a	00%
–3	00%	20%	20%	20%	00%	n/a	00%
–2	10%	40%	40%	40%	10%	n/a	10%
–1	90%	40%	40%	40%	90%	n/a	90%
Total COD	100%	100%	100%	100%	100%	n/a	100%

Table 13. Replacement Resource Construction Expenditure Profiles: O‘ahu (1 of 2)

	Replacement Resource Construction Expenditure Profiles: O'ahu						
Years Before Commercial Operation Date	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
–5	00%	00%	00%	00%	00%	00%	00%
–4	15%	10%	00%	00%	00%	00%	00%
–3	35%	35%	15%	00%	15%	15%	00%
–2	35%	40%	65%	10%	65%	65%	65%
–1	15%	15%	20%	90%	20%	20%	35%
Total COD	100%	100%	100%	100%	100%	100%	100%

Table 14. Replacement Resource Construction Expenditure Profiles: O'ahu (2 of 2)

Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island							
Years Before Commercial Operation Date	Onshore Wind	Onshore Wind	Onshore Wind	Onshore Wind	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV
–5	00%	00%	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%	00%	00%
–2	10%	10%	10%	00%	00%	10%	10%	10%
–1	90%	90%	90%	100%	100%	90%	90%	90%
Total COD	100%	100%	100%	100%	100%	100%	100%	100%

Table 15. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (1 of 2)

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island						
Years Before Commercial Operation Date	DG-PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
–5	n/a	00%	00%	00%	00%	00%	00%
–4	n/a	00%	00%	00%	00%	00%	00%
–3	n/a	20%	25%	20%	00%	25%	20%
–2	n/a	65%	60%	65%	40%	60%	65%
–1	n/a	15%	15%	15%	60%	15%	15%
Total COD	n/a	100%	100%	100%	100%	100%	100%

Table 16. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (2 of 2)

C. NREL Resource Potential Study

The Companies commissioned the National Renewable Energy Laboratory (NREL) to conduct three studies in support of our *PSIP Update Report: December 2016*. All three assessed various resource potentials on three of the islands we serve: O'ahu, Maui, and Hawai'i Island. These studies are:

- *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource* assessed these three resource potentials. At our request, NREL reran the utility-scale wind and PV portion of this study based on Stakeholder input.
- *Aggregated Wind Power Profile Time Series* used two scenarios to calculate hourly onshore wind power profiles.
- *Electricity Generation Capital, Fixed, and Variable O&M Costs* independently assessed our resource data assumptions.

Based on Party input and our request, NREL updated its *Electricity Generation Capital, Fixed, and Variable O&M Costs* study which resulted increased resource potential for utility-scale PV on O'ahu.

UTILITY-SCALE ONSHORE WIND, UTILITY-SCALE PV, AND CSP POTENTIAL RESOURCE

This NREL report estimated the onshore utility-scale PV and utility-scale wind potential for each of the three main islands we serve: O‘ahu, Maui, and Hawai‘i Island. NREL used a square (four kilometer by four kilometer) grid database that they developed and refined over several years. The grid details solar irradiance at the earth’s surface and wind speeds 80 meters above the earth’s surface. Their study assumed a “typical” year. Based on this database, their study identified areas with high solar or wind potential.

At our request, NREL reran this study using Stakeholder input.

For all three islands, the study excluded land with a greater than 5% slope, urban areas, wetlands, park lands, mountainous areas, ravines, and certain agricultural areas (those designated “B” and “C”). The study thus, assumed that the remaining land was available to be developed for utility-scale wind, utility-scale PV, or for both wind and PV together.

NREL ran two additional studies for O‘ahu that excluded land with a greater then 10% slope: one study excluded agricultural “B” and “C” land; another study included agricultural “B” and “C” land. These studies also assumed that the remaining land was available to be developed for utility-scale wind, utility-scale PV, or for both wind and PV together.

The results of the NREL resource potential study are indicative as they do not represent the actual developable land. In reality, the amount of land available for development is likely less than the potential shown in the NREL assessment, perhaps significantly. For instance, some of this available land might be privately held and not for sale. In addition, agriculture “B” and “C” land would require a Special Use Permit to be developed—not a trivial task as these permits are rarely granted. Finally, the capital cost for developing land with a greater than 5% slope would be moderately higher than for land with less than a 5% slope.

The results do suggest renewable resource potential on Maui and Hawai‘i Island that exceeds each island’s native electrical loads. The results for O‘ahu, however, suggest that additional utility-scale wind development is less than 100 MW, and that while the resource potential for utility-scale PV is becoming constrained, the addition of a few hundred megawatts is possible. Appendix E: New Resource Options discusses the implications of this NREL study.

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

Billy Roberts
Erol Chartan
Andrew Weekley
Anthony Lopez
Carlo Brancucci Martinez-Anido
Bri-Mathias Hodge

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on July 21, 2016.

I. Executive Summary

This report by the National Renewable Energy Laboratory NREL presents estimates for the total amount of developable utility-scale wind, utility-scale solar photovoltaic (PV) and concentrated solar power (CSP) potential for the Hawaiian islands of O‘ahu, Maui, and Hawai‘i Island. These estimates of technical potential do not take into account existing or committed wind and solar plants. Existing solar and wind resource data and the use of standard exclusion factors were utilized by NREL to provide independent estimates. Sites where both solar PV and wind could be deployed were examined together as possible dual use sites.

Table 5 through Table 22 show the utility-scale onshore wind and utility-scale solar PV resource potentials (in MWac terms) for the islands of Hawai‘i Island, Maui, and O‘ahu for the following four analyses that differ in terms of land exclusions:

1. Default slope analysis
2. Default slope analysis without DOD exclusions
3. Improved slope analysis without DOD exclusions
4. Improved slope analysis without DOD exclusions with updated agricultural land exclusions.

Table 5, Table 18, and Table 19 show the wind potential with an additional exclusion for each row excluding any site whose mean wind speed at 80m height is lower than the figures stated. Table 20, Table 21, and Table 22 show the utility-scale PV potential organized by two main exclusions, capacity factor and slope. The slope exclusions exclude all land with a slope steeper than the figure stated as potential for PV and the capacity factor exclusions exclude all PV whose capacity factor are lower than the figures stated. The difference between the default and improved slope analyses and the updated agricultural land exclusions are described in sections 4.1 and 4.2.

No technical potential values are provided for CSP. When considering the direct normal irradiance potential and the GIS exclusion factors in the three islands, very limited CSP potential exists.

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	3,276	3,276	3,303	3,532
>= 7.5	2,107	2,107	2,123	2,236
>= 8.5	1,290	1,290	1,299	1,334

Table 17. Utility-Scale Onshore Wind Potential for Hawai'i (MWac)

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	698	698	700	840
>= 7.5	412	412	417	448
>= 8.5	117	117	121	118

Table 18. Utility-Scale Onshore Wind Potential for Maui (MWac)

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	174	183	154	162
>= 7.5	81	81	69	68
>= 8.5	19	19	16	16

Table 19. Utility-Scale Onshore Wind Potential for O'ahu (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 3%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	10,868	30,634	10,868	30,703	12,557	33,012	11,514	30,484
>= 12	10,833	30,573	10,833	30,643	12,523	32,949	11,481	30,421
>= 14	10,703	30,036	10,703	30,105	12,385	32,405	11,467	30,039
>= 16	8,339	20,204	8,339	20,273	9,448	21,873	8,646	20,312
>= 18	5,481	14,841	5,481	14,911	6,322	16,338	6,019	15,757
>= 20	2,469	8,315	2,469	8,385	3,075	9,193	3,075	9,189

Table 20. Utility-Scale Solar PV Potential for Hawai'i (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,321	0	1,321	697	1,443	272	783
>= 12	0	1,321	0	1,321	697	1,443	272	783
>= 14	0	1,321	0	1,321	697	1,443	272	783
>= 16	0	1,321	0	1,321	697	1,443	272	783
>= 18	0	1,321	0	1,321	697	1,443	272	783
>= 20	0	1,110	0	1,110	697	1,230	272	576

Table 21. Utility-Scale Solar PV Potential for Maui (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)			
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 10%	Slope 10%*
>= 10	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 12	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 14	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 16	0	1,338	67	2,155	1,527	2,301	583	796	1,428	2,923
>= 18	0	1,338	67	2,134	1,527	2,277	583	793	1,368	2,756
>= 20	0	414	67	895	692	968	329	397	664	1,053

*"B" and "C" agricultural lands are not excluded (see section 4.2 for details).

Table 22. Utility-Scale Solar PV Potential for O'ahu (MWac)

II. Report Structure

This report is split into four main sections: introduction, overview of data and modeling assumptions, GIS exclusions, and the resource potential maps (for Analysis 1) for each technology type: utility-scale onshore wind, utility-scale PV, and concentrated solar power.

III. Overview of Data & Modeling Assumptions

a. Utility-Scale Onshore Wind

The REEDS data set containing utility-scale wind speed data was supplied from AWS [1]. A typical meteorological year (TMY) method was used with 20 km summary resolution where simulated hourly wind resource data and statistics were generated for each 3% gross capacity factor interval calculated from the 200 m spatial map. The mean wind speed data at 200 m spatial resolution were attained for 80 m height. The power density assumed was 3 MW/km as used in the Wind Vision report and seen in the Wind Vision Appendices [2].

b. Utility-Scale PV

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [3-5] which has 4 km x 4 km and 30 minute resolution. NSRDB is a serially complete collection of meteorological and solar irradiance data sets. The database is managed and updated using the latest methods of research by a specialized team of forecasters at the National Renewable Energy Laboratory (NREL). The data spans 1998 – 2014 and the latest version now uses satellite retrievals. Cloud properties, aerosol depth, and precipitable water vapor are used to calculate Global Horizontal Irradiance (GHI) values at each point in the mesh.

The System Advisor Model (SAM) [6] with parameters DC – AC ratio = 1.5 was used to attain capacity factors for 1-axis tracking panels with tilt fixed at zero. Please refer to Appendix A for an extended list of the SAM parameters used in this analysis. SAM is a performance and financial model which makes performance predictions for grid-connected power projects based on parameters that you specify as inputs to the model. It is distributed for free by NREL. SAM's user interface allows the user to input variables and simulation controls and displays tables and graphs of results. Information on the code can be found in the PVWatts Version 5 Manual [7].

The capacity-weighted average land use for a 1-axis small PV plant was taken to be 8.7acres/MWac [8].

Figure 6 illustrates the inter-annual variability of capacity factors as a function of location index. It highlights the value of having a wide temporal range of data. In this plot the two-dimensional geospatial dataset is displayed as a sequence rather than a map and each point in the sequence corresponds to a latitude and longitude in a geospatial grid. Neighbors in the sequence are either neighbors in latitude or longitude depending on how the data is converted from the geospatial grid, that is, whether the data is traversed in the latitude or longitude dimension.

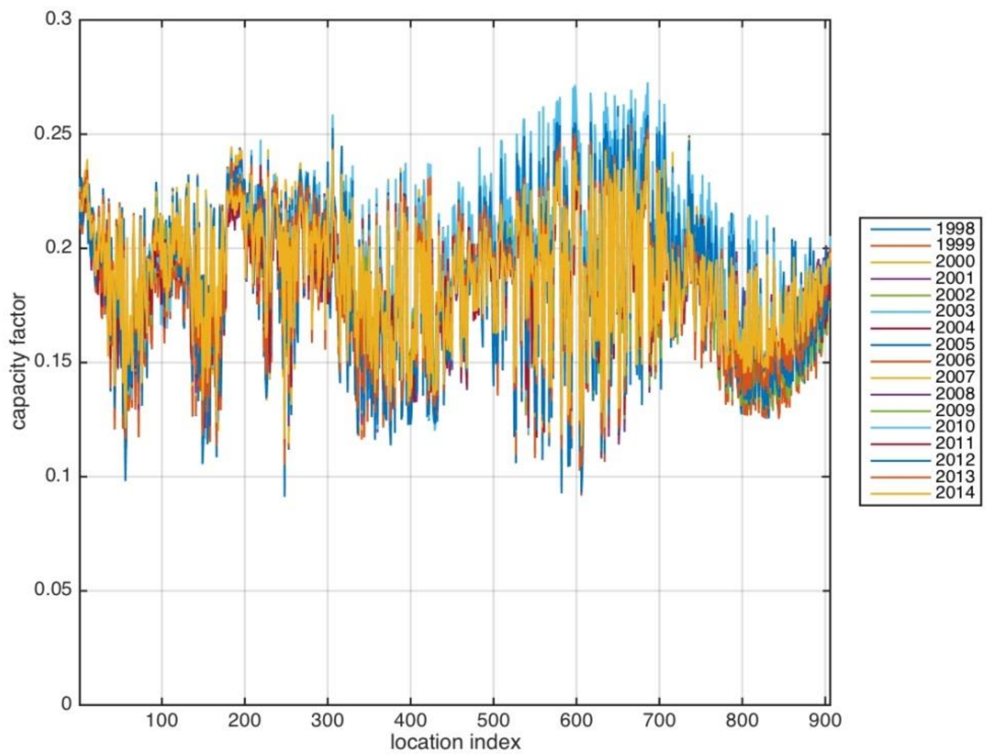


Figure 6. Annual Variability of Solar Capacity Factors

c. Concentrated Solar Power (CSP)

In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB. In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB as per the description above. DNI > 400 W/m^2 was calculated by finding the number of half hour intervals in a year where DNI > 400 W/m^2, dividing by the number of half hour intervals in the year and averaging across 1998 – 2014. The value 400 is chosen as a suitable benchmark given the current CSP technology.

