Applicability of Hawaii Renewable Energy Grid Project Enabling Technologies to Other Regions of United States

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Applicability of Hawaii Renewable Energy Grid Project Enabling Technologies to Other Regions of United States

Final Report

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imagination at work

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Acronyms and Nomenclature

Hawaii Related

HNEI	Hawaii Natural Energy Institute
HSIS	Hawaii Solar Integration Study
OWITS	Oahu Wind Integration and Transmission Study
RCUH	The Research Corporation of the University of Hawaii

General

$B	Billion Dollars
$M	Million Dollars
AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure (Smart Metering)
AMR	Automatic Meter Reading
BESS	Battery Energy Storage Systems
BTU	British Thermal Unit
CAISO	California Independent System Operator
CC/CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
DA	Day-Ahead
DER	Distributed Energy Resources
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency

EI	Eastern Interconnection
EMS	Energy Management System
EPA	Environmental Protection Agency
ERCOT	Electricity Reliability Council of Texas
ES	Energy Storage
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
GE	General Electric International, Inc. / GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" model
GE MARS	GE's "Multi Area Reliability Simulation" model
GE PSLF	GE's "Positive Sequence Load Flow" model
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HAN	Home Area Network
HR	Heat Rate
HVAC	Heating, Ventilation, and Air Conditioning
IHD	In-Home Displace
IPP	Independent Power Producers
IRP	Integrated Resource Planning
IROR	Internal Rate of Return
IOU	Independently Owned Utilities
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour

LAN	Local Area Network
lbs	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve
LMP	Locational Marginal Prices
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MDMS	Metered Data Management System
MMBtu	Millions of BTU
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NPV	Net Present Value
O&M	Operational & Maintenance
ROR	Rate of Return
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM Interconnection, LLC.
PPA	Power Purchase Agreement
PSH	Pumped Storage Hydro
PTR	Peak Time Rebate
PUC	Public Utility Commission
PV	Photovoltaic
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
RT	Real Time
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SC/SCGT	Simple Cycle Gas Turbine

SCUC/EC	Security Constrained Unit Commitment / Economic Dispatch
SG	Smart Grid
SO2	Sulfur Dioxide
SOx	Sulfur Oxides
ST	Steam Turbine
TOU	Time of Use
TW	Terawatts
TWh	Terawatts Hour
UCT	Coordinated Universal Time
VOC	Variable Operating Cost
WAN	Wide Area Network
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

Executive Summary

This report presents the results of a second component of the Hawaii Renewable Energy Grid Project (HREGP) that addresses how the findings of the principal report can be applied to other US regions that may have similar grid operational and renewable energy characteristics as Hawaii. After an initial literature search, the GE Energy Consulting study team performed a security-constrained based production cost modeling (based on the GE MAPS model) of the Eastern and Western Interconnections and ERCOT, and identified candidate areas in the United States where results of the HREGP report can be applied. The first of the common attributes is a *high penetration of renewable resources* (i.e., wind and solar). In addition to high renewable energy generation capacity, another significant factor is Hawaii's transmission constraint created by multiple, isolated island grids. Because of the robust interconnection network in the mainland U.S. where there is truly no isolation, transmission constraints must be modeled using proxies that are indicators of limits to power flow, whether physical (conductor and inter-tie capacity) or economic (low local marginal pricing). The second common attribute then is *export-constraint* due to transmission congestion. The third common characteristic is the generation of excess renewable energy with no load to utilize it. A *decrease in the area electricity price* when transmission constraints are taken into account serves as a proxy for excess supply of power combined with limited capability to export. These three conditions together make it likely that the selected areas would experience curtailment of renewable energy. Hence, in a narrow sense defined by these criteria, the selected areas can be considered to exhibit characteristics similar to Hawaii.

The model considered load and generation conditions and other model input assumptions are projected 5 years out to 2018.

The three conditions for choosing the top area candidates include:

- Wind and solar energy together constitute at least 10% of annual energy produced in the area.
- The area experiences a drop in the area load weighted electricity price when tie-line transmission constraints are taken into account.
- The area is export-constrained, i.e., imposing the tie-line transmission constraints results in reduction of the net electricity exports from the area.

The GE MAPS modeling identified the following pools/regions* and states in the Eastern Interconnect, with at least one candidate area within the state meeting the above conditions:

- MISO: Minnesota, Iowa, Indiana, Illinois, Montana, Michigan

- SPP: Kansas, Nebraska, Oklahoma, New Mexico
- MAPP: Iowa

* Area and pool names are GE model designations defined later in the report in Table 11 (Appendix 1).

In the Western Interconnection, the modeling results identified the following regions* and states within the regions with at least one candidate area within the state meeting the above conditions:

- Basin: Idaho
- NWP: Idaho, Washington
- RMP: Colorado, Wyoming
- DSW: Arizona, New Mexico
- CAISO: California

* Area and pool names are GE model designations defined later in the report in Table 11 (Appendix 1).

Some of the states straddle more than one pool or interconnection. No area in ERCOT met the 3 conditions above. Final rankings for the Eastern Interconnection and Western Interconnection are shown in Table 6 and Table 7, respectively.

The second section of the report addresses applications of technologies and programs identified in the HREGP report (e.g., policies, incentives, rule changes, etc.) that would be expected to mitigate renewable energy curtailments and enhance the stability of U.S. regional power grids in those regions that exhibit potential for excess renewable generation combined with some degree of energy export constraint.

Notwithstanding the 2 key characteristics, Hawaii remains unique in its grid characteristics, making general applicability of findings a tenuous proposition. In Hawaii each island is currently its own Balancing Area. (This would change with the integration of an interisland transmission cable). Hawaii does not have Grid Interconnection entity such as Western and Eastern Interconnection and Texas' ERCOT. Hawaii does not have Regional Entities that are responsible for compliance with reliability standards, nor Regional Transmission Organizations (RTO) or Independent System Operators (ISO) that are responsible for planning and operating a region's wholesale power markets. In addition to multiple oversight entities, each state has its own Renewable Portfolio Standards goals, and each utility has its own economic drivers based on power plant mix, fuel mix, customer demand and pricing that is likely regulated by a state utilities commission. In theory, the recommendations for Hawaii can be applied to mainland regions. However, the complexity of coordinating policies, technology and economic equity across multiple agencies that cross utility territory lines, state lines, regional markets, and regulated market environments, starkly contrasts with the conditions in Hawaii.

Most of the recommendations for Hawaii are applicable to mainland regions because the expansion of renewable energy in a regional generation portfolio is a relatively recent development, and the enabling technologies that are recommended in Hawaii are rapidly maturing and are being applied to many grids. This report summarizes many of those recommendations.

Recommendations from HREGP:

Smart Grid

Smart grid technologies enable multiple strategies that allow the grid to utilize more renewable energy by addressing both demand and supply-side management of power. *Ancillary services* are among the functions that provide grid stability, protect reliability, minimize production costs and enable optimized use of renewable energy. Smart Communications and controls will enable grid flexibility functions and optimum ancillary services that have been identified for Hawaii by the Reliability Standards Working Group (RSWG) and included in the HREGP. These include:

- Utilizing demand response and storage to provide fast, inertia-response to arrest frequency decay, and to secure frequency recovery capabilities from new plants,
- Requiring all generators (thermal and renewable) to be capable of frequency response to the extent economically feasible,
- Equipping all generators (thermal and renewable) with Automatic Grid Controls (AGC) where economic,
- Allowing storage and demand response to provide AGC response to the extent that they are physically capable,
- Requiring all generators (thermal and renewable) to be designed with spinning reserve capability with the best response practicable,
- Allowing storage and demand response to provide spinning reserve to the extent that they are physically and economically capable,
- Utilizing least cost replacement reserves resources for Contingency Reserve, and including storage and demand response to provide non-spinning and supplemental reserve,
- Requiring all generators (thermal and renewable) to be capable of providing reactive power and controlling voltage in response to system operator commands,
- Utilizing and positioning energy storage on grid to make best use of reactive power and voltage regulation capabilities,

- Changing problematic protection to a type that requires lower short-circuit current as more generators that provide little or no short-circuit current are installed, and
- Providing compensation for ancillary services to independent power producers for direct and opportunity costs of resources that provide inertia or frequency regulation, and spinning or replacement reserves.

Recommended areas of focus to overcome barriers to adoption of smart grid technologies include:

- Incentivize placing distributed generation in grid locations to maximize system benefits.
- Investigate and pursue utility ownership of distributed generation resources.
- Evaluate dynamic pricing strategies to give customers ability to optimize their end use.
- Evaluate regulatory changes to allow ancillary services to be monetized and provided by 3rd parties.
- Provide consumer education and awareness to enable customers to make informed energy choices through smart meters, data visualization tools using web portals, and energy use retrieval as reflected in the "Green Button" technical standard initiative launched in 2012.

Energy Storage

In Hawaii, regulatory initiatives, derived from or related to some of the policies listed above could have a significant impact on the widespread use of storage. Some of these are outlined in the Electricity Storage for Hawaii section of the HREGP, and summarized below:

1) Establish requirements for spinning and operating reserves on island-specific basis.

   FERC Rule 755 and CAISO Flexible Capacity Procurement rules can provide guidance to frame Hawaii-specific regulations for storage.

2) Modify the existing feed-in tariffs (FITs) to recover the additional cost of energy storage if it is integral to the proposed renewable energy project.

   Current state or federal regulations do not address this issue and it is unlikely that FERC or mainland PUC's will be considering this. However, a Hawaii (or region) -specific rule may incentivize future storage applications.

3) Establish electric system reliability metrics and re-examine the penetration limits of renewable systems integrated with energy storage on feeders.

   The Hawaii PUC recently received a report from the Independent Facilitator (IF)[1] summarizing the findings and recommending future actions for the Reliability Standards Working Group (RSWG) including a recommendation for the formation of a Hawaii Electricity Reliability Administrator (HERA). This is a role that does not exist in Hawaii, but is currently filled by ISO and RTO, as well as by Regional Entities and Balancing Authorities.

4) Modify the Renewable Energy Infrastructure Program (REIP) to allow cost recovery of future energy storage studies and projects.

   In addition to the regulatory recommendations above, several technical barriers such as valuation of storage services and sizing of storage systems exist and need to be addressed to facilitate future deployments.

Finally, it is recommended that performance data and lessons from the existing systems be gathered systematically and made available to facilitate the deployment of future system.

Vehicle Charging Infrastructure

A vehicle charging infrastructure represents a significant opportunity to utilize renewable energy by adding load to the grid. With appropriate incentives, dynamic pricing, and communication/smart grid protocols, grid connected vehicles can utilize renewable energy that may otherwise be curtailed.

Constraints in Hawaii do not always apply directly to mainland regions. A primary issue with renewable energy in Hawaii is the variability of the wind and solar sources. Peak generating capacity in Hawaii is less than 2.5 GW, small enough that there is insufficient load diversity to use all of the renewable energy at the time it is generated. Based on grid simulations from the HREGP in the hypothetically optimum condition, only 53% of the curtailed energy can be captured by using EVs. (Adding storage capacity will improve the number; however, the high cost of storage is an economic constraint.)

In most mainland regions, power generated in one region can be sold in another where the demand exists. The drivers to the wholesale transfer of renewable energy are *economic* (is the price right, is there a transparent market?); *electrical* (is there wire capacity to move the electrons?); and *regulatory* (are policies and regulatory issues aligned such regions are comparably motivated to invest in a renewable energy infrastructure?).

That leaves the question of how applicable is Hawaii's grid analysis to mainland utility regions? As with other the grid-related recommendations in this report, most of the suggestions are indeed relevant to the expansion of an EV infrastructure. The reasons for developing an EV infrastructure range from load and market building to consumer demand. This study focused on evaluating a vehicle charging infrastructure as a mechanism to make renewable energy more cost efficient by reducing curtailment. Because mainland balancing area loads are far larger than Hawaii's, a robust charging infrastructure is less about curtailment mitigation and more about sales growth. However, transmission congestion and the fact that each of the balancing areas may have their own curtailment protocols, can constrain the distribution of excess renewable energy, and therefore a vehicle charging infrastructure can play a minor role in mitigating the curtailment.

GE's findings are based on the Hawaii grid, a unique grid in terms geography, generating capacity and intermittence of renewable resource. Certain regions in the mainland U.S. exhibit transmission congestion and are facing an increase in renewable portfolio standards requirements. For these regions, the development of a vehicle charging infrastructure could contribute to the utilization of renewables.

Recommendations: A vehicle charging infrastructure will have storage and load building value to the utilities, but it would be necessary to develop the enabling technological infrastructure and the requisite policy/regulatory framework in order to achieve the maximum positive impact of EV charging on the power system. Recommendations for Hawaii that are applicable to these regions include:

- Adopt of national, regional, and local policies that promote adoption of EVs.
- Develop public and private infrastructure for EV charging.
- Evaluate the optimal charging policies and smart scheduling that would provide the most benefits at the right time (i.e., highest capture of curtailed renewable energy).
- Design and implement smart charging incentives, pricing schedules, and EV charging rates that would induce the desired EV driver charging behavior.
- Implement smart grid infrastructure and IT platforms for real-time communication of information and dynamic pricing, from the utility to the EV customers (both for public and private charging), in order to enable smart scheduling of EV, either manually or automatically.
- Support development of national open standards for communications protocols such that vehicle manufacturers, utility providers, and telecommunications have a consistent platform to implement local programs.

1 Project Scope and Study Approach

1.1 Introduction, Objectives, and Scope

This report presents the results of renewable grid integration overview study performed by GE Energy Consulting for the Hawaii Natural Energy Institute. The intent of the study is to identify regions in the United States where results of the Hawaii Renewable Energy Grid Project (HREGP) report can be applied. Specifically, these applicable regions would have certain conditions analogous to those found in Hawaii, i.e., a high penetration of renewable energy resources, high potential for energy curtailment, and a constrained ability to export excess power. The study scope included two principal tasks.

The first task was a literature search, investigate, screen and identify regions in the U.S. with expected high penetrations of renewable energy and hence a high likelihood of renewable energy curtailment. In addition, the task screens for regions with potential transmission constraints that impede export of power to other regions which is analogous to an island-based grid that is not interconnected to neighboring islands.

The second task was to provide a high-level overview of applications of new technologies and programs identified in the HREGP report (e.g. policies, incentives, rule changes, etc.) that would be expected to mitigate renewable energy curtailments and enhance the stability of the power grid.

The study was commissioned by the University of Hawaii – Hawaii Natural Energy Institute (UH-HNEI) in support of the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) Hawaii Renewable Energy Grid Project (HREGP). General Electric International, Inc., acting through the GE Energy Consulting department within the GE Energy Management was asked to investigate the applicability to other parts of the US specific findings from the HREGP.

For the first task, GE conducted a review of available public information to identify other electric grids in the U.S. with “similar characteristics to Hawaii”, preferably with rank ordering of the areas/regions in terms of the expected level of penetration of wind and solar power in their power system. Upon examination, the rankings from different sources were not necessarily consistent; hence, it was decided that a more detailed modeling study, beyond the scope of the present work, was needed in order to use a common metric across all the areas/regions with a future year baseline to produce a consistent ranking of U.S. areas/regions.

Because the inconsistent results prevented equitable regional comparisons, the GE team opted to perform additional regional grid modeling to make up for data gaps in publically available information. GE used the baseline database of its proprietary Multi-Area

Production Simulation (GE MAPS) model of the U.S. power system for all three interconnections (Eastern Interconnection, Western Interconnection, and ERCOT) - to simulate the entire North American power systems, with and without transmission constraints, in order to identify any area/region in the lower 48 U.S. states that could be expected to be both export limited and also have high penetration of renewable (wind and solar) energy by 2018.

Task 2 is a high-level overview of the host of issues, factors, and causalities that hinder further development of renewable resources, exacerbate renewable integration issues, or otherwise contribute to higher curtailment of renewable energy.

In addition to listing and describing these factors, the report also discusses potential solutions and application of enabling technologies or possible policy and regulatory changes that would be expected to support fostering faster and greater integration of renewable (wind and solar) energy, mitigate the adverse impacts of renewable integration, and reduce the level of potential renewable energy curtailments.

To summarize:

- The primary task was to identify regions, states, and areas within the U.S. electric power systems that are expected to experience high penetration of renewable (wind and solar) energy, high likelihood of renewable curtailment, and have constraints on exporting power.
- The process adopted for this study was to investigate mostly publicly available information to rank order the candidate regions, states, or areas.
- In addition, the project team utilized GE's GE MAPS database and model to identify areas within U.S. which would be expected to have both high penetration of wind and solar energy, together with high transmission constraints that would limit exporting power to neighboring regions; or in other words, have both a high potential for wind and solar energy and also exhibit islanding within the larger grid due to transmission constraints, resulting in limits on the energy export capability, which would imply potential likelihood of curtailment of renewable energy.
- Although at the start of the project the approach was to use available model results from previous model runs, the project team actually performed new simulations based on a new approach to identify regions with high wind renewable penetration but limited export capabilities.
- The year 2018 was used as the basis for comparison of regions, states, and areas. The model considered load and generation conditions and other model input assumptions are projected 5 years out to 2018 to account for anticipated additions of wind and solar resources in the various regions; reasonable projection of regional load and fuel prices; and inclusion of any announced and planned generation and

transmission development with high likelihood of coming online. Beyond 5 years, the modeling assumptions would have been far less reliable, particularly regarding the transmission additions and upgrades - which usually requires a few years of planning. Transmission configuration and constraints are key drivers of the results presented in this analysis.

The report references to renewable energy are limited only to wind and solar energy and exclude other types of firm renewable energy sources such as hydro power and biomass power.

1.2 Study Approach

1.2.1 Task 1: Investigation of the U.S. Electric Power Systems

The approach for the first task was to conduct a literature search and investigate publicly available sources in order to identify regions in the U.S. with expected high penetrations of renewable energy, high likelihood of renewable energy curtailment and with transmission constraints that limit the exchange of power.

Different sources were used to collect and tabulate the relevant information which included the following (among others):

- Database of State Incentives for Renewable Energy (DSIRE) [Ref. 2]
- National Renewable Energy Laboratory (NREL) [Ref. 3]
- Department of Energy (DOE) – Energy Information Agency (EIA) – Renewable Energy Data Book – Prepared by NREL [Ref. 4]
- American Wind Energy Association (AWEA) [Ref. 5]
- ISO/RTO related studies [Please see the Reference Section]
- Previous GE renewable integration studies [Please see the Reference Section]

After review and selection of the relevant information, the data were tabulated and presented in this report (Section on Task 1). To the extent possible, the identified areas have been rank ordered by the level of expected renewable penetration.

In the course of the investigation it became clear that useful and reportable information were rather sparse. It was observed that there was no single study that provided a complete picture, and in fact, the findings from different sources were not necessarily consistent. Therefore, more detail studies, beyond the scope of the present work, will be needed to extend the findings of this report, preferably by using a common metric across all the areas/regions with a future year baseline to produce a consistent ranking of U.S. areas/regions.

Since the collected information appeared to be inconclusive, GE team performed additional modeling using its baseline GE MAPS model of the U.S. power system. The GE MAPS model includes databases for all three major North American Grid Interconnections, i.e., Eastern Interconnection, Western Interconnection, and ERCOT. The GE MAPS model was used to simulate all three of the interconnections, with and without major transmission constraints modeled, in order to identify any area/region in the lower 48 U.S. states that would meet two generation conditions by 2018:

a) They will have a high penetration of wind and solar energy

b) They will be export limited due to transmission constraints

c) They will experience a price drop due if transmission constraints are taken into account

Areas/Regions identified as meeting these three conditions are considered as candidate regions that will have high likelihood of experiencing some level of curtailment of their renewable energy during low demand and high supply periods - or for a multitude of other technical or operational reasons as discussed in the Report Section on Task 2.

Tables at the end of the Task 1 section identify the candidate areas/regions identified in by the GE MAPS simulation. It should be noted that these results are based on an existing baseline GE MAPS database. No attempt was made to update or revise the database with the most current generation or transmission information, or incorporate new projections of fuel prices or regional loads. Hence, the reported results are demonstrative and representative rather than definitive and absolute, and should not be used as basis for any specific policy actions or investment activities related to the identified areas/regions.

1.2.2 Task 2: Applying Options to Enable Renewable Energy Expansion

The second principal project task was to provide a high level overview of the applications of technologies and programs (e.g. policies, incentives, rule changes, etc.) that would be expected to mitigate wind and solar renewable energy curtailments and enhance the stability of the power grid.

The approach was based on identifying major factors, issues, and causes that do or may hinder further development of renewable energy in the U.S., or potentially contribute to incidents of high curtailment of the renewable energy. The report provides an overview of these various factors, issues, and causes.

The next step was to apply the various technologies, programs, and policies identified in the HREGP that do or would be expected to alleviate the identified hurdles, foster further development of renewable wind and solar energy, resolve the identified integration issues, and mitigate adverse impacts of higher penetration of wind and solar energy.

2 Task 1: Investigation of the U.S. Electric Power Systems

2.1 Review of State RPS targets

Renewable portfolio standards (RPS) developed by the state governments and policy makers, are mainly structured to address policy and regulations on greenhouse gas emissions, notably CO2. A principal course of action promulgated by these policies is promotion of development of renewable energy to meet target levels of renewable energy as defined by each state's RPS policies in states that have such polices.

The Database of State Incentives for Renewables and Efficiency (DSIRE)[2] [Ref. 2] was used to identify the states with highest expected levels of renewable energy penetration. DSIRE provides the most comprehensive set of information on incentives and policies that support renewables and energy efficiency in the United States.

Renewable portfolio standards are defined as desired percentage of retail electricity sales and are classified as primary, secondary and tertiary based on the utility type. The definitions of these types vary from state to state, but generally the primary type is for investor owned utilities, and the secondary type is meant for other types of utilities (such as municipalities and cooperatives). Only Oregon has a tertiary standard, targeted at utilities with less than 1.5% of state's electricity load.

According to DSIRE[3], Hawaii:

> "… does not have any multipliers[4] (i.e., the extra credit awarded to specific resources or applications for RPS compliance purposes), and only has the most basic definition for hydropower ("falling water" with not additional restrictions). Municipal solid waste qualifies as a biomass resource. Through 2014 customer-sited renewable resources count as electricity displacement technologies rather than as renewable energy generation resources. Displacement technologies (including other energy efficiency measures) are limited to fulfilling 50% of the standard. Beginning in 2015, customer-sited renewables will count as renewable energy generation resources and energy efficiency and electricity displacement resources will be addressed under a separate energy efficient resource standard (EERS)."

