BEFORE THE PUBLIC UTILITIES COMMISSION
OF HAWAII

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PUBLIC UTILITIES COMMISSION	)	Docket No. 2011-0206
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Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited	)	

RELIABILITY STANDARDS WORKING GROUP
INDEPENDENT FACILITATOR'S SUBMITTAL

FINAL REPORT
AND CERTIFICATE OF SERVICE

March 17, 2013

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March 13, 2013

In 2010, the Hawaii Public Utilities Commission indicated its intent to establish a Reliability Standards Working Group (RSWG); that group began working together in July 2011 under Docket 2008-0273.[1] Since that time the RSWG has been meeting and working diligently to produce policy and technical recommendations that will facilitate the increased use of renewable energy in the islands without compromising grid reliability.

The RSWG concluded its work on January 24, 2013. The RSWG members have developed a shared, sophisticated technical understanding of the relevant issues and developed a number of work products that can help the state's utilities, generators, and

[1] The Commission subsequently created Docket 2011-0206 specifically for RSWG activities in an order dated September 8, 2011.

stakeholders operate the grid with high reliability and high levels of renewable generation. With this filing, the Independent Facilitator submits all of the RSWG's final work products to the Commission for its consideration and potential adoption.

This filing summarizes the RSWG's purpose, scope and process to provide context for the Commission and non-RSWG reviewers to appreciate the significance and value of the agreements and work products completed by the RSWG. It then reviews the materials that the Independent Facilitator hereby submits to the Commission on behalf of the RSWG, with brief descriptions of these work products and how they can be used to help Hawaii increase its use of renewable energy efficiently while protecting grid reliability. This filing closes with suggestions from the RSWG members and the Independent Facilitator (IF) for next steps to follow on and leverage the RSWG's work.

1.0 Background

1.1 RSWG mission, purpose and scope

The RSWG was created by the Hawaii PUC to increase the use of renewable energy in Hawaii without compromising grid reliability. The Commission approved the following statement of purpose:

> The RSWG will recommend fact-based standards, metrics, rules, criteria and processes to "help determine how we can interconnect the maximum amount of renewable generation to the grid while preserving grid reliability," consistent with Hawaii clean energy statutory mandates and policies. These standards, metrics, rules criteria and processes will be used to define the circumstances under which renewable energy projects of all sizes, technologies and procurement mechanisms can or cannot be incorporated into each of the Hawaiian Electric Companies' island grids. The standards, rules, criteria and processes will link closely to Hawaii's interconnection queues and must be clear, fair, transparent and unambiguous.

> The RSWG's recommendations must help to support the timely incorporation of large amounts of new renewable generation in Hawaii, subject to the following:
>
> - Renewable generation must not "substantially compromise" the reliable operation of the host island's distribution and transmission grid.
> - Renewable generation must not "markedly increase" curtailment or "meaningfully displace" other renewable generation.
>
> The group should identify, analyze and assess reliability and curtailment concerns. The RSWG should review and recommend additional operational, infrastructure and policy measures that the utilities, renewable energy providers, regulators and others could adopt to improve renewable generation use and grid reliability.
>
> While the RSWG will analyze reliability and curtailment issues and develop recommendations for how to improve renewables integration and grid reliability, the Public Utilities Commission will evaluate the RSWG's recommendations and decide which are reasonable to implement. The PUC, rather than the RSWG, shall decide which measures are not cost-justified or impose unreasonable costs upon ratepayers, generators or others.[2]

The Commission charged the RSWG to work as a surrogate for the PUC to develop fair, clear, factual, analytically based solutions that are consensus-based and serve the public interest. Additionally, the Commission made it clear that the RSWG was to act in a collaborative fashion outside traditional litigated and administrative processes.

Due to the complexity of the technical issues involved, the RSWG focused on the reliability and renewables interconnection and integration issues and was not able to analyze or offer insight into the costs and cost-effectiveness of implementing these recommendations. Cost and cost-effectiveness issues require a level of analytical effort and time that was not available to the RSWG given its limited resources and time, and they are ripe for Commission consideration in future proceedings.

[2] Independent Facilitator's filing, September 23, 2011, Docket 2008-0273, p. 4, approved by the Commission on October 12, 2011.

1.2 RSWG Membership

The Commission initially offered all parties to Docket 2008-0273 the opportunity to participate in the RSWG; after the RSWG was spun out into Docket 2011-0206, the Commission opened the opportunity for additional entities to join the new docket, with the caveat that all parties to the docket were expected to be active participants who contributed to solution development. Ultimately, twenty-five entities from diverse positions and interests -- plus observers – actively participated in the RSWG with attendance at meetings, contributions to work product development, and voting on finished work. These members include:

- Utilities – HECO, HELCO, MECO (Hawaiian Electric Companies or HECO Companies), Kauai Island Utility Cooperative (KIUC) (an observer, but counted as an abstainer in every RSWG vote)
- State Counties – Honolulu, Hawaii, Maui, Kauai
- State agencies – Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (Consumer Advocate or CA), Department of Business, Economic Development & Tourism (DBEDT)
- Generators and advocates –Tawhiri Power, Hawaii Renewable Energy Alliance (HREA), Hawaii Solar Energy Association (HSEA), Hawaii PV Coalition, Sun Edison, Solar Energy Industries Association (SEIA), Molokai Renewables, South Maui Renewable Resources, Zero Emissions Leasing, Interstate Renewable Energy Council (IREC), SolarCity, Castle & Cooke
- Environmental advocates – Life of the Land, Blue Planet Foundation
- Other – HD Baker and Company

The Hawaii Public Utilities Commission set the tone for the RSWG by offering continuing leadership, monitoring and guidance by Commissioners and staff and attendance at all of the RSWG's full group meetings. The Commission's active attention and commitment to the RSWG process helped to assure that the parties kept the RSWG's

activities high on their priority list and maintained good behavior and polite relationships over the duration of the RSWG work effort.

Because the RSWG's scope was highly technical, the Commission, the utilities and several of the parties brought in engineers and consultants with utility and renewable issue expertise to perform many crucial technical analyses and contribute to drafting reliability standards and interconnection processes and agreements.[3] Additionally, the group benefited from a series of technical briefings about Hawaii's island utility systems, utility operational issues (e.g., grid frequency, PV monitoring, renewables impacts on the distribution grid, turbine cycling, and several recent studies on renewables integration prospects in Hawaii) and resource options (including battery energy storage systems, hydro pumped storage, and automated demand response).

1.3 RSWG Process and Procedures

This description of the RSWG's process and procedures is intended to help those readers who were not RSWG participants understand and appreciate the high quality of the group's work products and the factors that ultimately made the RSWG successful.

In its early stages, the RSWG meetings and discussions were characterized by an apparent high degree of mistrust between the parties (particularly relative to the utilities' staff), a lack of shared understanding about technical issues, and a deep desire for hard and fast rules and procedures to manage the non-traditional, non-litigated RSWG

[3] The Commission's technical consultant, Brendan Kirby, performed insightful analyses of utility generator minimum load cycling patterns that proved pivotal to the RSWG's work. Additionally, most of the members of the Reliability Standards Drafting Group were engineers brought in by the parties to assure the development of technically sensible, effective and appropriate reliability standards for Hawaii. Last, the utilities committed extensive staff and consultant expertise and time to the work of the RSWG in a highly collaborative effort.

proceeding. In response, the Independent Facilitator adopted and used a number of rules and practices to manage the proceeding over its 19-month duration. These included:

- Strict participation and voting rules – Pursuant to direction from the Commission, the Facilitator identified to the Commission those parties that did not attend meetings consistently, actively participate in subgroups, nor vote on early issues, and asked the Commission to drop those parties from the RSWG. The rationale for this was that given the importance of the RSWG recommendations, active RSWG participation and attention was necessary to ensure high quality proposals that reflected the group's diverse interests but respected the island systems' significant needs, and these proposals deserved evaluation and voting by stakeholders who understood the terminology, issues and compromises before the issue came to vote.

- Consensus but no blackballs -- The RSWG's stated goal was to recommend policies and practices that enjoyed consensus support from the group. But given the prospect that a group composed principally of independent generators with a minimal number of utility votes, and a group that had more lawyers than engineers, the Facilitator imposed rules to prevent the possible tyranny of majority vote over sound engineering. To that end, any recommendation that received a majority of votes from the group was deemed approved by the full RSWG and sent forward to the Commission. But if any party dissented, it was responsible for submitting a statement explaining its concerns and offering alternate language, if any, to address those concerns; importantly, those concerns were to be framed in terms of the public interest and the impacts of the issue upon grid reliability, renewables success and ratepayer impacts. Where individual parties deemed dissents necessary, those dissents are identified and included in this package of work products for the Commission's consideration.

- Protective order to cover proprietary data – There was considerable frustration within the RSWG's non-utility members over the group's inability to access and analyze "business confidential" data possessed by the utilities. To resolve this issue, the group created a protective order to cover distribution and use of such data and analyses, but that order was not available for signature until late November 2011, and many of the members did not sign the order until a forced deadline in late January 2012. Once the confidential data sharing and analyses began – coincident with the end of an extended series of technical briefings which elevated the group members' grasp of the technical issues -- the RSWG began performing high-quality analyses and developing good insights and recommendations.

- Subgroups – As the RSWG began recognizing the breadth and complexity of the issues before it, we created subgroups to address sets of issues and develop recommendations to bring before the full group. All members were welcome to join one or more subgroups (although the Reliability Standards Drafting subgroup

was initially limited to those with significant utility operating and standards development experience). Subgroup scopes varied and assignments changed over time; some met monthly or bi-monthly and those meetings were announced to the full RSWG so that other members could monitor the subgroups as time permitted. The subgroups were led by group members and had minimal interference or oversight from the Commission or Independent Facilitator. The subgroup members hashed through numerous issues and achieved consensus or near-consensus on almost all work products before their recommendations were sent up to the full RSWG for presentation, discussion and vote. If a subgroup member was not happy with the final subgroup recommendation, that member filed a dissent with the final RSWG vote explaining the nature of the disagreement.

The subgroups were created and scoped based on initial understanding of the issues that had to be addressed, but as time progressed and group working relationships deepened, several groups expanded their scope markedly. The subgroups and their scopes were:

- Gap Analysis – identify relevant studies and analyses of renewable development potential and integration in the islands, and what is and is not known
- IRP Coordination – what RSWG work products and information should feed into the parallel Integrated Resource Planning docket
- Reliability Definitions and Metrics – develop a common vocabulary; how to measure reliability; ancillary services
- Reliability Standards Development – assess and develop reliability standards tailored for Hawaii and large generator interconnection requirements
- Minimum Load & Curtailments – how much curtailment is occurring; what is causing curtailments and how to reduce them
- Photovoltaics & Distributed Generation – share PV data with the utility to help understand PV generation patterns; develop better DG/PV interconnection and queuing processes
- Demand-side Options – identify energy efficiency, demand response and energy storage options to support renewable integration and protect grid reliability.

- Tight timelines – The RSWG began work in July 2011, and the Commission set a firm deadline of December 2012 for the completion of the RSWG's work (but then allowed the group to hold a final meeting in January 2013 to consider and vote on the work performed in December 2012. The RSWG prepared a workplan in fall 2011 to outline its anticipated work products and work schedule, and generally met that schedule while delivering additional work products. The Commission's hard deadline for the RSWG (as distinguished from the greater ambiguity of litigated proceedings, which offer ample opportunities for delay) helped to keep the group focused and on time.

- Process courtesies and efficiencies – We attempted to run the RSWG in ways that were fast, flexible, and efficient but courteous and firm. RSWG full group and subgroup meeting times were scheduled and announced weeks in advance of each meeting; draft meeting agendas were distributed at least two weeks before each meeting; and after some early problems with late distribution of briefing documents made it difficult for RSWG members to prepare adequately for meetings, we required meeting materials to be distributed seven days before a full RSWG meeting to facilitate thoughtful discussion and voting. All RSWG full group meetings and most subgroup meetings offered teleconferencing options to facilitate participation by members and contributors on the neighbor islands and on the mainland.

  The RSWG met about every two months for the first year, and more frequently in the latter half of 2012. Formal votes occurred in meetings and occasionally via email following a face-to-face meeting and discussion.

  RSWG and subgroup materials and communications were all shared by email to the full group or subgroup, using regularly updated contact lists. Once the RSWG process began, only the Independent Facilitator sent formal filings and work product about the RSWG to the Commission (except for those occasions when the Commission asked for feedback through an order). The Facilitator filed quarterly progress reports with the Commission, including work products. The Commission has stated that it will consider and act on all of the RSWG's work products at the conclusion of the Group's work.

2.0 RSWG Work Products

2.1 Listing

The table below lists all of the work products that the RSWG has completed and collectively approved.

As the table indicates, not every item the RSWG adopted received uniform or unanimous support. But despite the occasionally controversial nature of the issues studied, it is a mark of the RSWG members' hard work and commitment that they have started from widely divergent positions, worked through a wide range of technical issues, and crafted thoughtful explanations and recommendations that enjoy overwhelming

support from the group as a whole. In some cases, one or more stakeholders have laid out their concerns in commentary on a specific issue; that written commentary accompanies each relevant document (see list in the Table). Again, the fact that a party felt it necessary to comment or dissent on an RSWG proposal should not diminish the reality of approval by a large majority of the RSWG members.

All of the RSWG final work products – and a few documents prepared by other parties to support the RSWG's work -- are submitted to the Commission in a package of 80 documents that accompanies this report.

APPROVED WORK PRODUCTS OF THE HAWAII RELIABILITY STANDARDS WORKING GROUP AND VOTE COUNT AND WORK PRODUCTS ASSOCIATED WITH THE RSWG

RSWG-Approved Reliability Standards					
Standards	**Title**	**Approve**	**No**	**Abstain**	**Member comments and dissents**
HI-BAL-001	Real Power Balancing Control Performance (modified 1/25/13)	17	1	1	Tawhiri
HI-BAL-002	Disturbance Control Performance	18	0	1	
HI-BAL-502	Planning Resource Adequacy Analysis, Assessment and Documentation	18	0	1	
HI-MOD-010	Development and Reporting of Steady State System Models and Simulations	20	0	1	CA
HI-MOD-012	Development and Reporting of Dynamic System Models and Simulations	20	0	1	CA
HI-MOD-016	Actual and Forecast Demands, Net Energy for Load, Controllable DSM and Distributed Generation	20	0	1	CA
HI-MOD-025	Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources	20	0	1	CA
HI-MOD-026	Verification of Models and Data for Generator/Transmission Equipment Excitation System or Plant Volt/VAr Control System	20	0	1	CA
HI-MOD-027	Verification of Models and Data for Governor and Load Control or Active Power/Frequency Control	20	0	1	CA
HI-PRC-006	Under-frequency Load Shedding *(approved in concept)*	Majority		1	
					HECO comments on standards implementation

RSWG-Approved Policy Recommendations				
Work product	**Approve**	**No**	**Abstain**	**Voter comments and dissents**
Standards development framework • Proposed standards development framework (overview) • Proposed reliability standards framework (details) • Qualifications for the standards ballot body • Standards development process flowchart	16	0	3	Consumer Advocate comments
PV & DG				
PV Rule 14 H modifications	14	0	2	
PV Interconnection queuing	14	0	2	
PV proactive analysis	14	0	2	
Minimum Load & Curtailment				
Recommendations for cycling capabilities and minimum load capabilities of new generation	16	4	1	**Against**: CA, HECO, HD Baker **For**: Tawhiri **Responses**: DBEDT, HSEA
Recommendations for central station ancillary services requirements	14	0	3	
Recommendations for contractual treatment for curtailment whitepaper	14	4	3	CA, HECO
Other				
RSWG Glossary of terms	18	0	1	
Demand response white paper	14	0	4	
Recommendations on GE Ancillary Services Study	18	0	1	
Integrated Resource Planning subgroup recommendations	Majority	0		

Additional work products from subgroups, not adopted by RSWG, with relevant comments or dissents				
Gap analysis subgroup final report with list of completed and recently initiated study activities for the three utilities				
Reliability Standards Drafting subgroup final report and recommendations • Complements to the recommended standards listed above -- List of active NERC standards (A-1), standards the RSWG recommends for adoption in Hawaii (A-2), standards the RSDG is considering but have not reviewed for applicability to Hawaii (B-1), standards the RSDG is not recommending for adoption in Hawaii (C-1 and C-2), standards glossary (D) • Reiteration of the standards development framework -- Potential framework for development and implementation of electric utility reliability standards in Hawaii (D-1); proposed reliability standards program organization (D-2); development of the registered ballot body and segment qualification guidelines (D-3); proposed standards development, balloting and approval framework (D-4); NERC statement of compliance registry criteria (D-5) • Recommended large generator interconnection procedures and interconnection study process for the Hawaiian Electric Company				HECO comments on LGIP
PV subgroup final report • Includes rationale for all of the recommended changes to Rule 14H and interconnection screens • Includes recommendations for next steps				
Minimum Load & Curtailments subgroup final report				
Reliability Definitions & Metrics subgroup final report				

Completed RSWG-associated work products performed on behalf of the RSWG but not adopted by the RSWG				
Kirby analysis of HELCO minimum load operations & wind curtailment (spring 2012) *(filed under protective order, not included)*				
Kirby analysis of MECO minimum load operations & wind curtailment (spring 2012) *(filed under protective order, not included)*				
HECO cycling study of HELCO and MECO operations in 2013 (January 2013)				HECO (Ching) comments on HELCO/MECO cycling study final report
GE Energy Consulting Ancillary Services Study (under contract to HNEI) (December 2012)				

Several additional papers included in the RSWG package offer recommendations and reports from the RSWG subgroups. These papers are subgroup work products that were shared with the full Work Group but did not require full RSWG approval. These papers explain the subgroups' work products (i.e., those listed above), offer additional recommendations (for instance, the Reliability Standards Drafting subgroup offers an initial recommendation for a large generator interconnection process and standard agreement), and may offer observations, lessons learned and next steps for the Commission's consideration.

The RSWG has benefited from the opportunity to leverage and learn from the resources of several other organizations, with studies that were developed specifically for the RSWG or that predated the RSWG's work but inform it nonetheless. These analyses were conducted for or shared with the RSWG; while they are not formal RSWG work products, they should be considered as complements to the RSWG's work:

- PUC consultant Brendan Kirby conducted analyses of historical HELCO and MECO minimum load operations and wind curtailment practices in 2011. These analyses were conducted for the RSWG's Minimum Load & Curtailment subgroup with advice and oversight by that group. Due to the sensitive, proprietary information included in these studies, the Commission filed the studies under the Protective Order that was filed in this proceeding in November 2011. Mr. Kirby's studies are therefore not attached to this report.

- In response to the Kirby minimum load and curtailment studies, the Hawaiian Electric Companies initiated a more detailed set of studies of generator cycling capabilities and the renewable curtailment implications of current and possible central station operational patterns. Based on early results and analyses about curtailment issues, the Hawaiian Electric Companies developed and shared a work plan in September 2012 that made significant commitments for continuing generator modifications and changes in operational practices to reduce renewable curtailments going forward. The Hawaiian Electric Companies and its consultants completed its studies and presented them to the RSWG on January 24, 2013; the HELCO/MECO Cycling Study Final Report is submitted as an RSWG-associated work product, with additional comments from the Companies on its plans going forward.

- Thanks to financial support and contract management from the Hawaii Natural Energy Institute, the RSWG was able to secure consulting services from GE Energy Services to prepare a report that defines all ancillary services in performance-based, technology-neutral terms, lays out a method and process for determining the amounts of each ancillary service needed for a given mix of generation. and offers suggestions on how to acquire an economical portfolio of ancillary services. The Reliability Definitions and Metrics subgroup provided review and guidance for this effort and the GE Energy Services team gave several detailed briefings to the full RSWG and the subgroup. The GE Ancillary Services Study is filed in this package as an RSWG-associated work product, along with comments from the Hawaiian Electric Companies on the study.

- The National Renewable Energy Laboratory is now completing the multi-scenario, multi-year Hawaii Solar Integration Study (HSIS), that examines the operational implications of several high-penetration wind and solar generation scenarios for several island grids. The RSWG benefited from three NREL briefings as the study progressed. The HSIS work is a public document and will not be included in this filing.

2.2 Descriptions of major RSWG work products by theme

The RSWG's work focus can be broken into three large themes – reliability standards, new generation interconnection, and system operational flexibility and renewable generation curtailments. These themes cut across much of the RSWG's work and the subgroups' task assignments, as reflected below.

2.2.1 Reliability standards

Since the Hawaiian Electric Companies have operated for years with internal operational reliability practices, but absent formally documented reliability standards, creation of such standards was a priority for the RSWG. The Reliability Standards Drafting subgroup, composed primarily of experienced engineers with utility operational experience, reviewed all of the existing reliability standards adopted by the North

American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission for mandatory usage on mainland North America. The subgroup then drafted ten standards (encompassing the topics in 24 NERC standards) for priority adoption in Hawaii; all of these standards were adopted in full or concept by the RSWG.

The RSWG work product package includes both the text of the ten proposed standards and synopses of the standards. It should be noted that most of these standards cannot be finalized for compliance purposes until there is a year or more of operation and monitoring – specific to each island utility system -- to determine whether each standard in fact contributes to reliability, and is calibrated in a fashion that creates no unanticipated adverse effects on system reliability, renewable operations or ratepayer cost.

The Standards Drafting subgroup's final report offers a recommended process for testing and adopting those standards, and recommends what additional topics (as defined in the NERC standards) should and should not be developed into standards for Hawaii. As the entities that will be subject to these reliability standards, the Hawaiian Electric Companies offer observations on the work that will be required to implement each of the proposed standards, including the timeline to be expected for calibration, impact analysis, operator training, implementation, monitoring, and application for compliance purposes.

Recognizing that the RSWG's time would end before all necessary reliability standards would be drafted and finalized for compliance purposes, the Reliability Standards Drafting subgroup also prepared a proposed framework for the organizational structure and process that could be used in implementing the Hawaii Electric Reliability

Authority,[4] to develop additional reliability standards in the future. This framework was adopted by the full RSWG.

The Reliability Definitions & Metrics subgroup developed and the RSWG adopted a glossary of terms early on; we now recommend that the Commission adopt the glossary for use in its electricity-related regulatory proceedings. The Standards Drafting subgroup developed additional glossary terms specific to the reliability standards (see RSDG final report Table A-3), but that glossary has not been integrated into the initial RSWG Glossary and it may be prudent to delay doing so until the Commission determines how and when to implement the Hawaii Electricity Reliability Authority.

2.2.2 System operational flexibility and renewable curtailments

One of the charges from the Commission to the RSWG was to look at ways to avoid having new renewable generation cause curtailments of existing generation; and wind generators and renewable advocates within the RSWG were eager to find ways to reduce curtailment of existing generation. The fundamental questions that the RSWG and utilities addressed were, how can a utility that wants to maximize renewable energy use (intermittent and dispatchable) do so while protecting system reliability and minimizing fuel, operations and purchased energy costs? And since high levels of system flexibility are needed to achieve these conflicting goals, what are the ways to increase system flexibility and how much of the burden for assuring flexibility must be borne solely by the utility, or shared with generators and customers?

To address these questions, the RSWG and utilities began a number of initiatives:

[4] See Act 166, Session Laws of Hawaii 2012.

- The Hawaiian Electric Companies initiated a detailed set of studies to update its understanding of generator cycling costs and model the reliability consequences of operating fewer generators at minimum load levels. These studies confirmed that by modifying must-run generation requirements and operational procedures, HELCO and MECO can reduce the number of generators operating at minimum load and reduce most if not all of existing curtailments while still assuring reliable, secure system operations the following day. The utilities have committed to changing their dispatch practices accordingly – although the consequences to equipment of greater unit cycling are not yet fully known – and anticipate significant reductions in renewable generation curtailments and in fuel costs (savings from not keeping a third generator running at minimum load). This was a utility work product, rather than an RSWG work product, so the RSWG applauds the results but was not in a position to adopt the utility's findings.

- The Minimum Load & Curtailment (MLC) subgroup developed a white paper recommending minimum cycling capabilities of new central station generation for greater operational flexibility (to avoid the prospect that new generation exacerbates future renewable curtailments without improving reliability markedly). Principal ways to increase system flexibility and better use renewables are to:

    - Reduce generators' minimum operating level, enable its automated governor control range from minimum to maximum load, and enhance its ramping ability and on/off cycling capability to at least daily cycling.
    - Power purchase contracts should provide full access to a generator's operational capabilities and flexibility (e.g., do not use take-or-pay contracts, contract-specified minimum loads or fixed operating schedules).
    - Power purchase contracts should reflect the true real-time marginal operating cost of energy for each generator, to give more accurate incentives to both the system operators and generators to economically optimize real-time power system operations.

  The RSWG adopted these recommendations (albeit with concern voiced over the potential costs of such flexibility, and whether these recommendations might be construed to limit the Commission's flexibility in approving future generator contracts).

- To support the RSWG's work, the Hawaii Natural Energy Institute contracted with GE Energy Services (GE) to prepare a study on how to better define, use and procure ancillary services to enhance system reliability and renewables use. The GE Ancillary Services Study identifies the diverse resources that can be used to maintain system reliability and better integrate intermittent renewable resources, and provides guidance on how a utility might assemble a portfolio of such resources.

The Reliability Definitions & Metrics (RDM) subgroup monitored progress of the GE study and offered comments on the study that adopt all of the GE study's recommendations for ancillary service provision – including that future renewable generators in Hawaii be required to provide more ancillary services to take more of the burden off the utility generators and operators. The full RSWG adopted these RDM-GE recommendations.

The Hawaiian Electric Companies comment on the GE study's recognition that it will probably be necessary to incentivize future variable resources to provide ancillary services, and encourage careful study before introducing such compensation or unbundling ancillary services. The utilities offer to undertake a study utilizing the proposed methodology in the GE study "to determine the required level of ancillary services and then assess costs [and risks] under a variety of options."

- The Demand-side Options (DSO) subgroup developed a white paper and recommendations on how to use demand response – paying customers to moderate their loads at advantageous times – to increase electric system operational flexibility, rather than requiring all of the flexibility and system response to come from generators. Like the GE Ancillary Services study, the DSO paper documents that demand-side and energy storage technologies can provide high-value ancillary services effectively, and lays out a variety of program delivery options for the utilities' and Commission's consideration. The RSWG adopted these recommendations.

- The MLC subgroup prepared a white paper recommending that new central station generator contracts have ancillary services capabilities to reduce renewables curtailments. This paper explains why ancillary services are valuable and recommends that each utility establish an analytical process to define the ancillary service requirements necessary for reliable and efficient operations and a mechanism for securing them at the lowest cost. The paper offers a number of recommendations on assessing the need for various ancillary services, acquiring those ancillary services (including through mandatory requirements on generators), testing and validating resource ancillary service capabilities, the role of demand response and storage to meet those needs, and appropriate valuation and compensation for ancillary service provision. The RSWG approved the white paper, subject to the Consumer Advocate's dissent expressing concern over the potential costs that compensation to generators for ancillary services provision might impose on customers, particularly if a generator is not able to provide the full set of needed ancillary services.

- Continuing on the issue of renewable curtailments, the MLC subgroup prepared a white paper on potential contractual treatments of curtailment for variable resource independent power producers. This paper seeks to identify ways to "provide the correct economic signals to facilitate increased use of renewable energy" – particularly by exposing the utility to each generator's actual marginal

production cost for energy -- but does not attempt to address all of the complications associated with modifying existing IPP contracts. The paper includes commentary on alternative contract and pricing structures, and from HECO on a "tiered-energy purchase agreement" option, and recommends that the Commission open a proceeding to study these options further. The RSWG adopted this paper, with detailed dissents from the Consumer Advocate (concerned over the paper's unproven assertion that different contract structures would reduce ratepayers' costs) and the Hawaiian Electric Companies (which, among other concerns, opposes paying producers for curtailed energy).

2.2.3 New generation interconnection

One of the Commission's early charges to the RSWG was to improve and streamline the renewables interconnection process; it became clear that this was needed for both small, distributed generation (principally installed rooftop photovoltaics, which are doubling annually across Hawaii) and central station generation under Independent Power Producer contracts. The RSWG unanimously adopted a suite of policy recommendations to address DG-level renewables interconnection, and offers recommendations from a subgroup for a way to advance large generator interconnection.

In Order 30371,[5] the Commission directed the RSWG to "craft recommendations on new, streamlined interconnection screening processes for DG" for the HECO Companies using three frontier-pushing approaches for DG interconnection – the National Renewable Energy Laboratory Report, "Updating Interconnection Screens for PV System Integration," a California Public Utility Commission agreement revising California's distribution-level interconnection tariff (Rule 21), and the DG screening process used by KIUC. The Commission also directed the RSWG to resolve inconsistencies between Hawaii's net energy metering (Rule 18) and distributed

[5] Issued by the Commission in May 2012.

generation interconnection screens (Rule 14H) and recommend a process that covers DG interconnection regardless of energy procurement method.

The RSWG has done this through the work of the PV-DG subgroup, offering a suite of recommendations that were unanimously adopted:

- Revisions to Rule 14H with a new, transparent interconnection screening process (based on the sources directed by the Commission) that should allow more projects to interconnect expeditiously without sacrificing safety, reliability and power quality. The rationale for the modified screens is explained in detail in the PV subgroup's final report.
- A proposal to manage all distribution-level interconnection requests with a new queuing proposal that would give the utility and all developers "a window into the interconnection procedures and the status of projects" within the queue for each area of the queue. This could be integrated with the Hawaiian Electric Companies' Feed-in Tariff queue process.
- A proposal to enhance the monitoring and controllability of PV production, including sharing PV developers' data on PV production with the utility and plans to expand the HECO Companies' PV monitoring network across the distribution grid.
- A proactive approach for the HECO Companies to plan for higher penetrations of DG, which may require additional tariff modifications.

The RSWG believes that more time and effort is needed to harmonize the Rule 14H revisions with other parts of Rule 14H, as well as to allow participation by additional stakeholders. Therefore, we recommend that the Commission set up a new proceeding for this purpose, the scope of which is outlined in the PV subgroup's final report.

The Reliability Standards Drafting subgroup took on the challenge of developing a proposed interconnection agreement and study process for large generators, but was unable to complete that work within the time available. The subgroup's final report offers initial proposals for a new standardized large generator interconnection agreement and study process (in Appendix E), and offers the services of the subgroup to continue working with the utilities to complete this task and submit the result for Commission and stakeholder consideration. The Hawaiian Electric Companies comment on the proposed

large generator interconnection procedures, including the suggestion that Interconnection Requirements Studies be made a top priority and offering a work plan to complete the generator interconnection procedures in the months ahead.

3.0 Next steps

Because of the high quality of the RSWG's work products and the fact that they enjoy high levels of support from the members, the Independent Facilitator recommends that the Commission treat the RSWG's work products as the equivalent of stipulated, negotiated agreements and pour complete sets of work products on specific topics – including all relevant comments and dissents from the RSWG and any comments from the RSWG Technical Review Committee – directly into topic-specific new proceedings, and use the RSWG material collectively as a starting point for further consideration, public review, and Commission action. The Commission should expect the RSWG members to support the solutions they developed in each of those subsequent proceedings, and to elevate the quality of discussion in these and other future proceedings.

The RSWG members have recommended a number of next steps to build upon the work of this collaboration. Specific recommended next steps are included in each of the RSWG's adopted policy white papers, in the subgroups' final reports, and in closing comments filed by several of the RSWG members. Since many of these documents express recommendations on a specific topic in different ways and in differing levels of detail, this report does not compile and itemize every recommendation offered, but rather summarizes below the RSWG-recommended next steps, and some offered by the

Independent Facilitator, for the Commission's consideration and possible disposition. Readers and policy-makers should not rely on this summary list alone, but should review in detail all of the information, insight and specific recommendations offered in each of the relevant documents (listed by topic in Appendix 1) before deciding how to move forward. Rolling RSWG work products into any relevant new Commission dockets should save procedural time and shorten the participants' learning curve in those new proceedings.

In the table below, next steps proposed by the full RSWG or one or more RSWG members (as through a subgroup final report or an individual party's recommendation) are indicated by "**RSWG members:**" preceding the recommendation; where a recommended next step comes only from the IF or modifies one or more related RSWG recommendations, those are indicated by "**IF:**".

TOPIC	NEXT STEPS AND RATIONALE
Public review and RSWG member comment on the IF final report and RSWG work products	**IF:** Within the RSWG Docket (2011-0206), the RSWG members should have an opportunity to file comment on the IF's final report summarizing the RSWG's work. The TRC will be filing comments on whether there are any technical flaws or concerns within the RSWG's recommendations. Upon receipt of the above, the PUC may wish to file a closing order indicating its conclusions and intentions with respect to the RSWG's work.
	Reliability Standards
RSWG's first ten reliability standards	**IF:** Open a proceeding for review and comment on these proposed standards as written, with the stated intent to adopt these standards as written (unless in-docket comments offer substantive reasons why such adoption would be contrary to the public interest). Include the RSWG's and HECO Companies' commentary on the anticipated process for calibration and final implementation of the standards and follow the process as identified. Formalize data collection from utilities on these standards for calibration and assessment purposes, and set a tight schedule that runs from the start of the standards docket to adoption of the proposed standards, through assessment and calibration against operating data, to final adoption for compliance purposes.
Establish HERA	**RSWG members:** Establish the HERA and use that entity to initiate the process of adopting the RSWG's recommended reliability standards and standards adoption process. **IF:** The Commission should determine whether it wishes to adopt the RSWG's recommended standards development framework as proposed. The Commission should also determine whether HERA should play a role in tracking the Hawaiian Electric Companies' performance relative to the proposed reliability standards and in eventual calibration of the standards for final adoption.
Framework for new standards development	**RSWG members:** Open a proceeding on the Hawaii Electric Reliability Authority (HERA) and pour the RSWG recommendations into it. The Commission should determine whether it wishes the RSWG's Reliability Standards Drafting subgroup (or an expanded group) to draft additional reliability standards (per the RSDG's proposal).

Operational Flexibility and Curtailments	
Operational flexibility	**RSWG members:** The HECO Companies should: • Verify the EPS cycling study results and determine how to implement the findings. • Accelerate implementation of all the operating procedures and generator asset equipment modifications and enhancements to reduce curtailment as the system moves to further increase renewables use. • Stop using the term "must run" and refer to specific ancillary services and flexibility characteristics when addressing unit commitment and operating constraint challenges and needs. **IF:** The PUC should open a new docket for energy resource and ancillary services procurement.
Central station generator capital modifications and contract modifications for greater operational flexibility	**RSWG members:** The PUC should open a new docket addressing all utility operating resource enhancements, procedures, etc. **IF:** Unless the Commission is comfortable addressing the following topics sua sponte, open a fast proceeding on how to determine the value and cost-effectiveness of utility equipment modifications and contract modifications to increase operational flexibility, enhance ancillary services, and reduce renewables curtailments in the future. If the IRP docket will not address this point, issue an order that gives the utilities specific parameters for an avoided cost or other method to use as a prudence threshold for cost-effective generation (and contract generation) fleets. The alternative to setting a specific avoided cost or other specific thresholds and deadbands for prudence in contract negotiations and equipment modifications is for the utility to bring in such options one at a time for Commission consideration and approval, which will introduce levels of uncertainty and delay that Hawaii's electric system and energy investors cannot afford. Ask the utilities to pursue the initiatives proposed in Mr. Ching's comments on the HELCO/MECO cycling study. Direct the utilities to file regular reports on the costs, savings and operational impacts of generation equipment modifications already made.
Ancillary services	**RSWG members:** The RDM subgroup's comments on the GE Ancillary Services Study contain several recommendations for a future docketed proceeding. Those include: • Assess the feasibility of incorporating the ancillary service recommendations (both with respect to performance

	capabilities and compensation) into future standard large generator interconnection agreements. • Conduct cost-benefit analysis concerning any modifications to electric utility procurement of ancillary services consistent with the GE Study's recommendations. • Assess the feasibility and risks of restructuring existing power purchase contracts to allow for the purchase and acquisition of ancillary services from these facilities as unbundled service providers • Refining development and implementation of a methodology to identify the type, amount and method of supplying and procuring needed ancillary services. • Determine a method for valuing ancillary services for purposes of compensating or penalizing generators, storage or demand response providers for their ability to deliver needed ancillary services. • Determine the appropriate role of production cost modeling in determining ancillary services needs, impacts and costs. • Validate the capability of demand response and energy storage to deliver ancillary services. The MLC ancillary services paper, adopted by the RSWG, offers a number of recommendations on specific ancillary services. These should be incorporated into the proceeding recommended above. **IF:** The PUC should open a new docket to assess the relative costs, benefits and cost-effectiveness of alternative reliability-enhancing measures and ancillary services provision measures, and look into how the costs and value of providing such measures can be unbundled. The HECO Companies, in their comments on the GE Study, offered to model ancillary services and costs -- ask them to do so within the scope of the above docket. Frame the scope of this study effort to include all of the analytical issues raised above (as noted in the interconnection discussion above). It may be useful to pull together a group of RSWG participants to work with the utility staff on this effort. Roll the GE Study and recommendations into the IRP docket, to factor ancillary services portfolio concepts into new resource plans.

Demand response (DR)	**RSWG members:** Ask the utilities to take a fresh look at developing demand response programs and measures designed to deliver specific system operational needs, not just to update or expand traditional load management offerings. In particular, the utilities should be directed to pursue recommendations from the ancillary services and demand response paper, and do much more automated DR. Direct the utilities and Hawaii Energy to assist with the on-going energy efficiency and demand response potential study, and to figure out how (under PUC oversight) to divide up the customers, end uses and load reduction or flexibility capabilities in a way that allocates customers and end uses between EE and DR to minimize customer confusion while maximizing grid flexibility and cost-effectiveness. Direct and oversee on-going collaboration between the utilities and Hawaii Energy to assure that EE and DR are explained and marketed to customers in a coherent fashion, to prevent both confusion and possible cannibalization between the two programs and resource options. The IRP process should incorporate cost-effective energy efficiency and demand response into a year-by-year plan.
New Generation Interconnection	
Distributed generation interconnection	**RSWG members:** Take the collected recommendations from the RSWG on PV-DG interconnection and queuing and related topics and open a new docket to evaluate and build upon and implement the substantive recommendations offered: • Revise Rule 14H with a streamlined interconnection screening process • Adopt a Proactive Approach to integrate DG interconnection and distribution system planning • Create a distribution-level interconnection queue • Continue sharing data between the PV industry and the HECO utilities. • Determine whether modifications to Hawaii's current net energy metering regime are appropriate given the new interconnection guidelines and rising levels of PV on utility distribution feeders. This effort may entail examination and integration of Rules 14H, 18, 19, the Feed-in Tariff, and others. **RSWG members:** Identify those interconnection screens and processes that can be implemented more expeditiously, such as the Proactive Approach, and implement them as quickly as possible subject to Commission review (rather than waiting for completion of another collaborative process).

	IF: In its final report, the PV subgroup raises a number of equity and cost allocation issues (between DG owners and between DG owners and the utility and its ratepayers) in addition to pure process/technical issues. It might be feasible to handle the equity and cost allocation issues in a new multi-stakeholder process similar to the RSWG, to gain a faster resolution than might be possible through a formal rulemaking.
Interconnection for large generators	**RSWG members:** Ask the RSWG's Reliability Standards Drafting subgroup to meet with HECO to continue this work and bring back consensus proposal by specific deadline. **IF:** Consider inviting additional stakeholders with technical expertise to join the effort. Make it clear that a standard interconnection agreement, terms and conditions, and study procedures are needed and give the group a tight timeline for delivering a mutually acceptable proposal (that would then be made available for review and comment before adoption). Note that the GE Ancillary Study – and its recommendations, adopted by the RSWG via the comments of the Reliability Definitions & Metrics subgroup – recommends eight ancillary services measures that should be incorporated into new variable generation contracts. Similarly, the RSWG-adopted paper on central station ancillary services requirements offers more detailed recommendations on requirements that should be rolled into contract terms for new generators. Both sets of recommendations should be assessed as part of any continuing large generation interconnection effort. **IF:** As discussed below in the section on ancillary services, the GE study, the RDM and central services ancillary services papers, and the Consumer Advocate and HE Companies' comments all identify new analyses needed to understand the feasibility, potential costs, value, and compensation method for acquiring ancillary services through new generation requirements. These studies should be initiated earlier rather than later, since they should inform the Commission's decisions with respect to how to frame and compensate ancillary services requirements in large generator terms and conditions and the associated contract provisions. Based on the RSWG recommendations pertaining to central station flexibility and ancillary service provision, issue firm policy guidance that all new generators (renewable or not) will be expected to deliver some minimum required level of ancillary services and operational flexibility and the PUC is open to hearing

	justification for the costs of such ancillary services and flexibility. Anticipate the possibility that the Feed-in Tariff and pricing levels may have to be changed to reflect the potential costs to generators of delivering ancillary services. Also consider whether price decrements or premiums should be paid if an IPP can deliver more or less flexibility and ancillary services relative to the FIT-specified level, and give the utility some guidelines for how to issue RFPs and negotiate contracts with terms that differ from the desired or required level of flexibility and ancillary services.

Other topics	
Glossary	**IF:** Adopt the RSWG Glossary and use it in all subsequent PUC electric proceedings and filings, and direct parties practicing before the Commission to use this terminology in future filings and discussions. There is great value in having everyone understand the same meanings for the same terms, given the importance and cost of the issues being discussed, and miscommunications can cause significant controversy and delay. At such time as the Commission adopts new reliability standards, update the Glossary with the new standards-related terms identified in the RSDG's final report (Table A-3).
New utility business model	**IF:** The Hawaiian Electric Companies, more quickly than its counterparts on the mainland US and elsewhere, are facing a continuing erosion of its ratebase at the same time as its load served shrinks due to the combination of price-induced conservation, self-generation (particularly roof-top PV) and energy efficiency. At the same time it is being asked to perform the increasingly complex job of maintaining and improving reliability and holding down costs while integrating and increasing its take of third-party generation and renewable energy.

High wind generation v. high distributed PV and impacts on utility operations and ratepayer costs	**IF:** As the HSIS points out, growing levels of rooftop PV are rapidly changing the utility customers' load profile while reducing total system energy demand. This will cause cannibalization between small PV and big wind as follows: under current regulations, small PV will be able to operate without curtailment (and thus will impose greater requirements for peak capacity and ancillary services), but (absent aggressive energy storage or DR requirements at the customer/feeder) increasing levels of intermittent PV will place greater demands on central station minimum load operation to effectively integrate and backstop the growing levels of PV. This will in turn force higher levels of curtailment of wind generation (absent great improvements in the ability of new and current wind generation to provide the ancillary services and capacity now delivered by dispatchable central station generation). Consider starting a new collaborative process that addresses the technical, equity and policy implications of this issue, to anticipate and develop possible regulatory solutions for this challenge.
PV equity issues	As the amount of installed rooftop PV grows within Hawaii, it is creating significant economic cost transfers between groups of Hawaii's citizens. These include the fact that Hawaii taxpayers are providing tax credit subsidies for new PV that do not accrue to non-PV owners; the feeder upgrade and operational requirements that increasing levels of PV impose upon utility customers; and as more PV owners (often more affluent citizens) generate their own energy, they leave fewer customers remaining on the utility system to pay for the fixed capital and operational non-energy costs of system operations. Overall, there are a number of inter-related equity issues relating to the impacts of growing PV upon Hawaii's citizens, and it may be useful to open another collaborative proceeding to explore these issues and develop recommendations for how to address them fairly and constructively before levels of PV grow even higher.
TRC briefing	**RSWG members:** The RSWG subgroup chairs offer to brief the members of the RSWG's Technical Review Committee on the Group's and subgroups' recommendations.

Merits of the RSWG's work

The Independent Facilitator believes that the RSWG has effectively addressed the Commission's charge to find ways to increase renewable generation interconnection and reduce renewable curtailments in Hawaii while protecting grid reliability. The RSWG's work can be distinguished from the output of other Commission proceedings by the following considerations:

- The RSWG's recommendations address many inter-dependent technical issues with useful, sophisticated, long-term solutions to evolving, long-term challenges. The RSWG members rose above their traditional roles and economic interests to reach agreements about complex technical and economic issues based on sophisticated technical understanding and analyses. It is notable that each of these agreements and proposals is broadly supported and where there are dissents, those dissents are thoughtfully and narrowly framed in valid operational and public interest concerns, or raise issues that went beyond the RSWG's time and scope (in particular, questions of whether these solutions might raise costs to Hawaii's electric customers or restrict the Commission's future regulatory options).

- The Independent Facilitator believes that because the RSWG's work spanned so many issues, the members were forced to think and work far outside the typical silos that limit typical docket- and issue-specific work addressed in litigated or administrative regulatory proceedings. This broad issue scope enabled the group to develop much better quality, and better coordinated, solutions to a universe of issues than would have emerged from stove-piped issues within individual dockets operating in parallel or sequentially absent the RSWG. Additionally, while the RSWG took over a year to set up, and 19 months from first to last meeting, resolution of these issues could have taken years longer if handled in individual dockets.

- Due to the broad scope and high stakes of the RSWG proceeding, a number of parties brought in high-quality expertise and resources that might not otherwise have been committed – in toto -- to a Hawaii regulatory proceeding. This meant that the RSWG's work products reflect and distill many decades of experience and expert insight gained in utility operations, standards drafting and policy discussions from across the United States and the world.

- Thanks to the extended cross-education, lengthy discussions and close work required by the RSWG participants, many of the group members have developed a greater appreciation for their colleagues' positions, challenges and constraints. Many of the members developed more nuanced positions on key issues as their

knowledge of the issues and analytical results increased, and the utility staff in particular gained a new, laudable appreciation for the value of their non-utility colleagues' creative contributions.

Over the course of the RSWG's work together, we have seen significant movement in the attitudes and positions of the RSWG members. Overall, the members have moved from initial veiled or overt hostility to cooperation and have grown to value the opportunity to work together and explore new ideas together. And the parties have reached unprecedented agreements and collaborations, as evidenced by the PV developers sharing production data with the utility to improve PV generation forecasting and the Hawaiian Electric Companies modifying their prior feeder interconnection limits for new PV and agreeing to modify their unit commitment practices to reduce renewable generator curtailments.

In closing

As this report illustrates, the RSWG has accomplished most of the charges placed upon it by the Public Utilities Commission. The RSWG's body of work offers a solid, integrated foundation for the Commission, electric industry stakeholders, electricity customers, and the State of Hawaii to continue their world-leading effort to increase the amount of renewable energy used in Hawaii while protecting grid reliability and moderating customer costs.

The Independent Facilitator thanks the Public Utilities Commission of Hawaii (Commissioners and staff) for their courage in using an unpredictable, non-traditional process to address a large suite of inter-related problems, engaging me for the job of Facilitator, and for providing strong support for the Facilitator and strong direction to the

RSWG. The Independent Facilitator also thanks all of the RSWG members and the many contributors (listed in Appendix 2) who participated in this extraordinarily challenging yet productive process. In particular, the subgroup leads[6] stepped into undefined and ultimately long-running and time-consuming roles to coordinate and lead diverse groups of stakeholders through complicated issue development to high levels of agreement, and the high quality of the RSWG's work products reflect their leadership, determination and persistence as well as the hard work of the subgroup members.

The RSWG process has revealed that non-confrontational, collaborative efforts to resolve complex problems can be highly successful. The IF encourages the Commission to consider using such processes again to address other pressing issues before the Commission. The RSWG members and their colleagues should also bear in mind the potential benefits of talking together and advising each other on these complex issues, and should continue or initiate such discussions – particularly on RSWG issues – without waiting for PUC to direct them to do so in a docketed proceeding. This is a good path to develop sophisticated, wide-ranging public interest solutions that can be evaluated and implemented in a time-efficient fashion.

Respectfully submitted,

Alison Silverstein

Alison Silverstein
RSWG Independent Facilitator
March 17, 2013

[6] The subgroup leaders were: Doug Codiga (RDM), Sandra-Ann Wong (MLC), Bash Nola (RSDG), Brad Albert and Dora Nakafuji (PV-DG), Lisa Giang (IRP), Leon Roose, Jose Dizon and Marc DeNarie (Gap Analysis), and Will Rolston (DSO).

APPENDIX 1
HAWAII RELIABILITY STANDARDS WORKING GROUP DOCUMENTS LIST

DOCUMENT NAME	ITEM NUMBER
1 -- OVERALL	
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DBEDT Statement on all RSWG Work Products	1-3
Comments of the Hawaiian Electric Companies Regarding Next Steps and Further Process	1-4
DBEDT Comments in Response to Independent Facilitator's Request for Recommendations on Additional Work	1-5
Blue Planet Foundation – RSWG Findings & Recommendations Going Forward	1-6
Reliability Standards Working Group Glossary of Terms	1-7
RSWG Recommendations Regarding IRP	1-8
RSWG Gap Analysis Subgroup Final Report	1-9
Gap Analysis Team List of Completed and/or Recently Initiated Study Activities for the Three Utilities	1-10
2 -- RELIABILITY STANDARDS	
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Table A-2 Standards the RSWG is Recommending for Adoption in Hawaii	2a-3
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Table B-1 Standards the RSWG is considering, but have not reviewed to determine applicability to Hawaii	2a-5
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2b Proposed Hawaii reliability standards	
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HI-BAL-502-0 synopsis	2b-22
HI-MOD-010-0 synopsis	2b-23
HI-MOD-012-0 synopsis	2b-24
HI-MOD-016-0 synopsis	2b-25
HI-MOD-025-0 synopsis	2b-26
HI-MOD-026-0 synopsis	2b-27
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2c Standards development framework	
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D-2 Proposed Reliability Standards Program Organization	2c-2
D-3 Development of the registered ballot body and segment qualification guidelines	2c-3
D-4 Proposed standards development, balloting and approval framework	2c-4
D-5 NERC Statement of Compliance Registry Criteria	2c-5
Consumer Advocate's Comments to the RSWG Work Products and Recommendations Presented at the December 11, 2012 Meeting – 1. RSD Recommendations for the Standards Development Framework	2c-6
3 -- CURTAILMENT, FLEXIBILITY AND ANCILLARY SERVICES	
3a Subgroup final reports	
Minimum Load & Curtailment Subgroup final report	3a-1
Reliability Definitions & Metrics Subgroup final report	3a-2
3b Cycling & curtailments	
RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation	3b-1
Consumer Advocate's Dissent to the "RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation"	3b-2
Hawaiian Electric Companies' Dissent to RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation	3b-3
Hawaiian Electric Companies mark-up of "RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New	3b-4

Generation"	
Hugh Baker September 27, 2012 Memo on MLC Subgroup "Flexibility" Recommendation	3b-5
Tawhiri Power LLC Comments and Responses on the "RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation"	3b-6
Life of the Land letter to the Commission re RSWG Recommendations re Minimum Load & Curtailment	3b-7
Comments of DBEDT in support of the Recommendation of the MLC Subgroup	3b-8
Hawai'i Solar Energy Association's September 25, 2012 Comments Re: RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation	3b-9
Potential Contractual Treatments for Curtailment of Variable Renewable IPPs	3b-10
Consumer Advocate's Dissent to the MLC Paper Regarding Contractual Treatments for Curtailment of Variable Renewable IPPs	3b-11
Hawaiian Electric Companies' Dissenting Comments on the MLC Subgroup's Potential Contractual Treatments for Curtailment of Variable Renewable IPPs Paper	3b-12
Hawaiian Electric Companies' mark-up of the MLC Subgroup's Potential Contractual Treatments for Curtailment of Variable Renewable IPPs Paper	3b-13
Hawaiian Electric Companies' Comments on Potential Contractual Treatments for Curtailment of Variable Renewable IPPs Paper	3b-14
HELCO/MECO Cycling Study, Final Report, January 24, 2013	3b-15
Comments of the Hawaiian Electric Companies Regarding HELCO/MECO Cycling Study Final Report	3b-16
3c Ancillary services	
GE Ancillary Services Definitions and Capability Study Part 1 – General	3c-1
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Consumer Advocate's Comments to the RSWG Work Products and Recommendations Presented at the December 11, 2012 Meeting -- 2. MLC Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities	3c-7

3d Demand response	
Demand Response as a Flexible Operating Resource -- RSWG Demand Side Options Subgroup	3d
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4b PV-DG interconnection	
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PV-DG Subgroup Draft Interconnection Queue Language	4b-3
PV-DG Rule 14H sections 2 & 3 (clean)	4b-4
PV-DG Rule 14H sections 2 & 3 (redlined)	4b-5
RSWG PV Subgroup Distributed Photovoltaic Monitoring	4b-6
RSWG PV-DG Subgroup Summary of Proposal for Proactive Review Approach	4b-7
DBEDT Comments on PV Subgroup Final Report	4b-8

APPENDIX 2
List of RSWG Members and Contributors

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DATED: March 17, 2013

SIGNED: Alison Silverstein

Alison Silverstein

DBEDT STATEMENT ON ALL RSWG WORK PRODUCTS

The Department of Business, Economic Development and Tourism ("DBEDT") has been honored to participate in the Reliability Standard Working Group ("RSWG") process, including the various subgroups established for this proceeding. DBEDT has also reviewed the final work products and subgroup reports submitted during the RSWG proceeding. DBEDT appreciates the opportunity provided by the Independent Facilitator to comment by February 1, 2013 on each of the Final Subgroup Reports, and DBEDT concurrently submits its comments on the PV Subgroup Final Report.

Due to the interrelated nature of the various work products and recommendations in the final reports of the various subgroups, and in turn their relationship to the studies, orders and reports that relate to, but are not considered official RSWG work product, DBEDT hereby reserves its rights to submit formal comprehensive comments upon the Independent Facilitator's submission of her final report to the Hawaii Public Utilities Commission ("Commission") and in any other future opportunity for comment that the Commission may establish. *See e.g.*, Order No. 30694 *Clarifying Certain Procedural Matters*, Docket No. 2011-0206 (filed Oct. 18, 2012) at n.3 (noting that the Commission plans to allow the RSWG parties an opportunity to comment on the work product and final report filed by the Independent Facilitator). *See also id.* at 4-5 (noting that the Commission will allow the RSWG parties an opportunity to comment on the Technical Review Committee's report).

February 1, 2013

Consumer Advocate's Comments to the RSWG Work Products and RSWG Subgroup Reports

The Consumer Advocate respectfully offers the following general comments to the RSWG work products and subgroup reports. The Consumer Advocate thanks the Public Utilities Commissioners, their staff, Alison Silverstein, as Independent Facilitator ("IF"), Brendan Kirby, as consultant to the Commission and resource to the RSWG and the parties for their efforts in the RSWG process.

The Consumer Advocate notes that it has provided comments already that have been included in the IF's previous reports and will not reiterate those comments. The Consumer Advocate does want to note that, at the direction of the Commission, the focus of the RSWG process was to identify the potential technical solutions and concepts to meet the RSWG objectives, rather than focus on cost issues at this time. As such, the Consumer Advocate endeavored to defer the issue of ratepayer cost impacts to allow a focus that was anticipated to identify a broader set of technical solutions from which a more thorough analysis could be conducted to evaluate cost impacts to ratepayers. With this thought, the Consumer Advocate notes that it had several concerns and continues to have remaining concerns, especially with work products and recommendations of the Minimum Load and Curtailment ("MLC") subgroup as its work products and recommendations are based on more general analyses or assertions of cost savings.

Efforts were made by the parties to address the Consumer Advocate's concerns with several MLC work products and recommendations. Within the RSWG process, analysis was conducted to assess the technical aspects of cycling existing generating fossil fuels on HELCO and MECO (i.e., stability studies, estimating cycling costs). Also the recommendations of the MLC recognized that further analysis is needed to assess the reasonableness of implementing its recommendations (e.g., assess the reasonableness of requiring ancillary services from central generation stations). For MLC work products that proceeded to the voting process and for which the Consumer Advocate has remaining concerns, comments and dissents have been provided.

In general, the Consumer Advocate notes that although much work has been conducted within the RSWG process, the RSWG also recognizes that more work is necessary to move forward to assess the reasonableness of implementing the recommendations and work products that were developed within this process. Examples of such work will include assessing the pursuit of cost-effective solutions and ensuring that ancillary services from as-available sources (e.g., synthetic inertia, demand response programs) are implemented in a manner that will not impact electric service and reliability nor increase costs to ratepayers. Additional discussion, review, and analysis are critical to ensure that ratepayers receive the utmost benefits as the State moves forward in meeting its sustainability goals and will allow a formal and transparent process in which other stakeholders and interested parties can participate. The Consumer Advocate looks forward to these future endeavors and continuing work set forth by the RSWG.

DBEDT COMMENTS IN RESPONSE TO INDEPENDENT FACILITATOR'S REQUEST FOR RECOMMENDATIONS ON ADDITIONAL WORK

The Department of Business, Economic Development and Tourism ("DBEDT") appreciates the Independent Facilitator's request for comments on additional work that should be conducted next. DBEDT encloses as Attachment A to these comments, a copy of the remarks DBEDT made during the conclusion of the January 24, 2013 Reliability Standards Working Group ("RSWG") meeting, which is responsive to this request.

DBEDT reiterates its first two points from the January 24 comments, i.e., that the Hawaii Public Utilities Commission ("Commission") should establish the Hawaii Electricity Reliability Administrator ("HERA") as soon as possible and initiate the process for adopting the Reliability Standards that have been developed by the Reliability Standards Drafting Group ("RSDG"). In response to the Independent Facilitator's request, DBEDT submits that the work of the RSDG is extremely well-suited for continued collaborative processes until such time as the HERA or other Commission processes are initiated for reliability standards development and enforcement and supports such continued activities.

DBEDT also takes this opportunity to expand on the third recommendation set forth in DBEDT's January 24 comments (i.e., follow-on processes that should be undertaken). Specifically, DBEDT recommends that the Commission open a new "Interconnection Procedures" docket, which would comprehensively consider the following interrelated issues: (1) the PV Subgroup's recommendations for revisions to Rule 14H and other related revisions needed to Rules 14H, 18, 19, the Feed-in Tariff and other tariffs and procedures; (2) the draft Generator Interconnection Procedures ("GIP") that were developed by the Hawaiian Electric Companies ("HECO") at the very end of the RSWG process and the pending items outlined in the RSDG Subgroup Final Report related to the GIP; and (3) the Proactive Approach process and related issues identified in the PV Subgroup Final Report. As to the latter issue, DBEDT reiterates its comments regarding the PV Subgroup Final Report that the PV Subgroup should immediately identify any procedures that can be implemented on an expedited basis to achieve cost-effective and reliable interconnection of renewable resources subject to full vetting and administrative processes.

DBEDT also believes that a new docket should be opened in the very near future to address the types and amounts of ancillary services that can be acquired by various means to enhance such capabilities. Related issues that should be considered include the operating characteristics of existing and future generation and demand resources, the costs and benefits of the various ancillary services recommendations in the various subgroup work products, the system reliability thresholds and levels associated with the provision of these services, and the technical capabilities and cost effectiveness of other means of providing ancillary services such as energy storage and demand response to support increased penetration of renewable resources.

DBEDT also recommends that the Commission address utility resource operation enhancements that would serve to minimize or eliminate curtailment during excess generation periods, and otherwise reduce costs. Some of the strategies identified during the RSWG process, including those mentioned in the HECO/EPS Cycling Study Presentation of January 24, 2013, should be considered for accelerated implementation. For instance, HECO should be required to identify those procedures, such as revamping the manner in which the HELCO and MECO systems engage in unit operational commitments, which can be reliably and efficiently implemented immediately to achieve the associated objectives. In addition to incorporation of such methods on an accelerated basis, DBEDT also believes that the HECO Companies should be required to report on the implementation of those methods to the Commission.

ATTACHMENT A
CONCLUDING COMMENTS OF DBEDT
JANUARY 24, 2013 RSWG MEETING

On behalf of DBEDT, I would first like to thank the Independent Facilitator for her leadership in overseeing this proceeding. I also want to thank Brendan Kirby for his substantive analysis and work products on behalf of the Commission. His work has been invaluable to this process. Thanks also to the subgroup leads and the parties for working in good faith and tackling complicated issues and producing quality work product for the Commission's consideration. DBEDT also thanks the members of the TRC, whose significant and unique qualifications on these issues will provide valuable assistance to the Commission as it reviews the work products and recommendations.

As this proceeding wraps up, DBEDT looks forward to the opportunity to comment on the Independent Facilitator's report. In the meantime, DBEDT offers the following comments in response to Alison's December 18 request for next steps.

As a threshold matter, we stress the need to remain mindful of the underlying basis for our efforts – the fact that Hawaii has enacted specific legislation and has articulated clear policies designed to maximize the amount of renewable generation that is interconnected to Hawaii's grid. All Commission decisions stemming from this docket should be made against that backdrop.

Moving from the general to the specific, DBEDT submits that the Commission should take three specific actions, as soon as possible, to further the state's renewable energy goals.

One, the Commission should act promptly and establish the Hawaii Electricity Reliability Administrator or HERA. DBEDT submits there is broad support for establishing the HERA to assist the Commission in its efforts to establish and enforce the Reliability Standards that are necessary to ensure that the maximum amount of renewables can be interconnected to the grid on a reliable basis.

Two, the Commission should initiate the process to adopt Reliability Standards for Hawaii. The RSWG has presented the Commission with proposed Reliability Standards that include performance metrics, were developed through a stakeholder process, and are backed by technical analyses. In addition to the RSDG's work, in its report filed on December 27, 2012, Sandia National Laboratory identified a suite of standards that it recommends be adapted and applied in Hawaii. The RSWG has also approved a framework that – leveraging the work of the RSWG and Sandia with a stakeholder process overseen by the Commission or its designated administrator – could be used to facilitate the development of additional Reliability Standards that can be tailored to meet Hawaii's profile and submitted for Commission approval.

Three, the Commission should commence follow-on processes to address issues that would benefit from further exploration in an effort to maximize reliable interconnection of renewable energy into the Hawaii systems, including those recommended in the various subgroup reports.

For instance, DBEDT supports procedures that will promote an open and transparent Proactive Approach process pertaining to the HECO Companies' distributed generation, interconnection, distribution and transmission planning functions, including through opportunities for comment and reporting requirements to ensure the Proactive Approach meets its stated goals.

DBEDT also supports holistic consideration pertaining to accommodation of greater levels of renewable energy, including through use of energy storage, ancillary services and demand response, as well as evaluation and development of more standardized interconnection procedures and agreements.

In closing, DBEDT supports an "all of the above" strategy to meeting Hawaii's renewable energy goals and believes that the time for action is now without delay. All the amount of work and studies that still need to be completed is not an excuse for delay. DBEDT commends the Commission for initiating this proceeding and reiterates its appreciation of the efforts put forward by all interested parties. DBEDT looks forward to continued explorations of these issues and how they can further the State's objective of achieving a clean energy future.

Thank you.

RSWG Findings & Recommendations Going Forward

Submitted by Blue Planet Foundation

February 1, 2013

Background:

The RSWG has concluded its work and final reports have been prepared by the individual Sub-groups. The following is an attempt to synthesize all the work that has been done and to suggest to the RSWG Technical Review Committee and PUC a plan for initiating what Blue Planet Foundation believes to be critical next steps in adopting and expanding the work of the RSWG into existing and/or new PUC dockets toward advancing the increased penetration of renewable generation resources on the Hawaii electric systems.

Recommended Next Steps:

1. To facilitate the TRC review of the RSWG work, it is recommended that the working group chair persons brief the TRC members on the work that was accomplished and any open issues the chair persons feel relevant. If would afford an opportunity for the TRC members to ask questions for clarification purposes.
2. The PUC should form HERA as soon as possible in order to begin the adoption and follow on process of implementing the Reliability Standards developed by the RSWG – RSDG and continue to develop the full set of required standards.
3. Related to the above, open a docket to include affected Stakeholders to fully vet, adopt, and implement the Reliability Standards developed under the RSWG process, including the recommendations given in the RSDG Final Report and continue development of additional standards. Perform a cost effectiveness impact analysis as needed.
4. In the interim, allow the RSDG to continue its standards drafting work to allow a smooth transition into HERA through a collaborative effort by stakeholders.
5. Open a new Interconnection Procedures docket to address the following:
    a. Rule 14H recommended revisions, the melding of the provisions of Rule 18, Rule 19, SAS, and FIT processes for consistency.
    b. The Generation Interconnection Procedure/Process (GIP), including the formation of a Generation Interconnection Agreement (GIA). Much of this work can be accomplished in a continuing collaborative effort open to all stakeholders prior to opening a new docket to fully vet the process and resulting procedure.
    c. The Proactive Approach to distribution planning to promote timely identification of network upgrades to accommodate increased penetration of DG resources.
    d. Related issues identified both in the PV and RSDG Reports.

e. Incorporate/expand interconnection requirements to include additional Ancillary Service capabilities.

6. Regarding #5 above, industry stakeholders and HECO management have expressed a desire to continue the work outlined above in anticipation of the PUC opening a new docket. Acknowledgement and support of this effort from the PUC will further encourage the parties to take on this task.
7. Incorporate into the IRP docket or create a new docket to address the following:
    a. Identification of the required types and amounts of Ancillary Services and the acquisition thereof.
    b. Expand/incorporate flexible operating characteristics in existing and future generation resources.
    c. Determine system reliability thresholds and levels acceptable to consumers against costs/benefits.
    d. Determine the technical capabilities and the most cost effective method of providing the ancillary services that the electric systems need to meet the reliability thresholds including utility generators, IPP's, energy storage, demand response, and other ancillary service resources in support of increased penetration of renewable generation resources.
    e. Analyze unit operational commitments that might dictate "must run" status.
8. Based on the findings and recommendations of the RSWG direct the HECO Companies to address utility resource operations enhancements to increase the utilization of existing renewable generation resources and the increase penetration thereof to minimize curtailment during excess generation periods:
    a. Revamp existing operating procedures and create new procedures, criteria, and guidelines to implement the recommended Reliability Standards developed by the RSWG.
    b. Re-examine how generation units are committed and dispatched to achieve the least cost of reliable operation.
    c. Revamp generation AGC/governor control to improve unit response times.
    d. Make cost effective determinations of capital improvements to enhance existing generation unit minimum load capability and such measures as those identified in the Hawaii Solar Integration Study for HECO and MECO and the Stanley Study for MECO to improve overall system responsiveness to increased penetration of renewable resources and to reduce the impacts of curtailment.
    e. Verify and implement the findings of the HECO/EPS Cycling Study through a more detailed deterministic analysis to improve unit operational commitments and procedures for the HELCO and MECO systems to eliminate or substantially reduce excess energy curtailments of renewable generation.
    f. Investigate the full capability of wind and solar plants to enhance power system reliability and lower costs through appropriately compensated advanced controls

including AGC and synthetic inertia. Utilize expert assistance from entities that have successfully accomplished this elsewhere.

g. Implement computer based security constrained unit commitment and economic dispatch in the energy management systems of each utility, recognizing that analysis is cheaper than burning oil.

9. Open a new docket to address the procurement/contracting process of acquiring new generation resources that reflect the true value and marginal cost of such resources effecting unit commitment and economic dispatch.
10. Within existing energy efficiency related dockets or in a new docket address the following:
    a. Cost effective energy efficiency, and demand side management programs, the expected (quantified) customer response in terms of improvements or reduction of energy use, and the amount of demand response that can be accounted for as Ancillary Service contributions in case of emergencies and at the time of peak system conditions.
    b. Utilize demand response flexibility over all time frames to cost effectively integrate variable renewable generation and minimize or eliminate curtailment.
    c. Determine a year by year plan to achieve energy efficiency improvements and demand response contributions to the overall future generation resource acquisition plan and the need for new resources.

SJN: 01/28/13

Docket No. 2011-0206 – Reliability Standards Working Group

Comments of the Hawaiian Electric Companies Regarding Next Steps and Further Process

During the January 24, 2013 RSWG stakeholder meeting, the Independent Facilitator accepted comments from the RSWG members regarding recommendations for post-RSWG efforts and analyses. In a subsequent January 25, 2013 correspondence, the Independent Facilitator invited suggestions with regard to additional work that could be undertaken to implement the RSWG's recommendations and whether there are any topics that could better be handled through a collaborative process. The Hawaiian Electric Companies respectfully submit the following comments on these issues for the Commission's information and consideration.