Figure 7 shows the percentage of half hour intervals for all the years to give some visual indication of the variability in this statistic.

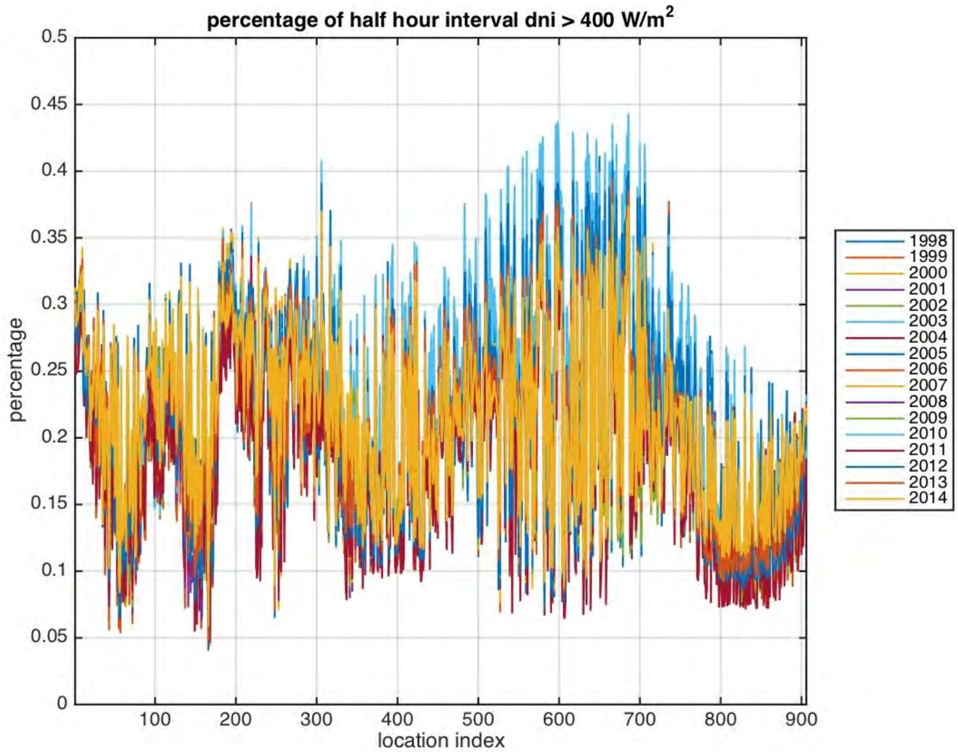


Figure 7. Percentage of Half-Hour Interval DNI > 400 W/m^2

IV. GIS Exclusions

Geospatial analysis and mapping of the wind and solar resources was accomplished through the use of Geographic Information Systems (GIS) technology. Using relevant and available geographic data, areas likely to be impediments to development were excluded from consideration. Standard exclusions applied to all technologies were National and State Parks, US Fish & Wildlife Service (FWS) lands, areas zoned as urban, areas classified as Important Agricultural Land, areas within any “A” level flood zone, areas classified as lava flow hazard zones 1 and 2, all military or Department of Defense (DOD) lands, and wetlands. All of these datasets, except for National and State Parks and FWS lands were acquired from the state through the Hawaii Office of Planning website (planning.hawaii.gov). Additional resource-specific exclusions were applied as well. The photovoltaic analysis included exclusions for terrain slopes greater than either 3% or 5%, as well as a minimum contiguous area requirement of 1 km^2. Concentrating solar included a slope exclusion of greater than 3% as well as the minimum contiguous area requirement of 1 square kilometer, plus a minimum resource threshold of 5/kWh/m2/day irradiance. Wind included an exclusion of slopes greater than 20% [9] and a minimum wind speed resource threshold of 6.5 m/s, 7.5 m/s, or 8.5 m/s.

4.1 Improved Slope Analysis

A percent slope analysis was performed in the default analysis in order to create slope constraints of 3% and 5% for PV and 20% for wind. The elevation data used for this analysis was 1/3 arc-second (approx. 10 meter) digital elevation models (DEMs) from the National Elevation Dataset (NED) available through the US Geological Survey's nationalmap.gov. These DEMs are currently the best available, but do contain known artifacts and artificial anomalies due to data sources, processing methods, etc. One of these anomalies is terracing effect, and can be thought of as appearing like artificial terraces in the data. Figure 8 shows a typical agricultural parcel on the island of O‘ahu.

Figure 8. Typical Agricultural Parcel on O‘ahu

Figure 9 shows the same area after the results of a 3% slope analysis has been applied. Areas highlighted in yellow are where slope is not more than 3%. All other areas are greater than 3%.

Figure 9. Typical Agricultural Parcel on O‘ahu after 3% Slope Analysis

It is evident from aerial photographs that the terracing effect seen in Figure 9 is not a genuine geographic feature, but a result of artifacts in the data. This terracing caused a large number of parcels to be divided incorrectly into strips of land rather than being shown as contiguous areas. This posed no significant problem for the wind analysis, which did not have a minimum contiguous area requirement, but it significantly reduced potential land area for PV, which for the purposes of this study included a minimum contiguous area requirement of 1 km^2. Upon applying that constraint, much potential land such as those areas shown in Figure 7 were eliminated.

In order to compensate for the artifacts in the data and attempt to recover the artificially segmented areas, the Boundary Clean tool was applied using ArcGIS. Boundary Clean is a process by which zones in a raster are expanded and shrunk programmatically over large areas in an attempt to fill in narrow bands or tiny gaps of missing data as well as eliminate tiny stray islands such as those that run along ridges seen in Figure 9.

The expansion/shrinking was run twice, and the results are shown in Figure 10. Large areas of land were unified, and tiny scattered areas were largely eliminated.

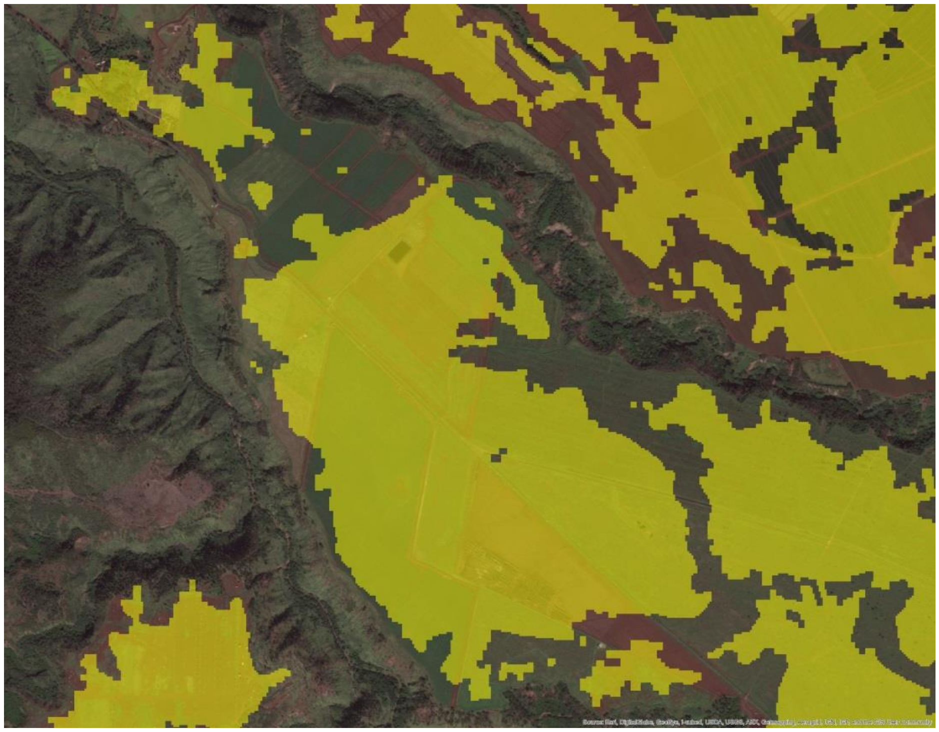


Figure 10. Typical Agricultural Parcel on O'ahu after the Boundary Clean Tool Analysis

This process was repeated on the 5% and 20% slope analyses, and the resulting "clean" slope areas were used to run the final technical potential analysis.

After applying the minimum contiguous area constraint, available land area for PV development increased significantly. Small land areas were still dropped out, but the larger, now-intact areas remained. For the wind analysis, however, the impact was minimal, and in some cases the clean slope decreased available land area. As previously stated, cleaning the slope analysis filled in gaps, but it also eliminated numerous scattered, tiny, disconnected areas. As the wind analysis did not consider a minimum contiguous area, these tiny areas in the slope data that was not cleaned were left in the original analysis. The net result for wind was the loss of small scattered areas but the gain of areas within filled gaps. By chance, some islands had a net gain and others had a net loss, but in all cases the differences were relatively minor.

Post-processing the calculated slope data by cleaning the boundaries appears to have yielded a more realistic representation of the slope of the terrain, and thus a more realistic estimate of the resource potential in the state. As with any analysis, a site-specific analysis combined with proper ground-truthing should be implemented to verify site suitability, as the methods employed here are suitable only for a broad sweep of the state to understand general scale and distribution of development potential.

4.2 UPDATED AGRICULTURAL LAND EXCLUSIONS

For Analyses 1, 2, and 3, agricultural land exclusions include lands classified as "Important Agricultural Land" (IAL) in the Hawaii Office of Planning website (planning.hawaii.gov) for both utility-scale onshore wind and utility-scale solar PV.

For Analysis 4, no agricultural land exclusions are considered for utility-scale onshore wind. For utility-scale solar PV, a different agricultural land classification from the Hawaii Office of Planning is used in addition to the IAL exclusions. This alternative agricultural land classification divides agricultural lands in five zoning designations: A, B, C, D, and E. Taking into consideration the statute* that details the agricultural land zoning designations, the following exclusions (in addition to IAL exclusions) are applied to the utility-scale solar PV resource assessment for Analysis 4:

- 100% of "A" lands are excluded
- 90% of "B" and "C" lands are excluded

It is important to note that a utility-scale PV resource area was removed if it was made too small to meet the minimum contiguous area requirement (1 km^2) due to an intersection with an "A" land. However, resource areas that fell partially or fully within "B" or "C" lands were not removed based on the minimum continuous area requirement; the total resource area within the "B" or "C" agricultural zone was reduced by 90%.

In summary, Analysis 4 includes the following agricultural land exclusions:

- Utility-scale onshore wind:
  - No agricultural land exclusion is applied
- Utility-scale solar PV:
  - "IAL" lands excluded
  - 100% of "A" agricultural lands excluded
  - 90% of "B" and "C" agricultural lands excluded

* http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm

V. Resource Potential Maps

The following self-explanatory maps refer to Analysis 1 and are included herein after in the following order:

* “B” and “C” agricultural lands are highlighted in the map.
† “B” and “C” agricultural lands are not excluded (see section 4.2 for details).