[2] Established in 1995, DSIRE is currently operated by the N.C. Solar Center at N.C. State University, with support from the Interstate Renewable Energy Council, Inc. DSIRE is funded by the U.S. Department of Energy (www.dsireusa.org).

[3] http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf

[4] DSIRE Definition: "The extra credit awarded to specific resources or applications for RPS compliance purposes."

The RPS targets for all the states are also been shown in the following DSIRE map.

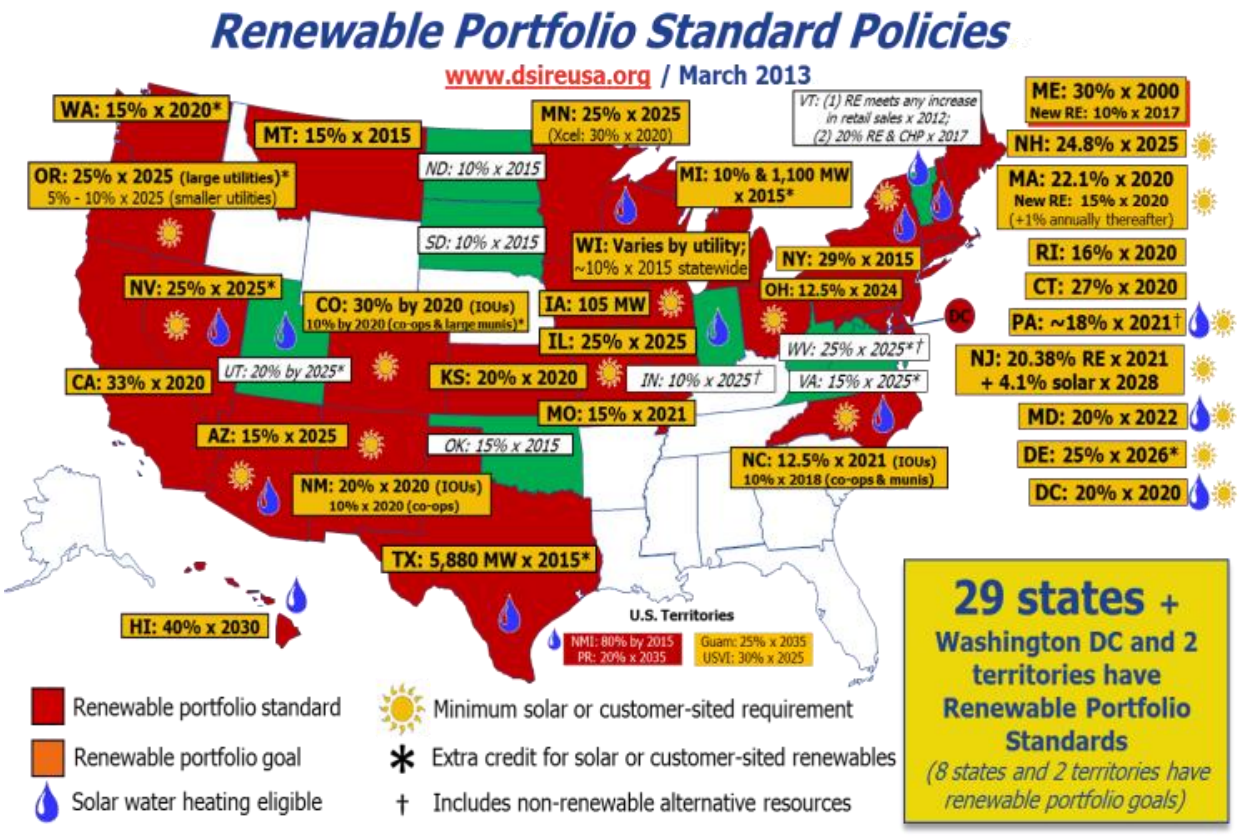

Figure 1: State RPS Policy Map

[Source: www.dsireusa.org – with written permission from NC Solar Center / Database of State Incentives for Renewable Energy (DSIRE)]

The RPS target for primary and secondary type from highest to lowest is as shown in the following figures.

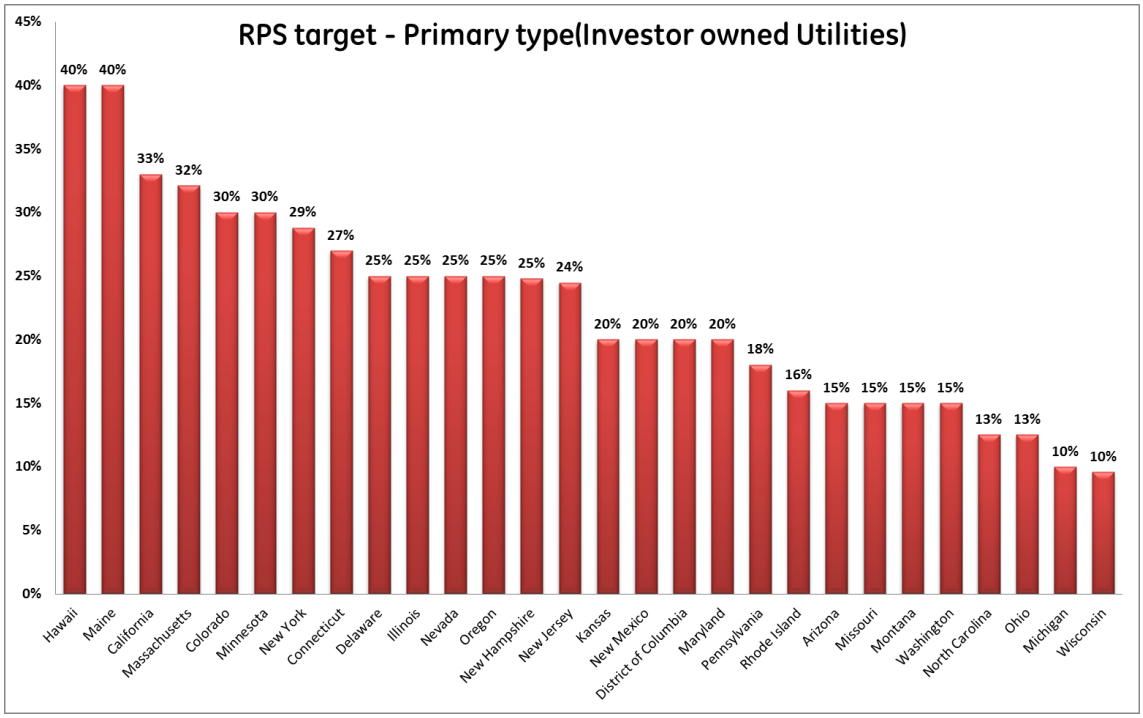

Figure 2: State RPS Targets (Primary Type) in Descending Order

[Original Data Source: www.dsireusa.org – with written permission from NC Solar Center / DSIRE]

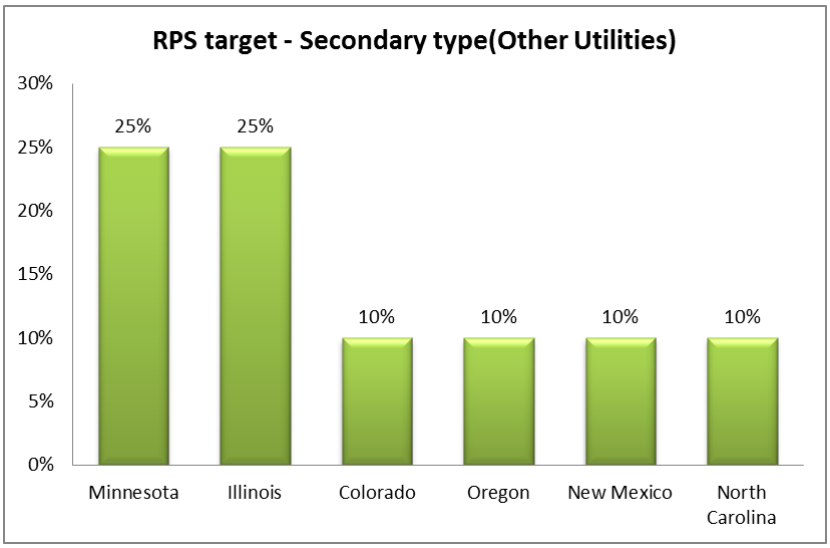

Figure 3: State RPS Targets (Secondary Type) in Descending Order

[Original Data Source: www.dsireusa.org – with written permission from NC Solar Center / DSIRE]

The RPS targets to be met by year 2018 are shown below. The highlighted states are forecasted to meet their target RPS before year 2018.

Table 1: State RPS Targets in Descending Order

Rank	State	Targets by 2018	MW targets	Will Meet Target Before 2018
1	Maine	40.00%		√
2	California	29.00%		
3	New York	28.79%		√
4	Minnesota	25.00%		√
5	Connecticut	24.00%		
6	Massachusetts	20.10%	400	√ (Only MW Target)
7	Nevada	20.00%		√
8	Colorado	20.00%		√
9	New Hampshire	18.50%		
10	Maryland	18.30%		
11	New Jersey	18.03%		
12	District of Columbia	16.50%		
13	Delaware	16.00%		
14	New Mexico	15.00%		
15	Hawaii	15.00%		√
16	Kansas	15.00%		√
17	Montana	15.00%		√
18	Oregon	15.00%		√
19	Pennsylvania	14.72%		
20	Rhode Island	14.50%		
21	Illinois	13.00%		
22	Michigan	10.00%	1,100	√
23	Missouri	10.00%		
24	North Carolina	10.00%		
25	Wisconsin	9.57%		√
26	Washington	9.00%		√
27	Arizona	8.00%		
28	Ohio	6.50%		
	Iowa		105	√
	Texas		5,880	√

Considering RPS targets set for the study year 2018 as of April 2013, the top 8 states that are projected to have highest level of renewable penetration as a percentage of retail electricity sales are:

1. Maine
2. California
3. New York
4. Minnesota
5. Connecticut.
6. Massachusetts
7. Nevada
8. Colorado

2.1.1 Case of Hawaii

It should be noted that Hawaii achieved its 15% target by 2015, and it is on track to meet its target by 2018. HECO's achieved 13.9% at end of calendar year 2012, and was well on track to meet its target for 2015 likely before end of 2013 [Ref. 1]. For 2012, HECO achieved an RPS energy savings - without DSM - of 13.9%, primarily through a comprehensive portfolio of renewable energy power purchase agreements, net energy metering programs and biofuels.

2.2 NREL Renewable Energy Futures Study

The Renewable Futures Study [Ref. 3] was conducted by NREL to analyze the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the U.S. electric system. The study assumes various scenarios based on the percentage of renewable energy penetration and estimates the generation and installed capacities till 2050. High demand baseline case assumes (and extends until 2050) trends for the residential, commercial, and industrial sectors as forecast to 2030 by the Energy Information Administration (EIA) in its Annual Energy Outlook (AEO).

The installed capacity by state for each year in MW for solar and wind as depicted by this study is shown below. The top five states based on installed capacity for years 2012 to 2050 is tabulated below:

Table 2: Top 5 States with Renewable Energy Installed Capacity (MW)

2012	2016	2018 (Study year)	2020	2038	2044	2050
Texas	Texas	**Texas**	Texas	Texas	California	California
California	Kansas	**Kansas**	Kansas	Kansas	Texas	Texas
Iowa	California	**California**	California	California	Kansas	Kansas
Kansas	Iowa	**Iowa**	Wyoming	Iowa	Iowa	New Mexico
New York	Wyoming	**Wyoming**	Illinois	Oklahoma	Oklahoma	Iowa

However, rather than the absolute level of installed capacity (MW), a more appropriate measure of the renewable penetration is the magnitude of renewable energy (MWh) relative to the total energy generated or consumed. The top five states based on renewable generation as a percentage of total generation for years 2012 to 2050 is tabulated below:

Table 3: The Top Five States Based On Renewable Generation as Percentage of Total Generation (MWh)

2012	2016	2018	2020	2038	2044	2050
South Dakota	South Dakota	**South Dakota**	South Dakota	South Dakota	South Dakota	South Dakota
Wyoming	Wyoming	**Wyoming**	Wyoming	Wyoming	Rhode Island	Wyoming
California	Kansas	**Rhode Island**	Rhode Island	Rhode Island	Wyoming	California
Maine	California	**Kansas**	California	Kansas	Kansas	Kansas
New Mexico	Rhode Island	**California**	Kansas	California	California	New Mexico

From the NREL study results, the installed wind and solar capacity as a percentage of total installed capacity by state for each year were calculated and are shown below. For the study year (2018) the top five states based on the various criteria are as below:

Table 4: Top 5 States with Renewable Energy in 2018 Based on Various Criteria

Renewable Installed Capacity	Renewable Energy as % of Total Generation (MWh)	Wind Capacity as % of Total Installed Base (MW)	Solar Capacity as % of Total Installed Base (MW)
Texas	South Dakota	Kansas	Rhode Island
Kansas	Wyoming	South Dakota	New Mexico
California	Rhode Island	Wyoming	Connecticut
Iowa	Kansas	North Dakota	California
Wyoming	California	Iowa	Nevada

Hence, based on the NREL study, the candidate states with highest expected levels of renewable energy penetration in 2018 are:

1. South Dakota
2. Wyoming
3. Rhode Island
4. Kansas
5. California

2.3 DOE/NREL 2011 Renewable Energy Data Book

The Renewable Energy Data book is published by US Department of Energy and is prepared by NREL [Ref. 4]. It summarizes the renewable energy scenario in US. The report shows the state rankings based on total renewable energy installed capacity, as shown in the following figure.

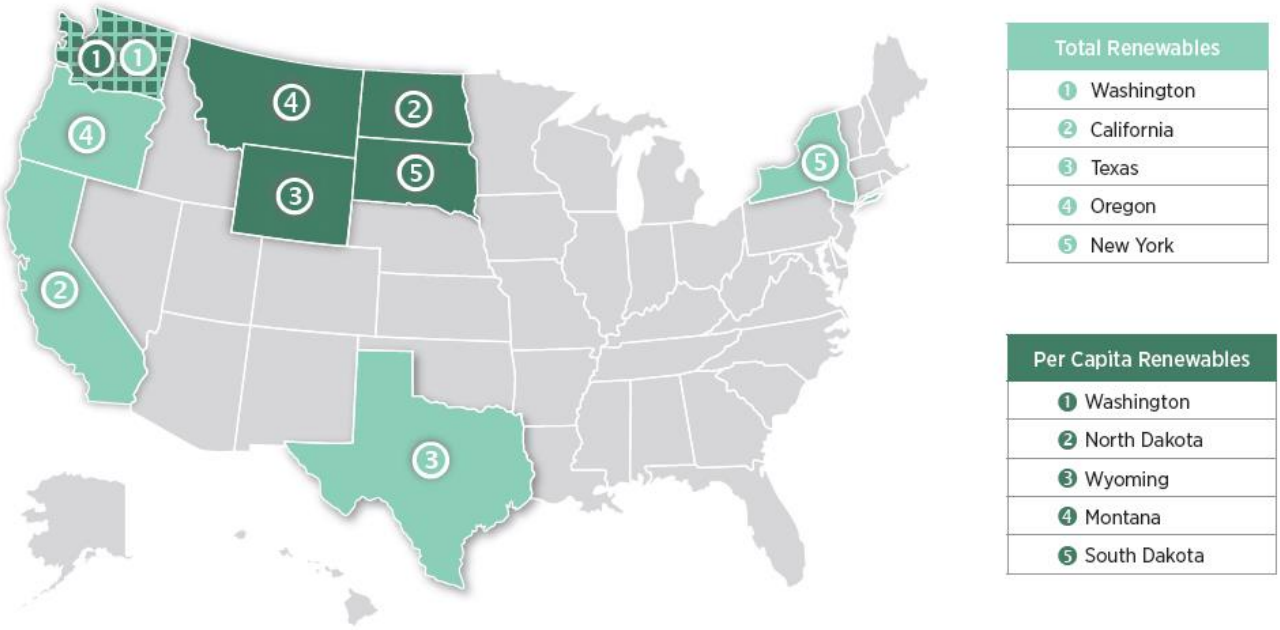

Figure 4: State Rankings Based on Total Installed Capacity

[Source: Renewable Energy Data Book, published by US Department of Energy and prepared by NREL]

When a Per Capita renewable installation is assumed to be more representative of the level of renewable energy penetration compared to the total renewable installation, the candidate states are:

1. Washington
2. North Dakota
3. Wyoming
4. Montana
5. South Dakota

The data book also ranked the states based on source-wise renewable installed capacity.

The renewable installed capacities for various states in 2011 are:

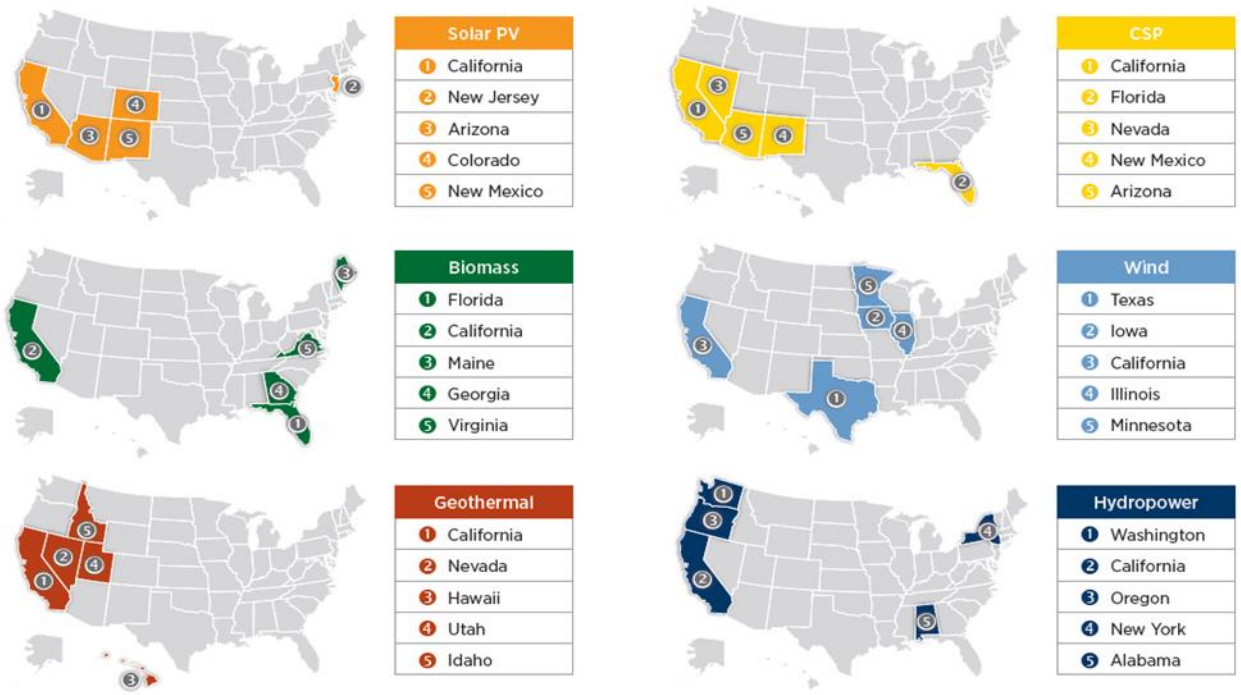

Figure 5: Renewable Installed Capacities for Various States In 2011

[Source: Renewable Energy Data Book, published by US Department of Energy and prepared by NREL]

Based on the above figure, the states with the highest installed wind capacity are:

1. Texas
2. Iowa
3. California
4. Illinois
5. Minnesota

2.4 EIA study year 2011

The state wind and solar generation in 2011 in MWh are given below.