The Companies appreciate and acknowledge the hard work and dedication of resources by the various RSWG subgroup members to deliberate and come to consensus on a number of recommendations for the Commission's consideration. Among those are recommendations to evaluate new processes and proceedings to consider issues such as the further development and implementation of reliability standards, contractual mechanisms to address excess energy curtailment, modifications to distribution level interconnection processes including the Companies Rule 14H, and potential methodologies to secure necessary ancillary services for the Companies' systems. The Hawaiian Electric Companies were active participants in each of the RSWG subgroups and fully support the additional process that will be required to comprehensively assess these issues and assure that implementation is conducted in a manner consistent with the maintenance of system reliability and power quality and at reasonable costs to customers.

The Companies remain open to collaborative processes to address and resolve the recommendations of the RSWG while recognizing that proceedings which will result in substantive changes to utility tariffs or the consideration of new rules will need to be consistent with relevant Hawaii Administrative Rules and Hawaii Revised Statutes. The Companies also acknowledge that a formal docketed proceeding provides all stakeholders with the protections of due process and can facilitate the effective discussion of issues through the protection of information which a stakeholder may consider confidential or proprietary. That said, institution of a docket does not mean that the process will necessarily be adversarial or contested. The procedural order that can be stipulated to by the parties and approved by the Commission may provide for diverse forms of technical and collaborative discussion in an attempt to resolve issues through a less formal mechanism before such issues and resolutions are submitted to the Commission for deliberation. The stipulated procedural order governing each proceeding and the issues unique to that particular proceeding would also include a schedule of proceedings to set forth both the procedural steps for the docket and timing associated with each step.

Regardless of whether issues are considered through a docket or through some other form of process however, the Hawaiian Electric Companies respectfully submit that such proceedings must incorporate mechanisms to ensure that the positions of all stakeholders are appropriately and fairly

considered. While the one vote per member mechanism utilized as a part of the RSWG process may have been conducive to a high level discussion and identification of issues, proceedings to develop substantive and detailed rules and requirements, which in the majority of cases will be applicable primarily if not exclusively to the utilities, must contain processes which effectively address utility and ratepayer concerns. This could include but not necessarily be limited to processes used by other energy regulatory bodies (e.g., NERC, ERCOT) in developing recommended standards for utilities. These types of processes allow stakeholder sectors to appoint voting representatives to ensure that those that are voting have the relevant technical expertise to appropriately evaluate and cognize the issues presented, and also weight the votes of such members accordingly. In essence, each stakeholder or stakeholder sector that is permitted to vote upon the standards or requirements to be imposed upon utilities and/or a generation or transmission provider, must be qualified and possess a shared and vested interest in maintaining the reliability of the electrical system for all that utilize the system.

RELIABILITY STANDARDS WORKING GROUP

GLOSSARY OF TERMS

Version 1 - 20120304

Submitted to the:

Hawaii Public Utility Commission
465 South King Street Room 103
Honolulu, Hawaii 96813

By the:

Reliability Standards Working Group
Reference: Docket No. 2011-0206

Preamble

This Glossary has been conceived and prepared by members of the Reliability Standards Working Group ("RSWG") as a compilation of general, utility-related terms, acronyms and abbreviations used in the electric power industry.

The RSWG Glossary is the result of preliminary drafts that were prepared, reviewed and subsequently revised by members of the Reliability Metrics and Definitions ("RDM") Sub-Working Group of the RSWG. The glossary will be forwarded to the entire RSWG for approval upon approval by the RDM subgroup.

Where possible, the RSWG Glossary includes actual definitions from related glossaries, such as the North American Electric Reliability Corporation ("NERC") Glossary, NERC Generator Availability Data System ("GADS") Data Reporting Instructions, Edison Electric Institute ("EEI") glossary, and IEEE Standards 1366 and 1547. Other sources, which are included in the Reference section of the RSWG Glossary, include the United States Department of Energy ("USDOE"), Federal Energy Regulatory Commission ("FERC"), and the National Renewable Energy Laboratory ("NREL"). Where a Hawaii-specific definition is needed, it is generally derived from one of the above glossaries.

Primarily, the RSWG will utilize this Glossary in the formation and understanding of recommended reliability standards to be submitted to the Hawaii Public Utility Commission ("Commission") as part of the Commission's Docket 2011-0206, entitled "Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited."

Secondarily, the RSWG believes this Glossary may serve to meet other purposes, such as communication and outreach activities with RSWG members and the general public.

Finally, the RSWG views this Glossary as a "Living Document" that will be reviewed and updated on a regular basis. It is proposed the definitions of specific terms that are incorporated into Commission-approved reliability standards will be approved by the Commission, and designated in an appropriate manner in the Glossary.

Editor of RSWG Glossary Version - 20120304
Warren S. Bollmeier, II, Hawaii Renewable Energy Alliance

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Notes to reviewers:

In some cases, multiple definitions are provided. These multiple all definitions are considered equally valid if they come from official glossaries such as EEI or NERC. Note: priority was given to the one easiest to understand or which uses language most similar to that used in Hawaii. Where a Hawaii-specific definition is warranted, it is highlighted with the following: "RSWG Proposed Definition" or it was modified within the definition.

RSWG Glossary
List of Abbreviations and Acronyms

Abbreviation or Acronym	Meaning (e.g., Stands for)
AC	Alternating Current
ACE	Area Control Error
AG	Adequacy
AS	Ancillary Services
AGC	Automatic Generation Control
CF	Capacity Factor
CHP	Combined Heat and Power
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DSM	Demand-Side Management
EEI	Edison Electric Institute
ERCOT	Electric Reliability Council of Texas
EERE	Office of Energy Efficiency & Renewable Energy, USDOE
FERC	Federal Energy Regulatory Commission
FRT	Fault Ride Through
GW	Gigawatt
GWh	Gigawatt hour or Gigawatt-hour
IEEE	Institute of Electrical and Electronic Engineers
IPP	Independent Power Producer
KV	Kilovolt: unit of voltage = 1,000 volts
KVA	Kilovolt-amp: unit of apparent power= 1,000 volt-amps
KVAR	Kilovolt-amp Reactive: unit of reactive power = 1,000 volt-amps reactive
kW	Kilowatt: unit of real power = 1,000 watts
kWh	Kilowatt-hour: unit of energy = 1,000 watt-hours
LVRT	Low Voltage Ride Through
MV	Megavolt: unit of voltage = 1,000,000 volts,
MVA	Megavolt-amp: unit of apparent power = 1,000,000 volt-amps
MVAR	Megavolt-amp Reactive: unit of reactive power = 1,000,00 volt-amps reactive
MW	Megawatt: unit of real power = 1,000,000 watts
MWh	Megawatt hour: unit of energy = 1,000,000 watt-hours
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NUG	Non-Utility Generator

RSWG Glossary
List of Abbreviations and Acronyms

PV	Photovoltaic
PF	Power Factor
RPM	Revolutions per minute
PQ	Power Quality
PU	Per Unit
PURPA	Public Utilities Regulatory Policy Act
QF	Qualifying Facility
QLPU	Quick Load Pick-Up
RPG	Reliability Performance Gap
RPS	Renewable Portfolio Standards
USDOE	United States Department of Energy
V	Volt; unit of voltage
VA	Volt-amp: unit of apparent power
VAR	Volt-amp Reactive; unit of reactive power
VG	Variable generator
VRF	Violations Risk Factor
VSL	Violation Severity Level
W	Watt: unit of power
Wh	Watt hours; unit of energy
WECC	Western Electricity Coordinating Council

RSWG Glossary
Terms

Ancillary Services - Those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission provider's transmission system. Ancillary services include:

> **Black Start Service** An ancillary service acquired for the benefit of all loads provided by generating resources capable of starting without support of the transmission grid.
> **Non-Spinning Reserve Service** An ancillary service that provides operating reserve not connected to the system but capable of serving demand within a specific time, or interruptible load that can be removed from the system in a specified time. Generally, the capacity needs to be able to be brought on-line within ten minutes, or the interruptible load needs to be removed within ten minutes.
> **Regulation and Frequency Response Service** An ancillary service which provides for following the moment-to-moment variations in the demand or supply in a control area and maintaining scheduled interconnection frequency.
> **Replacement Reserve Service** An ancillary service that is procured from generation resource units planned to be off-line, but requiring more that ten minutes to be brought on line; and load acting as a resource that are available for interruption during the period of requirement.
> **Spinning Reserve Service** An ancillary service provided by generators and interruptible/dispatchable load resources that are already synchronized to the power system and can respond to instructions to change output level within a specified amount of time (typically 10 minutes).
> **Voltage Support Service** An ancillary service that is required to maintain transmission and distribution voltages on the transmission grid within acceptable limits.

Sources: EEI Glossary of Electric Industry Terms, April 2005 and NYISO Ancillary Services Manual (NYISO 1999), as modified above for Hawaii

Area Control Error The instantaneous difference between a Balancing Authority's net generation and load taking into account the effects of frequency bias.

ACE = ~~(NIA – NIS)~~ – 10B (FA – FS) – IME
(Modified for Hawaii where there is no inter-area interchange)

Source: EEI Glossary of Electric Industry Terms, April 2005 and NERC Standard BAL-001-0.1a – Real Power Balancing Control Performance, modified.

Automatic Generation Control ("AGC") Equipment that automatically adjusts generation and responsive load from a central location to maintain the utility system generation and load balance plus Frequency Bias.

Source: NERC Glossary of Terms, January 11, 2012, modified

Availability Describes the reliability of power plants. It refers to the number of hours that a power plant is available to produce power divided by the total hours in a set time period, usually a year.

Source: EERE Glossary

Availability Availability = up time/total time, expressed as a fraction where "uptime" is the number of hours in a reference period of time (e.g., a year) where the unit (generator, airplane, etc.) is either operating or in a standby-condition; and total time = up time + down time; where down time = hours where the unit is down for maintenance (routine and emergency) and cannot operate.

RSWG Glossary
Terms

Base Load Generation Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Source: EEI Glossary of Electric Industry Terms, April 2005
Base Load Unit/Station Units or plants that are designed for nearly continuous operation at or near full capacity to provide all or part of the base load. An electric generation station normally operated to meet all, or part, of the minimum load demand of a power company's system over a given amount of time. Source: EEI Glossary of Electric Industry Terms, April 2005
Behind The Meter Term used to refer to an on-site generator that is between the utility's meter and the customers' load. Sometimes referred to as "Behind The Fence." Source: RSWG Proposed Definition
Blackstart Capability The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system. Source: EEI Glossary of Electric Industry Terms, April 2005
Bulk Electric System A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system. Source: EEI Glossary of Electric Industry Terms, April 2005
Capacity Factor ("CF") The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period. Source: EEI Glossary of Electric Industry Terms, April 2005
Gross Capacity Factor ("GCF") $GCF = \frac{\text{Gross Actual Generation}}{PH \times GMC} \times 100\%$; PH = Period Hours= # hours the unit is in an active state (= 8670 hours if the unit is in an active state all year); GMC=gross maximum capacity Source: NERC GADS Version 01012011, Appendix F; added "PH=8760 (non-leap year)" statement
Cascading The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. Note: an electric system includes both utility and non-utility elements. Source: NERC Glossary of Terms, January 11, 2012, as modified with note
Central Generation ("CG") A method of producing electricity with large power plants that typically serves large areas and many customers, and requires a high-voltage bulk transmission system to deliver the power to local distribution systems. Source: RSWG Definition
Combined Heat and Power ("CHP") The simultaneous production of electric energy and useful thermal energy for industrial, commercial, heating or cooling purposes. The Energy Information Administration (EIA) has adopted this term in place of "cogeneration." Source: EEI Glossary of Electric Industry Terms, April 2005
Constrained Facility A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Reliability Operating Limit. Source: NERC Glossary of Terms, January 11, 2012

Contingency The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages. **Single Contingency** The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency. Source: EEI Glossary of Electric Industry Terms, April 2005
Curtailment A reduction in the scheduled capacity or energy delivery Source: NERC Glossary of Terms, January 12, 2012, as modified
Critical Assets Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System. Source: NERC Glossary of Terms, January 11, 2012
Cyber Assets Programmable electronic devices and communication networks including hardware, software, and data. Source: NERC Glossary of Terms, January 11, 2012
Cycling Units Units which operate with rapid load changes and frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units regulated to cycling units or newly built units of a lower megawatt rating which require less capital investment per unit of output than required for base load units. See also Base Load Unit/Station. Source: EEI Glossary of Electric Industry Terms, April 2005
Demand or Load (Electric) The rate at which electricity is being used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts (kW = 1 Kilowatt = 1000 watts), while energy use is usually measured in Kilowatthours (kWh = Kilowatts x hours of use = Kilowatthours). The term "load" is considered synonymous with "demand." ("Load" may also be defined as an end-use energy-consuming piece of equipment or customer that receives power from the electric system. Using this definition of "load," "demand" is the measure of power that a "load" receives or requires). See also Load. Source: EEI Glossary of Electric Industry Terms, April 2005
Demand Response ("DR") Load Response called for by others and price response managed by end-use customers. Load response includes direct load control such as residential air conditioners, partial or curtailable load reductions, and complete load interruptions. Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs. Source: EEI Glossary of Electric Industry Terms, April 2005

Demand-Side Management ("DSM") The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility or third party-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth. Source: EEI Glossary of Electric Industry Terms, April 2005, as modified above for Hawaii
Demand-Side Management ("DSM") The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use. The Load Serving Entity is either the electric utility or a third party administrator as designated by the PUC. Source: NERC Glossary of Terms, January 11, 2012, as modified above for Hawaii
Diffuse Radiation (or Insolation): As solar radiation passes through the earth's atmosphere, some of it is absorbed or scattered by air molecules, water vapor, aerosols, and clouds. The radiation that has been scattered out of the direct beam is called Diffuse Solar Radiation. Source: Eppley Laboratory, Newport, Rhode Island: http://www.eppleylab.com/Radiation.htm, modified
Direct Radiation (or Insolation): As solar radiation passes through the earth's atmosphere, some of it is absorbed or scattered by air molecules, water vapor, aerosols, and clouds. The solar radiation that passes through directly to the earth's surface is called Direct Solar Radiation. Source: Eppley Laboratory, Newport, Rhode Island: http://www.eppleylab.com/Radiation.htm, modified
Dispatchable Generation A generation source that is controlled by a system operator or dispatcher who can increase or decrease the amount of power from that source as the system requirements change. Source: EEI Glossary of Electric Industry Terms, April 2005
Dispatching The operating control of an integrated electric system to (1) Assign generation to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls; (2) Control operations and maintenance of high-voltage lines, substations, and equipment, including administration of safety procedures; (3) Operate the interconnection; and (4)Schedule energy transactions with other interconnected electric utilities. Source: EEI Glossary of Electric Industry Terms, April 2005
Distributed Generation ("DG") A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source, and can use various technology, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics. Also known as a Distributed Energy Resource. See also Self Generation. Source: EEI Glossary of Electric Industry Terms, April 2005, as modified above. Note: In IEEE-5547, DG are up to 20 MW (RSWG Proposed Definition)

Distribution System The network of wires and equipment that is dedicated to delivering electric energy from the transmission system to the customer's premises. Electric energy is carried at high voltages along transmission lines. For customers needing lower voltages, it is reduced in voltage at a substation and delivered over primary distribution lines extending throughout the area where the electricity is distributed. For users needing even lower voltages, the voltage is reduced once again by a distribution transformer or a line transformer. At this point it changes from primary to secondary distribution voltage.

Distribution System, Primary An alternating-current system, which connects the generating station or substation distribution buses to the distribution transformers.

Distribution System, Secndary A low-voltage, alternating current system, which connects the secondary voltages of distribution transformers to the customers serviced.

Source: EEI Glossary of Electric Industry Terms, April 2005. See also Distribution Feeder — Primary and Primary Voltage.

Disturbance An unplanned event that produces an abnormal system condition.

Source: EEI Glossary of Electric Industry Terms, April 2005

Doubly Fed Induction Generator: A type of induction generator used with some wind turbines with significant solid state electronic control that further decouples the rotational speed of the wind turbine's rotor from the power system frequency providing control of both the real and reactive power output (within the limitations of the currently available wind energy).

Source: RSWG Proposed Definition

Droop The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop.

A governor tuned with speed droop will open the control valve a specified amount for a given disturbance. This is accomplished by using feedback from the main prime mover control mechanism (valve, gate, servomotor, etc.). A simplified block diagram of a droop governor is shown in Figure 2. If a 1% change in speed occurs, the main control mechanism must move enough to cause the feedback through the droop element to cancel this speed change. Thus, for a 1% speed change, the percent movement of the main control mechanism will be the reciprocal of the droop (i.e. if the droop is 5% the movement will be 1/.05 = 20).

If the governor is tuned to be "isochronous" (i.e. zero droop), it will keep opening the valve until the frequency is restored to the original value. This type of tuning is used on small, isolated power systems, but would result in excess governor movement on large, interconnected systems. Therefore, speed droop is used to control the magnitude of governor response for a given frequency change so all generators will share response after a disturbance.

Source: WECC Tutorial on Speed Governors, February 1998, including Figure 2: http://www.wecc.biz/library/WECC%20Documents/Documents%20for%20Generators/Governor%20Tutorial.pdf

Eastern Interconnection: The Eastern Interconnection is one of the four major alternating current power grids in North America. The other major interconnections are the Western Interconnection, the Texas Interconnection, and Quebec Interconnection. All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency operating at an average of 60 Hz. The Eastern Interconnection reaches from Central Canada eastward to the Atlantic coast (excluding Quebec), south to Florida, and back west to the foot of the Rockies (excluding most of Texas). Source: RSWG Proposed Definition
Economic Dispatch The start-up, shutdown, and allocation of load to individual generating units to effect the most economical production of electricity for customers. See also Dispatching. Source: EEI Glossary of Electric Industry Terms, April 2005
Electric Energy The ability of an electric current to produce work, heat, light, or other forms of energy. It is measured in watthours. Source: EEI Glossary of Electric Industry Terms, April 2005
Electric Reliability Council of Texas ("ERCOT"): ERCOT Electricity Reliability Council of Texas is the independent system operator for the Texas Interconnection which covers 75% of the Texas land area. ERCOT has two DC ties to the Eastern Interconnection. Source: ERCOT web-site, http://www.ercot.com/about/
Emergency Rating The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. Source: NERC Glossary of Terms, January 11, 2012
Office of **Energy Efficiency & Renewable Energy** The Office of Energy Efficiency and Renewable Energy ("EERE") invests in clean energy technologies that strengthen the economy, protect the environment, and reduce dependence on foreign oil. Source: EERE web-site at: http://www.eere.energy.gov/
Fault An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection. Source: EEI Glossary of Electric Industry Terms, April 2005; and NERC Glossary of Terms, January 11, 2012 (identical definitions)

Federal Energy Regulatory Commission ("FERC"): FERC is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Energy Policy Act of 2005 gave FERC additional responsibilities for electric power system reliability. As such the Commission:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews certain mergers and acquisitions and corporate transactions by electricity companies;
- Regulates the transmission and sale of natural gas for resale in interstate commerce;
- Regulates the transportation of oil by pipeline in interstate commerce;
- Approves the siting and abandonment of interstate natural gas pipelines and storage facilities;
- Reviews the siting application for electric transmission projects under limited circumstances;
- Ensures the safe operation and reliability of proposed and operating LNG terminals;
- Licenses and inspects private, municipal, and state hydroelectric projects;
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Monitors and investigates energy markets;
- Enforces FERC regulatory requirements through imposition of civil penalties and other means;
- Oversees environmental matters related to natural gas and hydroelectricity projects and other matters; and\Administers accounting and financial reporting regulations and conduct of regulated companies.

Source: FERC at: http://www.ferc.gov/about/ferc-does.asp.

Federal Power Act ("FPA") Enacted in 1935, the Federal Power Act established guidelines for the federal regulation of a utility's sales in interstate commerce. It is the primary statute governing the FERC regulation of electric utilities.

Source: EEI Glossary of Electric Industry Terms, April 2005.

Federal Power Act ("FPA") The Federal Power Act a law appearing in Chapter 12 of Title 16 of the United States Code, entitled "Federal Regulation and Development of Power". Enacted as the Federal Water Power Act on June 10, 1920, and amended many times since, its original purpose was to more effectively coordinate the development of hydroelectric projects in the United States. Prior to this time and despite federal control of navigable waters and the necessary congressional approval to construct such facilities, Congress had left the regulation of hydroelectric power to the individual states.

Source: Federal Power Act (16 U.S.C. 791-828c; Chapter 285, June 10, 1920, with modifications

Firm Demand That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Source: NERC Glossary of Terms, January 11, 2012

Firm Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions. Source: EEI Glossary of Electric Industry Terms, April 2005
Frequency The number of cycles per second through which an alternating current passes. Frequency has been generally standardized in the United States electric utility industry at 60 cycles per second (60 hertz). Source: EEI Glossary of Electric Industry Terms, April 2005
Frequency Response (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. **Frequency Response (System)** The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). Source: EEI Glossary of Electric Industry Terms, April 2005
Generator, Electric A machine which transforms mechanical energy into electric energy. Can also include wind, solar PV and other systems that convert energy of one form into electric energy. Source: EEI Glossary of Electric Industry Terms, April 2005, as modified
Grid An interconnected network of electric transmission lines, and related facilities. Source: EEI Glossary of Electric Industry Terms, April 2005
Heat Pump A year-round air conditioning system employing refrigeration equipment in a manner which enables usable heat to be supplied to a space during the winter period and by reversing the operation cycle to extract heat from the same space during the summer period. When operating as a heating system, heat is absorbed from an outside medium (either air, water, or the earth) and this heat together with the heat equivalent of the work of compression is supplied to the space to be heated. When operating on the cooling cycle, heat is absorbed from the space to be cooled and this heat together with the heat equivalent of the work of compression is rejected to the outside medium. Source: EEI Glossary of Electric Industry Terms, April 2005
Heat Rate A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatthour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatthour generation. Source: EEI Glossary of Electric Industry Terms, April 2005
Independent Power Producers ("IPPs") Power generators that are not affiliated with a vertically integrated utility. Source: EEI Glossary of Electric Industry Terms, April 2005
Independent Power Producers ("IPPs") Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators (or combined heat and power generators) and small power producers (including net metered and feed-in-tariff systems) and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are sometimes referred to as non-utility generators ("NUGs"). Source: NERC Glossary of Terms, January 11, 2012, as modified above

Induction Generator (Asynchronous Generator) A machine built as an induction motor and driven above synchronous speed, thus acting as an alternating-current generator. Below synchronism the machine takes in electrical energy and acts as an induction motor. At synchronism the power component of current becomes zero and changes sign, so that above synchronism the machine (driven for this purpose by mechanical power) gives out electrical energy as a generator. Source: EEI Glossary of Electric Industry Terms, April 2005
Inertia ("Rotational Inertia"): Applicable to electrical generators, rotational inertia refers to the fact that a rotating body maintains its state of uniform rotational motion unless an external force is applied. For example, large generators will tend to continue rotating at the same speed if there is as a small change in the load on the generator or a variation in source of its power, e.g., wind or water, or a governor response in the case of a conventional utility generator. Generator inertia or moment of inertia is typically measured in terms of kg•m2, and the larger and heavier the generator, the larger its inertia and resistance to external forces. Thus, larger and heavier generators help maintain power system stability by resisting sudden disturbances and provide time (from cycles to seconds) for governor control actions and ultimately AGC to respond to the disturbance. Source: USDOE EERE Glossary, with modifications
Inertia ("Synthetic Inertia") It is possible to deliberately control some asynchronous generators very fast to extract energy from their prime mover (wind turbine blades, for example) and inject it into the power system during a disturbance. This mimics the rotational inertia response of conventional generators, but the response can be tailored maximize the stability benefit to the power system. Source: RSWG Proposed Definition
Insolation: The solar power density incident on a surface of solar collector's area and orientation, usually expressed as Watts per square meter. Sometimes referred to as radiation. Source: USDOE EERE Glossary, with modifications
Institute of Electrical and Electronic Engineers ("IEEE") the world's largest professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. IEEE and its members inspire a global community through IEEE's highly cited publications, conferences, technology standards, and professional and educational activities. Source: IEEE Web-Site: http://www.ieee.org/about/index.html
Interconnection Requirements (Standards) a set of technical guidelines and procedures to facilitate the interconnection and parallel operation of generating facilities with the utility system. Source: Appendix I, Distributed Generating Facility Interconnection Standards, Technical Requirements, Revised Sheet No. 34B-1, from Final Statement of Position Dated October 14, 2011, Docket No. 2010-0015.
Inverter: A device that converts direct current ("DC") electricity to alternating current ("AC") either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and LVRT capability. Source: USDOE EERE Glossary, with modifications
Leading Indicators Indicators which tend to change before the general activity, and so may be used as a predictor," for example of trends in key indices. Source: NERC White Paper, Towards Ensuring Reliability: Reliability Metrics, December 2007

Load (or Demand), Electric See also Demand. The term "load" is considered synonymous with "demand." "Load" may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of "load," "demand" is the measure of power that a "load" receives or requires. **Base** The minimum load over a given period of time. **Connected** The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration. Source: EEI Glossary of Electric Industry Terms, April 2005
Load Balancing The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions, the system operator utilizes load following and frequency regulation for load balancing. Source: RSWG Proposed Definition
Load Following An electric system's process of regulating its generation to follow the changes in the customers' demand. Source: EEI Glossary of Electric Industry Terms, April 2005
Low Voltage Ride Through Capability ("LVRT") or Fault Ride Through ("FRT") The ability of a generator or inverter to remain connected to the power system throughout and after a disturbance that may bring the power system voltage ~~to zero~~ for a brief defined period of time. The voltage may be reduced in one, two or all the three phases of the AC grid. The severity of the voltage dip is defined by the voltage level during the dip (may go down to zero) and the duration of the dip (which maybe as long as 600 milliseconds). Generally, the electric devices with this capability will be required to stay operational and not disconnect from the grid, and possibly support the grid with reactive power Source: RSWG Proposed Definition
Metrics A system of parameters or ways of quantitative and periodic assessment of a process that is to be measured," for example to quantify and evaluate: (i) past and current reliability, (ii) progress in ensuring reliability, and (iii) effectiveness of reliability standards and enforcement programs. Source: NERC White Paper, Towards Ensuring Reliability: Reliability Metrics, December 2007
Must Run Unit A Baseload Generator facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant. Source: RSWG Proposed Definition
Name Plate Capacity or Normal Rating (Capacity): The normal rated capacity of a generator or piece of electric power equipment (usually expressed in megawatts [MW]) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life. It is so called because it is often stamped on a metal plate affixed to the equipment by the manufacturer. Source: RSWG Proposed Definition

Non-Utility Generator ("NUG") A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. NUGs can be owned by an unregulated subsidiary of an electric utility holding company, and are exempt from traditional utility regulations. Historically, non-utility generation was for the purposes of supplying electric power required by the owner for use in their industrial or commercial operations, and for heating and cooling of their facilities. Non-utility generators now include cogenerators (also referred to as combined heat and power), small power producers, Exempt Wholesale Generators ("EWGs"), Independent Power Producers, and other non-utility generators.

Source: EEI Glossary of Electric Industry Terms, April 2005

North American Electric Reliability Corporation ("NERC"): NERC is a non-profit, industry self-regulatory organization that relies on the diverse and collective expertise of industry participants that comprise its various committees and sub-groups. It is subject to oversight by governmental authorities in Canada and the United States. NERC's mission is to ensure the bulk power system in North America is reliable.

Source: NERC Web-Site: http://www.nerc.com/

National Renewable Energy Laboratory ("NREL"): NREL is the only federal laboratory dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies. Backed by 34 years of achievement, NREL leads the way in helping meet the growing demand for clean energy.

Source: NREL Web-Site: http://www.nrel.gov/

Operating Voltage: Operating voltage is the voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.

Source: NERC Glossary of Terms, January 11, 2012

Outage The period during which a generating unit, transmission line, or other facility is out of service. The following six terms are types of outages or outage-related terms:

Forced Outage The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Source: EEI Glossary of Electric Industry Terms, April 2005

Peaking Generation Generating capability normally designed for use only during the maximum load period of a designated time interval.

Source: EEI Glossary of Electric Industry Terms, April 2005

Peak Load Demand The greatest demand that occurred during a specified period of time.

Non-Coincident Peak The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as day, week, month, heating or cooling season, and usually for not more than one year.

Source: EEI Glossary of Electric Industry Terms, April 2005

Peak Shaving ("Clipping") Reduction of the system peak loads. It is generally accomplished by using direct load control, applied through direct utility control of the customers' appliances. While many utilities see direct load control as a means to reduce peaking capacity or capacity purchases, and consider control only during the most probable days of the system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic load management. See also Load Management.

Source: EEI Glossary of Electric Industry Terms, April 2005

Per Unit ("PU") A system of normalizing measurements similar to percent where 100% is equal to 1.0 PU.

Source: RSWG Proposed Definition

Power: the rate at which energy supplied to a load (consumed), usually measured in watts ("W"), kilowatts ("kW") or megawatts ("MW"). The following four terms are types of power:

Apparent Power ("KVA", "MVA") The product of the current and voltage

Source: : RSWG Proposed Definition (standard definition)

Apparent Power ("KVA", "MVA") The voltage-ampere requirement of a device designed to convert electric energy to a non-electrical form.

Source: USDOE EERE Glossary

Dynamic Reactive Power: is reactive power that can be controlled rapidly and accurately

Source: RSWG Proposed Definition

Reactive Power ("Var", "kvar', "Mvar"): The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, static var compensators, statcoms, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in vars, kilovars ("kvar") or megavars ("Mvar").

Source: NERC Glossary of Terms, January 11, 2012

Real Power ("W", "kW", "MW"): The portion of electricity that supplies energy to the load and performs work. Real power is measured in watts ("W"), kilowatts ("kW"), or megawatts ("MW")

Source: NERC Glossary of Terms, January 11, 2012, with modifications

Power Factor ("PF"): The ratio of the real power over the apparent power. It is a dimensionless number between 0 and 1 (frequently expressed as a percentage, e.g. 0.5 pf = 50% pf). Source: USDOE EERE Glossary
Power Quality ("PQ"): Power Quality is the extent to which the voltage and current at a point in the power system deviate from the intended perfect sine wave. Measures of power quality include: frequency variations, voltage variations, and harmonic distortion (variations in the power waveform). Without the proper power quality, an electrical device (load, generator, transformer, etc.) may malfunction, fail prematurely or not operate at all. Source: RSWG Proposed Definition
Power Quality ("PQ"): Power Quality is the extent to which the voltage and current at a point in the power system deviate from the intended perfect sine wave. Measures of power quality include: frequency variations, voltage variations, and harmonic distortion (variations in the power waveform). Without the proper power quality, an electrical device (load, generator, transformer, etc.) may malfunction, fail prematurely or not operate at all. Source: RSWG Proposed Definition
Public Utility Regulatory Policy Act ("PURPA"): The Public Utility Regulatory Policies Act of 1978 was implemented to encourage, among other things: The conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, equitable retail rates for electric consumers, expeditious development of hydroelectric potential at existing small dams, and conservation of natural gas while ensuring that rates to natural gas consumers are equitable. One of the ways PURPA set out to accomplish its goals was through the establishment of a new class of generating facilities which would receive special rate and regulatory treatment. Generating facilities in this group are known as qualifying facilities. Source: FERC *Web-site*: http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp
Qualifying Facilities ("QFs"): Under PURPA, QFs fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities. A qualifying small power production generating facility was initially limited to 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. A qualifying cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. Source: Federal Energy Regulatory Commission (FERC) 1995 Proposed Rule on Open-Access Transmission, March 29, 1995, with modifications.
Quick Load Pick-Up ("QLPU"): The amount of additional load that an operating unit could pick up (supply) in 3 seconds in response to a system frequency decrease when the unit is not at full load. Presumably also the amount of load a customer could reduce in the same amount of time in response to the same frequency decrease. Source: RSWG Proposed Definition
Ramp Rate: The rate, expressed in megawatts per minute, that a generator changes its output or a load changes its consumption. Source: NERC Glossary of Terms, January 11, 2012, with modifications

Reliability An electricity service level or the degree of performance of the bulk power ("utility" in Hawaii) system defined by accepted standards and other public criteria[1]. There are two basic, functional components of reliability: operating reliability and adequacy. The following are definitions of ten reliability-specific terms:

Source: NERC White Paper

Adequacy The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Source: NERC Glossary of Terms, January 11, 2012, with modifications

Adequacy Gap ("AG") A measure of the capacity and energy shortage from expected adequacy level under steady state conditions.

Source: NERC White Paper, with modifications

Operating reliability The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Source: NERC White Paper

Principles of Reliability For the purpose of the discussion in the RSWG, principles of reliability are concomitant with planning and operation of the utility system to achieve and sustain an "adequate level of reliability." And adequate level of system reliability is defined as a utility system that:

- Is controlled to stay within acceptable limits during normal conditions;
- Performs acceptably after credible contingencies;
- Limits the impact and scope of instability and cascading outages when they occur;
- Protects its facilities from unacceptable damage by operating them within facility ratings;
- Restores system integrity promptly if it is lost; and
- Has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Sources: NERC Glossary of Terms, January 11, 2012; and Kahakuloa Energy Advisors, LLC on behalf of the Blue Planet Foundation, Reliability Measure Discussion, presented at the RSWG September 9, 2011 meeting; with modifications

Reliability Performance Gap ("RPG") A measure of how far the system is from expected performance under contingencies (dynamic conditions).

Source: NERC White Paper

Risk For the purpose of the RSWG, risk is measure of the potential for there to be a violation of any of the Utility Reliability Standards requirements. To indicate the level of risk, each requirement will be assigned a **Violation Risk Factor**.

Source: NERC White Paper, with modifications.

[1] There are a number of ways to define "reliability." For example, "Reliability is defined as the probability that a given item will perform its intended function for a given period of time under a given set of conditions," NASA, KSC, Tim Adams. However, for the purpose of the RSWG, the suggested definition was proposed in "for conceptual discussion only" by NERC staff (not Reference 20, but in the earlier February12, 2008 NERC Glossary), as modified in the parenthetical comments.

Standards For each utility, the set of requirements that must be met in order to comply with the reliability principles established, approved and enforced by the Commission.

Source: RSWG Proposed Definition

Standards Violation a failure or inadequacy to meet a requirement of a reliability standard by an entity identified as responsible to comply with that requirement.

Source: NERC White Paper

System Reliability Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

Source: RSWG Proposed Definition

Violation Risk Factors ("VRFs") VFRs provide clear, concise and comparative association between the violation of a requirement and the expected or potential impact of the violation on the reliability of the utility system. One of three defined levels of risk is assigned to each standards requirement: Lower Risk Factor, Medium Risk Factor, or High Risk Factor.

Source: NERC White Paper

Violation Severity Levels ("VSLs"): VSLs are measurements of the degree to which a violator violated a requirement of a reliability standard. Whereas VRFs are determined pre-violation and indicate the relative potential impacts that violations of each standard requirement could pose to the reliability of the utility system, the VSLs are assessed post violation and are indicators of how severely the violator actually violated the standard(s) requirement(s) in question. Four VSLs have been designated for each standard requirement as: Lower, Moderate, High, or Severe.

Source: NERC White Paper

Reliability Indicators The following six terms are examples of general reliability indicators:

Equivalent Forced Outage Rate ("EFOR") The hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours).

$$\text{EFOR} = \frac{\text{FOH} + \text{EFDH}}{\text{FOH} + \text{SH} + \text{Synchronous Hrs} + \text{Pumping Hrs} + \text{EFDHRS}} \times 100\%$$

Where: FOH = Forced Outage Hours; EFDH = Equivalent Forced Derated Hours; SH = Service Hours; Synchronous Hrs = Sum of all hours the unit is in synchronous condensing mode. The units are considered to be in a non-generating service operation; Pumping Hrs = Sum of all hours the pumped storage unit is in pumping mode. The units are considered to be in a non-generating service operation; and EFDHRS = Equivalent Forced Derated Hours During Reserve Shutdowns.

Source: RSWG Proposed Definition; formula from NERC GADS, January 1, 2011

Equivalent Conventional Capacity ("ECP") The amount of conventional generation reduction that results in the same level of system reliability after the addition of a variable generator to the power system.

Source: NREL, Western Wind and Solar Integration Study, May 2010

Equivalent Firm Capacity ("EFC") The amount of firm capacity reduction that results in the same level of system reliability after the addition of a variable generator to the power system.

Source: NREL, Western Wind and Solar Integration Study, May 2010

Effective Load Carrying Capability ("ELCC") The amount of additional load that can be supported by a power system (with the same level of reliability) after the addition of a variable generator.

Source: NREL, Western Wind and Solar Integration Study, May 2010; with modifications

Loss Of Load Expectation ("LOLE") Expressed in units of days per year, the number of days calculated in which a shortfall ("unserved load") occurs divided by the total number of years simulated. Historically, many utilities have used a "one day in ten year" threshold (or 0.1 day/year) to plan for reliability. While LOLE is a frequency measure, it is not a frequency measure for shortfall events because multiple events can occur during a single day and a single event can last longer than one day. It also provides no information regarding duration or magnitude of resource shortfalls.

Source: North West Power Planning Council, with modifications

Loss Of Load Probability ("LOLP") Expressed in units of *percent*, a measure of the probability that at least one shortfall event ("unserved load") will occur over the time period being evaluated. LOLP is calculated as the number of simulations in which a shortfall occurs divided by the total number of simulations. It does not reflect the frequency of events because simulations with one or multiple shortfall occurrences are counted equally. LOLP also provides no information regarding duration or magnitude of resource shortfalls.

Source: North West Power Planning Council, with modifications

Reliability Indices The following four terms are examples of generator and transmission/distribution reliability indices (See also System Operation Indices)

Average Service Reliability Index ("ASAI") The fraction of time (often in percentage) that a customer has received power during the defined reporting period.

$$ASAI = 1 - \frac{100 * \Sigma\,(\text{Customer Interruptions} * \text{Interruption Duration in hrs})}{\text{Number of Customers} * 8{,}760 \text{ hrs/year (8,784 hours if leap year)}}$$

Source: IEEE 1366-2003

Customer Average Interruption Duration Index ("CAIDI") The average time required to restore service.

$$CAIDI = \frac{\Sigma\,(\text{Customer Interruption Duration})}{\text{Total Number of Customers Interrupted}}$$

CAIDI = 30 minutes means on average, those customers affected by an outage were without power for 30 minutes.

Source: IEEE 1366-2003, with added example

System Average Duration Index ("SAIDI") The total duration of interruption for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption.

$$SAIDI = \frac{\Sigma \text{ (Customer Interruption Duration)}}{\text{Total Number of Customers Served}}$$

SAIDI = 5 minutes means on average, every customer on the system experienced a 5 minute outage

Source: IEEE 1366-2003, with added example

System Average Interruption Frequency Index ("SAIFI") Indication how often the average customer experiences a sustained interruption over a period of time.

$$SAIFI = \frac{\Sigma \text{ Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

SAIFI = 1 means on average, every customer on the system experienced one outage

Source: IEEE 1366-2003, with added example

Renewable Portfolio Standards ("RPS"): Pursuant to Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 to 269-95, each electric utility company that sells electricity for consumption in the State must establish a renewable portfolio standard of: (1) Ten per cent of its net electricity sales by December 31, 2010; (2) Fifteen per cent of its net electricity sales by December 31, 2015; (3) Twenty-five per cent of its net electricity sales by December 31, 2020; and (4) Forty per cent of its net electricity sales by December 31, 2030.

Source: Hawaii Revised Statutes § 269-2(a)

Reserves: The following are definitions for five types of reserves

Non-Spinning Reserve: Generating reserve not connected to the system but capable of serving demand within a specified time (within 10 minutes in NERC Regions) and interruptible load that can be removed from the system in the same specified time.

Source: NERC Glossary of Terms, January 11, 2012, with modifications

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Source: NERC White Paper

Regulating Reserve: Generation and responsive load on automatic generation control that is used for Frequency Regulation.

Source: NERC White Paper

Spinning Reserve: The portion of Operating Reserve consisting of:

Generation synchronized to the system and fully available to serve load within a specified time (within 10 minutes in NERC Regions); or

Reserve (including responsive load) that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system and which

is capable of fully responding within ten minutes.

Source: NERC Glossary of Terms, January 11, 2012

Supplemental Reserve: The portion of Operating Reserve consisting of:

Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within a specified amount of time (30 minutes in some regions); or

Load fully removable from the system within the same specified amount of time.

Source: NERC Glossary of Terms, January 11, 2012

Smart Grid A type of electrical grid which incorporates appropriate hardware and software to collect data which can be used to predict and intelligently respond to the behavior and actions of all electric power users connected to it - suppliers, consumers and those that do both – in order to efficiently deliver reliable, economic, and sustainable electricity services.

Source: Kahakuloa Energy Advisors, LLC on behalf of the Blue Planet Foundation, Reliability Measure Discussion, presented at the RSWG September 9, 2011 meeting with modifications.

Storage For the purpose of the RSWG, storage is defined to be a system or a device capable of storing electrical energy to serve as an ancillary service resource on the utility system and/or to provide other energy services. Four types of storage are defined as follows:

Source: RSWG Proposed Definition

Battery An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and blackstart as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Note: also referred to as Battery Energy Storage ("BES")

Source: USDOE EERE Glossary, with modifications

Compressed Air Energy Storage ("CAES") Compressed air energy storage uses excess or low-cost electricity during off-peak periods to compress air to higher pressure. The compressed air can be stored in man-made vessels or underground caverns. The compressed air is then released as input to an air turbine or engine during higher value, peak electricity periods to generate electricity A relatively small amount of fuel is normally added to the compressed air stream to increase the amount of electricity generated. CAES facilities can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and blackstart as well as energy services such as peak shaving and energy arbitrage.

Source: USDOE EERE Glossary, with modifications

Flywheel A flywheel is a cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Source: USDOE EERE Glossary, with modifications

Pumped-Hydro Pumped hydro facilities *typically* use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water up hill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facilities can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and blackstart as well as energy services such as peak shaving and energy arbitrage. Source: USDOE EERE Glossary
Self Generation A generator installed on a customer's side of the utility meter that provides electricity for a portion, or all, of that customer's electric load. See also Distributed Generation. Source: EEI Glossary of Electric Industry Terms, April 2005 See also: Behind the Meter
Synchronous Generator An electrical generator that draws its magnetic excitation independently of the grid and runs at a constant speed that is "locked" to the grid frequency. As a synchronous generator is "started up," its internal control system is designed to insure that the generator's frequency is exactly 60 Hz before connecting the generator to the grid. Source: USDOE EERE Glossary, with modifications
System For the purpose of the RSWG, system refers to the utility grid: A combination of generation, transmission, and distribution components. Source: NERC Glossary of Terms, January 11, 2012, with modifications
System Operation Indices The following six terms are examples of system operation indices:
Adequacy of Supply Source: TBD
Balancing authority ACE limit ("BAAL") Source: TBD
Control Performance Standard 1 ("CPS 1") Source: TBD
Control Performance Standard 2 ("CPS 2") Source: TBD
Disturbance control standard ("DCS") Source: TBD
Generator Availability Conventionally, availability is defined as uptime/total time, where "uptime" is the numbers hours the "generator" is able and ready operate, regardless whether it is not operated, as in the case of a conventional generator that is not dispatched or a wind turbine or PV system that are "standing by" for the wind or sun. Total time, as in 8760 hours in a year, and consists of uptime + downtime, which includes scheduled or routine maintenance and emergency or repair maintenance. Source: RSWG Proposed Definition. See also: Availability

System Integrity The measure of the overall health of the utility system in terms of its design and operation which can be measured in part by its reliability and stability, and other characteristics such as its ability to survive natural disasters and terror or sabotage events.

Source: RSWG Proposed Definition

System Stability Broadly defined as the criteria for a system operating within prescribed conditions, including but not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Collapse Ratings (Applicable pre- and post-Contingency Voltage Collapse)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Source: NERC Glossary of Terms, January 11, 2012, with modifications.

Transmission system An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Source: USDOE EERE Glossary

Variable Generator ("VG") A generator whose output varies with the availability of it primary energy resource, such as wind, the sun and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched down, its output can not be guaranteed 100% of the time when needed. However, the primary energy source may be stored for future use, such as with solar thermal storage, or when converted into electricity via storage technologies.

Source: RSWG Proposed Definition

Voltage ("V") A unit of electrical force equal to that amount of electromotive force that will cause a steady current of one ampere to flow through a resistance of one ohm.

Source: USDOE EERE Glossary

Voltage Control The capability to maintain system voltages within acceptable limits throughout the utility system. Voltage control requires static and dynamic reactive power resources. Because reactive power does not travel as far through the power system as real power, voltage control is a more local requirement than frequency control

Source: Proposed Ancillary Services, B. Kirby, October 31, 2011

Watt ("W") The rate of energy transfer equivalent to one ampere under an electrical pressure of one volt. One watt equals 1/746 horsepower, or one joule per second. It is the product of voltage and current (amperage).

Source: USDOE EERE Glossary

Western Interconnection: The Western Interconnection is one of the four major alternating current power grids in North America[1]. The other major wide area synchronous grids are the Eastern Interconnection, the Québec Interconnection, and the Texas Interconnection. All of the electric utilities in the Western Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency of 60Hz. The Western Interconnection stretches from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

Source: RSWG Proposed Definition

Western Electricity Coordinating Council ("WECC"): WECC is the Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states. Source: RSWG Proposed Definition
Windmill An older term referring to wind machines that historically were used to grind grain, such as in Holland and other parts of Europe, and to pump water, such as in the Great Plains of the United States. Source: RSWG Proposed Definition
Wind Turbine A modern term referring to wind machines that generate electricity Source: RSWG Proposed Definition Notes: Wind turbines, like windmills, are mounted on a tower to capture the most energy. At 100 feet (30 meters) or more aboveground, they can take advantage of the faster and less turbulent wind. Turbines catch the wind's energy with their propeller-like blades. Usually, two or three blades are mounted on a shaft to form a *rotor*. A blade acts much like an airplane wing. When the wind blows, a pocket of low-pressure air forms on the downwind side of the blade. The low-pressure air pocket then pulls the blade toward it, causing the rotor to turn. This is called *lift*. The force of the lift is actually much stronger than the wind's force against the front side of the blade, which is called *drag*. The combination of lift and drag causes the rotor to spin like a propeller, and the turning shaft spins a generator to make electricity. Source: NREL

RSWG Glossary
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RSWG Recommendations Regarding IRP

July 27, 2012

I. BACKGROUND.

In Order No. 30371 Relating to Various Matters in RSWG Process filed on May 4, 2012 in Docket No. 2011-0206, the Commission set forth the following:

> ". . . the RSWG should pay attention to potential areas of overlap with IRP, and develop a list of recommended reliability issues and/or related studies, if any, that would be more appropriately and effectively addressed in the IRP Docket [Docket No. 2012-0036] than in this docket. This list should be as concise as possible, recognizing that the IRP stakeholders will already have multiple, complex issues to tackle in a relatively short time period."

The purpose and scope of the RSWG as set forth in Independent Facilitator's Submittal RSWG Purpose, Scope and Work Plan, filed on September 23, 2011 in Docket No. 2011-0206, is as follows:

Purpose:

The RSWG will recommend fact-based standards, metrics, rules, criteria and processes to "help determine how we can interconnect the maximum amount of renewable generation to the grid while preserving grid reliability," consistent with Hawaii clean energy statutory mandates and policies. These standards, metrics, rules, criteria and processes will be used to define the circumstances under which renewable energy projects of all sizes, technologies and procurement mechanisms can or cannot be incorporated into each of the Hawaiian Electric Companies' island grids. The standards, rules, criteria and processes will link closely to Hawaii's interconnection queues and must be clear, fair, transparent and unambiguous.

The RSWG's recommendations must help to support the timely incorporation of large amounts of new renewable generation in Hawaii, subject to the following:

- Renewable generation must not "substantially compromise" the reliable operation of the host island's distribution and transmission grid.
- Renewable generation must not "markedly increase" curtailment or "meaningfully displace" other renewable generation.

The group should identify, analyze and assess reliability and curtailment concerns. The RSWG should review and recommend additional operational,

infrastructure and policy measures that the utilities, renewable energy providers, regulators and others could adopt to improve renewable generation use and grid reliability.

While the RSWG will analyze reliability and curtailment issues and develop recommendations for how to improve renewables integration and grid reliability, the Public Utilities Commission will evaluate the RSWG's recommendations and decide which are reasonable to implement. The PUC, rather than the RSWG, shall decide which measures are not cost-justified or impose unreasonable costs upon ratepayers, generators or others.

Scope:

The RSWG's recommendations will pertain to all commercially viable renewable technologies, all procurement mechanisms, and all project sizes, on all of the Hawaiian Electric Companies' grids, over at least a five-year implementation horizon.

The RSWG can evaluate and recommend solutions and mitigation options that span:

- Utility infrastructure and operational practices, including procurement
- Renewable generation equipment, practices and contract or tariff terms
- Regulatory policies and processes
- Energy efficiency, demand response, energy storage, smart grid, and related policies and programs.

The RSWG shall be cognizant of grid requirements, including transmission and distribution-level operational and infrastructure options. Among other considerations, the group should be aware of operational and planning considerations including potential generator retirements and replacements.

The group shall consider existing and on-going technical analyses performed by Hawaii's utilities and the broader electric industry and technical experts. The RSWG should identify analytical or data gaps that are hampering renewable energy integration and suggest new work needed to remedy those gaps.

II. DISCUSSION AND RECOMMENDATIONS.

The RSWG acknowledges that its purpose and scope is different from the goals of the Integrated Resource Plan ("IRP"). Specifically, the RSWG has focused primarily on technical issues with some general cost considerations related to reliability

standards and the integration of renewables on the HECO Companies' grids, whereas in IRP additional issues will be considered, e.g., determination of reasonable cost, public policy and law, and environmental and community concerns. The RSWG recognizes that the HECO Companies, the Commission, and other Parties in the IRP process will consider scenarios, strategies and options other than those considered by the RSWG. Thus, the RSWG emphasizes that it is not the intention of the RSWG to advocate or promote to the IRP any particular strategy or option that is presented below as being better than those that may be considered in the IRP Process. By providing the discussion and recommendations below, it is the intent of the RSWG to provide a summary of the potential overlap areas that was conducted in the RSWG and any recommendations that the IRP may consider the in the IRP Process.

A. RSWG Minimum Load and Curtailment Subgroup ("MLC")

Analysis was conducted in the MLC by Brendan Kirby to study the Hawaii and Maui electric grid systems during the calendar year 2011 to assess the possible solutions to resolve curtailment of existing wind farms on the islands. The Hawaii study was filed under protective order on March 9, 2012 and the Maui study was filed under protective order on July 16, 2012 in Docket No. 2011-0206.

Brendan Kirby's study identified potential options for the island of Hawaii that included: (1) retirement of a HELCO steam unit; and (2) cycling one of the HELCO steam units that is currently operated for base load.

On April 3, 2012, HECO commissioned Electric Power Systems to conduct an additional analysis utilizing the 2011 study data as a starting point to determine the impacts of 2012-2013 factors to assess the impacts of renewable energy projects during that timeframe and costs such as cycling one of the baseload steam or combined cycle units with Hawaii specific cost data. A similar assessment is underway for the MECO system.

The MLC also began investigating the value of ancillary services in acquiring new generation, which resulted in the discussion paper, Valuing Flexibility When Acquiring New Generation by Brendan Kirby, dated June 30, 2012. HECO provided comments on the paper.

Therefore, the RSWG recommends that the IRP consider as two of the strategies or options in the IRP process: (i) retiring and/or operating the fossil fuel units differently (e.g., cycling instead of base load operation), and (ii) evaluating the ability of alternative new generation, energy storage resources and demand-side resources to provide ancillary services to the system and its ratepayers.

B. Ancillary Services Subgroup

As of June 9, 2012, the Ancillary Services Subgroup is conducting a study to identify specific ancillary services that may be needed for Hawaii in functional, technology-neutral terms, and to develop clear definitions and nomenclature for these forward-looking services.

The RSWG recommends that the IRP consider, as one of the strategies or options in the IRP Process, the development of ancillary services whether provided by the utility or third party developers.

C. Reliability Definitions and Metrics

In the development of standards in the RSWG process, the RSWG has developed an RSWG Glossary of Terms, dated March 4, 2012. The RSWG Glossary of Terms may be useful for reference and may provide some transparency within the IRP process when specific electric terms are discussed. The RSWG emphasizes that the RSWG Glossary of Terms is a "living document" and as the RSWG is still working on the development of standards for Hawaii, it is anticipated that the terms in the Glossary may need to be revised or updated.

D. Reliability Standards Drafting Subgroup

The Reliability Standards Drafting ("RSD") Subgroup is in the process of drafting standards based on various sources (e.g., North American Electric Reliability Corporation ("NERC"), Alaska Systems Coordinating Council ("ASCC")).

E. GAP Subgroup

The GAP Subgroup has compiled a list of studies, which include those: (i) previously performed and of relevance to the RSWG; and (ii) conducted on account of the RSWG. These studies include, but are not limited to, the Oahu Wind Integration and Transmission Study ("OWITS"), the Maui Wind Integration Study ("WIS"), the Hawaii Solar Integration Study ("HSIS"), and the MECO Stanley Study.

F. PV Subgroup

The PV Subgroup has been developing a framework for collecting solar photovoltaic (PV) performance data from various projects and project developers over the past several months. The data is useful for modeling and analysis to determine degrees of circuit penetration and distribution system impacts, mitigation measures, and integration solutions. The PV Subgroup is also discussing potential revisions to the interconnection and queuing processes for distributed generation, including Tariff Rules 14H and 18 regarding interconnection. The discussion includes a

consideration of the recent changes to California Rule 21 (approval of settlement is pending). These efforts recognize distributed PV as a resource that should likewise be included in the IRP process.

G. Demand Side Options

The Demand Side Options (DSO) Subgroup is proposing that DSO programs be included in the IRP process as a resource option on the basis that DSO provides potential solutions for a more efficient, flexible and cost-effective Utility Generation/Transmission system. These potential solutions include energy and demand reductions, and certain types of ancillary services. The DSO Subgroup is currently evaluating the Hawaiian Electric Company – Demand Response Roadmap Project Report (provided by Lawrence Berkeley National Laboratory) and is in the process of providing feedback, alternatives, and future filtering mechanisms for good DSO solutions/integration that may be of interest to the IRP.

RSWG Gap Analysis Subgroup Final Report
January 14, 2013

I. BACKGROUND

A. RSWG Gap Analysis Subgroup

In the Independent Facilitator's ("IF") Submittal RSWG Purpose, Scope of Work and Work Plan, filed on September 23, 2011 in Docket No. 2011-0206, the following tasks were assigned to the RSWG Gap Analysis Sub-Group ("Gap Subgroup"):

> *Review relevant existing and on-going system studies relating to renewable resource integration and system reliability studies for the Hawaii Electric Companies' systems, and understand key assumptions and analytical methods used.*
>
> ***
>
> *Review and evaluate findings and recommendations of the technical studies.*

On June 1, 2012, the IF submitted an RSWG Status Report, which among other things, updated its work plan into a single summary document that reflects what each subgroup is working on and how that work inter-relates to other groups and the RSWG as a whole.

Throughout 2012, the GAP Subgroup has worked to compile and update a list of studies, which include those: (i) previously performed and of relevance to the RSWG; and (ii) which were ongoing and discussed as a part of the RSWG process. These studies include, but are not limited to, the Oahu Wind Integration and Transmission Study ("OWITS"), the Maui Wind Integration Study ("WIS"), the Hawaii Solar Integration Study ("HSIS"), and the MECO Stanley Study.

A current (as of December 2012) study list is attached to this Final Subgroup Report as Attachment A.

B. Discussion of Processes Evaluated by the Gap Subgroup

During the RSWG process, the Gap Subgroup discussed a potential integration roadmap that could facilitate the reliable and cost effective integration of renewable energy resources. The Gap Subgroup recognized that potential opportunities exist to improve the system from both the utility side as well as demand side. The sub group discussed a process to identify issues and conduct the evaluations necessary to be able to recommend scenario-based modeling tools which could be used to explore options such as, but not limited to, modifying or changing operating guidelines, improvements to the energy management system, and modifications to generating units than could

provide positive system benefits, – recognizing that supplemental consideration would have to be given to issues such as cost, long-term impacts and feasibility.

As noted above, several operational studies were or are on-going in 2012. The Gap Subgroup also considered a framework to discuss and analyze the results of those studies, however due to the timing of completion of the studies, such as the Hawaii Solar Integration Study, and the timing of the RSWG's efforts, the Subgroup did not have sufficient time to hold discussions on the studies' findings.

The Gap Subgroup held limited meetings in the latter part of 2012 while awaiting study results, and many of its members contributed heavily to other RSWG sub-groups, such as the PV, RDM and MLC Subgroups.

C. Gap Analysis Sub-group Recommendations

Notwithstanding the limited ability of the Gap Subgroup to analyze the ongoing studies and present more specific recommendations to the RSWG, the Subgroup has identified several general topics which could be considered for future analysis and study as the utilities and Commission continue to work to integrate renewable energy resources of all types to the Companies' systems. These topics include but are not necessarily limited to:

1. Wind and Solar forecasting projects - Recent studies have indicated that the ability to forecast variable generation can have a positive impact on system reliability and the economics of system operation.

2. Demand Response studies - As indicated in the General Electric Ancillary Services study, Demand Response may have the potential to provide ancillary services, such as frequency response, regulation, non-spinning reserves and replacement reserves. Additional future studies should be implemented to evaluate the potential of demand response, and its potential value to provide some of the ancillary services listed above.

3. Ongoing issues that were not fully analyzed during the RSWG process should continue to be investigated, such as excess energy issues and ways to mitigate curtailment, improved generating unit response and flexibility of both dispatchable and variable generation resources to provide quick response to changing system conditions and ancillary services, appropriate modeling tools and transparency of results, and, how to increase the penetration of renewable resources to the existing island systems without compromising reliability and reducing ratepayer costs.

4. Future analysis should consider developing technologies and their potential effectiveness to further facilitate the integration of renewable

resources. (for example, improved forecasting, storage technologies, smart grid solutions, demand response capabilities, inverter-based generation technical capabilities)

II. CONCLUSIONS

In general, identifying particular information gaps that will require further study can be a complex and challenging task since a rapidly changing electrical system can often lead to issues that are difficult to predict. For example, in 2012 each of the Hawaiian Electric Companies' systems experienced tremendous growth of distributed photovoltaic system installations on customer premises that exceeded most planning and study assumptions at the start of the year. The quickly changing systems will require:

- revising and creating new operational guidelines/criteria
- revisit unit commitment and dispatch to meet hourly demand and energy needs
- monitoring of resource performance, and improved record keeping for the purpose of accommodating the constant change occurring with the electric systems, and
- understanding the impacts on the system as the utility grids increase penetration of renewable resources.

Additionally, in 2012, Oahu and Maui experienced major additions of large capacity generation resources such as the 69 MW Kawailoa wind farm on Oahu, and two new wind farms on Maui that will significantly alter the way the systems have been operated in the past. The day-to-day operational experience gained from these system additions will most likely lead to future issues that will need to be investigated.

The majority of the ongoing studies identified by the Gap Subgroup and presented in Attachment A are technical in nature, and specific in scope usually for the purpose of investigating particular issues on a certain island grid. While the Gap Subgroup was not able to fully evaluate the existing system studies that were being conducted for the Hawaiian Electric Companies' systems, the Subgroup members and RSWG were briefed on the status of the studies through presentations by the National Renewable Energy Laboratory (NREL), Hawaii Natural Energy Institute (HNEI) and Electric Power Systems, Inc (EPS) – the entities sponsoring and/or conducting the studies. Moreover, through their active participation with the other RSWG subgroups, many of the issues that would likely have been raised as a part of the Gap Subgroup analysis effort, were identified and raised through the other Subgroups.

GAP Analysis Team List of Completed and/or Recently Initiated Study Activities for the three Utilities.
Compilation of HECO Studies

Public Reports/Activities				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
High Penetration PV Initiative	SMUD, HECO/MECO/HELCO	1-page factsheet of the California Solar Initiative effort, modeling approach and preliminary assessment.	2013	
Developing an Operational Eye on Solar	SMUD, HECO/MECO/HELCO	1-page summary of utility efforts to increase visibility to distributed generation (DG) resources like PV. Visualization tools piloted for system operations and distribution level resources and simulation model improvement activities are discussed.	2013	
Power Supply 2020 Scenario Analysis	PA Consulting Group, HECO	Report focused on the business strategies development for the Power Supply Process Area. Efforts laid the groundwork for a strategic plan to allow HECO to remain flexible and on track to meet its clean energy goals. This study was not intended to serve as a replacement for the Integrated Resource Planning (IRP) process but was part of HECO's responsibility efforts to evaluate resource options.	2010	
Locational Value Map (LVM)	HECO/MECO/HELCO	Publicly accessible information identifying the high penetration areas (by street name) on each of the islands within the Company's service territory. NEW release to have nightly updates to penetration numbers as well capacity remaining until 15% penetration is reached.	Online 2010	

External Collaboration Report (non-utility report, should check with responsible agency on release of any documents)				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
High Penetration PV Initiative Distribution Assessments, Modeling and Simulation Preliminary Results 2010	BEW Engineering (DNV Company) / Utility	Report on preliminary work on detailed circuit modeling and monitoring validation work at HECO on one of the high penetration distribution circuits. Preliminary evaluation of solar data correlated with field data from monitoring devices. Effort ongoing and requires at minimum 1 year of data collection to validate model development efforts	2012	Onging. Requires a significant model validation by Hawaiian Electric
Solar Forecasting Development Effort	AWS TruePower, Utilities / EPRI	NEW initiative to develop solar forecasting capabilities using the LM-1, LM-2 and distribution feeder monitoring data being collected under the SMUD/HECO High Penetration PV (HiP-PV) Initiative.	2013	This is an operational guide ONLY and should not be considerd to be highly accurate. As this is a proxy methodology. And not an operational replacement for actual telemetry. Additional deployment of technology needed for further study.
Nodal Estimation Approach for PV Modeling and Integration	BEW Engineering / EPRI, HECO	Develop methodology and validate T&D model to aggregate equivalent PV generation at 12kV distribution substations	2013	

HECO Studies

Wind Forecasting and Remote Monitoring – HECO/MECO	AWS TruePower, Atmospheric Research Technology / Utilities	PLANNED initiative to deploy remote sensing devices for Oahu and complete field monitoring for HECO/HELCO/MECO. Utility wind forecasting implementation plan to be developed in cooperation with utilities in California, Oregon and Hawaii with anticipated Hawaii operations end of 2013/early 2014.	2013	
Hawaii Solar Integration Study (HSIS)	GE Energy Consulting, BEW Engineering / US DOE NREL & Utilities	Modeling effort to assess system level impacts due to various levels of solar PV on the HECO (Oahu) and MECO (Maui) system; Scenarios evaluate central station PV and distributed PV.	2012	
Stage 2 Analysis	GE Energy Consulting	Modeling effort to assess system level impacts and advantage from generation tie to Molokai and/or Lanai and the rusltting economic analysis, grid impacts and RE curtailment reduction posibilities.	2013	
EPS Cycling Study	MECO, HELCO	Analysis from both the power operations and economic perspective on cycling units off line and the related effects to system stability and RE curtailment.	2013	Results being discussed in MLC and the Hawaiian Electric Companies.
TRI-LABS Storage Analysis	MECO focus.	Analysis and dynamic modeling focusing on the impacts related to application of various storage technologies primarily focused on up to three circuits of MECOs choice having the highest PV penetration levels.	2013	On going.