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

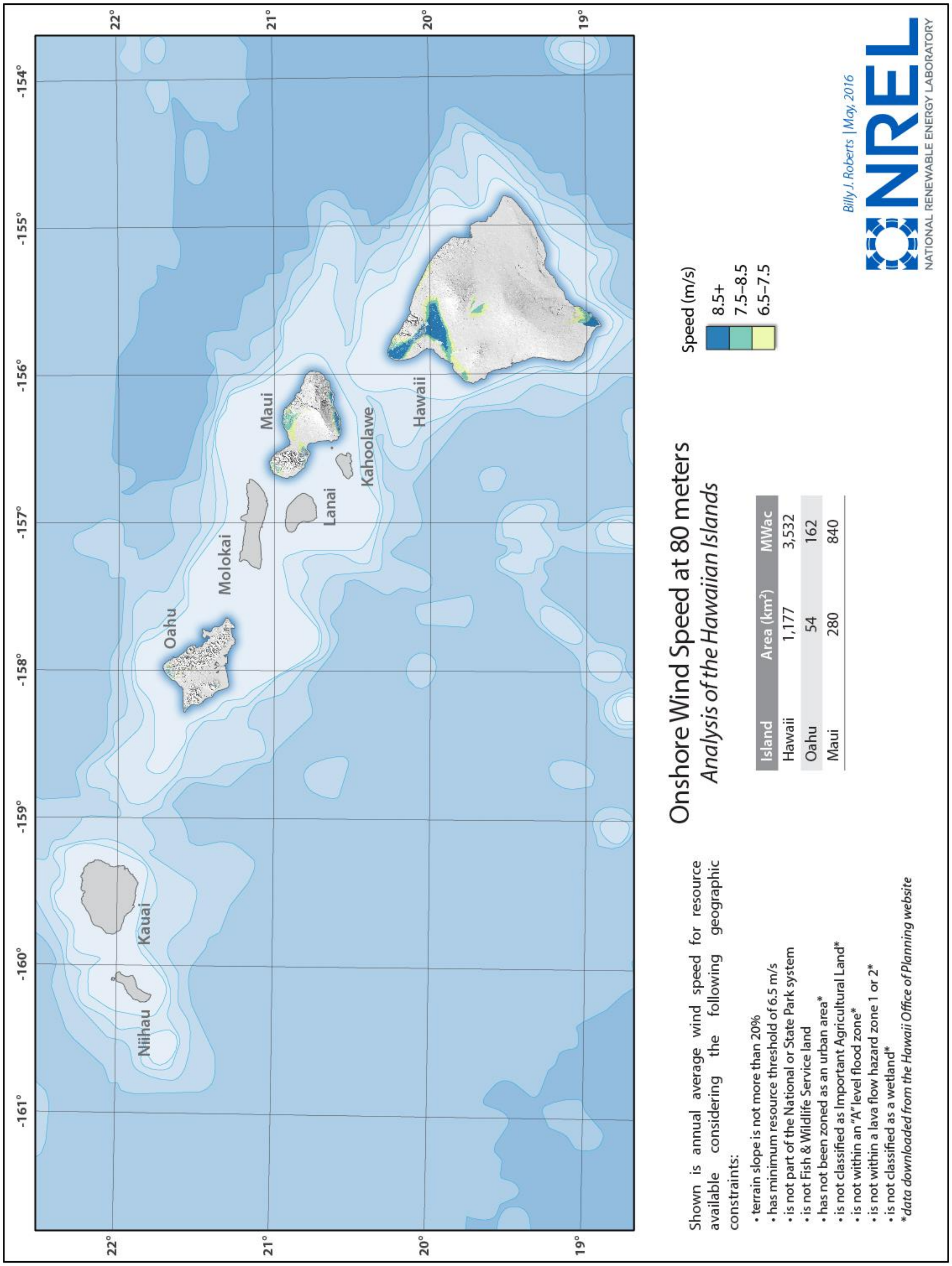


Figure 11. Utility-Scale Onshore Wind Development Potential for All Hawaiian Islands