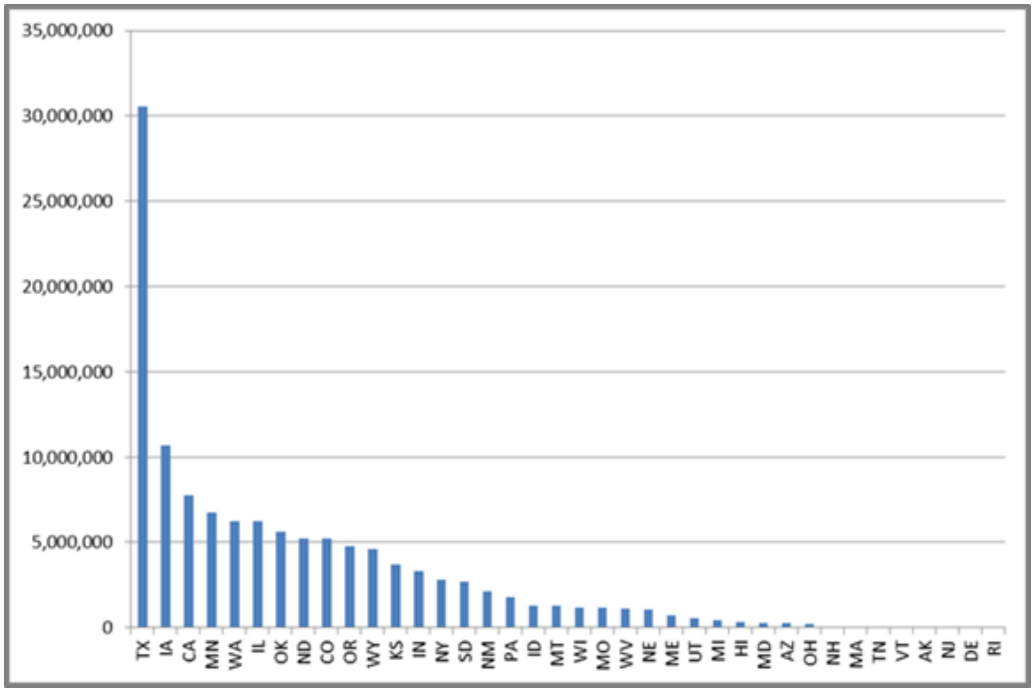

Figure 6: 2011 Wind Generation MWh

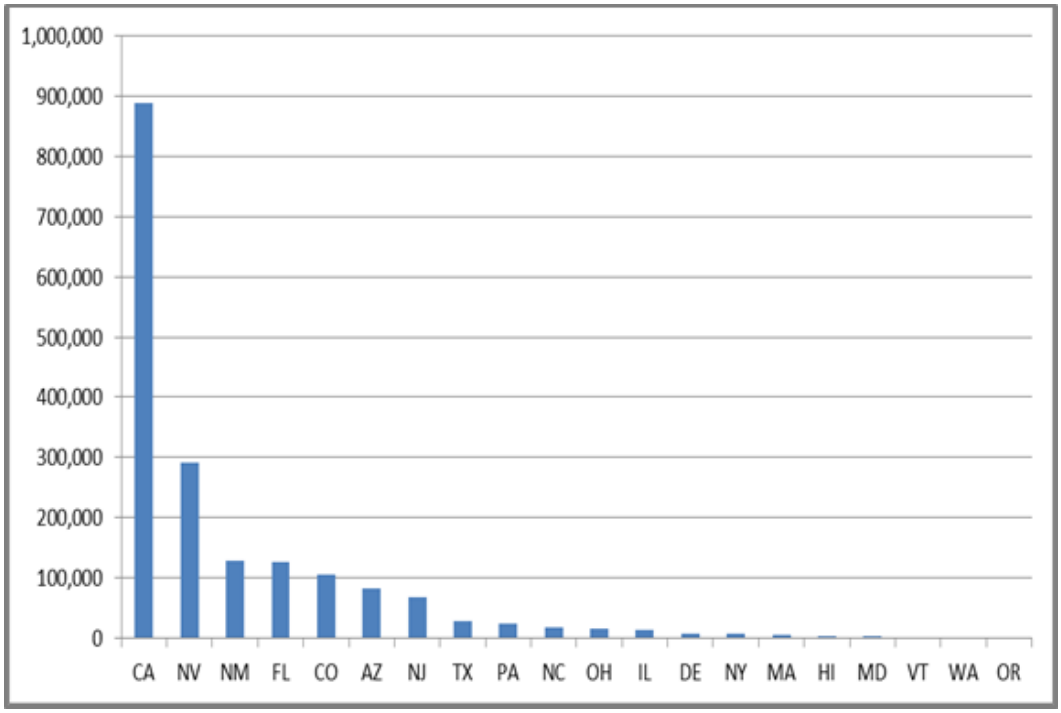

Figure 7: 2011 Solar Generation MWh

The state rankings based on wind Generation are:

1. Texas
2. Iowa
3. California
4. Minnesota
5. Washington
6. Illinois
7. Oklahoma
8. North Dakota

2.5 AWEA Wind Industry Annual Market Report

The U.S. Wind Industry 2012 Annual Market Report [Ref. 5] by American Wind Energy Association (AWEA) provides information on wind energy by states.

The following figure presents U.S. Wind Capacity Installations by State.

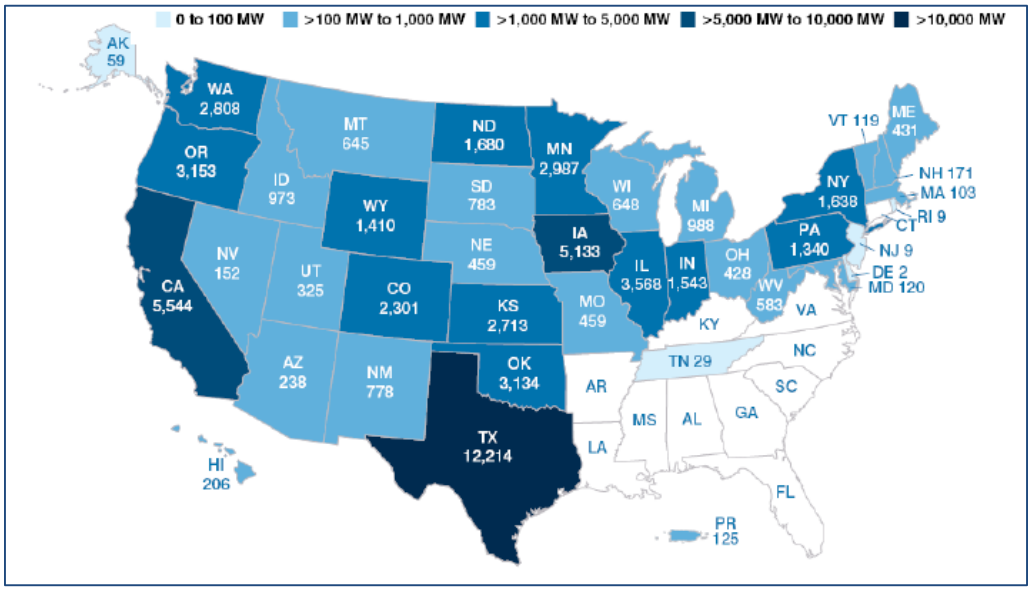

Figure 8: U.S. Wind Capacity Installations by State

[Source: U.S. Wind Industry 2012 Annual Market Report, American Wind Energy Association (AWEA)]

The following figure presents U.S. wind electricity generation by State.

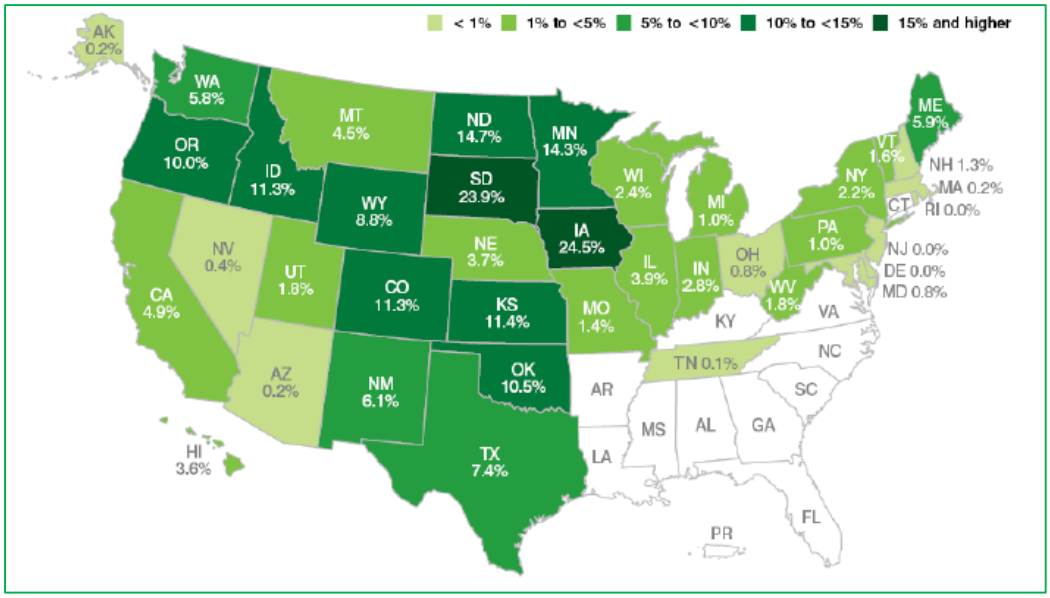

Figure 9: U.S. Wind Electricity Share of Generation by State

[Source: U.S. Wind Industry 2012 Annual Market Report, American Wind Energy Association (AWEA)]

The state ranking based on the wind electricity share of generation by state are provided in the following table:

Table 5: U.S. Wind Electricity Share of Generation by State (AWEA)

Rank	State	Share of Electricity Generation
1	IA	24.5%
2	SD	23.9%
3	ND	14.7%
4	MN	14.3%
5	KS	11.4%
6	ID	11.3%
7	CO	11.3%
8	OK	10.5%
9	OR	10.0%
10	WY	8.8%
11	TX	7.4%
12	NM	6.1%
13	ME	5.9%
14	WA	5.8%
15	CA	4.9%
16	CA	4.9%
17	MT	4.5%
18	IL	3.9%
19	NE	3.7%
20	HI	3.6%

2.6 Review of Renewable Energy Integration Studies Performed by GE

At the beginning of this applicability study, the intended approach was to use available model results from previous GE MAPS simulation runs from past GE renewable integration studies to identify areas/regions of interest.

A review of these studies concluded that they were actually not appropriate sources for selecting or ranking of candidate regions, states, or areas. The basis for these studies was the "assumption" and "presupposition" of high renewable penetration as future scenarios for consideration in the study, and hence, they do not demonstrate the regions under study have any intention or tendency, either due to natural settings or economic considerations, to become regions with high penetration of renewable energy.

2.7 Review of ISO/RTO Studies

A review of various Independent System Operator/Regional Transmission Organization (ISO/RTO) websites did not produce any results that would indicate wind and solar penetration targets beyond what has already been described and presented in the RPS tables.

2.8 GE MAPS Based Candidate Area/Regions

Because previous GE MAPS renewable integration simulation runs were not applicable to this study, GE elected to develop runs specific to this project to fill in potential gaps of data missing from publicly available information.

GE's Concorda Software Suite's Multi-Area Production Simulation (GE MAPS) model is a chronological hourly security constrained unit commitment and economic dispatch (SCUC/ED) model, used to simulate the hourly operation of the power grid. "Chronological" feature means that the model considered hours of operations in a sequential manner, in contrast to some other production costing models that only consider the level of hourly load from high to low (i.e., Load Duration Curve), with no consideration of the time chronology. "Security Constrained" feature means that the model takes into account the transmission constraints in the system that should be considered for the secure operation of the power system. GE MAPS accounts for all intra and inter-regional transmission. Hence, all the tie-line limits between regions are represented in GE MAPS. The model's scheduling (i.e., optimal dispatch) of generation does not violate the modeled transmission constraints, including the thermal limits of the lines and the system contingency limits (limits on power flows in lines needed to provide reserve capacity if other lines or power sources in the grid are tripped). All the renewable resources are properly represented in GE MAPS.

GE MAPS has been continuously developed, refined and benchmarked for over 30 years and has been applied to system economic analyses of interconnected power grids of the U.S., Canada, and a few other countries.

GE MAPS can be run for time horizons of any length, from a day to many years. The simulation outputs include, unit level hourly generation, fuel consumption, environmental emissions, and variable production costs, locational marginal prices, transmission flows, and transmission congestion (i.e., which constraints are binding or at their limit, when and for how long).

The GE team decided that there was need to get a fuller picture of areas/regions across the continental USA, their level of wind and solar penetration, and a view of their power export capabilities. To that end, the team performed new model runs to compare annual optimal dispatch of generation with and without modeled transmission constraints. The comparison

would help identify regions that would be expected to have limited power export capabilities due to transmission congestion by 2018. The same model results also identified the level of wind and solar penetration in each region as percentage of total annual energy in each corresponding area/region.

In the comparative approach, each of the U.S. Electric Interconnections - i.e., Eastern Interconnection, Western Interconnection, and ERCOT - were simulated under two transmission scenarios, one without any imposed transmission constraints, and another with high level transmission constraints fully taken into account.

Comparisons of the operational and economic metrics between the two scenarios (one without transmission limits, and one with transmission limits) in the 2018 Study Year allowed identification of the Regions/states/areas that would experience lower locational marginal prices due to transmission constraints: Decrease in prices in an area after the imposition of transmission limits indicates that the area's exports are constrained due to transmission limits, and that the outgoing transmission reaches its limits some of the time. If transmission limits are relaxed, more expensive generation in the area would be dispatched and exported, resulting in higher prices in the area.

Three tables found in Appendix 1 (Table 8, Table 9, and Table 10) present the results of comparison of two "No Constraint and With Constraint" scenarios for each of the three U.S. Electric Interconnections. Two of the columns are in absolute values (designated as "Absolute" in column headings), i.e., not changed between the No Constraints and With Constraints scenarios. The other columns are changes (Delta) going from No Constraint scenario to With Constraints scenario.

In addition, as shown in the tables, from the modeling results it is also possible to calculate the level of wind and solar penetration in each area, and the relative wind generation compared to the total generation. Based on the set-up of the model at the time of analysis, it was not possible to extract the amount of renewable curtailment in each area, although that is an option that can be considered in the future follow-ups to the study, if any.

As can be seen, imposition of transmission constraints results in changes in the following selected attributes:

- Change in Average Spot Price ($/MWh)
- Change in Net Exports – Imports (MWh)

As can be observed in Table 8, Table 9, and Table 10, there is strong correlation between change in "Average Spot Price", and change in "Annual Net Exports". For instance, large drops in Average Spot Price in the following tables are associated with large drops in Annual Net Exports. A large drop in exports after imposition of transmission limits, results in large drops in spot prices in the area. Conversely, going further down the tables, it can be

observed that large increases in average spot prices are associated with increase in net exports.

In general, if imposing transmission constraints results in lowering of the Annual Net Exports in an area, it also results in a drop in the Average Spot Price of the area.

Therefore, we can conclude that these areas become "export-limited" areas, due to transmission constraints. Export-limited areas cannot export their surplus generation, and spot prices are forced down in such areas due to surplus power. With additional available generation, there is less need for more expensive generation to be dispatched.

If the areas identified as "export-limited" also include high levels of wind and solar renewable energy, then there may be higher likelihood of renewable energy curtailment during low load periods. The reason is that such an area may experience high surplus power during low load periods, requiring curtailment of power. As discussed in the next section (Section on Task 2), the thermal resources are first in line for curtailment, but too much surplus power may push the thermal resources to their limits beyond which further curtailment of thermal energy may not be possible, causing additional curtailment to be applied to the renewable energy resources.

Hence, a list of candidate areas can be formed by identifying areas which are export-limited (i.e., those with drop in spot prices and power exports due to transmission constraints) which are also high in level of wind and solar generation (here measured in terms of percentage of total energy generation).

In Table 8, Table 9, and Table 10 (Appendix 1), characteristics analogous to Hawaii are presented for each Interconnection, by identifying areas with more than zero penetration of renewable (wind and solar) resources, and by comparing changes in area prices, level of exports, between a no-transmission-constraints scenario and with-transmission-constraints scenario:

- Areas with non-zero penetration of wind and solar were identified (areas where wind and solar penetration in either annual energy or installed capacity is greater than 0.0%)
- Areas which exhibited a decrease in spot prices (negative changes are in red) due to imposition of transmission constraints.
- Areas where net exports (i.e., Annual Exports divided by Average Daily Energy) decrease due to imposition of transmission constraints.

Those areas that meet all of the three conditions listed above, are the candidate areas that can be assumed have some features similar to Hawaii, i.e., experience isolation some of the time from the larger grid, and have high penetration of wind and solar resources.

To provide a ranking, it was assumed that each of the 3 factors (i.e., non-zero penetration of wind and solar, decrease in area prices, decrease in area exports) have equal weight. The final ranking is based on the sum of the ranks across the 3 factors. The short and long names of the pools, states, and areas modelled in the GE MAPS simulation are provided in in Appendix 1.

2.9 Final Candidate Areas

The candidate lists are further reduced in Table 6 and Table 7 when imposing a higher threshold of 10% for renewable penetration based on the findings in Table 8, Table 9, and Table 10 (Appendix 1). These tables list the areas which most closely resemble the combination of characteristics assumed for the Hawaii Renewable Energy Grid Project. The selected candidate areas meet the following criteria:

- Wind and solar energy constituted at least 10% of annual energy produced in the area.
- The area is export-constrained, i.e., imposing the tie-line transmission constraints results in reduction of the exports from the area.
- The area experiences a decrease in the area load weighted electricity price if the transmission constraints are taken into account.

The last condition is another indication of the area becoming export-limited, since prices in over-supplied export-constrained areas are typically lower than they would be without the transmission constraints. High renewable penetration and lack of outlet for exports would imply that at times of low load and high supply, there would be some likelihood of renewable energy curtailment. No area in ERCOT met all three conditions.

The primary objective was selection of candidate areas with characteristics similar to Hawaii, but the ranking within the selected candidate areas, by itself, is of less importance, since there is no single criterion that can be used for ranking. Hence, the process used should be viewed as “screening process” rather than a “ranking process”.

It is possible to weight different factors such as prices and net exports and then use a weighted average of these factors as the rank indicator. However, in the absence further information, a unity weight for each factor appears reasonable.

The identified areas have some similarity to Hawaii, but only in the sense that - based on the assumptions used in the modeling - there is an expectation that they will have a high penetration of renewable resources by 2018, and will also experience times when they will not be able to export their surplus power to the outside world, and hence, have a likelihood

of experiencing renewable energy curtailment during periods of low demand and high supply of electricity.

The list of top candidate areas can be expanded by lowering the 10% renewable penetration requirement. Some areas with lower penetration actually experience a larger reduction in area prices and export levels.

Table 6: Candidate Areas in the Eastern Interconnect

Final Ranking	Candidate?	Country	Inter-Connection	Area	Pool	State	Renewable Energy Penetration	Annual Net Exports as % of Average Daily Energy	Change in Average Spot Price ($/MWh)
1	YES	USA	EI	MECA	MISO	IL	30.2%	-50.1%	(9.48)
2	YES	USA	EI	ALTWA	MISO	IA	40.6%	-57.7%	(8.75)
3	YES	USA	EI	SECIA	SPP	KS	57.9%	-15.8%	(11.42)
4	YES	USA	EI	MDUA	MISO	MT	81.8%	-28.4%	(8.23)
5	YES	USA	EI	OTPA	MISO	MN	58.7%	-41.0%	(7.25)
6	YES	USA	EI	NPPDA	SPP	NE	19.8%	-14.8%	(11.07)
7	YES	USA	EI	SIGEA	MISO	IN	13.5%	-44.0%	(7.17)
8	YES	USA	EI	NSPA	MISO	IA	12.1%	-30.8%	(7.27)
9	YES	USA	EI	SMPA	MISO	MN	85.8%	-20.3%	(6.96)
10	YES	USA	EI	WFECA	SPP	OK	52.3%	-6.7%	(9.21)
11	YES	USA	EI	OKGEA	SPP	OK	11.0%	-24.4%	(8.82)
12	YES	USA	EI	GREA	MISO	MN	11.8%	-24.0%	(7.38)
13	YES	USA	EI	WRA	SPP	KS	11.7%	-7.7%	(9.40)
14	YES	USA	EI	WAUEA	MAPP	IA	20.0%	-7.4%	(8.89)
15	YES	USA	EI	SPSA	SPP	NM	11.4%	-7.9%	(3.04)
16	YES	USA	EI	UPPCA	MISO	MI	37.4%	-4.4%	(0.53)

Table 7: Candidate Areas in the Western Interconnect

Final Ranking	Candidate?	Country	Inter-Connection	Area	Pool	State	Renewable Energy Penetration	Annual Net Exports as % of Average Daily Energy	Change in Average Spot Price ($/MWh)
1	YES	USA	WECC	WACMCEA	RMP	CO	17.4%	-18.1%	(5.81)
2	YES	USA	WECC	SRPA	DSW	AZ	13.1%	-9.2%	(5.21)
3	YES	USA	WECC	IPCOA	BAS	ID	10.9%	-8.5%	(6.48)
4	YES	USA	WECC	PNMA	DSW	NM	12.8%	-4.5%	(5.02)
5	YES	USA	WECC	PACEIDA	BAS	ID	10.6%	-47.0%	(4.26)
6	YES	USA	WECC	AVAA	NWP	ID	43.1%	-3.4%	(3.98)
7	YES	USA	WECC	PACEWYA	RMP	WY	21.1%	0.0%	(4.42)
8	YES	USA	WECC	BPATA	NWP	ID	10.5%	-12.3%	(3.73)
9	YES	USA	WECC	WALCA	DSW	AZ	11.6%	-9.7%	(2.39)
10	YES	USA	WECC	LDWPA	CALS	CA	33.0%	-1.9%	(3.50)
11	YES	USA	WECC	PSEIA	NWP	WA	16.6%	-1.1%	(3.59)

The modeling results have identified candidate areas that are expected to be export-constrained in 2018 and thus, have similar characteristics to Hawaii. It can be observed that the following pools and following states have the largest number of selected candidate areas in each interconnection:

- Eastern Interconnection (16 candidate areas):
    - Pool/Region: MISO (9 candidate areas):
        - Minnesota: 3
        - Iowa: 2
        - Indiana: 1
        - Illinois: 1
        - Montana: 1
        - Michigan: 1
    - Pools/Region: SPP (6 candidate areas):
        - Kansas: 2
        - Oklahoma: 2
        - Nebraska: 1
        - New Mexico: 1
    - Pools/Regions: MAPP (1 candidate area)
        - Iowa: 1
- Western Interconnect (11 candidate areas)
    - Pools/Regions: Basin (2 candidate areas)
        - Idaho: 2
    - Pools/Regions: Northwest Power Pool (3 candidate area)
        - Idaho: 2
        - Washington: 1
    - Pools/Regions: Rocky Mountain Pool (2 candidate areas)
        - Colorado: 1
        - Wyoming: 1
    - Pools/Regions: Desert Southwest (3 candidate areas)
        - Arizona: 2

- New Mexico: 1

- Pools/Regions: California ISO (1 candidate area)
  - California: 1

It should be noted that other areas within the same states and pools which include one or more candidate areas, may not necessarily exhibit similar characteristics as the candidate areas, and hence it cannot be assumed that wider regions and territories encompassing these candidate areas would also be export constrained, or have high penetration of renewable energy.

A higher level of granularity above "Area" in GE MAPS is the "Pool", and the analysis did not consider these larger geographic regions, which are, in most cases, multi-state regions, and much larger than Hawaii in area.

As a follow-up project, a similar analysis can be performed to consider only these larger regions (or Pools in GE MAPS), and identifying these larger pools which would have high penetration of renewables and also be export constrained. But that would require additional analysis which is beyond the scope of this project.

2.10 Task 1 Endnote

It should be emphasized that the modeling results are representative and comparative rather than absolute. The input data and assumptions used for these GE MAPS models were from numerous previous regional studies. These results would need to be validated using updated modeling assumptions and then compared against historical data. Updating of these regional models and validating against historical data is well beyond the scope of this analysis.

However, using regional grid modeling assumptions that have been successfully applied in past studies by GE, reasonable conclusions can be drawn. Should these preliminary results trigger policy consideration, a follow-up study based on an updated database and consideration of alternative future scenarios is recommended.

It should be noted that the areas/regions modeled in GE MAPS are geographically more fine-grained and relatively smaller than the regions identified in the literature search effort and presented in earlier tables, which were all at state level. The presented methodology can be used to identify the smaller areas/regions with high wind and solar generation that would have a high likelihood of becoming "islanded" and isolated from the larger grid due to transmission constraints.