Compilation of HELCO - Hawaii Studies

Public Reports/Activities				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
Tools Used for Handling Variable Generation in the Hawaii Electric Light Co. Control Center	Dangelmaier, Nakafuji, Kaneshiro/ Utility, SMUD	IEEE PES proceedings article detailing tols used for managing the diverse mix of generating resources including variable generation on the HELCO system Panel session presentation available.	2012	http://www.ieee-pes.org/images/pesws/gm2012/slides/pesgm2012p-001908.pdf
System Frequency Performance of the Hawaii Electric Light System	L. Dangelmaier / Utility	IEEE PES proceedings article detailing a series of studies and renewable impacts over time, including system changes to improve system frequency performance	2011	
HELCO AGC Wind Impact Analysis	L. Dangelmaier, Daniel Brooks (EPRI) / Utility	Presentation highlighting the work to correlate wind variability on system frequency and AGC tuning (Summary of EPRI membership reports presented at UWIG Spring Meeting, Fort Worth, TX 2008)	2008	
Evaluation of Future Energy Technology Deployment Scenarios for the Big Island	HNEI / US DOE	Initial studies conducted by HNEI and their consultant, GE	2009	
Charting a Course Toward a Cost-Effective Renewable Utility - HELCO Resource Planning Study	PA Consulting Group, HECO	Report identified near-term activities for HELCO to pursue to be prepared for the next decade and to provide opportunities for viable future resource options to move forward. This study was not intended to serve as a replacement for the Integrated Resource Planning (IRP) process but was part of HELCO's responsibility to continue to plan in the absence of the formal IRP process.	2012	

External Collaboration Report (non-utility report, should check with responsible agency on release of any documents)				
Title	***Authors/Sponsor***	***Description***	***Date***	***Comments***
Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation (Membership Report 1018715)	EPRI / AREVA, HELCO	An assessment of the imapct of the HRD wind plant on the HELCO frequency control performance, and the effectiveness of various changes to automatic generation control (AGC) in mitigating impacts. Reference: EPRI Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation. EPRI, Palo Alto, CA: 2007. 1018715.	2007	
Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance - Phase 2 (Membership Report 1018716)	EPRI / AREVA, HELCO	An assessment of HELCO system frequency performance with two wind plants (HRD and Tawhiri). Contains statistical evaluation of the impacts on system frequency control and AGC, as well as regulating units, based on a large amount of collected data using an AGC performance measurement software tool. Also examines particular frequency events, including those resulting from conventional unit trips, to compare and contrast the system and operator performance. Reference: Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance – Phase 2. EPRI, Palo Alto, CA: 2009. 1018716.	2009	
Monitoring and Deployment Plan for WindNET Field Campaign – HELCO/MECO	AWS TruePower, Utilities / US DOE ARRA	Final report on remote sensing device deployment and field monitoring campaign on Hawaii for development of short-term wind forecasting and ramp event capabilities. Presentation materials available from September and upcoming July workshops on wind forecasting efforts.	2011	

HELCO - Hawaii Studies

Variable Renewable Monitoring - PMU	SEL, HELCO / US DOE ARRA	ARRA funded initiative to deploy phasor monitoring devices and begin capturing high-resolution system data for purposes of variability integration studies; 5 SEL PMUs (relays) procured and are gathering data. SEL conducted training on analysis tool to train utility staff on downloading and capturing data (HECO/MECO/HELCO).	Deployed 2010 - Ongoing data gathering	
Battery project for distribution voltage regulation	HELCO / DBEDT	Field installtion of battery to measure costs and performance in application for distribution voltage regulation on a high PV penetration circuit	2013	
Battery project to evaluate use of battery for tie line control to smooth wind plant power injection	HNEI / HELCO, HNEI, ONR	Field installation of battery to measure costs and performance in application to smooth wind plant (HRD) power active power injection into the HELCO system.	2013	

Utility Reports (Internal, Confidential, or Contains Infrastructure Sensitive Information)				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
Interconnection Study for 800kW PV System	PTI / HELCO	Interconnection study for customer site; DTT and special protection during light loads recommended for circuit	2002	
AGC Consulting Report	Brad Nelson (AREVA) / HELCO	Report from consultant documting his tuning HELCO AGC area and unit parameteres, and code changes, for optimal performance with the addition of the second wind plant (Tawhiri). Also contains recommendations for related system and unit changes.	2007	
Distributed Generation and As-Available Energy Impact Study	EPS / HELCO	EPS study to identify areas of operational concern on the island electrical system for anticipated high penetration of distributed and variable generatio on the HELCO system.	2005	
Wind Generation Impact Study - Phase II	EPS / HELCO	Evaluation of system stability issues following certain contingencies when operating at minimum steam generation configuration Led to recommendation that HELCO maintain at least 2 of the larger steam units on-line during all load conditions.	2006	
Wind Generation Impact Study - Phase III Minimum Steam Generator	EPS / HELCO	Follow-on study to study the impact of substituting one or two of the smaller steam units for a larger steam unit when the larger units are not available due to planned or unplanned outages. Studies evaluated and validated generator trip events and conducted load flow and transient stability models to assess impacts on HELCO's system	2007	
Wind Generation Impact Study - Phase III Documentation for PSS/E LM2500 Model	EPS / HELCO	Follow-on study to phase II to improve LM2500 generator response dynamics model to reflect in field performance. This was determined to be a critcial need for dyanmics simulations in the prior study. The recommendations are based upon control logic provided for in service plants including IPP.	2007	
Wind Generation Impact Study - Phase III Review of PSS/E Models for Steam Plants, Droop, Inertia, and Load Shedding	EPS / HELCO	Follow-on study to phase II to improve steam plant dyanamic response model to reflect in field performance. This was determined to be a critcial need for dyanmics simulations in the prior study. The study recommendations are based in part upon field data collected by HELCO engineers.	2007	

HELCO - Hawaii Studies

Maximum Penetration of Distributed Generation	EPS / HELCO	Study to evaluate the impact of distributed generation on the HELCO system. Six base case conditions were created highlighting HELCO's most constrained dispatch scenarios. DG resources were modeled as constant power sources and generalized as PV resources. Two sets of stability case were run 1) to evaluate the system response to unit trips as PV is incrementally added and 2) to determine the amount of PV that could be added to the system such that for certain unit outages, the PV would cause under-frequency load shedding during a trip of generation. UFLS and spinning reserves available were found to be 2 major impacts of DG to the system.	2009	
DG Voltage Impact Study	EPS / HELCO	The dyanmics and steady state performance of the HELCO system has changed as s result of the change in generation mix and in particular the distributed generation. This is project will assess consist of a) benchmark existing power flow and transient stabiltiy models against system data with emphasis on correlating voltage results with actual system, b) dyanmic simulations to evaluate dynamic system response including the impact of distributed generation off-normal voltage and frequency trip settings, c) make recommendations for distributed voltage ride-through requirements based on the results of the dynamic simulations, and c) review control and protection settings for the load shedding, capacity controls, and undervoltage relay protections indicated by teh analysis.		
Distribution Feeder Model Development, RE Penetration Studies for HECO/MECO/HELCO	BEW Engineering / HECO companies	Effort to complete the distribution model development and upgrade using SynerGEE for HECO/MECO/HELCO. Enables ability to conduct island-wide distribution system evaluation and aggregation studies. Aggregation methodology developed which "roll-up" distributed generators into equivaler generators to be able to account for DG resources and impact on system modeling efforts. Includes preliminary review of high penetration circuits for initial model development and follow-on monitoring efforts	2012	

MECO - Hawaii Studies

Compilation of MECO Studies (Maui, Molokai, Lanai)

Public Reports/Activities				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
Operational Flexibility Study for the Integration of Renewable Generation	Stanley Consultants / Utility	Evaluated MECO system modifications to improve performance for accepting intermittent generation; Submitted in MECO 2012 Rate Case	2011	
Maui Resource Planning Study	PA Consulting Group, Utility	Report identified near-term activities for MECO to pursue to be prepared for the next decade and to provide opportunities for viable future resource options to move forward This study was not intended to serve as a replacement for the Integrated Resource Planning (IRP) process but was part of MECO's responsibility to continue to plan in the absence of the formal IRP process.	2011	
Integrating High Levels of Renewables into the Lanai Grid	USDOE-NREL, Sandia	Evaluating the economic and technical feasibility of high penetration of renewables on the Lanai grid	2012	http://www.nrel.gov/docs/fy12osti/50994 pdf
Maui Energy Storage Study	Sandia	Investigates strategies to mitigate wind curtailment with a focus on energy storage	2012	http://www.ntis gov/help/ordermethods asp?loc=7-4-0#online
Fast Demand Response Pilot	Honeywell / Utility	Pilot to test a fast demand response program to provide load management capability	2013	

External Collaboration Report (non-utility report, should check with responsible agency on release of any documents)				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
Lanai High Penetration Renewable Energy Grid Study	P-Terra / USDOE-NREL & Utility	System and circuit level evaluation to assess renewable DG on the Lana grid.	2012	
Monitoring and Deployment Plan for WindNET Field Campaign – HELCO/MECO	AWS TruePower, Utilities / US DOE ARRA	Final report on remote sensing device deployment and field monitoring campaign on Hawaii for development of short-term wind forecasting and ramp event capabilities. Presentation materials available from September and upcoming July workshops on wind forecasting efforts.	2011	
Hawaii Solar Integration Study (HSIS)	GE Energy Consulting, BEW Engineering / US DOE NREL & Utilities	Modeling effort to assess system level impacts due to various levels of solar PV on the HECO (Oahu) and MECO (Maui) system. Scenarios *evaluate central station PV and distributed PV.*	2012	
Variable Renewable Monitoring - PMU	Equipment deployment & field campaign SEL / US DOE Sandia & Utility	Four PMU deployed and gathering data on Maui, through funding provided by US DOE through Sandia National Lab Objectives were to deploy phasor monitoring devices and begin capturing high-resolution system data for purposes of variability integration studies	Deployed 2009/2010 - Ongoing data gathering	

Utility Reports (Internal, Confidential, or Contains Infrastructure Sensitive Information)				
Title	**Authors/Sponsor**	**Description**	**Date**	**Comments**
Central Maui 23 kV/60 kV Tie Point Evaluation	Utility	Study to determine results on voltage due to loss of generation on 23 kV system and possible mitigation measures	2013	
Maui Wind Integration Study - Final Report	GE Energy Consulting / Utility & Wind Developer	Study with wind developer to assess the impact of a third wind facility on Maui and determine viable mitigation options to minimize curtailment. Results may be used to inform future studies; redacted executive summary available only at this time.	2010	
Distribution Circuit Studies	Pterra / Utility	Evaluation of 3 circuits to determine DG penetration limits for each	2011	
Operational Flexibility Study - Phase II	Stanley Consultants / Utility	Follow on from Phase I - more detailed analysis of Phase I recommedations	2013	
Useful Life Study	Sargent and Lundy	Determine the remaining useful life of the MECO units	2013	
Kaunakakai IRS	Pterra / Utility	Interconnection study on Molokai to determine the renewable DG that can be added to the circuit	2011	Follow on work ongoing.

RSWG Reliability Standards Drafting Subgroup – Final Report and Recommendations

January 14, 2013

Background:

The Reliability Standards Working Group (RSWG) was constituted by the Public Utilities Commission (PUC) by the Order Opening Docket (Docket No. 2011- 0206) filed September 8, 2011. In February, 2012 the RSWG approved the creation of a Reliability Standards Drafting Sub-group (RSDG) with the task of drafting reliability standards applicable to Hawaii and addressing the grid interconnection process.

The RSDG consists of representatives from the HECO Companies, KIUC, DBEDT, the Consumer Advocate, consultants to the electric utility industry, independent power producers (IPP), IPP trade organizations, the consultant to the PUC, and Blue Planet Foundation. The list of members can be found on Table 1, attached herein.

Standards Drafting Process:

The RSDG objective is to define terms and metrics for reliability standards as identified in the RSWG Independent Facilitator's submittal regarding the RSWG Purpose, Scope of Work and Work Plan, filed on September 23, 2011 in Docket No. 2011-0206 and to draft mandatory reliability standards applicable to Hawaii utilities in a timely manner for review and adoption by the RSWG and filing with the PUC.

The RSDG selected an approach to drafting reliability standards based on existing NERC Reliability Standards and selected state reliability standards applicable to electric systems similar to Hawaii. Initially, some fifty - one (51) reliability standards were selected from more than one hundred - seventeen (117) consolidated active NERC standards that have the potential for adoption to the Hawaii utilities as complied in Appendix A, Table A-1

Specifically, the HECO Companies currently operate their electric grids utilizing guidelines, operating criteria, and procedures similar to those associated with mainland utilities. Annual reports are prepared and submitted to the PUC concerning system performance pursuant to General Order No. 7.

The RSDG utilized current utility information, operating practices and procedures to create reliability standards based on the NERC Standard format.

Standards Completed:

Key standards were completed and approved by the RSWG in the following subject areas:

- System Balancing (BAL)
- Protection, Relaying and Control (PRC)

- Modeling (MOD)

Appendix A contains a summary table (Table A-2) of the reliability standards that have been completed and approved by the full RSWG and are forwarded to the PUC for further review, adoption, and implementation. Drafting the above standards for applicability for Hawaii, the RSDG took the liberty to combine the provisions of several NERC standards into those proposed Hawaii standards presented herein. For example, the RSDG combined the provisions of NERC Bal. Std. 005 into the proposed Hawaii Bal. Std. 001. Similarly, provisions of several NERC PRC Standards were combined into the proposed Hawaii standard PRC 006. In addition, the RSDG reviewed the applicability of NERC Bal. Std. 003 and concluded that the provisions of this particular standard would be more effective as an operating procedure to be drafted by the HECO Companies as part of the Hawaii standards implementation process. The development history is contained in Table A-2 and Table C-1. Table A-3 is a glossary and summarizes the definitions applicable to the developed standards. These definitions supplement those contained the Glossary prepared by the Reliability Metrics and Definitions (RDM) Sub-group. Further, Appendix A contains each recommended standard along with its accompanying synopsis for ease of reading.

Work in Progress:

Due to the complexity of the standards drafting process and time constraints, the RSDG is recommending that further work on the NERC standards be completed as follows:

- Transmission Planning (TPL)
- Facilities (FAC)
- Interconnection Reliability & Operations (IRO)
- Voltage and Reactive Control (VRO)
- Transmission Operations (TOP)

Drafting provisions have been initiated on the Transmission Planning Standard (TPL) and several Facilities Standards (FAC), but these drafts have not been fully vetted by the RSDG. A list of NERC Standards applicable to Hawaii are identified in Appendix B, Table B-1.

Further Standards Work for Consideration:

The PUC commissioned the Sandia National Laboratories (SNL) to address "Hawaii Electric System Reliability", which resulted in a report published in September 2012. The report addressed the need for additional standards development applicable to Hawaii as well as an independent body to take part in the reliability evaluation process and a collaborative process for achieving meaningful reliability metrics for the Hawaiian electric systems. Many of the standard development suggestions noted in the SNL report have been addressed by the RSDG as delineated herein.

SNL addressed further standard development work in the following areas and are also included in Appendix B, Table B-1:

- Cyber Security (CIP)
- Telecommunications (COM)
- Emergency Operations Planning (EOP - 001)
- Disturbance Reporting (EOP - 004)
- System Restorations Plans (EOP - 005)
- Loss of Control Center Functionality (EOP - 008)
- Black Start Generating Capability – Test Results (EOP - 009)
- System Personnel Training (PER)

In addition, Appendix C, Table C-2 identifies certain NERC Standards that have had a cursory review and are not recommended for application to Hawaii.

Guidance for Further Standards Development

Based on experience gained in the development of the reliability standards submitted herein, a majority of the RSDG members felt strongly that it should offer to the PUC and the Hawaii Electricity Reliability Administrator (HERA) prospective guidance as to how the PUC/HERA may pursue further efforts to complete the work of developing, revising, and implementing reliability standards for Hawaii.

Consistent with the PUC directive in Order No. 30694(filed October 18, 2012) concerning a Standards Framework, the RSDG has finalized a proposed Framework (largely developed prior to Order No. 30694). The Framework discusses an overview of the process, the organization required to develop, revise, implement and enforce standards, the key roles in the process, and the stakeholder segments that would be contributing parties to the development of standards and the voting body to approve the finished product for recommendation to the PUC for adoption. In drafting this guidance, the RSDG has identified several policy and procedural areas for further consideration by the PUC as it implements the overall reliability standards process. For ease of presentation, a standards development flow chart is also included. The proposed Framework has been approved by the RSWG.

Appendix D contains the following documents concerning this Framework:

1. Potential Framework for Development and Implementation of Electric Utility Reliability Standards in Hawaii (Overview)

2. Proposed Reliability Standards Organization

3. Development of the Registered Ballot Body and Segment Qualification Guidelines

4. Standards Drafting Process Flow Chart

5. For information only: NERC's Statement of Compliance Registry Criteria –Revision 5

Conclusions and Recommendations for Standards Adoption:

For the Standards that have been approved by the RSWG and submitted to the PUC as contained in this report, the RSDG recommends that the PUC and/or HERA consider the following recommendations and qualifications in adopting these standards and others to be developed in an ongoing process.

1. Historical operating data was utilized and incorporated in the development of the approved standards contained herein.
2. Any limits, metrics, numbers used in the completed standards were best estimates at the time of drafting. Where such limits, metrics, numbers were indicated by a place holder, these limits, etc should be determined by further impact analysis on the effected parties to the standard.
3. As Hawaii moves forward with the Reliability Standards process and recognizing the complexity of the process contained therein, the RSDG recommends that the Commission open a docket to address such issues, but not limited to, identification of the parties that will be responsible and liable once the standards are implemented, the costs associated with implementing the standards, compliance and enforcement of the standards, and a process that will allow vetting of these completed standards by the stakeholders that are affected by their formal adoption and implementation. The attached follow on process, standards flow chart, and suggested stakeholders segments contained in Appendix D are presented for further consideration by the PUC or HERA.
4. Adoption and implementation of each standard should proceed on the basis of a one year trial period to gain valuable operating experience and to allow time to revise the standard appropriately before the PUC/HERA begin actual enforcement of each standard.
5. The standards drafted to date represent the beginning of a process that will lead to full implementation. Accordingly, detailed operating procedures and guidelines will need to be drafted by the Hawaii utilities to support their implementation.
6. The RSDG recommends that the PUC accept the standards drafting process and guidance given in the proposed Standards Framework documents, including the development of a compliance registry.
7. The RSDG recommends that the PUC allow the RSDG to continue its standards drafting efforts as a transition to the establishment of HERA to allow a seamless transfer of work, experience, and knowledge as possible and to facilitate the implementation of these reliability standards for Hawaii.

Transparent Interconnection Process:

Background:

Since Order No. 30371, filed on May 4, 2012, and pursuant to subsequent instructions from the PUC, the RSDG focused on the standards-related issues presented therein. In the same time frame, the PV Subgroup developed recommendations concerning Tariff Rule 14H and processes for interconnections on the distribution system, and the chair of the RSDG undertook an effort to coordinate with HECO to draft a representative procedure that could be extended to all of the HECO Companies involving interconnection to the sub-transmission and transmission systems. Subject to additional review, the resulting draft documentation sets forth and standardizes existing practices with respect to the Interconnection Requirements Studies (IRS) process, at least pertaining to projects to be connected to the sub-transmission and transmission systems on Oahu. This documentation of the IRS process applies to projects seeking a Power Purchase Agreement (PPA) with HECO, and is generally relevant to all HECO IRS work, subject to coordination with existing processes that are governed by Tariff Rule 19, and resource procurement through a PUC-approved Request for Proposals (RFP) or through a Non-Utility Generator (NUG) application for bilateral negotiations of a PPA.

The existing interconnection process for generation resources on the distribution system is primarily governed by Tariff Rules 14H, 18, the Standard Interconnection Application (SIA), and the Feed-in Tariff (FIT) processes. Suggested revisions to Rule 14H have been approved by the RSWG and presented to the PUC for further review and adoption as part of the RSWG – PV Sub-group report. As recommended by the PV Sub – group further work needs to be undertaken to synthesize Rule 14H with Rule 18 and the FIT process. As a result of work initiated by the chair of RSDG, the documentation of IRS process for interconnections on the HECO sub-transmission and transmission systems is in an analogous condition, minus the forms and screening rules that do not apply to larger projects, and constrained to not intrude upon the requirements of Tariff Rule 19.

This documentation of the IRS process also may be helpful to fill in process particulars not specified in Rule 14H. Formal procedures related to the IRS process and the resulting work product may have to be constrained for smaller project sizes and the time limits stated in Rule 14H.

Interconnection Procedure – Drafting Process:

The documentation of the IRS process focuses on the sequence of work required to provide detailed studies and meaningful IRS reports for generation resources interconnecting to the sub-transmission and transmission systems. For convenience, the proposed HECO procedure is formatted to generally track the sequence of work that is set forth in the Federal Energy Regulatory Commission's (FERC) pro forma Generator Interconnection Procedures (GIP), modified to fit existing Hawaii conditions. This proposed procedure dealing with the IRS

process has been reviewed and commented upon by the RSDG, and presented to the RSWG for consideration and adoption for further action by the PUC. The proposed procedure is contained in Appendix E herein for reference.

The RSDG has identified issues that may require further deliberation and consideration, including but not limited to the following in a subsequent proceeding involving all interested stakeholders:

1. Whether a formal Interconnection Request application is appropriate in the context of existing Tariff Rules and should accompanying deposits be required to cover HECO administrative costs.
2. Whether to include study cost estimates by project size (either fixed or estimated).
3. Whether to attach a standard form Interconnection Request and or NUG Application.
4. Whether to specify requirements for site control in relation to IRS work flow.
5. Whether to attach a standard IRS Agreement and NDA.
6. Whether and to what extent is a NDA needed?
7. Resolution of bracketed items in the proposed GIP, including the appropriateness of establishing standardized due dates, timelines and procedures for requesting interconnections, work process performance timelines, and whether to provide modeling or other relevant studies to support the interconnection study work and/or post IRS results.
8. Whether to include a Standard Engineering and Procurement (E&P) Agreement
9. Whether to add a pro forma Generation Interconnection Agreement (GIA) apart from or in lieu of what is now contained in the existing PPA and/or other bilaterally negotiated structures. Address the incorporation of reliability and interconnection criteria and performance standards in the GIP or GIA.
10. Resolution of Section 13.1.8, Disclosures to the PUC or the State.
11. What is the appropriate venue to address funding/cost allocation for Network upgrades and Betterments.
12. Determine the applicability of the proposed Interconnection Procedure to MECO and HELCO.

Presently HECO has initiated actions to address many of these open items and update their current procedures and is drafting a work plan to be filed with the PUC as part of HECO's comments to this section of the RSDG Report.

Conclusions and Recommendations for Interconnection Procedures:

The RSDG recommends that the PUC provide input and guidance to HECO with respect to the subject interconnection procedure in order to give guidance and clarity to project developers wishing to interconnect with the sub-transmission and transmission grids. Further it is

recommended that the PUC direct HECO to convene a follow on stakeholder proceeding to fully vet the proposed procedure and work toward resolution of the open issues stated above.

As indicated in open item #9 above, the PUC may wish take steps to direct HECO to pursue completing the development of a transparent interconnection procedure by creating an accompanying GIA to this proposed GIP. A GIA can act as a pro forma agreement and can delineate the inter-relationship of the utility and the project developer, the findings of the IRS, the scope and cost responsibilities of the actual interconnection work, and the performance requirements to be met by the interconnecting party. This effort can be patterned after the existing FERC Large Generator Interconnection process.

The existing interconnection process requiring an IRS and the associated interactions of the utility and project developer requesting an interconnection to the grid, along with the scope and costs, and performance requirements are contained in each proposed project's individual Power Purchase Agreement (PPA).

A GIA can be created that will extract from the HECO Companies' model PPA the IRS results based on the overall interconnection study process as delineated in the proposed interconnection procedure and other pertinent provisions described above. The GIA can result in further clarity to the procedure and facilitate not only timely interconnection and non-discriminatory, comparable consideration of interconnection requests, but timely review by the PUC since the GIA will be a pro forma document. Further, separating the PPA negotiations from the GIA may also simplify and expedite the overall contracting and review process. Of course, there will be a need for a nexus between the PPA and GIA for each individually proposed project.

Lessons Learned:

The RSDG process of developing and drafting reliability standards for adoption and implementation in Hawaii is a complex process and requires expertise from the utilities, the IPP community, and other stakeholders to provide input as well as appropriate participation and oversight by independent or governmental bodies. From involvement in this process, the RSDG has learned the following lesions and wishes to share them with the PUC:

1. Input, active participation, and expertise in utility systems is critical to the understanding and development of reliability standards for Hawaii.
2. Drafting standards is very time consuming and there must be a dedication to do so by the members of the drafting team.
3. Red line standards with potential applicability to Hawaii were initially created from a list of NERC Standards. The HECO Companies' representatives/consultant made the first attempt in drafting standards from these red lines. Before a draft could be released to the full RSDG, an internal HECO Companies vetting process took place. This step slowed the overall process down. It is assumed that going forward under HERA, this would not be the case.

4. Considering the NERC reliability standards process and the time NERC has invested in development and revisions to standards, sometimes taking years to complete, the RSDG completed a significant amount of work in a very short time span.
5. A new proceeding is warranted to ensure the creation of a non-discriminatory GIP and GIA.

Time Constraints:

In further consideration to item #4 above, the RSDG, even though meeting almost on a weekly basis since being formed, has accomplished a great deal in identifying and drafting reliability standards for Hawaii utilities. The process is complex and time consuming to draft a standard, gather comments and input from stakeholders, and then develop a final proposed standard for full RSWG approval. If the RSDG had more time, it could have drafted and recommended more standards for adoption from the list in Table B-1and from other potentially applicable NERC standards.

Respectively submitted,

Sebastian J. Nola,
Consultant to the Blue Plant Foundation and
Chair of the RSDG

January 14, 2013

Attachments:
Appendix A – Reliability Standards - Adopted
Appendix B – Reliability Standards Applicable to Hawaii
Appendix C – Reliability Standards - Reviewed
Appendix D – Reliability Standards Framework
Appendix E – Proposed Interconnection Procedure

TABLE 1

RELIABILITY STANDARDS DRAFTING GROUP

MEMBERSHIP

Bash Nola	Blue Planet Foundation
Dennis Loria	DBEDT
Marcey Chang	DCCA
Dave Burlingame	HECO/Consultant
Robert Uyeunten	HECO
Robert Young	HECO
Ron Bushner	HECO
Lisa Dangelmaier	HELCO
Warren Bollmeier	HREA
Mike Sheehan	Interstate Renewable Energy Council
Mike Yamane	KIUC
Mat McNeff	MECO
Steve Rymsha	MECO
Brendan Kirby	PUC Consultant
Sandie Wong/Harrison Clark	Tawhiri
Erik Kvam	Zero Emissions

APPENDIX A
RELIABILITY STANDARDS ADOPTED

TABLE A-1 Consolidated List of Active NERC Standards (12/31/12)

TABLE A-2 RSWG Recommended Standards for Adoption

TABLE A-3 Glossary

RECOMMENDED HAWAII RELIABILITY STANDARDS

SYNOPSES OF RECOMMENDED RELIABILITY STANDARDS

APPENDIX B
RELIABILITY STANDARDS APPLICABLE TO HAWAII

TABLE B-1 RELIABILITY STANDARDS IDENTIFIED FOR APPLICABILITY FOR HAWAII

APPENDIX C
RELIABILITY STANDARDS - REVIEWED

TABLE C-1 STANDARDS REVIEWED AND RECOMMENDED FOR FURTHER ACTION

TABLE C-2 STANDARDS NOT RECOMMENDED FOR HAWAII

APPENDIX D
RELIABILITY STANDARDS FRAMEWORK

POTENTIAL FRAMEWORK – OVERVIEW

PROPOSED RELIABILITY STANDARDS ORGANIZATION

REGISTERED BALLOT BODY AND SEGMENT QUALIFICATION

STANDARDS DRAFTING FLOW CHART

NERC'S COMPLIANCE REGISTRY CRITERIA

APPENDIX E
INTERCONNECTION PROCEDURE
(PROPOSED)

TABLE A-1

CONSOLIDATED LIST OF ACTIVE NERC STANDARDS ON WEBSITE 12-31-2012

	14	Groups
	117	Consolidated Standards
Resource and Demand Balancing (BAL)	6	Standards withing Group
Communications (COM)	2	Standards withing Group
Critical Infrastructure Protection (CIP)	11	Standards withing Group
Emergency Preparedness and Operations (EOP)	8	Standards withing Group
Facilities Design, Connections, and Maintenance (FAC)	10	Standards withing Group
Interchange Scheduling and Coordination (INT)	9	Standards withing Group
Interconnection Reliability Operations and Coordination (IRO)	12	Standards withing Group
Modeling, Data, and Analysis (MOD)	20	Standards withing Group
Nuclear (NUC)	1	Standards withing Group
Personnel Performance, Training, and Qualifications (PER)	5	Standards withing Group
Protection and Control (PRC)	22	Standards withing Group
Transmission Operations (TOP)	8	Standards withing Group
Transmission Planning (TPL)	1	Standards withing Group
Voltage and Reactive (VAR)	2	Standards withing Group

TABLE A-2

STANDARDS THE RSWG IS RECOMMENDING FOR ADOPTION IN HAWAII			
HAWAII RELIABILITY STANDARD	**RELEVANT NERC STANDARD**	**TOPIC**	**COMMENTS**
HI-BAL-001	BAL-001, BAL-005	Real Power Balancing Control Performance	The Hawaii standard was written around frequency only rather than ACE. Also added 4 reqirements from BAL-005.
HI-BAL-002	BAL-002	Disturbance Control Performance	
HI-BAL-502-0	BAL-502	Planning Resource Adequacy Analysis, Assessment and Documentation	
HI-PRC-006-0	PRC-006, PRC-007, PRC-008, PRC-009	Underfrequency Load Shedding	combined portions of the NERC standards into one.
HI-MOD-010-0	MOD-012, MOD-013, MOD-015	Development of Steady State System Models and Simulations	Combined NERC standards into one.
HI-MOD-012-0	MOD-012, MOD-013, MOD-015	Development and Reporting of Dynamic System Models and Simulations	Combined NERC standards into one.
HI-MOD-016-0	MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021	Actual and Forecast Demand, Net Energy for Load, and Controllable Demand-Side Management, and Distributed Generation	Combined NERC standards into one.
HI-MOD-025-0	MOD-024, MOD-025	Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources	Combined NERC standards into one.
HI-MOD-026-0	MOD-026	Verification of Models and Data for Generator and applicable transmission equipment Excitation System or Plant Volt/VAr Control System	
HI-MOD-027-0	MOD-027	Verification of Models and Data for Turbine/Governor and Load Control and Active Power/Frequency Control Functions	

New Term	HI-BAL-001-0	HI-BAL-002-0	HI-BAL-502-0	HI-PRC-006-0	HI-MOD-010-0	HI-MOD-012-0	HI-MOD-016-0	HI-MOD-025-0	HI-MOD-026-0	HI-MOD-027-0
Actual Disturbance Recovery Period: The actual duration of time for the period, in minutes from the time of the initiating event to the time the frequency is restored to within acceptable frequency limits of 60.3 to 59.7 Hz for single contingency events and for excess contingency events off of nominal 60 Hz. Source: RSWG proposed definition	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area and governs the real time operation and control of the Balancing Authority Area. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

Base Year: The 2011 BA's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. Source: Proposed RSWG proposed definition.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Catastrophic Contingency Event: Any contingency event (greater than the N-1 Contingency Criteria) whose total requirements exceed the Contingency Reserve criteria plus Protection Reserve criteria within the Balancing Authority Area. Source: RSWG proposed definition	**No**	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**
Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other contingency requirements. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**No**	**Yes**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Contingency Reserve Restoration Period: The time in minutes required to re-establish the Contingency Reserves utilized during the Disturbance Recovery Period such that the system can sustain another contingency. The Contingency Reserve Restoration Period is 120	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

minutes. Source: RSWG proposed definition										
Direct Control Load Management (DCLM): A demand side management tool that is under the direct control of the system operator and measureable. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Facility: A set of electrical equipment that operates as a single system resource (e.g., a line, a generator, a shunt compensator, transformer, etc.). Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Firm Generation or Firm Power: Power producing capacity intended to be available at all times during the period covered by a commitment even under adverse conditions. Source: Originally from EEI Glossary of Electric Industry Terms, April 2005 and included into RSWG Glossary of Terms, Version 1 – 20120304. Firm	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

Generation was added as a *synonymous term with Firm* Power										
Forecasted Peak Demand: The highest peak demand of the BA's forecasted system load requirements for the highest demand level of the planning year. Source: Proposed RSWG definition.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Forced Outage: 1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Generator Owner: Entity that owns generating units. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**No**	**No**	**No**	**No**	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**Yes**
Interruptible Demand: Demand not under direct control of the system operator that the end-use customer makes available to its BA via contract or agreement for curtailment. Interruptible Demand may include interruptible load that is not available for use in reducing the BA's forecast demand	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

requirements due to contractual or implementation restrictions. Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.										
Maximum N-1 Contingency Criteria: The maximum loss of generation contingency reserves for the BA shall be calculated by the greatest of the following two values: 1) the maximum amount of generation capacity that can be lost following any single event, including the impact of waste heat generation following the loss of the primary generation unit or 2) the *maximum amount of generation* that can be lost by any single failure of a single transmission component. The maximum loss of load contingency reserves shall be calculated by the loss of load on the largest single transformer or load serving transmission line on the system. Source: RSWG proposed definition	**No**	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**
Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, and less Direct Control Load Management and Interruptible Demand. Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

Normal Net Capability: The maximum continuous rating of the resource minus the station service demand required to achieve the maximum continuous rating of the unit. Station service or plant loads not attributable to the operation of the unit must not be included in the Normal Net Capability of the unit. Source: Proposed RSWG definition.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Peak Demand: 1. The peak demand shall be the highest peak demand of the BA's forecasted system load requirements for the highest demand level of the planning year. 2. The highest instantaneous demand within the Balancing Authority Area. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Peak Period: A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur. Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Planning Reserve Margin: The	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

ratio of the total amount of planned available Firm Generation capacity divided by the Forecasted Peak Demand of the system minus 1.0, expressed in %. The Planning Reserve Margin requirement must be calculated by each BA by system analysis. Source: Proposed RSWG definition.										
Protection Reserves: The resources under the control of the Under Frequency Load Shedding System designed to protect the system against single or multiple contingency events. Source: RSWG proposed definition	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Reportable Single Contingency Disturbance: Any single event that causes System frequency to exceed the limits of +/- 0.3 Hz in the Balancing Authority's area Source: RSWG proposed definition	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Reportable Excess Contingency Disturbance: Any series of events, or multiple contingency events which exceed the maximum N-1 contingency event which occur in a manner that causes System frequency to exceed the limits of +/- 0.3 Hz in the Balancing Authority's area. The excess contingency events occur prior to the contingency reserves	**No**	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**Yes**

Terms were copied from the approved standards and consolidated.

being re-established following a single contingency disturbance or for multiple contingency events which exceed the reserve requirements of the single largest single contingency. Source: RSWG proposed definition										
Reserve Margin: The ratio of the actual total amount of available Firm Generation capacity, expressed in %, between the total available Firm Generation capacity divided by the Peak Demand of the system minus 1.0, expressed in %. Source: Proposed RSWG definition.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Resource Adequacy: The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses within a BA's area) at all times taking into account scheduled and reasonably expected unscheduled outages of system elements. Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Standard Disturbance Recovery Period: The time, in minutes set as the target goal in the standard to allow restoration of the frequency from the time of the initiating event to the time	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

the frequency is restored to within acceptable frequency limits of 60.3 to 59.7 Hz for single contingency events and for excess contingency events off of nominal 60 Hz. Source: RSWG proposed definition										
Transmission or Transmission System: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers. Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Transmission Owner: Entity that owns transmission equipment. Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012	**No**	**No**	**No**	**No**	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**Yes**
Year One: Year One is the first year of planning studies for future planning and evaluation requirements. Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.	**No**	**No**	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Terms were copied from the approved standards and consolidated.

TABLE B-1

STANDARDS THE RSWG IS CONSIDERING, BUT HAVE NOT REVIEWED TO DETERMINE APPLICABILITY TO HAWAII			
HAWAII RELIABILITY STANDARD	**RELEVANT NERC STANDARD**	**TOPIC**	**COMMENTS**
HI-TPL-001-0	TPL-001-2	Transmission System Planning Performance Requirements	
HI-EOP-001-0	EOP-001, EOP-005, EOP-008, EOP-009	Emergency Operations Planning	Combined portions of the NERC standards into one standard modified for Hawaii. In addtion, this would also include blackstart and loss of the control center.
HI-PER-002	PER-002, PER-005	Operating Personnel Training	Combined portions of the NERC standards into one standard modified for Hawaii.
HI-PRC-001-0	PRC-001, PRC-003, PRC-004, PRC-005	System Protection Coordination	Combined portions of the NERC standards into one standard modified for Hawaii.
HI-PRC-010-0	PRC-010, PRC-011, PRC-020, PRC-021, PRC-022	Undervoltage Load Shedding Program	Combined portions of the NERC standards into one standard modified for Hawaii.
HI-PRC-012-0	PRC-012, PRC-013, PRC-014, PRC-015, PRC-016, PRC-017	Special Protection Systems	Combined portions of the NERC standards into one standard modified for Hawaii.
HI-PRC-002-0	PRC-002, PRC-018	Disturbance Monitoring Equipment Installation and Data Reporting	Combined portions of the NERC standards into one standard modified for Hawaii.
	FAC-001	Facility Connection Requirements	Connection requirement are covered in Rules
	FAC-002	Coordination of Plans For New Generation, Transmission, and End-User Facilities	This standard is really needed to require coordination between various entities that do not exist in Hawaii.

FAC-003	Transmission Vegetation Management	This is an operations issue and not recommended for conversion.
FAC-008	Facility Ratings	This is an operations issue and not recommended for conversion.
FAC-009	Establish and Communicate Facility Ratings	This is an operations issue and not recommended for conversion.
FAC-010	System Operating Limits Methodology for the Planning Horizon	This standard is not needed since there is only one entity doing the planning for a system.
FAC-011	System Operating Limits Methodology for the Operations Horizon	This standard is not needed since there is only one entity doing the planning for a system.
FAC-012	Transfer Capability Methodology	Deals with the larger structure of the mainland utilities and are not need for the simpler organization in Hawaii.
FAC-013	Assessment of Transfer Capability for the Near-term Transmission Planning Horizon	Deals with the larger structure of the mainland utilities and are not need for the simpler organization in Hawaii.

TABLE C-1

STANDARDS THE RSWG IS NOT RECOMMENDING FOR STAND-ALONE ADOPTION IN HAWAII		
RELEVANT NERC STANDARD	**TOPIC**	**COMMENTS**
BAL-003	Frequency Response & Bias	Recommended as an operating procedure
BAL-005	Automatic Generation Control	Incorporated in BAL-001

TABLE C-2

STANDARDS THE RSWG IS NOT RECOMMENDING FOR ADOPTION IN HAWAII		
RELEVANT NERC STANDARD	**TOPIC**	**COMMENTS**
BAL-004	Time Error Correction	Standard not required for Hawaii
BAL-006	Inadvertent Interchange	There is only a single control area per island so there is no inadvertant interchange.
COM-001	Communications	Primarily deals with communication between different entities for the mainland system. The BA only need to communicate with the generator operators in Hawaii see R5.4 and R8.1. This standard is not required.
COM-002	Communication and Coordination	To ensure verbal communication between entities. A standard is not required for this.
CIP-0XX	Version X CIP Cyber Security Standards	Adopting these standards would not be practical due to the difference between the Hawaii systems. It could be feasible to make a simpler best practice standard.
EOP-002	Capacity and Energy Emergencies	Generally this is just good engineering practice and not a standard requirement.
EOP-003	Load Shedding Plans	Generally this is just good engineering practice and not a standard requirement.
EOP-004	Event Reporting	
EOP-006	Reliability Coordination – System Restoration	Not required since there is only one entity
FAC-014	Establish and Communicate System Operating Limits	This standard is not needed since there is only one entity doing the planning for a system.
INT-0XX	Interchange Scheduling and Coordination	The 9 standards deal with interchange scheduling and coordination and not required since there is only one BA per island.
IRO-0XX	Interconnection Reliability Operations Standards	The 12 standards deal with the interconnection and are directed towards a Reliability Coordinator which does not exist in Hawaii.
MOD-001	Available Transmission System Capability	This is for Transmission Service Providers, enity does not currently exist in Hawaii
MOD-004	Capacity Benefit Margin	Capacity Benefit Margin (CBM) not used in Hawaii

MOD-008	Margin Calculation Methodology	Standard for methodology not required in Hawaii.
MOD-028	Area Interchange Methodology	Methodology to calculate area interchange, not requried in Hawaii.
MOD-029	Rated System Path Methodology	Methodology to calculate total transfer capability, not required in Hawaii.
MOD-030	Flowgate Methodology	Methodology to calculate transfer capability, not required in Hawaii.
NUC-001	Nuclear Plant Interface Coordination	Not applicable, there are no nuclear plant in Hawaii.
PER-003	Operating Personnel Responsibility and Authority	This is good engineering practice that they can do the job.
PER-004	Operating Personnel Credentials	Certified through the NERC System Operator Certification Program is not required for Hawaii.
PRC-023	Transmission Relay Loadability	Protective relay settings shall not limit transmission loadability. This does not appear to be relevent to Hawaii
TOP-001	Transmission Operations	This is an operations standard and not recommended for conversion.
TOP-002	Operations Planning	This is an operations standard and not recommended for conversion.
TOP-003	Operational Reliability Data	This is an operations standard and not recommended for conversion.
TOP-004	Transmission Operations	This is an operations standard and not recommended for conversion.
TOP-005	Operational Reliability Information	This is an operations standard and not recommended for conversion.
TOP-006	Monitoring System Conditions	This is an operations standard and not recommended for conversion.
TOP-007	Limit (SOL) and Interconnection Reliability	This is an operations standard and not recommended for conversion.
TOP-008	Response to Transmission Limit Violations	This is an operations standard and not recommended for conversion.
VAR-001-3	Voltage and Reactive Control	This is an operations standard and not recommended for conversion.
VAR-002-2b	Maintaining Network Voltage Schedules	This is an operations standard and not recommended for conversion.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** HI-BAL-001-0
3. **Purpose:** To maintain system steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:** Balancing Authorities (BA),
5. **Effective Date:** TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)
6. **Exclusions:** The BA shall be excluded from meeting this standard for extraordinary contingencies. Extraordinary Contingency shall *mean any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency, including but not limited to transmission and distribution events if such act or cause results in any contingency contemplated in any Hawaii Reliability Standard(e.g., the "Most Severe Single Contingency" as defined in the Hawaii Reliability Criteria or any lesser contingency).*

B. Requirements

R1. The Balancing Authority (BA) for each island shall operate such that the Compliance Population 1 (CP1%) expressed in percent, on a rolling 12-month basis, of the absolute value of the frequency error from the actual frequency minus the nominal frequency is above 98.3% as defined in the equations below.

The equation for frequency error (ΔF) is:

$$\Delta F = FA - FS$$

Where:

- FA is the actual frequency Hz.
- FS is defined as the normal frequency target of 60.000 Hz. (Scheduled frequency other than 60.000 Hz shall be treated as 60.000 for reporting and measurement purposes)

Compliance Population in percent (CP1%) is:

$$CP1\% = \text{number of samples meeting criteria} \Delta F < "x" \text{ntotal valid sample} \times 100$$

Where:

- The minimum acceptable population of samples within the control region boundary is 98.3%.
- "x" is 0.055 Hz and represents the control region boundary from the normal frequency target.
- ΔF is the absolute value of the frequency error measured in Hz for valid samples.

- "n" is the total number of valid samples[1]

R2. The Balancing Authority (BA) for each island shall operate such that the Compliance Population 2 (CP2%) expressed in percent, on a 24-hour basis, of the absolute value of the frequency error from the actual frequency minus the nominal frequency is above 98.3% as defined in the equations below.

The equation for frequency error (ΔF) is:

$$\Delta F = FA - FS$$

Where:

- FA is the actual frequency Hz.
- FS is defined as the normal frequency target of 60.000 Hz. (Scheduled frequency other than 60.000 Hz shall be treated as 60.000 for reporting and measurement purposes)

Where:

Compliance Population in percent (CP2%) is:

$$CP2\% = number\ of\ samples\ meeting\ criteria \Delta F < "y" n total\ valid\ sample \times 100$$

Where:

- "y" is 0.055 Hz and represents the control region boundary from the normal frequency target.
- The minimum acceptable population of samples within the control region boundary is 98.3%.
- ΔF is the absolute value of the frequency error measured in Hz for valid samples.
- "n" is the total number of valid samples[2]

Each day that does not meet the CP2% compliance will be counted as a violation. The summation of the violations for the calendar month shall not exceed 10.

R3. The BA for each island shall maintain the Monthly Total Number (MTN) in percent of valid samples of not less than 99.9% of the maximum total number of samples per month based on the scan rate. The expected sample rate is to be not greater than a 2 second scan rate. (For purposes of the test standard, 12-month historical 2 second data will be used to determine frequency performance)

R3.1. Each BA shall maintain Regulating Reserve to meet the Requirements R1 and R2.

R3.2. The BA shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the BA's control center and other critical locations to ensure continuous operation of regulation control and vital data recording equipment during loss of the normal power supply.

[1] All samples during the disturbance recovery period, as defined in HI-BAL-002, shall be considered not valid samples and excluded from the CPS1% and CPS2% calculation.
[2] Ibid

R3.3. Each BA shall provide redundant and independent frequency measuring equipment that shall automatically activate upon detection of failure of the primary source.

R3.4. Each BA shall at least annually check and calibrate its time error and frequency devices against a common reference. The BA shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
Remote terminal unit [3]	≤ 0.25 % of full scale

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CP1%) Compliance Population of 98.3%. Each Balancing Authority shall be able to re-calculate and store each the number of samples where $\Delta F<"x"$ and the total number of valid samples, for each clock-hour, as well as for each of the twenty-four (24) hours (one for each clock-hour, ie., hour-ending (HE) 0100, HE 0200, ..., HE 2400). Each sample shall have a date-time stamp to uniquely identify each sample.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement 2 (CP2%) Compliance Population of 98.3%. The calculation will be the same as M1 except "y" in lieu of "x" and the period will be 24-hours. Then, each day that does not meet the CP2% compliance will be counted as a violation. The summation of the violations for the calendar month shall not exceed 10.

M3. Each Balancing Authority shall achieve, as a minimum, Requirement 3 (MTN) Monthly Total Number of 99.9%. The Monthly Total Number shall be the total number of valid samples (*ntotal valid sample*) divided by the total available of samples possible in the calendar month expressed in percent.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar month

1.3. Data Retention

The data that supports the calculation Appendix 1 are to be retained in electronic form for at least a two year period. If the data for the Balancing Authority Area is undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

None

[3] Requirement if Remote Terminal Unit used for frequency measurement for Requirement R1 and R2.

2. **Levels of Non-Compliance – CP1%**

   2.1. Level 1

   The Balancing Authority Area's value of CP1% is less than 98.3% but greater than or equal to 98.1%.

   2.2. Level 2

   The Balancing Authority Area's value of CP1% is less than 98.1%.

3. **Levels of Non-Compliance – CP2%**

   3.1. Level 1

   The Balancing Authority Area's value of number of day that CP2% is in violation is less than 12 but greater than or equal to 10.

   3.2. Level 2

   The Balancing Authority Area's value of the number of days that CP2% is in violation is greater than 12.

4. **Levels of Non-Compliance – MNT**

   4.1. Level 1

   The Balancing Authority Area's value of MNT is less than 99.9% but greater than or equal to 99.8%.

   4.2. Level 2

   The Balancing Authority Area's value of MNT is less than 99.8%.

E. Associated Documents

1. Appendix 1 – HI-BAL-001-0.

Version History

Version	Date	Action	Change Tracking

Appendix 1 – HI-BAL-001-0

CP1% and CP2% Data

CP1% and CP2% DATA	Description	Retention Requirements
"x"	A constant determined in Hz for each BA's.	Retain the value of "x" used in the CP1% calculation
"y"	A constant determined in Hz for each BA's.	Retain the value of "y" used in the CP2% calculation
FA	Is the actual frequency Hz for the Balance Authority Area.	Retain the values of FA used in the calculation for the period of two years.
FS	Is the normal frequency target of 60.000 Hz for the Balance Authority Area.	

MTD Data

MTD DATA	Description	Retention Requirements
ntotal valid sample	Is the total number of valid samples per calendar month.	Retain the values of *ntotal valid sample* used in the calculation for the period of two years.

Tawhiri Statement of Objection to BAL-001

BAL-001 is a useful standard. However, it contains numbers that cast in concrete a frequency regulation requirement that is anti-renewable and in particular is onerous for wind and solar. The standard establishes an unnecessarily stringent requirement that will be costly to rate payers. The standard establishes a regulation performance requirement that greatly exceeds that of any other renewables-friendly utility. HECO has declared that they will not relax the standard because doing so will degrade power quality and reliability. Relaxing the standard will not do this. Many other utilities have a less strict regulation requirement but have not experienced such problems. There appears to be no plan to require a review or analysis of the basis of this standard and change it as appropriate to accommodate renewables and reduce costs to rate payers.

This standard requires that 98.3% of two-second frequency measurements in a year show frequency between 59.95 and 60.05 Hz. The utility is obligated to achieve this standard year after year. Doing so may require running fewer as-available renewables and more thermal plants that provide regulation. The result will be increasing curtailment of wind and solar plants as renewables increase. Eventually, costly batteries or flywheels on the utility grid or in renewables plants will be required. HECO may also find it necessary to require wind plants to reduce output so they can provide regulation. The result will be ever increasing curtailment and investment at ratepayer expense to meet an unnecessarily strict requirement that is 250% more restrictive than found in renewables-friendly utilities around the world.

Reliability will not be reduced by relaxing the frequency regulation requirement. HECO has argued that allowing the frequency to fluctuate can increase the load shedding that occurs upon a generator trip. The argument is that if the frequency is lower when a generator trips, the frequency will drop lower and potentially result in more load shedding. This argument neglects that frequency will be higher than 60 Hz half of the time and that will reduce load shedding. The two are a wash; reliability is not an issue.

Power quality is also not an issue. Customer loads are not sensitive to second to second frequency fluctuations. Indeed, requests that HECO present complaints received from customers triggered by frequency deviations elicited no response. Utilities that have relaxed frequency regulation requirements have not found such problems. Clocks often come to mind but few clocks now use frequency for time keeping and in any event only day to day accumulated frequency error is a clock problem. Frequency fluctuations are not.

Maintaining tight frequency regulation has the additional cost of increased wear-and-tear on generators. With a larger frequency fluctuation tolerance, more frequency excursions will be self-correcting thus reducing generator regulation activity and it's consequent wear-and-tear.

Systems that encourage renewable energy such as Europe, the Nordel gird, New Zealand, and many others allow frequency to vary over more than twice the range established by HECO in BAL-001. In Europe and the Nordel grid the allowed deviations are 0.1 Hz on a 50Hz system (0.2%) compared with HECO's 0.05Hz on a 60 Hz system (0.083%). Their allowed frequency fluctuation is 2.5 times greater than HECO's. Some utilities including islands allow even larger second to second frequency fluctuations.

No engineering analysis was done to justify BAL-001. Had BAL-001 been based on sensible engineering; for instance a review of what the rest of the world is doing, it would not contain the needlessly tight and costly frequency regulation requirement. The standard should be subject to a proper engineering analysis.

A. Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** HI-BAL-002-0
3. **Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return System frequency within defined limits following a Reportable Disturbance. Both loss of generation and loss of load events are significant and both up and down reserves are required. Contingency Reserve activation applies to the loss of load as well as the loss of supply.
4. **Applicability:**
   - **4.1.** Balancing Authorities (BA)
5. **Effective Date:** TBD
6. **Exclusions:**
   - **6.1.** **Catastrophic Contingency Event**: Any contingency event (greater than the Maximum N-1 Contingency Criteria event) whose total requirements exceed the total amount of Contingency Reserves plus Protection Reserves within the Balancing Authority Area.
   - **6.2.** **Variable Generation Contingency**: Contingency Reserves utilized to cover unforecasted, unscheduled and/or unanticipated ramping events of renewable generation that do not trigger a reportable event shall not be counted as Contingency Reserve deficiency in reporting requirements.

B. Requirements

R1. The Balancing Authority shall have access to and/or operate Contingency Reserve to respond to disturbances. Contingency Reserve may be supplied from generation, controllable load resources, under frequency load shedding, and storage devices. The BA shall specify its Contingency Reserve criteria. As a minimum, the Balancing Authority shall carry at least enough Contingency Reserve to cover the most severe single contingency of generation and/or transmission that impact Contingency Reserve requirements. The requirements of the under frequency load shedding (UFLS) protection system shall define the amount of load shed at each stage and the contingency utilized to define the requirements of each stage. Up to 100% of the Contingency Reserve may be supplied by a portion of the UFLS Protection Reserves however; in no instance shall Contingency Reserves utilize 100% of the protection reserves.[1]

R2. Following a Reportable Single Contingency Disturbance, the Balancing Authority shall activate sufficient Contingency Reserve to return frequency to 60.3 or 59.7 Hz, within the Disturbance Recovery Period for 100% of Reportable Single Contingency Disturbances.

- **R2.1.** In general, the frequency recovery period shall be less than the damage and trip points for all generation resources within the balancing area such that no generation resource is damaged or lost due to the lack of frequency recovery. The Actual Disturbance Recovery Period shall be defined as the actual time required to restore the frequency from the time of the initiating event to the time the frequency is within the frequency limits of 60.3 to 59.7 Hz. The Standard Disturbance Recovery Period ($RSDRP1$) for single-contingency events is 10 minutes.

[1] The purpose of the UFLS system is to protect the system from an instantaneous imbalance between load and generation, including the supply in part or in whole of required contingency reserves.

R3. For Reportable Single Contingency Disturbance events a Balancing Authority shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for 100% of the Reportable Single Contingency Disturbances

R3.1. The Contingency Reserve Restoration Period begins at the end of the Actual Disturbance Recovery Period and is the time required to fully restore the Contingency Reserve following the Disturbance Recovery Period. The Contingency Reserve Restoration Period is defined as the period required to re-establish the Contingency Reserves utilized during the Actual Disturbance Recovery Period such that the system can sustain another contingency event under R2. Frequency deviations caused by the restoration of loads during the Contingency Reserve Restoration Period shall not constitute a new event under R2.1. The Standard Contingency Reserve Restoration Period is 120 minutes.

R4. Following a Reportable Excess Contingency Disturbance, the Balancing Authority shall *activate sufficient controls or actions to return frequency to 60.5 or 59.5Hz, within the* Disturbance Recovery Period for 100% of Reportable Excess Contingency Disturbances. The Standard Excess Contingency Disturbance Recovery Period ($RSDRP2$) for excess contingency disturbance events is 10 minutes.

R4.1. In general, the frequency recovery period shall be less than the damage, trip points and control instability regions for all generation resources within the balancing area such that no generation resource is damaged or lost due to the lack of frequency recovery. The Actual Disturbance Recovery Period is defined as the actual time required to restore the frequency from the time of the initiating multi-contingency event or the last in a series of contingency events to the time the frequency is within the frequency limits of 60.5 to 59.5Hz.

C. Measures For Reportable Excess Contingency Disturbance events a Balancing Authority must not be required to fully restore its Contingency Reserves until such a time that the BA determines that additional reserves are available and under the control of the BA to initiate the restoration of Contingency Reserves. For Reportable Excess Contingency Reserve events there will be no maximum required Contingency Reserve Restoration Period.

M1. The Balancing Authority must have documentation that it maintained 100% of the Contingency Reserve levels based upon data integrated over each clock hour except within the period of time determined by the sum of the Disturbance Recovery Period, plus the Contingency Reserve Restoration Period following the start of a Reportable Single Event Disturbance or a Reportable Excess Contingency Disturbance. For each hour the Balancing Authority shall have and provide upon written request by the Hawaii PUC (or designee) their Contingency Reserve requirement in MW, the calculations that define the reserve requirement in accordance with the reserve criteria, and the amount of Contingency Reserve available in MW from each Contingency Reserve resource.

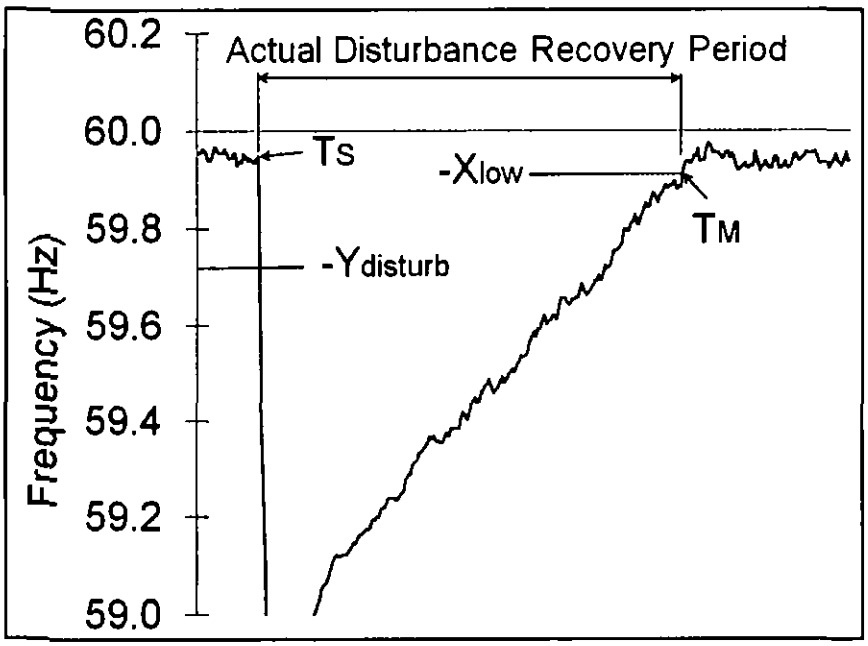
M2. The Balancing Authority shall have documentation that the system returned to the frequency range of 60.3 to 59.7 Hz, within the Actual Disturbance Recovery Period following each Reportable Single Contingency Disturbance. The Disturbance Control Standard for Reportable Single Contingency Disturbance(s) is measured as the monthly average recovery time in percent of the Standard Recovery Period.

The equation for Actual Disturbance Recovery Period ($\Delta Tf1$) is:

$$\Delta Tf1 = TM - TS$$

Where:

- *TM* is the time when system frequency returned to the respective limit, 60.3 or 59.7 Hz following the initial reportable disturbance.
- *TS* is the time at the start of the reportable disturbance.



Reportable Single Contingency Disturbance

The monthly average Disturbance recovery time ($Rf1avg$) in percent of the Standard Recovery Period is:

$$Rf1avg = 100 * number\ of\ events \Delta Tf1\ RSDRP1 * ntotal\ events$$

Where:

- $\Delta Tf1$ is the Disturbance recovery time in minutes for each disturbance.
- $RSDRP1$ is the Standard Recovery Period in minutes for a Single Contingency Disturbance.
- "n" is the total number of reportable events per month.

The Balancing Authority shall have records that indicate the number of Single contingency events and the number of events whose individual Actual Contingency Recovery period was greater than the Standard Contingency Recovery Period in each reporting interval (months).

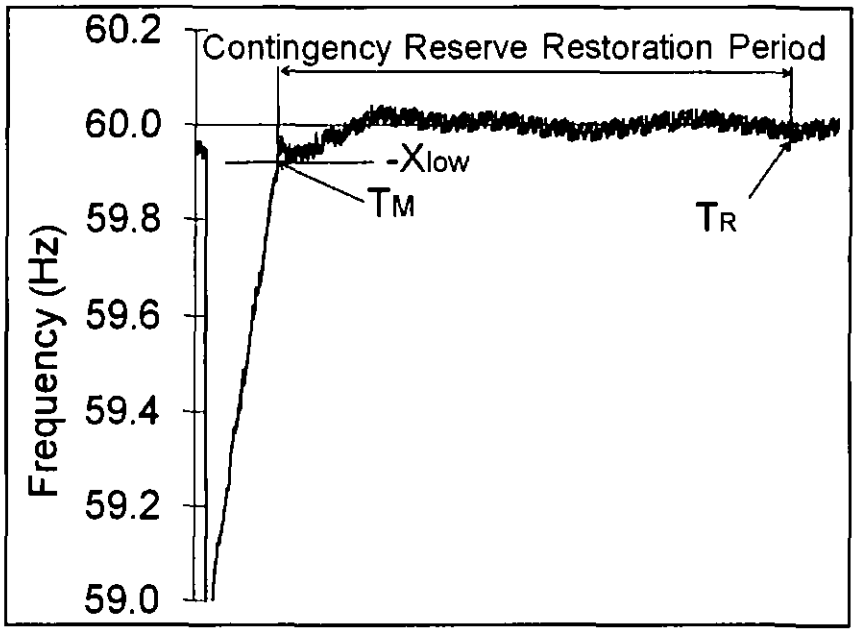
M3. The Balancing Authority shall have documentation to determine the Contingency Reserve Restoration Period to restore Contingency Reserve after the reportable disturbance.

The equation for Contingency Reserve Restoration Period (ΔTCR) is:

$$\Delta TCR = TR - TM$$

Where:

- *TM* is the time when system frequency returned to the respective limit, 60.3 or 59.7 Hz following the start of the reportable disturbance.
- *TR* is the time when the Contingency Reserve has been restored.



Reportable Single Contingency Disturbance

The monthly average Contingency Reserve restoration recovery period (*Rcrrpavg*) in percent of the Standard Contingency Reserve Restoration Period is:

$Rcrrpavg = number\ of\ events \Delta TCR 1.2 * ntotal\ events$

Where:

- *ΔTCR* is the Contingency Reserve Restoration Period in minutes for each disturbance.
- The Standard Contingency Reserve Restoration Period is 120 minutes.
- "n" is the total number of reportable events per month.

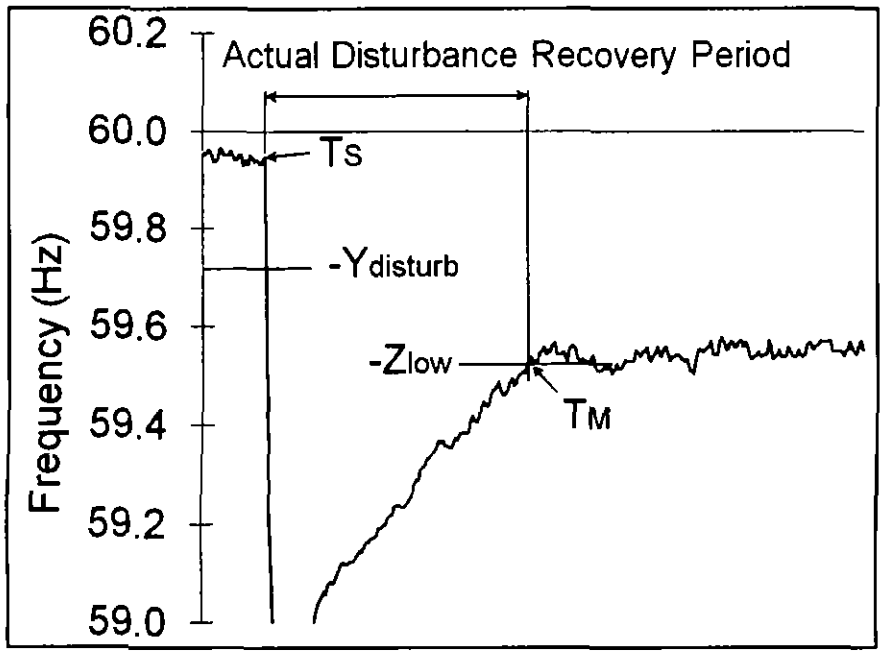
M4. The Balancing Authority shall have documentation that the system returned to the frequency range of 60.5 to 59.5 Hz, within the Disturbance Recovery Period following each Reportable Excess Contingency Disturbance. The Disturbance Control Standard for Reportable Excess Contingency Disturbance(s) is measured as the monthly average recovery time in percent of the Standard Recovery Period.

The equation for Actual Reportable Excess Disturbance Recovery Period ($\Delta Tf2$) is:

$$\Delta Tf2 = TM - TS$$

Where:

- *TM* is the time when system frequency returned to the respective limit, 60.5 to 59.5 Hz following the initial reportable disturbance.
- *TS* is the time at the start of the reportable disturbance.



Reportable Excess Contingency Disturbance

The monthly average Excess Contingency Disturbance Recovery Period in (*Rf2avg*) in percent is:

$$Rf2avg = 100 * number\ of\ events \Delta Tf2 RSDRP2 * ntotal\ events$$

Where:

- *ΔTf2* is the Disturbance recovery time in minutes for each disturbance.
- *RSDRP2* is the Standard Recovery Period in minutes for an Excess Contingency Disturbance.
- "n" is the total number of reportable events per month.

The Balancing Authority shall have records that indicate the number of Excess contingency events and the number of events whose individual Actual Contingency Recovery period was greater than the Standard Contingency Recovery Period in each reporting interval (months).

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured in percent as set forth in the measures M2, M3 and M4 above.

The Balancing Authority shall submit a Disturbance Control Standard Report to the PUC no later than the 10th day following the end of the calendar month.

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar *month without a violation.*

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits - The Hawaii PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a two-year period. If the DCS data for a Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

2. Levels of Non-Compliance

The Balancing Authority not meeting the DCS during a given calendar month shall initiate a study to increase its contingency reserve obligation or decrease the events creating the disturbances to achieve compliance in the following month.

A representative from the Balancing Authority that was non-compliant in the calendar month most recently completed shall provide written documentation verifying that the Balancing Authority will provide a report to the Hawaii PUC (or designee) outlining what positive measures have been taken to increase the level of compliance into agreement with the standard. The written documentation shall accompany the monthly Disturbance Control Standard Report when a Balancing Authority is non-compliant.

3. Levels of Non-Compliance for Requirement R1, Measure M1

3.1. Level 1 - The BA failed to meet one of the following conditions for Requirement R1 and Measurement M1:

3.1.1 Failed to meet the Contingency Reserve requirement 100% of the time but greater than 95%;

3.1.2 Failed to provide the required calculations that define the reserve requirement in accordance with the reserve criteria; and

3.1.3 Failed to provide the amount of Contingency Reserve available in MW from each Contingency Reserve resource.

3.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

4. **Levels of Non-Compliance for Requirement R2, Measure M2**

4.1. **Level 1** – The BA achieved a monthly average Disturbance recovery time (*Rf1avg*) greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period)

4.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

5. **Levels of Non-Compliance for Requirement R3, Measure M3**

5.1. **Level 1** – The BA achieved a monthly average Actual Contingency Disturbance Reserve recovery period (*Rcrrpavg)*greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period)

5.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

6. **Levels of Compliance for Requirement R4, Measure M4**

6.1. **Level 1** - *The BA achieved a monthly average Excess Contingency Disturbance* Recovery Period (*Rf2avg*) greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period)

6.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Standard BAL-502-0 - Planning Resource Adequacy Analysis, Assessment and Documentation**
2. **Number:** HI-BAL-502-0
3. **Purpose:** To establish common criteria for each BA based on "one day in "X" year" (determined by study) loss of Load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, shall include Planning Reserve Margins for meeting system load for the BA's System.
4. **Applicability:**
   - **4.1.** Balancing Authorities (BA) are divided into two groups based on the annual system Peak Demand.
     - **1.4.1.** **Group A** - Annual system peak is greater than or equal to 50 MW.
     - **1.4.2.** **Group B** - Annual system peak is less than or equal to 50 MW.
5. **Effective Date:** TBD

B. Requirements

R1. The goal of the Resourced Adequacy analysis is to plan the system to meet the following requirements annually.

R1.1. Group A – "one day in X year criteria". The utility shall establish the methodology and procedures used to establish the "one day in X year" criteria. The methodology should evaluate the reliability of service, the net present value of resource commitment and the alternatives to resource commitment available to meet the desired reliability criteria for each of the BA's utility loss of Load expectations methodologies.

R1.2. **Group A** - The total amount of Firm Generation unit(s) of the Balance Authority's system that shall include capability from storage resources if appropriate and designated for serving the entire period of the peak, plus the total amount of interruptible loads must be equal to or greater than the summation of the following:

- The capacity needed to serve the Forecasted Peak Demand.
- The capacity of the unit(s) scheduled for maintenance; and
- The capacity that would be lost by the Forced Outage of the largest unit/resource in service.

$$i=1NNi+LDR\geq(LPeak*FRM+m=1NNm+NFO)$$

Where:

- Ni is the Normal Net Capability of available units.
- LDR is the amount of Interruptible Demand and DCLM designated and measureable for the BA's interruption for the entire period of the expected capacity shortfall

- *LPeak* is the estimated system peak load and losses served from the available generation.
- *Nm* is the Normal Net Capability of units on scheduled maintenance.
- *NFO* is the Normal Net Capability of the largest available unit(s) lost by Forced Outage.
- *FRM is the Reserve Margin multiplier and the BA must give consideration to* using xx percent (1.xx) based on the reserve net capability.

However, in no case shall the selection of *FRM* in relationship to Normal Net Capability of the largest available unit(s) cause a shortage to serve the estimated system peak load and losses. Further, the analysis shall also consider all forecasted daily peak loads and losses and the annual maintenance schedule of all resources in the BA.

Group B - Group B shall use the same planning methodology as group A except there shall be no provision for using the loss of load expectation methodology.

R1.3. The Resource Adequacy analysis must calculate a Planning Reserve Margin for the applicable group that will either result in the sum of the probabilities for Loss of Load for the system Peak Demand for all days of each planning year[1] analyzed (per R1.3) being equal to ____. (This is comparable to a "one day in x year" criterion) or document that the applicable Balance Authority has developed a resource plan that encompasses a xx% Reserve Margin. The reserve margin shall be utilized until such a time that a new study determines a change in the reserve margin is warranted.

R1.3.1. The Reserve Margin shall be established by study for each BA utilizing *FRM* within its planning process.

R1.3.2. The utilization of DCLM or curtailment of Interruptible Demand must not contribute to the loss of Load probability.

R1.3.3. The Planning Reserve Margin developed from R1.2 must be expressed as a percentage of the median[2] forecast peak Net Internal Demand (Planning Reserve Margin).

R1.4. Be performed or verified separately for each of the following planning years:

R1.4.1. Perform an analysis for Year One.

R1.4.2. Perform an analysis or verification when changes in measured non-dispatchable generation or net load changes more than _ MW/year or _ MW (amount established by each BA) from Year One or there are planned or unplanned changes in resource development other than non-dispatchable generation or DG.

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low(50:50).

R1.5. Include the following subject matter and documentation of its use:

R1.5.1. Load forecast characteristics:

- Median forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- *Contractual arrangements concerning curtailable/Interruptible Demand.*
- Load response to frequency and short and long-term changes in voltage.

R1.5.2. Resource characteristics:

- Historic resource performance and any projected changes.
- Seasonal resource ratings.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind, PV, and cogeneration.
- Criteria for including planned resource additions in the analysis
- Starting/loading time if resources are to used as Contingency Reserves
- Frequency response characteristics
- Inertia response characteristics
- Frequency ride-through characteristics
- Voltage ride-through characteristics
- Short circuit current characteristics
- Dispatch characteristics (ramp rate, minimum values, regulation, etc)

R1.5.3. Transmission limitations that prevent the delivery of generation reserves

R1.5.3.1. Criteria for including planned Transmission Facility additions in the analysis

R1.5.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements

R1.6. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- *Market resources not committed to serving Load (uncommitted resources)* within each Balance Authority's Control Area.

R1.7. Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

R1.8. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.9. Document that all Load in the Balance Authority's Area is accounted for in its Resource Adequacy analysis

R2. The BA must annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years in Year One through ten.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 calendar days prior to the beginning of Year One.