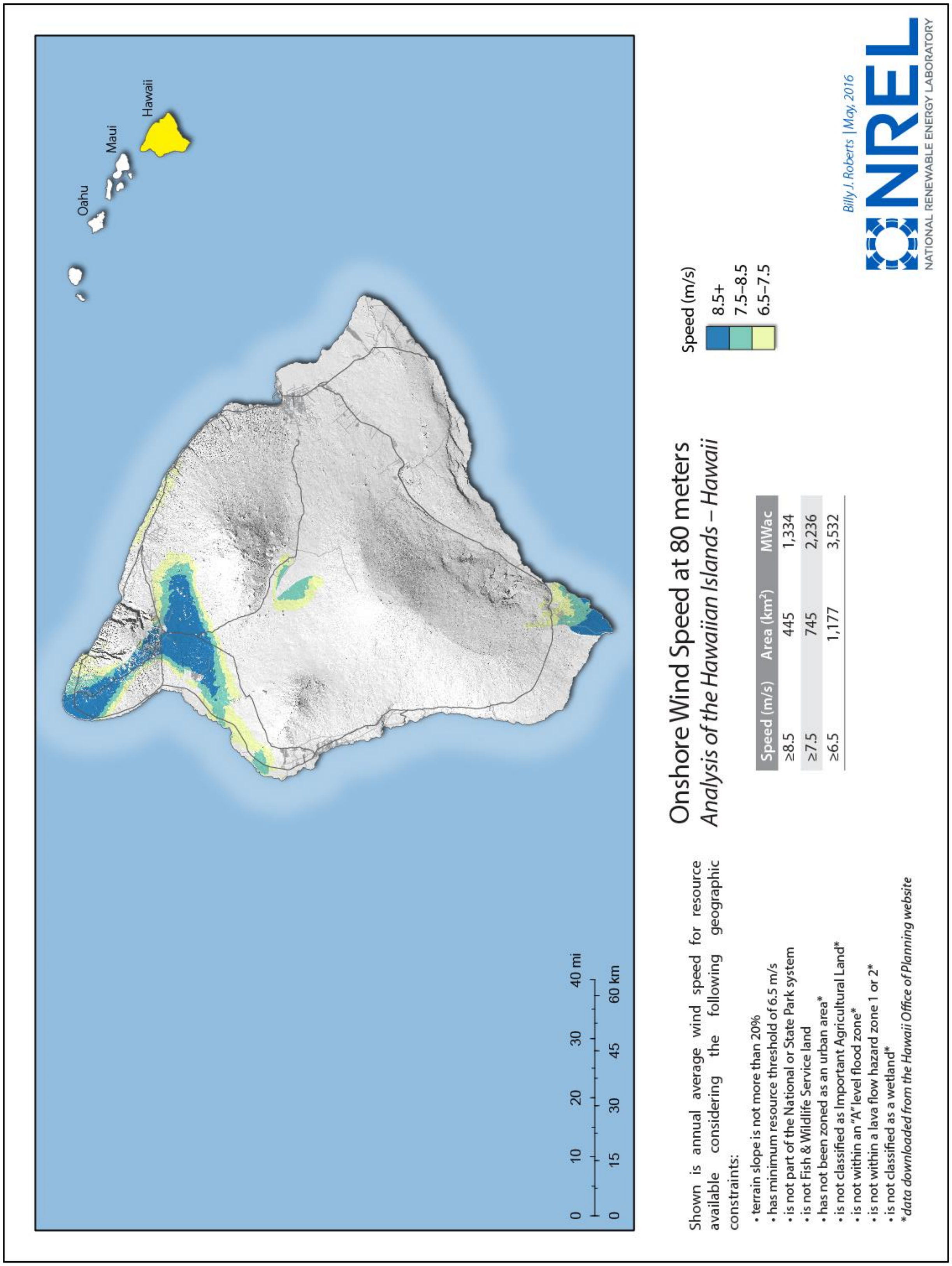


Figure 12. Utility-Scale Onshore Wind Development Potential for Hawai'i Island

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

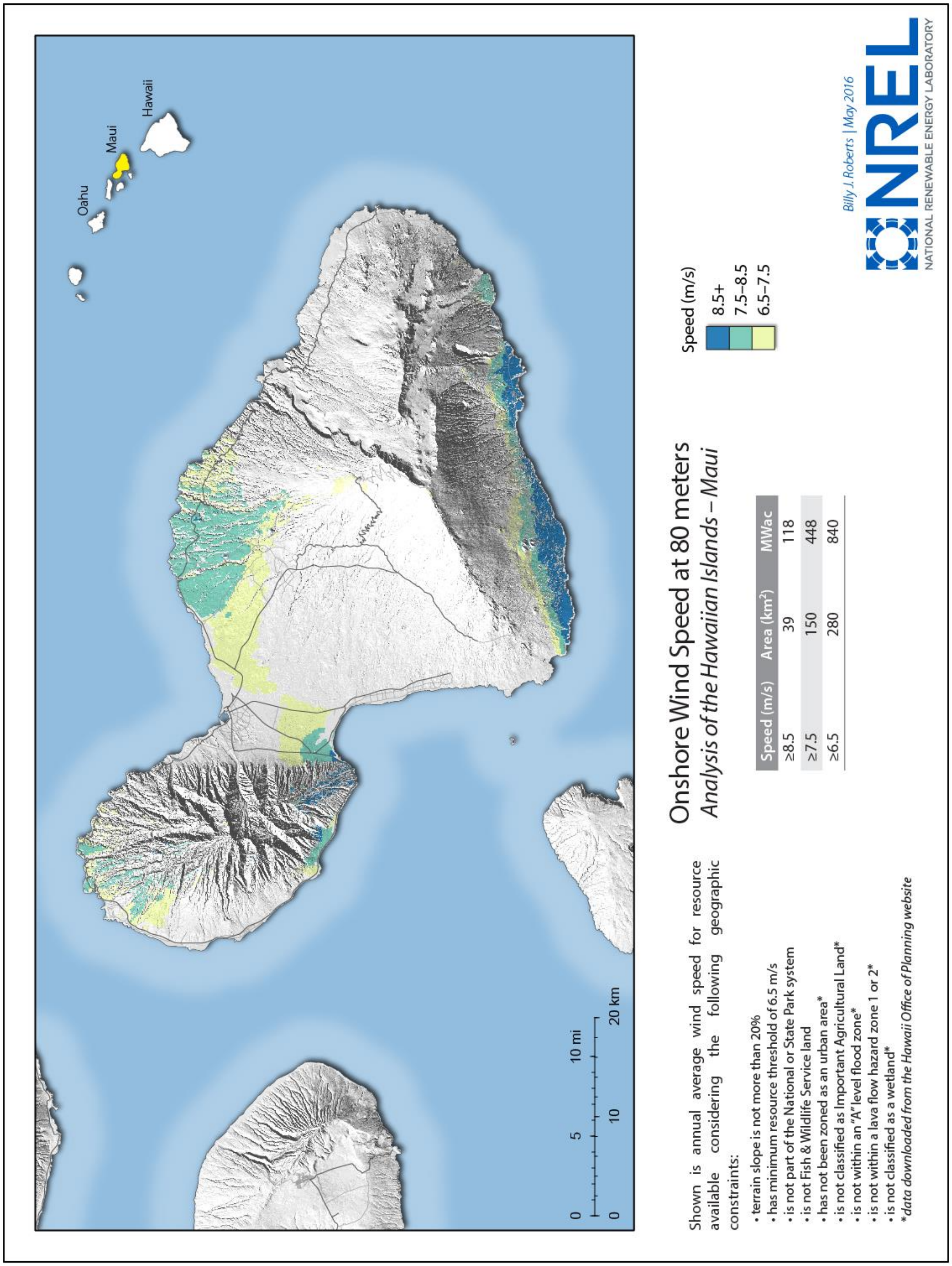


Figure 13. Utility-Scale Onshore Wind Development Potential for Maui

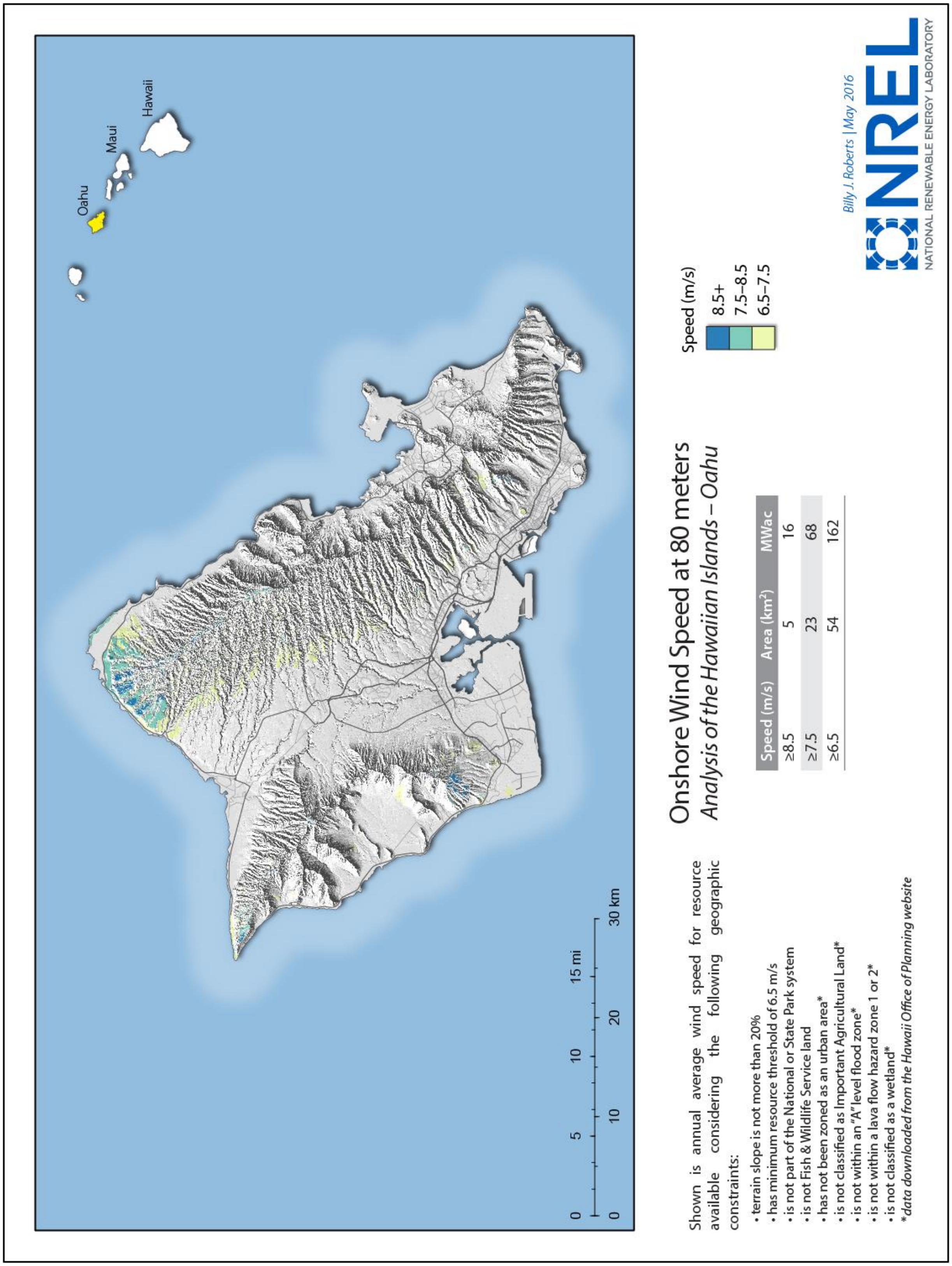


Figure 14. Utility-Scale Onshore Wind Development Potential for O'ahu

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

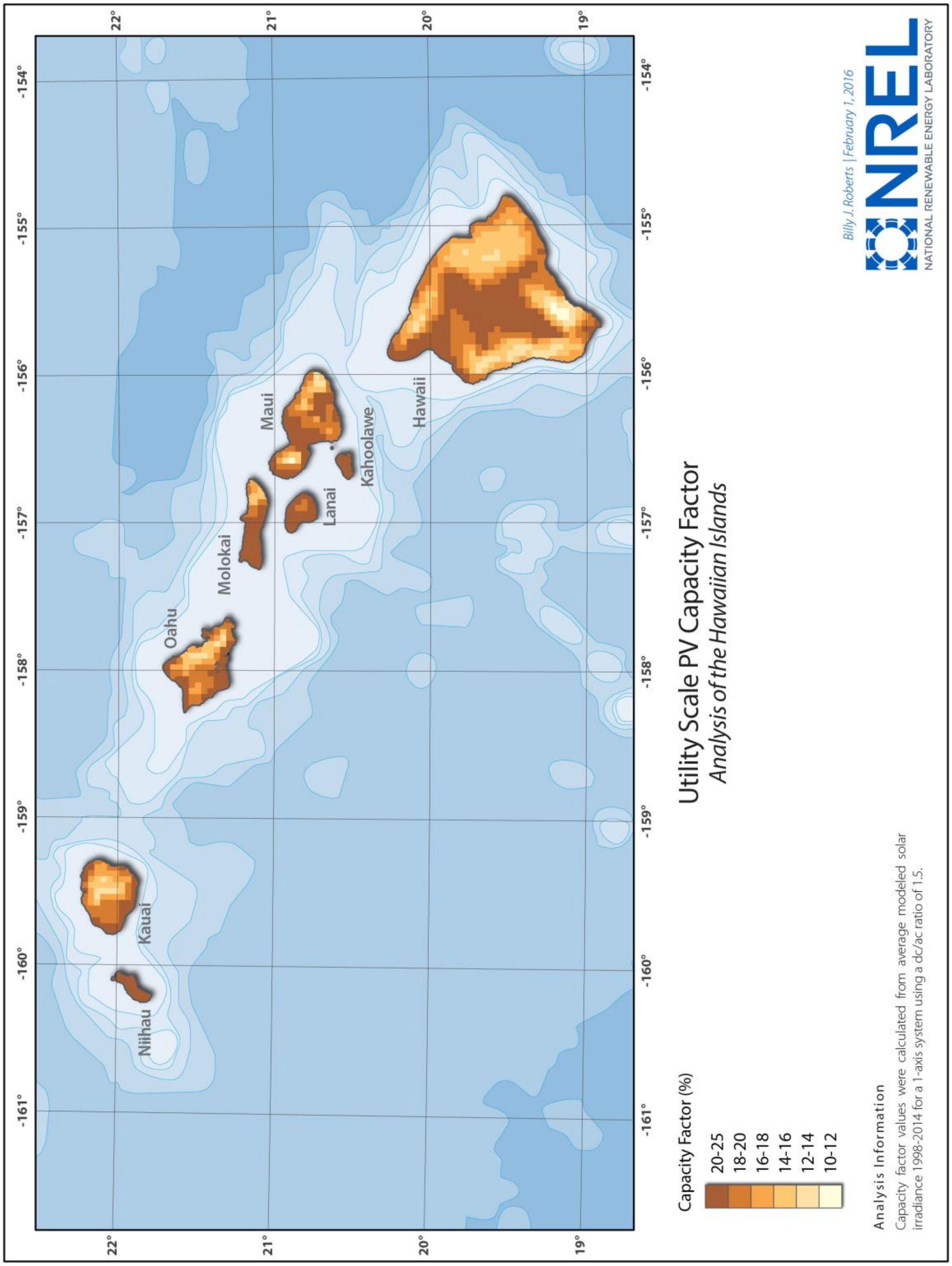


Figure 15. Capacity Factor for All Hawaiian Islands

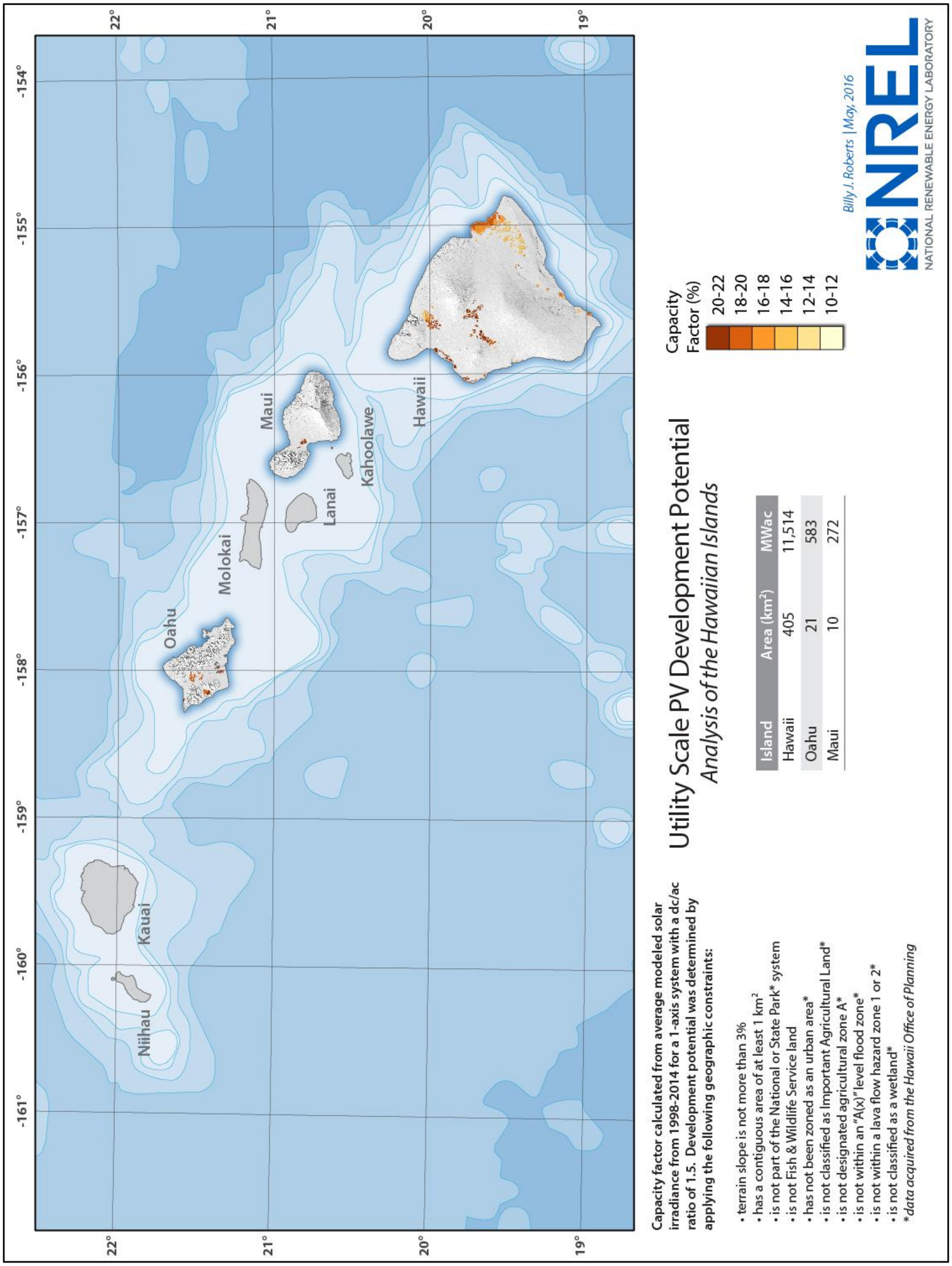
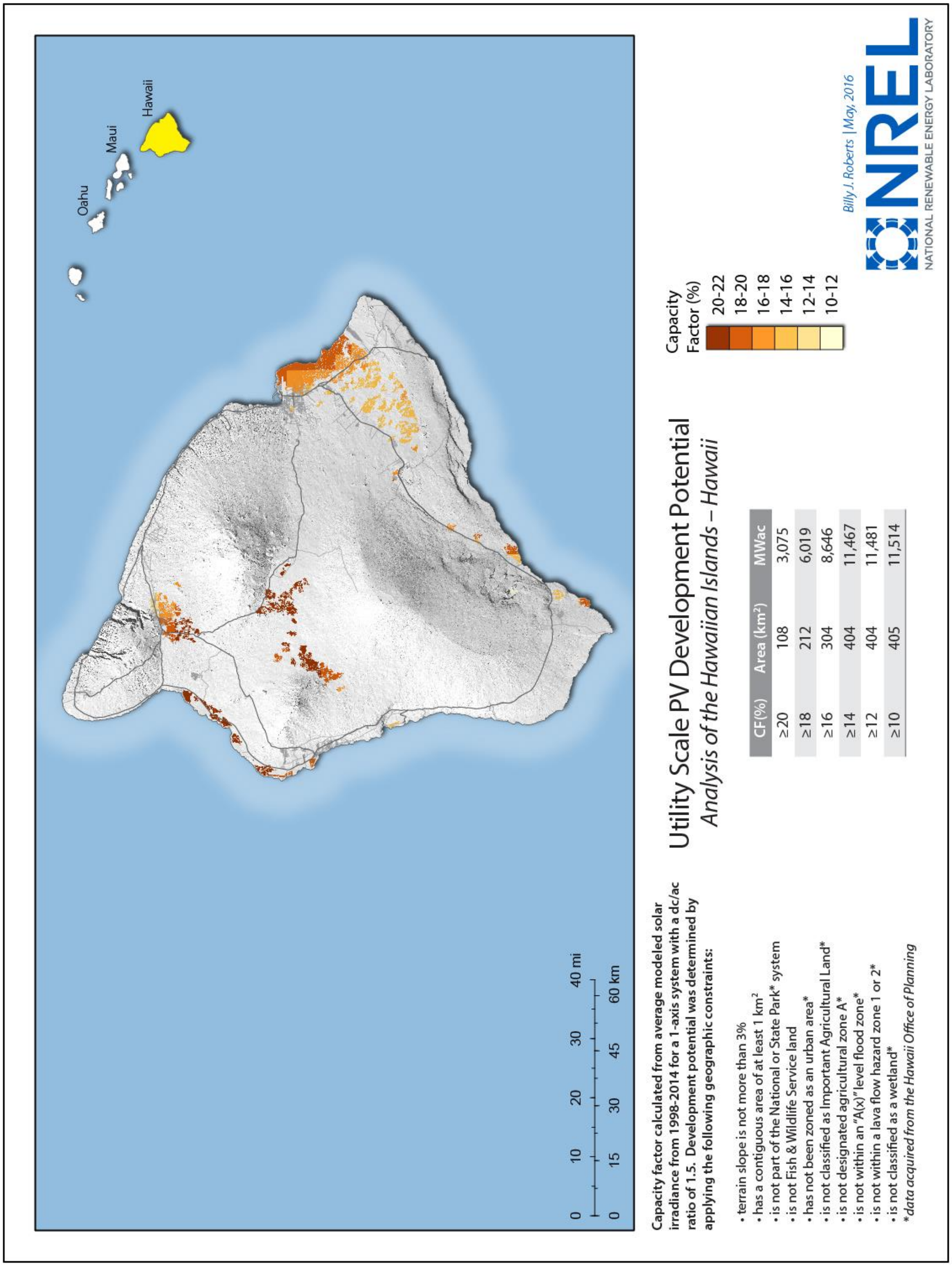