It should also be noted that purpose of this project was to identify areas/regions that would in some respect be similar to Hawaii in terms of wind and solar penetration and have some

likelihood of renewable energy curtailment. As such, the GE MAPS areas/regions were broken down it regions that are too small to operate on a stand-alone basis. Many of the individual regions in the continental U.S.A. operate together in groups or regional markets (like PJM and MISO), and each of those regions operate as one large all-encompassing entity subject to centralized operational rules and procedures. This aspect of larger regional balancing authorities and their interconnection and interrelationship with the wider grid, makes them fundamentally different from Hawaii and other island regions and truly isolated stand-alone power systems.

3 Task 2: Integration Issues and Potential Solutions

3.1 Introduction to Task 2

There are many factors and barriers that hinder adoption and integration of renewables into the grid—technical, economic, socio-political and regulatory. These may create operational and economic challenges for the acceptance of a high penetration of renewable energy on the power system, and in some cases result in less renewable energy to be delivered than is available.

Tasks 2 considers the application of enabling technologies or desired policy and regulatory changes that would help advance faster and greater integration of renewable energy, and reduce the level of potential renewable energy curtailments. This section of the report provides a high-level overview of a host of issues, factors, and causalities that either impede further development of renewable resources, or aggravate renewable integration issues, or cause higher curtailment of renewable energy.

Mitigating solutions include a range of enabling technologies and programs such as transmission upgrades, more flexible thermal generation, smart grid technologies and programs such as demand response and energy storage and electric vehicle charging.

This section first systematically identifies major issues, factors, or causalities, and then provides a discussion of potential mitigating solutions or options to contravene the adverse impacts. To the extent possible, the considered options will fall into one or more groupings of the options listed in the original scope of work, but not necessarily in the same order or grouping as the original work scope, which is reproduced here for reference:

- Technologies
    - Smart grid
    - Inter-grid Transmission (e.g. Intertie hardening)
    - Energy storage systems
- Programs
    - EV Charging incentives and controls
    - Policy and Rule Changes
    - Utility generation and grid operational policies
- Demand Response & Dynamic Pricing
    - Load Curtailment or Load Shifting
    - TOU, or CPP, or RTP

- Others

The causality factors and the mitigation options considered fall into one or more of the following general domains:

- Supply-Side (Generation Resources)
- Demand-Side (End Uses)
- Transmission and Distribution System
- System Operations
- Policy and Regulatory

3.2 Power Grid and Variable Energy Renewable Generation

To discuss the interplay of variable energy renewable generation with the power grid, a general perspective on the salient characteristics of the power grid and the essential features of grid connected wind and solar energy is useful.

3.2.1 Unique Features of Electricity Transmission and Distribution

There are three principal features that differentiate electricity from other commodities and marketable items:

A. Electricity flow in the power grid transmission follow patterns based on certain physical rules (Kirchhoff Current and Voltage Laws), following the path of least resistance. Power flows on transmission lines depend on the configuration of the transmission system and its characteristics, the topology of generation, and load on the system. The power flow path cannot be arbitrarily assigned.

B. Electricity demand is variable in time, and changes every second due to changes in customer (residential, commercial, and industrial) electricity usage which in some cases depend on the changes in weather. Electricity consumption can be random and uncertain subject to random events, such forced (i.e., unplanned) outage of power plants.

C. Electricity supply and demand need to be balanced on a moment to moment basis. This instantaneous balancing of supply and demand requires great flexibility and responsiveness in the integrated electricity grid, particularly considering that power grids are among the largest and most complex modern interconnected infrastructures on the planet. Indeed, the power grid is essentially a “just-in-time”

system where variable and imperfectly predictable demand must be met instantaneously with detailed planning and robust commitment and dispatch of generation. The same level of moment by moment balance of demand and supply is not expected of any other market commodity. In fact almost all tradable commodities can be stored in substantial amounts, which is not the case for electricity.

These three principal differentiating features of the electric power system contribute to the complexity of integrating wind and solar power into the power grid, particularly due to the variability and uncertainty of wind and solar generation.

3.2.2 Wind and Solar Variability and Uncertainty

Wind and solar generation cannot be perfectly forecast over any time horizon; they are variable across time scales ranging from seconds to seasons. System loads also exhibit variability and uncertainty across many operational time frames.

It is generally not possible to extract quantitative conclusions about operational impacts directly from statistics of renewable generation and load data. While certain features may stand out from the perspective of system operations – such as lower net loads (load minus renewable generation) during off-peak hours – a range of other factors must be considered to determine the magnitude of the impact. Production simulations, such as those performed by GE MAPS, take a great number of these other factors into account as they seek to mimic the actual operation of the system against the array of operating constraints, and therefore are the better framework for drawing operational conclusions.

Variations in net load translate into additional variability and uncertainty in the power system, which translate into additional requirements for back-up balancing resources that are composed of a mix of supply-side and demand-side resources. Operationally, the net of load will drive the decisions and procedures for deployment of dispatchable resources (e.g., conventional generating units, energy transactions with neighboring markets and areas, and demand response).

The time horizons for renewable generation variability are critical to power plant system operations, and can range from tens of seconds to seasons. Over shorter horizons, the variability appears as mostly random due to the extremely large number of factors that can influence production over this time frame, while in fact only the very shortest term variability is random. There are opportunities to introduce forecasting protocols into dispatch planning. The extreme randomness of PV under puffy cloud conditions can be predicted in the sense that puffy clouds can be observed, and therefore periods of high amplitude, random variability can be predicted. Over longer horizons, such as weeks or seasons, patterns reflecting the underlying meteorological drivers for wind generation can usually be

discerned. Over longer time scales such as years, varying production is driven by even larger meteorological patterns that were first identified a few decades ago, e.g., the El Nino/La Nina cycle in the Pacific, and closer to New England, the North Atlantic Oscillation.

3.2.3 Renewable Energy Curtailment

Curtailment of wind and solar power occurs when the power system cannot accept or export all of the wind power being generated at that time.

From an economic efficiency perspective, wind and solar generation, by the virtue of having zero or almost zero variable costs (i.e., wind and sun are free), should always be accepted by the grid if possible, and should only be curtailed if there are no other resources to be curtailed. This is when all other possible reduction in committed thermal (and hydro) generation has been achieved – or when there are no outlets for exporting the additional renewable energy. In theory, unless power plants are designated as "must-run", their generation can be reduced to their minimum load. A much more common constraint is that plants cannot be started and stopped easily enough, fast enough or reliably enough. This causes plants to stay committed at light load, because they are needed later for high load and cannot be shut down.

Curtailments of wind and solar energy increase dramatically in smaller systems such as islanded grids. Chances of curtailment increases during periods of low demand coupled with high renewable energy generation, given inflexibility of thermal plants to reduce their load.

Low levels of wind and solar curtailment necessary to provide intra-hour balancing will occur more often when other resources – such as thermal generation and demand response - are at minimum. Hence, renewable energy resource providers in high penetration regions could see reduced revenues if they are not compensated for curtailed energy.

Lack of neighboring markets for non-firm energy exchange due to limitations in inter-regional tie-line capacity or operation also contribute to higher curtailment of excess renewable generation.

3.2.4 Power versus Energy Penetration

The renewable portfolio standard (RPS) targets set by most of the American states are based on meeting a percentage of annual retail electricity sales from renewable resources. These annual energy targets translate into a required amount of installed renewable capacity, which depending on their location and technical conditions, will have a wide range of capacity factors (capacity factor is defined as the ratio of the total annual energy to an

annual energy produced if the plant runs at full rating every hour of the year). However, the inherent variability of wind and solar generation imply a high variation in generation levels from hour to hour, and month to month, and season to season. A certain percentage of installed capacity (in MW) being renewable, does not translate to the same percentage of annual renewable energy (in MWh) penetration. As a result, the renewable energy generation from a given renewable power capacity may vary widely depending on the time frame considered. The grid operator is concerned with maintaining the reliability of the system at any instant of time. Variability and uncertainty of wind and solar generation poses additional challenges to the grid operator.

[Ref. 37] presents examples of wind penetration duration curves from the perspective of different windows of time. In the following figure, the X-axis is the time period being considered (hour, day, week, month, or year). For example, the "Hour" curve is wind MW/Load MW for that hour – sorted from maximum to minimum.

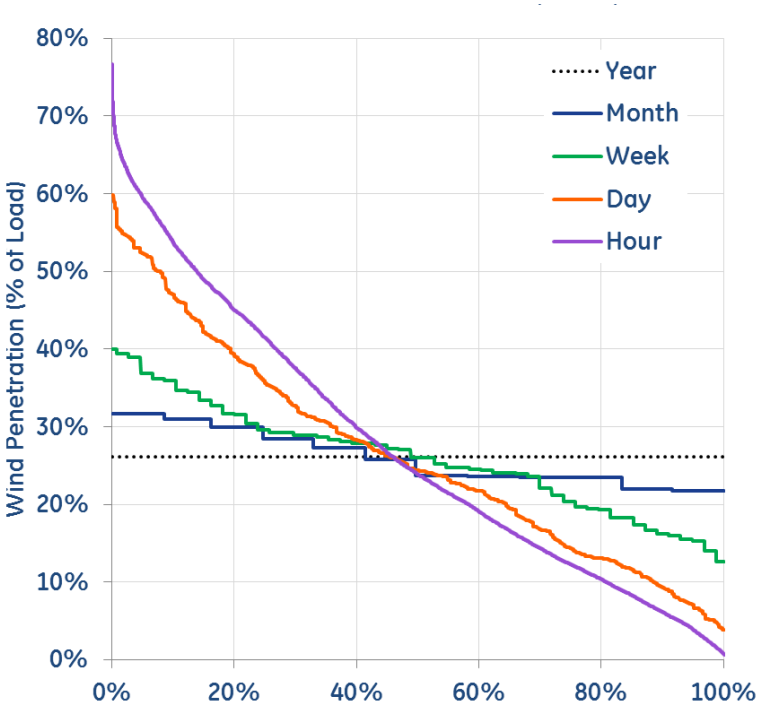

Figure 10: Wind Penetration Duration Curve

The increases in penetration help illustrate the changes for which the grid operator must be prepared. Even for low annual power penetration level, the hourly energy penetration level can be very high. For example, a 27% annual wind penetration may have a 75% penetration in a single very windy off-peak hour when there is little load and online thermal generation. Conversely, in the same system, there may hours when hourly wind penetration is zero (i.e.,

no wind blowing). Hence, a system operator would need to ramp thermal generation up and down to meet the range of wind and solar penetration over the course of a day, week and year.

3.3 Description of Issues and Their Mitigation

Keeping the particular features of the power grid and the wind and solar generation in perspective, this section provides a high-level overview and description of various renewable integration issues, factors, and causalities that impede further renewable integration or contribute to the adverse impacts of renewable integration.

The main operational issues with higher penetration of renewable resources into the power grid are mostly due to the variability, uncertainty, and non-dispatchable nature of wind and solar generation; the ability of T&D systems to get the electricity to market; the simultaneous matching of renewable energy supply to demand.

The main impacts of higher penetration of wind and solar energy on the grid include:

- Presenting higher variability and uncertainty into the power grid requiring a more robust system operational response.
- Increasing operational reserve requirements needing more operational flexibility from other resources that provide ancillary services.
- Providing untimely and unneeded energy supply to the power grid causing curtailment/spillage of valuable energy.
- Requiring additional transmission capacity for un-firm and probabilistic power.

To support further deployment of renewable energy, these adverse impacts must be addressed. The following are factors that adversely impact integration of renewable resources into the grid, and an overview of potential solutions.

3.4 Demand–Side Issues and Solutions

3.4.1 Too Little Demand, Too Much Supply

The opportunity costs of curtailment are high, since "free" renewable energy goes unused while more expensive thermal energy covers the load. Curtailment of renewable power frequently increases during periods of low load and high renewable energy supply. Hence, the primary problem for grid operators is lack of sufficient demand and oversupply of generation, particularly applicable to wind energy. Solar energy, on the other hand, generally peaks with high demand during on-peak periods, though not always true.

Therefore, the clearest path of action in cases of too little demand and too much generation is to either increase demand or lower other generation. When curtailment is required, the option of lowering generation would have most likely been exercised already by reducing thermal generation in the system.

The next two sections discuss the options for increasing demand.

3.4.2 Smart Grid Solutions

Smart grid technologies are becoming the basis of modernization in utilities worldwide, ranging from digital smart meters to automated two-way communication between customer and provider; from real-time utilization of renewable energy to smart charging of electric vehicles. In the context of enabling high penetration of renewable energy in Hawaii, smart grid technologies will maximize the control of electricity flows, including storage, demand response and demand management, real time rate structures, electric vehicle charging, renewable energy utilization and utility ancillary services.

3.4.3 Smart EV Charging

A smart grid-related option to reduce renewable energy curtailment is to promote deployment of electric vehicles (EVs), which with smart scheduling EV charging, can help increase demand for electricity during times of high curtailment [Ref. 23]. In this section, the term EV will be used to collectively apply to both total electric vehicles and also to plug-in hybrid electric vehicles (PHEVs).

To achieve maximum impact, the charging profiles of EVs should be managed in such a way that they coincide with periods of high likelihood of renewable energy curtailments. However, managing EV charging profiles in an intelligent manner, i.e., smart charging, would require active response by EV owners, whether manual or automatic, to event or price signals.

Recommendations: As a result, it would be necessary to develop the enabling technological infrastructure and the requisite policy/regulatory framework in order to achieve the maximum positive impact of EV charging on the power system. These include:

- Adopt of national, regional, and local policies that promote adoption of EVs.
- Develop public and private infrastructure for EV charging.
- Evaluate the optimal charging policies and smart scheduling that would provide the most benefits at the right time (i.e., highest capture of curtailed renewable energy).

- Design and implement smart charging incentives, pricing schedules, and EV charging rates that would induce the desired EV driver charging behavior.
- Implement smart grid infrastructure and IT platforms for real-time communication of information and dynamic pricing, from the utility to the EV customers (both for public and private charging), in order to enable smart scheduling of EV, either manually or automatically.
- Support development of national open standards for communications protocols such that vehicle manufacturers, utility providers, and telecommunications have a consistent platform to implement local programs.

It is reasonable to assume that more sophisticated and flexible charging will have the optimal level of charging response under an automated structure for event or price signal communication and for dynamic charging of the EV.

For instance, a simple Time of Use Pricing (TOU) can be very effective in shifting EV charging from on-peak periods to off-peak periods, but would do little to pinpoint the timing of most EV charging to the hours of highest wind and solar generation.

Conversely, a more complex EV charging rate based on Critical Peak Pricing (CPP) or Critical Peak Rebate (CRP), or even Real Time Pricing (RTP) would work better in aligning the hour by hour prices with the most desired periods for EV charging.

Complex pricing structure also requires corresponding automated intelligence on the part of the EV charger to allow projection of the EV charging needs, dynamic scheduling of EV charging, and ensuring full charging by designated hours.

A broader intelligent platform will also be needed on the utility side to manager the phased and clustered charging of EVs to avoid reliability problems in the distribution system due to local concentration and clustering of EV charging.

The effectiveness and impacts of different EV charging profiles to mitigate renewable energy curtailment, particularly the more sophisticated and smart dynamic EV charging, will vary by region depending on characteristics such as demand profile, seasonality, ability to implement policies across political jurisdictions, and the type of rates, tariffs and incentives.

3.4.4 Energy Storage Applications

Another smart grid-based potential resource to mitigate higher electricity supply and prevent additional curtailment is Energy Storage (ES). This following section is based on materials/conclusions of [Ref. 22] with permission of the principal author.

Energy storage can offer additional capacity and flexibility that will be necessary to dampen the variability of renewable generation and reduce the challenges that intermittence might

cause for the system operators. The principal benefit of ES is to provide flexibility which has the potential to reduce or remove externalities that drive curtailment, particularly the supply side constraints.

3.4.4.1 Energy Applications

Energy storage applications may best be discussed when matching a storage response to a need along a continuum of power (Watts, kW, or MW) vs. energy (Wh, kWh, or MWh). A particular ES technology lies in the spectrum of Power to Energy Ratio (Power/Energy or Watt/Watt-Hour). "Power" refers to the charging rate of the ES system (How has ES can charge or discharge). "Energy" refers to the storage size of the ES system (how much energy can be stored). Energy Applications

Energy applications can be defined as those that provide continuous delivery of power over long periods measured in hours or even days. Energy applications may include peak shifting, energy arbitrage to buy at low prices and sell at high prices, and storage of renewable or thermal energy generated at off-peak times.

Storage technologies suitable for energy applications are typically those that have the capacity to store many more watt-hours than they have the power rating to deliver in a short timeframe, and display a Power/Energy rating of 1:3 or greater. Storage of energy is best accomplished by high energy (kWh) in terms of volume - and low power (kW) in terms of charge and discharge rates.

Examples of energy storage technology types appropriate to energy applications include the following:

a. Thermal Energy Storage Systems - Heat and Cool (TESS), including Building Thermal Mass
b. Pumped Hydro Storage
c. Compressed Air Energy Storage (CAES)
d. Battery Energy Storage Systems (BESS

3.4.4.2 Power Applications

Power applications, in contrast, are those that typically need the rapid injection and absorption of energy over shorter durations. Power applications include regulating system frequency, providing ramp rate control for variable generation, such as wind and solar power, providing inertial/droop response characteristics, black-start of renewable generation, and regulating voltage, to name a few. Some of the power applications of storage, such as voltage regulation, are made possible by the power electronics of the storage system; the energy storage capacity is not necessarily needed.

The storage technologies that are well-suited to power applications are those that possess a Power/Energy rating of about 2:1 or greater.

Storage technologies deployed for power applications can also be used for energy applications, provided sufficient storage capacity is available, which may come at a higher cost. The types of technologies that can be used to provide energy storage have varying degrees of efficacy in different applications.

Examples of energy storage technology types appropriate to power applications include the following:

a. Flywheel Storage
b. Ultra Capacitors
c. Superconducting Magnetic Energy Storage (SMES)
d. Battery Energy Storage Systems (BESS)

Storage type (d) (BESS) covers many different types of technologies/chemistries, and straddles the grey zone between energy and power applications.

Battery types well suited to these applications are primarily flow batteries (e.g. vanadium, zinc bromine), and certain conventional battery chemistries (e.g. lead acid, sodium sulfur, etc.). The battery energy storage types well suited to power application, which deliver (or absorb) significant power over short timeframes, include certain battery chemistries such as various lithium chemistries.

For purposes of capturing and shifting potentially curtailed renewable energy, grid scale energy storage may be most appropriate when Time of Use pricing structure can support energy arbitrage. These include Pumped Hydro Storage, CAES, TESS, and (possibly) packaged banks of BESS. Such grid scale energy storage can be charged with electricity during the high supply times (times of potential curtailment of renewable energy) and then discharged later during high demand periods when electricity supply on the grid is low.

Two of the energy storage technologies, compressed air energy storage (CAES) and pumped hydro storage, generally have ratings measured in hundreds of MW and MWh. Because of their scale, they can provide significant power and energy. So even though they would typically have relatively low Power/Energy ratios, they can still provide large amounts of power and can be highly maneuverable.

The most likely applications of energy storage include the following:

A. Financial Energy Arbitrage: Purchasing and storing energy ("charging" the storage) in when electricity prices are low, and discharging and selling energy when electricity prices are high. For purposes of capturing and shifting potentially curtailed renewable energy, grid scale energy storage seems most appropriate. These include

Pumped Hydro Storage, CAES, BESS, and (possibly) packaged banks of BESS. Such grid scale energy storage can be charged with electricity during the high supply times (times of potential curtailment of renewable energy) and then discharged later during high demand periods when electricity supply on the grid is low. Economics of energy storage for such applications have been discussed in [Ref. 22], but perhaps a new look with actual ISO prices is warranted.

B. Line Congestion Management: Storage can be used to decrease curtailment of renewable energy that would otherwise be forced by transmission constraints. For instance, storage can capture wind energy when the amount of wind generation exceeds the transmission capacity at times of the year when the resource is especially robust. The stored energy is released when transmission is less heavily utilized. Again the economics of energy storage for such applications requires further investigation and have been discussed in [Ref.22]. Targeted analysis is required to implement energy storage for large scale, regional applications.

C. Wind or Solar Power Smoothing and Dispatch: Storage can be used to smooth out the variable wind and solar energy, rather than having the system operators take actions in response to the inherent variability of wind and solar generation. In these cases, the storage system could provide ramp-rate control, enabling the variable renewable energy source to meet upward or downward limits to its changes in power and inject a smoother energy profile into the grid at the point of interconnection. For wider regions, with dispersed renewable energy scattered over wide areas, the collective renewable energy profile will be smoother than profile of individual plants. For such systems, a grid scale storage systems under the control of system operator may be more economical, and technically more efficient, than having energy storage systems at each wind or solar generation site.

D. Frequency Regulation: Storage can be a substitute for thermal units that currently provide the frequency control services in the power grids that include maintaining the grid frequency at the target level (60Hz in the U.S.A) and keeping Area Control Error (ACE) between a region and its neighboring control areas at zero. Thermal units do experience additional O&M for providing such ancillary services, since at times of need they would operate loading levels which would be sub-optimal in terms of heat rate and emissions. Storage could be a good substitute for those thermal units.

E. Other Applications: BESS integrated into the operation and management of the power system could be capable of providing governor/inertial response characteristics, managing harmonics to improve power quality, voltage regulation, black-start contribution, and other ancillary services at the sub-transmission and distribution voltage levels. Evaluating the costs and benefits of storage providing

these services requires accounting for all streams of revenues for the storage system, assuming they can operate reliability in a multi-functional manner

The appropriate technology would depend on the intended application. For instance, application (A) and (B) are an energy application, suitable for storage types with low Power/Energy rating, The other applications, (C) to (E) are power applications and suitable for storage types with high Power/Energy ratings.

As with EV smart charging, targeted operation of the energy storage in the grid requires the requisite underlying integration platform, both for power interconnection with the grid, and also for smart and targeted scheduling of storage charge and discharge actions, while ensuring that storage does not run out of energy when needed most, and in such a manner that optimizes the energy storage economics. As with EV smart charging, and Demand Response (DR) discussed later, optimal ES scheduling can be based on dynamic pricing designed to accurately signal desired timings of ES charging and discharging.