C. Measures.

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2. The BA must possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   1.1.1. Hawaii PUC (or designee)

   1.2. Compliance Monitoring Period and Reset Timeframe

   1.2.1. One calendar year

   1.3. Data Retention

   1.3.1. The BA must retain information from the most current and prior two years. The Hawaii PUC (or designee) will retain any audit data for five years.

2. **Levels of Non-Compliance for Requirement R1, Measure M1**

   2.1. Level 1 – The BA met one of the following conditions for Requirement R1 and Measurement M1.

   2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

   2.1.2. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.5.

   2.2. Level 2 - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. **Levels of Non-Compliance for Requirement R2, Measure M2**

   3.1. Level 1 – The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

   3.2. Level 2 - The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2. The PUC or its designee shall give notice to the BA within 30 days of

years' end for a compliance audit and shall complete such audit within 90 days of such information being supplied by the BA.

Version History

Version	Date	Action	Change Tracking

November 5, 2012

Consumer Advocate's Comments to the Hawaii Modeling Reliability Standards, voted on by email on October 29, 2012

As expressed in its vote on October 29, 2012 regarding the Hawaii Modeling Reliability Standards (i.e., HI-MOD-010-0, HI-MOD-012-0, HI-MOD-016-0, HI-MOD-025-0, HI-MOD-026-0, HI-MOD-027-0), the Consumer Advocate votes yes, in concept, to these proposed MOD standards. The Consumer Advocate notes that the proposed MOD standards set forth several tasks (e.g., identification of acceptable models, filing of modeling data) for both the HECO Companies and independent power producers ("IPP"). In doing so, the Consumer Advocate observes that it has not been made clear how the proposed standards will facilitate one of the RSWG objectives of increasing renewable energy. There are also uncertainties regarding the costs that will be incurred by both the HECO Companies and the IPPs to execute these various tasks. Thus, while others have generally noted that the establishment of such standards will provide a transparency to reliability that meets the RSWG objectives, the Consumer Advocate only supports the concept of the proposed MOD standards at this time. The Consumer Advocate recognizes that some of its concerns can be addressed in future actions by the Commission as described in Order No. 30694 Clarifying Certain Procedural Matters, filed on October 18, 2012, in which further input from other stakeholders can provided and the impacts to ratepayers and the IPPs can be assessed.

A. Introduction

1. **Title:** **Development and Reporting of Steady State System Models and Simulations**
2. **Number:** HI-MOD-010-0
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Transmission systems including the aggregate impact of distributed generation.
4. **Applicability:**

   4.1. Functional Entities

   4.1.1. Balancing Authorities (BA)

   4.1.2. Generator Owner(s)

   4.1.3. Transmission Owner(s)

   4.2. Facilities: The Facilities are divided into two groups based on the annual system peak demand.

   4.2.1. Group A - Annual system peak is greater than or equal to 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2. Group B - Annual system peak is less than 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

B. Requirements

R1. The BA shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for the system. The BA shall document their steady-state data requirements and reporting procedures, shall review those data requirements and reporting procures (at least every five years), and shall make the data requirements and reporting procedures available on written request (within 30 calendar days) to the Hawaii PUC (or designee). The BA shall distribute the requirements to all Generator and Transmission Owners within its area. The system requirements shall include the following steady-state data requirements:

R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per HI-MOD-16-0 and location.

R1.2. Generating Units (including storage devices, synchronous condensers, thermal, hydro, wind etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage range, and aggregate modeling of distributed generation. DG below the applicable Group rating shall be aggregated and included with data as part of HI-MOD-16-0.

R1.3. AC Transmission line (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings, equipment status and metering locations.

R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings, and equipment status.

R1.6. Reactive Compensation (shunt and series capacitors and reactors, static var compensators, and statcoms): nominal Ratings, impedance, percent compensation, connection point, and controller device.

R2. Each Transmission Owner or Generator Owner within the applicable group shall provide appropriate equipment characteristics and system data in compliance with its respective Balancing Authority's requirements and reporting procedures as defined in R1. The reporting of the data will be based on four triggers:

R2.1. The BA's data reporting schedule (if any).

R2.2. When the BA has requested in writing (within 30 calendar days).

R2.3. When the Owner has completed commercial operation of a new facility or significant modification (within 30 calendar days).

R2.4. Whenever equipment characteristics experience a change that is expected to last more than 60 days (within 60 calendar days).

R3. The BA shall develop and maintain a library of solved (converged) transmission system – specific steady-state system models, including the relevant portions of the distribution system connecting distributed generation. The transmission system – specific steady-state system models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum and other appropriated system demand levels. The BA shall develop steady-state system models annually. The BA shall provide the most recent solved (converged) steady state models on written request (within 30 calendar days) to the Hawaii PUC (or designee).

C. Measures

M1. The BA shall maintain evidence such as reports, or other documentation of its requirements and reporting procedure per Requirement R1, Parts 1.1 through 1.6.

M2. Each Transmission Owner or Generator Owner shall have dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the data requirement and reporting procedures as specified in Requirement R1 were complied with.

M3. The BA shall have dated evidence for transmission-specific steady state system models as specified in Requirement R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority**

   Hawaii PUC (or designee)

   1.2. ***Compliance Monitoring Period and Reset Timeframe***

   1.2.1. Periodic review of data requirements and reporting procedures: at least every five years.

   1.2.2. Development of steady-state system models: Annually.

   1.2.3. Most recent steady-state system models: 30 calendar days.

   1.3. **Data Retention**

   Evidence of compliance with R1, R2 and R3 shall be kept for five years or until the next audit, whichever is longer, unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation..

2. **Levels of Non-Compliance for Requirement R1, Measure M1**

   2.1. **Level 1** - The BA met one of the following conditions for Requirement R1, Measure M1.

   2.1.1. Data of one of the Parts R1.1 through R1.2 is incomplete.

   2.1.2. Failed to provide data to the Hawaii PUC (or designee) within 30 calendar days but less than 45 calendar days.

   2.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. **Levels of Non-Compliance for Requirement R2, Measure M2**

   3.1. **Level 1** – The Transmission Owner or Generator Owner failed to meet one of the following conditions to supply applicable data to the BA as described in Requirement R1 and Measurement M1.

   3.1.1. Data requirements and reporting procedures for steady-data were provided, but were incomplete in one of the six areas defined in R1.

   3.1.2. Upon written request, failed to provide data to the BA within 30 calendar days but less than 45 calendar days.

   3.1.3. Upon completion of commercial operation of a new facility, failed to provide data to the BA within 30 calendar days but less than 45 calendar days.

   3.1.4. Upon change of equipment characteristics, failed to provide data to the BA within 60 calendar days but less than 75 calendar days.

   3.2. **Level 2** – The Transmission Owner or Generator Owner failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. **Levels of Non-Compliance for Requirement R3, Measure M3**

   4.1. **Level 1** - The BA failed to meet one of the following conditions to supply applicable data to the Hawaii PUC (or designee) as described in Requirement R3 and Measurement M3.

   4.1.1. Upon written request, failed to provide data within 30 calendar days but less than 45 calendar days.

4.1.2. One of the BA's cases was not fully solved/initialized or had other identified errors.

4.2. **Level 2** – The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Development and Reporting of Dynamic System Models and Simulations**
2. **Number:** HI-MOD-012-0
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the BA's transmission systems including the aggregate impact of distributed generation and to assure that generator and transmission system data is reported.
4. **Applicability:**

   4.1. Functional Entities

   4.1.1. Balancing Authorities (BA)

   4.1.2. Generator Owner(s)

   4.1.3. Transmission Owner(s)

   4.2. Facilities: The Facilities are divided into two groups based on the annual system peak demand.

   4.2.1. Group A - Annual system peak is greater than or equal to 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2. Group B - Annual system peak is less than 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

B. Requirements

R1. The BA shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior of the System. The BA shall document their dynamic data requirements and reporting procedures (at least every five years), and shall provide upon written request these data requirements and reporting procedures to the Hawaii PUC (or designee) within 30 calendar days. The BA shall provide the data requirements to the Transmission Owners and Generation Owners within its area annually. Each set of transmission system dynamics data requirements shall include the following:

R1.1. Design data shall be provided for new or refurbished excitation systems (for synchronous generators and synchronous condensers) at least three months prior to the installation date.

R1.1.1. If design data is unavailable from the manufacturer 3 months prior to the installation date, *estimated or typical manufacturer's data, based on excitation* systems of similar design and characteristics, shall be provided.

R1.2. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulator type and IEEE Model data, turbine-governor system type and IEEE model data, power system stabilizer type and IEEE model data, and other associated generation equipment models (block diagram) and data. Where standard IEEE models are not appropriate, the block diagrams provided by the manufacturer shall be submitted and the BA shall not be restricted in the use of these models in the analysis of its system.

R1.2.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.2.2. The BA may specify unit size thresholds smaller than stated in the applicable *Group to be included in the transmission system model, and must include:*

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

R1.3. The BA shall require specific dynamics data for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, storage units, and static compensators.

R1.4. Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard HI-MOD-010 Requirement 1.

R1.6. For non-synchronous generators, power electronic systems and storage units specific dynamic modeling data shall be provided in the form of block diagrams and associated data.

R1.7. DG below the applicable Group rating or if finer granularity is stipulated by the BA in R2.1.2 shall be aggregated and included with data as part of HI-MOD-16-0. The BA must determine the appropriate model.

R2. Each Transmission Owner or Generator Owner within the applicable Group shall provide appropriate equipment characteristics and system data in compliance with its respective Balancing Authority's dynamics modeling and simulation data requirements and reporting procedures as defined in R1. The reporting of the data will be based on four triggers:

R2.1. The BA's data reporting schedule (if any).

R2.2. When the BA has requested in writing (30 calendar days).

R2.3. When the Generator or Transmission Owner has completed commercial operation of a new facility or significant modification (within 30 calendar days).

R2.4. Whenever equipment characteristics experience a change that is expected to last more than 60 days (within 60 calendar days).

R3. The BA shall maintain a library of initialized (with no Faults or system Disturbances) transmission specific dynamics system models linked to the steady state system models, as appropriate, of Reliability Standard HI-MOD-010-0.

R3.1. The BA shall develop transmission-specific dynamics system models for at least two timeframes (present or near term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of the BA's transmission system.

R3.2. The BA shall develop dynamics system models for the transmission system annually for selected study years as determined by the BA and shall provide upon request the most recent initialized (approximately 25seconds, no-fault) models to the Hawaii PUC (or designee) within 30 calendar days.

C. Measures

M1. The BA shall have evidence that it documented its transmission system data requirements and reporting procedures in accordance to Requirement R1, Parts 1.1 through 1.7. The BA shall have evidence that it reviewed those data requirements and reporting procedures (at least every five years), and provided upon request those data requirements and reporting procedures to the Hawaii PUC (or designee) within 30 calendar days.

M2. Each Generator Owner or Transmission Owner shall have evidence such as dated reports or other documentation that it provided appropriate equipment characteristics and system data for dynamic modeling and simulation to its respective Balancing Authority as specified in R1.

M3. The BA shall have evidence that it has a library of initialized transmission-specific dynamics system models in accordance with Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee).

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. Data requirements and reporting procedures: on request (30 calendar days).

1.2.2. Periodic review of data requirements and reporting procedures: at least every five years.

1.2.3. Development of dynamics system models: Annually.

1.2.4. Most recent steady-state system models: 30 calendar days.

1.3. Data Retention

Evidence that the BA provided the required data to the Hawaii PUC (or designee) and that each Generator Owner or Transmission Owner provided required data to its BA shall be kept for five years or until the next audit, whichever is longer, unless directed

by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation.

2. **Levels of Non-Compliance for Requirement R1, Measure M1**

   2.1. **Level 1** - The BA met one of the following conditions for Requirement R1, Measure M1.

      2.1.1. Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the seven areas defined in R1.

      2.1.2. Failed to provide data to the Hawaii PUC (or designee) within 30 calendar days but less than 45 calendar days.

   2.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. **Levels of Non-Compliance for Requirement R2, Measure M2**

   3.1. **Level 1** – The Transmission Owner or Generator Owner failed to meet one of the following conditions for to supply applicable data to the BA as described Requirement R1 and Measurement M1.

      3.1.1. Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the seven areas defined in R1.

      3.1.2. Upon written request, failed to provide data to the BA within 30 calendar days but less than 45 calendar days.

      3.1.3. Upon completion of commercial operation of a new facility, failed to provide data to the BA within 30 calendar days but less than 45 calendar days.

      3.1.4. Upon change of equipment characteristics, failed to provide data to the BA within 60 calendar days but less than 75 calendar days.

   3.2. **Level 2** - The Transmission Owner or Generator Owner failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. **Levels of Non-Compliance for Requirement R3, Measure M3**

   4.1. **Level 1** - One of the BA's cases was not fully solved/initialized or had other identified errors.

   4.2. **Level 2** – The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Actual and Forecast Demand, Net Energy for Load, and Controllable Demand-Side Management, and Distributed Generation**

2. **Number:** HI-MOD-016-0

3. **Purpose:** Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, Load information related to controllable Demand-Side Management (DSM) programs and Distributed Generation (DG) is needed.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1. Balancing Authorities (BA)

5. **Effective Date:** TBD

B. Requirements

R1. The BA shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data (including the impact of distributed generation), (c) controllable DSM data, and (d) DG below the applicable requirements in MOD-010 to be reported for system modeling and reliability analyses. The data submittal requirements shall stipulate that the customer demand count once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer demand values. The DG shall be aggregated and the BA shall determine the appropriate model for the aggregate DG that accurately reflects the impact on the system.

R2. The BA shall develop and document the following information annually on an aggregated basis for modeling.

R2.1. Integrated hourly net-demand in megawatts (MW) for the prior year.

R2.2. Monthly and annual peak hour actual system demand in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.

R2.3. Monthly peak hour forecast demand in MW and Net Energy for Load in GWh for the next two years.

R2.4. Annual Peak hour forecast system demand in MW and annual Net Energy for load in GWh for at least ten years into the future.

R2.5. Annual daytime Peak hour forecast system demand in MW and annual Net Energy for load in GWh for at least ten years into the future.

R2.6. Minimum annual load hour forecast system demand in MW and annual Net Energy for load in GWh for at least ten years into the future.

R3. The BA's report of actual and forecast demand data (reported on an aggregated and dispersed basis) shall address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demand and Net Energy for Load. These uncertainties include the impact of distributed generation and customer installed generation.

R4. The BA shall report data associated with Requirement R3 to the Hawaii PUC (or designee) on written request (within 30 calendar days).

R5. The BA shall annually forecast the interruptible demand and Direct Load Management (DCLM) data for at least ten years into the future for peak system conditions.

R5.1. The BA's forecasts shall clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demand, and Direct Control Load Management) are defined and included in the forecast.

R5.2. The BA shall include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Requirement R1.

R5.3. The BA shall make documentation on the treatment of its DSM programs available to the Hawaii PUC (or designee) on written request (within 30 calendar days).

R6. The BA will make known its amount of interruptible demand and DCLM to the Hawaii PUC (or designee) within 30 calendar days.

C. Measures

M1. The BA's documentation for actual and forecast customer data shall contain all items identified in Requirement R1.

M2. The BA shall provide evidence that it developed load data per Requirement R2.

M3. The BA shall provide evidence that its actual and forecast demand data were addressed as described in the reporting procedures developed for Requirement R3.

M4. The BA shall report current information for Requirement R4 to the Hawaii PUC (or designee) on written request (within 30 calendar days).

M5. The BA shall provide evidence that it developed forecasts of interruptible demand and DCLM data per Requirement R5. The BA forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time of-use rates, interruptible demand, and Direct Control Load Management) are addressed. The information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures. Evidence the BA provided documentation on the treatment of DSM to the Hawaii PUC (or designee) as requested (within 30 calendar days).

M6. The BA shall make known the amount of interruptible demand and DCLM to the Hawaii PUC (or designee) within 30 calendar days.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

2.1.1. Development of Actual and Forecast Demand, Net Energy for Load, Controllable DSM: Annually.

2.1.2. On Requests: 30 calendar days.

1.3. Data Retention

Six years.

1.4. Additional Compliance Information

Evidence of compliance with R1 through R6 shall be maintained for six years or until the next audit, whichever is longer, unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation.

2. Levels of Non-Compliance for Requirement R1, Measure M1

2.1. **Level 1** – Documentation does not address completeness and double counting of customer data.

2.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2

3.1. **Level 1** – Did not provide actual and forecast demand and Net Energy for Load data in one of the six areas as required in Requirement R2 and Measurement M2.

3.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3

4.1. **Level 1** - Only partially addressed the assumptions, methods, and the manner in which uncertainties are treated made in the report as required in Requirement R3 and Measurement M3.

4.2. **Level 2** – The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4

5.1. **Level 1** - Failed to provide data to the Hawaii PUC (or designee) within 30 calendar days but less than 45 calendar days.

5.2. **Level 2** - *The BA failed to meet all the requirements of Level 1 for Requirement R4* and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5

6.1. **Level 1** - The BA met one of the following conditions for Requirement R6, Measure M6.

1.6.1. Only partially provided evidence that it provided forecasts of interruptible demand and DCLM data per Requirement R5 and Measurement M5.

1.6.2. Failed to provide data to the Hawaii PUC (or designee) within 30 calendar days but less than 45 calendar days.

6.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R5 and Measurement M5.

7. Levels of Non-Compliance for Requirement R6, Measure M6

7.1. **Level 1** - The BA failed to make known the amount of interruptible demand and DCLM to the Hawaii PUC (or designee) within 30 calendar days but less than 45 calendar days.

7.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R6 and Measurement M6.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources**

2. **Number:** HI-MOD-025-0

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser or static source Reactive Power capability is available for planning models used to assess transmission system reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authorities (BA)

   4.1.2. Generator Owner(s)

   4.1.3. Transmission Owner(s)

   4.2. Facilities: The Facilities are divided into two groups based on the annual system peak demand.

   4.2.1. Group A - Annual system peak is greater than or equal to 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2. Group B - Annual system peak is less than 50 MW.

   - Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Synchronous condenser, power electronic or static source greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.
   - Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

B. Requirements

R1. Each Generator Owner or applicable Transmission Owner in the applicable group shall provide the BA with verification of the Real Power capability of its applicable Facilities as follows:

R1.1. Verify the Real Power capability of its generating units, power electronics in accordance with Attachment 1.

R1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to the BA within 30 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner or Transmission Owner (including synchronous condenser, power electronic or static source) in the applicable group shall provide the BA with verification of the Reactive Power capability of its applicable Facilities as follows:

R2.1. Verify the Reactive Power capability of its generating units (including synchronous condenser, power electronic or static source) and shall verify the Reactive Power capability in accordance with Attachment 1.

R2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to the BA within 30 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

C. Measures

M1. Each Generator Owner or applicable Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments 1 and 2, and will have evidence that it submitted the information within 30 calendar days to its BA; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.

M2. Each Generator Owner or applicable Transmission Owner (including synchronous condenser, power electronic or static source) will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner or applicable Transmission Owner (including synchronous condenser, power electronic or static source) form with the same information, or dated information collected and used to complete Attachments 1 and 2 and will have evidence that it submitted the information within 30 calendar days to its BA; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

D. *Compliance*

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Data Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Hawaii PUC (or designee) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner or applicable Transmission Owner shall keep the data or evidence to show compliance as identified below, unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation. The Generator Owner or applicable Transmission Owner shall retain the latest Attachment 1 and 2 and the data behind these attachments or Owner form with *equivalent information and submittal evidence for Requirements* R1 *and* R2, *Measures* M1 and M2 for the time period since the last compliance audit.

If a Generator Owner or applicable Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer. The Hawaii PUC (or designee) will keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. Levels of Non-Compliance for Requirement R1, Measure M1

2.1. **Level 1** - The Generator Owner or applicable Transmission Owner met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The Generator Owner or applicable Transmission Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to the BA more than 30 calendar days, but within 45 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

2.1.2. The Generator Owner or applicable Transmission Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.

2.1.3. The Generator Owner or applicable Transmission Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months bus less than or equal to 69 months.

2.1.4. The Generator Owner or applicable Transmission Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.

2.2. **Level 2** - The Generator Owner or applicable Transmission Owner failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2

3.1. **Level 1** - The Generator Owner or applicable Transmission Owner met one of the following conditions for Requirement R2 and Measurement M2.

3.1.1. The Generator Owner or applicable Transmission Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser or static source, but submitted the data to its BA more than 30 calendar days, but within 45 calendar days, from the date of the verification by staged test or the date the historical operating data that was selected for verification.

3.1.2. The Generator Owner or applicable Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data.

3.1.3. The Generator Owner or applicable Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months bus less than or equal to 69 months.

3.1.4. The Generator Owner or applicable Transmission Owner performed the *Reactive Power verification per Attachment 1, "Periodicity for conducting a* new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.

3.2. **Level 2** - The Generator Owner or applicable Transmission Owner failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

Version History

Version	Date	Action	Change Tracking

Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The BA shall in conjunction with the Generation and Applicable Transmission Owners establish an initial testing date for all units within its BA and all testing and verification shall be completed within the following three years. Following the initial testing, the periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date.

It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers or static sources, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with the System Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the System Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For individual generating units of the applicable group MVA or less that are part of an applicable group plant MVA or greater in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser or static source of the applicable group MVA or greater (gross nameplate rating).
2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). *Operational data from within the two years prior to the verification date is* acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1. Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1. At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2. At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the System Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

3.4.1. Ambient air temperature

3.4.2. Relative humidity

3.4.3. Cooling water temperature

3.4.4. Other data as applicable

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary Load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

4.2. If an adjustment is requested by the BA develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as higher temperature conditions, can be determined. Adjust MW values tested to ambient conditions specified by the BA upon request and submit them to the BA within 90 days of the request or the date the data was recorded/selected whichever is later.

NOTES

1. Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.
2. While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the BA can use for modeling.
3. It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.
4. The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.
5. Synchronous Condensers or static sources only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in Attachment 1) is reported.

Company: **Reported by (name):**

Plant: **Unit No.** **Date of Report:**

Check all that apply:

☐ Over-excited Full Load Reactive Power Verification

☐ Under-excited Full Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

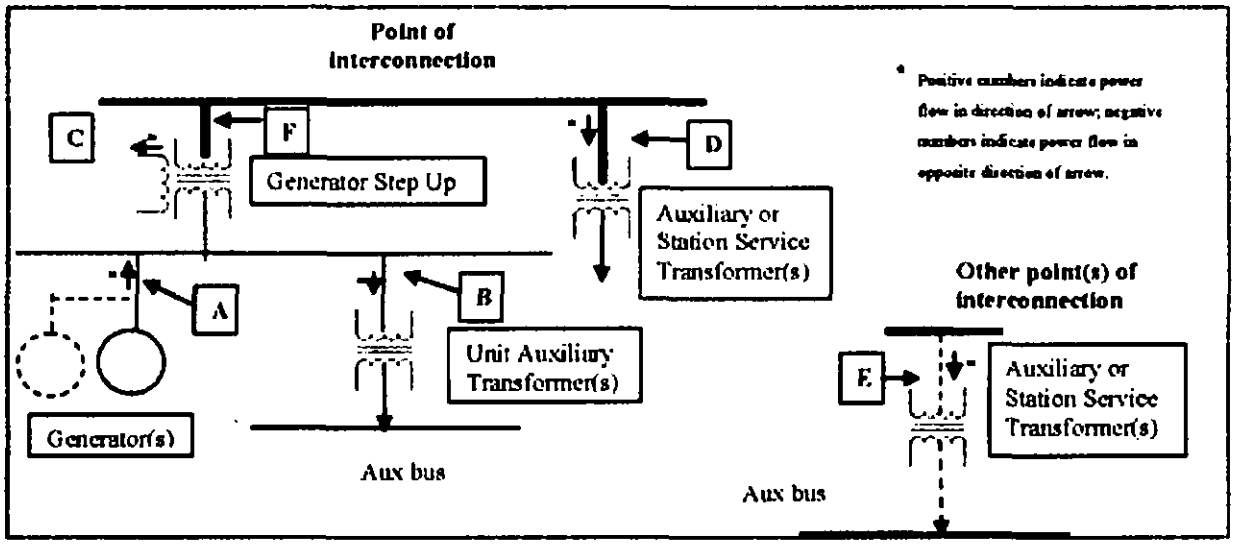
☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage (kV)	Real Power (MW)	Reactive Power (MVAR)	Comment
A				Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers depending on applicable group.
Identify calculated values, if any:				
B				*Sum multiple unit auxiliary transformers.*
Identify calculated values, if any:				
C				Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D				Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E				Sum multiple unit auxiliary transformers.
F				Net unit capability
Identify calculated values, if any:				

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power Capability (*MVAR)		
Aux Reactive Power (*MVAR)		
Net Reactive Power Capability (*MVAR) equals Gross Reactive Power Capability (*MVAR) minus Aux Reactive Power connected at the same bus (*MVAR) minus tertiary Reactive Power connected at the same bus(*MVAR)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU-MVAR)		

Summary of Verification

Date of Verification _____, Verification Start Time _____, Verification End Time _____

- Scheduled Voltage _____

- Transformer Voltage Ratio: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____

- Ambient conditions at the end of the verification period:

  Air temperature: _____

  Humidity: _____

  Cooling water temperature: _____

  Other data as applicable: _____

- The recorded MVAR values were adjusted to rated generator voltage, where applicable.

• Generator hydrogen pressure at time of test (if applicable) _____

Date that data shown in last verification column in table above was taken _____

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Standard HI-MOD-026-0 — Verification of Models and Data for Generator/ Transmission Equipment Excitation System or Plant Volt/VAr Control System

A. Introduction

1. **Title:** Verification of Models and Data for Generator and applicable transmission equipment Excitation System or Plant Volt/VAr Control System

2. **Number:** *HI-MOD-026-0*

3. **Purpose:** To verify that the generator or transmission equipment excitation system or plant Volt/VAr control system[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation system or plant Volt/VAr control system behavior when assessing a BA's System reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 *Generator Owner (s)*

   4.1.2 Balancing Authority (BA)

   4.1.3 Transmission Owner(s)

   4.2. Facilities:

   The Facilities are divided into two groups based on the annual system peak demand of the BA's area. For the purpose of the requirements contained herein, Facilities that are electrically connected to the system will be collectively referred as an "applicable units" that meets the following:

   4.2.1 Group A - Annual system peak is greater than or equal to 50 MW.

   4.2.1.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.

   4.2.1.2 Synchronous condenser, power electronic or static source greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.

   4.2.1.3 Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2 Group B - Annual system peak is less than 50 MW.

   4.2.2.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.

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[1] Excitation control system or plant Volt/VAr control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.

b. For an aggregate generating plant, the Volt/VAr control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.2.2 Synchronous condenser, power electronic or static source greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.

4.2.2.3 Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

B. Requirements

R1. The BA shall provide one or more of the following to its requesting Generator Owner or Transmission Owner within 30 calendar days of receiving a written request:

- Acceptable excitation system or plant Volt/VAr control system models that are acceptable to the BA for use in dynamic simulation,
- Acceptable dynamic excitation system or plant Volt/VAr control system model library block diagrams and/or data sheets for models that are acceptable to the BA, or
- Model data for any of the Generator Owner's or Transmission Owner's existing applicable unit specific excitation control system or plant Volt/VAr control system contained in the BA's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner or Transmission Owner shall provide, for each applicable unit, a verified generator excitation system, plant Volt/VAr control system model, including documentation and data as specified in Part 2.1, or transmission equipment model and documentation to its BA in accordance with the periodicity specified in Attachment 1.

2.1. Each applicable unit's excitation system or plant Volt/VAr control system performance shall be verified by the Generator Owner or Transmission Owner using a model acceptable to the BA. Verification of an individual unit less than the applicable group MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s) or both. Each verification shall include the following:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

2.1.2. Manufacturer, model number (if available), and type of excitation system or plant Volt/VAr control system installed including, but not limited to static, AC brushless, DC rotating, and Volt/VAr function,

2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator ,

2.1.4. Model structure and data for the excitation system, or the model structure and data for the plant Volt/VAr control system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner or Transmission Owner shall provide a written response to the BA within 90 calendar days of receiving one of the following items for an applicable unit:

- Written notification from the BA (in accordance with Requirement R6) that the excitation system or plant Volt/VAr control system model is not usable, or
- Written comments from the BA identifying technical concerns with the verification documentation related to the excitation system or plant Volt/VAr control system model, or
- Written comments and supporting evidence from the BA indicating that the simulated excitation system or plant Volt/VAr control model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[2] (in accordance with Requirement R2).

R4. Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification[2](in accordance with Requirement R2) for an applicable unit to the BA within 90 calendar days of making changes to the excitation system or plant Volt/VAr control system that alter the equipment response[3] characteristic.

R5. Each Generator Owner and Transmission Owner shall provide a written response to the BA, within 60 calendar days following receipt of a technically justified unit request from the BA to perform a model review of a unit or plant that includes one of the following:

- Details of plans to verify the model (in accordance with Requirement R2), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. The BA shall notify the Generator Owner and Transmission Owner within 30 calendar days of receiving the verified excitation system or plant Volt/VAr control system model information in accordance with Requirement R2 that the model is useable (meets the criteria specified in Parts 6.1 through 6.3) or is not useable; and shall include a technical description if the model is not useable that includes the following:

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[2]If verification is performed, the 5 year period as outlined in Attachment 1 is reset.

[3]Exciter, voltage regulator, plant Volt/VAr or power system stabilizer replacement including software alterations that alter excitation system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant Volt/VAr function equipment addition or replacement (such as static VAr systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

6.1. The excitation system or plant Volt/VAr control system model initializes to compute modeling data without error,

6.2. A no-disturbance simulation results in negligible transients, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation system or plant Volt/VAr control system model exhibiting appropriate positive damping.

C. Measures

M1. The BA must have and provide the dated request for instructions or data, the transmitted instructions or data and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 30 calendar days in accordance with Requirement R1.

M2. The Generator Owner or Transmission Owner must have and provide dated evidence it verified each generator excitation control system or plant Volt/VAr control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to the BA, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 90 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 60 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not useable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Hawaii PUC (or designee) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner or Transmission Owner and the BA shall each keep data or evidence to show compliance as identified below unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain the information/data request and provided response evidence of Requirements R1 and R6. Measures M1 and M6 for three calendar years from the date the document was provided.
- The Generator Owner or Transmission Owner shall retain the latest excitation control system or plant Volt/VAr control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner or Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner, Transmission Owner or the BA is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Hawaii PUC (or designee) will keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance for Requirement R1, Measure M1

2.1. Level 1 - The BA provided the instructions and data to the Generator Owner or Transmission Owner more than 30 calendar days but less than or equal to 45 calendar days of receiving a request for Requirement R1 and Measurement M1.

2.2. Level 2 - *The Generator Owner or Transmission Owner failed to meet all the* requirements of Level 1 for Requirement R1 and Measurement M1.

3. **Levels of Non-Compliance for Requirement R2, Measure M2**

   3.1. **Level 1** - The Generator Owner or Transmission Owner met one of the following conditions for Requirement R2 and Measurement M2.

      3.1.1 The Generator Owner or Transmission Owner provided its verified model(s) to the BA after the timeframe specified in Attachment 1 but less than or equal to 30 calendar days late;

      3.1.2 The Generator Owner or Transmission Owner provided the BA verified models that omitted one of the six Parts identified in Requirement R2, Parts2.1.1 through 2.1.6.

   3.2. **Level 2** - The Generator Owner or Transmission Owner failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. **Levels of Non-Compliance for Requirement R3, Measure M3**

   4.1. **Level 1** - The Generator Owner or Transmission Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice for Requirement R3 and Measurement M3.

   4.2. **Level 2** - The Generator Owner or Transmission Owner failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. **Levels of Non-Compliance for Requirement R4, Measure M4**

   5.1. **Level 1** - The Generator Owner or Transmission Owner provided revised model data or plans to perform model verification more than 90 calendar days but less than or equal to 180 calendar days of making changes to the excitation control system or plant Volt/VAr control function that altered the equipment response characteristic for Requirement R4 and Measurement M4.

   5.2. **Level 2** - The Generator Owner or Transmission Owner failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. **Levels of Non-Compliance for Requirement R5, Measure M5**

   6.1. **Level 1** - The Generator Owner or Transmission Owner provided a written response more than 60 calendar days but less than or equal to 75 calendar days to the BA following receipt of a technically justified request to perform a model review of a unit or plant for Requirement R5 and Measurement M5.

   6.2. **Level 2** - The Generator Owner or Transmission Owner failed to meet all the requirements of Level 1 for Requirement R5 and Measurement M5.

7. **Levels of Non-Compliance for Requirement R6, Measure M6**

   7.1. **Level 1** - The BA provided a written response to the Generator Owner or Transmission Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 30 calendar days but less than or equal to 45 calendar days of receiving verified model information for Requirement R6 and Measurement M6.

   7.2. **Level 2** - The Generator Owner or Transmission Owner failed to meet all the requirements of Level 1 for Requirement R6 and Measurement M6.

Version History

Version	Date	Action	Change Tracking

E. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, "Model Validation for Wind Turbine Generator Models", IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, "Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,"IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, "Dynamic Modeling of GE Wind Plants for Stability Simulations," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, "Description and Technical Specifications for Generic WTG Models – A Status Report," Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ
9. K. Clark, N.W. Miller, R.A. Walling,"Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, "Modeling of GE Wind Turbine-Generators for Grid Studies," version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, "Field Testing &Model Validation of Wind Plants," in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008

12. N. Miller, K. Clark, J. MacDowell and W. Barton, "Experience with Field and Factory Testing for Model Validation of GE Wind Plants," in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008

13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307

14. W.W.Price and J. J. Sanchez-Gasca, "Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies," in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992

15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, "On the Integration of Wind Power Plants in Large Power Systems," Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006

16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, "Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations," Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003

17. P. Pourbeik, C. Pink and R. Bisbee, "Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data", Proceedings of the IEEE PSCE, March, 2011

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Excitation System or Plant Volt/VAr Control System Model Verification Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit (Requirement R2) The BA shall in conjunction with the Generation and Applicable Transmission Owners establish an initial testing date for all units within its BA and all testing and verification shall be completed within the following three years.	Transmit the verified model, documentation and data to the BA on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 5-year implementation period See Section 5 for Effective Dates
2	Subsequent verification for an applicable unit (Requirement 2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 5 year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system and plant Volt/VAr control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the BA within 365 days after the commissioning date.

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Excitation System or Plant Volt/VAr Control System Model Verification Periodicity

Row Number	Verification Condition	Required Action
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is less than 3 times the individual unit threshold MVA rating for the applicable group. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the BA for the verified equivalent unit. Verify a different equivalent unit during each ten year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.
5	The Generator Owner or Transmission Owner has submitted a verification plan in accordance with R3, R4 or R5. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the BA within 365 days after the submittal of the verification plan.

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Excitation System or Plant Volt/VAr Control System Model Verification Periodicity

Row Number	Verification Condition	Required Action
6	New or existing applicable unit or plant does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement transmitted to the BA Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).

NOTES:

NOTE 1: Establishing the Recurring Five Year Unit Verification Period Start Date:

The start date is the actual date of submittal of a verified model to the BA for the most recently performed unit verification.

NOTE 2: Consideration for Early Compliance

Existing generator excitation system or plant Volt/VAr control system model verification is sufficient for demonstrating compliance for a five year period from the actual transmittal date if either of the following applies:

- **The Generator Owner or Transmission Owner has a verified model that is compliant with the applicable policies, guidelines or criteria existing at the time of model verification.**
- **The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard.**

Standard HI-MOD-027-0 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. **Number:** HI-MOD-027-0

3. **Purpose:** To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess the BA's transmission system reliability, accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner

   4.1.3 Balancing Authority (BA)

   4.2. Facilities

   The Facilities are divided into two groups based on the annual system peak demand of the BA's area. For the purpose of the requirements contained herein, Facilities that are electrically connected to the system will be collectively referred as an "applicable unit" that meet the following:

   4.2.1 Group A - Annual system peak is greater than or equal to 50 MW.

   4.2.1.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.

   4.2.1.2 Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2 Group B -Annual system peak is less than 50 MW.

   4.2.2.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.

   4.2.2.2 Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

B. Requirements

R1. The BA shall provide one or more of the following to its requesting Generator or its applicable Transmission Owners within 30 calendar days of receiving a written request:

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[1]Turbine/governor and load control and active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to variable energy plants, high voltage direct current systems, flexible AC transmission systems and storage units.

- Acceptable turbine/governor and load control or active power/frequency control system models that are acceptable to the BA for use in dynamic simulation,
- Acceptable dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the BA, or
- Model data for any of the Generator or applicable Transmission Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the BA's dynamic database from the current (in-use) model(s).

R2. Each Generator and applicable Transmission Owners shall provide, for each of its applicable units, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to the BA in accordance with the periodicity specified in Attachment 1.

2.1. Each applicable unit's model shall be verified by the Generator or applicable Transmission Owner using one or more models acceptable to the BA. Verification of an individual unit less than the applicable group MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s) or both. Each verification shall include the following:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either a frequency excursion from a system disturbance that meets Attachment 1 Note 1 with applicable unit on-line, a speed governor reference change with the applicable unit on-line, or partial load rejection test,

2.1.2. Type of governor and load control or active power control/frequency control equipment,

2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),

2.1.4. Model structure and data for turbine/governor and load control and active power/frequency control, and

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator and applicable Transmission Owner shall provide a written response to the BA within 90 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from the BA (in accordance with Requirement R5) that the turbine/governor and load control and active power/frequency control model is not "usable,"
- Written comments from the BA identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or

- Written comments and supporting evidence from the BA indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for one or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[2] (in accordance with Requirement R2).

R4. Each Generator and applicable Transmission Owner shall provide revised model data or model verification[3] (in accordance with Requirement R2) for an applicable unit to the BA within 90 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[4].

R5. The BA shall notify the Generator and applicable Transmission Owner within 30 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is useable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable; and shall include a technical description if the model is not useable that includes the following:

5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

5.2. A no-disturbance simulation results in negligible transients, and

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping having fully decayed within 20 seconds.

C. Measures

M1. The BA shall have evidence such as the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipts, or confirmation of facsimile) that it provided the request within 30 calendar days in accordance with Requirement R1.

M2. The Generator and applicable Transmission Owners shall have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to the BA, in accordance with Requirement R2.

M3. Evidence for Requirement R3 shall include the Generator and applicable Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

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[2] If verification is performed, the 5 year period as outlined in Attachment 1 is reset.

[3] Ibid

[4] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

M4. Evidence for Requirement R4 shall include, for each of the Generator and applicable Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 90 calendar days of making changes.

M5. Evidence of Requirement R5 shall include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator and applicable Transmission Owner was notified within 30 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Hawaii PUC (or designee)

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Hawaii PUC (or designee) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator or applicable Transmission Owner and the BA shall each keep data or evidence to show compliance as identified below unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator or applicable Transmission Owner shall retain the latest and previous turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator or applicable Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator or applicable Transmission Owner or the BA is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Hawaii PUC (or designee) shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance for Requirement R1, Measure M1

2.1. Level 1 - The BA provided the instructions and data to the Generator Owner more than 30 calendar days but less than or equal to 45 calendar days of receiving a request for Requirement R1 and Measurement M1.

2.2. Level 2 - The Generator Owner failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2

3.1. Level 1 - The Generator or applicable Transmission Owner met one of the following conditions for Requirement R2 and Measurement M2.

3.1.1 The Generator or applicable Transmission Owner provided its verified model(s) to the BA after the periodicity timeframe specified in Attachment 1 but less than or equal to 30 calendar days late;

3.1.2 The Generator or applicable Transmission Owner provided the BA verified model that omitted one of the five Parts identified in Requirement R2, Parts2.1.1 through 2.1.5.

3.2. Level 2 - The Generator or applicable Transmission Owner failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3

4.1. Level 1 - The Generator or applicable Transmission Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice for Requirement R3 and Measurement M3.

4.2. Level 2 - The Generator or applicable Transmission Owner failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4

5.1. Level 1 - The Generator or applicable Transmission Owner provided revised model data or plans to perform model verification more than 90 calendar days but less than or equal to 180 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic for Requirement R4 and Measurement M4.

5.2. Level 2 - The Generator or applicable Transmission Owner failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5

6.1. **Level 1** - The BA provided a written response to the Generator or applicable Transmission Owner indicating whether the model is useable or not useable (including a technical description if the model is not useable) more than 30 calendar days but less than 45 calendar days of receiving verified model information for Requirement R5 and Measurement M5.

Level 2 - The BA failed to meet all the requirements of Level 1 for Requirement R5 and Measurement M5.

Version History

Version	Date	Action	Change Tracking

E. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control and active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES *General Meeting 2007, paper 07GM1307*

2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005

3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004

4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004

5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004

6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, "Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data", Proceedings of the IEEE PSCE, March, 2011

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Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit (Requirement R2) The BA shall in conjunction with the Generation and Applicable Transmission Owners establish an initial testing date for all units within its BA and all testing and verification shall be completed within the following three years.	Transmit the verified model, documentation and data to the BA on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 5-year implementation period See Section A5 for Effective Dates
2	Subsequent verification for an applicable unit (Requirement R2)	Transmit the verified model, documentation and data to the BA on or before the 5-year anniversary of the last transmittal (per Note 2).
3	Unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6 (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the unit's real power response to a frequency excursion is installed and expected to be available) (Requirement R2)	Requirement 2 is met with a written statement transmitted to the BA. Transmit the verified model, documentation and data to the BA on or before365 days after a frequency excursion per Note 1 occurs and the recording equipment captures the unit's real power response as expected.

Row Number	Verification Condition	Required Action
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed(Requirement R2)	Transmit the verified model, documentation and data to the BA within 365 days after the commissioning date.
5	Existing applicable unit that is equivalent to another unit(s) at the same physical location: AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is less than 3 times the individual unit threshold MVA rating for the applicable group. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the BA for the verified equivalent unit. Verify a different equivalent unit during each ten year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.

Row number	Verification Condition	Required Action
6	The Generator Owner has submitted a verification plan in accordance with R3 or R4. (Requirement R3 orR4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 days after the submittal of the verification plan.
7	Applicable unit is not responsive to both over and under frequency excursion events (The unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established

NOTES:

NOTE 1: Unit Model Verification Frequency Excursion Criteria as defined by the Reportable Excess Contingency Disturbance:

NOTE 2: Establishing the Recurring Five Year Unit Verification Period Start Date:

The start date is the actual date of submittal of a verified model to the BA for the most recently performed unit verification.

A. Introduction

1. **Title:** **Underfrequency Load Shedding**

2. **Number:** HI-PRC-006-0

3. **Purpose:** To establish design documentation, maintenance and operational requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Balancing Authorities (BA)

   4.2. Facilities

   The Facilities are divided into two groups based on the annual system peak demand of the BA's area. For the purpose of the requirements contained herein, Facilities that are electrically connected to the system will be collectively referred as an "applicable unit" that meet the following:

   4.2.1 Group A - Annual system peak is greater than or equal to 50 MW.

   4.2.1.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 2.0 MVA (gross nameplate rating) electrically connected to the system.

   4.2.1.2 Generating plant/Facility greater than 4.0 MVA (gross aggregate nameplate rating) electrically connected to the system.

   4.2.2 Group B -Annual system peak is less than 50 MW.

   4.2.2.1 Individual generating unit, high voltage direct current systems, electronic inverter, storage units, etc. greater than 0.2 MVA (gross nameplate rating) electrically connected to the system.

   4.2.2.2 Generating plant/Facility greater than 0.4 MVA (gross aggregate nameplate rating) electrically connected to the system.

5. **Effective Date:** TBD

6. **Exclusions:**

   6.1. **Catastrophic Contingency Event**: These events are excluded since they are not planned.

B. Requirements

R1. The BA shall develop and document criteria, including consideration of historical events and system studies, to select loads within the Balance Authority's Area to form load shedding blocks.

R2. The BA shall identify multiple load shedding blocks to utilize in designing its UFLS program including those blocks selected by applying the criteria in Requirement. In designing the UFLS program, the BA shall consider the magnitude of the demand response and interruptible load program to ensure that those programs do not interfere with the successful implementation of the UFLS.

R3. The Balancing Authority shall develop a UFLS program that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = (load — actual generation output) / (load).

R.3.1 The design of the program should consider a minimum of the following cases.

R3.1.1 *Loss of a medium sized generator at a normal load value*

R3.1.2 Loss of generation as determined by the Maximum N-1 Contingency Criteria plus 10% at a normal load value.

R3.1.3 Loss of generation as determined by the Maximum N-1 Contingency Criteria plus 10% at the system minimum load value.

R3.1.4 Loss of generation as defined in HI-BAL–002 as a Reportable Excess Contingency

R3.1.5 Provision for a backup block of load with an extended time delay to prevent extended low frequency operation.

R3.2 Following activation of UFLS, the frequency shall remain above the low frequency requirements as defined in HI-BAL-002.

R3.3 Following activation of UFLS, the frequency shall remain below the high frequency requirements as defined in HI-BAL-002.

R3.4 *Simulated UFLS events shall not result in Volts per Hz (V/Hz) exceeding the trip settings or* equipment damage limits if no protection exists. V/Hz shall be assessed at each generator bus and generator step-up transformer high-side bus associated with each of the following:

R3.4.1 Individual generating units greater than the applicable unit's MVA (gross nameplate rating) directly connected to the system.

R3.4.2 Generating plants/facilities greater than the applicable unit's MVA (gross aggregate nameplate rating) directly connected to the system.

R3.4.3 Facilities consisting of one or more units connected to the system at a common bus with total generation above the applicable units' MVA gross nameplate rating.

R4. The BA shall conduct and document a UFLS design assessment at least once every five years or upon any significant changes in BA resources. Each design assessment shall update the UFLS program design as necessary to maintain ongoing performance characteristics that meet Requirement R3 for each load shedding block identified in Requirement R2. The simulations shall model each of the following:

R4.1. Underfrequency trip settings of individual generating units greater than the applicable unit's MVA (gross nameplate rating) directly connected to the system.

R4.2. *Underfrequency trip settings of generating plants/facilities greater than the applicable* unit's MVA (gross aggregate nameplate rating) directly connected to the system.

R4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the system at a common bus with total generation above the applicable units' MVA (gross nameplate rating).

R4.4. Underfrequency trip settings of all variable generation modeled as equivalent units if the summation of the variable generation for each frequency trip point exceeds 1.0 MW.

R4.5. Overfrequency trip settings or ratings of individual generating units greater than the applicable unit's MVA (gross nameplate rating) directly connected to the system.

R4.6. Overfrequency trip settings or ratings of generating plants/facilities greater than the applicable unit's MVA (gross aggregate nameplate rating) directly connected to the system.

R4.7. Overfrequency trip settings or ratings of any facility consisting of one or more units connected to the system at a common bus with total generation above the applicable units' MVA (gross nameplate rating).

R4.8. Overfrequency trip settings or ratings of all variable generation modeled as equivalent units if the summation of the variable generation for each frequency trip point is exceeds 1.0 MW.

R4.9. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R4.10. The most recent estimated frequency response of the BA's load to changes in frequency.

R5. The BA shall maintain a UFLS database, in a format to be determined, containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.

R6. The BA shall provide data in the format and on the schedule specified to support maintenance of the UFLS database.

R7. The BA shall provide automatic tripping of Load in accordance with the UFLS program design and schedule.

R8. The BA shall provide automatic switching of its existing capacitor banks, transmission lines, and reactors as necessary to control over-voltage or undervoltage as a result of loss of generation and underfrequency load shedding.

R9. The BA, in whose Control Area an event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an initial assessment of the event within two weeks of the event to evaluate the need for further analysis considering:

R9.1. The performance of the UFLS equipment,

R9.2. The effectiveness of the UFLS program to maintain system frequency within an acceptable range.

R9.3. If further analysis is not required, all documentation should be completed within 3 weeks from the initial event.

R10. The BA, in whose UFLS initial event assessment (per R9) shows need for further analysis, shall conduct and document a UFLS design assessment as outlined in R4 to evaluate the event and the response of the UFLS system within six months of the event. The analysis shall include, but not be limited to:

R10.1. A description of the event including initiating conditions.

R10.2. A review of the UFLS set points and tripping times.

R10.3. A simulation of the event.

R10.4. A summary of the findings.

R11. The BA shall have its UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R12. the BA shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to the Hawaii PUC (or designee) on written request (within 30 calendar days).

C. Measures

M1. The BA shall have evidence such as reports, or other documentation of its criteria to select portions of its system that may form load shedding blocks including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. The BA shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of load shedding blocks as a basis for designing a UFLS program that meet the criteria in Requirement R2.

M3. The BA shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the implementation schedule that meets the criteria in Requirement R3.

M4. The BA shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4.

M5. The BA shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R5 at least once each calendar year, with no more than 15 months between maintenance activities.

M6. The BA shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that data according to the format and schedule specified to support maintenance of the UFLS database per Requirement R6.

M7. The BA shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R7.

M8. The BA shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks. Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R8.

M9. The BA shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R9.

M10. The BA shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R10 and R4 if UFLS program deficiencies are identified in R9.

M11. The BA UFLS equipment maintenance and testing program contains the elements specified n Requirement R11.

M12. The BA shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to the Hawaii PUC (or designee) on written request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Hawaii PUC (or designee)

1.2. Data Retention

The BA shall keep data or evidence to show compliance as identified below unless directed by the Hawaii PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain the current evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 as well as any evidence necessary to show compliance since the last compliance audit.
- The BA shall retain the current evidence of UFLS database update in accordance with Requirement R5, Measure M5, and evidence of the prior year's UFLS database update.
- The BA shall retain evidence of UFLS data transmittal in accordance with the format and schedule since the last compliance audit in accordance with Requirement R6, Measure M6.
- The BA shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R7, Measure M7, and evidence of adherence since the last compliance audit.
- The BA shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R8, Measure M8, and evidence of adherence since the last compliance audit.
- The BA shall retain evidence of Requirements R9 and Measures M9, for 6 calendar years. If a BA is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer. The Hawaii PUC shall keep the last audit records and all requested and submitted subsequent audit records.
- The BA shall retain evidence of Requirement R10, Measure M10 for 6 calendar years as identified in Requirement R9, Measure M9.
- The BA shall retain the current evidence of Requirement R11 and Measure M11 and evidence of adherence since the last compliance audit.
- The BA shall retain the current evidence of Requirement R12 and Measure M12 for 6 calendar years.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits - The Hawaii PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- *Self-Certifications*
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. **Levels of Non-Compliance for Requirement R1, Measure M1**

   2.1. **Level 1** - The BA developed and documented criteria but failed to include either the consideration of historical events or the consideration of system studies, to the system.

   2.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. **Levels of Non-Compliance for Requirement R2, Measure M2**

   3.1. **Level 1** - NA

   3.2. **Level 2** - The BA failed to identify load shedding blocks to serve as a basis for designing its UFLS program as specified in Requirement R2.

4. **Levels of Non-Compliance for Requirement R3, Measure M3**

   4.1. **Level 1** - The BA developed a UFLS program, including a schedule for implementation within its area where imbalance = (load — actual generation output) / (load), considering the minimum cases, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, 3.3 or 3.4 in simulations of underfrequency conditions.

   4.2. **Level 2** – The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. **Levels of Non-Compliance for Requirement R4, Measure M4**

   5.1. **Level 1** - The BS conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each load shedding block identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.10.

   5.2. **Level 2** – The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. **Levels of Non-Compliance for Requirement R5, Measure M5**

   6.1. **Level 1** - NA

   6.2. **Level 2** - The BA failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.

7. **Levels of Non-Compliance for Requirement R6, Measure M6**

   7.1. **Level 1** - The BA provided data more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by Requirement R6 to support maintenance of the UFLS database.

7.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R6 and Measurement M6.

8. **Levels of Non-Compliance for Requirement R7, Measure M7**

8.1. **Level 1** - The BA provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Requirement R7.

8.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

9. **Levels of Non-Compliance for Requirement R8, Measure M8**

9.1. **Level 1** - The BA provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by Requirement R8.

9.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R8 and Measurement M8.

10. **Levels of Non-Compliance for Requirement R9, Measure M9**

10.1. **Level 1** - The Balancing Authority's Area event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R9, Parts 9.1 and 9.2 within a time greater than two weeks but less than or equal to three weeks of actuation.

10.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R9 and Measurement M9.

11. **Levels of Non-Compliance for Requirement R10, Measure M10**

11.1. **Level 1** - The BA, in which UFLS program deficiencies were identified per Requirement R9, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than six months but less than or equal to 7 months of event actuation.

11.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R10 and Measurement M10.

12. ***Levels of Non-Compliance for Requirement R11, Measure M11***

12.1. **Level 1** - The BA developed maintenance and testing programs for the UFLS equipment. The program failed to include one of the following, UFLS equipment identification, or the schedule for testing UFLS equipment, or the schedule for UFLS equipment maintenance.

12.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R11 and Measurement M11.

13. **Levels of Non-Compliance for Requirement R12, Measure M12**

13.1. **Level 1** - The BA provided less than 100% but more than (and including) 95% of the UFLS equipment identified by the Requirement R11.

13.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R12 and Measurement M12.

Version History

Version	Date	Action	Change Tracking

Hawaii Reliability Standard Presentation Synopsis: HI-BAL-001-0

Standard No: HI-BAL-001-0

Title: Real Power Balancing Control Performance

Purpose: To maintain system steady state frequency within defined limits by balancing real power demand and supply in real time.

What Is It About:

- Establishes a Balancing Authority (BA), ie HECO Company's individual system control area, ie, HECO, MECO, HELCO.
- Must balance load and supply such that system frequency is maintained within specified limits around 60 Hz.

Key Features:

- Sets criteria for maintaining system frequency within specified limits on a rolling 12 month basis for the BA's system.
- Sets criteria for maintaining system frequency within specified limits on a 24 hour basis for each BA's system.
- The criteria for the 24-hour basis provides an early warning indicator of regulation issues.
- Allows for not meeting standard performance due to extraordinary circumstances, such as acts of God, non affiliated third parties, labor disturbances, etc, beyond the BA's reasonable control, as long as good industry practices and design are followed.
- BA must maintain Regulation Reserve to meet the frequency requirement.
- BA must have reliable backup power supply for control room and other critical locations along with periodic testing.
- BA must have redundant and independent frequency measuring equipment that will activate upon detection of primary source along with annual testing of equipment.

How Is Standard Measured:

- BA must maintain the frequency within +/- 0.055 Hz of nominal.
- Disturbance data is excluded from the data sample calculation as defined in HI-BAL-002-0
- BA must maintain a population of 98.3% within the frequency bounds for a rolling 12 month basis.
- BA must maintain a population of 98.3% within the frequency bounds for each 24 hour period and must have less than 10 excessive days per month.
- BA must maintain a valid sample set of not less than 99.9%.
- Compliance reporting on a monthly basis to the PUC (or designee) required, who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- The BA will require time for custom modifications to the EMS.
- At least one year of operating experience should be gained prior to enforcement by the PUC.

Major Implications:

- **To Utilities:**
  - Increased reporting and monitoring requirements.
  - Additional costs of administration and performance penalties.
  - Requirements to prepare operating criteria and procedures.
  - Risk of performance penalties may impact operational decisions
  - *Risk of selecting frequency criteria too tight/too loose for adequate operation*
- **To IPP's**
  - Risk of selecting frequency criteria too tight for adequate operation resulting in increase curtailment

Recommendations to the RSWG:

- Allow one year of operating experience before standard becomes enforceable.

Hawaii Reliability Standard Presentation Synopsis: HI-BAL-002-0

Standard No: HI-BAL-002-0

Title: Disturbance Control Performance

Purpose: To ensure the Balancing Authority (BA) is able to utilize its Contingency Reserves to balance generation and demand in order to return system frequency within defined limits following a system disturbance.

What Is It About:

- Identifies contingency reserves (both up and down reserves) to be activated under loss of load or loss of generation events.
- Identifies single contingency and excess contingency events and establishes different requirements for the two types of events
- Excludes catastrophic events where reserve requirement plus available under frequency load shedding resources exceed requirements to restore system frequency.
- Excludes unforecasted, unscheduled, and/or unanticipated ramping events as reportable deficiencies in contingency reserves during such events.

Key Features:

- Sets up sufficient contingency reserves to cover the BA's most severe single contingency loss of a generator and/or transmission asset.
- Establishes the requirements for each BA to return system to the frequency range of 60.3 to 59.7 Hz within a 10 minute time limit for single contingency events.
- Establishes the requirements for each BA to return system to the frequency range of 60.5 to 59.5 Hz within a 10 minute time limit for excess contingency events.
- The excess contingency events occur prior to the contingency reserves being re-established following a single contingency disturbance or for multiple contingency events which exceed the reserve requirements of the single largest single contingency.
- Establishes the requirements to restore contingency reserves within 120 minutes time limit for single-contingency events.
- Establishes metrics for reportable incidents and compliance requirements.

How Is Standard Measured:

- Whether the BA has maintained adequate Contingency Reserves for each hour of operation.
- Whether the BA has returned the system to the frequency range of 60.3 to 59.7 Hz and within the 10 minute time limit after every Reportable Single Contingency Disturbance event. The Actual Disturbance Recovery Period is measured and then both as a number

of events that meet the criteria and as the average duration relative to the criteria per month.

- Whether the BA has returned the system to the frequency range of 60.5 to 59.5 Hz and within the 10 minute time limit after a Reportable Excess Contingency Disturbance event. The Actual Disturbance Recovery Period is measured and then both as a number of events that meet the criteria and as the average duration relative to the criteria per month.
- Whether the BA has restored Contingency Reserve levels to the specified amount within the 120 minute time limit both as a number of events that meet the criteria and as the average duration relative to the criteria per month.
- Compliance reporting to the PUC is required on a monthly basis.
- Compliance for DCS will be evaluated for each reporting period.
- Reset is one calendar month without a violation.
- Compliance Audits with notice to the BA within 30 days of years' end and completed within 90 days of such information being supplied.
- Other forms of Monitoring is self-Certification, spot checking, compliance violation investigations, self reporting and complaints
- BA keeps data for at least a two years period unless questions arise and retention can be longer

Caveats/Conditions Place on Implementation:

- Will require further impact analysis on impacts to companies
- At least one year of operating experience should be gained prior to enforcement by the PUC.

Major Implications:

- ***To Utilities***
    - Increased reporting requirements.
    - Additional costs of administration and performance penalties.
    - Requirements to identify contingency reserves plus load shedding resources.
    - Requirements to establish single largest contingency.
    - Requirements to prepare operating criteria and procedures.
    - Additional risk of penalties and enforcement
    - Risk of incorrect selection of criteria
- **To IPP's**
    - *Frequency criteria for restoration relative to IPP resources*

Recommendations to the RSWG:

- Complete the impact analysis on companies.
- Allow one year of operating experience before standard becomes enforceable.

Draft Hawaii Reliability Standard Presentation Synopsis: HI-BAL-502

Standard No: HI-BAL-502-0

Title: Planning Resource Adequacy Analysis, Assessment and Documentation

Purpose: To establish common criteria for each BA based on "one day in __ year" (determined by study) loss of Load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, shall include Planning Reserve Margins for meeting system load for the BA's System.

What Is It About:

- On an annual basis, the BA must develop, analyze and document the Planning Resource Adequacy.

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The analysis must calculate a Planning Reserve Margin for the applicable group.
- Include the following subject matter and documentation of its use:
    - Load forecast characteristics
    - Resource characteristics
    - Transmission limitations that prevent the delivery of generation reserves
    - Resource availability characteristics and document how and why they were included or excluded in the analysis
    - Transmission maintenance outage schedules and document how and why they were included or excluded in the analysis.
    - Capacity resources are appropriately accounted for
    - All Load in the Balance Authority's Area is accounted for
- The BA must annually document the projected Load and resource capability
- Must be publicly posted no later than 30 calendar days prior to the beginning of Year One

How Is Standard Measured:

- Each Measure has two levels of Non-Compliance.
- There are Measures that monitor the Resource Adequacy analysis and is accessed by audit process by the Hawaii PUC (or designee).
- There is no periodic audit requirement. However, notice to the BA within 30 days of years' end for a compliance audit.

- The Hawaii PUC to complete such audit within 90 days of such information being supplied.
- The BA must publicly post the documents timely.

Caveats/Conditions Placed on Implementation:

- Will require further analysis to determine appropriate loss of load expectation.
- Will require further impact analysis on utilities, customers and IPPs

Major Implications:

- **To Utilities**
  - Increased reporting requirements.
  - Additional costs of administration.
  - Additional risk of penalties and enforcement

Recommendations to the RSWG:

- Complete the analysis to determine appropriate loss of load expectation.
- Complete the impact analysis on utilities.

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-010-0

Standard No: HI-MOD-010-0

Title: Development and Reporting of Steady State System Models and Simulations

Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Transmission systems including the aggregate impact of distributed generation.

What Is It About:

- Establishes that the Balancing Authority (BA) shall develop and document comprehensive steady-state data requirements and reporting procedures.
- Each Transmission Owner or Generator Owner shall provide appropriate equipment characteristics and system data to the BA for the model development.
- The BA shall develop and maintain a library of solved (converged) transmission system – specific steady-state system models, including the relevant portions of the distribution system connecting distributed generation.

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The BA shall document their steady-state data requirements and reporting procedures and shall review them at least every five years.
- Each Transmission Owner or Generator Owner shall provide information to the BA based on four triggers, the BA's schedule (if any), BA's request in writing, the Owner has completed commercial operation of a new facility or significant modification, or whenever equipment characteristics experience a change that is expected to last more than 60 days.
- The BA shall develop steady-state system models annually and maintain a library of solved (converged) transmission system – specific steady-state system models, including the relevant portions of the distribution system connecting distributed generation. Most recent steady-state system models: 30 calendar days.
- The models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum and other appropriated system demand levels.

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.
- There are three Measures for the three Requirements.
    - The BA shall maintain evidence such as reports, or other documentation of its requirements and reporting procedure.
    - Each Transmission Owner or Generator Owner shall have dated evidence of transmittal that the data requirement and reporting procedures were complied with.

    - The BA shall have dated evidence for transmission-specific steady state system models.
- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive steady-state data requirements and reporting procedures.

Major Implications:

- **To Utilities:**
    - Increased reporting and monitoring requirements.
    - Additional costs of administration and performance penalties.
    - Requirements to comprehensive steady-state data requirements and reporting procedures.
- **To IPP's**
    - Additional costs of administration and implementation.

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-012-0

Standard No: HI-MOD-012-0

Title: Development and Reporting of Dynamic System Models and Simulations

Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the BA's transmission systems including the aggregate impact of distributed generation and to assure that generator and transmission system data is reported.

What Is It About:

- Establishes that the Balancing Authority (BA) shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior of the System.
- Each Transmission Owner or Generator Owner shall provide appropriate equipment characteristics and system data to the BA for the model development.
- The BA shall maintain a library of initialized (with no Faults or system Disturbances) transmission specific dynamics system models linked to the steady state system models, as appropriate.

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The BA shall document their dynamic data requirements and reporting procedures and shall review them at least every five years and distribute them to the owners annually.
- The BA shall not be restricted in the use of non-standard models in the analysis of its system.
- Each Transmission Owner or Generator Owner shall provide information to the BA based on four triggers, the BA's schedule (if any), BA's written request, the Owner has completed commercial operation of a new facility or significant modification, or whenever equipment characteristics experience a change that is expected to last more than 60 days.
- The BA shall develop dynamics system models annually and maintain a library of initialized (with no Faults or system Disturbances) transmission specific dynamics system models linked to the steady state system models, as appropriate.
- The models shall include at least two timeframes (present or near term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of the system..

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.
- There are three Measures for the three Requirements.
    - The BA shall maintain evidence such as reports, or other documentation of its requirements and reporting procedure.

    - Each Transmission Owner or Generator Owner shall have dated evidence of transmittal that the data requirement and reporting procedures were complied with.
    - The BA shall have dated evidence for transmission-specific steady state system models.
- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive steady-state data requirements and reporting procedures.

Major Implications:

- **To Utilities:**
    - Increased reporting and monitoring requirements.
    - Additional costs of administration and performance penalties.
    - Requirements to comprehensive dynamics data requirements and reporting procedures.
- **To IPP's**
    - Additional costs of administration and implementation.

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-016-0

Standard No: HI-MOD-016-0

Title: Actual and Forecast Demand, Net Energy for Load, and Controllable Demand-Side Management, and Distributed Generation

Purpose: Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, Load information related to controllable Demand-Side Management (DSM) programs and Distributed Generation (DG) is needed.

What Is It About:

- The BA shall develop and document the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data (including the impact of distributed generation), (c) controllable DSM data, and (d) DG below the requirements in MOD-010 to be reported for system modeling and reliability analyses.
- The BA's report of actual and forecast demand data shall address assumptions, methods, and the manner in which uncertainties are treated.
- The BA shall annually forecast the interruptible demand and Direct Load Management (DCLM) data for at least ten years into the future for peak system conditions.
- The BA will make known its amount of interruptible demand and DCLM to the Hawaii PUC (or designee).

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The BA shall develop and document the information annually on an aggregated basis for modeling.
    - Integrated hourly net-demand, monthly and annual peak hour actual system demand and Net Energy for Load for the prior year.
    - Monthly peak hour forecast demand and Net Energy for Load for the next two years.
    - Annual Minimum, daytime and Peak hour forecast system demand and annual Net Energy for load for at least ten years into the future.
- The customer demand count once and only once in developing its actual and forecast customer demand values.
- The BA shall determine the appropriate model for the aggregate DG that accurately reflects the impact on the system.
- The BA shall develop and document the information annually on an aggregated basis for modeling.
- The BA's forecasts shall clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demand, and Direct Control Load Management) are defined and included in the forecast.

- The BA shall include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load
- The BA shall documentation on the treatment of its DSM programs available

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.
- There are six Measures for the six Requirements.
    - The BA shall maintain documentation for actual and forecast customer data.
    - The BA shall provide evidence that it developed load data
    - The BA shall provide evidence that its actual and forecast demand data were addressed
    - The BA shall report current information to the Hawaii PUC (or designee) on written request
    - The BA shall provide evidence that it developed forecasts of interruptible demand and DCLM data.
    - The BA shall make known the amount of interruptible demand and DCLM to the Hawaii PUC (or designee) within 30 calendar days.
- The development of Actual and Forecast Demand, Net Energy for Load, Controllable DSM is performed annually.
- Requests must be responded to in 30 calendar days.
- Data Retention is six years.
- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive steady-state data requirements and reporting procedures.

Major Implications:

- **To Utilities:**
    - Increased reporting and monitoring requirements.
    - Additional costs of administration and performance penalties.
    - Requirements to comprehensive steady-state data requirements and reporting procedures.
- **To IPP's**
    - None

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-025-0

Standard No: HI-MOD-025-0

Title: Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources

Purpose: To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser or static source Reactive Power capability is available for planning models used to assess transmission system reliability.

What Is It About:

- Each Generator Owner or applicable Transmission Owner shall provide the BA with verification of the Real Power capability of its generating units, power electronics.
- Each Generator Owner or Transmission Owner (including synchronous condenser, power electronic or static source) shall provide the BA with verification of the Reactive Power capability.

Key Features:

- *Sets testing criteria for verification of Real Power capability of its generating units, power* electronics and Reactive Power capability of generating units, synchronous condenser, power electronic or static source.
- The BA will establish an initial testing date for all units for verification to be completed within three years.
- Verification is required at least every five years, or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent.
- Verification for new applicable Facility within 12 calendar months of its commercial operation date.
- Verification can be done by either stage testing or operational data.

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.
- There are two Measures for the two Requirements.
    - Each Generator Owner or applicable Transmission Owner will have evidence that it performed the verification of the Real Power capability and will have evidence that it submitted the information within 30 calendar days to its BA.
    - Each Generator Owner or applicable Transmission Owner (including synchronous condenser, power electronic or static source) will have evidence that it performed the verification of the Reactive Power capability and will have evidence that it submitted the information within 30 calendar days to its BA.
- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive steady-state data requirements and reporting procedures.