Figure 16. Utility-Scale PV Development Potential for All Hawaiian Islands (3% slope exclusion)



CF(%)	Area (km²)	MWac
≥20	108	3,075
≥18	212	6,019
≥16	304	8,646
≥14	404	11,467
≥12	404	11,481
≥10	405	11,514

Figure 17. Utility-Scale PV Development Potential for Hawai'i Island (3% slope exclusion)

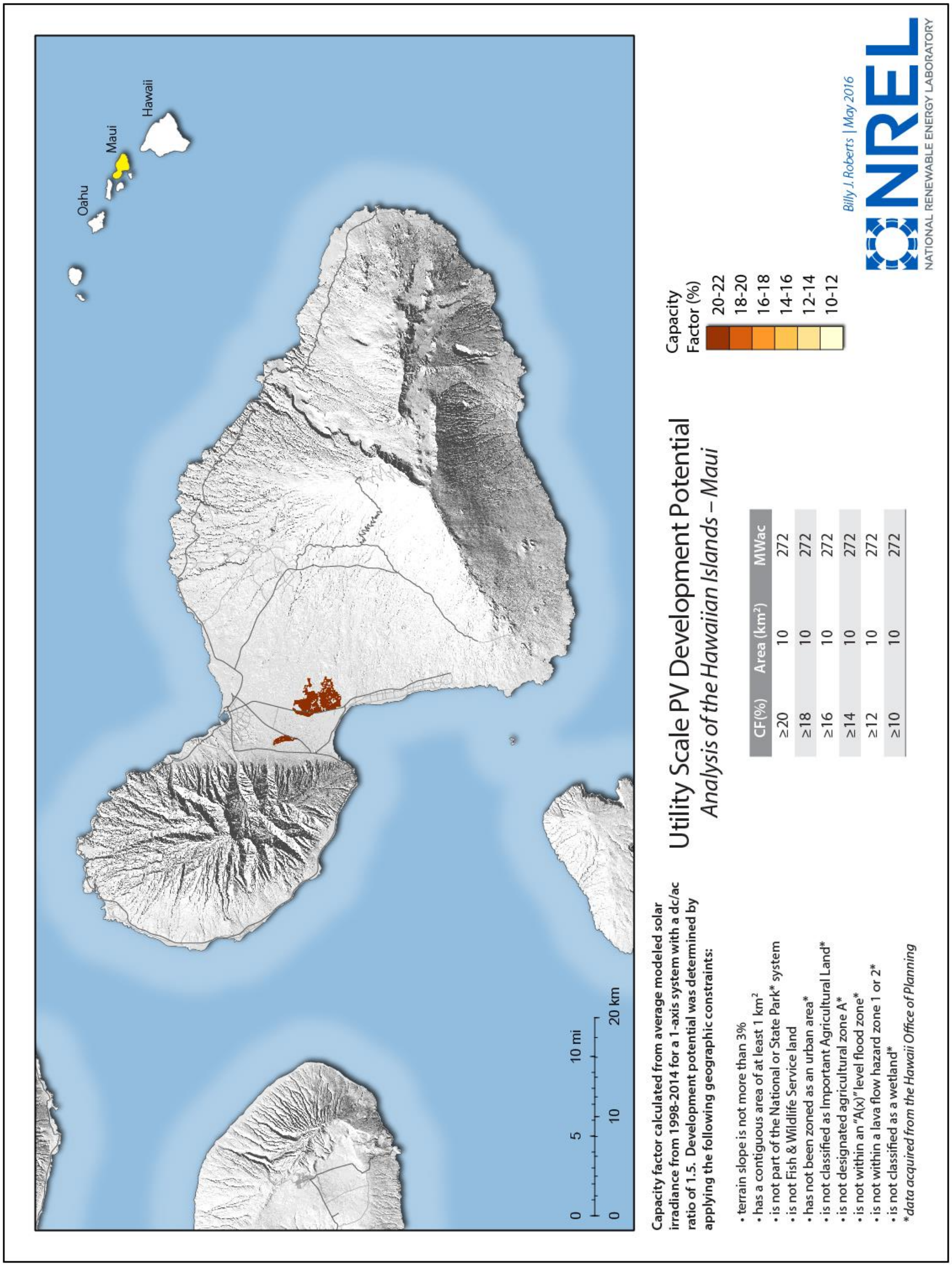


Figure 18. Utility-Scale PV Development Potential for Maui (3% slope exclusion)

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

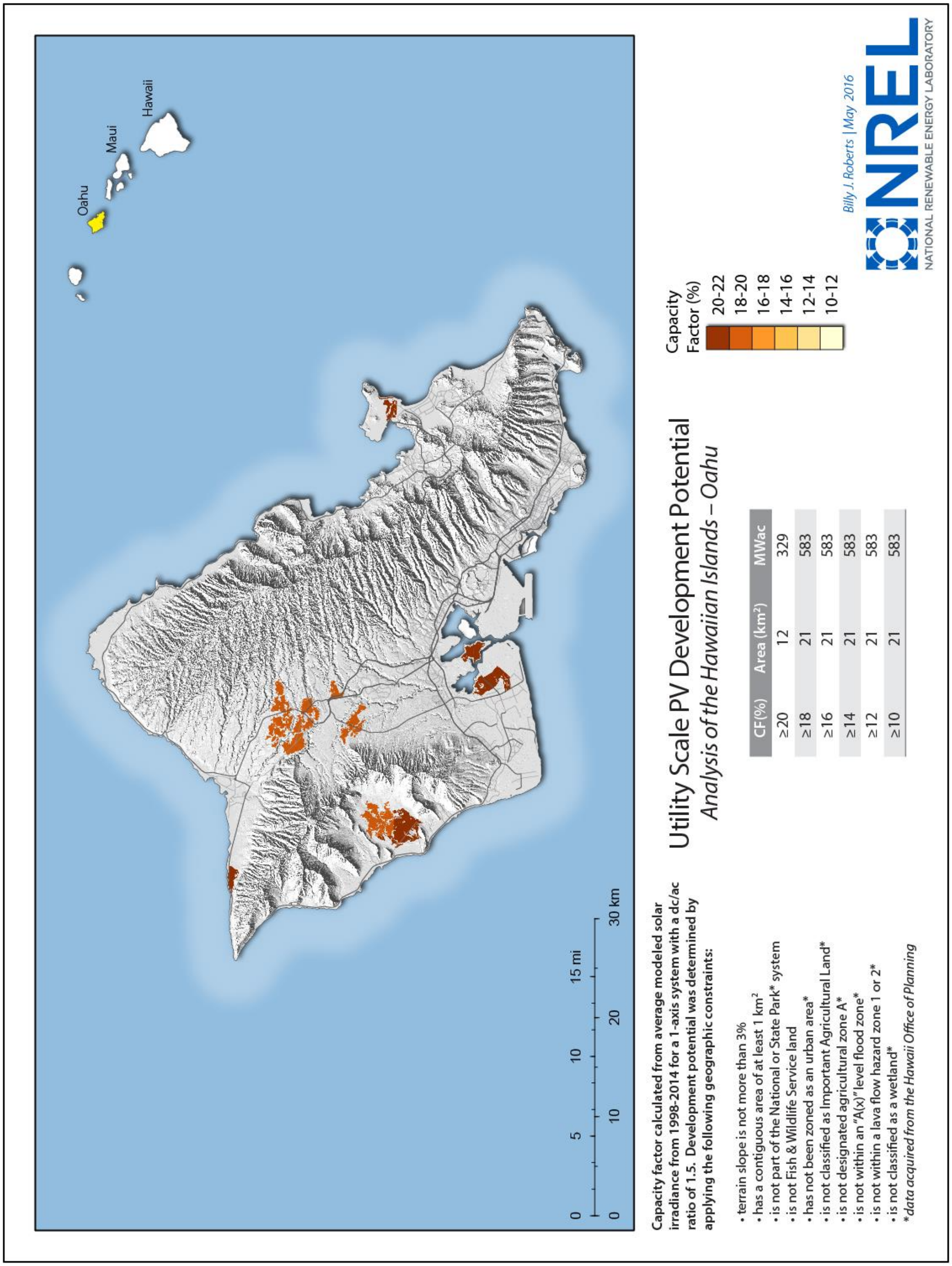


Figure 19. Utility-Scale PV Development Potential for O'ahu (3% slope exclusion)

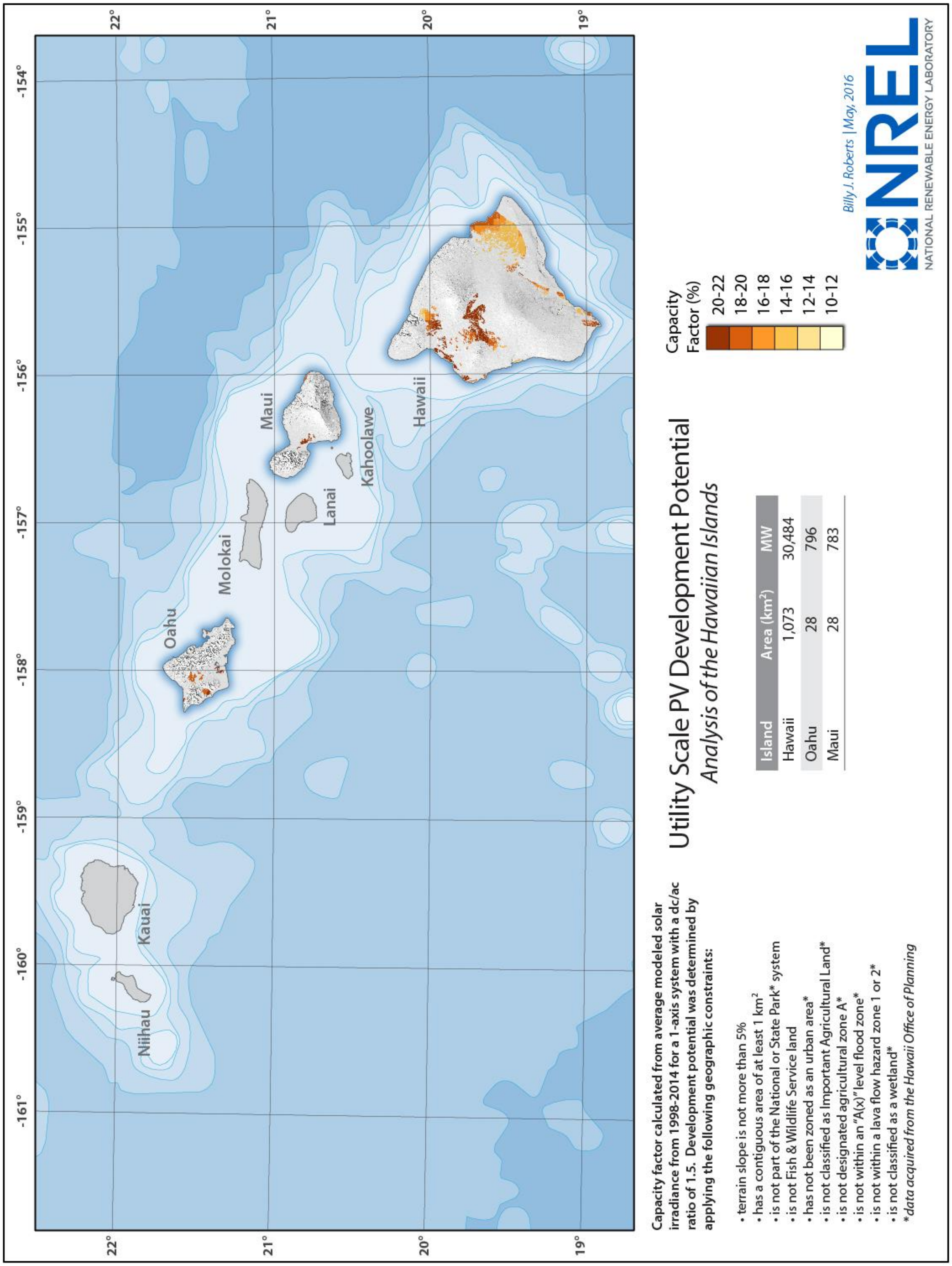


Figure 20. Utility-Scale PV Development Potential for All Hawaiian Islands (5% slope exclusion)