A sophisticated optimal ES scheduling algorithm can be designed to maximize economic benefits of ES under variable time prices subject to limit constraints on the ES MWh capacity and its maximum charging and discharging rates, with accounting of the ES round-trip efficiency.

A holistic evaluation of economic value of ES value in conjunction with impact on reduction of potentially curtailed renewable energy requires detailed production simulation modeling.

Economic viability of any storage asset depends on its cost (both fixed and variable), its efficiency (loss), and its life. While costs for any individual technology can vary, either due to the fact that some newer technologies have yet to be manufactured at scale and realize full cost savings or because costs of installation can vary from site to site, the range of these costs is reasonably well understood. Roundtrip efficiencies can be similarly estimated within a reasonable range, and may be assumed to improve modestly with further development.

Hawaii has a high degree of environmental sensitivity. With Hawaii's topography and geology, pumped hydro and compressed air using underground storage (natural or man-made) would face potential negative environmental impact and permitting risks. However, on the mainland, such energy storage types may be suitable depending on market pricing of energy and the availability of appropriate sites.

3.4.5 Application of Demand Side Solutions

For most of the history of electric power system, the main approach to balancing the electric supply and demand has been based on reliance on supply side resources such as fast acting hydro plants and agile thermal peaking units. It is expected that in the grids of the future,

demand side resources will play a larger role than they have now in energy, capacity, and ancillary services markets.

Demand Management or Demand Response (DR) covers the whole range of demand side resources from conventional Interruptible Load (IL) and Direct Load Control (DLC) to more responsive demand based on dynamic pricing and other event and control signals. The advent of new technology constituting smart grid is enabling more sophisticated and engaging demand response solutions that, coupled with dynamic pricing, are making possible more flexible and robust customer electricity usage behavior. Smart Grid innovations in advanced metering infrastructure (AMI), WAN and HAN communication, and home energy management systems, are making DR technologically feasible and economically viable, resulting in wider deployment.

Currently, utility and retail DR programs are being driven by state regulatory commissions and by utilities in need of managing their peak demand and reducing or delaying long-term investments in generation capacity. More recently, FERC orders [Ref. 6] on "Demand Response Compensation in Organized Wholesale Markets" are expected to open up opportunities for participation by demand resources in the electricity wholesale markets operated by Independent System Operators (ISOs) such as ISO-NE, NYISO, PJM, MISO, CAISO, SPP, and ERCOT; with a DR resource to be paid the hourly locational marginal price (LMP), and to be treated similarly to supply side resources in the energy, capacity, and ancillary services markets.

There are four general types of time-varying dynamic pricing structures (also referred to as time-differentiated rates or tariffs):

- Time of Use (TOU) Pricing: TOU pricing provides two different electricity rates for on-peak and off-peak periods – utilities and customers benefit by lowering on-peak demand, or shifting demand from on-peak periods to off-peak periods.
- Critical Peak Pricing (CPP): CPP, in addition to an underlying TOU rates, include, with advanced notification, a very high price during a few critical peak periods during the year.
- Critical Peak Rebate (CPR), also called Peak Time Rebate (PTR): which is similar to CPP in some ways with the major difference being that instead of a high price, customers are given a rebate if they reduce their demand from a pre-determined base line.
- Real Time Pricing (RTP): Is the most complex and provides the most economically based pricing signal reflecting the hour by hour cost of electricity service, where prices change by the hour, typically provided a day in advance. RTP is suitable for more advanced or technically savvy customers.

Although the application of these methods and programs to deal with incidents of high renewable energy curtailment could be presumed to be limited - since these programs are

mostly intended to curtail demand for electricity, whereas, what is needed is increased demand for electricity – some variations to these DR programs and Dynamic Pricing rates can be employed to influence the EV charging behavior. For instance:

- TOU rates can be designed: to have high prices during low supply and high demand periods to discourage EV charging, and to have low prices during high supply and low demand periods (likely periods for high renewable energy curtailment) to encourage EV charging. Design of the TOU rate and timing of the periods requires a study similar to the one performed for this project, albeit in more detail and with consideration of probabilistic solar, wind, and load hourly patterns, in order to account of a wide range of possibilities.
- A "reverse-CPP" rate can be designed to send a day-ahead low price to hold for the periods of expected high curtailment, to signal a good time for EV charging (among other electricity consuming activities).
- A "reverse-CPR/PTR" rate can be designed to also provide a day-ahead notice of rebate for higher demand during the periods of expected high curtailment, also to signal a good time for EV charging.
- RTP hourly prices can drop very low during high supply periods, providing incentive for increased electricity usage and timing of EV charging. In addition large industrial, commercial, and agricultural customers can shift high electricity usage periods to low price times that could coincide with high renewable energy supply periods.

In contrast to situations that result in renewable curtailment, there could be times when a power system can find itself with insufficient power supply or import capability to meet demand for electricity. These most likely happen during periods of high load, or forced outage of thermal generation.

However, another factor would be high forecast error under high renewable penetration situations, which would result in insufficient day-ahead unit commitment because of overestimation of next day's renewable generation availability.

In such situations, demand response can be used as a resource of last resort, assuming cost of unserved energy to be higher than average price of electricity.

Hence, availability of sufficient demand response resources could alleviate impact of forecast over-estimation error and under-commitment of thermal units.

Demand response is a valuable resource, especially in high wind systems. Other studies have shown demand response to be highly economical for helping systems handle occasional extremes caused by wind power. Isolated power systems should pursue development of more and more agile, demand response resources.

Proper design of the rates and incentives should significantly influence the scheduling of DR, similar to EV smart charging and optimal ES scheduling.

It should be noted that higher variability and uncertainty of renewable resources may also impose a greater need for more frequent calls on response from demand responsive resources, necessitating even more DR programs to come online.

3.5 Supply-Side Issues and Solutions

3.5.1 Reliability-Must-Run Generation

Some power plants in a grid are strategically designated as reliability-must-run (RMR) generation by system operators when they are needed, to:

- To maintain local system stability
- To provide voltage support
- To meet load in constrained areas

RMR designated units are required to operate even if they are not economically viable in the competitive markets. However, RMR units are compensated for their services through bilateral contracts with the system operator or through other means.

Although essential for the reliable operation of the system, the inherent flexibility in the RMR unit operations - as dictated by the needs of the grid - means that during periods of low demand and high supply, they cannot be candidates for power curtailment. The RMR designation precludes such plants from curtailment, and contributes to higher curtailment of inexpensive – and thus valuable - renewable energy.

To reduce or eliminate the RMR designations of units requires changes in operational policies and transmission congestion management procedures of the grid.

Designating RMR units for voltage support is very common. Typically, to enhance reactive power capabilities in areas identified as having shortages of reactive power, most common forms of reactive compensation are either generation solutions sited within the impacted pocket, or a transmission solution, such as reactors, capacitors, static VAR capacitors (SVCs), or even a distribution solution such as demand response or distributed generation. The non-generation solutions free up operational flexibility of otherwise RMR units. However, the proper choice of reactive compensation requires a holistic cost-benefit analysis considering the value of renewable energy that would otherwise be curtailed.

In recent years many markets such as CAISO, MISO, and ERCOT have moved away from the more rigid and inflexible congestion management procedures to a more dynamic and nodal market- based pricing with security constrained economic dispatch. This has reduced the

need for RMR generation and has allowed economics and market competition to determine the best mix of resources to be reliably dispatched without violating transmission constraints. A nodal pricing system loosens up the rigidity of operation of must-run generation and allows more flexibility in response to the needs of system and reduces the need for curtailment of renewable energy.

3.5.2 Thermal Plant Flexibility Constraints

Thermal plant flexibility constraints reduce the maneuverability of the system and available options for response during periods of low load and high generation, thus forcing curtailment of renewable energy. The thermal plant flexibility is defined by the plant's ability to cycle within a wide range on demand and by the speed of the plant's ramp up and ramp down operations.

Thermal plan inflexibility could be a major issue in systems with high renewable penetration which need to mitigate the variability of renewable resources within their systems on the one hand, and also deal with the forecast errors caused by the uncertainty of the renewable generation.

Enabling thermal plants to start and stop more easily, more reliably, and more often, would be of high value to the system. Frequently plants operate at light load because of minimum run time and down time constraints, resulting in some of the primary causes of renewable curtailment.

A direct approach to addressing plant inflexibility is to invest in technology and processes that help increase operational flexibility of power plants.

3.5.3 Heat Rates and Emission Limit Constraints

In some instances, system regulators impose average heat rate and/or emission limits on thermal plants and subject the cost recovery to meeting set heat rate requirements, motivated by energy efficiency considerations.

Consider that the marginal heat rate of a plant at its best point (or lowest) when operating at or near its rated output. Therefore the fuel consumption and emissions per MWh are lowest. When plants are dispatched to lower power output in order to accommodate wind and solar power, the heat rate always degrades. Under some regulatory regimes, the plant can be penalized for deterioration of its average heat rate. However, the overall benefit to the system of replacing thermal energy with renewable energy will more than compensate for the incremental degradation of the thermal plant performance.

Consider a simple illustrative example: A thermal 100 MW plant thermal plant might have a heat rate of 8,500 Btu/kWh, and generate 0.75 tons of CO2/MWh. Therefore in 1 hour it will generate 75 tons of CO2 and consume 850 MMBtu of fuel.

Suppose that to accommodate wind, the plant is ramped down to minimum of 50 MW, with a 20% penalty on heat rate. The plant will consume 850 x 1.2 x 0.50 = 510 MMBtu of fuel/hour, and produce 75 x 1.2 x 0.5 = 45 tons of CO2. This is a huge reduction in carbon emissions and fuel consumption, which is the result of replacing the 50 MWh of thermal generation with clean and free renewable energy.

However, if the plant performance is measured on a per MWh production basis, the 50MW dispatch will look 20% worse (due to 20% penalty on heat rate), and may violate regulatory targets and be subject to heat rate and/or emission penalties. The plant owner may not want to dispatch to lower power and become subject to penalties, for purely regulatory reasons.

This is another factor that results in operational inflexibility of the power plants, except that the inflexibility is not technical, but due to economic and policy-related considerations as well as the opportunity cost of being more flexible. Power plants subject to such payment constraints would want to avoid violating their heat rate limits by operating within a set loading range, which again would reduce the thermal generation curtailment options and result in higher curtailment of renewable resources.

The regulators might consider performing longer term, life cycle cost-benefit analysis when designing the heat rate limit rules by allowing more cost recovery flexibility when the longer range outcome is a reduction in curtailment of more valuable and cleaner renewable energy.

Balancing tradeoffs between individual plant emissions and the wider benefit of having emission free renewable generation is a policy issue that requires a social-good cost-benefit analysis by policy makers and regulators in order to strike a right balance with imposing emissions limits and resulting penalties on the one hand, and providing more flexibility to allow more renewable generation on the other hand.

3.5.4 CHP/Cogeneration Constraints

In the U.S., most Combined Heat & Power (CHP) plants (also called Cogeneration plants) are installed at industrial sites (e.g., chemical and mining industries), or certain commercial sites (e.g., medical and education campuses) to produce electrical power and also heat/steam used for industrial processes or district/community heating. Operation of CHP plants are more constrained than conventional thermal plants since the scheduling of their power production is, in most cases, dictated by the need for their heat/steam products.

More flexibility in operation of the CHP plants can be achieved by providing thermal storage for the heat/steam product for a later use when there is demand for the heat/steam. Thermal storage would free up the power generation from the rigid schedule of the heat/steam demand and hence allow more flexibility in high renewable penetration systems.

It should be noted that thermal storage is not the only solution, and may not be the easiest one. Another approach is to change CHP controls, including reconfiguring heat exchangers and combustion processes, so that electricity and heat production need not stay in lock-step, which would allow for supply of thermal loads without generating electricity (or as much electricity) when it isn't needed or wanted.

3.5.5 Thermal Plant Cycling, Maneuvering and Mileage

The variability of renewable power increases the maneuvering of thermal power plants. As the level of renewable penetration increases, the thermal plants experience more starts and stops and their dispatch adjusted more frequently and by more MWs. In high wind and solar penetration cases, the count of coal plants starts can increase substantially. Starts and stops of other thermal resources can increase or decrease depending on the resource and study case. Therefore, higher penetration of renewable resources in a power grid may result in higher levels of cycling of the thermal plants.

One measure of operational maneuvering is "mileage" – the sum of the absolute value of the total hourly MW changes in dispatch. Hence, cycling would result in increased mileage. Increased thermal plant cycling has a cost in terms of wear-and-tear. This is the subject of fierce debate and investigation in the industry today. Estimates of these costs vary wildly. Recent work sponsored by National Renewable Energy Laboratory (NREL) [Ref. 28], that includes current state-of-the-art estimates for these costs showed that they would be expected to reduce the variable cost savings from wind energy between $0.06 and $2.0 per MWh of wind energy. Based on the amount of wind energy that could be operating on a power system in the high wind penetration cases, the cycling costs could possibly be as high as a few percentage points of total system production costs.

In competitive wholesale markets, such costs can be explicitly accounted for by thermal plants when developing their bids for the day-ahead and real-time energy markets. They can also factor those costs in their bilateral contracts and power purchase agreements. In vertically integrated utilities, such costs can be evaluated/estimated and accounted for as additional VOM adders in the unit commitment and economic dispatch process.

The ultimate result may be a lower level utilization of more costly thermal plants which cannot somehow decrease their cycling costs. This is not a directly renewable power issue, but rather the individual thermal power plant issue. But from a societal or system-wide perspective, the resulting cycling costs need to be taken into account, which reduce the

overall benefits of integration of more renewable energy into the system. At the same time, this problem also opens up an opportunity for more efficient and less costly thermal plants to become more competitive and ultimately replace the higher cost thermal generation.

Excessive cycling of thermal power plants may also result in higher levels of criteria pollutant and greenhouse gas emissions compared to steadier operation of thermal plants.

3.5.6 Inflexible Gas Contracts and Markets

Inflexible gas contracts for gas-fueled generation, such as take-or-pay contracts, are one of the factors that constrain the system flexibility in response to wind and solar variability. In most cases, the gas-fueled generation appears to be the resources that are expected to the back-up generation and counterbalance the intermittency and variability of these renewable resources. The additional expected flexibility needs call for not only flexibility in gas-fueled plant operations, but also for flexibility in natural gas contracts of power plants in more flexibility in the gas market.

It is expected that with high penetration of renewable resources, gas demand profiles will be more variable than the basic daily gas import profiles under traditional contracts. Therefore, it would also be expected that the gas system operations, contracts, and markets will also require higher flexibility.

Currently, the take-or-pay contracts are fairly common in long-term gas supply agreements, where the buyer must pay for the contracted gas volume regardless of whether at a later time the buyer wants or needs or is able to actually take the contracted volume.

Take-or-pay contracts provide the incentive by the gas-fired generation to operate instead of forgo operations during system generation over-supply, since the fuel has to be paid for even if it is not used, and power generation enables recovery of the contact costs.

Hence, more flexibility in natural contracts, pipeline operations, and gas markets, would contribute to more flexible system operations in higher renewable penetration situations.

3.5.7 Hydro Operational Constraints

Hydro generation can play an important role in mitigating adverse impacts of higher penetration of renewable resources in the grid. However, even if hydro power is inherently very flexible electrically, its flexibility can be constrained by other non-power-grid considerations such as environmental, fish habitat, and recreational concerns. For instance, scheduling of hydro power operation in the Northwest USA is highly constrained by fish and bank erosion concerns. In contrast, Hydro Quebec aggressively utilizes its hydro generation for balancing of its system.

In isolated/islanded systems where hydro power plants have relatively little operational flexibility, and are typically scheduled well in advance of real-time operation, even a small and very flexible hydro plant can be a valuable asset from a flexibility perspective, particularly if can be equipped for manual or automatic operation under complex decision logics in order to cover for errors in wind and solar forecasts.

Any operational flexibility that can be obtained from the hydro plants will offset the need for maneuvering of thermal plants and the need to depend on the inter-regional tie-lines. Investments in hydro facilities to increase operational flexibility may prove to be highly cost effective and should be a high priority in a region's power sector investment planning.

3.5.8 Need for Increased Reserves Requirements

The wind variability adds to the short-term volatility of net load (load minus wind), which requires following with synchronized reserve. This additional synchronous reserve requirement is above and beyond the synchronized contingency reserves or Regulation Up and Regulation Down since most variations should not impinge on the contingency reserves. The grid operator needs guidance, in advance, to set and hold these incremental reserves.

In typical analysis, the focus is primarily on the 10-minute variability, since any variation within that period must be covered by synchronized reserves or 10-minute spinning reserves. It is also the finest resolution of most available wind and solar data sets. Industry practice is continuing to evolve regarding incremental reserves required for wind variability.

The statistics for wind power variation tend to be normal up to about 2 to 3 standard deviations. The outliers are not normal (in the statistical sense). The significance of this behavior is that the host utility has the ability to cover the majority of sub-hourly deviations with a relatively modest amount of incremental reserves. However, it is impractical and uneconomic to maintain separate reserves intended to cover very rare wind variation occurrences, i.e. to cover the extreme outliers.

Typically, the midrange of wind power exhibits the largest 10-minute one standard of deviation (1σ), i.e., the standard variation increases as the wind power level rises and then stays constant at its highest level. Hence, some multiples of standard variation of 10-minute wind variability would be a good choice for additional incremental load following reserves to cover intra-hour wind variability. Previous studies have established that a statistically high level of confidence for reserve is achieved at about 3σ. In other words, with a reserve margin of 3σ, the chances of a 10-minute wind level drop being greater than 3σ, is highly unlikely. Some system like ERCOT, base their reserve requirements on a 2.5 σ target. The reserve requirement can increase with the wind power level until it plateaus at its maximum level and they stays at that level as the wind power increases beyond the maximum level of its variability.

Previous studies have established that a statistically high level of confidence for reserve is achieved at about three times the standard variation (i.e., 3σ). In other words, with a reserve margin of 3σ, the chances of a 10-minute wind level drop being greater than 3σ, is highly unlikely.

In the case of wind power, the physical reality is that it is more variable at moderate power levels (e.g. around ½ of turbine rating) than at full power. A high penetration system would need to carry incremental reserves capable of handling more than 99% (3 standard deviations or 3σ) of all wind power drops that are expected to occur in any 10-minute period. Some larger systems may carry less reserve. But for smaller systems, with less expansive thermal fleet a more conservative approach to reserves is warranted.

Hence, the incremental on-line reserve will be a function of wind power level, and then stay at its highest level as wind power level increases beyond the its maximum short-term variability level. The reason for not decreasing the operating reserve as wind power level continues to increase is to ensure maintenance of reserve if the wind levels start falling, which would be accompanied by higher levels of variability.

In systems with wind power, the wind variability related operating reserve should be scaled according to the total MW nameplate in the system. This reserve should be considered during day-ahead unit commitment and during real-time economic dispatch. This reserve can be supplied by both supply-side (flexible generators) and demand-side (demand response or DR) resources.

This reserve requirement should be added to the contingency based on the power system's operating reserve requirements.

The wind and solar variability necessitate additional ancillary services, i.e., operating reserves, beyond and above the conventional ancillary services. Although operating reserves go by different names in different markets, they are typically grouped into the following types:

- Frequency Response
- Load Following
- Regulation Reserve (Up and Down)
- 10-Minute Spinning Reserve
- 30-Minute Non-Spinning Reserve

The amount and types of additional reserve depend on the type of the power system and its size, and the penetration level and statistical characteristics of the sub-hourly net load (i.e., load minus renewable energy). In general, the operating reserves needed should enable response to three aspects of power supply, which include:

- Contingency
- Variability
- Uncertainty

The contingency component of reserve is sized to deal with the largest possible contingency in the system such as forced outage of the largest power plant in the system. The variability component is meant to cover the sub-hourly variability of net load. The uncertainty component is designed to cover the power shortages resulting from the uncertainty characteristics of the renewable energy.

In larger systems, such as a larger ISO, which have high renewable penetration and geographic diversity with wind and solar plants dispersed in a wide area, the collective temporal profile of renewable resources is more predictable and less variable.

In a typical small system, additional regulation reserves will be required to handle the sub-hourly variation in net load. Recent studies suggest a regulation type reserve that is about 3 standard of deviation of the 10-minute variability of the net load.

Therefore, some incremental synchronous reserves must be running and have the necessary speed and maneuvering range to cover the majority of short term variation in wind and solar output. One approach is to use statistical analysis to establish the expected variability of renewable power over 10-minute intervals. The variation is dependent on the amount of actual renewable production, rather than just the total MW rating of installed renewable resources.

As far as inter-hour variability is concerned, other options such as demand response, reliance on flexible imports and exports, use of thermal and hydro plants, or even energy storage systems, can be utilized to provide the needed reserve. Simulation and modeling can determine the economic cost benefit analysis of each option.

3.6 Transmission Related Issues and Solutions

3.6.1 Transmission Infrastructure Development

A major impediment to further deployment of grid scale renewable energy is lack of proximity of the best renewable resource locations to the load centers and lack of available transmission needed to provide access to markets. High penetration of renewable resources may also, depending on their location on the grid, either introduce new congestion or exacerbate existing ones, and hence, increase congestion related costs of the power system. Any transmission congestion in the grid forces utilization of more accessible and more expensive generation in place of locked out and less expensive generation.

Hence, any major deployment of renewable power also requires evaluation and planning for new transmission or upgrade of existing transmission.

However, transmission development in the U.S. involves a host of non-technical factors, including community, regulatory, jurisdictional issues on the socio-political side, and economic viability, cost allocation, and cost recovery issues on the economic side.

Before considering additional transmission development, an important issue to consider is that the industry often under-utilizes existing transmission assets. This can have many institutional causes, including inflexible transmission rights, inflexible scheduling policies, which are referred to later in this section, and also failure to invest in improvements other than actual new circuitry, that can relieve constraints (e.g., reactive compensation, fixing current limited elements, upgrading circuit breakers, etc.). Hence, before building a new transmission line, other technical and institutional barriers to using the existing ROWs and infrastructure well should be exhaustively considered.

The business of electricity transmission in the US comes in different shapes and forms. FERC has jurisdiction over the interstate transmission of electricity. Typically, state utility commissions have jurisdiction over the regulation of public utilities in their states, local governing boards regulate Municipal utilities, and member boards regulate the Rural Electric Associations.

In general, the transmission business in the US, with the exception of a few merchant transmission companies, is a franchised monopoly, and therefore, a cost-of-service based regulated service.