Major Implications:

- **To Utilities:**
  - Increased reporting and monitoring requirements.
  - Additional costs of administration and performance penalties.
  - Requirements to prepare procedures and assess operational implications.
  - Risk of performance penalties may impact operational decisions
  - Risk of selecting frequency criteria too tight/too loose for adequate operation
- **To IPP's**
  - Additional costs of administration and implementation.

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-026-0

Standard No: HI-MOD-026-0

Title: Verification of Models and Data for Generator and applicable transmission equipment *Excitation System or Plant Volt/VAr Control System*

Purpose: To verify that the generator or transmission equipment excitation system or plant Volt/VAr control system model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation system or plant Volt/VAr control system behavior when assessing a BA's System reliability.

What Is It About:

- Establishes responsibility between the Balancing Authority (BA) and each Generator Owner or Transmission Owner for verification of applicable facilities.
- Establishes that verification shall be done as a minimum every 5 years or if there is a change in the facilities that would change the characteristics.
- Establishes time limits for actions and responses between the BA and each Owner.

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The BA shall assist a requesting Generator Owner or Transmission Owner with several alternatives as a starting point for model verification.
- *Each Generator Owner or Transmission Owner shall provide a verified system or transmission* equipment model, including documentation and data to its BA.
- Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification to the BA within 90 calendar days of making changes that alter the equipment response characteristic.
- Each Generator Owner and Transmission Owner shall provide a written response to the BA, within 60 calendar days following receipt from the BA to perform a model review that includes either plans to verify the model or corrected model data or updating of data parameters.
- The BA shall notify the Generator Owner and Transmission Owner within 30 calendar days of receiving the verified model information that the model is or is not useable; and shall include a technical description if the model is not useable that includes the following:

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.
- There are six Measures for the six Requirements.
    - The BA must have the dated request for instructions or data, the transmitted instructions or data and dated evidence of a written transmittal.

- The Generator Owner or Transmission Owner must have dated evidence it verified each model for each applicable unit and a dated transmittal.
- The Generator Owner or Transmission Owner shall have a dated written response containing either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification.
- The Generator Owner or Transmission Owner shall have a dated revised model data or plans to perform a model verification and dated evidence it provided the information within 90 calendar days of making changes.
- The Generator Owner's or Transmission Owner's dated written response from a model review request containing the information it provided a written response within 60 calendar days following receipt.
- The BA must have the dated response that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information, that the model was usable or not usable according to the criteria and for a model that is not useable, a technical description.

- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive verification requirements and reporting procedures.

Major Implications:

- **To Utilities:**
  - Increased reporting and monitoring requirements.
  - Additional costs of administration and performance penalties.
  - Requirements to comprehensive steady-state data requirements and reporting procedures.
- **To IPP's**
  - Additional costs of administration and implementation.

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard.

Hawaii Reliability Standard Presentation Synopsis: HI-MOD-027-0

Standard No: HI-MOD-027-0

Title: Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Purpose: To verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess the BA's transmission system reliability, accurately represent generator unit real power response to system frequency variations.

What Is It About:

- Establishes responsibility between the Balancing Authority (BA) and each Generator Owner or Transmission Owner for verification of applicable facilities.
- Establishes that verification shall be done as a minimum every 5 years or if there is a change in the facilities that would change the characteristics.
- Establishes time limits for actions and responses between the BA and each Owner.

Key Features:

- The Facilities are divided into two groups based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
- The BA shall assist a requesting Generator Owner or Transmission Owner with several alternatives as a starting point for model verification.
- Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the BA.
- Verification of an individual unit less than the applicable group MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s) or both.
- Each verification shall include documentation comparing the applicable unit's MW model response to the recorded MW response for one of three methods, type of facilities with detailed description and technical data with complete disclosure of any controls limiting the frequency response.
- Each Generator and applicable Transmission Owner shall provide a written response to the BA's model concerns within 90 calendar days and contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification
- Each Generator and applicable Transmission Owner shall provide revised model data or model verification for an applicable unit to the BA within 90 calendar days of making changes.
- The BA shall notify the Generator and applicable Transmission Owner within 30 calendar days of receiving the verified model information that the model is useable or is not usable and shall include a technical description if the model is not useable.

How Is Standard Measured:

- There are two levels of non-compliance; Level 1 was established to indicate that the requirement was just missed.

- There are five Measures for the five Requirements.
    - The BA must have the dated request for instructions or data, the transmitted instructions or data and dated evidence of a written transmittal within 30 calendar days.
    - The Generator and applicable Transmission Owners shall have dated evidence it verified each model for each applicable unit and a dated transmittal.
    - The Generator and applicable Transmission Owner shall have dated evidence of transmittal and contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification.
    - The Generator and applicable Transmission Owner shall have dated evidence of transmittal and contain revised model data or model verification for an applicable unit after making changes.
    - The BA shall have dated evidence of transmittal of the response after receiving the verified model information that the model is useable or is not usable and shall include a technical description if the model is not useable.
- Compliance by audit or written request by the PUC (or designee), who may enforce penalties on the BA.

Caveats/Conditions Place on Implementation:

- Will require time to develop comprehensive verification requirements and reporting procedures.

Major Implications:

- **To Utilities:**
    - Increased reporting and monitoring requirements.
    - Additional costs of administration and performance penalties.
    - Requirements to comprehensive steady-state data requirements and reporting procedures.
- **To IPP's**
    - Additional costs of administration and implementation.

Recommendations to the RSWG:

- Complete the impact analysis on adopting the standard.

Draft Hawaii Reliability Standard Presentation Synopsis: HI-PRC-006

Standard No: HI-PRC-006-0

Title: Underfrequency Load Shedding

Purpose: To establish design documentation, maintenance and operational requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

What Is It About:

- On a periodic basis, the BA must develop and document the criteria for an UFLS program.
- Identifies the minimum requirements in establishing an UFLS program.
- Identifies the UFLS equipment and establishes maintenance and testing program.
- Excludes catastrophic events where reserve requirement plus available under frequency load shedding resources exceed requirements to restore system frequency.

Key Features:

- The Facilities are divided into two groups (A and B, A>B) based on the BA's annual system peak demand to determine minimum MVA modeling requirements. The dividing level is 50 MW.
    - Individual generating units greater than 2.0 MVA for group A and 0.2 MW for group B.
    - Generating plants/facilities greater than 4.0 MVA for group A and 0.4 MW for group B.
    - Underfrequency trip settings of all variable generation modeled as equivalent units for each frequency trip point exceeds 1.0 MW.
- The program must consider historical events and system studies.
- Establishes the requirements for loss of generation to be considered in the program as well as the metrics for the system response.
- Establishes a procedure for data base update.
- Establishes post activation review requirements to determine program effectiveness.
- Establishes metrics for reportable incidents and compliance requirements.
- Establishes metrics for UFLS equipment maintenance testing program.

How Is Standard Measured:

- There are Measures that monitor the procedures and scope that the program has established the design and operational requirements for an UFLS program.
- There is a Measure for each of the 13 Requirements.
- Each Measure has two levels of Non-Compliance.

- All post activation events are reviewed within two weeks to determine if further analysis is required.
- If deemed necessary, further analysis and actions must be completed within six months.
- Metrics were established for identification and scheduling of UFLS equipment maintenance and testing.

Caveats/Conditions Placed on Implementation:

- Will require further impact analysis on utilities, customers and IPPs

Major Implications:

- **To Utilities**
  - Increased reporting requirements.
  - Additional costs of administration and performance penalties.
  - Requirements to establish formal program.
  - Requirements to prepare operating criteria and procedures.
  - Additional risk of penalties and enforcement
- **To IPP's**
  - Requirement to report any changes to the BA that will have an impact on design.

Recommendations to the RSWG:

- Complete the impact analysis on utilities, customers and IPPs.

Docket No. 2011-0206 – Reliability Standards Working Group

Comments of the Hawaiian Electric Companies Regarding Implementation of Reliability Standards

During the January 24, 2013 RSWG stakeholder meeting it was suggested that it could be helpful if the Hawaiian Electric Companies were able to provide the RSWG stakeholders and process with further detail regarding the Companies' efforts to implement any reliability standards developed and proposed by the Reliability Standards Drafting Group, and the estimated timeframes to accomplish such implementation, once adopted or approved by the Commission.

In response to this request, the Hawaiian Electric Companies respectfully submit for the Commission's information and consideration the following comments on the process for implementation of formal reliability standards in Hawaii.[1] The Companies' good faith preliminary estimate of timeframes is set forth in the Excel spreadsheet attached to these comments. To support the estimated timeframes, the Hawaiian Electric Companies provide the following discussion of tasks that need to be considered for the implementation of these reliability standards.

- Calibration: Prior to implementation of the standards, the Hawaiian Electric Companies will need to comprehensively assess their current status relative to the proposed standards to determine specifically what will be required to meet the standards.

- Impact Analysis: The impact of each proposed standard on the utility and other stakeholders (such as ratepayers and IPPs) should be assessed prior to a decision to implement the standard.

- Operator Guides: As discussed extensively during the presentations to the RSWG stakeholders, for each standard that is to be implemented, operator guides will need to be created that provide the specific means to implement the standard. For example, to comply with BAL-001, guides will required for the operators to be able to assess compliance prior to the 24-hr CPS-2 period such that corrective action can be taken prior to a non-compliance day being recorded. Procedures for correction and actions for compliance and monitoring of all impacted facilities including the Companies' and IPP generators must also be developed. Additionally, procedures for forced restriction and curtailment of those responsible for the deviations must be developed as well as procedures for reconnecting to the system following corrective action.

- Implementation Requirements: Related to the issue of Calibration above, the particular requirements to implement each standard must be developed. For example, if a standard requires monitoring and reporting, the Companies will need sufficient time to put into place the procedures, software systems, equipment, etc., necessary to fulfill these requirements. To the extent that a standard imposes additional requirements over past practice or performance, work may be required to implement the necessary modifications or system enhancements so that the standards can be met.

[1] Hawaiian Electric Company, Inc., Maui Electric Company, Limited and Hawaii Electric Light Company, Inc. (collectively "Hawaiian Electric Companies" or "Companies").

- Monitoring/Assessment Phase: After the implementation has been completed, certain standards will need to be monitored and assessed. During this period, the relevant performance measures would be collected to allow review of compliance and whether measures and metrics are appropriate. Based on these results, a change may be made to the requirements or metrics, or additional changes may be required to operator guides and implementation, so that the standards can be met.

Due to the fairly extensive nature of the tasks that must be performed as a part of standards implementation, and due to the fact that certain stakeholders (e.g., IPPs) were not parties to the RSWG process but will nevertheless be required to comply with the standards, it is recommended that the candidate standards that may be suitable for implementation be prioritized. For each of the standards the affected stakeholders or groups may collaborate on the standards to be placed into effect. A time frame will need to be identified given the resources available to perform this work and the tasks that need to be fulfilled. The prioritization of the standards for implementation should be based on consideration of a) the value of each proposed standard in promoting reliability and security of the electrical grid and b) the anticipated amount of work to implement the standard.

With respect to the stakeholders that may be affected by the standards that were not part a part of the RSWG standards development process, the Companies respectfully offer the following discussion on what is anticipated to be required for the implementation of the new standards.

- Though the best efforts of the parties engaged in the RSDG drafting process contributed to the development of the standards; there were other groups that were not represented in the meetings. These groups (e.g., certain IPP's, City and County of Honolulu) that will be affected by the new standards need to be included in the yet to be determined framework so that the proposed standards can be thoroughly vetted through the impact analysis with the stakeholders that will be directly affected by their implementation. To facilitate a balanced review of proposed standards, each participant group should have a designated representative to consolidate the opinions of that particular affected segment of the stakeholders and the votes of each group of stakeholders should be weighted such that a balanced approach can be developed.
- A process for the official adoption of these standards will also need to be developed to formalize the new rules and guidelines that are being put into place.
- Given the discussion above, other stakeholders will also have a number of implementation issues that will need to be determined, equipment or software that may need to be ordered, tasks that need to be identified and resources scheduled following the determination of which standards should be adopted.
- Based on a high level assessment of what is needed the attached preliminary estimate of the time frames required has been prepared based on a brief assessment of probable next steps. This is meant to be illustrative as a more in-depth refinement of the impact analysis and implementation plan is required.

The Hawaiian Electric Companies respectfully submit that the implementation of these new reliability standards needs to be afforded close scrutiny by both stakeholders and the Commission. While it is important to put these standards into effect sooner rather than later it is important for the work to be done prudently. As the Commission is aware, many of the reliability standards discussed and developed during the RSWG proceeding have a foundation in standards adopted by the North American Electric Reliability Corporation ("NERC"). For utilities and companies that are

required to comply with the NERC standards, it is not uncommon for significant amounts of time to elapse before the standards are implemented primarily because of the impact that standards could have on the entities that need to apply them. The estimated timeframes presented in the attached spreadsheet are made without any prior experience with actual timeframes for standards implementation and therefore they tend to reflect optimistic time frames. However, as a State committed to integrate increasing levels of renewable resources to its electrical grids, the Companies recognize the importance of the adoption of these standards to ensure that customers continue to have reliable and secure electric power. In summary:

- The Companies suggest that each standard should undergo the process of an impact assessment, development of necessary operator guides, and implementation plan.
- Following the implementation plan, certain standards may require a monitoring and assessment period.
- Based on the tasks that need to be accomplished and the formal process to institute these standards, the Companies offer the attached spread sheet to illustrate the type of envisioned impacts and implementation plans, resulting in preliminary estimates of the timeframes to implement these standards, following adoption.

TABLE A-2

STANDARDS THE RSWG IS RECOMMENDING FOR ADOPTION IN HAWAII				Implementation Plan		
HAWAII RELIABILITY STANDARD	RELAVANT NERC STANDARD	TOPIC	COMMENTS	Implementation Tasks	Estimated Implementation Schedule[1]	Monitoring Schedule
HI-BAL-001	BAL-001, BAL-005	Real Power Balancing Control Performance	The Hawaii standard was written around frequency only rather than ACE. Also added 4 reqirements from BAL-005.	1. SCADA Modifications 2. Develop daily implementation/ monitoring 3. Develop notification/ compliance issue procedures	1. 6 - 9 months 2. 2 -3 months (concurrent with 1) 3. 3-4 months (one month lag with 1 above)	1. 12-month implentation period 2. monitor compliance and report monthly, evaluate quarterly if metrics need revision
HI-BAL-002	BAL-002	Disturbance Control Performance		1. SCADA Modifications 2. Develop daily implementation/ monitoring 3. Develop notification/ compliance issue procedures	1. 6 - 9 months 2. 2-3 months (concurrent with 1) 3. 3-4 months (one month lag with 1 above)	1. 12-month implentation period 2. monitor compliance and report monthly, evaluate quarterly if metrics need revision
HI-BAL-502-0	BAL-502	Planning Resource Adequacy Analysis, Assessment and Documentation		1. develop "X" in formula for LOLP 2. develop planning reserve margin	1,2 6-12 months	
HI-PRC-006-0	PRC-006, PRC-007, PRC-008, PRC-009	Underfrequency Load Shedding	combined portions of the NERC standards into one.	1. HECO/MECO -review UFLS philosophy 2. MECO develop philosophy 3. test/develop PV UFRT/LVRT capability	1. 6-9 months 2. 9-12 months	
HI-MOD-010-0	MOD-012, MOD-013, MOD-015	Development of Steady State System Models and Simulations	Combined NERC standards into one.	1. develop standards acceptable to HECO - IPPs 2. resolve confidentiality issues in PPA 3 work with each IPP to obtain models 4. develop compliance/non-compliance reporting 5. develop protocols for notification/monitoring	9-12 months	
HI-MOD-012-0	MOD-012, MOD-013, MOD-015	Development and Reporting of Dynamic System Models and Simulations	Combined NERC standards into one.	1. develop standards acceptable to HECO - IPPs 2. resolve confidentiality issues in PPA 3. work with each IPP to obtain models 5. develop acceptable reporting procedures. 6. develop compliance/non-compliance guides and reporting	9-12 months	

HI-MOD-016-0	MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021	Actual and Forecast Demand, Net Energy for Load, and Controllable Demand-Side Management, and Distributed Generation	Combined NERC standards into one.	1. develop reporting standards	3-5 years	
HI-MOD-025-0	MOD-024, MOD-025	Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources	Combined NERC standards into one	1. develop standards acceptable to HECO - IPPs 2. resolve confidentiallity issues in PPA 3. work with each IPP to obtain models 4. develop acceptable testing procedures 5. develop acceptable reporting procedures. 6. develop compliance/non-compliance guides and reporting	3-5 years	
HI-MOD-026-0	MOD-026	Verification of Models and Data for Generator and applicable transmission equipment Excitation System or Plant Volt/VAr Control System		1. develop standards acceptable to HECO - IPPs 2. resolve confidentiallity issues in PPA 3. work with each IPP to obtain models 4. develop acceptable testing procedures 5 develop acceptable reporting procedures. 6. develop compliance/non-compliance guides and reporting	3-5 years	
HI-MOD-027-0	MOD-027	Verification of Models and Data for Turbine/Governor and Load Control and Active Power/Frequency Control Functions		1. develop standards acceptable to HECO - IPPs 2. resolve confidentiallity issues in PPA 3. work with each IPP to obtain models 4 develop acceptable testing procedures 5. develop acceptable reporting procedures 6. develop compliance/non-compliance guides and reporting	3-5 years	

Note 1: These estimated times may need to be adjusted for material or software installation lead times or for larger cost items the PUC application process. These time frames will be adjusted when a clearer picture of what is required to meet the standard is known.

RSDG Appendix D-1
Potential Framework for Development and Implementation of Electric Utility Reliability Standards in Hawaii

Introduction

The Hawaii Public Utility Commission ("Commission" or "PUC") formed the Reliability Standards Working Group ("RSWG") in the Feed-In Tariff Docket (No. 2008-0273[1]), and subsequently opened a new docket (No. 2011-0206[2]) to focus attention to the creation of reliability standards for electric utilities in Hawaii starting with the Hawaiian Electric Companies[3].

Per the "RSWG Purpose, Scope and Work Plan – Final 9/23/11"[4], prepared by the RSWG's Independent Facilitator ("IF"), Alison Silverstein, the primary purpose of the RSWG is to recommend to the Commission an appropriate set of reliability standards, metrics, rules and criteria to "help determine how we can interconnect the maximum amount of renewable generation to the grid while preserving grid reliability," consistent with Hawaii's clean energy statutory mandates and policies.

The Reliability Standards Drafting Group ("RSDG") of the RSWG was formed to identify and draft recommended reliability standards. The RSDG utilized the existing North American Electric Reliability Corporation's ("NERC") standards and other regional standards as a basis of screening their applicability to Hawaii utilities. The resulting proposed standards, even though not a complete set due to time constraints and the complexity of the drafting process to adapt existing reliability standards to Hawaii, have been approved by the RSWG and are submitted to the PUC for their review and adoption in accordance to the recommendations contained the RSWG/RSDG report.

Procedurally, the RSDG has had to deal with the "mechanics" of preparing, reviewing and seeking consensus within the RSDG and the RSWG on specific draft standards. Quite naturally, as the standard's drafting process has evolved, questions have arisen regarding what happens after the RSWG's work[5] is complete.

Therefore, the RSDG is recommending to the PUC this potential framework for the development and implementation of electric utility reliability standards in Hawaii ("Framework"). . The Framework includes a discussion of the essential elements for due process pertaining to the development and implementation of reliability standards and associated modifications, updates, definitions, interpretations, any associated violation risk factors, violation severity levels, and/or implementation plans (hereinafter, collectively "associated information"). This Framework also

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[1] Docket No. 2008-0273, entitled "Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs," was opened by the Commission in its order, dated October 24, 2008.

[2] Docket No. 2011-206, entitled "Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited" was opened by the Commission in its order, dated September 8, 2011.

[3] The Hawaiian Electric Companies are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited

[4] The RSWG Purpose, Scope and Work Plan was drafted by the IF, then reviewed with the RSWG, revised and then filed by the IF on September 23, 2011.

[5] The work of the RSWG is to be complete by December 31, 2012.

includes some outstanding questions that could not be fully addressed by the RSDG, for the PUC's deliberations.

This Framework is intended to be an overarching document and to be incorporated with the following documents prepared by the RSDG:

1. Proposed Reliability Standards Program Organization
2. Development of Registered Ballot Body and Segment Qualification Guidelines
3. Suggested Process Flow Chart

Note that the NERC Standards Processes Manual has served as a key reference in preparing these documents.

Mission Statement

To strengthen the electric utility industry in Hawaii with the development and implementation of clear and consistent, fact - and consensus-driven reliability standards that are consistent where appropriate with reliability standards on the U. S. mainland and elsewhere and consistent with all applicable laws and policies governing the electric utility industry in Hawaii.

Objectives

To ensure the reliability of Hawaii's electricity grids, including peripheral systems, equipment and procedures, through adoption and implementation of formal uniform standards pertaining to planning, design, construction and installation, operation and maintenance, interconnection and decommissioning of facilities. These standards shall be based upon engineering principles or accepted industry practices that are competent, unbiased, relevant and useful.

The procedures governing the development of a reliability standard shall be uniformly applied and shall conform to a high degree of quality, so that resulting standards can be of maximum benefit to the electricity grids and all stakeholders, including the utilities, independent power producers, energy service providers, and rate payers in a manner consistent with all applicable laws and policies governing the electric utility industry in Hawaii.

The implementation of the Framework should ensure that each reliability standard and associated information is the result of thorough consideration by impartial, representative and qualified persons directly and materially affected by the reliability standards and associated information.

Overall Approach

Introduction. Typically, there is an order associated with the development and implementation of standards. For example, an entity (e.g., NERC, ANSIIEEE or an industry group such as AWEA) will sanction or endorse the development of standards based on its mission statement and objectives. The standards development entity may also approve said standards, and/or the standards may be subject to the approval of another entity. For the standards that have been created to date and submitted to the PUC as part of the RSWG final

report and those that are to be developed going forward, the PUC or its designee, the Hawaii Electricity Reliability Administrator ("HERA"), should consider the following:

Challenges. This Framework and accompanying documents propose a structure and process for the PUC to address the following questions and issues:

What is the appropriate approach (i.e., standards order) for the development and implementation of electric utility reliability standards and associated information in Hawaii? For example, given that the RSDG has already undertaken the development of formal reliability standards in the RSWG,

- What entity will continue the development of the standards, including what entity will be in charge of approving standards and associated information?,

What entity will be involved in the drafting and reviewing of the standards and associated information?

What procedures will be used to propose and draft standards and associated information?,

- How will consensus be achieved and what governance rules (including voting or ballots) apply?

- Will procedures be implemented to protect entities involved in the development and approval process from liability?

As further described in the accompanying documents, the RSDG recommends that the "Standards Process" be delegated by the PUC to HERA who will then formally establish the procedures encompassing the overall process for development and implementation of reliability standards and associated information for PUC approval and adoption. Once reliability standards are adopted, the RSDG recommends that HERA, as delegated by the PUC, manage, administer, and enforce compliance with the standards through well thought out procedures which will need to address the details of administration, compliance, enforcement, and the establishment of appropriate penalties and assessment thereof for non-compliance.

The Process. The RSDG recommends that the Reliability Standards Process be structured based on the following essential elements to achieve due process in the formulation and implementation of Hawaii reliability standards:

1. Openness
2. Lack of dominance
3. Balance
4. Consensus vote
5. Written procedures
6. Compliance

Each essential element is discussed below:

Openness

Timely and adequate notice of any action to create, revise, reaffirm, or withdraw a standard, and the establishment of a new consensus body or drafting team shall be provided to all known directly and materially affected interests. Notice should include a clear and meaningful description of the purpose of the proposed activity and shall identify a readily available source for further information. In addition, should a consensus body or drafting team be constituted by HERA, the member's name (or if membership is by organization, the name of the organization with a point of contact), affiliation and

interest category of each member of the consensus body shall be made available to interested parties upon request.

Lack of dominance
Unless it is claimed in writing (including electronic communications) by a directly and materially affected party that a single interest category, individual or organization dominated the standards development process, no test for dominance is required.

Balance
Historically the criteria for balance are that a) no single interest category constitutes more than one-third of the membership of a consensus body dealing with safety-related standards or b) no single interest category constitutes a majority of the membership of a consensus body dealing with other than safety-related standards.
The interest categories appropriate to the development of consensus in any given standards activity are a function of the nature of the standards being developed. Interest categories shall be discretely defined, cover all materially affected parties and differentiate each category from the other categories. Such definitions shall be available upon request.

Evidence of consensus and consensus body vote
Evidence of consensus in accordance with these procedures of the standards developer shall be documented. Consensus is demonstrated, in part, by a vote of the consensus body. The developer's procedures shall state specifically how consensus will be determined. An example of the criteria for consensus includes a requirement that a majority of the consensus body cast a vote (counting abstentions) and at least two-thirds of those voting approve (not counting abstentions). The developer may submit for approval an alternative methodology for determining consensus.

Evidence of compliance
The developer of reliability standards shall retain records to demonstrate compliance with all aspects of these and the developer's accredited procedures. Such records shall be available for audit as directed by the Commission.

Potential Standards Organizational Order. The following order is suggested for further PUC consideration as described in more detail in the Proposed Reliability Standards Program Organization document:

1. Commission

2. HERA

3. Standards Development Board/Committee

4. Standards Stakeholder Segments: Stakeholders should include the following entities that would make up the Standards Board/Committee:

    - HERA
    - Hawaii Utilities
    - Hawaii Consumer Advocate
    - Large End-Use Customers

- Small End-Use Customers
- IPP/NUG's
- Federal Agency Customers, ie DOD
- State and County Representatives
- Hawaii Department of Business, Economic Development and Tourism (DBEDT)
- Independent Transmission Providers or Certified Cable Company
- Distributed Generation Developers
- Demand Response Providers/Aggregators
- Non Governmental Organizations (NGO's)

Development and drafting of reliability standards and associated information would encompass representation from the various Stakeholder Segments above as deemed appropriate and applicable, which will have voting rights as noted in the Proposed Reliability Standards Program Organization document, as well as non-voting technical experts or other non-voting interested entities, such as energy service providers, or manufacturers of electric, generation, transmission or distribution equipment.

Policies For Consideration

Introduction. Policies and Procedures are required to ensure that the Reliability Standards Development and Implementation process is clear and transparent, and functions well. For the purpose of this discussion, policies are intended to be the "guiding principles" of the process, while the procedures are intended to "guide" the "day-to-day" standards process.

Proposed Policies. The following policies questions are proposed by the RSDG for consideration to help the PUC deliberate and on-going process for reliability standards development:

1. Type of Process

   a. Technically-Driven Process. The Standards Development Board/Committee could be formed with a group of individuals with expertise in utility, reliability and standards. Those with direct knowledge of and experience with the HECO Companies' systems would be preferred. There would be limited outreach to the general public. The standards would be approved by HERA, vetted by the Stakeholders and other interested parties via a PUC proceeding and then adopted by the PUC for implementation. The RSDG does not see this process as ANSI-accredited; or

   b. Consensus-Driven Process. The Standards Development Board/Committee could be formed with a group of individuals with expertise in utility, reliability, standards and other interested stakeholders. There would be a an outreach activity to inform the general public. The standards would be approved by HERA, vetted by the Stakeholders and other interested parties via a PUC proceeding and then adopted by the PUC for implementation. The process could be ANSI-accredited.

2. Role of the PUC

   a. Shall have the responsibility and accountability for the development and implementation of electric utility reliability standards and associated information in Hawaii

   b. May delegate the responsibility and accountability for all or a portion of standards development, implementation, and administration and enforcement to HERA, in accordance with Act 166 adopted into law on June 27, 2012 and became effective July 1, 2012.

   c. Shall review and approve reliability standards and associated information, including implementation procedures and mediate any issues that arise

   d. May retain a consultant to be a member of the Standards Development Board/Committee and to assist and support the "day-to-day" activities of HERA.

3. Role of the HERA

   a. Shall monitor the "day-to-day" standards activities, including proposing specific standards, and implementation, administration and enforcement policies and procedures

   b. Shall oversee the activities of the Standards Development Board/Committee and/or sub-committees

   c. Shall establish the eligibility criteria for membership on the Standards Development Board/Committee

   d. Shall select and/or remove members from the Board/Committee

   e. Shall have an employee (s) or representative (s) on the Board/Committee

   f. Shall prepare implementation policies and procedures, including, but not limited to, administration, enforcement, compliance oversight, and establishment of penalties and assessment thereof for review and approval by the PUC

   g. Shall implement and enforce all approved standards, policies and procedures

4. Role of the Standards Development Board/Committee

   a. Shall identify potential standards for drafting; review and approve standards and associated information

   b. Shall submit the standards and any associated information to an approved Review Panel/Stakeholder Segments for comments

   c. Shall resolve comments/issues and revise standards and any associated information as appropriate and re-circulate revisions to the reviewers

d. Shall seek consensus on draft standards and any associated information and vote or ballot as appropriate in Committee and then by the whole Board

e. Shall submit draft standards approved by the Board/Committee to HERA for approval as a formal standard

f. Shall revise and resubmit standards and associated information to HERA as appropriate

g. Shall respond to requests from HERA to review existing standards and associated information for possible updates

5. Additional Issues to Be Resolved Between HERA, the Board/Committee and the Stakeholder Segments

a. Who should chair the Board, e.g., HERA or a member of the Board elected by its members?

b. Should there be co-chairs, e.g., one from HERA and a non-HERA Board member?

c. How should standards be proposed, e.g., could any stakeholder propose a standard?

d. Who would approve a specific standard for drafting?

e. How would committees be formed and by whom, e.g., for a single standard or a set of related standards, and would this be the responsibility of the Board/Committee, HERA or a shared responsibility?

f. What constitutes consensus on or approval of a draft standard?

g. Given that draft standards undergo a Panel Review, how many reviews will be conducted and at what point or points in the process?

h. Will reviewers be informed of revisions made or not made on account of the reviewers' comments, with explanations as appropriate?

i. If a draft standard does not gain 100% consensus from the Board, can it be approved by the Board (first within Committee and then the whole Board) by a vote or ballot?

j. If so, what constitutes approval e.g., a simple majority or by 2/3 vote by the weighted stakeholder segment?

k. Should approved standards be reviewed and updated on a regular basis?

l. If so, what should be the review cycle, e.g., every year, every three years or?

m. Does the Board have any role in the implementation of the standards?

n. Would administrative support to the Board be provided by HERA?

o. Would this support include any remuneration to Board members?

p. Should HNEI or similar organizations be a member or an observer of a standards drafting group or a Stakeholder Segment? What would be their contribution and function to the standards process? Do these entities have operational control of system equipment?

Conclusion and Recommendation

The RSDG has made great progress is initiating and completed certain reliability standards specifically for the state of Hawaii as directed by the RSWG docket. The completed standards are provided for the PUC's adoption and implementation. But more work remains to be completed. This Framework and the accompanying documents are provided for the PUC's consideration as a potential approach to moving forward toward completing the task of development, adoption, and implementation of reliability standards and associated information for Hawaii. The RSDG would welcome the opportunity to continue this work under the auspices of the HERA and/or the PUC.

Proposed Reliability Standards Program Organization

HERA
The Hawaii Electricity Reliability Administrator ("HERA") shall consider for adoption reliability standards and associated modifications, updates, definitions, interpretations, any associated violation risk factors and/or violation severity levels, and/or implementation plans (hereinafter, collectively "associated information") that have been developed according to the processes identified in this document. Once HERA adopts a reliability standard or associated information, HERA shall submit the reliability standard or associated information along with applicable supporting documentation to the Hawaii Public Utilities Commission ("Commission" or "PUC") for approval.

Registered Ballot Body
The Registered Ballot Body comprises all entities or individuals that qualify for one of the stakeholder segments and are registered with HERA as potential ballot participants in the voting on reliability standards and associated information. Each member of the Registered Ballot Body is eligible to join the ballot pool for each standard action.

*The Industry Segment Qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document attached. The Standards Committee Charter is also attached for reference.

Ballot Pool
Each standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular standard action. The ballot pool votes on each standard action. The ballot pool remains in place until all balloting related to that standard action has been completed.

Standards Board/Committee
The Standards Board/Committee serves at the pleasure and direction of HERA. HERA shall direct the Standards Board/Committee to draft a charter delineating their scope and responsibilities and shall approve said Charter. Standards Board/Committee members are elected by their respective segment's stakeholders. The Standards Board/Committee consists of two members of each of the stakeholder segments in the Registered Ballot Body. A member of the HERA staff shall serve as the nonvoting secretary to the Standards Committee.

The Standards Board/Committee is responsible for managing the standards processes for development of reliability standards and associated information in accordance with this document. The responsibilities of the Standards Board/Committee are defined in detail in the Standards Board/Committee's Charter. The Standards Board/Committee is responsible for ensuring that the reliability standards and associated information developed by drafting teams are developed in accordance with the processes in this document and meet HERA's benchmarks for reliability standards as well as any applicable criteria for PUC approval.

The Standards Board/Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team for process (not technical)

reasons. The Standards Board/Committee may direct a drafting team to revise its work to follow the processes in this document or to meet the criteria for any applicable HERA process benchmarks for reliability standards, or to meet the process criteria for PUC approval. However the Standards Committee shall not direct a drafting team to change the technical content of a draft reliability standard or associated information.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

HERA or Designated Representative

HERA or its designated representative is responsible for administering HERA's standards processes in accordance with this document. HERA's representative shall provide support to the Standards Board/Committee in managing the standards processes and in supporting the work of all drafting teams. HERA's representative shall work to ensure the integrity of the standards processes and consistency of quality and completeness of the reliability standards and associated information. HERA's representative shall facilitate all steps in the development of standards and associated information. HERA's representative shall work with drafting teams in developing requirements for each standard, in accordance with HERA criteria.

HERA shall be responsible for presenting reliability standards and associated information to the PUC. When presenting standards-related documents to the PUC for adoption or approval, HERA shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

Drafting Teams

HERA through the Standards Board/Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), reliability standards and associated information.

Each drafting team consists of a group of technical experts that work cooperatively with the support of HERA or its designated representative. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the reliability standard and associated information. The technical experts maintain authority over the technical details of the reliability standard and associated information. Each drafting team appointed to develop a reliability standard or associated information is responsible for following the processes identified in this document as well as procedures developed by the Standards Board/Committee from the inception of the assigned standard development through the final acceptance of that reliability standard or associated information by the HERA and the PUC.

Collectively, each drafting team:

• Drafts proposed language for the reliability standards and/or associated information.

• Solicits, considers, modifies the draft reliability standard or associated information as appropriate, and responds to comments related to the specific standards development project.

• Participates in industry forums to help build consensus on the draft reliability standards and/or associated information.

• Assists in developing the documentation used to obtain HERA and PUC approval of the reliability standards and/or associated information.

All drafting teams report to the Standards Board/Committee.

Governmental Authorities
The PUC is the applicable Governmental Authority in the state of Hawaii. HERA has been legislatively constituted with the authority to submit each new, revised or withdrawn reliability standard or associated information to the PUC for adoption and implement and enforce said standards at the direction of the PUC.

Committees, Subcommittees, Working Groups, and Task Forces
HERA may form technical committees, subcommittees, working groups, and task forces to provide technical research and analysis used to justify the development of new reliability standards or associated information and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified standards or requirements with the HERA staff for use in identifying the need for new standards projects.

Compliance
The PUC shall be responsible for monitoring HERA's compliance with its reliability standards processes and procedures and for monitoring HERA's compliance with the HERA procedures regarding the development of new or revised reliability standards and associated information. HERA shall verify that each proposed reliability standard is enforceable as written before the reliability standard is *posted for formal stakeholder comment and balloting.*

Compliance Enforcement Program
The HERA compliance enforcement program manages and enforces compliance with approved reliability standards. The compliance enforcement program shall provide feedback to drafting teams during the standards development process to ensure the compliance enforcement program can be practically implemented for the reliability standards under development.

The compliance enforcement program may conduct field tests or data collection related to compliance elements of proposed reliability standards and may provide assistance with field tests or data collection when requested. The compliance enforcement program shares its observations regarding the need for new or modified requirements with the HERA staff for use in identifying the need for new standards projects.

Certification
The PUC shall certify each stakeholder as to its participation and responsibilities to the standards development process and membership on the Standards Board/Committee

Operating Procedures
HERA has responsibility for developing reliability standards to support reliability as well as the responsibility for seeing to the development and implementation of electric system operating guidelines and procedures that amplify each reliability standard as needed. Coordination

between reliability standards and operating guidelines and procedures is needed as a means of providing the full implementation and assurance of electric system reliability.

RSDG Appendix D-3
Development of the Registered Ballot Body and Segment Qualification Guidelines

Registration Procedures

The Registered Ballot Body comprises all entities/stakeholders (organizations, individuals, corporations, etc) that:

1. Qualify for one of the segments below, and
2. Are registered with HERA as potential ballot participants in the voting on standards, and revisions and modifications thereof.

Each entity, when initially registering to join the Registered Ballot Body, and annually thereafter, shall self-select to belong to one of the stakeholder segments described below.

HERA will review all applications for joining the Registered Ballot Body, and make a determination of whether the self-selection satisfies at least one of the guidelines to belong to that segment. The entity will then be "credentialed" to participate as a voting member of that segment.

All registrations shall be done electronically.

Segment Qualification Guidelines

The segment qualification guidelines are inclusive; i.e., any entity with a **legitimate interest in the reliability of the bulk power system** that can meet any one of the guidelines for a segment is entitled to belong to and vote in that segment.
The general guidelines for all segments are:

- Entities with integrated operations or with affiliates that qualify to belong to more than one segment (e.g., transmission owners and electric generators, storage and ancillary services owners) may belong to each of the segments in which they qualify, provided that each segment constitutes a separate membership and is represented by a different representative.

- At any given time, affiliated entities may collectively be registered only once within a segment.

- Any person or entity, such as a consultant or vendor, providing products or services related to bulk power system reliability within the previous 12 months to another entity eligible to join Segments 1 to 7 shall be qualified to join any one segment for which one of the entities receiving those products or services is qualified to join.

- Entities may participate freely in any or all subgroups.

- After their initial selection, registered participants may apply to change segments annually, according to a defined schedule as determined by HERA.

- The qualification guidelines and rules for joining segments shall be reviewed periodically to ensure that the standards process continues to be fair, open, balanced, and inclusive. Public

input as determined as appropriate by the PUC, shall be solicited in the review of these guidelines.

- Since all balloting approval of standards shall be done electronically, any registered entity may designate a proxy to vote on its behalf. There are no limits on how many proxies a person may hold. However, HERA must have in its possession, either in writing or by email, documentation that the voting right by proxy has been transferred.

Segments

Segment 1. Independent Transmission Providers, including Certified Cable Company

a. Any entity that owns or controls integrated transmission facilities.

Segment 2. Hawaii Utilities, including Load-Serving Entities (LSEs)

a. Entities serving end-use customers under a regulated tariff, a contract governed by a regulatory tariff, or other legal obligation to serve.

Segment 3. Electric Generators

a. Affiliated and independent generators (IPPs and/or NUGs).
b. A corporation that sets up separate corporate entities for each one or multi generating plants in which it is involved may only have one vote in this segment regardless of how many single-plant or multi-plant corporations the parent corporation has established or is involved in.
c. Owners/developers of Distributed Generation.

Segment 4. Electricity Brokers, Aggregators, and Marketers

a. Entities serving end-use customers under a power marketing agreement or other authorization not classified as a regulated tariff.
b. An entity that buys, sells, or brokers energy and related services for resale in wholesale or retail markets, whether a non-jurisdictional entity operating within its charter or an entity licensed by a jurisdictional regulator.
c. Demand Response aggregators.

Segment 5. Large Electricity End Users

a. A customer with an average aggregated service load (not purchased for resale) of at least _____ MWh annually, excluding cogeneration or other back feed to the serving utility.
b. Federal Agency customers, e.g. DOD, etc.
c. Agents or associations can represent groups of large end users.

Segment 6. Small Electricity Users

a. A customer with an average aggregated service load of less than ?? MWh annually.
b. Agents or associations can represent groups of large end users.

Segment 7. State and County Government Entities

a. State and County customers
b. State and County Elected Representatives
c. Consumer Advocate (CA)
d. Dept. of Business, Economic Development and Tourism (DBEDT)
e. Does not include the HPUC

Segment 8. Non Governmental Organizations (NGOs)

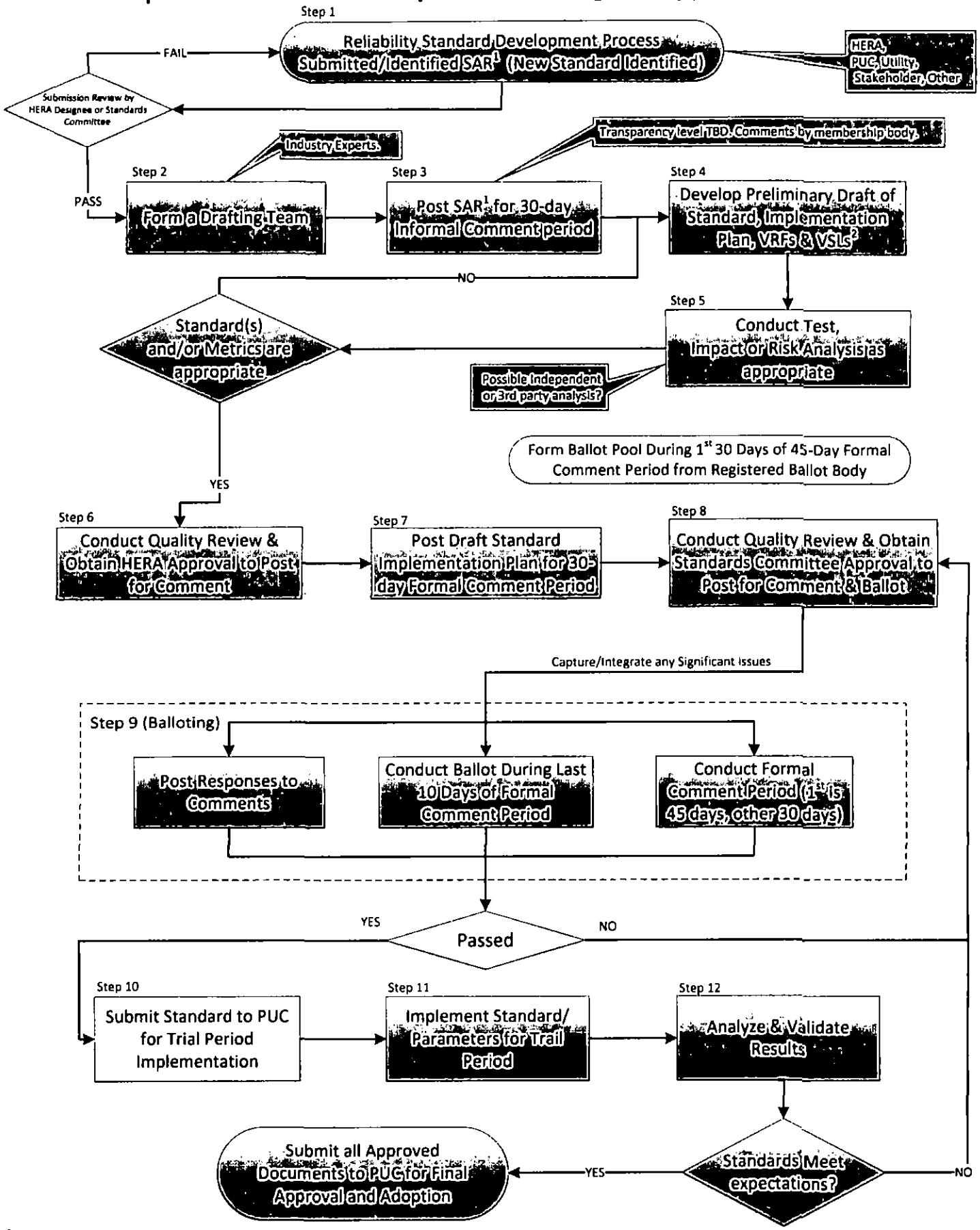
a. Non-profit public interest entities/organizations, including but not limited to energy, environmental, social, and/or cultural advocacy organizations.

Fair and Equitable Representation

The Registered Ballot Body in whole or participating in any ballot action shall be a fair and equitable representation of the ballot body membership with balance to ensure that results of ballot actions are not slanted toward a specific segment and that the Registered Entity signs, agrees to, and is bound by a formal disclaimer stipulating that they are acting to ensure the improved reliability of the electric grid and no other specific interest.

SJN/BKK: 10/31/12 12/13/12

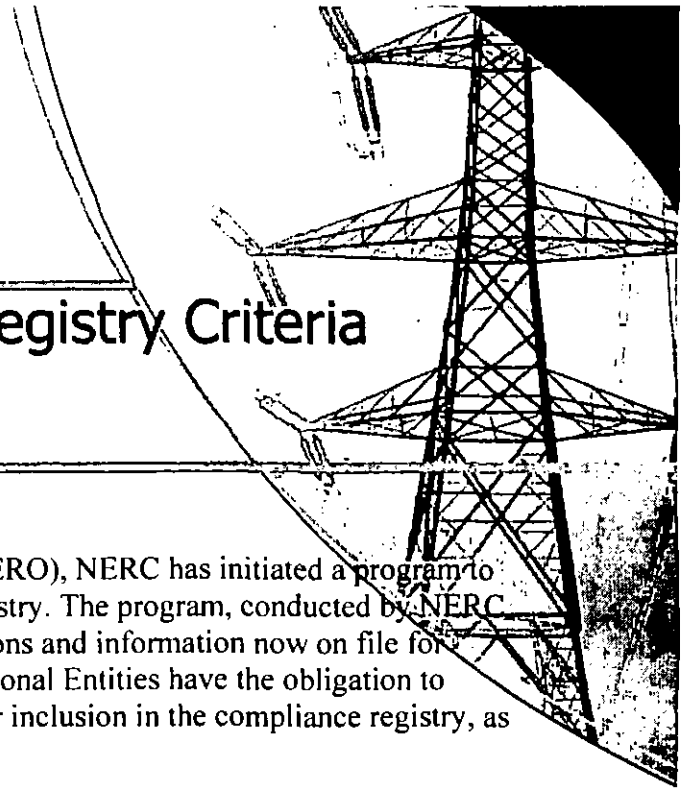
Proposed Standards Development, Balloting and Approval Framework



[1] Standards Authorization Request
[2] Violation Risk Factors/Violation Severity Levels

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Statement of Compliance Registry Criteria (Revision 5.0)

Summary

Since becoming the Electric Reliability Organization (ERO), NERC has initiated a program to identify candidate organizations for its compliance registry. The program, conducted by NERC and the Regional Entities[1], will also confirm the functions and information now on file for currently-registered organizations. NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion in the compliance registry, as further explained in the balance of this document.

This document describes how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.

Organizations will be responsible to register and to comply with approved reliability standards to the extent that they are owners, operators, and users of the bulk power system, perform a function listed in the functional types identified in Section II of this document, and are material to the reliable operation of the interconnected bulk power system as defined by the criteria and notes set forth in this document. NERC will apply the following principles to the compliance registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the bulk power system who have a material impact[2] on the bulk power system through a compliance registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material reliability impact on the bulk power system in order to develop a complete and current registry list. The registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the compliance registry are responsible and will be monitored for compliance with applicable mandatory reliability standards. They will be subject to NERC's and the Regional Entities' compliance and enforcement programs.
- NERC and Regional Entities will not monitor nor hold those not in the registry responsible for compliance with the standards. An entity which is not initially placed on the registry, but which is identified subsequently as having a material reliability

[1] The term "Regional Entities" includes Cross-Border Regional Entities.

[2] The criteria for determining whether an entity will be placed on the registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the director of compliance that an organization be added to or removed from the compliance registry, pursuant to NERC ROP 501.1.3.5.

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impact, will be added to the registry. Such entity will not be subject to a sanction or penalty by NERC or the Regional Entity for actions or inactions prior to being placed on the registry, but may be required to comply with a remedial action directive or mitigation plan in order to become compliant with applicable standards. After such entity has been placed on the compliance registry, it shall be responsible for

complying with Reliability Standards and may be subject to sanctions or penalties as well as any remedial action directives and mitigation plans required by the Regional Entities or NERC for future violations, including any failure to follow a remedial action directive or mitigation plan to become compliant with Reliability Standards.

- Required compliance by a given organization with the standards will begin the later of (i) inclusion of that organization in the compliance registry and (ii) approval by the appropriate governmental authority of mandatory reliability standards applicable to the entity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC. Presence on or absence from the compliance registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

Background

In 2005, NERC and the Regional Entities conducted a voluntary organization registration program limited to balancing authorities, planning authorities, regional reliability organizations, reliability coordinators, transmission operators, and transmission planners. The list of the entities that were registered constitutes what NERC considered at that time as its compliance registry.

NERC has recently initiated a broader program to identify additional organizations potentially eligible to be included in the compliance registry and to confirm the information of organizations currently on file. NERC believes this is a prudent activity at this time because:

- As of July 20, 2006, NERC was certified as the ERO created for the U.S. by the Energy Policy Act of 2005 (EPAct) and FERC Order 672. NERC has also filed with Canadian authorities for similar recognition in their respective jurisdictions.
- FERC's Order 672 directs that owners, operators and users of the bulk power system shall be registered with the ERO and the appropriate Regional Entities.
- As the ERO, NERC has filed its current reliability standards with FERC and with Canadian authorities. As accepted and approved by FERC and appropriate Canadian authorities, the reliability standards are no longer voluntary, and organizations that do not fully comply with them may face penalties or other sanctions determined and levied by NERC or the Regional Entities.
- NERC's reliability standards include compliance requirements for additional reliability function types beyond the six types registered by earlier registration programs.

- Based on selection as the ERO, the extension and expansion of NERC's current registration program[3] is the means by which NERC and the Regional Entities will plan, manage and execute reliability standard compliance oversight of owners, operators, and users of the bulk power system.
- Organizations listed in the compliance registry are subject to NERC's and the Regional Entities' compliance and enforcement programs.

Statement of Issue

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its compliance registry each entity that NERC concludes can materially impact the reliability of the bulk power system. However, the potential costs and effort of ensuring that every organization potentially within the scope of "owner, operator, and user of the bulk power system" becomes registered while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC wishes to identify as many organizations as possible that may need to be listed in its compliance registry. Identifying these organizations is necessary and prudent at this time for the purpose of determining resource needs, both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations. NERC and the Regional Entities believe that primary candidate entities can be identified at this time, while other entities can be identified later, as and when needed. Selection principles and criteria for the identification of these initial entities are required. This list will become the "Initial Non-binding Organization Registration List". With FERC having made the approved Reliability Standards enforceable, this list becomes the NERC Compliance Registry.

Resolution

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between regions and across the continent with respect to which entities are registered, and;
2. Any entity reasonably deemed material to the reliability of the bulk power system will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the bulk power system.

In order to promote consistency, NERC and the Regional Entities intend to use the following criteria as the basis for determining whether particular entities should be identified as candidates for registration. All organizations meeting or exceeding the criteria will be identified as candidates.

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[3] *See: NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.*

The following four groups of criteria (Sections I-IV) plus the statements in Section V will provide guidance regarding an entity's registration status:

- Section I determines if the entity is an owner, operator, or user of the bulk power system and, hence, a candidate for organization registration.
- Section II uses NERC's current functional type definitions to provide an initial determination of the functional types for which the entities identified in Section I should be considered for registration.
- Section III lists the criteria regarding smaller entities; these criteria can be used to forego the registration of entities that were selected to be considered for registration pursuant to Sections I and II and, if circumstances change, for later removing entities from the registration list that no longer meet the relevant criteria.
- Section IV — additional criteria for joint registration. Joint registration criteria may be used by Joint Action Agencies, Generation and Transmission Cooperatives and other entities which agree upon a clear division of compliance responsibility for Reliability Standards by written agreement. Pursuant to FERC's directive in paragraph 107 of Order No. 693, rules pertaining to joint registration and Joint Registration Organizations will now be found in Sections 501 and 507 of the NERC Rules of Procedure.

I. Entities that use, own or operate elements of the bulk electric system as established by NERC's approved definition of bulk electric system below are (i) owners, operators, and users of the bulk power system and (ii) candidates for registration:

> *"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.*[4]*"*

II. Entities identified in Part I above will be categorized as registration candidates who may be subject to registration under one or more appropriate functional entity types based on a comparison of the functions the entity normally performs against the following function type definitions:

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection

[4] However, ownership of radial transmission facilities intended to be covered by the vegetation management standard (applicable to transmission lines 200 kV and above) would be included in this definition.

Function Type	Acronym	Definition/Discussion
		frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-

Function Type	Acronym	Definition/Discussion
		time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

III. Entities identified in Part II above as being subject to registration as an LSE, DP, GO, GOP, TO, or TOP should be excluded from the registration list for these functions if they do not meet any of the criteria listed below:

III (a)Load-serving Entity:

III.a.1 Load-serving entity peak load is > 25 MW and is directly connected to the bulk power (>100 kV) system, or;

III.a.2 Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system, or;

III.a.3 Load-serving entity is designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the bulk power system.

[Exclusion: A load-serving entity will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

III.a.4 Distribution providers registered under the criteria in III.b.1 or III.b.2 will be registered as a load serving entity (LSE) for all load directly connected to their distribution facilities.

[Exclusion: A distribution provider will not be registered based on this criterion if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

III(b) Distribution Provider:

III.b.1 Distribution provider system serving >25 MW of peak load that is directly connected to the bulk power system.

[Exclusion: A distribution provider will not be registered based on this criterion if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.] or;

III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:

- a required UFLS program.
- a required UVLS program.
- a required special protection system.
- a required transmission protection system.

[Exclusion: A distribution provider will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

III(c) Generator Owner/Operator:

III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or;

III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or;

III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or;

III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system.

[Exclusions:

A generator owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.

As a general matter, a customer-owned or operated generator/generation that serves all or part of retail load with electric energy on the customer's side of the retail meter may be excluded as a candidate for registration based on these criteria if (i) the net capacity provided to the bulk power system does not exceed the criteria above or the Regional Entity otherwise determines the generator is not material to the bulk power system and (ii) standby, back-up and maintenance power services are provided to the generator or to the retail load pursuant to a binding obligation with another generator owner/operator or under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable.]

III(d) Transmission Owner/Operator:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

[Exclusion: A transmission owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

IV. Joint Registration Organization and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint registrations and Joint Registration Organizations are now found in Section 501 and 507 of the NERC Rules of Procedure.

V. If NERC or a Regional Entity encounters an organization that is not listed in the compliance registry, but which should be subject to the reliability standards, NERC or the Regional Entity is obligated and will add that organization to the registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure and as described in Note 3 below.

Notes to the above Criteria

1. The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate[5] that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for registration if it believes and can reasonably demonstrate to NERC that the bulk power system owner, operator, or user does not have a material impact on the reliability of the bulk power system.

2. An organization not identified using the criteria, but wishing to be registered, may request that it be registered. For further information refer to: NERC Rules of Procedure, Section 500 – Organization Registration and Certification; Part 1.3.

3. An organization may challenge its registration within the compliance registry. NERC or the Regional Entity will provide the organization with all information necessary to timely challenge that determination including notice of the deadline for contesting the determination and the relevant procedures to be followed as described in the NERC Rules of Procedure; Section 500 – Organization Registration and Certification.

4. If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations.

[5] The reasonableness of any such demonstration will be subject to review and remand by NERC itself, or by any agency having regulatory or statutory oversight of NERC as the ERO (e.g., FERC or appropriate Canadian authorities).

December 18, 2012

Consumer Advocate's Comments to the RSWG Work Products and Recommendations Presented at the December 11, 2012 Meeting

The Consumer Advocate respectfully offers the following comments to the RSWG work products and recommendations presented and voted on at the December 11, 2012 meeting. In general, the Consumer Advocate supported a majority of the work products and recommendations presented at that meeting, as it has been acknowledged that although much work has been conducted within the RSWG process, additional work is still necessary to further develop these work products and recommendations to address various issues.

The two RSWG work products and recommendations that the Consumer Advocate abstained upon are related to: (1) the Reliability Standards Drafting ("RSD") Subgroup recommendations for the Standards development framework; and (2) the Minimum Load and Curtailment ("MLC") Subgroup recommendations concerning central generator station ancillary service supply capabilities in a renewable based grid.

1. RSD Recommendations for the Standards Development Framework.

Primarily, the Consumer Advocate abstained from voting on this RSD recommendation, as the issues relating to the Framework extends beyond the scope of the RSWG proceeding. The Consumer Advocate recognizes that a process will need to be considered related to the proposed standards developed in the RSWG process, as well as the relationship of those standards to the functions of the Hawaii Electricity Reliability Administrator ("HERA"). However, when the role of HERA is considered in relationship to the proposed standards, issues such as ratepayer costs, identification of who will be responsible and accountable when the standards are implemented, to name a few examples, will need to be addressed and such considerations will be the subject of another proceeding.

2. MLC Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities.

Primarily, the Consumer Advocate abstained from voting on the MLC recommendation, as it believes that the paper did not evenly address the issue of compensation to the developers as offered by the Consumer Advocate's suggested language to the draft paper. The Consumer Advocate appreciates the efforts of the MLC Subgroup and the drafters of the paper to include several of the Consumer Advocate's proposed revisions and comments, especially the inclusion of language recognizing that additional analysis and evaluation must be conducted before implementing the recommendations. However, the Consumer Advocate contends that any consideration of compensation of direct and opportunity costs for ancillary services must include consideration of system charges to those resources that are only able to provide individual ancillary services or can only provide these services on an intermittent basis. The consideration of systems charges is necessary to mitigate impacts to ratepayer cost and quality of service to provision the other ancillary services that resource is unable to provide or cannot provide on demand.

HAWAII RELIABILITY STANDARDS WORKING GROUP'S

MINIMUM LOAD AND CURTAILMENT SUBGROUP'S FINAL REPORT

JANUARY 18, 2013

I. Genesis of the Subgroup:

During a September 9, 2011 Reliability Standards Working Group ("RSWG") meeting, the RSWG formed a set of subgroups to undertake the many tasks of the RSWG and to investigate these issues in more detail.[1] One of the subgroups formed was the Minimum Load and Curtailment Subgroup ("MLC").

II. Members of the Subgroup:

Regular attendees of MLC included: Hawaii Solar Energy Association; The Consumer Advocate, the HECO Companies, Blue Planet, Hawaii Renewable Energy Alliance, The County of Maui, The County of Kauai, Zero Emissions, DBEDT, Life of the Land, Tawhiri, and the Commission Consultant.[2]

III. Tasks of the Subgroup:

The RSWG initially outlined the MLC Subgroup's tasks as follows:

1. Identify additional technical studies and assessments that may be necessary to review and assess the HECO Companies systems to determine physical capabilities or limits of utility systems, to establish how much renewable generation can be added to the island grids without substantially compromising reliability, increasing curtailment of existing or planned renewable resources, or imposing unreasonable costs on the ratepayers. Understand that the PUC, rather than the RSWG or the utilities, may determine whether such studies will be undertaken. [3]
2. Identify and recommend specific changes or enhancements, including estimated costs and timelines, to address and mitigate current factors that constrain the addition of further renewable resources, to increase renewable energy use without substantially compromising system reliability or markedly increasing renewable curtailments. Those recommendations can address but are not limited to:
    - Utility infrastructure and operational practices, including procurement
    - Renewable generation equipment, practices and contract or tariff terms
    - Regulatory policies and processes

[1] IF Report at 5, filed on September 23, 2011.

[2] The IF listed in her September 23, 2011 filing a list of the official members of the MLC. MLC has had an inclusive policy, thus all members of the RSWG have been welcomed and encouraged to attend and vote on issues. However, not all official members have participated.

[3] Id. at 6.

- Energy efficiency, demand response, energy storage, smart grid, and related policies and programs.[4]

3. Understand when and why curtailment happens and develop transparent policies and rules that do not markedly increase curtailment and partial curtailment of existing and planned renewable generators.[5]

IV. Workproducts of the Subgroup:

1. Brendan Kirby's[6] One Month Variability, Reserves, & Curtailment On The Big Island: A Preliminary Analysis, dated 1/22/2012 and Preliminary Results Of One Year HELCO Analysis Results, 3/19/2012 (hereinafter jointly referred to as the "Kirby HELCO Analysis ").
2. Brendan Kirby's One Year MECO Curtailment Analysis, dated 7/11/12 and Results of One Year MECO Curtailment Analysis, dated 7/18/2012 ("hereinafter jointly referred to as the "Kirby MECO Analysis").
3. RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation ("Flexibility Recommendation").
4. RSWG Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities in a Renewable Based Grid ("Ancillary Service Recommendation").
5. Recommendation on Potential Contractual Treatments for Curtailment of Variable Generation IPPs ("Contracts Recommendation")

V. Summary of Activities by the Subgroup:

The MLC has met consistently from September 16, 2011 to January11, 2013. MLC members have worked diligently and spent countless hours addressing the subgroup's tasks. Although the subgroup was able to complete five work products which the MLC believes will be beneficial to the Commission, there is still much to be done.

Many of the issues discussed by the MLC have been controversial and, thus, many meetings have been filled with very spirited discussions which reflected the passion, commitment and resolve of each member. In other words, members did not always agree with each other, but were respectful of alternative positions and willing to hear the positions of all members.

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[4] Id. at 7.
[5] Id. at 7.
[6] Mr. Kirby is the consultant for the Commission. Mr. Kirby's contributions to the MLC have been invaluable. The MLC could not have done its work without the guidance and expertise of Mr. Kirby.

1. **Kirby HELCO analysis:** As stated in Section IV above, the first completed work product of the MLC was the Kirby HELCO Analysis which was performed by Mr. Kirby after HELCO presented curtailment and system data for the 2011 on October 4, 2010. Kirby HELCO Analysis was initially performed for November 2011 and then repeated for all of 2011 once sufficient data was provided. Kirby HELCO analysis assessed the possible solutions to resolve curtailment of existing wind farms on the HELCO grid.

   The Kirby HELCO Analysis was filed with the Commission under protective order on March 9, 2012 and was accepted by the MLC and the RSWG.

2. **Kirby MECO Analysis:** As stated in Section IV above, the second completed work product of the MLC was the Kirby MECO Analysis at the direction of the Commission, which was performed by Mr. Kirby after MECO provided curtailment and system data. The Kirby MECO Analysis for calendar year 2011 assessed the possible solutions to resolve curtailment of existing wind farms on the MECO grid.

   Kirby MECO Analysis was filed with the Commission under protective order on July 16, 2012 and was accepted by the MLC and the RSWG.

3. **Flexibility Recommendation:** As stated in Section IV above, the third completed work product of the MLC was the Flexibility Recommendation. The genesis of the Flexibility Recommendation was a paper from Brendan Kirby entitled, *Valuing Flexibility When Acquiring New Generation* (the "Paper") which was first sent to RSWG members on May 14, 2012. The Paper was initially adopted by the majority of members of the MLC on June 21, 2012. However, the IF requested further efforts to reach unanimity concerning disagreement between HECO and members of the MLC regarding issues such as the operating characteristics of the Hu Honua biomass project under development on the HELCO system and the potential lack or actual degree of operating flexibility the project could have. Concerted efforts were under taken to address these concerns and reach a consensus on the paper. The paper was further revised to stress the need for operating flexibility in future generation resources. The final paper was adopted by the MLC and presented to and accepted by the RSWG with HECO, the CA, and Hugh Baker dissenting.

4. **Ancillary Service Recommendation:** As stated in Section IV above, the fourth completed work product of the MLC was the Ancillary Service Recommendation. The genesis of the Ancillary Service Recommendation was proposed recommendations concerning Ancillary Service Supply Capabilities in a Renewable Based Grid by Tawhiri and Brendan Kirby to the MLC on September 24, 2012.

The Ancillary Service Recommendation was fully vetted by the MLC which included at least 4 meetings and 6 drafts. During the vetting the MLC was also cognizant of the ongoing GE Ancillary Service Study and, thus, tracked the process of the Study and its results.

A vote was taken on the December 3, 2012 MLC meeting to have the Recommendation presented and voted on by the RSWG. All members voting agreed.

The Ancillary Service Recommendation was adopted by the RSWG during its December *2012 meeting with 14 yes, 0 No, and 3 abstaining.*

5. **Contracts Recommendation:**

On Aug. 22, 2012 Zero Emissions suggested that MLC discuss the take or pay issue.

During the Oct. 10, 2012 MLC meeting, it was proposed that the MLC consider a White Paper on alternatives to addressing curtailment in the PPA context. Such alternatives would include, but not be limited to: (i) Take or Pay; (ii) KIUC model; (iii) HECO's model on its underwater cable RFP website; (iv) Mr. Kirby's-two part contract structure that facilitates full economic dispatch of all generation including variable renewables based on marginal production cost. Warren Bollmeier, Brendan Kirby, Erik Kvam, and Dennis Loria were tasked to be the drafting leads.

The Contracts Recommendation was fully vetted by the MLC which included at least 4 meetings and 6 drafts.

An e-mail vote to have the Recommendation presented and voted on by the RSWG vote was taken between December 7-9, 2013 via e-mail. The votes were: 5-Yes, 2-No, and 1 Abstaining.

6. **Other Activities:**

The MLC discussed developing a proposal for a Minimum Load and Curtailment Study. Issues of how to procure and pay for such a study were raised, which limited the MLC's ability to pursue the proposal in a timely fashion. During the discussion, HECO volunteered to do a cycling study to extend the Kirby HELCO Analysis and Kirby MECO Analysis and to expand the new study to include a "peer review".

HECO contracted with Electric Power Systems ("EPS") to do the study. The MLC formed a technical subcommittee ("TSC") to monitor the study. The TSC has been talking to EPS and HECO on a regular basis to discuss the study results. The ability to perform a full technical review of the study itself within the schedule was limited by the inherently probabilistic nature of the study methodology. A follow-on deterministic analysis will be required to

verify the study results and to determine how to practically implement the findings.

There was a discussion on whether or not ancillary services can be provided by wind generators based on the responses from Tawhiri and HRD to HECO's IRs. The PUC consultant's position is that wind generators could provide significant quantities of several ancillary services. EPS' position is that the value of wind generators providing ancillary services in 2013 is limited as indicated in the study.

VI. Lessons Learned by Some Members of the Subgroup:

1. Based on information provided by EPS, by modifying must run generation requirements and operational procedures, most if not all existing curtailment can be eliminated on the HELCO system. For the MECO system curtailment can be significantly reduced, but not eliminated in the present system configuration.

VII. Next Steps:

1. The MLC understands that the HECO Companies are committed to addressing revamping operating procedures, retuning their AGC/Governor Control system to improve overall unit response, and capital investments to lower minimum load capabilities on existing generation resources to help mitigate and reduce curtailment as the system moves to a greater penetration of renewable resources in a cost-effective and reliable manner.
2. Perform a follow-on deterministic analysis to verify the cycling study results and determine how to practically implement the findings.
3. Investigation is warranted into the technical capabilities and cost effectiveness of deployment and utilization of energy storage, demand response and various ancillary services in support of increasing the penetration of renewable generation resources on the Hawaii utility grids such that the electric system continues to operate in a reliable, safe, and stable manner.
4. The EPS studies have defined, characterized and quantified the various unit commitment and operating constraints that have traditionally been collectively called "must run." In the interest of improved communications among stakeholders and to ensure an understanding of and focus on issues that result in curtailments and uneconomic operation, use of the term "must run" should cease. In its place, the various flexibility and ancillary service issues themselves such as cycling, minimum load, voltage support, inertia, and reserves should be referenced when unit commitment and operating constraints are being discussed.