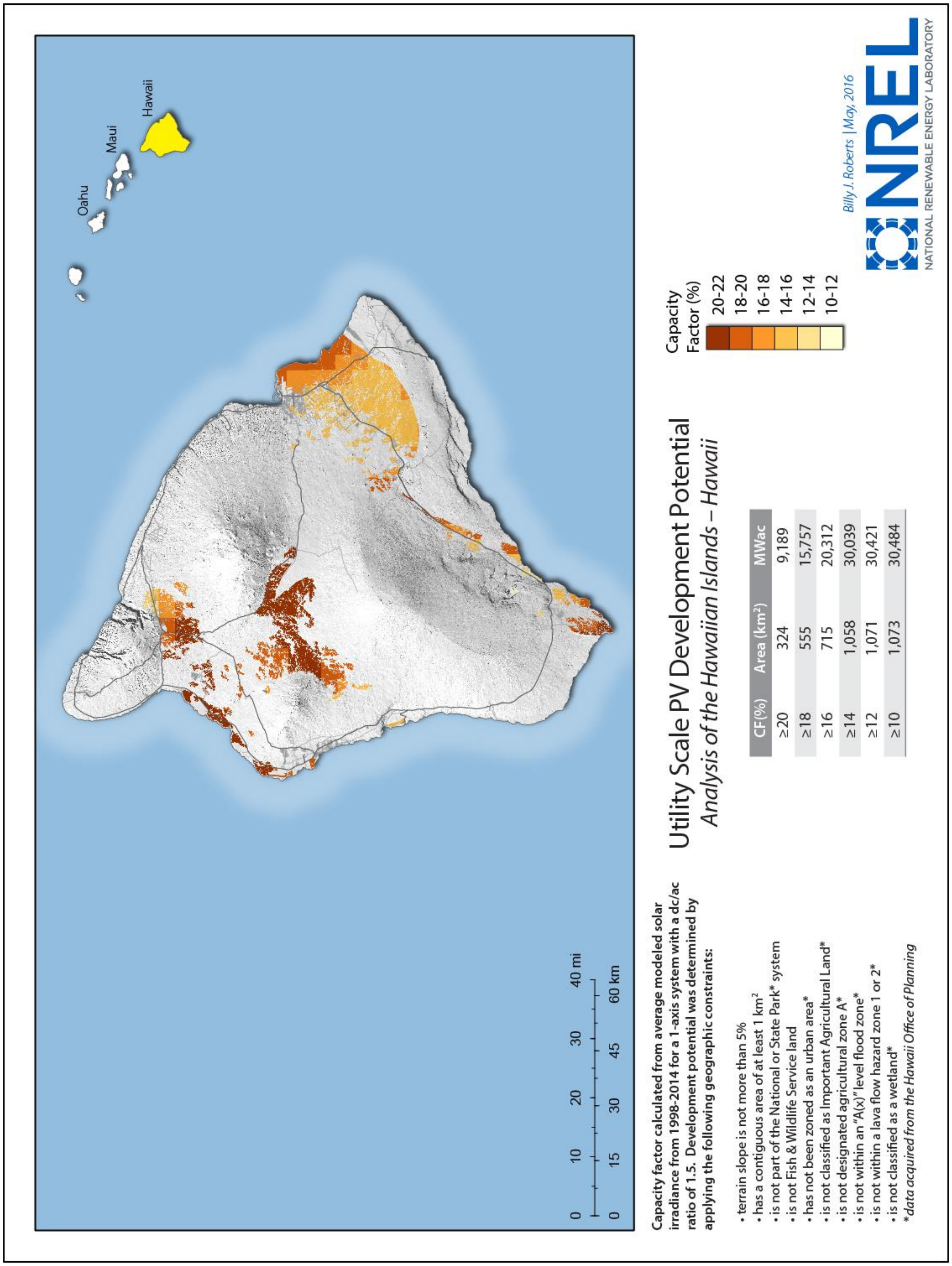


Figure 21. Utility-Scale PV Development Potential for Hawai'i Island (5% slope exclusion)

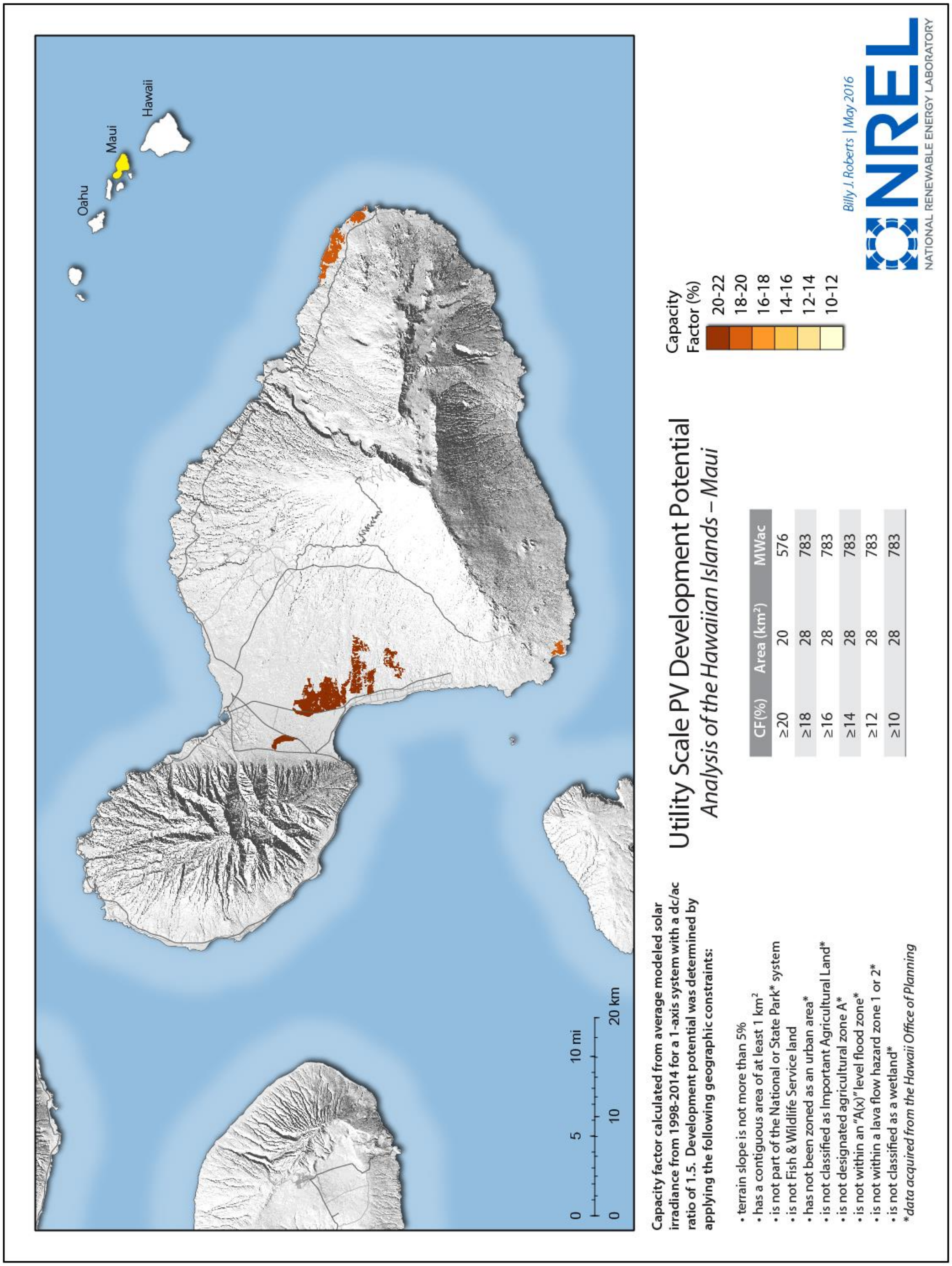


Figure 22. Utility-Scale PV Development Potential for Maui (5% slope exclusion)

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

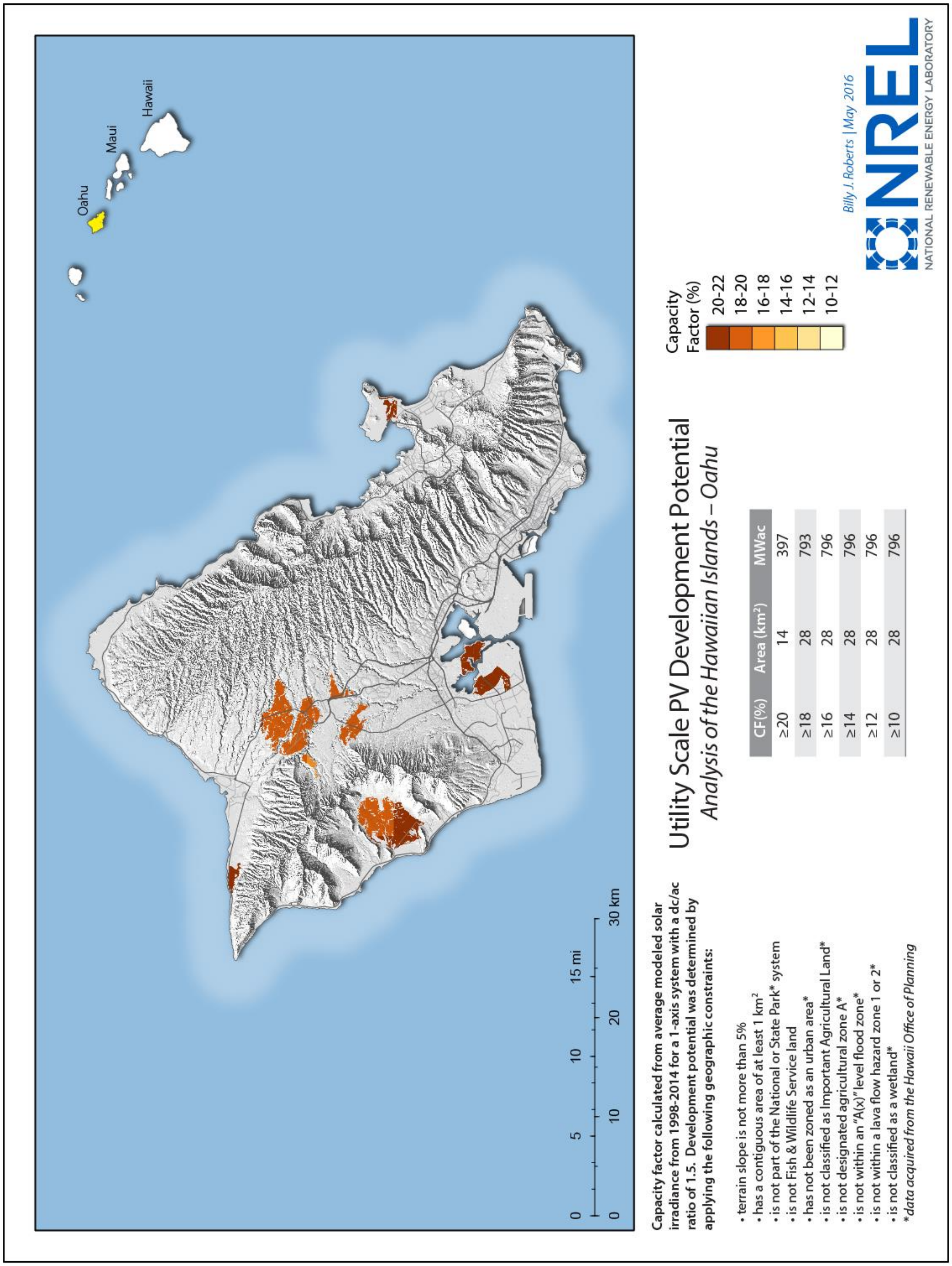


Figure 23. Utility-Scale PV Development Potential for O'ahu (5% slope exclusion)