A number of federal bodies have authority over the interconnected transmission system and the generation and transmission entities that are formed or empowered at the national level. The most important of these bodies include Federal Energy Regulatory Commission (FERC), which is responsible for utility corporate policy, wholesale electricity markets, and interstate transmission rates, and North American Electric Reliability Corporation (NERC), which is responsible for transmission grid reliability. There are, in addition, other federal and state level entities, such as state utility commissions, that have a say in overall transmission development policies and regulations.

Any interstate transmission would fall under the jurisdiction of the FERC because of the role transmission plays in interstate trade in the US, and all regulation of all interstate trade is under federal jurisdiction by US law.

Transmission development is a very complex process, and in the case of ISO/RTOs it involves a multi-stakeholder effort, both technical and non-technical, culminating in long-term transmission planning studies that require complex modeling and consideration of various load and generation scenarios.

At a regional and local level, states play an important role in regulating businesses of natural monopolies for the interest of the citizens. The basic authority and state jurisdiction is typically established by the legislators in each state. Most state PUCs are empowered to regulate public utilities in their states, which are mostly franchised natural monopolies. The exceptions are municipal and cooperative utilities and federal power marketing administrations. State PUCs usually review and set the retail rates for the public utilities and have primary responsibility for approval and siting of transmission projects and upgrades. Environmental issues, land use, and eminent domain fall under state authority. However, in most cases, local authorities have significant control over siting and permitting of new transmission development.

To provide a framework for coordinated approach to both renewable energy and the needed transmission infrastructure development, a number of policy and technical options can be considered. One important approach is integrated long-term transmission planning and generation expansion planning with explicit inclusion of renewable generation additions and representation of their time dependent and time variable characteristics. The expected result will be appropriate sizing of transmission capacity that would account for the infirm nature of renewable energy demand on the transmission capacity.

3.6.2 Transmission System Reliability and Security

An essential objective of the power system operations is to maintain system reliability and integrity (also referred to as system security), and prevention of uncontrolled cascading outages.

Violations of limits on transmission flows not only may impact system reliability and integrity, the limits themselves can impose renewable power delivery limits and impact curtailment of renewable energy. Reliable operation of the grid require respecting various transmission constraints identified on the power grid. Transmission constraints may result in curtailment of valuable renewable energy and also force down locational marginal prices (LMP) at the wind plant sites. Any generation that exacerbates transmission congestion may result in power curtailment/spillage in order not to violate power flow limits, which also would cause a drop in the plant's LMP (i.e., through congestion component of the LMP), resulting in lower revenues for the plant in ISO energy markets. In addition, power flow limits. Conversely, the LMP becomes higher if the renewable generation helps relieve existing transmission congestion.

There are different types of transmission constraints. Examples are:

- Thermal Limits: Overhead transmission lines sag and lose tensile strength due to temperature increases on the energized conductors. Thermal power flow limits are intended to prevent too much sagging that may contact trees and vegetation and

cause power outages. Thermal limits are not a function of the line length. Thermal limits may be extended by reinforcing the structures and upgrading with a larger conductor. More sophisticated approaches include weather dependent dynamic thermal rating of transmission lines.

- Stability Limits: There are two kinds of stability limits, which are termed rapid (i.e., transient or angular stability – for example, reaction of the voltage to faults caused by lightning) or slow (i.e., dynamic stability – for example, power oscillations resulting from loss or large amounts of load or generation). Stability limits are often reached before the thermal limits. Flexible AC Transmission (FACT) technologies, such as dynamic shunt compensation and series compensation, can address stability issues.
- Voltage Limits: Maintaining acceptable voltage on transmission is essential. Voltage limits typically require keeping voltage levels within a certain range (e.g., 5% of the nominal voltage), and are usually arrived at before reaching the line thermal limits. Improvements in system voltages, and the profile of voltage across the system, can often be achieved by appropriately designed reactive compensation. As loadings increase, the sophistication of reactive compensation schemes typically must increase, with relatively simple switched shunt capacitors and load-tap transformers (LTCs) needing to be augmented with faster and more controllable devices, like SVCs or synchronous condensers. It is often the case that considerable increases in power carrying capability can be realized by these means before much more expensive options, such as rebuilding the line or adding new circuits are required.

For more details on range of technical aspects related to the grid connection of wind turbines, please see [Ref. 7], which provides the following list of issues:

- Feeder concept between wind turbine / wind farm and grid
- Grid protection
- Reactive power requirements
- Voltage control and tolerance of voltage deviations
- Short circuit power
- Dynamic and transient stability
- Low voltage ride through
- Participation in frequency control and tolerance of frequency deviations
- Neutral point treatment
- Insulation coordination
- Flicker and harmonics

- n-1 contingency criteria

3.6.3 Advanced Grid Code

As wind and solar generation displaces synchronous generation, the features of the displaced generation that have made power systems stable, and have provided controlled system frequency and voltage to serve load must continue to be provided. Early wind turbine technologies were considered simple energy sources, incapable of even providing reactive power. Wind farms on the power grid today can produce reactive power to control system voltage and their output can be curtailed on demand, but they are still usually not required to control system frequency, provide operating reserve and system inertia, tie-line control and black-start capability. All of these functions, except black-start, can be provided by some commercially available wind technology, but they are not presently in widespread use. The North American Electric Reliability Corporation (NERC) has initiated a project to ensure that future renewable generation technologies, including wind, can provide the ancillary services traditionally provided by synchronous generators. This will mean that grid codes, the set of requirements for interconnection of new generation, must be enhanced and standardized. It is expected that the provision of ancillary services will come at a cost, so the industry must find encourage the development of markets and price signals for the services. Some jurisdictions in North America, notably ERCOT, AESO and Hydro Quebec, have moved already to require frequency responsive controls on wind plants.

3.6.4 Exports and Imports

In a wider interconnected grid, transmission access, and hence capability to export and import power, would be additional resource to mitigate the variable of renewable energy. Excess energy can be exported, and energy shortage can be met by imports.

The inter-regional transmission ties with the neighboring regions can be beneficial and important elements in system operation. The variability of wind power increases the need to maneuver thermal and hydro generation to balance the system. The reinforced interconnections with neighboring systems can provide a region with resources that allow it to adapt to variable wind power.

However, the flexibility of using imports to balance the system and using exports to utilize otherwise curtailable power, depends on the transactional arrangements between neighboring power systems. For example, if the imports and exports are based on agreed upon firm schedules, then the import and export capabilities will not be useful in mitigating the variability or curtailment of renewable energy.

Furthermore, an inter-regional tie-line may have imposed limitations on the level of power

exchange or available capacity for variable power.

Unavailability of import and export options does in turn require higher flexibility on the part of non-renewable (i.e., thermal and hydro) generation to support the instantaneous supply and demand balance.

Highly flexible operation of the inter-regional tie-lines which can be scheduled on very short notice without scheduled energy being cut or curtailed – can reduce variable operating costs significantly compared to long lead (day-ahead) and firm scheduling of power exchange.

In high wind and solar scenarios, there could be many hours when the power system may not be able accept any more wind or solar power, due to physical and reliability constraints on the system. During those hours, the excess wind power must be either exported or curtailed/spilled. The feasibility of exporting excess wind power is a function of the ability of the neighboring markets to accept the exported energy at a time when the power system of concern would be looking to sell it. Being part of a wider interconnected grid allows more flexibility in non-firm export of power and hence, in reducing curtailment of renewable energy.

3.7 Other System Wide Issues and Solutions

3.7.1 Wind and Solar Forecast Errors

Reliance of wind and solar forecasting is essential for reliable operation of power systems with substantial penetration of wind and solar generation. It is an industry consensus that wind and solar forecasting improves reliability and economy of operation in high wind and solar systems.

Errors in wind and solar forecasting may cause over or under-commitment of thermal generation. System operators perform a daily (i.e., day-ahead) unit commitment based on the best information available. If wind and solar forecasts are taken into account, then unit commitment of thermal generation make allowances for the expected wind and generation of the next day. In real time (i.e., hour-ahead) system operators, when doing economic dispatch, may be faced with actual wind and solar generation that deviates significantly from their forecast values. Under-forecasting of renewable energy results in over-commitment of the thermal generation. Over-forecasting of renewable energy results in under-commitment of thermal generation, which is a greater problem for the system operators. It increases the likelihood of supply shortage and incidents of unserved energy (i.e., blackouts). Hence, the challenges of renewable forecast errors cannot be overemphasized.

Much debate today surrounds discussions of how to improve wind forecasting, making it: more accurate, more usable by grid operators, with more information. Forecasting of big wind ramp events is the current hottest topic. Failure to use wind forecasts has been found to be cripplingly expensive in other large system studies. However, the value to wind and solar forecasting very much depends on the generation portfolio and the size and the make-up of the power system. In smaller systems, the operational cost penalty of over-forecasting (predicting more wind power than actually shows up – i.e., being caught short) could be higher compared to the operational penalty of under-estimating wind production. This is because the cost of running quick start peaking generation is usually very high compared to, for example, base load coal. Depending on the generation make-up, a smaller power system may want to operate with a bias towards operating conservatively (i.e., underestimating renewable availability) or operating aggressively (overestimating renewable availability). Progressively better forecasting can provide progressively more savings in term of reduction in system production costs. Changes in generating fleet mix of a utility or a region may also increase the value of forecasting. Steps to further develop wind data collection, archiving and mining are likely to pay dividends in the future.

In addition to better forecasts with less forecast error, another option for reducing uncertainty, is the a more frequent renewable forecast coupled with shorter-term unit commitment with available flexible generation, such as every 4 or 6 hours, instead of every 24 hours. A 4 tor 6 hour unit commitment combined with updated renewable forecast would result in more efficient utilization of generation assets by the system operators.

3.7.2 Capacity Valuation

Another renewable integration issue is the proper valuation of the capacity contribution of renewable energy.

The addition of wind and solar generation to a power system, as with the addition of any new generation resource, has a beneficial impact on the ability of the system to serve load. The difference with conventional generation is that the capacity added to the system from incremental renewable generation is much less than other forms of generation due to the variability of the renewable generation.

Accurate accounting of the capacity valuation of renewable energy, as a measure of the ability of the renewable energy to serve load, is essential for proper compensation of the renewable energy in established capacity markets (or as capacity payment component in bilateral contracts).

This aspect of system reliability is normally measured in terms of “loss-of-load-expectation” (LOLE). This metric is calculated using a given annual hourly load profile (8760 hours per year) and generation portfolio which includes individual power plant MW rating and forced

outage rates. It establishes the frequency with which a system, through a combination of high load and generator unavailability, has insufficient generation to serve load. Typical industry practice for large systems targets a value of 0.1, meaning one incident in 10 years. A measure of an individual generator contribution to improving LOLE is the "capacity value" (this has different names in different places). For example, a 200 MW thermal plant with a 5% forced outage rate, will have a 190 MW or 95% capacity value – from a reliability perspective it is "worth" 95% of a theoretical "perfect" generator. This industry standard method applies to the addition of wind (and other renewable resources, such as hydro, solar and tidal) generation as well.

Incremental additions of wind plants in the same location have diminishing returns, due to loss of spatial and temporal diversity.

3.7.3 Small System/Footprint/Lack of Geographic Diversity

The size and footprint of the balancing authority is also an important factor in wind and solar integration. A larger footprint allows for greater geographic diversity of wind and solar resources. A greater diversity and dispersion of wind and solar resources contributes to the collective smoothness of renewable generation profiles since inherent fluctuations of weather patterns are not limited to a small areas and a few clustered wind farms, but rather spread over a much larger territories where local weather patterns are not correlated. The collective smoothness of the generation profiles of more diverse renewable to some extent alleviates some of the additional needs for different types of operating reserves that would be required to mitigate the impact of higher renewable penetration. For instance, greater geographic diversity and resource dispersion could decrease the need for the additional longer-period operating reserves such as 10-minute spinning reserve and 30-minute non-spinning reserve.

This could be a statement of the obvious, but creation and development of larger balancing authorities would reduce some of the renewable integration hurdles by providing more operational flexibility in addition to resource diversity. This option makes sense for smaller systems within larger interconnected grids, but is not applicable to island systems such as Hawaii which are physically isolated and not connected to a larger grid.

3.7.4 National Policies

Federal government and its administrative bodies and congress can pass laws, adopt policies, and devise regulation that would promote further development of renewable energy and remove some of the obstacles in their adoption. Examples include:

- Extending the federal load guarantee programs

- Extending federal investment tax credits
- Making federal renewable energy production tax credit permanent
- Adopting national RPS policy with a national REC market
- Passing Clean Energy and Climate Change legislation
- Simplifying transmission cost allocation and recovery regulation and process
- Performing long-term transmission planning with explicit consideration with generation planning

3.7.5 State and Regional Policies

Similarly, state governments and regional entities can also adopt policies that would promote further development of renewable energy and remove some of the obstacles in their adoption. Examples include:

- Development of state and regional entities with jurisdictional authority to develop transmission systems
- Building of transmission capacity beyond what is required to serve native load
- Early purchase of transmission corridors for potential future needs of renewable resources
- Construction of towers expandable from single to double circuits.
- Closing the gaps between timing of building transmission and building generation
- Renewable generation financing before transmission is built
- Providing loan guarantees for new transmission
- Providing state and regional incentives for transmission development

3.8 Task 2 Endnote

This report provides an overview of a selected number of factors that hinder wider integration of wind and solar power as well as mitigation options that would be expected to address the impacts of higher penetration on the system.

As noted earlier, a more detailed, regionally-based evaluation of the factors and solutions are needed in order to quantify the impacts of each factor and assess the technical feasibility and economic viability of various mitigation options. There may be additional

factors, not considered here, that impact grid integration or contribute to higher curtailment of renewable energy.

An important consideration missing from this study is the need for performing comprehensive feasibility study, modeling, impact analysis, and the requisite cost-benefit analysis, before deciding on the implementation of any potential solutions. These factors are regionally dependent and highly variable. Hence, this study does not make any claims on technical feasibility and economic viability of the suggested mitigating solutions.

In addition to recommendations based on Hawaii conditions, other recommendations are put forward that might be considered part of a "menu" of options that might apply to some regions of the U.S., even if they do not apply to Hawaii at this time due to the geographic, political and regulatory constraints that are truly unique to Hawaii.

4 Conclusions

Hawaii's unique geographic isolation makes it an interesting laboratory for a whole host of utility related investigations. Indeed, the growth of renewable energy from 2008 to 2014 is unprecedented, forcing Hawaii to consider changes in technology, regulation and policy due to the demands on the grid. Utilities, regulatory agencies, legislative bodies as well as public and private research entities are moving so quickly that some of this report will be out of date before it is released.

The uniqueness of Hawaii extends beyond its tropical splendor, importantly into its isolation, its high concentration of renewable energy relative, its small self-contained balancing areas, and its lack of multiple levels of regional utility authority. Included in the appendix is a brief discussion of the local balancing authorities and regional entities that are so important to the stability and reliability of a large, well-interconnected grid. The numerous planning and operating authorities are also compounded by the complexities of the power markets in the U.S., given the diversity of generation assets, fuels, loads and transmission corridors. This implies that solutions that may hold true for Hawaii may or may not hold true for a particular region. This report has focused on solutions that are recommended for a Hawaii with a theoretical imbalance of high renewable energy penetration, 1 GW of solar and wind energy serving a maximum potential of 1.5 GW of system peak load (assuming hypothetically that all loads could be interconnected).

To address the first Hawaii-based criteria, high renewable penetration, the report identified regions of the U.S. that have, or have the potential for, high penetration of renewable energy. Using several matrices and sources to evaluate expected levels of renewable energy penetration, the states were ranked in terms of solar and wind generation. Then using GE's Multi-Area Production Simulation (GE MAPS), criteria was added to screen for regions with both high renewable energy potential and transmission constraints in order to simulate Hawaii's challenge of limited export capacity to help balance instantaneous energy supply and demand. This list was culled to 27 candidate areas based on combination of high renewable penetration, high probability of excess generation, and some degree of export-constraint.

- Eastern Interconnect (16 candidate regions)
    - MISO: Minnesota (3), Iowa (2), Indiana (1), Illinois (1), Montana (1), Michigan (1)
    - SPP: Kansas (1), Nebraska (1), Oklahoma (2), New Mexico (1)
    - MAPP: Iowa (1)
- Western Interconnect (11 candidate regions)
    - Basin: Idaho (2)

- NWP: Idaho (2), Washington (1)
- RMP: Colorado (1), Wyoming (1)
- DSW: Arizona (2), New Mexico (1)
- CAISOL California (1)

These regions exhibit a combination of factors that approximate, but do not duplicate Hawaii conditions. In addition to identifying these regions, this report assesses the applicability of renewable energy enabling technologies to these regions. The findings conclude that fundamentally, the menu of technologies remains consistent throughout all regions. How each technology can best optimally address the regions' unique combination of needs will vary by region and can only be answered with detailed assessments that considers energy and power storage, regional transmission capacity, market access, and operational constraints. These considerations include:

- Rates, tariffs and policies that support optimal generation of renewable energy.
- Policies that support market for transfer of energy across region.
- Rates, tariffs and policies that support optimal utilization of renewable energy:
  - Third party delivery of ancillary services including inertial response and fast frequency response.
  - Electric vehicle charging infrastructure; vehicle to grid delivery; smart charging.
  - Utilization of renewable energy to substitute thermal generation in Reliability-Must-Run conditions.
  - Utilize downward reserve capabilities.
- Incentives and utility cost recovery available for energy storage:
  - Power, Volt/Var management, load smoothing.
  - Energy storage / energy arbitrage.
- Operational protocols and that may interfere with optimal distribution of curtailment risk across a specific region.

While technologies continue to develop to enable increased utilization of renewable energy, the implementation of these technologies is only enabled by changes in policies, protocols and regulatory controls that can currently interfere with optimized renewable energy transfer. Hawaii is a laboratory for the implementation of technology and policy and will continue to provide its mainland counterparts with lessons learned.

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6 Appendix 1

US Grid Interconnections, Regional Entities and Balancing Authorities

Relative to other regions of the United States, Hawaii is unique in terms of the factors that determine how much renewable energy can be accepted and utilized by the grids. The factors that are relevant to Hawaii may in fact not be relevant in other regions. This is due to the complex and robust interdependence of regional grids that transport energy across the country, combined with disparate state RPS goals and individual utility drivers including generation mix, plant capacities, operations and load profiles, which ultimately result in a localized marginal price. The following geographic and market hierarchy represents the levels of control, policy, investment and implementation that would impact how renewable energy can be generated, distributed and utilized on the US grid.

- Interconnections (Three major interconnections define US grid)
- Regional Entities (Cooperate to maintain reliability through standards and enforcement)
- Balancing Authorities (Balance generating resources with demand in real time through operating protocols)
- Electric Power Markets
- Utilities (Investment and Fuel Mix)
- State (Policies)

Three major US ***interconnections*** (Western, Eastern, and Texas) are largely independent alternating current (AC), synchronous systems, with an ability to transfer limited amount of power through direct current (DC) interties. Under the auspices of the North American Electric Reliability Corporation, Eight ***Regional Entities*** are responsible to ensure compliance with reliability standards.

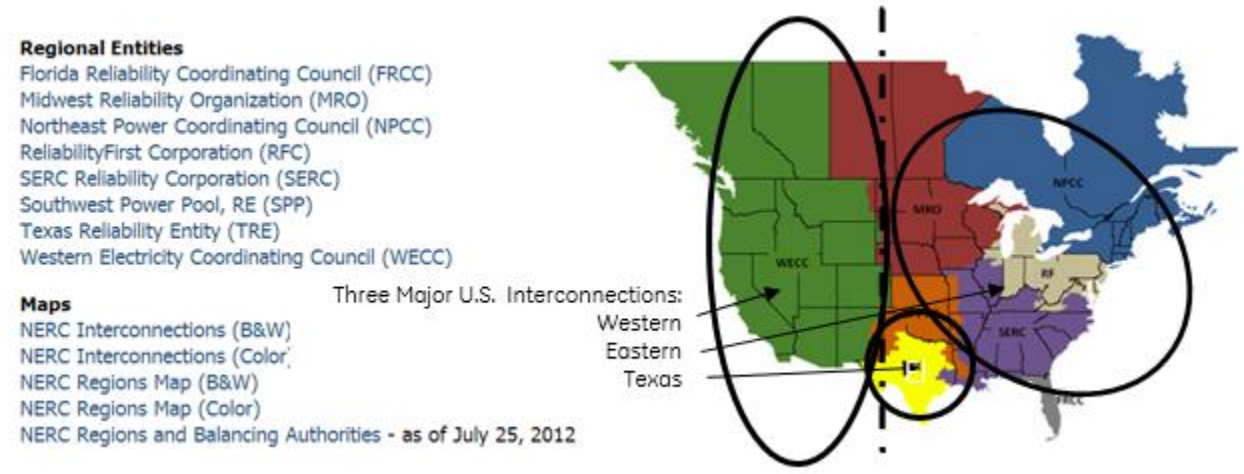

Figure 11: Regional Entities Responsible for Ensuring Compliance with Reliability Standards

[Source: North American Electric Reliability Corporation (NERC) – with macro-level grouping added for this report: http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx]

Electric Power Markets Electric Power Markets

With slightly different specific roles, Regional Transmission Organizations (RTO) and Independent System Operators (ISO) are also responsible for planning and operating regional wholesale electricity grid systems and administering a region's wholesale market.