Docket No. 2011-0206 – Reliability Standards Working Group
Reliability, Definitions and Metrics Subgroup Report
January 18, 2012

The Reliability Definitions and Metrics Subgroup ("RDM Subgroup") of the Reliability Standards Working Group ("RSWG"), pursuant to the RSWG process in Docket No. 2011-0206, hereby submits its report to the Commission ("Report"). This Report has been reviewed and approved by RDM Subgroup members.[1]

I. BACKGROUND

The Commission originally established the RSWG pursuant to its Order Approving, With Modifications, the HECO Companies' Reliability Standards Working Group and Technical Support Group filed August 26, 2010 in Docket No. 2008-0273 concerning the Hawaii feed-in tariff program.[2] On September 8, 2012, the Commission filed its Order Opening Docket for this proceeding, which initiated an investigation to examine the implementation of reliability standards for the services territories of the HECO Companies[3] and directed the parties to file a final statement of RSWG purpose and scope of work, and a proposed work schedule.[4]

On September 23, 2011, the RSWG Independent Facilitator, Alison Silverstein ("IF"), filed the Reliability Standards Working Group Independent Facilitator's Submittal, RSWG Purpose, Scope of Work and Work Plan ("Work Plan"). The Work Plan states that the RSWG will form subgroups to "focus on specific topic areas and report back" to the RSWG with findings and recommendations. *Id.* at 6. The Work Plan confirmed establishment of the RDM Subgroup[5] and assigned two tasks to it: Task 1, "Define terms and metrics for operations, reliability, reliability standards, renewables, curtailment, ancillary services, and related issues[,]" due in the fourth quarter of 2011 ("Task 1"),[6] and Task 10, "Look at how to define, provide and use ancillary services from technical and policy perspectives[,]" due in the second quarter of 2011 ("Task 10").[7] *Id.* at 6-7.

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[1] Members of the RDM Subgroup include the following RSWG parties: Blue Planet Foundation ("Blue Planet"); Department of Business, Economic Development and Tourism ("DBEDT"); Department of Commerce and Consumer Affairs, Division of Consumer Advocacy; HECO Companies; Hawaii Renewable Energy Alliance ("HREA"); Interstate Renewable Energy Council ("IREC"); Life of the Land; and Tawhiri.

[2] *See* Order Opening Docket (Docket No. 2011-0206) at 1-7 (discussing RSWG process in Docket No. 2008-0273).

[3] Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd. (collectively, "HECO Companies").

[4] *Id.* at 19.

[5] The RDM Subgroup and other RSWG subgroups were formed during the September 11, 2011 RSWG meeting. *See* Reliability Standards Working Group Independent Facilitator's Submittal, RSWG Status Report filed June 1, 2012 at 5.

[6] Insofar as Task 1 is construed to encompass the development of formal reliability standards, it is noted that formal reliability standards have been developed by the RSWG's Reliability Standards Drafting Group ("RSDG") and not by the RDM Subgroup.

[7] Insofar as Task 10 is construed to encompass interconnection and ancillary services requirements for utility-scale facilities, this task has been assigned to the RSDG.

RDM Subgroup members worked diligently to complete Tasks 1 and 10 through in-person meetings,[8] conference call meetings, drafting, commenting on and revising draft documents, and e-mail communications.

II. ANCILLARY SERVICES (TASK 10)

The RDM Subgroup has completed Task 10, concerning ancillary services, except insofar as issues to be addressed in a subsequent proceeding have been identified. The following summarizes relevant background information, work product, and recommendations.[9]

A. Background.

The RDM Subgroup met regularly during the period of September 2011 through January 2013 to work on completing Task 10 concerning ancillary services.

On September 20, 2011, the Commission's consultant Brendan Kirby submitted to the RDM Subgroup a paper titled, "Proposed Ancillary Services" ("Kirby paper").[10]

In January and February 2012, the RDM Subgroup developed a work plan based in part on proposals from IREC, DBEDT and Blue Planet.

In March, April and May 2012, RDM Subgroup members worked to develop a scope of work for a study on ancillary services to be prepared by General Electric International, Inc., acting through its Energy Consulting group ("GE"), with funding and contract management provided by the University of Hawaii Natural Energy Institute ("HNEI"), and coordination between HNEI, GE and the RDM Subgroup facilitated by the IF. The final study, dated December 19, 2012, is titled, "Ancillary Services Definitions and Capability Study" ("GE Study").

On May 4, 2012, the Commission filed Order No. 30371 "Relating to Various Matters in RSWG Process ("Order 30371"). Section 5 of Order No. 30371, "Utility-Scale Interconnection and Ancillary Services Issues," directed the RSWG parties to respond to questions including the following:

> (6) *What is the most beneficial method for Hawaii to obtain* ancillary services that are required in order to operate the power system reliably – (a) by requiring the capability as a condition of

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[8] The RDM Subgroup held approximately seventeen scheduled meetings on the following dates: September 21, October 27, November 16, and December 14, 2011; January 11, February 8, March 14, April 11, April 25, May 16, June 20, September 6, October 17, November 27, December 10, and December 13, 2012; and January 8, 2013.

[9] It is noted that the Commission identified ancillary services as relevant to reliability issues as early as its September 25, 2009 Decision and Order in Docket No. 2008-0273, which directed the HECO Companies to develop reliability standards, and to subsequently modify the standards, as needed to reflect changes in "transmission, distribution, generation, demand generation mix, ancillary services availability, the results of ongoing studies, and any other relevant factors." *Id.* at 51 (emphasis added).

[10] The Commission attached a copy of this paper to its Order No. 30371 (Docket No. 2011-0206) filed October 31, 2011.

> grid interconnection; (b) through procurement of the capability as an ancillary service; or (c) through a hybrid approach of the first two options or another option? *See* Brendan Kirby's Report titled "Proposed Ancillary Services" dated October 31, 2011, attached hereto as Exhibit A, at 2. Should the method vary depending on the character of the ancillary service or the magnitude of requirement?
>
> (7) What are the commercial compensation mechanisms associated with interconnection requirements and/or ancillary services? Should renewable energy projects be assessed a "system ancillary service charge" if they are not able to meet the required standards, or conversely, a "system benefit premium" if best practice interconnection standards are met?
>
> (8) How will Hawaii benefit from increased employment of energy storage and demand response to supply ancillary services?

Id. at 10-11. The Commission attached the Kirby paper as Exhibit A to Order No. 30371. Responses by the Parties to the Order No. 30371 ancillary services questions were due on June 4, 2012.

On July 9, 2012, GE provided its study proposal identifying four main tasks, the deliverables of a report with PowerPoint, and scheduled completion for the GE Study in September 2012.

During the period of September to December 2012, GE presented draft reports and PowerPoints to the RDM Subgroup and RSWG. RDM Subgroup members reviewed and submitted detailed written comments on the GE drafts, and also discussed these drafts with GE in person, by conference call meetings and by e-mail.

On December 24, 2012, the IF filed the paper generated by the RSWG Minimum Load and Curtailment ("MLC") Subgroup, and approved by the RSWG, titled, "RSWG Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities in a Renewable Based Grid" ("MLC Subgroup ancillary services paper").[11]

On January 14, 2013, the RDM Subgroup submitted its comments on the GE Study, titled, "RDM Subgroup Comments on the General Electric Ancillary Services Study" ("RDM Subgroup Comments on GE Study") to the IF for review and approval by the RSWG during the RSWG meeting scheduled for January 24, 2013.

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[11] *See* IF, Reliability Standards Working Group Independent Facilitator's Submittal, Progress Report, and RSWG Work Product Submittal filed Dec. 24, 2012 ("IF Dec. 24, 2012 Submittal").

B. Task 10-Related Work Product.

1. GE Study.[12]

As described by GE, the purpose of the GE Study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems in Hawaii and elsewhere. GE suggests the study results may be proposed for consideration and adoption by the Commission and used for RSWG standards proposals, revised generation interconnection technical requirements, and the Integrated Resource Planning process. The GE Study focuses on four tasks, which it describes as follows:

> • Task 1: Define a standardized set of ancillary services along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems, and provide for the integration of variable generation technologies.
>
> • Task 2: Assess resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.
>
> • Task 3: Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island).
>
> • Task 4: Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

Id. at 1. The GE Study consists of a written narrative report and extensive PowerPoint documentation concerning its analyses and recommendations with regard to the foregoing four tasks. The GE Study includes eight major recommendations and a proposed methodology for determining type and quantities of required ancillary services.

2. RDM Subgroup Comments on GE Study.

The RDM Subgroup has unanimously approved its RDM Subgroup Comments on the GE Study and submitted this document for review and approval by the RSWG. This paper consists of three main sections titled, "Background," "General Support for GE Study," and "Comments on GE Study," with the latter including more specific comments related to topics for a future docketed proceeding, requirements for utility-scale projects, procuring and incentivizing

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[12] As noted in the IF's Reliability Standards Working Group Independent Facilitator's Submittal, Progress Report, and RSWG Work Product Submittal filed Dec. 24, 2012 ("IF Dec. 24, 2012 Submittal"), the GE Study is not formal RSWG work product and not subject to approval by the RSWG, but is rather "RSWG-associated work product." *Id.* at 5, 6.

ancillary services, production cost modeling, resource planning processes, technical feasibility of storage and demand response, and the wind energy opportunity cost for up reserves.

The comments paper incorporates the study's eight major recommendations mentioned above and notes that, although the GE Study itself is not subject to approval by the RSWG (or any RSWG subgroup, including the RDM Subgroup), the RDM Subgroup views the GE Study as providing a useful and valuable contribution to the RSWG process; the RDM Subgroup appreciates the opportunity it has had to collaborate with GE on the study; and although its members hold differing views on certain aspects of the study, the RDM Subgroup generally supports the information and analyses developed through the GE Study at the same time that it offers comments, clarifications, corrections and further suggestions to the study by means of the paper, and also by means of anticipated future submissions to the Commission by individual subgroup members.

3. Kirby Paper.

As noted above, the Kirby paper is a part of the record in this proceeding that is directly relevant to Task 10. RDM Subgroup members reviewed and discussed this paper and it has informed and contributed to the Subgroup's work on ancillary services issues.

4. Other.

Although not RDM Subgroup work product, it is noted that on December 12, 2012 the RSWG approved a paper by the RSWG Demand Side Options Subgroup titled, "Demand Response as a Flexible Operating Resource" ("DSO paper").[13] The DSO paper discusses ancillary services as related to demand response, including a section titled, "Use of Demand Response and Storage to Provide Ancillary Services." Similarly, the MLC Subgroup ancillary services paper is directly relevant to the RDM Subgroup's investigation of ancillary services. Finally, as noted above the Commission directed all parties to respond to the questions concerning ancillary services issues set forth in Order No. 30371 and these responses have been filed with the Commission.

C. Comments and Recommendations.

The RDM Subgroup's substantive and procedural comments and recommendations to the Commission concerning Task 10 are as set forth in the RDM Subgroup Comments on the GE Study which has been approved by all RDM Subgroup members.

III. GLOSSARY (TASK 1)

The RDM Subgroup has completed Task 1 concerning a glossary of terms. The following summarizes relevant background information, work product, and recommendations.

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[13] *See* IF Dec. 24, 2012 Submittal at 3.

A. Background.

The RDM Subgroup met regularly beginning in September 2011 to work on completing Task 1 concerning a glossary of terms. Warren Bollmeier (HREA) and Jose Dizon (HECO Companies), and other Subgroup members, contributed to preparing draft versions of the "Glossary of Terms" document which were subject to extensive review and revision by RDM Subgroup members.

During its March 19-20, 2012 meeting, the RSWG formally adopted the RDM Subgroup's "Reliability Standards Working Group Glossary of Terms, Version 1 – 2012" ("RSWG Glossary"), subject to further necessary changes.[14] The RSWG Glossary identifies Mr. Bollmeier as its Editor.

B. Task 1-Related Work Product.

The RDM Subgroup respectfully submits that the RSWG Glossary completes Task 1. As explained in the Preamble to the RSWG Glossary:

> This Glossary has been conceived and prepared by members of the Reliability Standards Working Group ("RSWG") as a compilation of general, utility-related terms, acronyms and abbreviations used in the electric power industry. The RSWG Glossary is the result of preliminary drafts that were prepared, reviewed and subsequently revised by members of the Reliability Metrics and Definitions ("RDM") Sub-Working Group of the RSWG. The glossary will be forwarded to the entire RSWG for approval upon approval by the RDM subgroup.
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> Where possible, the RSWG Glossary includes actual definitions from related glossaries, such as the North American Electric Reliability Corporation ("NERC") Glossary, NERC Generator Availability Data System ("GADS") Data Reporting Instructions, Edison Electric Institute ("EEI") glossary, and IEEE Standards 1366 and 1547. Other sources, which are included in the Reference section of the RSWG Glossary, include the United States Department of Energy ("USDOE"), Federal Energy Regulatory Commission ("FERC"), and the National Renewable Energy Laboratory ("NREL"). Where a Hawaii-specific definition is needed, it is generally derived from one of the above glossaries.
>
> Primarily, the RSWG will utilize this Glossary in the formation and understanding of recommended reliability standards to be submitted to the Hawaii Public Utility Commission ("Commission") as part of the Commission's Docket 2011-0206,

[14] *See* IF, Reliability Standards Working Group Independent Facilitator's Submittal, RSWG Status Report filed June 1, 2012 at 6, Attachment C.

> entitled "Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited."
>
> Secondarily, the RSWG believes this Glossary may serve to meet other purposes, such as communication and outreach activities with RSWG members and the general public.
>
> Finally, the RSWG views this Glossary as a "Living Document that will be reviewed and updated on a regular basis. It is proposed that that the definitions of specific terms that are incorporated into Commission-approved reliability standards will be approved by the Commission, and designated in an appropriate manner in the Glossary.

Id. at 1. References to the RSWG Glossary are made in the GE Study and in reliability standards developed by the RSDG (the RSDG standards also include certain defined terms that, due to time constraints, are not reflected in the RSWG Glossary at this time).

C. Comments and Recommendations.

The RDM Subgroup has no further substantive or procedural recommendations to the Commission with regard to the RSWG Glossary.

IV. LESSONS LEARNED

The IF's December 24, 2012 Submittal requests the subgroups to identify "lessons learned," or "processes, issues and insights that could be helpful to the Commission and others working to enhance the use of renewable generation in Hawaii while protecting system reliability." *Id.* at 7. The RDM Subgroup respectfully submits that any relevant processes, issues or insights generated by its members through the RSWG process, that are specific to the RDM Subgroup, are contained in the RDM Subgroup Comments on GE Study, particularly the procedural comments that include a list of ancillary services-related issues to be addressed in a future docketed proceeding.

RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation

Background and Basis for Recommendations

As the RSWG, primarily through the Minimum Load and Curtailment Subgroup, has engaged in the task of addressing curtailment problems and solutions, a concern has been raised that the characteristics of new generation resources may directly and substantially bear on the RSWG's work on curtailment.[1] The RSWG recognizes that proposals for new generation are subject to PUC proceedings independent of this RSWG docket. The RSWG also recognizes that its charge from the PUC includes the responsibility to provide recommendations for the PUC in considering proposed new generation. This includes both utility-owned and IPP-owned generation, as well as modification of existing generation such as conversion to non-fossil fuel sources. Such recommendations are all the more important when resource acquisition decisions may not only affect the RSWG's ongoing efforts, but also create opportunities or impose limitations on the power system for decades to come.

Generally, generators are turned down to minimum output or are turned off as daily customer demand decreases. Thus, only least costly generators should be on-line to serve lower daily load. If generators that are on-line during heavy load hours cannot be cycled off or turned down sufficiently in times of low demand, they force other more flexible generation, including lower incremental cost and/or renewable generation, to be turned down or off.

The recommendations offered here address two physical characteristics (cycling ability and minimum load) and one contracting characteristic (treatment of a generator's marginal cost) that currently contribute to curtailment, or may affect it in the future. In addition to any PUC action in this proceeding, these recommendations articulate basic principles and high-level concepts that the PUC should comprehensively evaluate in subsequent proceedings considering proposed new or modified generation, in order to assess the impacts on issues including, but not limited to: reliability, cost to ratepayers, the state's objectives of integrating renewable energy, and predictability and transparency to developers.. Furthermore, the PUC should evaluate the characteristics discussed here from a comprehensive cost-benefit perspective, along with numerous other power system requirements and generator features including but not limited to: inertia, frequency response, dispatch capability, black start, voltage regulation, voltage and frequency ride through, reliability/maintenance requirements, capital cost, operating cost, ability to site to benefit the power system, technical risk. To this end, the

[1] HECO is currently conducting a cycling analysis study to examine the minimum generation requirements for HELCO and MECO, including cycling capabilities and costs, for the projected power systems through 2013. These RSWG recommendations address a longer-term scope.

RSWG offers these recommendations for PUC consideration as it more fully evaluates proposals for new generators and modifications to existing generators, along with the associated contracts.

Power plants have very long lives. It usually costs much less to incorporate power plant flexibility at the outset than to attempt to add flexibility later. Hawai'i consumers will likely live with, and pay for, design decisions associated with new power plants (utility or IPP owned) for forty years or more. This emphasizes the importance of making sure that new power plants have the flexibility to meet the needs of the power system for decades, not just for the next few years. Similarly, power purchase contracts can either facilitate or block access to power plant physical flexibility. Power purchase contracts should be evaluated for flexibility as well as for energy cost.

Indigenous and environmentally friendly solar and wind generation are abundant in Hawai'i but also add to the variability and uncertainty of the total net load. Variable renewables also have the characteristic that they consume no fuel, such that the marginal production cost of energy and environmental impacts of pollutant emissions are essentially zero.[2] For both economic and environmental reasons it is beneficial to maximize the use of solar and wind, particularly once the plants are built (rather than to dispose of the energy), as well as to ensure system flexibility so as not to foreclose further opportunities to tap such resources. Robust demand-side programs can also aid in this effort. The objective here is not to favor certain renewable technologies, developers, or projects over others, but rather to maximize overall clean energy benefits and opportunities from a comprehensive and long-term perspective while economically optimizing power system efficiency and maintaining system reliability.

The generation mix that will be obtained as the Islands become ever more dependent on renewable energy sources is uncertain. This makes it essential to maximize the flexibility of the new and modified plants even at the risk of providing more than the minimum amount of flexibility that is immediately required. It is also essential to develop or have ready for development additional sources of flexibility (e.g., demand response and storage) that can be implemented should the future renewables growth be heaviest among renewable plant types that do not usually provide certain flexibility and ancillary services.

In sum, in order to fully utilize variable renewables, maximize overall renewable generation on the system economically and reliably, and move toward the clean energy system of the future, the power system requires greater flexibility from the other, dispatchable portion of the generation fleet (along with responsive load and storage). The RSWG, therefore, encourages the PUC to fully evaluate the physical and contractual flexibility of all generation additions and modifications to the island power systems.

[2] While this essentially zero marginal energy production cost for wind and solar is not reflected in most current utility contracts, one recommendation is to better align the physical and contractual marginal energy costs (see *infra*).

Cycling Capabilities and Minimum Load

The two characteristics addressed in this RSWG recommendation to the PUC when evaluating generator flexibility are:

- Minimum load and control range. Lower minimum loads provide for a larger operating range and more flexibility.
    - AGC range should be the full range from minimum to maximum load.
    - Environmental restrictions that limit the number of starts within a given period or that prevent a generator from operating at minimum load for extended periods are also important.
    - Ramp rate (MW/min). Faster ramp rate provides for better control and requires fewer resources to provide the required reserves.
- On/off cycling ability. Generators with the ability to cycle on and off daily or multiple times per day can better facilitate variable renewables integration, saving fuel whenever the sun or wind is available.

These recommendations apply to the consideration of all generators with a marginal production cost, including fossil fuel burning plants, biofuel burning plants, and biomass burning plants, if there is a cost associated with the fuel. These recommendations also may apply to geothermal plants if they incur a marginal cost for energy.

Recommendations

The RSWG provides two basic types of recommendations. The first is to assure that new and modified generators have on/off cycling and minimum load capabilities the power system will need for many decades to come. The second is to assure that power purchase contracts accurately reflect physical costs, especially marginal energy costs, and that contracts provide full access to the physical flexibility that generators are capable of providing. Contracts should also provide incentives for increased flexibility.

Physical Flexibility

- On/off cycling capability: The existing generation fleet already includes generation that is unable to cycle off economically and results in curtailment. New fuel-consuming generation that is unable to cycle off at least daily should not be added to the power system. Even if the power system can tolerate a new non-cycling generator for the next few years, it is unlikely to be able to do so for decades as the amount of geothermal, solar, wind, or other renewable generation increases. It is likely in the ratepayers' economic interest to invest in a plant with somewhat higher capital cost if it has greater ability to cycle off at lower cost. Such broader economic analysis is needed in evaluating new generation.
    - Cycling cost: Cycling costs should also be minimized.
- Minimum load and operating range: Lower minimum loads and greater operating range also facilitate low cost and reliable integration of variable renewables. These features enable variable renewables to save on fuel consumption and the new generator to provide spinning

reserves and regulation with a wider operating range. High minimum loads should not be allowed, and the economic cost and benefits of lower minimum loads should be evaluated.

Power Purchase Contracts

- Contracts should provide full access to the physical flexibility that the new generation is capable of supplying. Fixed operating schedules, for example, do not provide access to all of the physical flexibility. Contract specified minimum loads that are above the minimum load that the new generator is capable of also do not provide access to the full physical capability of the generator.
- Contracts should reflect the true real-time marginal operating cost for energy for all generators (fossil fuel burning, biofuel or biomass burning, geothermal, and variable renewable) in the purchase price to the utility. This will enable new generation to be economically committed and dispatched in real time, along with the rest of the utility owned and IPP generators.[3] Priority dispatch can still be utilized to reflect non-monetized environmental and other benefits if the PUC so desires. Contracts that reflect true marginal energy production costs would provide more accurate economic incentives to both the system operators and the generators to economically optimize the real-time power system operations. This should help minimize costs for ratepayers.
    - Take-or-pay fuel contracts should be avoided since fuel is, at least to some extent, storable and transportable.
- With the true marginal energy cost included in the contract, there will be a need for the fixed and capital costs to be included as a fixed component of new generator contracts.[4] These costs should not be reflected in the energy component of the contract to avoid having the fixed costs distort the utility unit commitment and economic dispatch.

[3] Full security constrained unit commitment and economic dispatch should reflect the added cost of any additional reserves required to reliably integrate variable and uncertain renewable generation; likewise, it should not penalize renewable generation for the high minimum load requirements or the inability of new conventional generation to cycle.

[4] The "fixed" component should likely reflect generator equipment availability (i.e. the fixed payment would be reduced if unit availability declined, possibly assessed monthly, and include the anticipated normal maintenance amounts) in order to provide an incentive for the owner to keep the plant properly maintained. The "fixed" component could reflect the underlying resource availability, either placing the risk of wind and solar availability on the generator owner or on the consumer, whichever is more advantageous.

September 25, 2012

Consumer Advocate's Dissent to the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation," voted on at the RSWG September 18, 2012

In addition to its comments offered on August 16, 2012 (posted on the RSWG website on September 18, 2012), the Consumer Advocate provides the following dissent to the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation," voted on at the RSWG September 18, 2012 meeting.

At the start of the RSWG process on July 13, 2011, Chair Morita urged the RSWG members to work in the public interest, keeping in mind that grid and system reliability was not to be compromised nor costs raised excessively high to facilitate higher levels of renewable penetration onto the grid. In doing so, Chair Morita noted that our participation would require the members to work toward consensus rather than advocating specific interests and positions. In consideration of these thoughts by Chair Morita, the Consumer Advocate has been willing to defer the need for more thorough analysis to evaluate impacts on ratepayers in order to allow the identification of potential technical concepts and solutions to evolve. As such, as it relates to the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper, although the Consumer Advocate has remaining concerns, the Consumer Advocate has expressed and continues to support the general concepts set forth in the paper.

Based on working group discussions of the Minimum Load and Curtailment Subgroup ("MLC") regarding the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper that was ultimately voted on at the RSWG September 18, 2012 meeting, it is the Consumer Advocate's understanding that the MLC members' intention of the paper is to offer high-level concepts that will ultimately require further comprehensive evaluation to assess the reasonableness of these recommendations in consideration of such issues as reliability, cost to ratepayers, the state's objectives of integrating renewable energy, and predictability and transparency to developers. The Consumer Advocate recognizes that in attempting to reach consensus, the working members accepted some language offered by the Consumer Advocate to convey this intention in paragraph 3 of the paper. The Consumer Advocate, however, is not able to fully support the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation," as the paper still contains misleading language that is not well supported nor substantiated and reflects biases toward certain renewable resources. The Consumer Advocate considers this approach to be inconsistent with not only its intention, but also the RSWG's purpose and is not in the public interest.

Examples of such language include, but are not limited to the following:

> For both economic and environmental reasons it is beneficial to maximize the use of solar and wind, particularly once the plants are built (rather than to dispose of the energy), as well as to ensure

> system flexibility so as not to foreclose further opportunities to tap such resources.
>
> New fuel-consuming generation that is unable to cycle off at least daily should not be added to the power system. . . It is likely in the ratepayers' economic interest to invest in a plant with somewhat higher capital cost if it has greater ability to cycle off at lower cost.
>
> Minimum load and operating range: Lower minimum loads and greater operating range also facilitate low cost and reliable integration of variable renewables.
>
> Contracts that reflect the true marginal energy production costs would provide more accurate economic incentives to both the system operators and the generators to economically optimize the real-time power system operations and the generators to economically optimize the real-time power system operations. This should help minimize costs for ratepayers.

These types of statements in the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper are unsubstantiated conclusions that lead one to assume that the paper is recommending that:

- There are substantiated economic and environmental reasons to maximize the use of **only** solar and wind technologies.
- New fuel-consuming **renewable** generation resources such as biomass, biofuel, geothermal should not be interconnected unless it is able to cycle or turn off at least daily.
- Mimimum load and operating ranges will facilitate low cost and reliable integration of variable renewables.
- Contracts based on true marginal energy production costs provide more accurate economic incentives and would help to minimize costs to ratepayers.

The paper fails to identify the issues that must be addressed in making these conclusory statements such as:

- In requiring that new fuel-consuming **renewable** generation such as biomass, biofuel, geothermal be cycled or turned off daily, what impact does that have on developer's decisions to invest in such renewable generation resources, which is at this time one of the options to maintain system reliability of the electric system?
- Does cycling or turning off at least daily fuel-consuming **renewable** generation support the Renewable Energy Portfolio ("RPS") goals as set

forth in Hawaii Revised Statutes Section 269-92(a), when that renewable generator's energy is contributing to the RPS goals?

- Is requiring new fuel-consuming **renewable** generation to cycle off or turn off in order to accommodate wind or solar generation, discriminatory to that renewable generation technology?
- What are the impacts to ratepayers (i.e., bill impact, reliable service) associated with requiring that new fuel-consuming **renewable** generation resources be cycled or turned off at least daily?
- What are the costs associated with setting lower minimum load and operating ranges and are these costs lower than that of the variable renewable generation and can system reliability be maintained?
- What is the ultimate impact to developers' decisions on investing in renewable energy projects in Hawaii associated with the new pricing scheme recommended in the paper?
- What risks do ratepayers bear in paying fixed costs as opposed to energy payments associated with renewable energy projects? In other words, to the extent that independent power producers are paid a fixed payment, what risks are shifted to ratepayers associated with that fixed payment as opposed to a payment for the energy which variable renewable generation provides and how is that in the public interest?
- If the recommendations set forth in the paper are implemented to apply to projects that are currently being negotiated, have recently been negotiated or for those unsigned contracts related to the Feed In Tariff, how is transparency and predictability addressed for those developers?
- What financial information will be available from developers to determine the fixed and marginal pricing components recommended in the paper?

It is important to remember that the purpose of the RSWG set forth in the Reliability Standards Working Group Independent Facilitator's Submittal RSWG Purpose, Scope of Work and Work Plan and Certificate of Service, filed September 23, 2011, includes recommending fact-based standards, metrics, rules, criteria and processes to "help determine how we can interconnect the maximum amount of renewable generation to the grid while preserving grid reliability," consistent with Hawaii clean energy statutory mandates and policies, which are clear, fair, transparent and unambiguous and do not "markedly increase" curtailment or "meaningfully displace" other renewable generation. Thus, the statements from the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper are inconsistent with RSWG purpose.

In an attempt to be solution oriented to address some of the issues identified above and to reach consensus, the Consumer Advocate reviewed two previous drafts presented by Isaac and Brendan associated with the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper. On August 16, 2012, the Consumer Advocate submitted comments and questions to the MLC subgroup for discussion at the August 22, 2012 meeting. In general, members of the MLC did not provide answers to the Consumer Advocate's concerns and for the

most part conveyed that these issues did not need to "worked out" or addressed at this time. Furthermore, as it relates to the second draft, the Consumer Advocate proposed revisions consistent with the request to keep revisions to a minimum.

Based on the above, the Consumer Advocate dissented to the "RSWG Recommendation Concerning Capabilities and Minimum Load Capabilities of New Generation" paper and offers its proposed alternative.

HAWAIIAN ELECTRIC COMPANIES' DISSENT TO RSWG RECOMMENDATION CONCERNING CYCLING CAPABILITIES AND MINIMUM LOAD CAPABILITIES OF NEW GENERATION

On September 7, 2012, Sandra-Ann Y. H. Wong, on behalf of the RSWG's Minimum Load and Curtailment ("MLC") subgroup, sent to Alison Silverstein "for presentation, discussion, and vote during the Sept. RSWG meeting" a paper entitled "RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation" ("Capabilities of New Generation Paper" or "Paper"). The following provides the Hawaiian Electric Companies' dissent to the Capabilities of New Generation Paper and recommendations for adoption of a revised draft of the Paper that is attached to this dissent for the Commission's consideration.

Proposed recommendations to the RSWG regarding operating characteristics that could be considered for new generation on the utilities' grids was first discussed at a MLC subgroup meeting on August 8, 2012. A first draft of the Capabilities of New Generation Paper was distributed to the MLC subgroup members on August 10, 2012. Since that time, the MLC subgroup has been working collaboratively to incorporate comments from the various parties. On August 29, 2012, the MLC subgroup voted on a version of the Paper that was not agreed to by the Hawaiian Electric Companies or Division of Consumer Advocacy. Most recently, on August 31, 2012, the Hawaiian Electric Companies submitted certain comments in an effort to come to agreement on a comprehensive document that could be provided to the full RSWG for discussion and consideration. On September 4, 2012, members of the MLC subgroup expressed their appreciation for the Companies' comments and efforts, but in the end suggested that given timing and efforts to date, the subgroup thought it would be more productive if those who did not agree with the majority view to simply provide their substantive objections for the larger group to consider.

Attached to this dissent is a redline draft of the Capabilities of New Generation Paper which provides comments and proposed modifications which the Hawaiian Electric Companies believe are necessary in order for the Paper to appropriately present a recommendation to the Commission that both maximizes the flexibility that the Commission has to consider and adopt any of the recommendations contained in the Paper, and assure that the Paper does not unduly favor one particular resource technology over another. Both the MLC subgroup's and Companies' draft of the Paper recognize that "the generation mix that will be obtained as the islands become ever more dependent on renewable energy sources is uncertain." It is the Companies' position that given this uncertainty, flexibility in new generation resources should be considered on both a technology neutral and comprehensive basis to allow the Companies and Commission to make decisions regarding new generation resources that are fair, non-discriminatory, ensure system reliability and appropriately consider customer costs. The Companies' recommended modifications include comments indicating why the Companies believe that the specific changes are necessary and why in totality the Companies' recommendation is better for Hawaii, grid reliability and the increasing use of renewable resources in the State.

The Hawaiian Electric Companies also respectfully submit the following more detailed comments on the Paper approved by the MLC subgroup for the Commission's consideration and in support of the Companies' draft of the Paper.

Flexibility to Utilize Least Cost Best Fit Resources

The MLC subgroup's draft of the paper ("MLC draft") appears in certain instances to favor specific renewable resources such as wind and solar, over other renewable energy technologies such as biomass and geothermal. As the Commission is aware, for purposes of complying with the State's Renewable Portfolio Standards, renewable energy technologies include wave, tidal, biofuel, biomass, geothermal, municipal solid waste and other technologies as well as wind and solar. In planning future integrated electrical systems, the Companies, and Commission through its oversight of the Companies, should maximize the flexibility to utilize those renewable resources which are best suited to serve customers at the least cost given the circumstances present at the time resource selection decisions are made.

Related to this, the MLC draft also appears to favor intermittent generation over firm dispatchable generation. As one example of this, the MLC draft argues that new fuel-consuming generators (including renewable energy generators) should not be allowed on the system if those generators cannot be cycled. The MLC draft states "[i]n order to fully utilize variable renewables, maximize overall renewable generation on the system economically and reliably, and move toward the clean energy system of the future, the power system requires greater flexibility from other, dispatchable portion of the generation fleet..." In planning future electrical systems however, it must be recognized that there may be circumstances present that make if more cost effective to curtail a variable generation source that does not provide ancillary services than to cycle off a dispatchable renewable energy source such as a biomass plant that provides needed ancillary services. Conversely, there may be circumstances where increasing the cost of a dispatchable renewable energy generator for the sole purpose of being able to take additional intermittent generation that does not provide needed ancillary services is neither economic nor operationally sound.

In order to assure that any new generation is capable of being cycled, both from a physical and economic perspective, an increase in capital expenditures to allow for the cycling capabilities will be required. In addition to the increase in capital construction costs, increased maintenance, operation and financing costs will also be incurred by a renewable project that is designed to be base loaded and serve as a dispatchable, low-cost renewable energy unit if that unit is converted to a cycling unit designed to optimize the use of variable renewable energy. These cost increases may have the effect of transforming what was the lowest cost unit on the system into a high cost unit all for the perceived benefit of increasing the consumption of higher cost, variable energy at the expense of low-cost renewable energy. Accordingly, the requirement that all units be capable of on/off cycling cannot be justified in the foreseeable future either economically or as a means to increase the take of variable energy. The requirement will increase the costs of renewable energy development to the consumer and provide little or no benefit to system costs or renewable energy consumption.

Significant Curtailment is *not* Occurring on the HELCO System

During the September 18, 2012 RSWG face-to-face meeting, it was mentioned that the level of curtailment is significant. That is not true. HELCO is currently at a 51.28% RPS (based on 2011 RPS data). As stated during a number of recent RSWG subgroup and stakeholder meetings, removal of all curtailment on the Big Island results in only a 1% addition to the HELCO RPS percentage. This is indicative of the fact that curtailment is not significant on the HELCO system. Moreover, the capacity factors for certain of the wind farms on the HELCO system approach levels in the range of 65% which is significantly higher than a typical wind farm capacity factor in the range of 30%. The combination of this level of production with legacy contracts tied to the price of oil provides significant benefits to wind farms on the island of Hawaii. Oil prices were around $70/bbl when the wind contracts were signed. Oil prices today are around $126/bbl.

Fixed costs vs. Capacity Costs vs. Energy Payments

During the September 18, 2012 RSWG meeting additional information was provided with regard to a zero-marginal cost proposal developed by certain members of the MLC subgroup and how they propose that fixed costs be recovered. This group takes the position that wind is a zero marginal cost unit and that all capital costs should be treated as a fixed cost, like a capacity payment. This proposal should not be accepted by the Commission for the following reasons:

a. While dispatch of units based on incremental energy cost is valid for dispatchable generators, intermittent resources, such as most wind and solar facilities, are not dispatchable and therefore are considered for the most part to be must take resources.

b. The fixed cost component of a firm, dispatchable IPP project is called the "Capacity Cost" because the firm, dispatchable IPP provides firm capacity and the ancillary services associated with a firm, dispatchable unit. Most wind or solar facilities are not dispatchable. They are variable and intermittent. Therefore, these as-available resources do not receive a "capacity cost" in the manner that the MLC members describe.

c. During the meeting there was a brief discussion about placing all costs in the fixed or capacity component of a wind project in order to have a zero energy cost. This is not recommended regardless of technology. The developer can choose to omit maintenance and choose not to operate the unit. The developer gets paid whether the unit produces or not.

   Penalties on availability can be negotiated, but these negotiated penalties may not represent the true cost of the impact to the system. Indeed, the regulatory climate that allowed this type of compensation was one of the root causes of the 2001 energy crisis in California and led to utility and energy marketers' bankruptcy filings and the subsequent collapse of the California energy market system.

d. The HECO Companies assert that there is a cost associated with a zero-marginal cost unit. For dispatch purposes, the marginal cost should be a positive, non-zero number that is monotonically increasing.

The Hawaiian Electric Companies respectfully offer their alternative version of the Paper and these comments for the Commission's consideration.

HECO MARK-UP

RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation

Background and Basis for Recommendations

As the RSWG, primarily through the Minimum Load and Curtailment Subgroup, has engaged in the task of addressing curtailment problems and solutions, a concern has been raised that the characteristics of new generation resources may directly and substantially bear on utilities' ability to reliably and cost effectively integrate renewable resources to the utilities' systems~~the RSWG's work on curtailment~~.[1] The RSWG recognizes that proposals for new generation are subject to PUC proceedings independent of this RSWG docket. The RSWG also recognizes that its charge from the PUC includes the responsibility to provide recommendations for the PUC in considering proposed new generation. This includes both utility-owned and IPP-owned generation, as well as modification of existing generation such as conversion to non-fossil fuel sources. Such recommendations are all the more important when resource acquisition decisions may ~~not only affect the RSWG's ongoing efforts, but also~~ create opportunities or impose limitations on the power system for decades to come.

Comment [HECO1]: The focuse of the paper should be upon integration of renewable resour not the RSWG

Comment [HECO2]: The focuse of the paper should be upon integration of renewable resour not the RSWG.

Generally, generators are turned down to minimum output or are turned off as daily customer demand decreases. Thus, only least costly generators should be on-line to serve lower daily load or address a system constraint. If generators that are on-line during heavy load hours cannot be cycled off or turned down sufficiently in times of low demand, they force other more flexible generation, including lower incremental cost and/or renewable generation, to be turned down or off.

Comment [HECO3]: Generators may need t on-line for reasons other than solely serving loa

The recommendations offered here address two physical characteristics (cycling ability and minimum unit turndown rating~~load~~) and one contracting characteristic (treatment of a generator's marginal cost) that currently contribute to curtailment, or may affect it in the future. In addition to any PUC action in this proceeding, these recommendations articulate basic principles and high-level concepts that the PUC should comprehensively evaluate in subsequent proceedings considering proposed new or modified generation, in order to assess the impacts on issues including, but not limited to: reliability, cost to ratepayers, the state's objectives of integrating renewable energy, and predictability and transparency to developers.. Furthermore, the PUC should evaluate the characteristics discussed here from a comprehensive cost-benefit perspective, along with numerous other power system requirements and generator features including but not limited to: inertia, frequency response, dispatch capability, black start, voltage regulation, voltage and frequency ride through, reliability/maintenance requirements, capital cost, operating cost, ability to site to benefit the power system, and technical risk. To this end,

Comment [HECO4]: This is a more accurate descriptive term

[1] HECO is currently conducting a cycling analysis study to examine the minimum generation requirements for HELCO and MECO, including cycling capabilities and costs, for the projected power systems through 2013. These RSWG recommendations address a longer-term scope.

the RSWG offers these recommendations for PUC consideration as it more fully evaluates proposals for new generators and modifications to existing generators, along with the associated contracts.

Power plants have very long lives. It usually costs ~~much~~ less over the life of the plant to incorporate power plant flexibility at the outset than to attempt to add flexibility later. Hawai'i consumers will likely live with, and pay for, design decisions associated with new power plants (utility or IPP owned) for forty years or more. This emphasizes the importance of making sure that new power plants have the flexibility to meet the needs of the power system for decades, not just for the next few years. Similarly, power purchase contracts can either facilitate or block access to power plant physical flexibility. All new generation ~~Power purchase contracts~~ should be evaluated for flexibility as well as for energy cost.

Comment [HECO5]: This is a more accurate statement.

Comment [HECO6]: This recommendation should apply prospectively.

~~Indigenous and environmentally friendly solar and wind generation are abundant in Hawai'i but also add to the variability and uncertainty of the total net load. Variable renewables also have the characteristic that they consume no fuel, such that the marginal production cost of energy and environmental impacts of pollutant emissions are essentially zero.[2] For both economic and environmental reasons it is beneficial to maximize the use of solar and wind, particularly once the plants are built (rather than to dispose of the energy), as well as to ensure system flexibility so as not to foreclose further opportunities to tap such resources. Robust demand-side programs can also aid in this effort.~~ The objective here is not to favor certain renewable technologies, developers, or projects over others, but rather to maximize overall clean energy benefits and opportunities from a comprehensive and long-term perspective while economically optimizing power system efficiency and maintaining system reliability.

Comment [HECO7]: Given the future uncertainty as to resource mix that is acknowled in the paper, the paper should be resource type agnostic to the degree possible.

The generation mix that will be obtained as the Islands become ever more dependent on renewable energy sources is uncertain. ~~This makes it essential to M~~maximizinge the flexibility of ~~the~~ new and modified generation ~~plants~~ even at the risk of providing more than the minimum amount of flexibility that is immediately required should be considered. It is also essential to develop or have ready for development additional sources of flexibility (e.g., demand response and storage) that can be implemented should the future renewables growth be heaviest among renewable plant types that do not usually provide certain flexibility and ancillary services.

Comment [HECO8]: There should be an opportunity to consider costs to ratepayers.

In sum, in order to ~~fully utilize variable renewables,~~ maximize overall renewable generation on the system economically and reliably, and move toward the clean energy system of the future, the power system requires greater flexibility ~~from the other, dispatchable portion of the generation fleet (along with responsive load and storage)~~. The RSWG, therefore, encourages the PUC to fully evaluate the physical and contractual flexibility of all generation additions and modifications to the island power systems.

Comment [HECO9]: This paper should be resource type agnostic.

~~[2] While this essentially zero marginal energy production cost for wind and solar is not reflected in most current utility contracts, one recommendation is to better align the physical and contractual marginal energy costs (see infra).~~

Cycling Capabilities and Minimum Load

The two characteristics addressed in this RSWG recommendation to the PUC when evaluating generator flexibility are:

Lower unit turndown rating~~Minimum load~~ and control range. Lower unit turndown ratings~~minimum loads~~ provide for a larger operating range and more flexibility.

- AGC range should be the full range from minimum to maximum load.
- Environmental restrictions that limit the number of starts within a given period or that prevent a generator from operating at minimum load for extended periods are also important to the extent system reliability is not compromised.
- Ramp rate (MW/min). Faster ramp rate provides for better control and requires fewer resources to provide the required reserves.

On/off cycling ability. Generators with the ability to cycle on and off daily or multiple times per day can better facilitate variable renewables integration, saving fuel whenever the sun or wind is available.

~~These recommendations apply to the consideration of all generators with a marginal production cost, including fossil fuel burning plants, biofuel burning plants, and biomass burning plants, if there is a cost associated with the fuel. These recommendations also may apply to geothermal plants if they incur a marginal cost for energy.~~

Comment [HECO10]: This is a more accurat term.

Comment [HECO11]: System reliability mus a consideration throughout any recommendatio to the Commission.

Comment [HECO12]: Characteristics propo for the evaluation of generator flexibility should technology agnostic to the degree possible.

Recommendations

The RSWG recognizes that the electric utilities have implemented some of these recommendations. For the purposes of this document, the RSWG feels it is relevant to discuss these issues wholistically as they apply to new generation. The RSWG provides two basic types of recommendations. The first is to recommend ~~assure~~ that new and modified generators have on/off cycling and low turndown rating~~minimum load~~ capabilities the power system will need for many decades to come. The second is to recommend~~assure~~ that power purchase contracts accurately reflect physical costs, especially marginal energy costs, and that contracts provide full access to the physical flexibility that generators are capable of providing. Contracts should also provide incentives for increased flexibility.

Comment [HECO13]: Given potential syster impacts and considerations, the recommendatio to the Commission should be viewed in totality a not in a manner that would cause unintended consequences.

Comment [HECO14]: The RSWG should pro the Commission with the flexibility to adopt thos recommendations that the Commission is comfortable with based upon the record presen

Physical Flexibility

On/off cycling capability: Consideration must be given to providing on/off cycling capability for future generation.~~The existing generation fleet already includes generation that is unable to cycle off economically and results in curtailment. New fuel-consuming generation that is unable to cycle off at least daily should not be added to the power system.~~ Even if the power system can tolerate a new non-cycling generator for the next few years, it may not ~~is unlikely to~~ be able to do so for decades as the amount of ~~geothermal, solar, wind, or other~~ renewable generation increases. It is likely in the ratepayers' economic interest to invest in a plant with somewhat higher capital cost if it has greater ability to cycle off at lower cost. Such broader economic analysis is needed in evaluating new generation.

- Cycling cost: Cycling costs should also be minimized.

Comment [HECO15]: This should be a forw looking affirmative recommendation

Comment [HECO16]: The recommendation should be technology agnostic to the extent possible

Lower unit turndown rating~~Minimum load~~ and operating range: Lower unit turndown rating~~minimum loads~~ and greater operating range ~~also~~ facilitate ~~low cost and reliable~~ integration of variable renewables. These features ~~enable variable renewables to save on fuel consumption and the new generator to~~ provide spinning reserves and regulation with a wider operating range. High minimum loads should not be allowed, and the economic cost and benefits of lower minimum loads should be evaluated.

Comment [HECO17]: This is a more accurat term.

Power Purchase Contracts

Contracts should provide full access to the physical flexibility that the new generation is capable of supplying. Fixed operating schedules, for example, do not provide access to all of the physical flexibility. Contract specified minimum loads that are above the minimum load that the new generator is capable of also do not provide access to the full physical capability of the generator. Contracts should reflect the true real-time marginal operating cost for energy for all generators (fossil fuel burning, biofuel or biomass burning, geothermal, and variable renewable) in the purchase price to the utility. This will enable new generation to be economically committed and dispatched in real time, along with the rest of the utility owned and IPP generators.[3] Priority dispatch can still be utilized to reflect non-monetized environmental and other benefits if the PUC so desires. Contracts that reflect true marginal energy production costs would provide more accurate economic incentives to both the system operators and the generators to economically optimize the real-time power system operations. This should help minimize costs for ratepayers.

- Take-or-pay fuel contracts should be avoided since fuel is, at least to some extent, storable and transportable.

With the true marginal energy cost included in the contract, there will be a need for the fixed and capital costs to be included as a fixed component of new generator contracts.[4] These costs should not be reflected in the energy component of the contract to avoid having the fixed costs distort the utility unit commitment and economic dispatch.

[3] Full security constrained unit commitment and economic dispatch should reflect the added cost of any additional reserves required to reliably integrate variable and uncertain renewable generation; likewise, it should not penalize renewable generation for the high minimum load requirements or the inability of new conventional generation to cycle.

[4] The "fixed" component should likely reflect generator equipment availability (i.e. the fixed payment would be reduced if unit availability declined, possibly assessed monthly, and include the anticipated normal maintenance amounts) in order to provide an incentive for the owner to keep the plant properly maintained. The "fixed" component could reflect the underlying resource availability, either placing the risk of wind and solar availability on the generator owner or on the consumer, whichever is more advantageous.

MEMORANDUM

TO: RSWG Members
Docket No. 2011-0206

CC: Alison Silverstein

FROM: Hugh Baker

DATE: September 27, 2012

SUBJECT: MLC Subgroup "Flexibility" Recommendation

This memorandum will set forth the positions of HDBaker & Company with respect to the MLC subgroup recommendation regarding flexibility of generating units considered for approval in the future by the Public Utility Commission.

I believe that my positions, and the context in which they were originally explained, were made clear in my email to the RSWG members on September 17, 2012 and again in the RSWG meeting on September 19, 2012. Since it seems to be fashionable to submit "formal" comments in this matter, mine follow.

Also, because there seems to be a fixation with respect to the RSWG process and its application in this particular matter, I offer my comments on that topic as well.

Position with Respect to the MLC Recommendation

There are two kinds of "flexibility" being thrown around in these comments. First, there is the flexibility with respect to the operating capabilities of future generating resources. The MLC paper recommends that the Commission require future generating resources to have capabilities to cycle. It is clear from the context of the MLC paper that the issue the MLC is addressing is curtailment of wind resources. I agree that flexibility of generators is desirable in many *operational* circumstances. However there are other circumstances (e.g. *financial*) in which this may not be appropriate. Specifically, if someone came along and proposed a firm base load generator with a very low all-in cost (e.g. geothermal), with the understanding that it must either be on or off (i.e. no cycling ability), and it reduces rates for ratepayers, then my vote is for the baseload unit. If it causes curtailment of, for example, an as-available wind resource with an avoided cost contract (and the contract with the wind generator allows curtailment) sorry, but as a ratepayer myself, let's curtail the as-available resource!

Additionally, it is interesting that the MLC paper does not differentiate between flexibility of new renewable resources versus new non-renewable resources. If the standards of the MLC group are applied, then presumably the MLC group accepts

that a new *non-firm* renewable generator (e.g. wind) will be penalized in some manner because of its inability to cycle. Similarly, using the MLC logic, a new *firm* renewable resource that can cycle will be rewarded in some manner. To the extent that this is indeed what MLC is saying, then I would agree on this point.

In summary, the operational flexibility that the MLC recommends is fine in concept, but it seems to go too far in making an *a priori* determination as to what will be in the best interest of ratepayers.

The second kind of flexibility is the *Commission's* flexibility under its statutory authority. I believe that the MLC recommendation, if it were to be adopted as policy by the Commission (and I fully understand that is NOT what was voted upon!), would reduce the Commission's flexibility to judge a future generating plant or PPA application on its own merits and in the context of what is known at the time. The Commission in fact has the authority and flexibility to consider the factors that the MLC subgroup (at least a majority of the subgroup anyway) has recommended. But, it also has the authority to approve generation and PPA's that do not meet these criteria e.g. base load units. I see no reason for the Commission to voluntarily reduce its flexibility to consider a broad range of operational alternatives with respect to future generating resources.

With respect to demand response, there is clearly an opportunity to address wind curtailment in the near term by working on the load curve. Before we start limiting future generating choices, let's get the most we can out of demand side resources, a resource that I believe has not been fully exploited in any of the Hawaii power systems. This will also allow us to optimize the use of the existing generation fleet, including existing renewable energy resources. The use of demand side resources to shift the load curve is entirely consistent with the MLC subgroup desires and in fact addresses the very issue that seems to be the focus of the MLC subgroup's concerns.

Before jumping to conclusions about what we want for future generation, we also need to understand the implications of the ancillary services work that is being done by GE. If we need certain kinds of ancillary services to support greater renewable energy penetration (and less curtailment of existing renewables), let's first find out what those ancillary serves are and make a recommendation to the Commission that is consistent with the findings of the ancillary services study. The outcome of that study may fully support the MLC recommendation that future generators should be flexible enough to provide ancillary services needed to support greater penetration of renewables. However, to the extent that a given generator (renewable or otherwise) requires the system to carry additional ancillary services, that generator should be assigned the cost of those additional services. From a non-firm generator's perspective, that may not be a desirable outcome, but you can't have it both ways.

Finally, I disagree with the MLC's recommendation that all generating units should be dispatched at their physical marginal cost. There are clearly times when it is advantageous for a generator to be paid based on a contractual price. To offer up a theoretical example, there could be situations in the future where a generator is used as a "tolling" resource. Under a tolling arrangement, one party (for example the utility) buys the fuel and delivers it a generator owned by another party (for example an IPP). The party providing the fuel receives the power output of the unit at a conversion cost that is based upon a contractually stipulated heat rate. Beyond the theoretical realm, several existing IPP contracts in Hawaii already have a stipulated heat rate provisions. There is nothing inherently wrong from a ratepayer perspective if a generator is willing to take this operational risk. To the extent it takes that risk off of the ratepayer (who otherwise bears the risk of inefficiencies in the form of higher rates), then the generator deserves a premium for taking this risk. Under the MLC recommendation, generators willing and able to take this risk would have zero incentive to take this risk. We would therefore forgo an option that would benefit ratepayers.

Comments Regarding the RSWG Voting and Vetting "Process"

The comments of other parties in this matter also discuss the RSWG process. Accordingly, my thoughts follow below.

The paper that the MLC put forth did not rise to a level of objectivity, which in my opinion, made it worthy of a formal RSWG vote. No doubt the MLC subgroup tried to get a consensus document, but they failed in that endeavor. Nice try. In spite of the inability of the subgroup to reach a consensus, for some reason, there was insistence that it be voted upon. Not to trivialize the importance of this subject, but we might as well have voted on "my favorite color is blue." Some of us would say: "... yes, my favorite color is blue as well!" There are others who would say: "... well, my favorite color is green." No matter how many times the subgroup voted there would never be an agreement on a favorite color, and when it moves to a larger group, other opinions would be voiced. Why? ... because a given person's opinion regarding their favorite color is a subjective matter of course.

Here we have the same problem. If the RSWG subgroup could not get a unanimous consensus, that suggests a high level of subjectivity in the document. Yet, in spite of the difference of opinion even before it got out of the subgroup, the entire RSWG was more or less forced to vote – up or down. The insistence that this matter be put to a vote suggests an agenda that is not within the spirit of collaboration, respectful debate and acceptance of other points of view that is supposed to be the foundation of the RSWG process. Respectfully, the effort and extremely valuable time expended on this by the full RSWG could have been put to much better use.

I note that several parties continue to make comments regarding the "vetting" process that the MLC used to arrive at its recommendation. I have praised the MLC's efforts in my original comments and in the open RSWG meeting last week. I do so again here: *thank you to all the MLC members for your hard work and considerable debate and discussion in developing the flexibility paper.* However if the implication of the "vetting" comment is that an RSWG member who was not a member of a subgroup should not have the right to vote "no" and explain his/her "no" vote, then I would respectfully suggest that a subgroup and its members think twice before forcing something as subjective and controversial as this was to a vote by the entire RSWG group.

A final note: I believe a healthy debate is vital to make sure that the best ideas win, whether a given idea is mine, yours, or somebody else's. We all understand that the Commission can accept or reject, in whole or in part, any recommendations that are put forth by the RSWG. However, I think the Commission expects us to debate and disagree from time to time so that they have a good basis for making the hard and important decisions that affect the future of Hawaii. In this matter, I am not representing the specific interests of any client or project in which I am involved. I favor no particular party in the RSWG docket, nor do I have an axe to grind with anyone in this docket. That position affords me the opportunity in RSWG to call them exactly like I see them, and that is what I will continue to do. I welcome differing opinions and passionate debate, provided that the conversation is about getting to the right answer for <u>everybody</u>.

I look forward to continuing these discussions.

Tawhiri Power LLC ("Tawhiri") provides the following comments to the RSWG Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation ("Recommendation") that was passed by a vote of 13 (in favor) and 5 (against).

1. Tawhiri continues to support the recommendation because this recommendation is vital if Hawaii is to meet its goal of interconnecting the maximum amount of renewable generation to the grid while preserving grid reliability and not markedly increasing or meaningfully displace other renewable generation.

2. It should be noted that the MLC group went through several hours of discussions and at least four drafts of the document before finally voting on it. In each revised draft, the MLC drafting team tried to incorporate the comments of HECO Companies and the Consumer Advocate. If a comment was not accepted, the MLC drafting team tried to explain the reason for the non-acceptance. Mr. Baker and the County of Hawaii did not provide comments during the drafting period. It is interesting to note, that the County of Hawaii did vote in favor of the recommendation during the MLC vote.

Tawhiri provides the following comments to the HECO Companies comments to the Recommendation made during the Sept. 18th RSWG meeting and to its proposed edits forwarded on Sept. 14th:

1. During the Sept. 18th RSWG meeting, a HECO representative stated that the flexibility issue is not important because HELCO's use of as-available energy would increase by just 1% if curtailments were eliminated. However according to HELCO 16.45% of energy comes from Wind. The lion's share of that is from Tawhiri, and Tawhiri's energy production is reduced by about 12% by curtailments. Havi's production is also heavy impacted by curtailments. Clearly curtailments are far more than 1% of HELCO's energy supply. Curtailment will increase dramatically when additional wind and solar are added in the future. But, more importantly, Tawhiri's loss of 12% of production due to curtailments is important to Tawhiri. It should also be important to everyone interested in growing renewables on the Big Island. According to most studies, wind is the cleanest form of renewable energy and the cost is dropping. The future growth of wind on the Big Island may hinge on how well the curtailment problem is solved.

2. Also, during the Sept. 18th RSWG meeting, a HECO representative stated that the Recommendation would pay the wind plants even if was not maintained and it would put all the risk on the utility customers. That is not correct. The Recommendation explicitly states that the "fixed" part of the payment tied to plant availability and do not place that risk on the utility customers.

3. HECO's proposed edits to the Recommendation largely focus on making flexibility "agnostic;" applying equally to all generators. Flexibility is essential in the Island systems where night load can be less than half of peak load and thus require low load operation or shutdown of most generators. However, in a system with significant as-available content, consideration of

flexibility becomes especially important. The cleanest and potentially least costly sources of energy are as-availables and the flexibility needed to accommodate them is not unduly costly. Even some firm renewables such as geothermal for which flexibility is technically feasible albeit relative costly should to the extent practical be accommodated by less costly flexibility in thermal plants.

Tawhiri provides the following comments to Hugh Baker's comments to the Recommendation forwarded on Sept. 17th:

Mr. Baker's comments focus largely on whether or not the flexibility recommendations are mandatory or binding upon the PUC. His comments ignore the fact that the flexibility paper simply outlines why flexibility is important and recommends the need for flexibility be recognized in the PUCs deliberations, particularly as accommodating as-availables is concerned.

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The Honorable Chair and Members of the
Hawaii Public Utilities Commission
465 S. King Street, First Floor
Kekuanaoa Building
Honolulu, HI 96813

Dear Commissioners:

Subject: RSWG Recommendations re Minimum Load & Curtailment (MLC)

On September 18, 2012 the Public Utilities Commission (PUC) Reliability Standards Working Group (RSWG) voted on recommendations made by its Minimum Load and Curtailment (MLC) Subgroup. This vote and the recommendations will be filed with the PUC.

Vote	Yes	Yes With Reservations (WR)	No
Initial Vote	10	2	3
Final Vote	11	0	4

After the Independent Observer forbid the WR votes, Life of the Land reluctantly switched from "WR" to "Yes" because we more favored than opposed the MLC recommendations and we can live with them. The other WR entity switched to a NO vote.

We have a serious concern.

Often project proponents assert that there is a "zero" impact or "no" impact when in fact a closer examination reveals there is a significant non-zero impact or cost.

The MLC recommendations includes the following statement: "Variable renewables also have the characteristic that they consume no fuel, such that the marginal production cost of energy and environmental impacts of pollutant emissions are essentially zero."

This is the wrong comparison.

The utility operates the grid using an ever changing portfolio of supply-side generators. Each portfolio has different spinning reserve, ramping, and storage requirements.

Having these ancillary services available is a fixed cost. Operating them is a variable cost. Operating them also has an environmental impact.

Assuming that all variable costs have zero environmental and zero rate impacts implies assuming that either

(1) The ancillary services portfolio has zero financial and environmental impacts; or

(2) The impacts are identical for each supply-side generation alternative, and therefore can be dropped out of the equation.

Neither of these alternative explanations has been analyzed.

Rather it has just been assumed that the "marginal production cost of energy and environmental impacts of pollutant emissions are essentially zero."

Supply-side portfolios can be optimized to meet different objectives: for example, maximizing corporate revenue or profit, maximizing renewable energy penetration percentages, minimizing pollution, and/or minimizing ratepayer impacts.

Assuming zero impacts means that the impacts do not have to be studied, and that allows someone to option to game the system.

In all likelihood, it winner won't be the ratepayer, who is kept in the dark about system operations, sees a long-term upward ramping of their rates, and are being told "Don't Worry, You will soon have levelized rates."

We raise this issue not to challenge the YES vote, but to accurately reflect our concern that all costs paid for by ratepayers should be accurate and transparent.

Mahalo,

HENRY Q CURTIS
VICE PRESIDENT

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---- In the Matter of ----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	
	)	
Instituting a Proceeding to	)	
Investigate the Implementation	)	Docket No. 2011-0206
Of Reliability Standards for	)	
Hawaiian Electric Company, Inc.,	)	
Hawaii Electric Light Company,	)	
Inc., and Maui Electric Company,	)	
Limited	)	

COMMENTS OF
THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM
IN SUPPORT OF THE RECOMMENDATION OF THE
MINIMUM LOAD AND CURTAILMENT SUBGROUP

DBEDT supports the MLC recommendation ("Recommendation") that the RSWG approved by a wide majority at the September 18, 2012 meeting. As was agreed at the September 18, 2012 meeting, the Independent Facilitator should submit the Recommendation to the Commission with any dissenting views and comments.

As DBEDT understands it, one basis for opposing the Recommendation is that "significant disagreement" has been expressed over the purpose of the document, *i.e.*, formally recommending the implementation of new requirements and contractual provisions for new and modified generation resources. While DBEDT does not discount that certain parties disagree with the Recommendation to this extent, the fact that there is significant agreement on this issue also should not be ignored. In Order No. 30371, the Commission was explicit that work product does not have to be unanimously approved by the full RSWG before it is filed with the Commission. Consistent with the Commission's guidance, the RSWG voting protocols, which were proposed by the Independent Facilitator in the "RSWG Decision-Making Process" memorandum and unanimously approved by the RSWG at the July meeting, expressly permit the RSWG to vote on items where consensus has not been established. The voting protocols establish that an item has been deemed "approved" if a majority of the RSWG vote in favor of that item and specify that the Independent Facilitator will submit approved items to the Commission. The Recommendation was approved by an overwhelming majority of the RSWG in a 15-5 vote and, therefore, should be submitted to the Commission as was agreed at the September RSWG meeting.

A second basis for opposing the Recommendation was that it would reduce flexibility. DBEDT does not agree with this conclusion. In fact, the premise underlying the majority Recommendation, which stems from the work product of the Commission's independent consultant, is that flexibility should be increased in order to integrate more, and reduce the curtailment of, renewable generation sources. DBEDT believes the Recommendation facilitates achievement of that goal.

Other bases for opposing the Recommendation relate to considerations of short-run versus long-run costs, the interrelationship between flexibility and demand response, and the appropriate role of true marginal cost. DBEDT believes that the MLC and the RSWG followed a process that allowed for these issues to be fully considered and, in fact, these issues were fully considered. In particular, prior to being put before the RSWG, the Recommendation was subjected to a substantial iterative process. After considering numerous rounds of proposed revisions, the MLC finalized a draft that garnered broad support. That support carried over to the RSWG meeting where the Recommendation was approved.

We are heartened that the participants in the RSWG process are moving forward in a constructive manner and continuing to work together. DBEDT is hopeful that the process will accelerate through the end of the year. In sum, DBEDT supports the Recommendation.

Respectfully,

Gregg J. Kinkley
Deputy Attorney General
Commerce and Economic Development Division
Counsel for DBEDT

Hawai'i Solar Energy Association's September 25, 2012 Comments Re: RSWG's Recommendation Concerning Cycling Capabilities And Minimum Load Capabilities Of New Generation

As a member of the RSWG and the Minimum Load and Curtailment Subgroup ("MLC") who has fully participated in the MLC from the beginning, I would like to take this opportunity to submit comments regarding the RSWG's Minimum Load and Curtailment Subgroup Recommendation Concerning Cycling Capabilities and Minimum Load Capabilities of New Generation ("Recommendation"). This Recommendation has been adopted by a majority of the MLC and RSWG. The Recommendation speaks for itself, and the Commission is fully capable of understanding the issues and addressing the Recommendation as it sees fit. I wish to clarify and highlight several points, particularly regarding some comments by the dissent.

Background: The Recommendation arose from MLC discussions stretching nearly a year, beginning with the analysis by the Commission's consultant, Brendan Kirby, indicating that lack of flexibility in the HECO Companies' "must run" generation was resulting in curtailment of renewable energy. In response, the HECO Companies commissioned the ongoing EPS study. The HECO Companies also indicated that anticipated generation resources would alter the conditions Mr. Kirby analyzed. After spending much time inquiring about the flexibility of such resources without much progress, the MLC instead requested Mr. Kirby to draft proposed general recommendations on flexibility of new generation.

Process: An extensive drafting and vetting process followed. I volunteered to assist Mr. Kirby with incorporating feedback and revising drafts and, thus, have first-hand knowledge of the entire process. The MLC circulated Mr. Kirby's draft on August 10, 2012. The MLC and RSWG members were notified of the pending draft and MLC vote on the Recommendation. Based on feedback from various parties, including Tawhiri, the HECO Companies, and the Consumer Advocate, a revised draft was circulated on August 21. Additional drafts based on further feedback were circulated on August 22 and 27. The majority of the MLC voted to approve the draft on August 29, with a further edit by DBEDT. A final draft was circulated on August 29. In total, the Recommendation underwent five drafts.[1]

Prior to the August 29 MLC vote, the HECO Companies offered to provide more suggested edits to the Recommendation. The MLC voted to approve the Recommendation, but remained open to revisiting the draft if Mr. Kirby and I and the HECO Companies could reach consensus. We could not reach consensus, as documented in my email response dated September 4, 2012, which is attached hereto.

On September 18, 2012, a majority of the RSWG approved the Recommendation, with several parties dissenting, including the HECO Companies and the CA.

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[1] This does not include prior drafts of a similar paper by Mr. Kirby regarding valuing flexibility in Integrated Resource Planning process, which provided much of the material for the Recommendation. Mr. Kirby had worked for several months drafting and revising this other paper in an attempt to reach consensus with the HECO Companies, with no final resolution.

Comments on Recommendation and Dissents:

With all due respect, the dissenting comments on the Recommendation reflect a level of disconnect from what the Recommendation actually says. Through the drafting process, the Recommendation was repeatedly revised to incorporate substantive feedback, including the points that the dissenters continue to raise. Assertions that the Recommendation "ignores" or "precludes" certain considerations particularly miss the mark. The point of the Recommendation is to ensure consideration of flexibility in generation before it is too late or costly to do so, not to foreclose other considerations. Again, the Recommendation already explains this, which the Commission can ultimately read for itself.

One of the main (and most serious) allegations is that the Recommendation is "biased" in favor of certain generation resources. Not so. As the Recommendation expressly makes clear: "The objective here is not to favor certain renewable technologies, developers, or projects over others, but rather to maximize overall clean energy benefits and opportunities from a comprehensive and long-term perspective while economically optimizing power system efficiency and maintaining system reliability." Id. at 2. See also attached email (The Recommendation "is not about favoring wind or solar, nor is it about privileging other resources. It's about considering how all resources can best work together over a long-term system perspective.").

Finally, criticisms of the process of developing the Recommendation are particularly disappointing, particularly coming from those who did not participate in the extensive process described above. Instead of criticizing the Recommendation for "ignoring" certain issues (e.g., demand-side solutions, which the Recommendation twice expressly states should also be pursued, see id. at 2), it would be more constructive if RSWG members took the initiative to help develop such recommended solutions. In fact, the MLC is continuing to work on further recommendations to address the curtailment problem and invites and encourages all RSWG members to participate in this effort.

Respectfully submitted,

Isaac Moriwake
EARTHJUSTICE
Attorney for
HAWAI'I SOLAR ENERGY ASSOCIATION

January 7, 2012

Potential Contractual Treatments for Curtailment of Variable Renewable IPPs

Introduction and Summary

Increasing the use of renewable energy resources ("renewable resources") to generate electricity for our island grids is a broadly-accepted goal as we seek to achieve our clean energy future in Hawaii. It is also broadly recognized that integrating higher levels of renewable resources, and especially variable renewable resources, is a complex, challenging task for our island utilities. To date, the RSWG has focused its efforts on identifying technical integration issues and searching for viable solutions. Two issues which should be evaluated as a part of this integration discussion are: (1) how can contracts with energy providers better reflect a generator's marginal production cost to enable the utility to economically optimize the reliable operation of the power system and minimize ratepayer costs; and (2) what can be done to minimize or eliminate curtailment, not just now, but as we increase penetration and utilization of these resources?