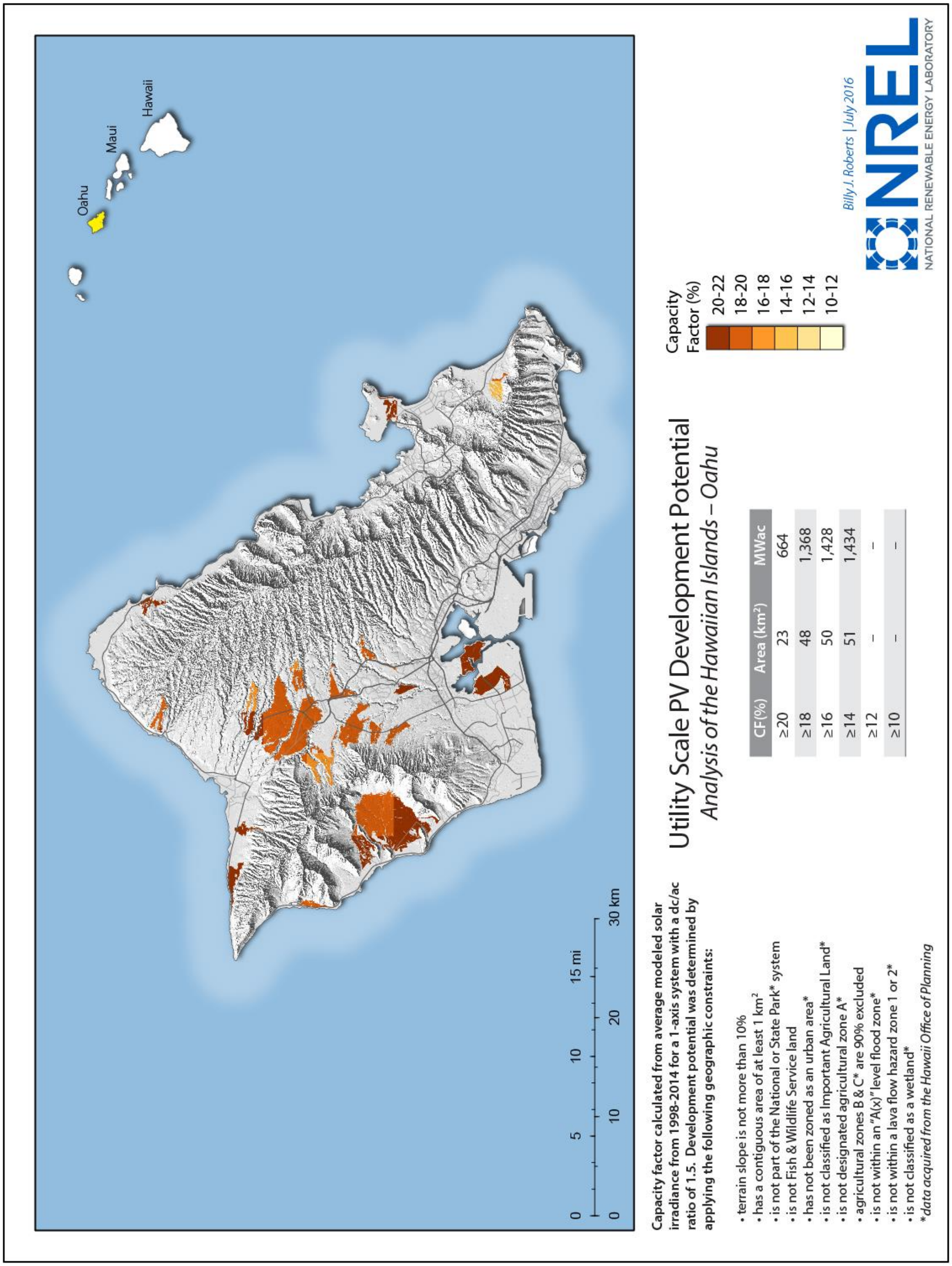


Figure 24. Utility-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag "B" and "C" land 90% excluded)

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

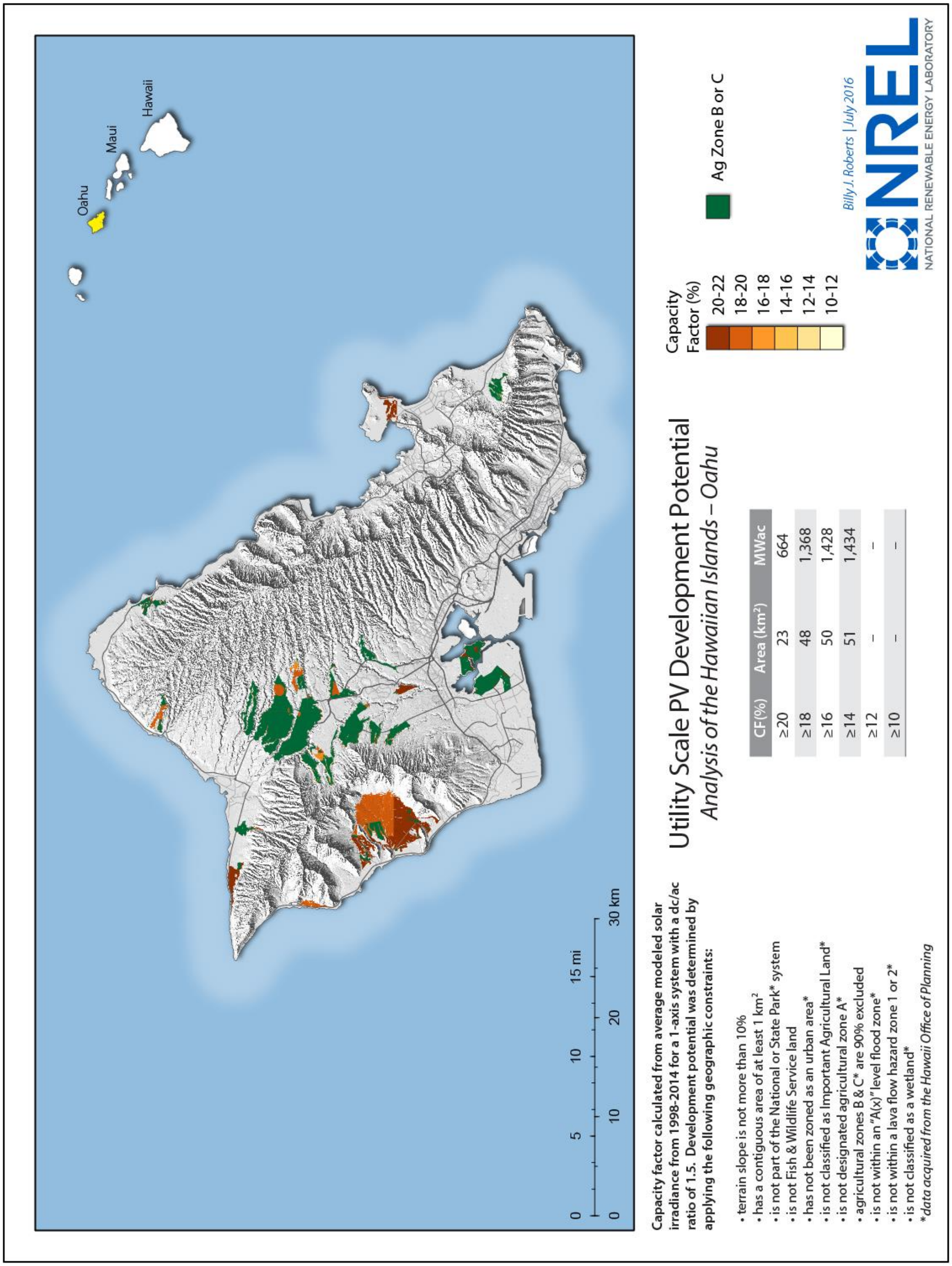


Figure 25. Utility-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag "B" and "C" land highlighted)

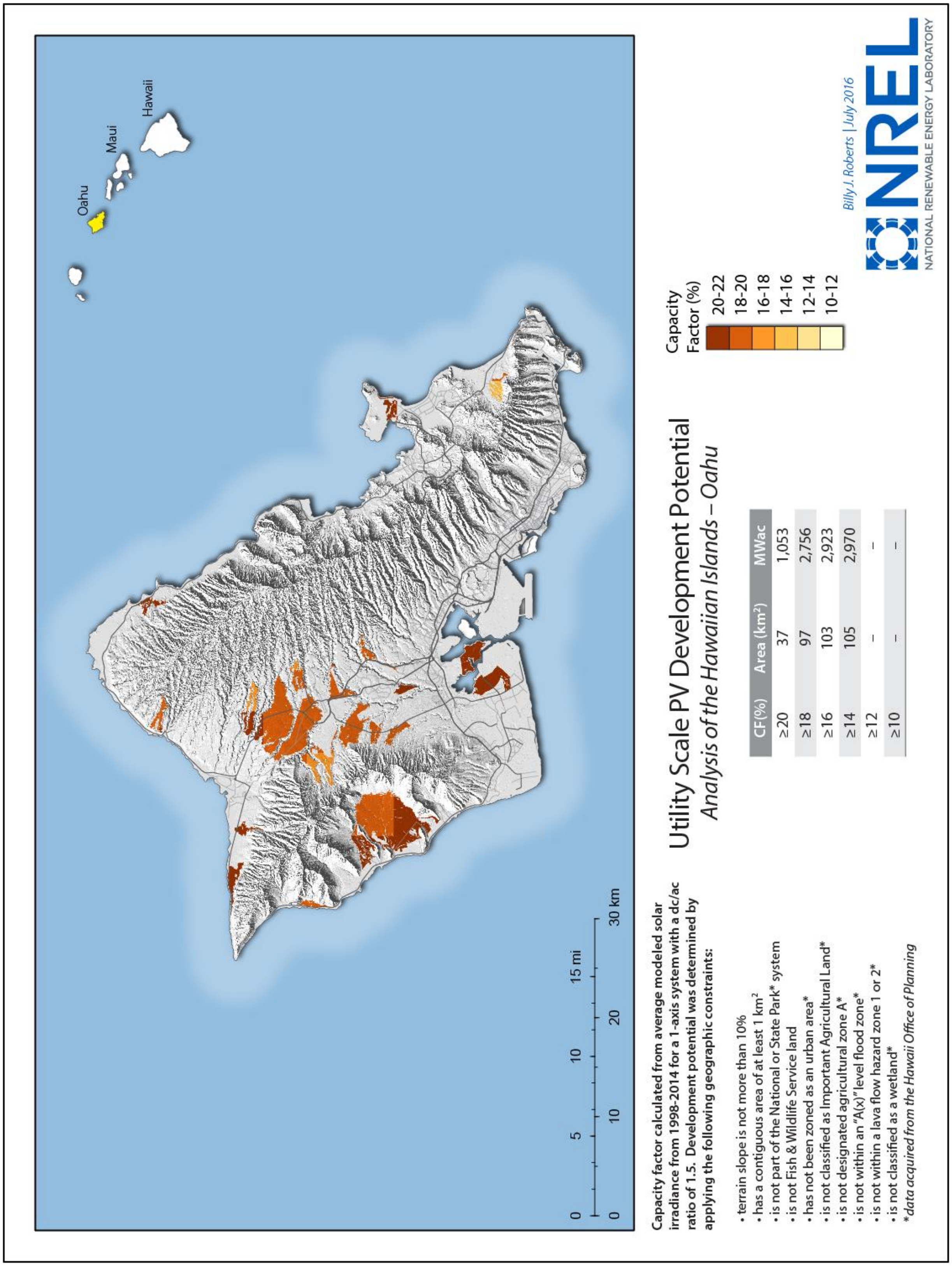


Figure 26. Utility-Scale PV Development Potential for O‘ahu (10% slope exclusion; Ag “B” and “C” land included)