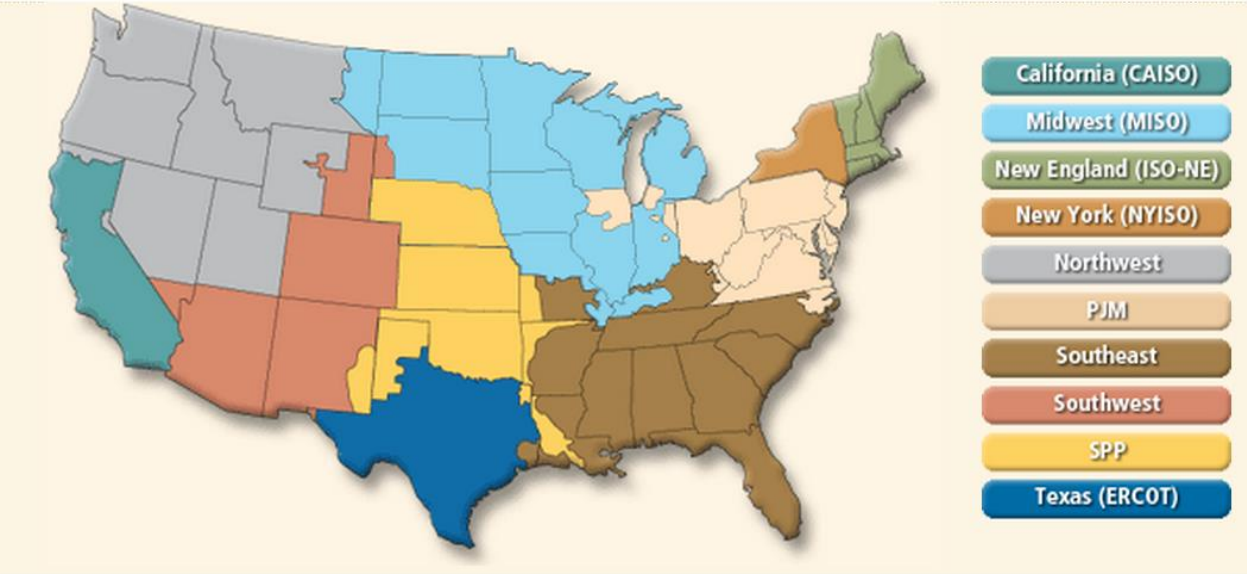

Figure 12: Ten US Electric Power Markets: Regional Transmission Organizations (RTO) and Independent System Operators (ISO)

[Source: Federal Energy Regulatory Commission (FERC): http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-rto-map.pdf]

Balancing Authorities (Over 100 balancing authorities in US and Canada)

The NERC definition of Balancing Authority follows: "One of the regional functions contributing to the reliable planning and operation of the bulk power system. The Balancing Authority integrates resource plans ahead of time, and maintains in real time the balance of electricity resources and electricity demand." Balancing areas have a range of ownership and operating structures and protocols. Each of these balancing authorities is responsible for balancing load and generation in its area. Variable energy resources create operating challenges that interfere with regionally optimized transmission and utilization of power.

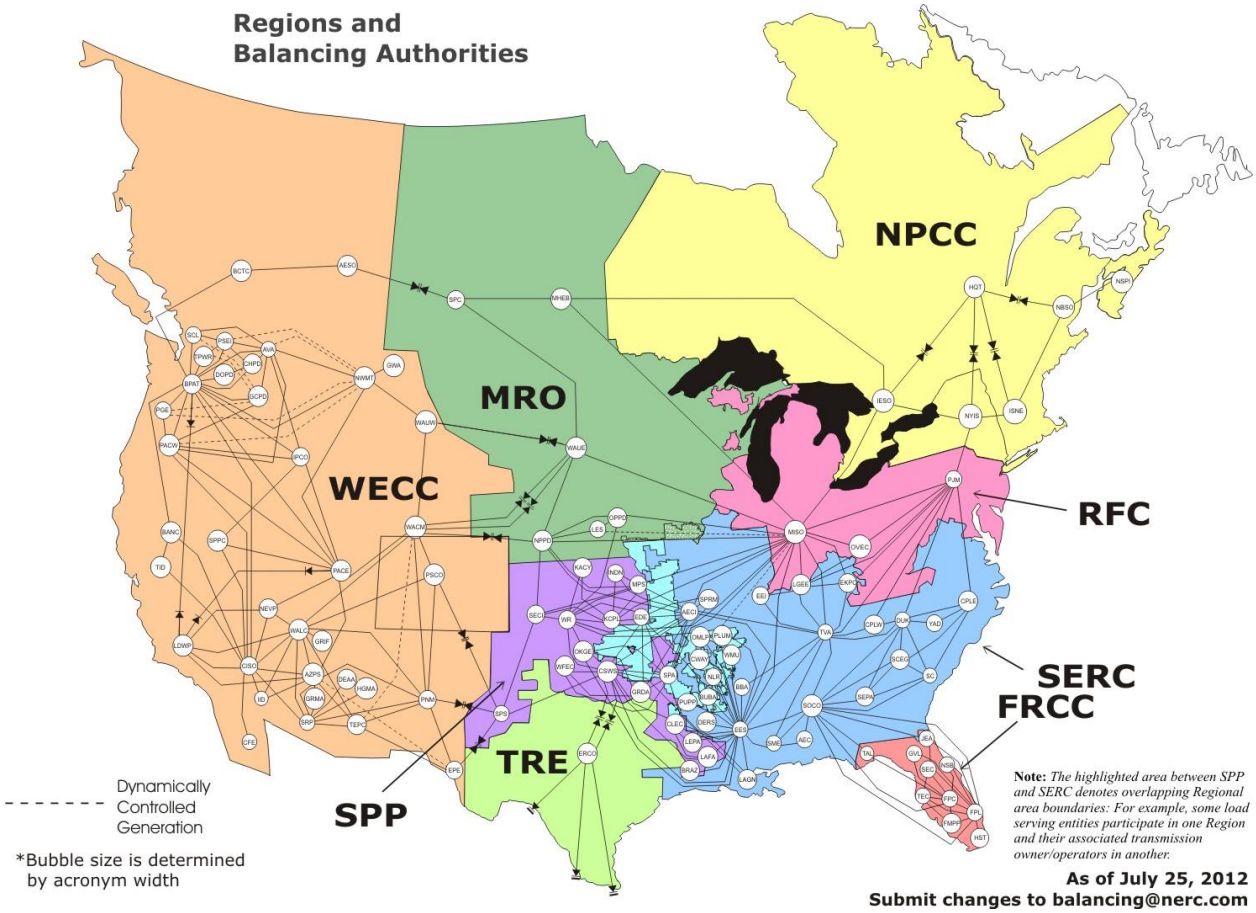

Figure 13: Balancing Authorities in the U.S. and Canada

[Source: North American Electric Reliability Corporation (NERC): http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx]

Utilities: Utilities are responsible for generation transmission and distribution of electricity. Utilities may be responsible for one or all of these electric power company functions, and may be investor owned, publicly owned, or a local cooperative. Utilities participate in wholesale markets by buying and selling power, facilitated by the RTO's and ISOs. As such, providing lowest cost of service requires a delicate balance between demand predictions, real time cost of generation, availability of lower cost power, and operating protocols, in order to maintain their own lowest cost of operation. Most utilities are subject to regulation by public utility commissions, and are therefore constrained in many of their own decisions.

State: States can play multiple roles in determining how renewable energy can be absorbed into the grid. Foremost, the states are represented by regulatory bodies such as utility commissions or public service entities that stipulate many of the rules that determine how utilities can invest their assets, operate their plants, and charge customers for their power. Many states also have imposed Renewable Energy Standards (RPS) that provide targets for

the generation of renewable energy (and/or energy efficiency) as a percent of energy generated and sold (Please see Figure 1).

Endnote

The complexity of a robust, interconnected grid on the mainland United States creates a challenge when seeking to identify and implement policies that maximize acceptance of renewable energy across multi-jurisdictional regions. In order to optimize grid acceptance, policies will need to straddle utility territories, state lines, regional power markets, balancing authorities and U.S. Interconnections. Hawaii's constraints are inherently different with a single utilities commission, only two utilities, and each island serving as its own balancing area. While many of the technical conclusions can apply to most utilities that seek to increase acceptance of renewable energy, aligning policies will be the largest challenge for mainland utilities.

GE MAPS Analysis Results

Table 8: GE MAPS Results for Eastern Interconnection (EI)

Final Ranking	Candidate?	Country	Inter-Connection	Area	Pool	State	Renewable Energy Penetration	Annual Net Exports as % of Average Daily Energy	Change in Average Spot Price ($/MWh)	Rank of Renewable Penetration	Rank of Drop in Exports	Rank of Decrease in Price	Sum of the Ranks
1	YES	USA	EI	MECA	MISO	IL	30.2%	-50.1%	(9.48)	1	10	9	6
2	YES	USA	EI	ALTWA	MISO	IA	40.6%	-57.7%	(8.75)	2	7	5	17
3	YES	USA	EI	SECIA	SPP	KS	57.9%	-15.8%	(11.42)	3	4	33	1
4	YES	USA	EI	MDUA	MISO	MT	81.8%	-28.4%	(8.23)	4	2	22	20
5	YES	USA	EI	OTPA	MISO	MN	58.7%	-41.0%	(7.25)	5	3	14	27
6	YES	USA	EI	NPPDA	SPP	NE	19.8%	-14.8%	(11.07)	6	13	36	2
7	YES	USA	EI	SIGEA	MISO	IN	13.5%	-44.0%	(7.17)	7	16	12	28
8	YES	USA	EI	CSWSA	SPP	AR	4.0%	-47.8%	(10.21)	8	42	11	5
9	YES	USA	EI	NSPA	MISO	IA	12.1%	-30.8%	(7.27)	9	18	18	26
10	YES	USA	EI	SMPA	MISO	MN	85.8%	-20.3%	(6.96)	10	1	32	29
11	YES	USA	EI	WFECA	SPP	OK	52.3%	-6.7%	(9.21)	11	5	51	10
12	YES	USA	EI	OKGEA	SPP	OK	11.0%	-24.4%	(8.82)	12	23	29	16
13	YES	USA	EI	GREA	MISO	MN	11.8%	-24.0%	(7.38)	13	19	30	24
14	YES	USA	EI	WRA	SPP	KS	11.7%	-7.7%	(9.40)	14	20	47	7
15	YES	USA	EI	AECIA	SERCN	MO	2.1%	-61.4%	(7.43)	15	49	3	23
16	YES	USA	EI	WAUEA	MAPP	IA	20.0%	-7.4%	(8.89)	16	12	49	14
17	YES	USA	EI	ALTEA	MISO	WI	6.5%	-55.6%	(5.24)	17	30	6	41
18	YES	USA	EI	MPA	MISO	MN	1.9%	-54.9%	(7.38)	18	50	7	25
19	YES	USA	EI	CONSA	MISO	MI	6.5%	-31.5%	(4.57)	19	29	17	50
20	YES	USA	EI	EKPCA	SERCN	KY	4.3%	-27.6%	(5.69)	20	39	24	38
21	YES	USA	EI	KCPLA	SPP	KS	1.6%	-15.1%	(9.00)	21	53	35	13
22	YES	USA	EI	NIPSA	MISO	IN	8.1%	-29.3%	(2.99)	22	26	21	57

23	YES	USA	EI	WPSA	MISO	IA	4.4%	-24.5%	(5.58)	23	37	28	39
24	YES	USA	EI	WECA	MISO	MI	3.6%	-34.0%	(4.87)	24	44	15	46
25	YES	USA	EI	AMILA	MISO	IL	1.5%	-33.4%	(6.03)	25	54	16	36
26	YES	USA	EI	IPLA	MISO	IN	5.7%	-14.2%	(5.44)	26	32	39	40
27	YES	USA	EI	OPPDA	SPP	NE	1.0%	-6.7%	(11.03)	27	60	50	3
28	YES	USA	EI	DPCA	MISO	IA	1.3%	-25.7%	(6.77)	28	58	26	31
29	YES	USA	EI	SPSA	SPP	NM	11.4%	-7.9%	(3.04)	29	21	45	56
30	YES	USA	EI	COMEDA	PJM	IL	5.3%	-13.3%	(2.95)	30	34	40	58
31	YES	USA	EI	UPPCA	MISO	MI	37.4%	-4.4%	(0.53)	31	9	58	65
32	YES	USA	EI	DUKINA	MISO	IN	0.8%	-14.7%	(5.92)	32	62	37	37
33	YES	USA	EI	DECOA	MISO	MI	2.2%	-7.5%	(5.21)	33	47	48	42
34	YES	USA	EI	TVAA	SERCN	TN	2.4%	-13.2%	(4.02)	34	46	41	52
35	YES	USA	EI	AMMOA	MISO	IL	0.2%	-5.4%	(8.19)	35	66	54	21
36	YES	USA	EI	AEPA	PJM	IN	4.0%	-9.5%	(2.46)	36	41	44	60
37	YES	USA	EI	DUQA	PJM	PA	1.3%	-4.1%	(1.69)	37	57	59	64
38	NO	USA	EI	MPWA	MISO	IA	0.0%	-156.7%	(8.83)	38	102	1	15
39	NO	USA	EI	EDEA	SPP	KS	0.0%	-54.4%	(8.72)	39	79	8	19
40	NO	USA	EI	MPSA	SPP	MO	0.0%	-27.3%	(9.31)	40	101	25	8
41	NO	USA	EI	SIPCA	MISO	IL	0.0%	-61.2%	(6.45)	41	113	4	33
42	NO	USA	EI	LESA	SPP	NE	0.0%	-15.5%	(10.97)	42	98	34	4
43	NO	USA	EI	INDNA	SPP	MO	0.0%	-29.9%	(8.17)	43	92	20	22
44	NO	USA	EI	CWLPA	MISO	IL	0.0%	-66.8%	(5.18)	44	75	2	43
45	NO	USA	EI	EESARKA	SERCW	AR	0.0%	-42.3%	(6.55)	45	80	13	32
46	NO	USA	EI	LKEA	SERCN	KY	0.0%	-27.9%	(6.13)	46	99	23	35
47	NO	USA	EI	CLECA	SPP	LA	0.0%	-47.9%	(4.65)	47	71	10	49
48	NO	USA	EI	HEA	MISO	IN	0.0%	-24.0%	(6.87)	48	91	31	30
49	NO	USA	EI	EESMSA	SERCW	MS	0.0%	-30.7%	(4.95)	49	83	19	44
50	NO	USA	EI	KACYA	SPP	KS	0.0%	-4.7%	(9.09)	50	94	55	12
51	NO	USA	EI	SPAA	SPP	AR	0.0%	-6.5%	(8.73)	51	119	52	18

52	NO	USA	EI	GRDAA	SPP	AR	0.0%	-2.8%	(9.20)	52	89	63	11
53	NO	USA	EI	SPRMA	SPP	MO	0.0%	-1.6%	(9.24)	53	120	65	9
54	NO	USA	EI	CWLDA	MISO	MO	0.0%	-7.7%	(6.20)	54	74	46	34
55	NO	USA	EI	EESLAA	SERCW	LA	0.0%	-24.7%	(2.32)	55	82	27	61
56	NO	USA	EI	APSA	PJM	MD	9.8%	-1.1%	0.50	56	25	67	68
57	NO	USA	EI	SCEGA	SERCE	GA	0.0%	-14.5%	(3.06)	57	112	38	55
58	NO	USA	EI	DPLA	PJM	DE	13.6%	0.7%	0.83	58	15	77	72
59	NO	USA	EI	DUKOHA	PJM	OH	0.0%	-10.2%	(3.78)	59	78	43	53
60	NO	USA	EI	LAGNA	SERCW	LA	0.0%	-10.4%	(1.97)	60	96	42	63
61	NO	USA	EI	MGEA	MISO	WI	0.0%	-3.1%	(4.84)	61	100	62	47
62	NO	USA	EI	BRECA	MISO	KY	0.0%	-1.3%	(4.95)	62	70	66	45
63	NO	USA	EI	DUKKYA	PJM	KY	0.0%	-2.7%	(4.05)	63	77	64	51
64	NO	USA	EI	METEDA	PJM	PA	6.0%	0.6%	0.97	64	31	75	78
65	NO	USA	EI	EESNOA	SERCW	LA	0.0%	-3.8%	(2.50)	65	84	60	59
66	NO	USA	EI	FEATSIA	PJM	OH	0.0%	-4.4%	(2.15)	66	86	57	62
67	NO	USA	EI	SOCOMSA	SERCSE	MS	0.0%	-6.4%	0.05	67	118	53	66
68	NO	USA	EI	AECOA	PJM	NJ	10.4%	3.7%	0.90	68	24	89	75
69	NO	USA	EI	DAYA	PJM	OH	0.0%	-0.9%	(3.12)	69	76	68	54
70	NO	USA	EI	JCPLA	PJM	NJ	11.1%	4.0%	0.99	70	22	90	79
71	NO	USA	EI	NYZEA	NYISO	NY	38.2%	2.3%	6.05	71	8	88	96
72	NO	USA	EI	PSEGA	PJM	NJ	4.2%	1.6%	0.89	72	40	83	74
73	NO	USA	EI	BGEA	PJM	MD	5.0%	1.5%	1.24	73	35	82	82
74	NO	USA	EI	LEPAA	SPP	LA	0.0%	1.7%	(4.74)	74	97	84	48
75	NO	USA	EI	PPLA	PJM	PA	1.9%	0.4%	0.95	75	51	73	76
76	NO	USA	EI	PENELECA	PJM	MD	5.6%	4.0%	1.09	76	33	91	80
77	NO	USA	EI	YADA	SERCE	NC	0.0%	0.0%	0.62	77	125	71	69
78	NO	USA	EI	UGIA	PJM	PA	0.0%	-4.6%	1.26	78	124	56	83
79	NO	USA	EI	PEPCOA	PJM	DC	6.9%	4.6%	1.96	79	28	92	88
80	NO	USA	EI	PECOA	PJM	MD	0.8%	0.6%	0.86	80	63	76	73

81	NO	USA	EI	VTA	ISONE	NH	15.3%	0.9%	9.33	81	14	80	118
82	NO	USA	EI	DOMA	PJM	NC	1.0%	2.1%	0.30	82	59	87	67
83	NO	USA	EI	MEA	ISONE	ME	43.6%	14.4%	7.63	83	6	99	109
84	NO	USA	EI	EESTXA	SERCW	TX	0.0%	-3.7%	2.88	84	85	61	89
85	NO	USA	EI	SOCOFLA	SERCSE	FL	0.0%	0.8%	0.82	85	116	79	71
86	NO	USA	EI	NYZCA	NYISO	NY	6.9%	20.0%	5.97	86	27	102	95
87	NO	USA	EI	NYZAA	NYISO	NY	1.9%	11.5%	0.97	87	52	96	77
88	NO	USA	EI	RECOA	PJM	NJ	0.0%	0.0%	5.93	88	110	70	93
89	NO	USA	EI	CPLWA	SERCE	NC	12.9%	68.3%	5.93	89	17	120	94
90	NO	USA	EI	EESGSUA	SERCW	LA	0.0%	0.7%	1.55	90	81	78	85
91	NO	USA	EI	AECA	SERCSE	AL	0.0%	7.9%	0.82	91	68	94	70
92	NO	USA	EI	SMEPAA	SERCSE	MS	0.0%	1.8%	1.10	92	114	85	81
93	NO	USA	EI	SMEA	ISONE	ME	24.6%	58.8%	7.66	93	11	117	110
94	NO	USA	EI	NYZBA	NYISO	NY	0.4%	1.1%	6.27	94	65	81	98
95	NO	USA	EI	LAFAA	SPP	LA	0.0%	8.4%	1.47	95	95	95	84
96	NO	USA	EI	CPLEA	SERCE	NC	1.4%	20.0%	3.68	96	56	103	90
97	NO	USA	EI	NYZIA	NYISO	NY	0.0%	0.0%	7.84	97	107	69	112
98	NO	USA	EI	NYZHA	NYISO	NY	0.0%	0.5%	7.80	98	106	74	111
99	NO	USA	EI	SOCOALA	SERCSE	AL	0.0%	14.2%	1.60	99	115	98	87
100	NO	USA	EI	DUKA	SERCE	NC	1.5%	30.2%	5.53	100	55	107	92
101	NO	USA	EI	SOCOGAA	SERCSE	GA	0.0%	17.5%	1.57	101	117	101	86
102	NO	USA	EI	NYZDA	NYISO	NY	4.0%	48.6%	6.42	102	43	113	105
103	NO	USA	EI	SEMAA	ISONE	MA	4.3%	30.0%	9.35	103	38	106	119
104	NO	USA	EI	NORA	ISONE	CT	0.0%	0.4%	9.79	104	103	72	124
105	NO	USA	EI	BHEA	ISONE	ME	4.6%	131.3%	7.11	105	36	125	107
106	NO	USA	EI	NYZGA	NYISO	NY	0.0%	4.8%	7.28	106	105	93	108
107	NO	USA	EI	CMANEMAA	ISONE	MA	0.0%	2.0%	9.32	107	72	86	117
108	NO	USA	EI	WMAA	ISONE	MA	2.2%	23.1%	9.36	108	48	104	120
109	NO	USA	EI	TALA	FRCC	FL	0.0%	39.4%	6.22	109	122	109	97

110	NO	USA	EI	NHA	ISONE	ME	3.0%	52.0%	9.25	110	45	115	115
111	NO	USA	EI	NYZJA	NYISO	NJ	0.0%	12.5%	8.21	111	108	97	113
112	NO	USA	EI	SECA	FRCC	FL	0.5%	41.1%	6.40	112	64	110	104
113	NO	USA	EI	NYZFA	NYISO	NY	0.0%	68.7%	5.45	113	104	121	91
114	NO	USA	EI	GVLA	FRCC	FL	0.0%	44.1%	6.39	114	90	112	103
115	NO	USA	EI	FPCA	FRCC	FL	0.0%	49.1%	6.36	115	88	114	102
116	NO	USA	EI	TECA	FRCC	FL	0.0%	57.3%	6.33	116	123	116	100
117	NO	USA	EI	FPLA	FRCC	FL	0.0%	63.9%	6.31	117	67	119	99
118	NO	USA	EI	FMPPA	FRCC	FL	0.0%	62.9%	6.34	118	87	118	101
119	NO	USA	EI	BOSTONA	ISONE	MA	0.0%	29.8%	9.32	119	69	105	116
120	NO	USA	EI	CTA	ISONE	CT	0.0%	15.4%	9.63	120	73	100	122
121	NO	USA	EI	JEAA	FRCC	FL	0.0%	74.0%	6.43	121	93	122	106
122	NO	USA	EI	NYZKA	NYISO	NY	0.0%	38.4%	11.12	122	109	108	125
123	NO	USA	EI	SWCTA	ISONE	CT	0.0%	41.7%	9.74	123	121	111	123
124	NO	USA	EI	SCA	SERCE	SC	0.0%	81.2%	9.17	124	111	123	114
125	NO	USA	EI	RIA	ISONE	CT	0.9%	84.7%	9.38	125	61	124	121

Table 9: GE MAPS Results for Western Electricity Coordinating Council (WECC)