There was a discussion in the subgroup as to whether and to what extent the energy payment structure in existing as-available energy contracts affects the utilities' decisions to curtail the output of as-available energy facilities, or the amount of curtailed energy. This led to a discussion of and an exchange of whitepapers and comments with respect to (1) the energy payment structures in existing as-available energy contracts, and the reasons for those structures, (2) the impact of pricing structures on economic efficiency, (3) the pros and cons of different payment structures from other perspectives (such as the risk transfers between project developers and utility customers inherent in different pricing structures, and the impact of different pricing structures on project financing costs), and (4) challenges arising out of changing the pricing structures in new as-available energy contracts, while retaining the pricing structures in existing as-available energy contracts.

Objectives and Scope

Maximizing the economically efficient use of each generator (utility and IPP) should be an objective of the contract structure with independent power producers ("IPP"). The overall objective of such contracts should be to obtain reliable power (energy, capacity, and/or ancillary services) and renewable attributes at the lowest reasonable cost on a risk-adjusted basis.[1] The scope of this paper is limited to identifying potential contractual treatments which can assist in providing the correct economic signals to facilitate increased use of renewable energy while also considering potential impacts to utility ratepayers and shareholders. Issues will be identified, but specific recommendations will not be made as to a preferred treatment. This paper also does not address all of the complications associated with seeking to modify existing IPP contracts, or make specific recommendations for revisions to existing contracts. Instead it focuses on the desired contract structure which will motivate the economic use of each generator and therefore, we believe, will help ultimately reduce ratepayer costs. It will also provide greater certainty to IPPs which should help reduce the perceived risks associated with contracts and therefore reduce financing costs. Given that, IPPs will be able to offer energy at

[1] Costs to customers are comprised of both payments to the IPPs and system impact costs. Both costs need to be taken into consideration when examining the issue of curtailment policies.

lower costs and that will benefit the ratepayer. The principles discussed in this paper apply to all generation technologies, but the paper focuses on variable renewable generation and especially on how curtailment of variable renewable generation is treated during excess energy conditions. This change in contract structure also provides the correct incentives for cost effective modernizations to the existing utility generation fleet minimum load capabilities and to institute operating procedures and protocols to increase the integration of renewable energy resources.

The RSWG recommends that the PUC investigate potential alternative contract structures in a public process, open to all stakeholders,

Key Issues

One fundamental principle expressed in this paper is the concept that the utility should be exposed to each generator's actual marginal production cost for energy. If the utility pays the marginal production cost for energy from all generators, it is able to optimize the economic operation of the power system thus minimizing ratepayer costs while maintaining reliability. Current contracts with energy prices based on factors other than the marginal production cost, such as contracts where the entire compensation is included in the energy payment, with some assumed level of curtailment, provide the utility with a distorted economic signal. If an incorrect energy price is used in economic decisions then those decisions will not be optimal and ratepayers will pay more than they need to:

- If the incorrect energy/marginal price was used in the utility's hourly operational economic dispatch,[2] the result could be an inefficient and more expensive dispatch of the generation fleet.
- If the incorrect energy price is used in deciding which generators to operate or to cycle off overnight (unit commitment), then a more expensive set of generators than is necessary may be operated at times.
- If the incorrect energy price is used in deciding on transmission system upgrades, then opportunities that might alleviate or reduce curtailment and reduce costs may be missed.
- Similarly, if the incorrect energy price is used when deciding on investments to increase the flexibility of the fuel consuming dispatchable generation fleet (reduced minimum loads, reduced cycling costs, etc.) that might alleviate curtailment, opportunities to reduce system costs and reduce curtailment may be missed.

Existing Contracts

Under existing as-available renewable energy PPAs, the utilities pay the contract prices for energy delivered in accordance with the terms and conditions of the PPAs, but do not pay for curtailed energy. Accordingly the prices represent the Companies' marginal costs of acquiring more energy from the facilities. The contract price is not the actual marginal production cost for energy from the renewable generator and thus cannot be used to optimally commit and dispatch the generation fleet. Existing contracts partially get around this limitation by requiring as-available energy facilities to be treated as must-take energy subject to the limited reasons for

[2] Economic dispatch is the short-term determination of the optimal output of a number of electricity generation facilities, to meet the system load, at the lowest possible cost, while serving power to the public in a robust and reliable manner (Wikipedia). Utilities around the world, and on the islands, use the marginal energy production cost of the utility owned generation and the contract price from non-renewable IPPs when economically dispatching the power system, typically hourly or more frequently. Existing wind generation contracts explicitly exclude wind generation from economic dispatch in Hawaii. (Note that the contract structures described in this paper are used for these non-renewable IPPs) Consequently, no effort was made to design wind generation contracts to reflect the marginal production cost and enable them to be incorporated in the utilities' economic dispatch.

curtailment provided in the existing as-available energy PPAs. Hence as-available energy PPAs are essentially treated correctly as zero marginal cost resources in the utilities' economic dispatch.

However, the existing contract structure does not present the utility with the correct marginal production cost from variable renewable resources for determining which generators to run (security constrained unit commitment) and whether to modify or reconfigure utility systems. The marginal costs of curtailed as-available energy used in determining whether to modify or reconfigure utility systems are based on the energy prices in the existing as-available energy PPAs, because that is the cost to the utility and its customers of taking more energy from the existing as-available energy facilities. This inherently results in an economically suboptimal decision process and ultimately higher costs to rate payers.

Curtailment

In crafting solutions to maximize the acceptance of renewable energy on the utility systems, it is important to understand the reasons for the current levels of curtailment of both variable and dispatchable renewables and how these curtailments may change in the future.[3] Curtailment of variable renewable resources along with other generation or demand-side resources is needed at certain times, such as when there are system emergencies and when there is generation in excess of load on the grid. These types of curtailment allow the system operator to maintain reliability in the existing grids. The ability to manage excess energy through curtailment of renewable energy is of particular significance in island systems, as there is no means to export excess energy.

If the objective was only to minimize or avoid curtailment, rather than to maximize the use of renewable generation and minimize the use of fossil fueled generation, renewable energy would have been restricted to the amount the system could accept during typical minimum demand periods. With the ability to curtail renewable energy to match demand, larger amounts of renewable energy were installed, understanding that they would be curtailed during minimum demand periods, but that they would be able to increase production during higher demand periods. The result is a larger amount of renewable energy purchased than would be possible had the capacity of connected renewable energy been restricted to the level where excess energy curtailments were avoided or minimized. As the island grids move to reduce fossil fuel use and increase the penetration of renewable generation resources, curtailment will naturally become a more prevalent reality.

On the other hand, curtailment is a reduction in the amount of energy delivered. The impact of curtailment (on the generator, ratepayers and on society) differs depending on the type of generator being curtailed. Dispatchable renewable generators and fossil fuel burning generators save the fuel when curtailed and can use that fuel to generate electricity at a later time when it is needed. Variable renewable generators are not able to save the "fuel" so the production opportunity is lost forever. Similarly, dispatchable renewable generators and conventional fossil fueled generators have a higher (typically much higher) marginal production cost than the near zero marginal production cost of variable renewables. The marginal production cost of dispatchable generators is saved when they are curtailed. There is no marginal production cost savings when variable renewable generators are curtailed.

[3] Dispatchable resources have their output controlled by the utility at all times to balance supply and demand, to reflect system constraints and to reflect the economics of the system at time of dispatch. Variable renewables can be dispatched down under utility operator control for the same reasons but cannot be dispatched up above the power level currently being provided by the wind or sun.

It is recognized that as the amount of renewable resources is increased in the islands, due to the limited demand, there will be an increasing number of instances where there is insufficient demand to accept all available renewable energy and therefore some renewable energy will result in displacement or curtailment of other renewables. This happens regularly on the Big Island where dispatchable renewable energy is reduced in order to accept maximum amounts of variable renewable energy. While dispatchable renewable generation is preferable precisely because it is dispatchable, it also typically has a marginal production cost that is greater than (often significantly greater than) the near zero marginal production cost of wind and solar variable renewable generation.[4] So while both dispatchable and variable renewable generation are renewable, it is still preferable to utilize the maximum amount of variable renewable generation, in keeping with the standard utility practice of security constrained unit commitment and economic dispatch.

Importantly, while potential solutions are being examined to reduce or eliminate curtailment, it may or may not be possible to eliminate curtailment in certain situations, or to do so may come at an unacceptable cost. There are also concerns about the impacts of curtailment when it cannot be eliminated. These impacts can affect not just renewable IPPs, but also the utility and its ratepayers and shareholders. Therefore, as investigations continue in succeeding proceedings to examine the issue of curtailment, it is also important to examine ways to mitigate curtailment impacts on all of these stakeholders. The RSWG has tendered to the PUC a curtailment analysis for both the HELCO and MECO systems that contained recommendations as to mitigation measures to reduce or eliminate curtailment. Subsequently, these analyses initiated a further study by the HECO Companies to assess cycling impacts of existing fossil generation.

The detailed implementation of each alternative contract structure must result in essentially the same power system reliability. This requirement and assumption will not be repeated throughout the paper though it should be understood to apply.

Guiding Principles

Contracts with energy prices based on a generator's marginal production cost are critical for enabling the utility to economically optimize the reliable operation of the power system and minimizing ratepayer costs. If the utility passes the marginal price signal on to demand response and storage resources, that will enable them to make productive use of excess wind and solar energy.

Total costs must be considered when deciding on new generation investments; utility owned or IPP, renewable or fossil based, variable or dispatchable. But once an investment is made and a generator is operational, then it is the marginal production cost that is important for optimizing the power system, not the sunk fixed costs.

The RSWG recognizes that maintaining reliability is a fundamental principal for all power system planning and operations. That assumption and understanding should be taken into consideration in addressing curtailment mitigation contractually on a going forward basis.[5]

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[4] Wind and solar variable renewable generation may not have near zero marginal cost from a system cost perspective. They may require ancillary services, which have a cost associated with them, typically on the order of a few $/MWH of wind and solar energy.

[5] Curtailment may be implemented for a number of reasons. The focus of the paper is on curtailment due to excess energy conditions.

It also should be noted that some of the benefits of changing the contract structure cannot be fully achieved unless the contract structure in existing contracts can be re-negotiated with the mutual consent of the parties. However, re-negotiating existing contracts should not be a deterrent to moving to a revised/updated contract structure for new or updated facilities.

Presentation and Brief Discussion

The following is a description of potential contractual treatments starting with the historical treatment of variable generation IPPs and ending with an alternative generation contract structure based on a marginal production cost compensation for energy coupled with a modified fixed payment to cover capital and fixed costs (Attachment C) that facilitates optimal investment and operations.

Historical Treatment ("Baseline")

Historically, the utility provides a developer with information about the power system such as operating practices, constraints (including other renewable energy constraints) and anticipated system demand. From this information, the developer makes its determination as to the amount of energy that could be delivered to the utility. Projects historically were treated as must-take, and therefore all energy would be purchased except under curtailment conditions. The difference between the amount of the developer's estimated energy production and the developer's estimated energy delivery to the utility was the developer's expected curtailment of the project. Upon signing a PPA, the developer agrees to assume the risk for all curtailments upon commercial operation of the facility that are in accordance with PPA terms. In the PPA, hours of curtailment are not capped, but are restricted to only non-economic curtailment, i.e. the energy was accepted except when the system is constrained or when there are emergency contingencies Note: the utility and its ratepayers and shareholders do not share any of the curtailment risk (although they may end up paying for it through higher accepted PPA prices).

If actual curtailments are within the amounts projected by the developer, based on the utility supplied information, the owner/operator should not be under any financial stress on account of the curtailments. However, in many cases curtailments have been higher than anticipated and this has put financial stress on variable renewable IPPs. Looking forward, future developers and their investors may view the risk of uncapped levels of curtailment as too high, and projects may be more difficult to finance and/or bear a risk premium.

It is important to note that there are actually already several types of "avoided cost payments," including:

(i) the conventional avoided energy costs payments which are updated monthly, and which can go up and down, (the Commission has discouraged the use of this payment structure going forward and has recommended the utility re-negotiate existing contracts),

(ii) a modified, avoided cost payment based on a "rolling average" over a longer period (e.g., one or more years, which typically softens the typical payment volatility associated with the price of oil),

(iii) a hybrid avoided and levelized cost payment,

(iv) straight levelized payment, and

(v) potentially a real time avoided cost rate which takes into account regulation, and other ancillary services which may be required to integrate the variable renewable energy.

Arguably, the risk to ratepayers may be less in (ii) compared to (i), in (iii) compared to (ii), and so on.

Tiered-Energy Payment Alternative (adapted from HECO's RFP)

As an alternative to the Baseline treatment, HECO's 200 MW RFP includes a tiered-energy pricing alternative or "TEPA" to replace a straight levelized payment. For example, there would be three tiers, where the energy payments differ for each of the three tranches of energy delivery. Specifically, the payment rate would be highest for the first tier and its tranche of 70% of the total energy delivery; the payment for the "second" tier would be lower (but not more than 20% lower than for the first tier) for up to 15% of the total energy delivery; and the price of "third" tier would the lowest for up to 15% of the total energy delivery. Bidders on the RFP are allowed to propose a specific TEPA, including degradation factors moving forward from Year 1 of a proposed PPA to Year 20. In addition, HECO will "bank" the amount of curtailment over the contract period, and offer the IPP the option of extending the contract period by the number of days necessary to deliver the amount of banked curtailed energy See Attachment A from HECO for more details of this treatment.

As an alternative to the Baseline treatment, the TEPA requires further discussion. For example, there are concerns expressed in the RFP about the possibly of "gaming" by bidders in their proposed TEPAs, and HECO will therefore look closely at how the proposals: (i) will mitigate risks to the Seller, (ii) provide lower energy pricing to ratepayers, and (iii) avoid gaming. There are also questions as to whether this approach will appear to bidders as lower risk than a straight, levelized payment, as it may appear to add another layer of uncertainty to the basic curtailment uncertainty or it may appear to the bidders as a way to ensure a known amount of total revenue for the project by using the banked curtailment provision. Thus, the major question appears to be whether the risk profiles differ from the Baseline treatment, and if so, by how much? Note: When financing projects, the financial institutions will assume the most conservative, least risk case which will result in high cost of financing and ultimately higher cost of energy to ratepayers.

Take or Pay Treatment (Wholly Compensated Curtailment Provision)

An alternative to the "Baseline" treatment is "Take or Pay." Specifically, a PPA with a variable renewable IPP would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered but for curtailment. For the IPP this treatment will ensure revenues when the IPP delivers electricity or when curtailed during periods when the project could have exported power to the utility. In this treatment, the risk for the curtailed energy is shifted to the ratepayer. See Attachment B [Take or Pay Treatment (Wholly compensated curtailment)] for a detailed discussion of the "Take or Pay" option.

As an alternative to the Baseline treatment, this treatment option requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the renewable electricity that is provided to the grid and other considerations. It

would also be important to develop specific means to calculate and verify the actual amounts of any "curtailed energy" and additional record keeping and reporting would also be required.

Take or Pay Treatment - Variant 1 - Payment for Curtailment above Threshold (Based on the KIUC Model)

An alternative to the "Baseline" treatment is a variant to "Take or Pay". Specifically, a PPA with a variable renewable IPP would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered above a threshold level of curtailment specified as a number of hours per year. For the IPP this treatment would ensure revenues when the IPP delivers electricity or when curtailed above the curtailment "threshold". Compared to the "Take or Pay", the risk for curtailment in Variant 1 is shared between the IPP and the ratepayers.

As a Variant to the "Take or Pay," this treatment requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the additional renewable electricity that is provided to the grid and other considerations. Specific means must be identified for calculation and verification of the actual amount of the "curtailed hours" and additional record keeping and reporting would be required.

Fixed Payment-Marginal Cost Dispatch Treatment

Another alternative to the "Baseline" treatment is "Fixed Payment-Marginal Cost Dispatch." Specifically, a PPA with a renewable IPP would include provisions to compensate the IPP based on fixed-payments to cover capital costs and fixed-operating costs and energy-payments based on the IPP's marginal operating costs (variable O&M). Basically, from a financial perspective, renewable resources would be treated the same as utility owned generators. Given that, it would be economically efficient if all generators could be economically dispatched based on their marginal production costs and system cost impacts.[6] For example, since the marginal production costs of variable renewable resources would likely be lower compared to other generators (including costs associated with accommodating the variability and uncertainty of the renewable resources), variable renewable resources would likely be dispatched whenever they are available to provide energy to the grid. Clearly, the utility would be motivated to accept as much of the variable generation as possible for economic reasons and in order to meet its RPS. And when the system operator needs to curtail variable generators, the variable generation IPPs would not be financially harmed. Thus, there is no need to pay for curtailment. Meanwhile, there is little or no risk to the utility, its ratepayers and shareholders with this type of treatment.

The risk to the utility ratepayers with this type of treatment is the split between fixed payment and energy payment. The utility will pay for non-firm fuel-saving renewable energy capability through the contract mechanism which fairly addresses the availability of the variable generators and the adequacy of the resource over the life of the project. The terms and conditions of a "fixed payment marginal cost dispatch" PPA are substantially different from the terms and conditions of an "as-available energy" PPA. In addition to payment terms, all of the terms and conditions of the contract would have to be modified. It will be essential that incentives be built into the contractual proposal to ensure that equipment is maintained and

[6] In an ideal, economically-efficient system, all generation resources would be dispatchable by the system operator within their physical limits. Dispatch of generation resources would be based on their marginal production costs, and other marginal system costs.

operating so that it is available to provide the low-cost energy. If the equipment is not made available then the fixed compensation should be reduced, or sanctions applied.[7] In addition, there is concern about how this treatment would affect the utility's financial integrity and cost of capital (and, thus, it's overall cost of service). See Attachment C (Alternative Generation Contract Structures for Optimal Investment and Operations) for discussion of this treatment.

Given that this treatment is a departure from the Baseline treatment, further discussion is required.

Conclusions

The RSWG did not reach consensus concerning what variable renewable generation IPP contract structure to recommend to the PUC for either new or existing contracts. Instead, this paper examines concerns with the existing practice along with several alternatives. The RSWG recommends that the PUC investigate potential alternative contract structures in a public process, open to all stakeholders.

[7] Interestingly, while we recommend considering linking the IPP's fixed payment to equipment availability and the IPP's ability to maintain its generators the same linkage is not applied to utility generators which ratepayers must pay for regardless of their maintenance condition or performance.

Attachment A
HECO Comments on an Alternative to a "Take or Pay" Contract – the Tiered-Energy Purchase Agreement

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It is important to understand that "curtailment" **is an issue for all generators, but particularly** for as-available providers. Renewable energy can also be supplied by providers who can control their source energy (i.e.; biofuel, biomass, and geothermal). Dispatchable firm-capacity projects are subject to control of the energy to meet utility demand. Where feasible, dispatchable renewable energy projects can offer the ability to procure renewable energy that can be made available to serve demand when needed, rather than having the energy being dependent upon the source resource being available. These types of renewable energy providers offer an alternative to some systems which may compete with as-available providers to serve demand.

For as-available providers, there are several alternative ways to address this issue. One alternative that is currently being offered by Hawaiian Electric in its new RFP for renewable energy is to allow developers to propose a tiered pricing structure in connection with the power purchase agreement and the ability to "bank" a certain amount of curtailed energy for later sale to the utility, as described below. The tiered pricing structure is intended to provide the developer with the ability to shift the recovery of fixed costs into the earlier tiers thereby allowing the developer to reduce the risk of fixed cost recovery and contribute to the financeability of the project.

The Term Sheet for Tiered Energy Pricing Alternative ("TEPA Term Sheet") sets forth the basic terms and conditions upon which Hawaiian Electric is prepared to negotiate a tiered energy pricing alternative ("TEPA") to the single tier pricing set forth in the Model PPA. Below is a summary of the TEPA Term Sheet. The TEPA Term Sheet is included in the revised draft Request for Proposal for Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu posted on www.heco.com/renewableRFP on September 28, 2012 as follows.

Term Sheet for Tiered Energy Pricing Alternative:

- Offers tiered pricing structure as an alternative to the single pricing structure set forth in the Model PPA.

- The TEPA break points are set at 0-70%, 70-85% and 85-100%+ of Initial Annual Contract Energy (as defined in the Model PPA), with the price differential between any two adjacent tiers limited to 20%.

- Certain portions of the "Curtailed Energy" (as defined in the Model PPA) will be eligible for "banking," as more fully set forth in the TEPA Term Sheet. At a high-level, Curtailed Energy eligible for "banking" will consist of Curtailed Energy resulting from (i) outages on the Hawaiian Electric System unless such outages were caused by Seller's actions or inactions that were not in compliance with the PPA, (ii) Force Majeure affecting the Hawaiian Electric System unless such Force Majeure was caused by Seller's actions or inactions that were not in compliance with the PPA, and (iii) operating conditions on the Hawaiian Electric System (including Excess Energy).

- Such "Banked Curtailed Energy" will give the "Seller" under a TEPA modified PPA an option to extend the Initial Term of such PPA to provide the Seller with an opportunity to continue to sell electric energy to Hawaiian Electric.

- The length of such extended term will be proportionate to the amount of Banked Curtailed Energy but in no event will exceed two years.

- If, following the close of the third Contract Year and at the close of each Contract Year thereafter, there is no Contract Year among the three preceding Contract Years during which the sum of Actual Output plus the amount of both Curtailed Energy eligible for "banking" and energy that could not be generated due to certain force majeure events, equals at least 90% of the Initial Annual Contract Energy, then the amount of Banked Curtailed Energy will be zeroed out, banking will cease and the PPA will revert to flat energy pricing, as more fully set forth in the TEPA Term Sheet.

The purpose of TEPA is to mitigate some of the financial uncertainties faced by Sellers and Financing Parties due to possible curtailment of renewable generators under the Model PPA. Although TEPA will not eliminate such uncertainties, Hawaiian Electric would expect the risk mitigation available under TEPA to benefit rate payers in the form of lower energy pricing over the initial term of TEPA-modified PPAs. However, the risk to rate payers under a poorly structured TEPA is that the pricing tiers are too susceptible to "gaming" (e.g., overestimating the Initial Annual Contract Energy), such that little of the Facility's output is actually sold at the lower priced tiers, thereby depriving rate payers of the benefit of lower energy pricing. Consequently, developers seeking to negotiate a TEPA modified PPA should be prepared to support their TEPA proposals (including modifications to the TEPA Term Sheet) in terms of (i) risk mitigation to Seller, (ii) lower energy pricing to rate payers and (iii) disincentive to "gaming." Each developer who desires to include TEPA in its PPA will, at a minimum, be required to make available to Hawaiian Electric, both as part of the negotiation process as well as during the Initial Term of the PPA, the same information concerning the projected output of its Facility as is made available to its Financing Parties. In addition to facilitating the negotiation of TEPA-modified PPAs, such information will facilitate the process of obtaining PUC approval of such PPAs.

Attachment B
Take or Pay Treatment (Wholly Compensated Curtailment)

An alternative to the "Baseline" treatment described above is a PPA with a variable renewable IPP which would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered but for utility curtailment. For the IPP this treatment will ensure revenues when the IPP delivers electricity or when curtailed during periods when the project could have exported power to the utility. In this treatment, the risk of additional curtailed energy beyond what was originally forecasted and built into the project financing is shifted to the ratepayer. As an alternative to the Baseline treatment, this treatment option requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the renewable electricity that is provided to the grid and other considerations.

The following are some points for further consideration and discussion:

1) Under wholly compensated curtailment, renewable electricity has a marginal cost of almost zero, which accurately reflects the zero fuel cost of renewable wind, solar and hydro resources. This would facilitate economically efficient decisions with respect to the commitment of generation and whether to modify or reconfigure utility systems. Will this also reduce overall costs and provide benefits to rate payers?

2) Wholly compensated curtailment on future PPAs could reduce the generation costs of as-available renewable energy projects by making predictable the revenue streams from such projects and reducing the costs of financing such projects. If the price for energy actually delivered fully reflects the enhanced revenue flow and reduced risk for the variable energy facility, customers could end up paying less (while accepting the market risk that loads and sales in the future will be lower than forecast resulting in more than expected curtailment).

3) Wholly compensated curtailment on future PPAs may minimize overall generation costs by accelerating the rate of renewable generation development, and thus accelerating generation cost reductions from replacement of high-cost imported fuel generation with low-cost renewable generation.

4) Wholly compensated curtailment on future PPAs simplifies HECO's modeling, planning and decision-making by fixing the amount of existing as-available renewable generation subject to uncompensated curtailment.

5) Utility customers already pay for estimated curtailed energy indirectly in the payment rates for delivered energy. Project developers and their financing parties may not be able to estimate the future curtailment risk, and may overestimate the risk as a result. Take or pay contracts may reduce overall costs and provide benefits to rate payers.

6) Curtailed energy cannot be measured directly. There would need to be detailed calculations of curtailed energy during all curtailment periods (and not just periods where there is a valid claim of improper curtailment). This would require continuous resource data, and power output curves for all generators reflecting their current status. This problem has been successfully addressed in Texas and other regions so it should not present an insurmountable obstacle. It also provides operational benefits and enhances reliability.

7) Under wholly compensated curtailment, in effect, the utility would be paying for capability instead of energy. The terms and conditions of the standard as-available energy contract should be reviewed in light of that change. In addition, the accounting and credit quality implications for the utility off-takers (which are currently rated BBB-) should be analyzed.

8) Issues as to how such a different curtailment regime for new PPAs would mesh with obligations and curtailment priorities under existing PPAs should be addressed, given the limited ability of the utilities to modify existing contracts. This would include identification of modifications and/or additions that would be necessary to existing forms of utility power purchase agreements to be able to reasonably balance the increased risk for ratepayers. These could include provisions such as: (1) the right to control energy output, and monitor equipment and resource availability to confirm the amounts of potential energy available from the new as-available energy facilities (and potentially existing as well), since new projects would be paid on the basis of energy made available, and not energy accepted, (2) appropriate modifications to the form of pricing paid to the developer, and (3) requiring verified cost information to ensure that any transfer of risk to customers is resulting in lower prices.

9) Issues as to how any such change in curtailment policy could increase the potential for stranded costs (in the form of payment obligations under long-term contracts) if the energy market in Hawaii is ever restructured should be addressed.

10) Whether utilities, subject to Commission review and approval, should be permitted to limit agreements to purchase variable and/or as-available energy, and to optimize their systems, to avoid a situation where unconstrained risk to ratepayers could exist.

11) How to incentivize developers of renewable energy projects to develop projects that will provide energy during periods that are less subject to curtailment, to take commercially reasonable steps to minimize their exposure to curtailment and to meet expected utility operational and reliability thresholds.

Attachment C
Alternative Generation Contract Structures For Optimal Investment and Operations

The power system can be operated reliably and economically, and renewable curtailment can be dealt with efficiently, only when the utility sees the true marginal cost of each generator. This requires contracts that are designed to provide both the utility and the IPP with correct economic signals. This paper briefly discusses generator fixed and variable costs for both utility and IPP investment and operations decisions.

Note that the contract discussion here is not addressing changes in the total compensation to the resource. Total compensation is the same in each alternative to facilitate comparison. Instead the discussion concerns how the generator is treated in the utility security constrained unit commitment and security constrained economic dispatch for optimal reliable and economic operation of the power system.

Three basic time frames are important when deciding what generation provides the lowest cost reliable supply for ratepayers: investment, unit commitment, and economic dispatch. These time frames are important when considering both utility and IPP owned generation. These time frames are important when considering all generation technologies including fossil fueled steam plants, combustion turbines, combined cycle, reciprocating engines, hydro, biomass, geothermal, solar, and wind.

Investment Decision: Project Viability

The project investors, the Public Utilities Commission, the rate payers, and the utility all have essentially the same concern when considering a new generation project: will the power produced be worth the total cost? If the total capital and operating costs divided by the total expected production result in an attractive $/MWH average total cost in relation to the cost of existing generation or alternative investments, also taking into account broader economic and social costs and benefits, then the proposed generator may be worth investing in.

Note that when considering an investment (IPP or utility) all costs are included in the decision. Capital cost and financing costs are important as are annual operating costs as well as fuel and maintenance costs.

Unit Commitment: Turning On a Generator

Fuel burning generators (fossil or biomass) typically cannot turn on and off instantaneously. Large coal fired steam plants on the mainland require days to be prepared for operations. Oil fired steam plants on the islands require hours to be brought on line. While some modern reciprocating engine driven generators can be started and fully loaded in minutes others require an hour or more to be brought on line. Combustion turbines and combined cycle plants are in the middle. Thermal plants also typically have minimum run times and minimum off times.

All of these temporal constraints complicate the power system operator's efforts to minimize the cost of operating the power system. In many regions operators use a security constrained unit commitment ("SCUC") tool to help determine what the lowest cost mix of generation will be to reliably serve the expected load over the next few days. This helps the system operator

decide which thermal generators to start up (commit). Once started (or not started) the system operator must live with the decision and operate the power system with the mix of generation that was selected for operation each hour.

Because wind and solar PV plants do not typically require hours to prepare for operations and they typically have no minimum run time or down time the unit commitment process affects variable renewable resources only because it determines what other generators must operate. On the other hand, wind and solar uncertainty complicate the decision of which conventional generators to commit.

Economic Dispatch: Operating the Power System

In real time the system operator in many regions selects the lowest cost available generators to supply energy, within the reliability constraints by using a security constrained economic dispatch (SCED) tool. Only the marginal costs are important in economic dispatch. On the mainland, for example, the full output of a nuclear plant will tend to be selected because while the capital cost may be high, turning down the nuclear plant does not save capital cost. The mortgage must be paid regardless of if the nuclear plant is used or not. It is only the nuclear plant fuel cost (~$8/MWH) that is important when deciding how much power to take from a specific generator in real-time. This is true regardless of who owns the nuclear plant, the utility or an IPP. Building the nuclear plant may or may not be a good economic decision but once built then operating the plant is the correct decision because the $8/MWH cost for the next MWH produced is typically lower cost than the MWH that are available from coal, combined cycle, or combustion turbine plants. Similarly, once a wind or solar plant is built the capital cost is sunk. Curtailing wind or solar does not reduce the fixed financing costs, so no money is actually saved when the plant is not operated. The most economically efficient operation of the power system results from dispatching the system based on true marginal production costs, within the limits imposed by reliability.

Demand Response and Storage

Demand response and storage can help reduce ratepayer costs, support reliability, and reduce variable renewable generation curtailment if included in the utility's marginal cost based economic dispatch by making more efficient use of all generators. Excess variable renewable generation can be utilized, variability and uncertainty can be mitigated, and peak loads can be reduced. Benefits must be compared with costs to determine which demand response and storage projects are economic.

Utility System Upgrade: Investment Decision

The utility may have the opportunity to invest in upgrading its transmission system or its generators to reduce variable renewable generation curtailment. This might involve upgrading a transmission facility that connects the renewable generation to load. Alternatively, it might involve lowering the minimum load capability or reducing the cycling cost of an existing fuel burning generator. The cost of any utility investment must be evaluated against the expected benefit. In this case the expected benefit is the reduction in fuel-consuming generation and the increase in renewable generation. Uncurtailing renewable generation brings environmental benefits, but it should also save ratepayers money, if the renewable generation contract is structured properly. Reducing the fuel burning generation saves fuel costs. There is no

corresponding increase in production costs from wind or solar generation when it is uncurtailed. Ratepayers capture the full benefit of investing in upgrading the utility power system, if the variable renewable generation contract reflects the marginal production cost of the renewable generator.

Hypothetical Generator: Renewables Investment and Operations

Consider an overly simplistic hypothetical proposed wind plant with the following characteristics[8]:

- 20 MW nameplate capacity
- $2,500/kW installed capital cost
- 50% expected annual wind availability (capacity factor)
- 5% expected curtailment for power system reasons
- 90% plant equipment availability
- 15% annual financing cost
- $1M annual operating and maintenance cost
- $2/MWH variable operating and maintenance cost
- $5/MWH integration cost

Investment Decision

Total plant cost is $50 million for this 20 MW wind plant. Financing, taxes, profit, etc require a 15% return, or $7.5 million/year to make the project viable. There is an additional $1 million/year in operating and maintenance costs. The plant is expected to produce 74,898 MWH per year based on the 20 MW plant rating, 50% wind capacity factor, 90% turbine availability, and an expected 5% curtailment due to power system conditions (minimum load, line maintenance, etc.).[9] This results in expected $113.49/MWH in fixed costs.[10] That is, the $113.49/MWH will be incurred once the decision is made to build the plant. Unlike fuel costs, the plant operator can't save any of the $8.5 million per year or $113.49/MWH by deciding to generate fewer MWH. These costs are sunk.

But there are additional costs too. There is an additional $2/MWH in variable O&M and the utility incurs $5/MWH in integration costs for the added regulation and reserves required to deal with the variability and uncertainty of the wind. The total additional cost for getting an additional MWH from this plant (if additional production is available) is $7/MWH. Similarly, the total savings available for reducing plant output is $7/MWH.

This results in a total expected cost of energy from this proposed wind plant of $120.49/MWH. If that average energy cost looks attractive compared with the average fuel cost of the existing generation fleet or compared with alternative new generation then it may be worthwhile for either the utility or an IPP to invest in the plant.

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[8] These are example numbers. Actual numbers for Hawaii will likely be different. The concept is the same regardless of the exact numbers.

[9] 74,898 MWH/yr = 20 MW * 8760 hr/yr * 90% turbine availability * 50% wind capacity factor * (100% - 5% expected system curtailment)

[10] $113.49/MWH = ($7.5 million/yr capital costs + $1.0 million/yr overhead and maintenance) / (74,898 MWH/yr)

Operating Decision: Lowest Cost Reliable Energy

The standard utility industry security constrained unit commitment and economic dispatch decision process selects the lowest cost reliable energy supply (including conventional generators and variable renewable generators) for current operations. Only marginal costs are considered because only marginal costs can be controlled in real-time. When the utility selects among its own generators, for example, it considers the fuel and variable O&M costs because the utility has to pay for additional fuel when it increases an existing generator's output. There is no additional capital cost. Similarly, the utility cannot reduce the mortgage payment for its own generators by running them less. The ratepayers pay the full mortgage and fixed costs even if the utility generator is seldom run.

If the hypothetical wind plant is built then the capital cost and annual operating costs are sunk. They must be paid by someone regardless of how much the plant operates. Only the $2/MWH variable O&M and the $5/MWH integration costs can be avoided by not running the wind plant. Similarly, if the wind is blowing it only costs $7/MWH to operate the wind plant. $7/MWH is the correct cost to put into the utility's security constrained unit commitment and economic dispatch program for finding the optimal, lowest cost, mix of generation to reliably supply energy in real-time. This is true if the utility invests in the wind plant or if an IPP invests in the wind plant. It is the total cost of energy supply for the rate payers that is being minimized with the SCUC/SCED.

Minimize Ratepayer Costs

Utility and IPP Similarities: Operating Costs

Regardless of generator ownership, capital costs are sunk once the investment decision is made. This is true regardless of the generation technology. The short-term operating decision that selects which generators should provide energy during the next hour should be made based on the true marginal production cost of each generator. If capital costs and additional costs are added to the decision process it raises costs for rate payers by selecting a less than optimal generation mix.

In the case of a combined cycle plant, for example, it is fuel and variable O&M costs that should be considered regardless of plant ownership. For the hypothetical wind plant discussed above, it is the $2/MWH variable O&M cost and the $5/MWH utility integration cost that should be considered.

Utility and IPP Differences: Risk

When the utility invests in a new generator it is the rate payers, not the utility that take essentially all of the risk. If the plant has higher maintenance expenses than forecast or lower availability than forecast the rate payers must still pay the full cost. One benefit of an IPP contract is that much of the risk can be moved from the ratepayers to the IPP investor. The IPP investor can take on the risk of the capital cost being higher than expected, the renewable resource being lower than expected, the plant availability being lower than expected, and the plant maintenance cost being higher than expected. The IPP can control all of these variables and the IPP is in the best position to take these risks. (Of course, there is always a cost associated with assigning risk to a 3rd party. Although the ratepayer is insulated from risks of significant deviations from the norm in an IPP contract, as with any insurance policy the cost of

energy from the IPP to the ratepayer is marginally higher for the 3rd party, IPP to take the "reasonable" risks.) These capital cost, maintenance, and resource availability risks can still be assigned to the IPP under this proposed contract structure.

Contract Structure

Because there are two types of costs it makes sense for contracts to be structured with two payment parts. This mirrors the utility treatment of its own generation where fuel and variable O&M are considered in the security constrained unit commitment and security constrained economic dispatch while the capital costs and long-term O&M are considered in the investment time frame.

MWH Hourly Energy Component

An IPP contract could be structured with a variable cost portion to cover the $2/MWH variable O&M for our example wind plant. (Note that the utility would add to this the $5/MWH of integration cost the utility incurs in additional reserves when the utility puts the variable cost into the SCUC/SCED.)

Monthly Component

The monthly payment would be negotiated to cover the capital, financing, tax, and longer term O&M expenses. It would be adjusted based on wind availability and plant forced outage rate. This results in the IPP assuming all of the risk for resource availability, plant maintenance, maintenance costs, etc. Our example plant might receive a monthly payment of:

Monthly $ = $1,574,074 * Actual Wind Capacity Factor * Actual Plant Availability[11]

If the wind has 50% availability as expected and the plant has 90% maintenance availability as expected then the plant receives $708,333 for the month.[12] If system related curtailment were also the expected 5% this would result in the equivalent of $113.49/MWH of wind energy. The IPP is responsible for all of the maintenance costs, financing costs, etc. regardless of how high they are, minimizing rate payer risk. Lower wind availability or worse plant maintenance results in lower payment to the IPP and no risk to the rate payer.

Note that the contract could be written capping the wind availability and/or the maintenance availability and thus limit the rate payer risk of higher costs if the wind resource or maintenance is better than expected. This could be reasonable since the IPP would not incur additional costs based on better wind.

What about Curtailment Risk?

Security constrained unit commitment and security constrained economic dispatch, the basic utility tools universally used to optimize utility operations, both start with the word "*security*". It is absolutely critical that the system operator have the authority to curtail any generator if that is required for system reliability. Especially on island systems with high

[11] $1,574,074 /month = [($7.5 million/yr capital costs + $1.0 million/yr overhead and maintenance) / (12 months/yr) / (90% expected turbine availability * 50% expected wind capacity factor)]

[12] $708,333/month = $1,574,074 /month * 90% actual turbine availability * 50% actual wind capacity factor

penetrations of wind and solar generation curtailment at some times is likely. Expected curtailment must be estimated before making an investment decision. In our example the utility estimates that the proposed wind plant will have 5% of its energy curtailed for system reliability reasons. The IPP, the utility, and the PUC need to factor the expected curtailment into the calculation to determine if this investment still makes sense. If the total cost of production ($120.49/MWH in this example) is not attractive then the utility should not sign the contract, the PUC should not approve the project, and the IPP should not make the investment.

Once the investment is made who should assume the risk of additional power system reliability-based curtailment? The IPP has no control over power system related curtailment so it is not logical to force the risk on the IPP. The IPP is arguably the most knowledgeable about wind conditions so it makes sense for the IPP to assume the wind availability risk. Similarly the IPP controls maintenance procedures so it makes sense for the IPP to assume the plant availability risk. But power system related curtailment depends on the utility choices for the rest of the generation fleet and is outside the control of the IPP. Thus it makes little sense to force the power system reliability-related curtailment risk onto the IPP.[13]

Why a Bundled $/MWH Contract Price Could Be Bad for Ratepayers

Contracts that use a single $/MWH price or an on-peak and off-peak price are economically inefficient when they result in selecting more expensive generation to operate than necessary. This would be bad for rate payers.

Existing contracts were not designed to work with real-time operating decisions. They were only designed to facilitate long-term average energy cost comparisons. If a current contract $/MWH price is used for operating decisions it could lead to incorrect, and expensive, choices. Our example wind plant has a long term average cost of $115.49/MWH with an additional $5/MWH integration cost for a total $120.49/MWH cost. If during a particular hour the utility had a generator available with a $100/MWH incremental fuel and variable O&M cost, then using the current wind contract price as the basis for dispatching the wind farm down and the utility plant up would result in the incorrect decision to obtain energy from the $100/MWH plant and curtail the $120.49/MWH wind plant. This is a bad decision because the true marginal cost of energy from the wind plant in this example treatment is $2/MWH in variable O&M plus $5/MWH in utility integration cost. Only $7/MWH is actually saved when the wind plant is not operated compared with $100/MWH that is saved if the fuel burning plant is not operated. Curtailing (dispatching down) the wind plant would result in a $93/MWH error that ratepayers will ultimately have to pay for in additional fuel costs.[14] The economically efficient solution is to have the contracts reflect the true marginal production cost. This will eliminate any misleading and inefficient economic incentives to curtail the renewable energy and provide maximum transparency in renewable energy compensation and utility system operation.

Conclusion

IPP contracts that reflect each generator's true marginal cost facilitate the lowest cost reliable operation of the power system. Rate payers can continue to be shielded from the risk of poor generator performance due to lower wind or solar availability or poor maintenance through the inclusion of appropriate contractual terms and conditions.

[13] This is not intended to be a complete discussion of the appropriate allocation of risks affecting an IPP's revenue stream.

[14] As noted earlier, however, the wind farm currently is essentially treated as a zero marginal cost resource in the utility's economic dispatch though not necessarily the unit commitment.

February 1, 2013

Consumer Advocate's Dissent to the MLC Paper Regarding Contractual Treatments for Curtailment of Variable Renewable IPPs

As has already been brought up by the Consumer Advocate in several discussions, regarding the MLC paper, Potential Contractual Treatments for Curtailment of Variable Renewable IPPs, evaluation of the reasonableness of contractual terms for purchase power agreements must be done in a comprehensive manner to avoid adverse impacts to the various stakeholders, the ratepayers, the State of Hawaii, independent power producers ("IPPs"), and the electric utilities. The Consumer Advocate appreciates that the paper attempts to address one of the Consumer Advocate's concerns by acknowledging that further investigation by the Commission is necessary to evaluate the potential alternative contract structures in a public process allowing all stakeholders to participate. Ultimately, the Consumer Advocate, however, was not able to support the paper for several reasons.

First, the paper asserts that ratepayer costs will be reduced as a result of the implementation of the potential alternative contract structures. Examples of such assertions include the following:

- *Page 1, paragraph 3*

  > Instead it focuses on the desired contract structure which will motivate the economic use of each generator and **therefore, we believe, will help ultimately reduce ratepayer costs**. It will also provide greater certainty to IPPs which should help reduce the perceived risks associated with contracts and therefore reduce financing costs. Given that, IPPs will be able to offer energy at lower costs and **that will benefit the ratepayer**.

- Page 2, paragraph 2

  > If the utility pays the marginal production cost for energy from all generators, it is able to optimize the economic operation of the power system **thus minimizing ratepayer costs while maintaining reliability**. Current contracts with energy prices based on factors other than the marginal production cost, such as contracts where the entire compensation is included in the energy payment, with some assumed level of curtailment, provide the utility with a distorted economic signal. If an incorrect energy price is used in economic decisions then those decisions will not be optimal and **ratepayers will pay more than they need to**. . .

- Page 3, paragraph 1

  However, the existing contract structure does not present the utility with the correct marginal production cost from variable renewable resources for determining which generators to run (security constrained unit commitment) and whether to modify or reconfigure utility systems. The marginal costs of curtailed as-available energy used in determining whether to modify or reconfigure utility systems are based on the energy prices in the existing as-available energy PPAs [(power purchase agreement)], because that is the cost to the utility and its customers of taking more energy from the existing as-available energy facilities. **This inherently results in an economically suboptimal decision process and ultimately higher costs to rate payers.**

The Consumer Advocate notes that it is premature to make such assertions, as no analysis has been conducted to support these statements and notes that the paper itself acknowledges that further Commission investigation is necessary related to the potential alternative contract structures. Whether cost savings to ratepayers will result from the potential alternative contract structures will depend on the details of such structures. Such details include, but are not limited to, what will be the fixed and marginal cost rates, how much will ratepayers be at risk to pay IPPs for curtailed energy, how much more will ratepayers pay existing IPPs for curtailed energy that is already included in their existing prices, how much have ratepayers already compensated existing IPPs for their existing generating resource, what measures (e.g., review of the IPP financial information, operating procedures, generating unit heat rates, material procurement process) will be available to regulators to ensure that these cost savings are realized.

The Consumer Advocate posed these types of questions as the recommendations in the paper were being developed without substantive or meaningful responses. The Consumer Advocate recognizes that these types of questions raise other issues (e.g., whether requiring such information from IPPs will be seen as a barrier and will result in IPPs investing their monies elsewhere) that may impact the State's goals of increasing the interconnection of renewable energy resources. However, as the paper is recommending a greater shift of risk to ratepayers in ensuring a greater level of comfort to IPPs in cost recovery or minimizing curtailment, additional provisions must be put in place to ensure that ratepayers are not harmed.

Furthermore, it has been unclear throughout the subgroup's discussions of the paper, how the potential alternative contractual structures will ultimately "minimize or ideally eliminate curtailment," as the cause of curtailment is not an economic issue.[1] As recognized by the paper, as-available energy PPAs are currently treated essentially as zero marginal cost resources in the utilities' economic dispatch, so these as-available

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[1] Consistent with the Public Utility Regulatory Policies Act ("PURPA"), the existing PPA contracts do not allow curtailment for economic reasons.

resources are considered "must take" and are taken before any of the fossil fuel units on an economic basis. The cause of curtailment, as was discussed early on in the RSWG process, is related to minimum load periods where there is excess generation on the system. Without properly addressing this technical issue, requiring additional resources to further investigate contractual matters is not consistent with the objectives of the RSWG process.

Thus, the Consumer Advocate opposes the Potential Contractual Treatments for Curtailment of Variable Renewable IPPs paper as a recommendation of the RSWG since its focus does not seem consistent with the intent of the RSWG process.

Docket No. 2011-0206 – Reliability Standards Working Group

Hawaiian Electric Companies' Dissenting Comments on the MLC Subgroup's Potential Contractual Treatments for Curtailment of Variable Renewable IPPs Paper

The Hawaiian Electric Companies appreciate the work of the MLC subgroup members, and particularly the drafters of the Potential Contractual Treatments for Curtailment of Variable Renewable IPPs paper ("Paper), to consider the written and verbal comments of all subgroup members and to reflect the comments that they felt they were able to include. From the Companies' perspective, the Paper has come a long way from the initial talking points presented for discussion. Certainly, with the limited edits proposed by the Companies to the most recent draft and some of the additional edits proposed by the authors, the Companies anticipated being in a position to vote in favor of the Paper.

However, while the Companies do not object to the majority of the revised Paper, due to the deletion of some of the issues which the Companies discussed and supported during the subgroup meetings, and the addition of certain modifications and statements, particularly in Attachment B, which could be interpreted to advocate in favor of wholly compensated curtailment versus presenting the issue for a conceptual discussion, the Companies were not able to vote in favor of the Paper during either the MLC subgroup meetings or at the RSWG meeting on January 24, 2013. The Companies notified the MLC subgroup that due to the fact that there was not sufficient time to continue to work on a consensus draft, the Companies would separately submit their limited comments to address areas of continuing concern.

The Companies respectfully submit for the Independent Facilitator's and Commission's consideration the limited but important modifications to the Paper that were not accepted by the subgroup as Attachment 1 to these comments. The Companies also submit for consideration and the record in this proceeding the Companies' comments on the Paper which were requested to be incorporated as a part of the subgroup Paper but which were not included (Attachment 2).

The Companies submit that these comments, which provide both specific language regarding the Companies' preferred version of the Paper as well as a discussion of the reasons why the Companies' positions are more consistent with the furtherance of increasing renewable use while maintaining grid reliability at a reasonable cost to customers. The Companies request that these comments together with attachments be submitted as a part of the work product sent to the Commission for the record and their deliberation as they evaluate the further steps necessary to address these important issues.

HAWAIIAN ELECTRIC COMPANIES' COMMENTS ON
POTENTIAL CONTRACTUAL TREATMENTS FOR CURTAILMENT OF VARIABLE RENEWABLE IPPS PAPER

The following provides the Hawaiian Electric Companies' comments to the paper entitled "Potential Contractual Treatments for Curtailment of Variable Renewable IPPs" ("Paper") dated January 7, 2013 that was presented and voted upon at the January 24, 2013 meeting of the RSWG.[1]

Consistent with the spirit in which the issue was raised by Zero Emissions Leasing LLC, the Companies remain open to discussing the issue of excess energy curtailment and contractual provisions related thereto. However, the Companies disagree with the primary focus of the Paper which is to look at ways to mitigate potential revenue losses to IPPs as a result of excess energy curtailment. The Companies believe that the proper scope of the inquiry should be to look at the relationship between the excess energy curtailment issue and the overall costs to customers. In addition to meeting the state's RPS goals, it is the Companies' objective to minimize costs to customers. Costs to customers are comprised of both payments to the IPPs and system impact costs. Both costs need to be taken into consideration when examining the issue of curtailment policies as further discussed below.

A. Background

Initially, the Paper was conceived as a concept document which would lay out the background regarding the issues, identify alternative contractual pricing approaches to curtailed energy due to excess energy conditions, identify potential benefits and detriments of the alternative treatments, and lay a foundation for future consideration of these issues. Over a period of several months, there was significant discussion regarding whether and to what extent the energy payment structure in existing as-available energy contracts affects the utilities' decisions to curtail the output of as-available energy facilities, or the amount of curtailed energy. This led to a discussion of and an exchange of papers and comments with respect to (1) the energy payment structures in existing as-available energy contracts, and the reasons for those structures, (2) the impact of pricing structures on economic efficiency, (3) the pros and cons of different payment structures from other perspectives (such as the risk transfers between project developers and utility customers inherent in different pricing structures, and the impact of different pricing structures on project financing costs), and (4) challenges arising out of changing the pricing structures in new as-available energy contracts, while retaining the pricing structures in existing as-available energy contracts. As discussed more fully in these comments, under existing as-available energy PPAs, the utilities pay the contract prices for energy delivered in accordance with the terms and conditions of the PPAs. In determining how to dispatch on-line generation (which includes all as-available energy facilities interconnected to the system), the as-available energy facilities

[1] The Hawaiian Electric Companies' comments on the Paper (as distributed on November 9, 2012) were originally transmitted to the Minimum Load and Curtailment Subgroup on November 21, 2012. The comments submitted in November have been revised to reflect the changes to the Paper made in the December 2012 – January 2013 period.

are treated as zero-marginal cost generating units, because the utilities generally must take their energy subject to the limited reasons for curtailment provided in the existing as-available energy PPAs.

From the Companies' perspective, the Paper has come a long way from the initial talking points presented for discussion, and any initial misunderstandings appear to have been resolved. Indeed, with the limited edits proposed by the Companies on January 4, 2013 to the subgroup's December 18, 2012 draft and some of the additional edits proposed by the authors of the subgroup draft, the Companies anticipated being in a position to vote in favor of the Paper during the final meeting of the MLC subgroup as well as during the January 24, 2013 RSWG meeting. While the Companies do not object to the majority of the revised paper presented to the subgroup on January 7, 2013, and to the RSWG on January 24, 2013, due to the deletion of some of the issues which the Companies discussed and supported during the subgroup meetings, and the addition of certain modifications and statements, particularly in Attachment B to the Paper, which could be interpreted to advocate in favor of wholly compensated curtailment versus presenting the issue for a conceptual discussion, the Companies were not able to vote in favor of the Paper. Unfortunately, there was not sufficient time to continue to work on a consensus draft, and the Companies therefore respectfully submit these comments to address these remaining items.

B. <u>The Paper</u>

In order to properly evaluate the issue of curtailment, it is critical to understand how the purchase of variable renewable energy is managed by the Companies today. The purchased power from IPPs is accepted according to the terms of the agreements and is not based on relative cost. This is unlike certain mainland jurisdictions where interconnections are under a market jurisdiction. Here in Hawaii, the Companies accept variable renewable generation as "must-take" energy today. All energy produced by the variable energy providers is accepted except when it is not feasible due to system constraints, regardless of the relative price of the energy: it is essentially treated as $0 MWh cost in the energy dispatch. As a result of the present policies which require purchase of all available variable energy except under system constraints (or other operational reasons for curtailment as set forth in the PPA, such as system emergencies, localized system maintenance or failure of the IPP to meet performance standards), changing the price of the variable renewable generation will have no impact on the amount of variable renewable generation utilized in the Companies' systems today nor will it do anything to minimize the number or length of curtailments. Taking into account these realities, it appears that a significant purpose of the Paper is to promote contractual provisions in power purchase agreements that guarantee a revenue stream for a developer. As stated above, the Companies do not believe that guaranteeing revenues to developers should be the scope of the issue addressed when considering excess energy curtailment policies unless such can be achieved with a commensurate reduction in risks to the ratepayers and utility which are incurred by the present agreements, which require purchase of the variable energy even when acceptance results in higher costs than if the energy were produced by other available resources.

Nonetheless, the Companies agree with the drafters of the Paper that integration of higher levels of renewable generation, particularly variable renewable resources, is a complex and challenging

task that will require a comprehensive evaluation of all potential impacts before decisions can be made. The Companies also agree that because potential options must be fully evaluated before implementation, specific recommendations as to any preferred option for addressing excess energy curtailment should not be made to the Commission. Rather, the RSWG should simply recommend that the Commission consider the issue of excess energy curtailment as a part of its deliberations moving forward. The Companies submit that any evaluation of these issues will require a separate process or proceeding involving affected stakeholders. A thorough analysis of the curtailment issue should include an assessment of options which increase the integration of renewable energy, lower overall cost to customers (including overall system costs for integrating renewables) and increase the reliability of the system. In this assessment the Companies believe that it is important to consider that renewable energy is provided by resources that are not variable but provide firm capacity which can be dispatched according to costs. Firm capacity renewable energy is in some cases already displaced by higher cost variable energy as a result of the existing "must-take" provisions for variable energy providers. Actions focused solely on reducing or minimizing existing or future excess energy curtailments, without consideration of other factors, could result in eliminating future opportunities for generation additions that could result in higher overall renewable energy, lower costs, and/or improved reliability.

Therefore, the Companies provide general comments in response to the Paper, a listing of the types of broader issues which will need to be addressed as a part of any comprehensive evaluation of excess energy curtailment, and an example of a potential alternative that was submitted as a part of Hawaiian Electric's recent RFP for as-available energy and which was referenced in part in the Paper.

C. General Comments

It must be understood that economic dispatch of as-available energy projects based on $/Mwh price is not generally the case as economic dispatch is not permitted under the Companies' power purchase contracts (except in unique "negative avoided cost" circumstances), as a result of PURPA and HRS §269-27.2. Perhaps more importantly, the utilities are already motivated to accept as much renewable generation as possible in order to meet RPS goals and currently accept energy as is feasible while maintaining reasonable costs and reliability. In light of this goal, the Companies have worked to reduce the constraints on the system that require curtailments of renewable energy for non-renewable sources. Accordingly, modifying the payment to existing or future "must-take" variable renewable energy facilities won't change how much energy the utilities accept from them.

One of the major reasons for curtailment presently occurs where the resource does not fit the demand on a particular system - i.e. facilities that produce significant energy, or even at their highest levels, when the demand is the lowest. To the greatest degree possible, ratepayers or shareholders should not be put in a position of having to pay for the development and installation of projects that do not provide needed services or which are ill-suited for the particular system into which the developer seeks to integrate. Moreover, it should be recognized that requiring utility shareholders to "pay" for curtailed energy necessitated by mandated contract provisions would be unlawful pursuant to Act 55 (2012).

While there appear to be several different options presented in the paper, the differences do not appear to be substantively significant, and effectively result in a "take or pay" type option. As one example, the Wholly Compensated Curtailment Provision and the Fixed Payment-Marginal Cost Dispatch Treatment described in the Paper, do not seem to differ very much from the perspective of what the utility would pay to a developer. Moreover, the Paper does not address in any detail the issues associated with changing the manner in which curtailment would be handled in new PPAs, while having to manage the curtailment considerations in existing PPAs. Finally, it is also of note that the Paper does not address reduction of purchases from dispatchable renewable energy providers. These resources are reduced to the minimum contractual purchase level (plus regulating reserve) in order to accommodate "must-take" variable renewable energy, even where the relative cost of the dispatchable renewable energy is lower than the variable renewable energy.

D. <u>Issues Which Must Be Discussed and Addressed</u>

There are a number of interrelated issues, some of which are mentioned in the Paper, which must be evaluated and addressed on a comprehensive basis as a part of any effort to modify the Companies' current curtailment procedures and processes. These include, but are not limited to, the following:

(1) Determination if there should be a shift in policy from electric utility customers paying only for energy received, to a policy of electric utility customers also paying for energy not received. Numerous as-available energy projects have been financed by experienced, qualified developers, pursuant to PPAs that contain the current provisions. The change in policy would result in a dramatic risk transfer from developers of renewable energy projects to electric utility customers. Moreover, developers of renewable energy projects would have less incentive to develop projects that will provide energy during periods that are less subject to curtailment, or to take commercially reasonable steps to minimize their exposure to curtailment.

(2) Addressing the fact that shifting the responsibility to pay for curtailed energy to customers is inconsistent with mandated acquisition requirements such as those contained in PURPA and the existing FIT program. Utilities, subject to Commission review and approval, should be permitted to limit agreements to purchase intermittent and/or as-available energy, and to optimize their systems, to avoid a situation where unconstrained risk to ratepayers could exist.

(3) Addressing the fact that costs incurred to modify components of utility systems to enable more intermittent energy to be accepted should ultimately benefit customers more than existing sellers of energy (with PPA prices based on the system "as-is" and with contracts that already account for estimated curtailment risk). System changes to minimize the need for curtailment under new contracts requiring payment for curtailed energy would primarily benefit sellers under existing contracts with curtailment priority, and could result in significant benefits (and potential windfalls) for those sellers.

(4) Addressing how such a different curtailment regime for new PPAs would mesh with obligations and curtailment priorities under existing PPAs, particularly given the limited ability of the utilities to modify existing contracts. This would include identification of modifications and/or additions that would be necessary to existing forms of utility power purchase agreements to be able to reasonably balance the increased risk for ratepayers. These would include provisions such as but not limited to: (1) the right to control energy output , and monitor equipment and resource availability to confirm the amounts of potential energy available from the new as-available energy facilities (and potentially existing as well), since new projects would be paid on the basis of energy made available, and not energy accepted; (2) a shortened contract term or lower "tail" prices, since project developers would essentially have paid for their projects on a limited risk basis during the financing term; (3) pre-PPA demonstration of energy availability including appropriate performance guarantees, energy availability commitments, and liquidated damages provisions to back up the commitments; (4) appropriate modifications to the form of pricing paid to the developer; (5) providing the utility a purchase option at the end of the contract term or otherwise providing for reduced pricing over time to account for the reduced risk to the developer; and (6) requiring verified cost information to ensure that any transfer of risk to customers is resulting in lower prices.

(5) Developing processes to address the difficulties in determining and confirming claimed amounts of curtailed energy.

(6) Identifying and evaluating any accounting and/or credit quality implications that may exist as a result of any change in curtailment practices and what the potential costs of such implications could be.

(7) Evaluating how any such change in curtailment policy could increase the potential for stranded costs (in the form of payment obligations under long-term contracts) if the energy market in Hawaii is ever restructured.

(8) Differing the reasons for curtailment which can occur due to conditions such as: (a) failure to meet performance standards, (b) excess energy conditions, (c) system-wide conditions, (d) localized system maintenance, and (e) transmission constraints.

(9) Addressing whether there are other alternatives that would mitigate the curtailment risk to developers of renewable energy projects and their financing parties without requiring electric utility customers to pay for curtailed energy.

(10) Addressing considerations for adding new as-available, variable energy projects and the corresponding impact on potential firm capacity, dispatchable renewable energy projects, including the following:

- Evaluating the impact of additional "must-take" as-available energy on opportunities to procure dispatchable renewable energy. If there is little remaining demand after being served by "must-take" as-available providers, there would be insufficient incentive for other types of renewable energy providers on the system which may offer greater potential to displace fossil generation (having similar characteristics to conventional generation). Further, changes in policies could potentially reduce purchases from existing and anticipated dispatchable renewable energy providers.

- Evaluating the impact of additional "must-take" as-available energy on the utility's ability to optimize production costs if lower-cost options become available in the future. Production cost can only be minimized for the portion of energy which is not served by must-take resources, which are accepted regardless of cost.

- Evaluating whether the new as-available, energy projects can provide ancillary services (such as have been agreed to in some recent as-available PPAs).

- Evaluating whether the development and application of grid standards and additional performance standards is required, which can facilitate the acceptance of additional as-available resources.

- Evaluating whether to require maintenance coordination between the renewable generating facilities and the utilities.

E. Alternative to "Take or Pay" Contracts

It is important to understand that "curtailment" only is an issue for as-available providers; renewable energy can also be supplied by providers who can control their source energy (i.e.; biofuel, biomass, and geothermal). Dispatchable firm-capacity projects are subject to control of the energy to meet utility demand. Where feasible, dispatchable renewable energy projects can offer the ability to procure renewable energy that can be made available to serve demand when needed, rather than having the energy being dependent upon the source resource being available. These types of renewable energy providers offer an alternative to some systems which may compete with as-available providers to serve demand.

For as-available providers, there are several alternative ways to address, via contract provisions, the potential economic risk to developers for curtailment due to excess energy. One alternative that is currently being offered by Hawaiian Electric in its new RFP for renewable energy is to allow developers to propose a tiered pricing structure in connection with the power purchase agreement and the ability to "bank" a certain amount of curtailed energy for later sale to the utility, as described below. The tiered pricing structure is intended to provide the developer with the ability to shift the recovery of fixed costs into the earlier tiers thereby allowing the developer to reduce the risk of fixed cost recovery and contribute to the financeability of the project.

The Term Sheet for Tiered Energy Pricing Alternative ("TEPA Term Sheet") sets forth the basic terms and conditions upon which Hawaiian Electric is prepared to negotiate a tiered energy pricing alternative ("TEPA") to the single tier pricing set forth in the Model PPA.

Below is a summary of the TEPA Term Sheet. The TEPA Term Sheet is included in the revised draft Request for Proposal for Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu posted on www.heco.com/renewableRFP on September 28, 2012.

Term Sheet for Tiered Energy Pricing Alternative:

- Offers tiered pricing structure as an alternative to the single pricing structure set forth in the Model PPA.

- The TEPA break points are set at 0-70%, 70-85% and 85-100%+ of Initial Annual Contract Energy (as defined in the Model PPA), with the price differential between any two adjacent tiers limited to 20%.

- Certain portions of the "Curtailed Energy" (as defined in the Model PPA) will be eligible for "banking," as more fully set forth in the TEPA Term Sheet. At a high-level, Curtailed Energy eligible for "banking" will consist of Curtailed Energy resulting from (i) outages on the Hawaiian Electric System unless such outages were caused by Seller's actions or inactions that were not in compliance with the PPA, (ii) Force Majeure affecting the Hawaiian Electric System unless such Force Majeure was caused by Seller's actions or inactions that were not in compliance with the PPA, and (iii) operating conditions on the Hawaiian Electric System (including Excess Energy).

- Such "Banked Curtailed Energy" will give the "Seller" under a TEPA modified PPA an option to extend the Initial Term of such PPA to provide the Seller with an opportunity to continue to sell electric energy to Hawaiian Electric.

- The length of such extended term will be proportionate to the amount of Banked Curtailed Energy but in no event will exceed two years.

- If, following the close of the third Contract Year and at the close of each Contract Year thereafter, there is no Contract Year among the three preceding Contract Years during which the sum of Actual Output plus the amount of both Curtailed Energy eligible for "banking" and energy that could not be generated due to certain force majeure events, equals at least 90% of the Initial Annual Contract Energy, then the amount of Banked Curtailed Energy will be zeroed out, banking will cease and the PPA will revert to flat energy pricing, as more fully set forth in the TEPA Term Sheet.

The purpose of TEPA is to mitigate some of the financial uncertainties faced by Sellers and Financing Parties due to possible curtailment of renewable generators under the Model PPA. Although TEPA will not eliminate such uncertainties, Hawaiian Electric would expect the risk mitigation available under TEPA to benefit rate payers in the form of lower energy pricing over the initial term of TEPA-modified PPAs. However, the risk to rate payers under a poorly structured TEPA is that the pricing tiers are too susceptible to "gaming" (e.g., underestimating the Initial Annual Contract Energy), such that

little of the Facility's output is actually sold at the lower priced tiers, thereby depriving rate payers of the benefit of lower energy pricing. Consequently, developers seeking to negotiate a TEPA modified PPA should be prepared to support their TEPA proposals (including modifications to the TEPA Term Sheet) in terms of (i) risk mitigation to Seller, (ii) lower energy pricing to rate payers and (iii) disincentive to "gaming." Each developer who desires to include TEPA in its PPA will, at a minimum, be required to make available to Hawaiian Electric, both as part of the negotiation process as well as during the Initial Term of the PPA, the same information concerning the projected output of its Facility as is made available to its Financing Parties. In addition to facilitating the negotiation of TEPA-modified PPAs, such information will facilitate the process of obtaining PUC approval of such PPAs.

F. Other Considerations

The curtailment provisions in the existing as-available energy PPAs reflect the energy procurement policies embedded in the Public Utilities Policy Act of 1978 ("PURPA"), the regulations of FERC implementing PURPA, the prior versions of the Hawaii law (H.R.S. § 269-27.2) encouraging PPAs with "nonfossil fuel producers" (which was first enacted in 1977), and Hawaii PUC rules based on the foregoing provisions.

In general, as a result of PURPA and H.R.S. §269-27.2, an electric utility in Hawaii was obligated to offer to purchase energy and capacity from QFs or non-fossil fuel producers at rates based on avoided costs, and to offer to interconnect with such QFs or non-fossil fuel producers at their costs. At the same time, an electric utility was not obligated to purchase energy or capacity from a QF where purchasing energy or capacity from a generating facility would conflict with a utility's obligation to provide reliable and adequate electric service. In situations where a QF seeks to have a utility purchase more energy or capacity than the utility requires to meet its total system load, the utility is only obligated to pay for energy or capacity that the utility can use to meet its total system load. The FERC Preamble on electric utility obligations under 18 C.F.R. § 292.303, Order No. 69, 45 Fed. Reg. 12214, 12219 (1980) ("FERC Commentary") provides in relevant part:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules imply no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.

The curtailment provisions take into account the small, isolated island systems that are accepting the energy, and numerous as-available energy projects have been financed by experienced, qualified developers, pursuant to PPAs that contain these provisions. The revenue stream that can reasonably be expected from projects selling energy under such PPAs is a function of the amount of energy that can be generated, less the energy that may be curtailed, times the price for the net energy delivered. The prices for energy generated in Hawaii tend to be higher than the prices available elsewhere, which has compensated developers for any incremental curtailment risk they may assume.

The curtailment provisions do not permit Hawaiian Electric to require as-available resources to curtail, interrupt or reduce deliveries of electric energy based on Hawaiian Electric's economic dispatch. In addition, the Model PPA requires Hawaiian Electric to take all reasonable steps (such as reducing the output of Base Load Units, including its own Base Load Units, during light loading conditions, taking into consideration factors such as the need to maintain the reliability and stability of the Hawaiian Electric System under changing system conditions and configurations, the need to operate must-run units above their minimum loading levels in non-economic dispatch and periodically commit cycling units for operational purposes, the need for downward regulating reserves, the terms and conditions of power purchase agreements for firm capacity Base Load Units or scheduled electric energy, and the normal minimum loading levels of such units) to minimize the number and duration of curtailments, interruptions or reductions.

If the curtailment policies in the as-available energy PPAs are modified to reflect a "take or pay" policy, the utility (in effect) would be paying for capacity (i.e., capability), instead of energy, and all of the terms and conditions of the standard as-available energy contract would have to be reviewed and modified to reflect that change.