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

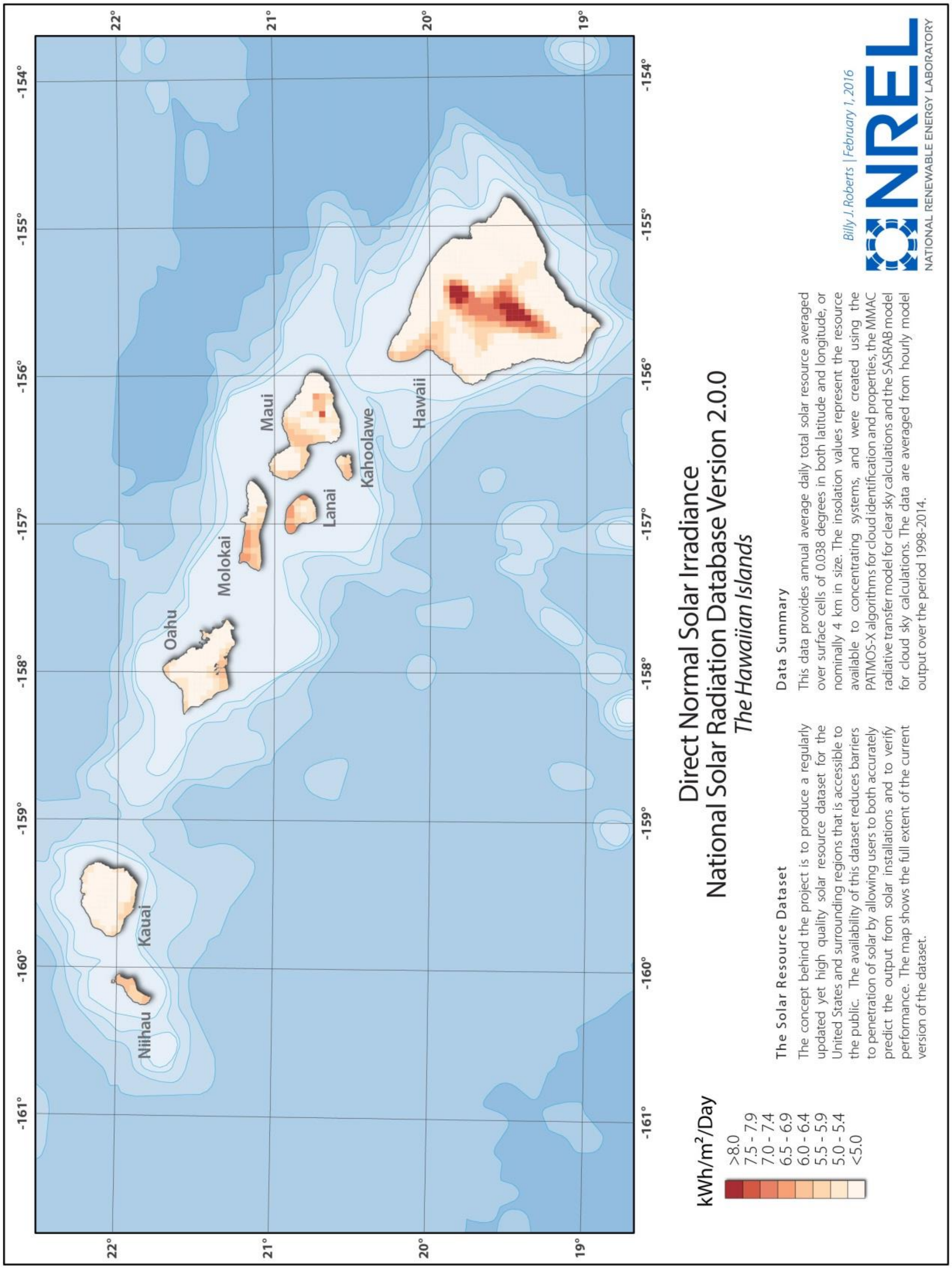


Figure 27. Direct Normal Irradiance for All Hawaiian Islands

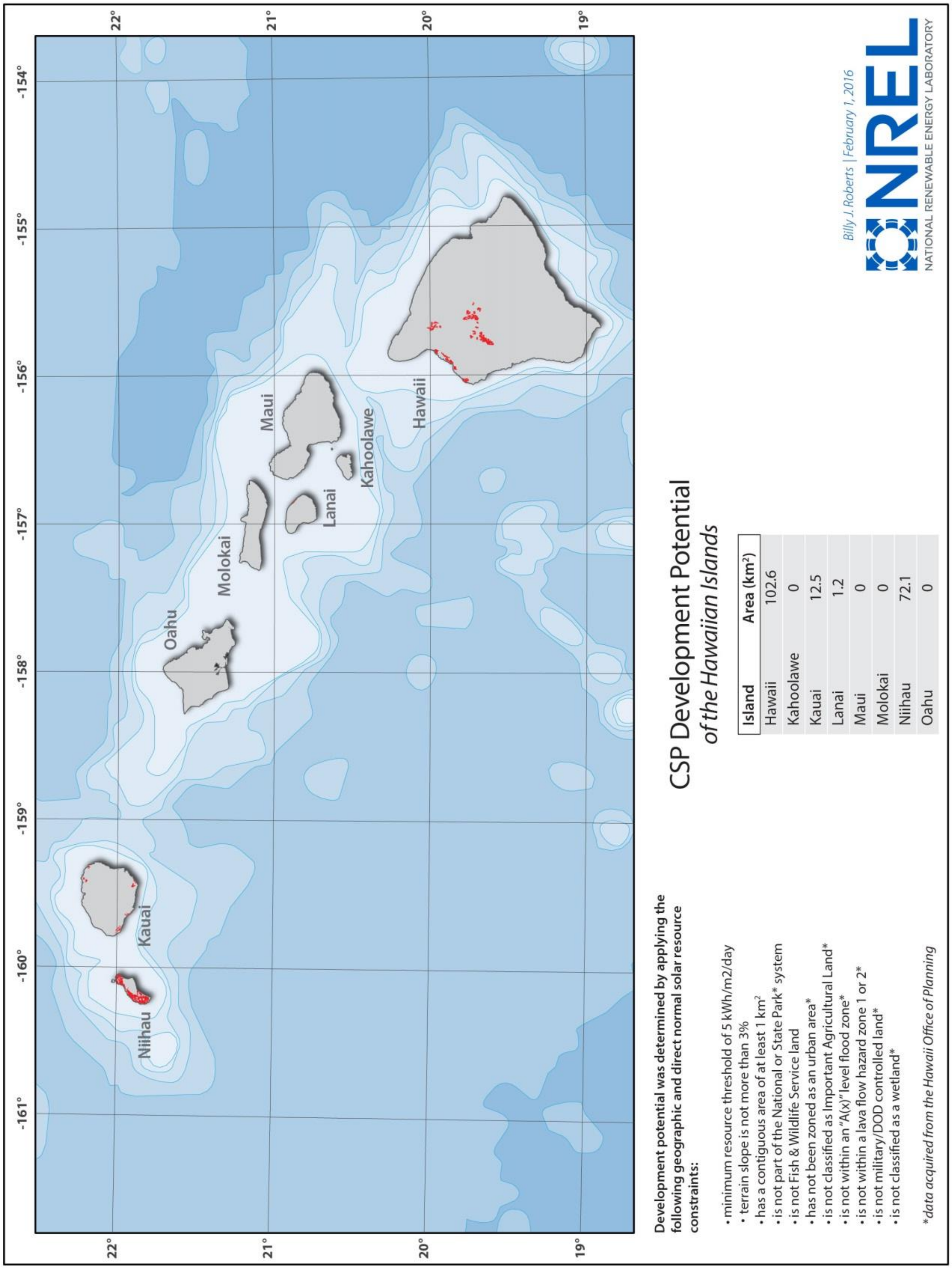


Figure 28. Concentrated Solar Power Development Potential for All Hawaiian Islands

C. NREL Resource Potential Study

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

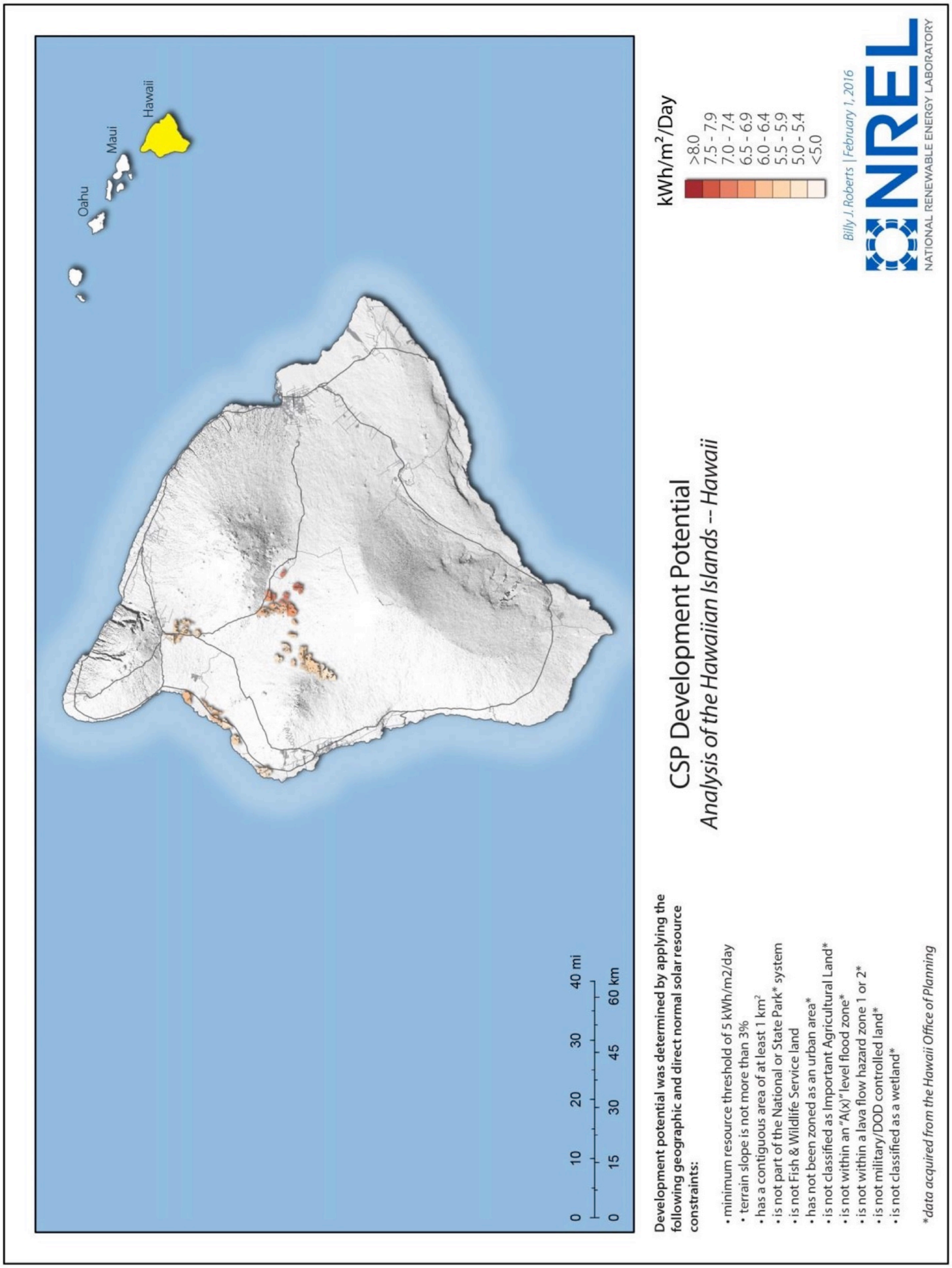


Figure 29. Concentrated Solar Power Development Potential for Hawai'i Island

Appendix A: SAM Parameters

System parameters	Value
self.system_capacity	10000
self.dc_ac_ratio	1.5
self.tilt	0
self.azimuth	180
self.inv_eff	96
self.losses	14.0757
self.array_type	2
self.gcr	0.4
self.adjust_constant	0

Table 23. System Advisor Model (SAM) Parameters

References

[1] AWS Truepower, LLC, NREL REEDS LICENSED DATASETS AND USER'S GUIDE, November 5, 2014.

[2] Wind Vision: A New Era for Wind Power in the United States, U.S. Department of Energy, April 2015.

[3] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[4] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Anderberg, M.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[5] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NREL's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237.

[6] System Advisor Model, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[7] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[8] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-56290, June 2013.

[9] Lopez, Anthony, et al. US renewable energy technical potentials: A GIS-based analysis. National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-51946, 2012.