Final Ranking	Candidate?	Country	Inter-Connection	Area	Pool	State	Renewable Energy Penetration	Annual Net Exports as % of Average Daily Energy	Change in Average Spot Price ($/MWh)	Rank of Renewable Penetration	Rank of Drop in Exports	Rank of Decrease in Price	Sum of the Ranks
1	YES	USA	WECC	WACMCEA	RMP	CO	17.4%	-18.1%	(5.81)	1	7	2	6
2	YES	USA	WECC	SRPA	DSW	AZ	13.1%	-9.2%	(5.21)	2	9	7	7
3	YES	USA	WECC	IPCOA	BAS	ID	10.9%	-8.5%	(6.48)	3	13	8	2
4	YES	USA	WECC	PNMA	DSW	NM	12.8%	-4.5%	(5.02)	4	10	9	8
5	YES	USA	WECC	PACEIDA	BAS	ID	10.6%	-47.0%	(4.26)	5	14	1	13
6	YES	USA	WECC	AVAA	NWP	ID	43.1%	-3.4%	(3.98)	6	1	13	16
7	YES	USA	WECC	NWMTA	NWP	MT	6.3%	-3.3%	(7.36)	7	20	14	1
8	YES	USA	WECC	PACEWYA	RMP	WY	21.1%	0.0%	(4.42)	8	6	20	11
9	YES	USA	WECC	AZPSA	DSW	AZ	2.9%	-13.5%	(4.93)	9	24	4	10
10	YES	USA	WECC	NEVPA	DSW	AZ	3.9%	-16.4%	(4.08)	10	22	3	14
11	YES	USA	WECC	BPATA	NWP	ID	10.5%	-12.3%	(3.73)	11	16	5	18
12	YES	USA	WECC	WACMWYA	RMP	WY	1.0%	-3.7%	(6.07)	12	27	11	5
13	YES	USA	WECC	WALCA	DSW	AZ	11.6%	-9.7%	(2.39)	13	12	6	28
14	YES	USA	WECC	LDWPA	CALS	CA	33.0%	-1.9%	(3.50)	14	4	15	27
15	YES	USA	WECC	TEPCA	DSW	AZ	7.9%	-0.4%	(4.97)	15	19	19	9
16	YES	USA	WECC	PSEIA	NWP	WA	16.6%	-1.1%	(3.59)	16	8	16	25
17	YES	USA	WECC	PACEUTA	BAS	UT	1.6%	-3.8%	(4.01)	17	26	10	15
18	YES	USA	WECC	PACWA	NWP	CA	3.8%	-0.9%	(3.69)	18	23	17	21
19	NO	USA	WECC	WACMCWA	RMP	CO	0.0%	-3.6%	(6.14)	19	38	12	3
20	NO	USA	WECC	PSCOEA	RMP	CO	22.3%	0.4%	(3.86)	20	5	29	17
21	NO	USA	WECC	WAUWA	NWP	MT	0.0%	0.0%	(6.09)	21	36	23	4
22	NO	USA	WECC	IIDZA	CALS	CA	36.1%	0.3%	(1.34)	22	2	28	30
23	NO	USA	WECC	PSCOWA	RMP	CO	0.0%	0.0%	(4.26)	23	37	27	12

24	NO	USA	WECC	PGEA	NWP	OR	0.0%	-0.6%	(3.66)	24	30	18	23
25	NO	USA	WECC	GCPDA	NWP	WA	0.0%	0.0%	(3.71)	25	33	26	19
26	NO	USA	WECC	TPWRA	NWP	WA	0.0%	0.0%	(3.67)	26	35	21	22
27	NO	USA	WECC	CHPDA	NWP	WA	0.0%	0.0%	(3.69)	27	31	24	20
28	NO	USA	WECC	SCLA	NWP	WA	0.0%	0.0%	(3.62)	28	34	22	24
29	NO	USA	WECC	CISOSCEA	CALS	CA	33.4%	8.7%	2.24	29	3	35	38
30	NO	USA	WECC	DOPDA	NWP	WA	0.0%	0.0%	(3.53)	30	32	25	26
31	NO	USA	WECC	SPPCA	BAS	CA	4.6%	1.4%	(1.10)	31	21	31	31
32	NO	USA	WECC	EPEA	DSW	NM	2.1%	1.1%	(2.02)	32	25	30	29
33	NO	USA	WECC	SMUDA	CALN	CA	8.8%	6.3%	1.57	33	18	34	32
34	NO	USA	WECC	CISOSDGA	CALS	CA	12.6%	9.8%	1.79	34	11	36	37
35	NO	USA	WECC	CISOPGEA	CALN	CA	10.5%	16.7%	1.61	35	15	37	33
36	NO	USA	WECC	CISOZ26A	CALN	CA	9.4%	28.8%	1.78	36	17	38	36
37	NO	USA	WECC	CISOSFA	CALN	CA	0.0%	2.6%	1.61	37	28	33	34
38	NO	USA	WECC	TIDA	CALN	CA	0.0%	2.3%	1.62	38	29	32	35

Table 10: GE MAPS Results for Electricity Reliability Council of Texas (ERCOT)

Final Ranking	Candidate?	Country	Inter-Connection	Area	Pool	State	Renewable Energy Penetration	Annual Net Exports as % of Average Daily Energy	Change in Average Spot Price ($/MWh)	Rank of Renewable Penetration	Rank of Drop in Exports	Rank of Decrease in Price	Sum of the Ranks
1	YES	USA	ERCOT	ERCONA	ERCOT	TX	0.7%	-2.0%	(1.21)	1	3	1	1
2	NO	USA	ERCOT	ERCOWA	ERCOT	TX	73.9%	0.6%	(0.95)	2	1	3	3
3	NO	USA	ERCOT	ERCOHA	ERCOT	TX	0.0%	-0.8%	(0.96)	3	4	2	2
4	NO	USA	ERCOT	ERCOSA	ERCOT	TX	8.9%	3.6%	(0.56)	4	2	4	4

The following table provides the full name of the Pools, States, and Areas used in the GE MAPS modeling.

Table 11: List of Short and Long Names of Pools, States, and Areas Modeled in GE MAPS

Interconnection	Pool - Short	Pool - Long	State - Short	State - Long	Area - Short	Area - Long
EI	FRCC	Florida Coordinating Council	FL	Florida	FMPPA	Florida Municipal Power
EI	FRCC	Florida Coordinating Council	FL	Florida	FPCA	Progress Energy Florida
EI	FRCC	Florida Coordinating Council	FL	Florida	FPLA	Florida Power & Light
EI	FRCC	Florida Coordinating Council	FL	Florida	GVLA	Gainesville Regional Utility
EI	FRCC	Florida Coordinating Council	FL	Florida	JEAA	JEA
EI	FRCC	Florida Coordinating Council	FL	Florida	SECA	Seminole Electric Cooper
EI	FRCC	Florida Coordinating Council	FL	Florida	TALA	Tallahassee Electric Dep.
EI	FRCC	Florida Coordinating Council	FL	Florida	TECA	Tampa Electric Company
EI	ISONE	ISO - New England	CT	Connecticut	CTA	ISNE - Connecticut - Central
EI	ISONE	ISO - New England	CT	Connecticut	NORA	ISNE - Connecticut - North
EI	ISONE	ISO - New England	CT	Connecticut	RIA	ISNE - Rhode Island
EI	ISONE	ISO - New England	CT	Connecticut	SWCTA	ISNE - Connecticut - South
EI	ISONE	ISO - New England	ME	Maine	BHEA	ISNE - Maine - Bangor Hydro
EI	ISONE	ISO - New England	ME	Maine	MEA	ISNE - Maine - Central
EI	ISONE	ISO - New England	ME	Maine	NHA	ISNE - New Hampshire
EI	ISONE	ISO - New England	ME	Maine	SMEA	ISNE - Maine - Southwest
EI	ISONE	ISO - New England	MA	Massachusetts	BOSTONA	ISNE - Boston
EI	ISONE	ISO - New England	MA	Massachusetts	CMANEMAA	ISNE - Massachusetts - Central
EI	ISONE	ISO - New England	MA	Massachusetts	SEMAA	ISNE - Massachusetts - South
EI	ISONE	ISO - New England	MA	Massachusetts	WMAA	ISNE - Massachusetts - West
EI	ISONE	ISO - New England	NH	New Hampshire	VTA	ISNE - Vermont
EI	MAPP	Mid-Continent Area Power Pool	IA	Iowa	WAUEA	WAPA - Upper Great Plains
EI	MISO	Midwest ISO	IL	Illinois	AMILA	Ameren Illinois
EI	MISO	Midwest ISO	IL	Illinois	AMMOA	Ameren Missouri

EI	MISO	Midwest ISO	IL	Illinois	CWLPA	Springfield Illinois
EI	MISO	Midwest ISO	IL	Illinois	MECA	Mid-American Energy Co.
EI	MISO	Midwest ISO	IL	Illinois	SIPCA	Southern Illinois Power
EI	MISO	Midwest ISO	IN	Indiana	DUKINA	Duke Energy Indiana
EI	MISO	Midwest ISO	IN	Indiana	HEA	Hoosier Energy Rural Electric
EI	MISO	Midwest ISO	IN	Indiana	IPLA	Indianapolis Power & Light
EI	MISO	Midwest ISO	IN	Indiana	NIPSA	Northern Indiana Public
EI	MISO	Midwest ISO	IN	Indiana	SIGEA	Southern Indiana Gas & Electric
EI	MISO	Midwest ISO	IA	Iowa	ALTWA	Alliant West - Interstate
EI	MISO	Midwest ISO	IA	Iowa	DPCA	Dairyland Power Cooperative
EI	MISO	Midwest ISO	IA	Iowa	MPWA	Muscatine Power & Water
EI	MISO	Midwest ISO	IA	Iowa	NSPA	Northern States Power Co
EI	MISO	Midwest ISO	IA	Iowa	WPSA	Wisconsin Public Service
EI	MISO	Midwest ISO	KY	Kentucky	BRECA	Big Rivers Electric Corp
EI	MISO	Midwest ISO	MI	Michigan	CONSA	Consumers Energy - METC
EI	MISO	Midwest ISO	MI	Michigan	DECOA	Detroit Edison Company
EI	MISO	Midwest ISO	MI	Michigan	UPPCA	Upper Peninsula Power Co
EI	MISO	Midwest ISO	MI	Michigan	WECA	Wisconsin Electric Power
EI	MISO	Midwest ISO	MN	Minnesota	GREA	Great River Energy
EI	MISO	Midwest ISO	MN	Minnesota	MPA	Minnesota Power and Light
EI	MISO	Midwest ISO	MN	Minnesota	OTPA	Otter Tail Power Company
EI	MISO	Midwest ISO	MN	Minnesota	SMPA	Southern MN Municipal Power
EI	MISO	Midwest ISO	MO	Missouri	CWLDA	Columbia Missouri Water
EI	MISO	Midwest ISO	MT	Montana	MDUA	Montana-Dakota Utilities
EI	MISO	Midwest ISO	WI	Wisconsin	ALTEA	Alliant East - Wisconsin
EI	MISO	Midwest ISO	WI	Wisconsin	MGEA	Madison Gas and Electric
EI	NYISO	New York ISO	NJ	New Jersey	NYZJA	New York Zone J - NY City
EI	NYISO	New York ISO	NY	New York	NYZAA	New York Zone A - West
EI	NYISO	New York ISO	NY	New York	NYZBA	New York Zone B - Genesee
EI	NYISO	New York ISO	NY	New York	NYZCA	New York Zone C - Central

EI	NYISO	New York ISO	NY	New York	NYZDA	New York Zone D - North
EI	NYISO	New York ISO	NY	New York	NYZEA	New York Zone E - Mohawk
EI	NYISO	New York ISO	NY	New York	NYZFA	New York Zone F - Capital
EI	NYISO	New York ISO	NY	New York	NYZGA	New York Zone G - Hudson
EI	NYISO	New York ISO	NY	New York	NYZHA	New York Zone H - Millwood
EI	NYISO	New York ISO	NY	New York	NYZIA	New York Zone I - Dunwoodie
EI	NYISO	New York ISO	NY	New York	NYZKA	New York Zone K - L Island
EI	PJM	PJM Power Pool	DE	Delaware	DPLA	Delmarva Power & Light
EI	PJM	PJM Power Pool	DC	District of Columbia	PEPCOA	Potomac Electric Power Co
EI	PJM	PJM Power Pool	IL	Illinois	COMEDA	Commonwealth Edison Co.
EI	PJM	PJM Power Pool	IN	Indiana	AEPA	American Electric Power
EI	PJM	PJM Power Pool	KY	Kentucky	DUKKYA	Duke Energy Kentucky
EI	PJM	PJM Power Pool	MD	Maryland	APSA	Allegheny Power
EI	PJM	PJM Power Pool	MD	Maryland	BGEA	Baltimore Gas & Electric
EI	PJM	PJM Power Pool	MD	Maryland	PECOA	PECO Energy Company
EI	PJM	PJM Power Pool	MD	Maryland	PENELECA	Pennsylvania Electric Co
EI	PJM	PJM Power Pool	NJ	New Jersey	AECOA	Atlantic Electric
EI	PJM	PJM Power Pool	NJ	New Jersey	JCPLA	Jersey Central Power & Light
EI	PJM	PJM Power Pool	NJ	New Jersey	PSEGA	Public Service Electric
EI	PJM	PJM Power Pool	NJ	New Jersey	RECOA	Rockland Electric Company
EI	PJM	PJM Power Pool	NC	North Carolina	DOMA	Virginia Power Company
EI	PJM	PJM Power Pool	OH	Ohio	DAYA	Dayton Power & Light Co.
EI	PJM	PJM Power Pool	OH	Ohio	DUKOHA	Duke Energy Ohio
EI	PJM	PJM Power Pool	OH	Ohio	FEATSIA	FirstEnergy ATSI
EI	PJM	PJM Power Pool	PA	Pennsylvania	DUQA	Duquesne Light Company
EI	PJM	PJM Power Pool	PA	Pennsylvania	METEDA	Metropolitan Edison Company
EI	PJM	PJM Power Pool	PA	Pennsylvania	PPLA	Pennsylvania Power & Light
EI	PJM	PJM Power Pool	PA	Pennsylvania	UGIA	UGI Corporation
EI	SERCE	SERC - East	GA	Georgia	SCEGA	South Carolina Electric
EI	SERCE	SERC - East	NC	North Carolina	CPLEA	Progress Energy Carolina

EI	SERCE	SERC - East	NC	North Carolina	CPLWA	Progress Energy Carolina
EI	SERCE	SERC - East	NC	North Carolina	DUKA	Duke Energy Carolinas
EI	SERCE	SERC - East	NC	North Carolina	YADA	Yadkin Inc.
EI	SERCE	SERC - East	SC	South Carolina	SCA	Santee Cooper
EI	SERCN	SERC - North	KY	Kentucky	EKPCA	East Kentucky Power Coop
EI	SERCN	SERC - North	KY	Kentucky	LKEA	Louisville Gas & Electric
EI	SERCN	SERC - North	MO	Missouri	AECIA	Associated Electric Coop
EI	SERCN	SERC - North	TN	Tennessee	TVAA	Tennessee Valley Authority
EI	SERCSE	SERC - South	AL	Alabama	AECA	PowerSouth Energy Coop
EI	SERCSE	SERC - South	AL	Alabama	SOCOALA	Alabama Power Company
EI	SERCSE	SERC - South	FL	Florida	SOCOFLA	Gulf Power Company
EI	SERCSE	SERC - South	GA	Georgia	SOCOGAA	Georgia Power Company
EI	SERCSE	SERC - South	MS	Mississippi	SMEPAA	South Mississippi Electric
EI	SERCSE	SERC - South	MS	Mississippi	SOCOMSA	Mississippi Power Co
EI	SERCW	SERC - West	AR	Arkansas	EESARKA	Entergy Arkansas
EI	SERCW	SERC - West	LA	Louisiana	EESGSUA	Entergy Gulf States
EI	SERCW	SERC - West	LA	Louisiana	EESLAA	Entergy Louisiana
EI	SERCW	SERC - West	LA	Louisiana	EESNOA	Entergy New Orleans
EI	SERCW	SERC - West	LA	Louisiana	LAGNA	Louisiana Generating/Cajun
EI	SERCW	SERC - West	MS	Mississippi	EESMSA	Entergy Mississippi
EI	SERCW	SERC - West	TX	Texas	EESTXA	Entergy Texas
EI	SPP	Southwest Power Pool	AR	Arkansas	CSWSA	AEP West
EI	SPP	Southwest Power Pool	AR	Arkansas	GRDAA	Grand River Dam Authority
EI	SPP	Southwest Power Pool	AR	Arkansas	SPAA	Southwestern Power Admin
EI	SPP	Southwest Power Pool	KS	Kansas	EDEA	Empire District Electric
EI	SPP	Southwest Power Pool	KS	Kansas	KACYA	Board of Public Utilities
EI	SPP	Southwest Power Pool	KS	Kansas	KCPLA	Kansas City Power & Light
EI	SPP	Southwest Power Pool	KS	Kansas	SECIA	Sunflower Electric Power
EI	SPP	Southwest Power Pool	KS	Kansas	WRA	Westar Energy/Western Region
EI	SPP	Southwest Power Pool	LA	Louisiana	CLECA	Central Louisiana Electric

EI	SPP	Southwest Power Pool	LA	Louisiana	LAFAA	Lafayette (City of)
EI	SPP	Southwest Power Pool	LA	Louisiana	LEPAA	Louisiana Energy and Power
EI	SPP	Southwest Power Pool	MO	Missouri	INDNA	City Power & Light
EI	SPP	Southwest Power Pool	MO	Missouri	MPSA	KCPL-Greater Missouri
EI	SPP	Southwest Power Pool	MO	Missouri	SPRMA	City Utilities Springfield
EI	SPP	Southwest Power Pool	NE	Nebraska	LESA	Lincoln Electric System
EI	SPP	Southwest Power Pool	NE	Nebraska	NPPDA	Nebraska Public Power
EI	SPP	Southwest Power Pool	NE	Nebraska	OPPDA	Omaha Public Power District
EI	SPP	Southwest Power Pool	NM	New Mexico	SPSA	Southwestern Public Service
EI	SPP	Southwest Power Pool	OK	Oklahoma	OKGEA	Oklahoma Gas & Electric
EI	SPP	Southwest Power Pool	OK	Oklahoma	WFECA	Western Farmers Electric
ERCOT	ERCOT	ERCOT - Texas	TX	Texas	ERCOHA	ERCOT Houston Zone
ERCOT	ERCOT	ERCOT - Texas	TX	Texas	ERCONA	ERCOT North Zone
ERCOT	ERCOT	ERCOT - Texas	TX	Texas	ERCOSA	ERCOT South Zone
ERCOT	ERCOT	ERCOT - Texas	TX	Texas	ERCOWA	ERCOT West Zone
WECC	BAS	Basin	CA	California	SPPCA	Sierra Pacific Power
WECC	BAS	Basin	ID	Idaho	IPCOA	Idaho Power
WECC	BAS	Basin	ID	Idaho	PACEIDA	PACE - Idaho
WECC	BAS	Basin	UT	Utah	PACEUTA	PACE - Utah
WECC	CALN	California - North	CA	California	CISOPGEA	PG&E - Main
WECC	CALN	California - North	CA	California	CISOSFA	PG&E San Francisco
WECC	CALN	California - North	CA	California	CISOZ26A	PG&E - ZP26
WECC	CALN	California - North	CA	California	SMUDA	Sacramento Municipal Utility
WECC	CALN	California - North	CA	California	TIDA	Turlock Irrigation District
WECC	CALS	California - South	CA	California	CISOSCEA	Southern California Edison
WECC	CALS	California - South	CA	California	CISOSDGA	San Diego Gas & Electric
WECC	CALS	California - South	CA	California	IIDZA	Imperial Irrigation District
WECC	CALS	California - South	CA	California	LDWPA	LA Department of W & P
WECC	DSW	Desert South West	AZ	Arizona	AZPSA	Arizona Public Service
WECC	DSW	Desert South West	AZ	Arizona	NEVPA	Nevada Power

WECC	DSW	Desert South West	AZ	Arizona	SRPA	Salt River Project
WECC	DSW	Desert South West	AZ	Arizona	TEPCA	Tucson Electric Power Co
WECC	DSW	Desert South West	AZ	Arizona	WALCA	WAPA - Desert Southwest
WECC	DSW	Desert South West	NM	New Mexico	EPEA	El Paso Electric
WECC	DSW	Desert South West	NM	New Mexico	PNMA	Public Service Co of New Mexico
WECC	NWP	Northwest Power Pool	CA	California	PACWA	PacifiCorp West
WECC	NWP	Northwest Power Pool	ID	Idaho	AVAA	Avista
WECC	NWP	Northwest Power Pool	ID	Idaho	BPATA	Bonneville Power Administration
WECC	NWP	Northwest Power Pool	MT	Montana	NWMTA	Northwestern Energy - Montana
WECC	NWP	Northwest Power Pool	MT	Montana	WAUWA	WAPA - Upper Great Plain
WECC	NWP	Northwest Power Pool	OR	Oregon	PGEA	Portland General Electric
WECC	NWP	Northwest Power Pool	WA	Washington	CHPDA	PUD No 1 of Chelan County
WECC	NWP	Northwest Power Pool	WA	Washington	DOPDA	PUD No 1 of Douglas County
WECC	NWP	Northwest Power Pool	WA	Washington	GCPDA	PUD of Grant County
WECC	NWP	Northwest Power Pool	WA	Washington	PSEIA	Puget Sound Energy
WECC	NWP	Northwest Power Pool	WA	Washington	SCLA	Seattle City Light
WECC	NWP	Northwest Power Pool	WA	Washington	TPWRA	Tacoma Public Utilities
WECC	RMP	Rocky Mountain Pool	CO	Colorado	PSCOEA	Public Service of Colorado
WECC	RMP	Rocky Mountain Pool	CO	Colorado	PSCOWA	Public Service of Colorado
WECC	RMP	Rocky Mountain Pool	CO	Colorado	WACMCEA	WAPA - Colorado Missouri
WECC	RMP	Rocky Mountain Pool	CO	Colorado	WACMCWA	WAPA - Colorado Missouri
WECC	RMP	Rocky Mountain Pool	WY	Wyoming	PACEWYA	PACE - Wyoming
WECC	RMP	Rocky Mountain Pool	WY	Wyoming	WACMWYA	WAPA - Colorado Missouri


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