As a result of the mandated procurement policies pursuant to which existing PPAs were developed, as-available energy PPAs typically have the following characteristics:

- Utility acquires right to purchase output when available, and renewable energy attributes
- Obligation to purchase energy made available, with no economic dispatch
- Limited curtailment rights for system or performance reasons
- Curtailment priority is contractually dictated
- Developer controls site selection, equipment selection, array design, financing selection
- Output varies from moment to moment, from hour to hour and from year to year
- Resource and cost structure have generally been deemed proprietary (with exceptions tied to exemptions, waivers from competitive bidding)
- 20-year contracts, generally with no price step down when financing is repaid, or at end of term
- Pay for energy as the energy is delivered, as there is no obligation to make the energy available
- Price varies based on short-term avoided energy costs (or, more recently, is fixed with or without escalation)

In contrast, firm capacity PPAs typically have the following characteristics:

- Performance Guarantees (output capability, availability, ancillary services, ramp rates, etc.)
- LDs, Engineering Reviews, Events of Default to back up performance guarantees
- Contractual maintenance outages, with utility review and approval of changes

- Design and Construction Review
- Dispatch Control, subject to facility's inherent operating parameters
- Cost must be less than utility alternative
- Acquired only as needed
- Step-in rights, purchase options, rights of first refusal, etc.
- Pricing provisions may be tailored to facility cost structure

The only valid reason for transferring curtailment risk to customers is to reduce the overall cost of purchased energy to customers. Thus, customers need to be assured that the project developers' lower risk and cost of financing will be passed through in their energy payment rates. That may require that developers provide verified cost information as a quid pro quo. Any such change also should be predicated on a change in the manner in which energy is procured, so that the utility does not have to acquire more intermittent energy than its system can reasonably accommodate, and project developers price their projects at truly competitive prices.

The KWP II PPA on Maui provides an example of why the risk transfer provisions in the PPA (including the curtailment provisions) must be tailored to the market structure under which the PPAs are made, and the electricity system to which the energy will be delivered.

KWP II contended that the Maui system could somehow accommodate the energy supplied from the existing KWP I wind farm (30 MW), the planned Auwahi wind farm (21 MW) and its planned KWP II wind farm (21 MW), and that MECO was obligated to negotiate a PPA for the entire 21 MW wind farm. A very detailed GE wind integration study determined that the KWP II wind farm would have to be substantially curtailed if it were added to the system, even if several innovative operational measures could be implemented to accommodate more of its output. This outcome was hardly surprising given the minimum system load for the Maui system is on the order of 85 MW. KWP II made a business decision to proceed anyway, knowing that much of its output would be curtailed, perhaps because wind turbine generators had already been delivered to Maui.

From a planning perspective, it did not make sense to add another 21 MW wind farm. From a risk transfer perspective, it would have been imprudent and irrational for MECO, on behalf of Maui customers, to accept the obligation to pay for curtailed energy from the KWP II facility. However, the final negotiated arrangement, under which KWP II accepted responsibility for providing certain ancillary services using a Battery Energy Storage System (BESS) sized for that purpose, agreed to be curtailed during excess energy situations, and accepted the risk that the electricity "market" on Maui may not grow as much as expected, does make sense for Maui customers. Moreover, the tiered pricing structure in the KWP II PPA creates the possibility of a win-win situation in the future if the Maui system can accommodate more of the KWP II output in the future than was estimated.

The best way to reduce costs to consumer probably is to change the way energy is procured. When considering cost-effective energy options for customers in Hawaii, the following need to be discussed and considered:

- Provide a competitive procurement option for renewable energy projects designed to lower costs to consumers, create a competitive renewable energy market in Hawaii, and provide better value to customers.

- Evaluate competing renewable energy projects on the basis of overall value including favorable characteristics allowing displacement of conventional fossil plants, or negative impacts requiring additional support services from the power system. (i.e., dispatchable, firm capacity, frequency responsive vs. non-dispatchable, variable, causes imbalance).

- Develop a flexible procurement mechanism to identify the competitive market price for renewable energy in Hawaii and to take advantage of market opportunities as they arise.

- Provide a regularly scheduled and timely process for bidders to compete to sell renewable power in Hawaii and to provide opportunities for project developers to continue to develop their projects through proper market signals.

- Assist HECO, MECO and HELCO to meet RPS targets in a systematic and orderly manner in conformance with electric system expansion requirements.

- Develop a process designed to reduce transaction costs for developers and the utility.

- Consider the unique constraints of Hawaii in the development of procurement mechanisms, which are the result of the State's isolation, such as:

    - Limited market
    - No ability to import/export energy
    - Existing levels of variable/renewable energy

Procurement mechanisms in other states have resulted in cost effective renewable savings for the customers. For example:

- In California, the utilities participate in the Renewable Auction Mechanism (RAM) solicitation program mandated by the California Public Utilities Commission (CPUC). The program has resulted in selection of variable renewable generation projects (2-20MW in size) that resulted in PPAs at $0.089 per KWh. The success in the program's ability to achieve cost effective energy for their customers can be attributed to the following:

    - Shorter solicitation process (approximately 6 months)
    - Standard PPA contract
    - 30 day regulatory approval for the PPA

- In Arizona, Arizona Public Service (APS) conducts periodic Small Generation RFPs for variable renewable generation project (2-15MW in size). APS' solicitation was able sign PPAs from the solicitations well below $0.13 per KWh. The success in APS' program's ability to achieve cost effective energy for their customers can be attributed to the following:

    - Shorter solicitation process (approximately 6 months)

- Maximum Bid Price requirement that was set at $0.13 per KWh
- Minimal regulatory oversight for the PPA

G. Summary

In conclusion, the Companies reiterate that any evaluation of these issues will require a separate process or proceeding involving affected stakeholders. A thorough analysis of the curtailment issue should include an assessment of options which increase the integration of renewable energy, lower overall cost to customers (including overall system costs for integrating renewables) and increase the reliability of the system.

MLC Draft HECO MARK-UP December 26, 2012

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Potential Contractual Treatments for Curtailment of Variable Renewable IPPs

Introduction and Summary

Increasing the use of renewable energy resources ("renewable resources") to generate electricity for our island grids is a broadly-accepted goal as we seek to achieve our clean energy future in Hawaii. It is also broadly recognized that integrating higher levels of renewable resources, and especially variable renewable resources, is a complex, challenging task for our island utilities. To date, the RSWG has focused its efforts on identifying technical integration issues and searching for viable solutions. Two issues which should be evaluated as a part of this integration discussion are: (1) how can contracts with energy providers better reflect a generator's marginal production cost to enable the utility to economically optimize the reliable operation of the power system and minimize ratepayer costs; and (2) what can be done to minimize or eliminate curtailment, not just now, but as we increase penetration and utilization of these resources?

There was a discussion in the subgroup as to whether and to what extent the energy payment structure in existing as-available energy contracts affects the utilities' decisions to curtail the output of as-available energy facilities, or the amount of curtailed energy. This led to a discussion of and an exchange of whitepapers and comments with respect to (1) the energy payment structures in existing as-available energy contracts, and the reasons for those structures, (2) the impact of pricing structures on economic efficiency, (3) the pros and cons of different payment structures from other perspectives (such as the risk transfers between project developers and utility customers inherent in different pricing structures, and the impact of different pricing structures on project financing costs), and (4) challenges arising out of changing the pricing structures in new as-available energy contracts, while retaining the pricing structures in existing as-available energy contracts.

Objectives and Scope

Maximizing the economically efficient use of each generator (utility and IPP) should be an objective of the contract structure with independent power producers ("IPP"). {The overall objective of such contracts should be to obtain reliable power (energy, capacity, and/or ancillary services) and renewable attributes at the lowest reasonable cost on a risk-adjusted basis.[1]} The scope of this paper is limited to identifying potential contractual treatments which can assist in providing the correct economic signals to facilitate increased use of renewable energy while also considering potential impacts to utility ratepayers and shareholders. Issues will be identified, but specific recommendations will not be made as to a preferred treatment. This paper also does not address all of the complications associated with seeking to modify existing IPP contracts, or make specific recommendations for revisions to existing contracts. Instead it focuses on the desired contract structure which will motivate the economic use of each generator and therefore, we believe, will help ultimately reduce ratepayer costs. It will also provide greater certainty to IPPs which should help reduce the perceived risks associated with

[1] Costs to customers are comprised of both payments to the IPPs and system impact costs. Both costs need to be taken into consideration when examining the issue of curtailment policies.

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contracts and therefore reduce financing costs. Given that, IPPs will be able to offer energy at lower costs and that will benefit the ratepayer. The principles discussed in this paper apply to all generation technologies, but the paper focuses on variable renewable generation and especially on how curtailment of variable renewable generation is treated.

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The RSWG recommends that the PUC investigate potential alternative contract structures in a public process, open to all stakeholders.

Key Issues

One fundamental principle expressed in this paper is the concept that the utility should be exposed to each generator's actual marginal production cost for energy. If the utility pays the marginal production cost for energy from all generators, it is able to optimize the economic operation of the power system thus minimizing ratepayer costs while maintaining reliability. Current contracts with energy prices based on factors other than the marginal production cost, such as contracts where the entire compensation is included in the energy payment, with some assumed level of curtailment, provide the utility with a distorted economic signal. If an incorrect energy price is used in economic decisions then those decisions will not be optimal and ratepayers will pay more than they need to:

- If the incorrect energy/marginal price was used in the utility's hourly operational economic dispatch,[2] the result could be an inefficient and more expensive dispatch of the generation fleet.
- If the incorrect energy price is used in deciding which generators to operate or to cycle off overnight (unit commitment), then a more expensive set of generators than is necessary may be operated at times.
- If the incorrect energy price is used in deciding on transmission system upgrades, then opportunities that might alleviate or reduce curtailment and reduce costs may be missed.
- Similarly, if the incorrect energy price is used when deciding on investments to increase the flexibility of the fuel consuming dispatchable generation fleet (reduced minimum loads, reduced cycling costs, etc.) that might alleviate curtailment, opportunities to reduce system costs and reduce curtailment may be missed.

Existing Contracts

Under existing as-available renewable energy PPAs, the utilities pay the contract prices for energy delivered in accordance with the terms and conditions of the PPAs, but do not pay for curtailed energy. Accordingly the prices represent the Companies' marginal costs of acquiring more energy from the facilities. The contract price is not the actual marginal production cost for energy from the renewable generator and thus cannot be used to optimally commit and dispatch the generation fleet. Existing contracts partially get around this limitation by requiring as-available energy facilities to be treated as must-take energy subject to the limited reasons for curtailment provided in the existing as-available energy PPAs. Hence as-available energy PPAs

[2] Economic dispatch is the short-term determination of the optimal output of a number of electricity generation facilities, to meet the system load, at the lowest possible cost, while serving power to the public in a robust and reliable manner (Wikipedia). Utilities around the world, and on the islands, use the marginal energy production cost of the utility owned generation and the contract price from non-renewable IPPs when economically dispatching the power system, typically hourly or more frequently. Existing wind generation contracts explicitly exclude wind generation from economic dispatch in Hawaii (Note that the contract structures described in this paper are used for these non-renewable IPPs) Consequently, no effort was made to design wind generation contracts to reflect the marginal production cost and enable them to be incorporated in the utilities' economic dispatch.

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are essentially treated correctly as zero marginal cost resources in the utilities' economic dispatch

However, the existing contract structure does not present the utility with the correct marginal production cost from variable renewable resources for determining which generators to run after must-run and must-take resources are committed (unit commitment) and whether to modify or reconfigure utility systems. The marginal costs of curtailed as-available energy used in determining whether to modify or reconfigure utility systems are based on the energy prices in the existing as-available energy PPAs, because that is the cost to the utility and its customers of taking more energy from the existing as-available energy facilities. This inherently results in an economically suboptimal decision process and ultimately higher costs to rate payers.

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Curtailment

In crafting solutions to maximize the acceptance of renewable energy on the utility systems, it is important to understand the reasons for the current levels of curtailment of both variable and dispatchable renewables and how these curtailments may change in the future.[3] Curtailment of variable renewable resources along with other generation or demand-side resources is needed at certain times, such as when there are system emergencies and when there is generation in excess of load on the grid. These types of curtailment allow the system operator to maintain reliability in the existing grids. The ability to manage excess energy through curtailment of renewable energy is of particular significance in island systems, as there is no means to export excess energy.

If the objective was only to minimize or avoid curtailment, rather than to maximize the use of renewable generation and minimize the use of fossil fueled generation, renewable energy would have been restricted to the amount the system could accept during typical minimum demand periods. With the ability to curtail renewable energy to match demand, larger amounts of renewable energy were installed, understanding that they would be curtailed during minimum demand periods, but that they would be able to increase production during higher demand periods. The result is a larger amount of renewable energy purchased than would be possible had the capacity of connected renewable energy been restricted to the level where excess energy curtailments were avoided or minimized.

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On the other hand, curtailment is a reduction in the amount of energy delivered. The impact of curtailment (on the generator, ratepayers and on society) differs depending on the type of generator being curtailed. Dispatchable renewable generators and fossil fuel burning generators save the fuel when curtailed and can use that fuel to generate electricity at a later time when it is needed. Variable renewable generators are not able to save the "fuel" so the production opportunity is lost forever. Similarly, dispatchable renewable generators and conventional fossil fueled generators have a higher (typically much higher) marginal production cost than the near zero marginal production cost of variable renewables. The marginal production cost of dispatchable generators is saved when they are curtailed. There is no marginal production cost savings when variable renewable generators are curtailed.

[3] Dispatchable resources have their output controlled by the utility at all times to balance supply and demand, to reflect system constraints and to reflect the economics of the system at time of dispatch. Variable renewables can be dispatched down under utility operator control for the same reasons but cannot be dispatched up above the power level currently being provided by the wind or sun.

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It is recognized that as the amount of renewable resources is increased in the islands, due to the limited demand, there will be an increasing number of instances where there is insufficient demand to accept all available renewable energy and therefore some renewable energy will result in displacement or curtailment of other renewables. This happens regularly on the Big Island where dispatchable renewable energy is reduced in order to accept maximum amounts of variable renewable energy. While dispatchable renewable generation is preferable precisely because it is dispatchable, it also typically has a marginal production cost that is greater than (often significantly greater than) the near zero marginal production cost of wind and solar variable renewable generation.[4] So while both dispatchable and variable renewable generation are renewable, it is still often preferable to utilize the maximum amount of variable renewable generation, in keeping with the standard utility practice of security constrained unit commitment and economic dispatch.

Importantly, while potential solutions are being examined to reduce or eliminate curtailment, it may or may not be possible to eliminate curtailment in certain situations, or to do so may come at an unacceptable cost. There are also concerns about the impacts of curtailment when it cannot be eliminated. These impacts can affect not just renewable IPPs, but also the utility and its ratepayers and shareholders. Therefore, as investigations continue in succeeding proceedings to examine the issue of curtailment, it is also important to examine ways to mitigate curtailment impacts on all of these stakeholders. The RSWG has tendered to the PUC a curtailment analysis for both the HELCO and MECO systems that contained recommendations as to mitigation measures to reduce or eliminate curtailment. Subsequently, these analyses initiated a further study by the HECO Companies to assess cycling impacts of existing fossil generation.

The detailed implementation of each alternative contract structure must result in essentially the same power system reliability. This requirement and assumption will not be repeated throughout the paper though it should be understood to apply

Guiding Principles

Contracts with energy prices based on a generator's marginal production cost are critical for enabling the utility to economically optimize the reliable operation of the power system and minimizing ratepayer costs. If the utility passes the marginal price signal on to demand response and storage resources, that will enable them to make productive use of excess wind and solar energy

Total costs must be considered when deciding on new generation investments; utility owned or IPP, renewable or fossil based, variable or dispatchable. But once an investment is made and a generator is operational, then it is the marginal production cost that is important for optimizing the power system, not the sunk fixed costs.

The RSWG recognizes that maintaining reliability is a fundamental principal for all power system planning and operations That assumption and understanding should be taken into consideration in addressing curtailment mitigation contractually on a going forward basis.[5]

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[4] Wind and solar variable renewable generation do not have near zero marginal cost from a system cost perspective. They may require ancillary services, which have a cost associated with them.

[5] Curtailment may be implemented for a number of reasons. The focus of the paper is on curtailment due to excess energy conditions.

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It also should be noted that some of the benefits of changing the contract structure cannot be achieved unless the contract structure in existing contracts also is changed, and that the contract structure in existing contracts cannot be unilaterally changed.

Presentation and Brief Discussion

The following is a description of potential contractual treatments starting with the historical treatment of variable generation IPPs and ending with an alternative generation contract structure based on a marginal production cost compensation for energy coupled with a modified fixed payment to cover capital and fixed costs (Attachment C) that facilitates optimal investment and operations.

Historical Treatment ("Baseline")

Historically, the utility provides a developer with information about the power system such as operating practices, constraints (including other renewable energy constraints) and anticipated system demand. From this information, the developer makes its determination as to the amount of energy that could be delivered to the utility. Projects historically were treated as must-take, and therefore all energy would be purchased except under curtailment conditions The difference between the amount of the developer's estimated energy production and the developer's estimated energy delivery to the utility was the developer's expected curtailment of the project. Upon signing a PPA, the developer agrees to assume the risk for all curtailments upon commercial operation of the facility that are in accordance with PPA terms. In the PPA, hours of curtailment are not capped, but are restricted to only non-economic curtailment, i.e. the energy was accepted except when the system is constrained or when there are emergency contingencies Note: the utility and its ratepayers and shareholders do not share any of the curtailment risk (although they may end up paying for it through higher accepted PPA prices).

If actual curtailments are within the amounts projected by the developer, based on the utility supplied information, the owner/operator should not be under any financial stress on account of the curtailments. However, if the curtailments are higher, this will put financial stress on the variable renewable IPP. Looking forward, future developers and their investors may view the risk of uncapped levels of curtailment as too high, and projects may be more difficult to finance and/or bear a risk premium.

It is important to note that there are actually already several types of "avoided cost payments," including:

(i) the conventional avoided energy costs payments which are updated monthly, and which can go up and down, (the Commission has discouraged the use of this payment structure going forward and has recommended the utility re-negotiate existing contracts),

(ii) a modified, avoided cost payment based on a "rolling average" over a longer period (e.g., one or more years, which typically softens the typical payment volatility associated with the price of oil),

(iii) a hybrid avoided and levelized cost payment,

(iv) straight levelized payment, and

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(v) potentially a real time avoided cost rate which takes into account regulation, and other ancillary services which may be required to integrate the variable renewable energy.

Arguably, the risk to ratepayers may be less in (ii) compared to (i), in (iii) compared to (ii), and so on.

Tiered-Energy Payment Alternative (adapted from HECO's RFP)

As an alternative to the Baseline treatment, HECO's 200 MW RFP includes a tiered-energy pricing alternative or "TEPA" to replace a straight levelized payment. For example, there would be three tiers, where the energy payments differ for each of the three tranches of energy delivery. Specifically, the payment rate would be highest for the first tier and its tranche of 70% of the total energy delivery; the payment for the "second" tier would be lower (but not more than 20% lower than for the first tier) for up to 15% of the total energy delivery; and the price of "third" tier would the lowest for up to 15% of the total energy delivery. Bidders on the RFP are allowed to propose a specific TEPA, including degradation factors moving forward from Year 1 of a proposed PPA to Year 20. In addition, HECO will "bank" the amount of curtailment over the contract period, and offer the IPP the option of extending the contract period by the number of days necessary to deliver the amount of banked curtailed energy See Attachment A from HECO for more details of this treatment.

As an alternative to the Baseline treatment, the TEPA requires further discussion. For example, there are concerns expressed in the RFP about the possibly of "gaming" by bidders in their proposed TEPAs, and HECO will therefore look closely at how the proposals: (i) will mitigate risks to the Seller, (ii) provide lower energy pricing to ratepayers, and (iii) avoid gaming. There are also questions as to whether this approach will appear to bidders as lower risk than a straight, levelized payment, as it may appear to add another layer of uncertainty to the basic curtailment uncertainty or it may appear to the bidders as a way to ensure a known amount of total revenue for the project by using the banked curtailment provision. Thus, the major question appears to be whether the risk profiles differ from the Baseline treatment, and if so, by how much? Note: When financing projects, the financial institutions will assume the most conservative, least risk case which will result in high cost of financing and ultimately higher cost of energy to ratepayers

Take or Pay Treatment (Wholly Compensated Curtailment Provision) - By Ratepayers

An alternative to the "Baseline" treatment is "Take or Pay " Specifically, a PPA with a variable renewable IPP would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered but for curtailment. For the IPP this treatment will ensure revenues when the IPP delivers electricity or when curtailed during periods when the project could have exported power to the utility. In this treatment, the risk for the curtailed energy is shifted to the ratepayer. See Attachment B [Take or Pay Treatment (Wholly compensated curtailment)] for a detailed discussion of the "Pros" and "Cons" of "Take or Pay."

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As an alternative to the Baseline treatment, this treatment option requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the renewable electricity that is provided to the grid and other considerations. It

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would also be important to develop specific means to calculate and verify the actual amounts of any "curtailed energy" and additional record keeping and reporting would also be required.

Take or Pay Treatment - Variant 1 - Payment for Curtailment above Threshold (Based on the KIUC Model)

An alternative to the "Baseline" treatment is a variant to "Take or Pay". Specifically, a PPA with a variable renewable IPP would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered above a threshold level of curtailment specified as a number of hours per year. For the IPP this treatment would ensure revenues when the IPP delivers electricity or when curtailed above the curtailment "threshold". Compared to the "Take or Pay", the risk for curtailment in Variant 1 is shared between the IPP and the ratepayers.

As a Variant to the "Take or Pay," this treatment requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the additional renewable electricity that is provided to the grid and other considerations. Specific means must be identified for calculation and verification of the actual amount of the "curtailed hours" and additional record keeping and reporting would be required.

Fixed Payment-Marginal Cost Dispatch Treatment

Another alternative to the "Baseline" treatment is "Fixed Payment-Marginal Cost Dispatch." Specifically, a PPA with a renewable IPP would include provisions to compensate the IPP based on fixed-payments to cover capital costs and fixed-operating costs and energy-payments based on the IPP's marginal operating costs (variable O&M) Basically, from a financial perspective, renewable resources would be treated the same as utility owned generators. Given that, it would be economically efficient if all generators could be economically dispatched based on their marginal production costs and system cost impacts [6] For example, since the marginal production costs of variable renewable resources would likely be lower compared to other generators (including costs associated with accommodating the variability and uncertainty of the renewable resources), variable renewable resources would likely be dispatched whenever they are available to provide energy to the grid. Clearly, the utility would be motivated to accept as much of the variable generation as possible for economic reasons and in order to meet its RPS. And when the system operator needs to curtail variable generators, the variable generation IPPs would not be financially harmed. Thus, there is no need to pay for curtailment. Meanwhile, there is little or no risk to the utility, its ratepayers and shareholders with this type of treatment.

The risk to the utility ratepayers with this type of treatment is the split between fixed payment and energy payment. The utility will pay for non-firm fuel-saving renewable energy capability through the contract mechanism which fairly addresses the availability of the variable generators and the adequacy of the resource over the life of the project The terms and conditions of a "fixed payment marginal cost dispatch" PPA are substantially different from the terms and conditions of an "as-available energy" PPA. In addition to payment terms, all of the terms and conditions of the contract would have to be modified. It will be essential that

[6] In an ideal, economically-efficient system, all generation resources would be dispatchable. Dispatch of generation resources would be based on their marginal production costs, and other marginal system costs

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incentives be built into the contractual proposal to ensure that equipment is maintained and operating so that it is available to provide the low-cost energy. If the equipment is not made available then the fixed compensation should be reduced, or sanctions applied.[7] In addition, there is concern about how this treatment would affect the utility's financial integrity and cost of capital (and, thus, it's overall cost of service). See Attachment C (Alternative Generation Contract Structures for Optimal Investment and Operations) for discussion of this treatment.

Given that this treatment is a departure from the Baseline treatment, further discussion is required.

Conclusions

The RSWG did not reach consensus concerning what variable renewable generation IPP contract structure to recommend to the PUC for either new or existing contracts. Instead, this paper examines concerns with the existing practice along with several alternatives. The RSWG recommends that the PUC investigate potential alternative contract structures in a public process, open to all stakeholders.

[7] Interestingly, while we recommend considering linking the IPP's fixed payment to equipment availability and the IPP's ability to maintain its generators the same linkage is not applied to utility generators which ratepayers must pay for regardless of their maintenance condition or performance.

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Attachment A
HECO Comments on an Alternative to a "Take or Pay" Contract – the Tiered-Energy Purchase Agreement

It is important to understand that "curtailment" **is an issue for all generators, but particularly** for as-available providers. Renewable energy can also be supplied by providers who can control their source energy (i.e.; biofuel, biomass, and geothermal). Dispatchable firm-capacity projects are subject to control of the energy to meet utility demand. Where feasible, dispatchable renewable energy projects can offer the ability to procure renewable energy that can be made available to serve demand when needed, rather than having the energy being dependent upon the source resource being available. These types of renewable energy providers offer an alternative to some systems which may compete with as-available providers to serve demand.

For as-available providers, there are several alternative ways to address this issue. One alternative that is currently being offered by Hawaiian Electric in its new RFP for renewable energy is to allow developers to propose a tiered pricing structure in connection with the power purchase agreement and the ability to "bank" a certain amount of curtailed energy for later sale to the utility, as described below. The tiered pricing structure is intended to provide the developer with the ability to shift the recovery of fixed costs into the earlier tiers thereby allowing the developer to reduce the risk of fixed cost recovery and contribute to the financeability of the project

The Term Sheet for Tiered Energy Pricing Alternative ("TEPA Term Sheet") sets forth the basic terms and conditions upon which Hawaiian Electric is prepared to negotiate a tiered energy pricing alternative ("TEPA") to the single tier pricing set forth in the Model PPA. Below is a summary of the TEPA Term Sheet. The TEPA Term Sheet is included in the revised draft Request for Proposal for Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu posted on www.heco.com/renewableRFP on September 28, 2012 as follows.

Term Sheet for Tiered Energy Pricing Alternative:

- Offers tiered pricing structure as an alternative to the single pricing structure set forth in the Model PPA.
- The TEPA break points are set at 0-70%, 70-85% and 85-100%+ of Initial Annual Contract Energy (as defined in the Model PPA), with the price differential between any two adjacent tiers limited to 20%
- Certain portions of the "Curtailed Energy" (as defined in the Model PPA) will be eligible for "banking," as more fully set forth in the TEPA Term Sheet At a high-level, Curtailed Energy eligible for "banking" will consist of Curtailed Energy resulting from (i) outages on the Hawaiian Electric System unless such outages were caused by Seller's actions or inactions that were not in compliance with the PPA, (ii) Force Majeure affecting the Hawaiian Electric System unless such Force Majeure was caused by Seller's actions or inactions that were not in compliance with the PPA, and (iii) operating conditions on the Hawaiian Electric System (including Excess Energy).

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- Such "Banked Curtailed Energy" will give the "Seller" under a TEPA modified PPA an option to extend the Initial Term of such PPA to provide the Seller with an opportunity to continue to sell electric energy to Hawaiian Electric.

- The length of such extended term will be proportionate to the amount of Banked Curtailed Energy but in no event will exceed two years.

- If, following the close of the third Contract Year and at the close of each Contract Year thereafter, there is no Contract Year among the three preceding Contract Years during which the sum of Actual Output plus the amount of both Curtailed Energy eligible for "banking" and energy that could not be generated due to certain force majeure events, equals at least 90% of the Initial Annual Contract Energy, then the amount of Banked Curtailed Energy will be zeroed out, banking will cease and the PPA will revert to flat energy pricing, as more fully set forth in the TEPA Term Sheet.

The purpose of TEPA is to mitigate some of the financial uncertainties faced by Sellers and Financing Parties due to possible curtailment of renewable generators under the Model PPA. Although TEPA will not eliminate such uncertainties, Hawaiian Electric would expect the risk mitigation available under TEPA to benefit rate payers in the form of lower energy pricing over the initial term of TEPA-modified PPAs. However, the risk to rate payers under a poorly structured TEPA is that the pricing tiers are too susceptible to "gaming" (e.g., overestimating the Initial Annual Contract Energy), such that little of the Facility's output is actually sold at the lower priced tiers, thereby depriving rate payers of the benefit of lower energy pricing. Consequently, developers seeking to negotiate a TEPA modified PPA should be prepared to support their TEPA proposals (including modifications to the TEPA Term Sheet) in terms of (i) risk mitigation to Seller, (ii) lower energy pricing to rate payers and (iii) disincentive to "gaming." Each developer who desires to include TEPA in its PPA will, at a minimum, be required to make available to Hawaiian Electric, both as part of the negotiation process as well as during the Initial Term of the PPA, the same information concerning the projected output of its Facility as is made available to its Financing Parties. In addition to facilitating the negotiation of TEPA-modified PPAs, such information will facilitate the process of obtaining PUC approval of such PPAs.

Attachment B
Take or Pay Treatment (Wholly Compensated Curtailment)

An alternative to the "Baseline" treatment described above is a PPA with a variable renewable IPP which would include a provision to compensate the IPP for all electricity generated and delivered, and all electricity that would have been generated and delivered but for curtailment. For the IPP this treatment will ensure revenues when the IPP delivers electricity or when curtailed during periods when the project could have exported power to the utility In this treatment, the risk for the curtailed energy, is shifted to the ratepayer. As an alternative to the Baseline treatment, this treatment option requires further discussion. A key issue is whether this treatment would result in an appropriate cost to the ratepayers, given the value of the renewable electricity that is provided to the grid and other considerations.

Potential benefits of the wholly compensated curtailment approach that were identified included:

1) Under wholly compensated curtailment, renewable electricity has a marginal cost of almost zero, which accurately reflects the zero fuel cost of renewable wind, solar and hydro resources. This would facilitate economically efficient decisions with respect to the commitment of generation and whether to modify or reconfigure utility systems.

2) Wholly compensated curtailment on future PPAs could reduce the generation costs of as-available renewable energy projects by making predictable the revenue streams from such projects and reducing the costs of financing such projects Customers would pay for energy that the utility could not accept, as well as for energy actually delivered If the price for energy actually delivered fully reflects the enhanced revenue flow and reduced risk for the intermittent energy facility, customers could end up paying less (while accepting the market risk that loads and sales in the future will be lower than forecast resulting in more than expected curtailment).

3) In concept, utility customers already pay for estimated curtailed energy indirectly in the payment rates for delivered energy. Project developers and their financing parties may not be able to estimate the future curtailment risk, and may overestimate the risk as a result.

Potential detriments of the wholly compensated curtailment approach that were identified included:

1) Under wholly compensated curtailment, customers would have to pay for energy that the utility could not accept, as well as for energy actually delivered. Unless the price for energy actually delivered fully reflects the enhanced revenue flow and reduced risk for the intermittent energy facility, customers could end up paying more. One question is how do we make sure that the lower financing costs are passed on to customers?

2) Curtailed energy cannot be "measured". There would need to be detailed calculations of curtailed energy during all curtailment periods (and not just periods where there is a valid claim of improper curtailment). This would require continuous resource data, and power output curves for all generators reflecting their current status.

3) To the extent that utilities are required to enter into wholly-compensated-curtailment PPAs for renewable generation beyond the point at which it does not make economic sense to

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4) Wholly compensated curtailment on future PPAs simplifies HECO's modeling, planning and decision-making by fixing the amount of existing as-available renewable generation subject to uncompensated curtailment

5) Utility

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procure that generation (i e , because the economic cost of compensating the curtailed energy from such generation exceeds the economic benefit of the uncurtailed energy delivered from such generation), customers would be subjected to unnecessary costs.

Some of the other issues that should be considered were identified as follows:

1) There should be a differentiation between the reasons for curtailment, which can occur due to conditions such as: (a) failure to meet performance standards, (b) excess energy conditions, (c) system-wide conditions, (d) localized system maintenance, and (e) transmission constraints. Customers should not be required to pay for curtailment that is triggered by the intermittent energy facility's failure to comply with performance standards

2) Under wholly compensated curtailment, in effect, the utility would be paying for capacity (i e , capability), instead of energy. The terms and conditions of the standard as-available energy contract should be reviewed in light of that change. In addition, the accounting and credit quality implications for the utility off-takers (which are currently rated BBB-) should be analyzed

3) Issues as to how such a different curtailment regime for new PPAs would mesh with obligations and curtailment priorities under existing PPAs should be addressed, given the limited ability of the utilities to modify existing contracts. This would include identification of modifications and/or additions that would be necessary to existing forms of utility power purchase agreements to be able to reasonably balance the increased risk for ratepayers. These could include provisions such as: (1) the right to control energy output, and monitor equipment and resource availability to confirm the amounts of potential energy available from the new as-available energy facilities (and potentially existing as well), since new projects would be paid on the basis of energy made available, and not energy accepted, (2) appropriate modifications to the form of pricing paid to the developer, and (3) requiring verified cost information to ensure that any transfer of risk to customers is resulting in lower prices.

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4) Issues as to how any such change in curtailment policy could increase the potential for stranded costs (in the form of payment obligations under long-term contracts) if the energy market in Hawaii is ever restructured should be addressed.

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5) Whether utilities, subject to Commission review and approval, should be permitted to limit agreements to purchase intermittent and/or as-available energy, and to optimize their systems, to avoid a situation where unconstrained risk to ratepayers could exist.

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6) How to incentivize developers of renewable energy projects to develop projects that will provide energy during periods that are less subject to curtailment, to take commercially reasonable steps to minimize their exposure to curtailment and to meet expected utility operational and reliability thresholds

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Attachment C
Alternative Generation Contract Structures For Optimal Investment and Operations

The power system can be operated reliably and economically, and renewable curtailment can be dealt with efficiently, only when the utility sees the true marginal cost of each generator. This requires contracts that are designed to provide both the utility and the IPP with correct economic signals This paper briefly discusses generator fixed and variable costs for both utility and IPP investment and operations decisions.

Note that the contract discussion here is not addressing changes in the total compensation to the resource. Total compensation is the same in each alternative to facilitate comparison. Instead the discussion concerns how the generator is treated in the utility security constrained unit commitment and security constrained economic dispatch for optimal reliable and economic operation of the power system.

Three basic time frames are important when deciding what generation provides the lowest cost reliable supply for ratepayers: investment, unit commitment, and economic dispatch. These time frames are important when considering both utility and IPP owned generation. These time frames are important when considering all generation technologies including fossil fueled steam plants, combustion turbines, combined cycle, reciprocating engines, hydro, biomass, geothermal, solar, and wind.

Investment Decision: Project Viability

The project investors, the Public Utilities Commission, the rate payers, and the utility all have essentially the same concern when considering a new generation project: will the power produced be worth the total cost? If the total capital and operating costs divided by the total expected production result in an attractive $/MWH average total cost in relation to the cost of existing generation or alternative investments, also taking into account broader economic and social costs and benefits, then the proposed generator may be worth investing in.

Note that when considering an investment (IPP or utility) all costs are included in the decision Capital cost and financing costs are important as are annual operating costs as well as fuel and maintenance costs.

Unit Commitment: Turning On a Generator

Fuel burning generators (fossil or biomass) typically cannot turn on and off instantaneously. Large coal fired steam plants on the mainland require days to be prepared for operations. Oil fired steam plants on the islands require hours to be brought on line While some modern reciprocating engine driven generators can be started and fully loaded in minutes others require an hour or more to be brought on line. Combustion turbines and combined cycle plants are in the middle. Thermal plants also typically have minimum run times and minimum off times.

All of these temporal constraints complicate the power system operator's efforts to minimize the cost of operating the power system. In many regions operators use a security constrained unit commitment ("SCUC") tool to help determine what the lowest cost mix of generation will be to reliably serve the expected load over the next few days. This helps the system operator

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decide which thermal generators to start up (commit). Once started (or not started) the system operator must live with the decision and operate the power system with the mix of generation that was selected for operation each hour.

Because wind and solar PV plants do not typically require hours to prepare for operations and they typically have no minimum run time or down time the unit commitment process affects variable renewable resources only because it determines what other generators must operate. On the other hand, wind and solar uncertainty complicate the decision of which conventional generators to commit.

Economic Dispatch: Operating the Power System

In real time the system operator in many regions selects the lowest cost available generators to supply energy, within the reliability constraints by using a security constrained economic dispatch (SCED) tool. Only the marginal costs are important in economic dispatch. On the mainland, for example, the full output of a nuclear plant will tend to be selected because while the capital cost may be high, turning down the nuclear plant does not save capital cost. The mortgage must be paid regardless of if the nuclear plant is used or not. It is only the nuclear plant fuel cost (~$8/MWH) that is important when deciding how much power to take from a specific generator in real-time. This is true regardless of who owns the nuclear plant, the utility or an IPP. Building the nuclear plant may or may not be a good economic decision but once built then operating the plant is the correct decision because the $8/MWH cost for the next MWH produced is typically lower cost than the MWH that are available from coal, combined cycle, or combustion turbine plants. Similarly, once a wind or solar plant is built the capital cost is sunk Curtailing wind or solar does not reduce the fixed financing costs, so no money is actually saved when the plant is not operated. The most economically efficient operation of the power system results from dispatching the system based on true marginal production costs, within the limits imposed by reliability.

Demand Response and Storage

Demand response and storage can help reduce ratepayer costs, support reliability, and reduce variable renewable generation curtailment if included in the utility's marginal cost based economic dispatch by making more efficient use of all generators. Excess variable renewable generation can be utilized, variability and uncertainty can be mitigated, and peak loads can be reduced. Benefits must be compared with costs to determine which demand response and storage projects are economic.

Utility System Upgrade: Investment Decision

The utility may have the opportunity to invest in upgrading its transmission system or its generators to reduce variable renewable generation curtailment. This might involve upgrading a transmission facility that connects the renewable generation to load. Alternatively, it might involve lowering the minimum load capability or reducing the cycling cost of an existing fuel burning generator. The cost of any utility investment must be evaluated against the expected benefit. In this case the expected benefit is the reduction in fuel-consuming generation and the increase in renewable generation Uncurtailing renewable generation brings environmental benefits, but it should also save ratepayers money, if the renewable generation contract is structured properly. Reducing the fuel burning generation saves fuel costs. There is no

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corresponding increase in production costs from wind or solar generation when it is uncurtailed Ratepayers capture the full benefit of investing in upgrading the utility power system, if the variable renewable generation contract reflects the marginal production cost of the renewable generator.

Hypothetical Generator: Renewables Investment and Operations

Consider an overly simplistic hypothetical proposed wind plant with the following characteristics[8].

- 20 MW nameplate capacity
- $2,500/kW installed capital cost
- 50% expected annual wind availability (capacity factor)
- 5% expected curtailment for power system reasons
- 90% plant equipment availability
- 15% annual financing cost
- $1M annual operating and maintenance cost
- $2/MWH variable operating and maintenance cost
- $5/MWH integration cost

Investment Decision

Total plant cost is $50 million for this 20 MW wind plant. Financing, taxes, profit, etc require a 15% return, or $7.5 million/year to make the project viable. There is an additional $1 million/year in operating and maintenance costs. The plant is expected to produce 74,898 MWH per year based on the 20 MW plant rating, 50% wind capacity factor, 90% turbine availability, and an expected 5% curtailment due to power system conditions (minimum load, line maintenance, etc.).[9] This results in expected $113.49/MWH in fixed costs.[10] That is, the $113.49/MWH will be incurred once the decision is made to build the plant. Unlike fuel costs, the plant operator can't save any of the $8.5 million per year or $113.49/MWH by deciding to generate fewer MWH. These costs are sunk.

But there are additional costs too. There is an additional $2/MWH in variable O&M and the utility incurs $5/MWH in integration costs for the added regulation and reserves required to deal with the variability and uncertainty of the wind. The total additional cost for getting an additional MWH from this plant (if additional production is available) is $7/MWH. Similarly, the total savings available for reducing plant output is $7/MWH

This results in a total expected cost of energy from this proposed wind plant of $120.49/MWH If that average energy cost looks attractive compared with the average fuel cost of the existing generation fleet or compared with alternative new generation then it may be worthwhile for either the utility or an IPP to invest in the plant.

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[8] These are example numbers Actual numbers for Hawaii will likely be different. The concept is the same regardless of the exact numbers.

[9] 74,898 MWH/yr = 20 MW * 8760 hr/yr * 90% turbine availability * 50% wind capacity factor * (100% - 5% expected system curtailment)

[10] $113 49/MWH = ($7.5 million/yr capital costs + $1.0 million/yr overhead and maintenance) / (74,898 MWH/yr)

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Operating Decision: Lowest Cost Reliable Energy

The standard utility industry security constrained unit commitment and economic dispatch decision process selects the lowest cost reliable energy supply (including conventional generators and variable renewable generators) for current operations. Only marginal costs are considered because only marginal costs can be controlled in real-time When the utility selects among its own generators, for example, it considers the fuel and variable O&M costs because the utility has to pay for additional fuel when it increases an existing generator's output There is no additional capital cost. Similarly, the utility cannot reduce the mortgage payment for its own generators by running them less. The ratepayers pay the full mortgage and fixed costs even if the utility generator is seldom run

If the hypothetical wind plant is built then the capital cost and annual operating costs are sunk. They must be paid by someone regardless of how much the plant operates Only the $2/MWH variable O&M and the $5/MWH integration costs can be avoided by not running the wind plant. Similarly, if the wind is blowing it only costs $7/MWH to operate the wind plant. $7/MWH is the correct cost to put into the utility's security constrained unit commitment and economic dispatch program for finding the optimal, lowest cost, mix of generation to reliably supply energy in real-time. This is true if the utility invests in the wind plant or if an IPP invests in the wind plant. It is the total cost of energy supply for the rate payers that is being minimized with the SCUC/SCED.

Minimize Ratepayer Costs

Utility and IPP Similarities: Operating Costs

Regardless of generator ownership, capital costs are sunk once the investment decision is made. This is true regardless of the generation technology. The short-term operating decision that selects which generators should provide energy during the next hour should be made based on the true marginal production cost of each generator. If capital costs and additional costs are added to the decision process it raises costs for rate payers by selecting a less than optimal generation mix.

In the case of a combined cycle plant, for example, it is fuel and variable O&M costs that should be considered regardless of plant ownership For the hypothetical wind plant discussed above, it is the $2/MWH variable O&M cost and the $5/MWH utility integration cost that should be considered.

Utility and IPP Differences: Risk

When the utility invests in a new generator it is the rate payers, not the utility that take essentially all of the risk. If the plant has higher maintenance expenses than forecast or lower availability than forecast the rate payers must still pay the full cost One benefit of an IPP contract is that much of the risk can be moved from the ratepayers to the IPP investor. The IPP investor can take on the risk of the capital cost being higher than expected, the renewable resource being lower than expected, the plant availability being lower than expected, and the plant maintenance cost being higher than expected. The IPP can control all of these variables and the IPP is in the best position to take these risks. (Of course, there is always a cost associated with assigning risk to a 3rd party. Although the ratepayer is insulated from risks of

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significant deviations from the norm in an IPP contract, as with any insurance policy the cost of energy from the IPP to the ratepayer is marginally higher for the 3rd party, IPP to take the "reasonable" risks.) These capital cost, maintenance, and resource availability risks can still be assigned to the IPP under this proposed contract structure

Contract Structure

Because there are two types of costs it makes sense for contracts to be structured with two payment parts. This mirrors the utility treatment of its own generation where fuel and variable O&M are considered in the security constrained unit commitment and security constrained economic dispatch while the capital costs and long-term O&M are considered in the investment time frame.

MWH Hourly Energy Component

An IPP contract could be structured with a variable cost portion to cover the $2/MWH variable O&M for our example wind plant. (Note that the utility would add to this the $5/MWH of integration cost the utility incurs in additional reserves when the utility puts the variable cost into the SCUC/SCED.)

Monthly Component

The monthly payment would be negotiated to cover the capital, financing, tax, and longer term O&M expenses It would be adjusted based on wind availability and plant forced outage rate. This results in the IPP assuming all of the risk for resource availability, plant maintenance, maintenance costs, etc. Our example plant might receive a monthly payment of.

Monthly $ = $1,574,074 * Actual Wind Capacity Factor * Actual Plant Availability[11]

If the wind has 50% availability as expected and the plant has 90% maintenance availability as expected then the plant receives $708,333 for the month.[12] If system related curtailment were also the expected 5% this would result in the equivalent of $113 49/MWH of wind energy. The IPP is responsible for all of the maintenance costs, financing costs, etc. regardless of how high they are, minimizing rate payer risk. Lower wind availability or worse plant maintenance results in lower payment to the IPP and no risk to the rate payer.

Note that the contract could be written capping the wind availability and/or the maintenance availability and thus limit the rate payer risk of higher costs if the wind resource or maintenance is better than expected. This could be reasonable since the IPP would not incur additional costs based on better wind.

What about Curtailment Risk?

Security constrained unit commitment and security constrained economic dispatch, the basic utility tools universally used to optimize utility operations, both start with the word

[11] $1,574,074 /month = [($7.5 million/yr capital costs + $1.0 million/yr overhead and maintenance) / (12 months/yr) / (90% expected turbine availability * 50% expected wind capacity factor)]

[12] $708,333/month = $1,574,074 /month * 90% actual turbine availability * 50% actual wind capacity factor

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"*security*". It is absolutely critical that the system operator have the authority to curtail any generator if that is required for system reliability. Especially on island systems with high penetrations of wind and solar generation curtailment at some times is likely Expected curtailment must be estimated before making an investment decision. In our example the utility estimates that the proposed wind plant will have 5% of its energy curtailed for system reliability reasons. The IPP, the utility, and the PUC need to factor the expected curtailment into the calculation to determine if this investment still makes sense. If the total cost of production ($120.49/MWH in this example) is not attractive then the utility should not sign the contract, the PUC should not approve the project, and the IPP should not make the investment.

Once the investment is made who should assume the risk of additional power system reliability-based curtailment? The IPP has no control over power system related curtailment so it is not logical to force the risk on the IPP. The IPP is arguably the most knowledgeable about wind conditions so it makes sense for the IPP to assume the wind availability risk. Similarly the IPP controls maintenance procedures so it makes sense for the IPP to assume the plant availability risk. But power system related curtailment depends on the utility choices for the rest of the generation fleet and is outside the control of the IPP. It makes little sense to force the power system reliability-related curtailment risk onto the IPP [13]

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Why a Bundled $/MWH Contract Price Could Be Bad for Ratepayers?

Contracts that use a single $/MWH price or an on-peak and off-peak price would be economically inefficient if they result in selecting more expensive generation to operate than necessary. This would be bad for rate payers.

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Existing contracts were not designed to work with real-time operating decisions. They were only designed to facilitate long-term average energy cost comparisons. If a current contract $/MWH price is used for operating decisions it could lead to incorrect, and expensive, choices. Our example wind plant has a long term average cost of $115.49/MWH with an additional $5/MWH integration cost for a total $120.49/MWH cost. If during a particular hour the utility had a generator available with a $100/MWH incremental fuel and variable O&M cost, then using the current wind contract price as the basis for dispatching the wind farm would result in the incorrect decision to obtain energy from the $100/MWH plant and curtail the $120 49/MWH wind plant. The true marginal cost of energy from the wind plant is $2/MWH in variable O&M plus $5/MWH in utility integration cost. Only $7/MWH is actually saved when the wind plant is not operated compared with $100/MWH that is saved if the fuel burning plant is not operated. Curtailing (i.e., not dispatching) the wind plant would result in a $93/MWH error.[14] The economically efficient solution is to have the contracts reflect the true marginal production cost. This will eliminate any misleading and inefficient economic incentives to curtail the renewable energy and provide maximum transparency in renewable energy compensation and utility system operation.

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Conclusion

[13] This is not intended to be a complete discussion of the appropriate allocation of risks affecting an IPP's revenue stream.

[14] As noted earlier, however, the wind farm currently is essentially treated as a zero marginal cost resource in the utility's economic dispatch.

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IPP contracts that reflect each generator's true marginal cost facilitate the lowest cost reliable operation of the power system. Rate payers can continue to be shielded from the risk of poor generator performance due to lower wind or solar availability or poor maintenance through the inclusion of appropriate contractual terms and conditions.

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HELCO/MECO Cycling Study

Final Report

RSWG Meeting

Honolulu, HI

January 24, 2013

Opening Comments

The HELCO and MECO Cycling Study identifies opportunities to reduce curtailments, add renewable energy from new and existing resources and reduce costs while maintaining reliability

Study Conclusions and Implementation Strategy

- The study increases the use of renewable energy from both dispatchable and variable resources
- The EPS Study indicates that curtailments for both HELCO and MECO can be reduced from historical or previously projected 2013 levels
- The utilities are committed to implementing the study recommendations

History

- One of the MLC subgroup tasks was to:
  - Identify and recommend specific changes or enhancements, including estimated costs and timelines, to address and mitigate current factors that constrain addition of further renewable resource, to increase renewable energy use without substantially compromising system reliability or markedly increasing renewable curtailments (September 9, 2011 filing on RSWG Purpose Scope and Work Plan)
- Brendan Kirby – One year HELCO and MECO operations analysis for 2011, completed in March and July 2012
- EPS cycling study expands and extends the Brendan Kirby analysis to look at HELCO and MECO operations in 2013

EPS Study Purpose

- Using Brendan Kirby's study as a starting point, the EPS Study developed insights on how HELCO and MECO could operate generation assets in 2013 to minimize curtailments of renewable resources while achieving system lowest cost and maintaining reliability
- Based recommendations on thorough analysis of system security constraints, generation costs, and accepted engineering methods

Study Building Blocks: HELCO

In 2012, HELCO completed the following steps that were to increase the use of RE through resource additions, reduced curtailments and increased dispatch:

- Commercial operation of PGV expansion: 8 MW additional geothermal capacity with voltage regulation, frequency response, & AGC dispatch control for entire 38 MW facility
- Placed Shipman on dry lay-up around mid-2012
- Reduced the minimum load ratings of must-run units by 9 MW
- Increased ramp rate of Hill 5 by 1–1.5 MW
- Modified Keahole controls to allow AGC dispatch during transition to dual train
- Submitted for PUC approval Hu Honua PPA: 20.5 MW biomass with similar frequency response, dispatch capabilities, and range as existing dispatchable fossil units
- Continued wind/solar forecasting development working with HECO Renewables Integration Group

Study Building Blocks: MECO

In 2012, MECO completed the following steps that were utilized to reduce curtailment in the study:

- Implemented alternate day cycling of Kahului Units 1 and 2 in 2012
- Limited upward regulation on the system with three wind farms (72 MW) to 50 MW
  - Allocated 10 MW of upward regulation to the KWP II BESS
  - Allocated 3 MW of downward regulation to the KWP II BESS
- Modified the AGC to incorporate the three wind farms and battery energy storage systems into the AGC system

2012 Renewable Generation is High and Growing

HELCO at 40.9%

- Does not include distributed solar PV
- Attain 100% renewable with Hu Honua online in 2013, Aina Koa Pono (AKP) biofuel and additional geothermal

MECO at ~18%

- Does not include distributed solar PV
- 72 MW of wind generation online in 2013
- Continuing exponential growth in solar PV

HELCO and MECO Implementation Strategy

EPS Cycling Study provided insights into reliable system operation

- Developed comprehensive planning models including revised load models and distributed generation
- Identified minimum number of units needed to operate for system security through comprehensive analysis of system security requirements
- Identified cycling costs and capabilities

HELCO and MECO Implementation Strategy

- Develop production cost models to evaluate how the systems might be operated to maximize renewable energy, minimize curtailments while reducing cost and maintaining reliability through various scenarios
- Estimate generation cost savings potential of these alternative scenarios and provide insights into key dependencies
- Inform the system operators of the minimum generation for system security
- Provide foundation for action plans to migrate to the identified optimal generation commitment and dispatch

HELCO Study Conclusions

- Production cost simulations indicate significant increases in renewable energy and reductions in curtailment in 2013 compared to historic operation
- Variable generation & net load forecasting is critical to the ability to minimize curtailments & production costs
- HELCO & HEP units will experience significant cycling costs to minimize curtailments with some fuel cost savings; total system costs need to be optimized
- Units will be cycled more than historical practice which will require capital investments and operational changes
- Cycling costs might change as a result of new operations
- Over- or under-prediction of wind has an impact on costs; limited amount of over-prediction appears to provide better results

MECO Study Conclusions

- Significant reductions in curtailment are simulated in the study when compared to previous simulations and historical experience
- Voltage constraint security was reduced by 7.5 MW during curtailment periods
- New voltage constraint/increased cycling allows significantly more renewable usage during day and evening peak hours
- Wind/PV & net load forecasting is important
- MECO units will experience significant cycling costs to minimize curtailments with some fuel cost savings; total system costs need to be optimized
- Over-prediction of wind appears to provide better results than under-prediction

EPS Study Methodology

for

HELCO and MECO

EPS Study Phases

Phase 1 Develop actual cycling costs for units presently operated at HELCO and MECO, using historical data and measurements

Phase 2 Determine reliability & transmission security constraints on generator operation

Phase 3 Determine production costs for 2013 considering these cycling costs, transmission and reliability constraints, demand forecast data, and profiles for wind and hydro production

Phase 4 Conclusions and recommendations based on study results

Phase 1: Cycling Costs Study

- Comprehensive analysis by APTECH for HELCO-owned units (recognized industry expert in cycling)
- Analyzed 10 years of historical data for startups, daily changes in unit output
- Reviewed transient temperatures/pressures for fatigue and effective thermal ramp rates
- Determined equivalent hot starts from data/analysis
- Interviewed personnel for operating and maintenance procedures
- Developed costs data and recommendations

Phase 2: System Security

- Identify all security constraints that could impact the unconstrained commitment and dispatch of energy and capacity

Phase 2: Identified Security Constraints

Stability

- System remains operable after grid events

Load Shed

- The amount of customer load outages due to operation of under-frequency relays following the loss of a generator should remain close to historical levels

Rate of Change of Frequency

- How fast the frequency changes after a unit trip; should not exceed historic levels

Phase 2: Security Constraints

Ramping Capability

- Ability to increase or decrease dispatchable generation to match net load and wind production changes over several minutes to an hour

Voltage/Transmission

- Keep equipment within operating limits

Regulation

- Manage balance of demand and supply in the seconds to minutes time frame

Phase 3: Production Cost Simulations

- Use security constraints and cycling cost analysis to determine the most economic unit commitment/dispatch conditions for the HELCO/MECO systems under various case studies to maximize renewables
- Utilize annual production cost simulations to identify trends and procedures that can reduce curtailment and minimize cost
- Begin to determine the sensitivity of the optimum solution to variations in wind forecast accuracy

Phase 4: Conclusions

- Develop conclusions based on the results of the study
- Recommendations based on study results for both immediate tasks and future planning
- Enumerate future tasks

HELCO
Cycling Study

Phase 1:
Cycling Costs Study

-HELCO-

Phase 1: Cycling Cost Study – Recommendations HELCO

- HELCO cost of cycling for typical starts estimated by APTECH
- Layup of more than 7 days requires long-term lay-up measures (will require new equipment and other investments)
- Add plant station service requirements to system loads
- Make necessary plant changes to minimize maintenance and operating costs from increased deep cycling and offline cycling

Phase 2: System Security

-HELCO-

System Security Constraint Summary
HELCO

System Constraint	Existing Practice	Study Recommendations
Historical operation	Five units operated continuously except during maintenance (PVG + Hill 6 + Hill 5 + Puna Steam + Keahole STCC + HEP STCC)	
Stability at minimum	Minimum of two HELCO steam units in addition to other online units	PGV + Hu Honua
Load shed	Met by normal historical unit operation	PGV + Hu Honua + (Keahole DTCC or HEP or 2 steam units)
ROCOF	Met by normal historical unit operation	PGV + Hu Honua + 2 units

NOTES:
1) Generating units must operate as modeled, for improved performance, fewer units might be required, for poorer performance – additional units might be required
2) Units in blue are typical operating units on the HELCO system due to historic cycling policy

System Security Constraint Summary
HELCO

System Constraint	Existing Practice	Study Recommendations
Ramp Rate	Met by normal historical unit operation	PGV + Hu Honua + one unit
Voltage/ Transmission	>130MW Keahole up to DTCC	>120MW Keahole CT up to 1CTCC + 1 more unit
Regulations	Operational practice – dependent on wind, For Prod Cost Model used 17 MW (avg on-peak reg)	Operational practice – no change Prod Cost Model: 1:1 up to 15 MW of wind, 6 MW load

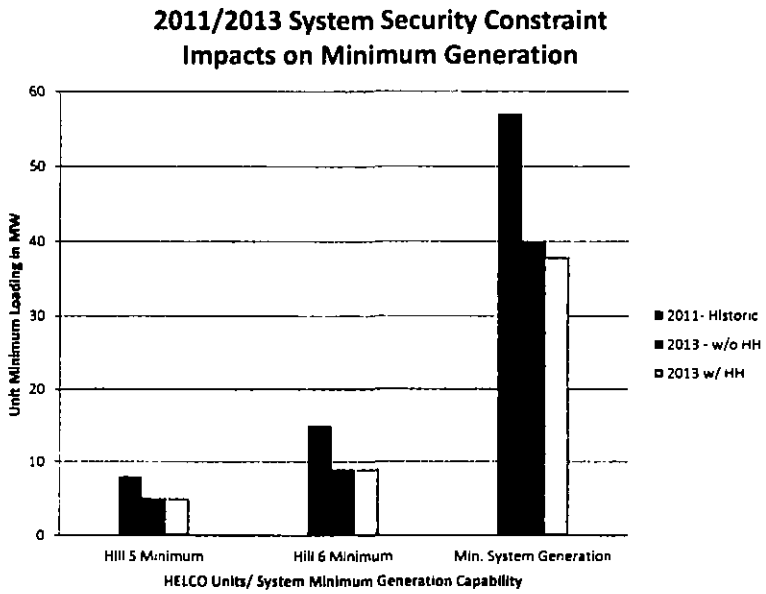
NOTES:
Generating units must operate as modeled, for improved performance, fewer units might be required, for poorer performance – additional units might be required

Minimum Generation Summary - HELCO

- PGV/Hu Honua meet stability requirements at minimum load. Additional constraints require:
  - Two additional units required for ROCOF, or
  - One additional unit required to mitigate UFLS, or
  - One steam or turbine/steam CC required for ramping
- Voltage Constraint (Generation to meet voltage constraint can also serve above constraints)
  - 120 MW < Load < 147 MW CT2 or equivalent
  - 147 MW < Load < 180 MW, Keahole 1CTCC
  - Load > 180 MW Keahole 1CTCC + additional unit

Impact of 2013 Security Constraints

(represents only minimum security not optimum commitment)/dispatch)



System Security Analysis: HELCO Stability Constraints

- Under steady state conditions with all transmission lines operating, two large operating units will satisfy the stability requirements at minimum load
- The renewable energy units, Hu Honua and PGV can satisfy this constraint at minimum load

System Security Analysis: HELCO Load Shed Constraint

Acceptable unit combinations: PGV, Hu Honua plus:

- One combined cycle train at HEP or Keahole, or
- A combination of any one steam units: H5, H6, Puna)(The two shipman units count the same as one larger steam unit)

Two diesels will not provide the necessary inertia to turn off a steam unit for load shed response

HELCO Load Shed Requirements

- Worst case condition occurs:
  - When thermal units are at minimum load
  - Wind plant is at maximum output
- Loss of wind plant is largest single contingency
- Historical system response with minimum online generation resulted in loss of first stage load shed
- Spinning reserve completely covers 100% of the largest contingency at minimum load conditions
- To prevent a decrease in reliability as defined by the industry (NERC and IEEE), future system performance for the largest contingency should not increase load shed beyond the first stage

System Security Analysis: HELCO Rate of Change of Frequency

- Historical ROCOF was developed using minimum stability requirements and historic unit commitment
- ROCOF restrictions could potentially be decreased with additional studies and verifications
- Additional required studies include unit control testing for PGV, Hu Honua, and critical system units
- Testing is required due to critical nature of ROCOF; extreme consequences can occur if units trip due to increased ROCOF (system-wide blackout implications)

System Security Analysis: HELCO Rate of Change of Frequency

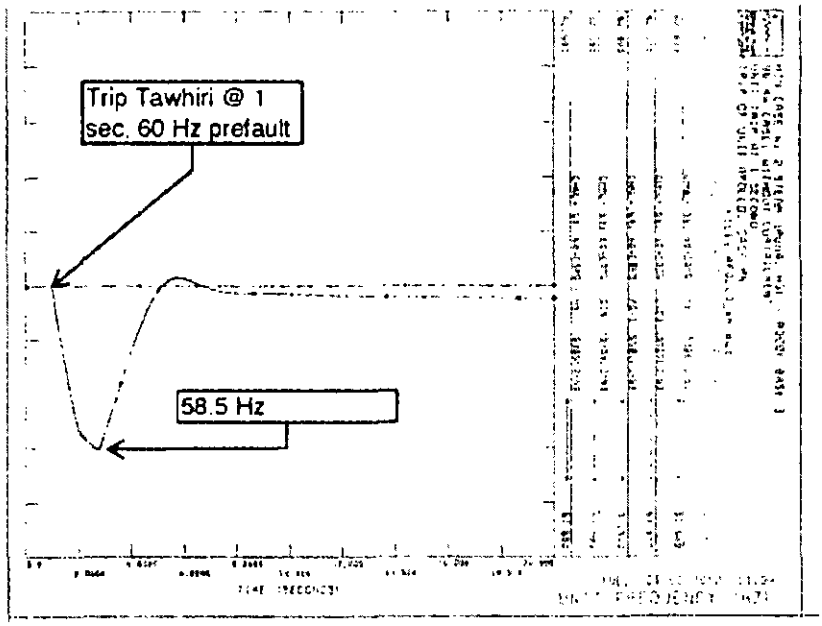
Acceptable unit combinations: PGV, Hu Honua plus:

- One combined cycle train at HEP or Keahole, or
- A combination of any two steam units (H5, H6, Puna)

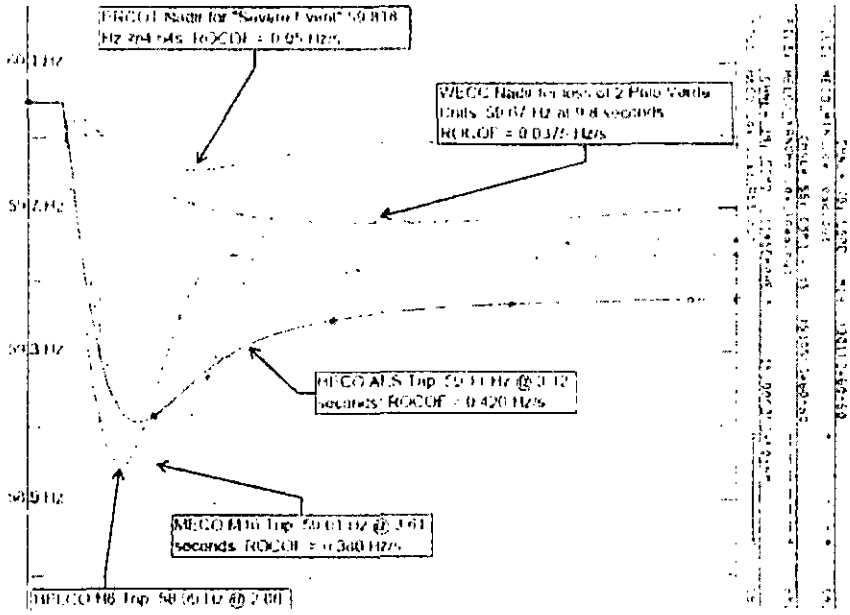
HELCO ROCOF Generation Requirements

- ROCOF calculations depend on designed response of Hu Honua and PGV
- ROCOF outages have been experienced on the HELCO system (for example, July 3, 2010)
- ROCOF capabilities of HELCO turbines must be verified
- ROCOF failures of HELCO turbines have system-wide blackout implications
- Prior to decreasing ROCOF criteria, turbine capabilities must be confirmed
- PGV/Hu Honua capabilities must be confirmed

HELCO ROCOF for Loss of Wind Plant



ROCOF Comparison with Other Systems



Frequency Bias Comparison with Other Systems

Frequency Response Comparison of HECO/HELCO/MECO with other grids							
System	HELCO	MECO	HECO	WECC	% Diff	ERCOT	% Diff
Beta (MW/0.1 Hz) *	2.2-5.6	3.2-6.8	33.0	1980	60,000-90,000%	662	2,000-30,000%
ROCOF (Hz/Sec)**	0.61	0.38	0.42	0.0375	1,000-1,600%	0.05	760-1200%
Nadir (Hz) (large event)	58.99	59.01	59.11	59.67		59.818	
Inertia MW*s	347-754	421-711	6084-6848	564,000	8,235 - 162,500%	390,000	5,700 – 112,400%

*System Beta was computed assuming all units are available for respond to load in the up and down direction. In actual practice, the HELCO/MECO/HECO max Beta can be reduced by 50% in the up direction by units operating at maximum load

**The ROCOF numbers do not reflect the values being treated as constraints in the cycling study. The study results show a potential increase in the ROCOF to approximately twice the numbers presented in the table. Verification that critical generation and/or system components will remain operable through faster ROCOF is required prior to operating the system in configurations that might result in this faster ROCOF is required to avoid potential system failure.

This table illustrates the differences and critical nature of frequency control in the HECO systems with other power grids on the mainland

System Security Analysis: HELCO Ramp Rate Constraints

- ≥ 4MW/min
- Actual need will increase due to distributed PV — further assessment will be required using current load data
- Table at right shows the ramp rates
- Note that Shipman units provide almost no ramp response
- Diesels have limited dispatch range so cannot support ramp response

Unit	Ramp Rate
Hu Honua (future)	1.00
PGV (geothermal)	1.00
Total ramping capability	2.00
Above units must be supplemented by any one line of units below to meet minimum ramping capability	
HEP UNITS CC (1 Im2500 + 1 Steam)	2.00
Keahole 1CTCC	2.50
Keahole CT-2 (gas turb, solar)	2.00
Puna CT-3 (gas turb, Im2500)	2.50
Keahole CT-4 (gas turb Im2500)	2.50
Keahole CT-5 (gas turb, Im2500)	2.50
Hill Unit No 6 (steam)	2.00
Hill Unit No 5 (steam)	2.50
Puna Steam Plant (steam)	2.00
Waimea D-12 (emd diesel)	2.00
Waimea D-13 (emd diesel)	2.00
Waimea D-14 (emd diesel)	2.00
Kanoelehua D-15 (emd diesel)	2.00
Kanoelehua D-16 (emd diesel)	2.00
Kanoelehua D-17 (emd diesel)	2.00
Keahole D-21 (emd diesel)	2.00
Keahole D-22 (emd diesel)	2.00
Keahole D-23 (emd diesel)	2.00
Note, two Shipman units do not meet minimum ramping requirement	

HELCO Ramp Requirements

- Many times wind down ramps coincide with load up ramps
- Ramp rate requirements are the sum of the wind plus net load ramp
- 99% of net demand ramp rates are less than 1.0 MW/30-seconds or 2.0 MW/minute rate
- 30-second wind ramp rate is 1.2 MW or 2.4 MW/minute rate
- 1-minute actual wind ramp rate is 1.3 MW/minute
- Total actual ramp rate is 2.2 MW/30-seconds using 30-second data or 3.3 MW/minute using 1-minute data
- Recommend minimum ramping capability be ≥ 4.0 MW/minute which is slightly greater than the minute ramp rate and lower than the 30-second ramp rate
- Frequency stability in the sub-minute timeframe might require increased ramping capability

System Security Analysis: HELCO Voltage/Transmission Constraints

- Constraint is on the west side of the island
- Total System Load < 120 MW
  - Keahole not required
- 120 MW <System Load < 147 MW
  - CT2 or equivalent MW capacity
- 147 MW <System Load < 180 MW
  - Keahole 1CTCC
- Total System Load > 180 MW
  - Keahole 1CTCC + additional unit

Phase 3:
Production Cost Simulations

-HELCO-

HELCO/MECO Production Cost Model Input Data

Provided by HELCO/MECO:

- Load profile curve
- Fuel cost projections
- PV projections
- Generator dispatch limits, heat-rates, and variable cost data
- 2011/ 2013 avoided costs
- 2011/ 2013 IPP costs

Developed by EPS

- Hydro generation curve
- Wind generation curve
- Geothermal generation curve

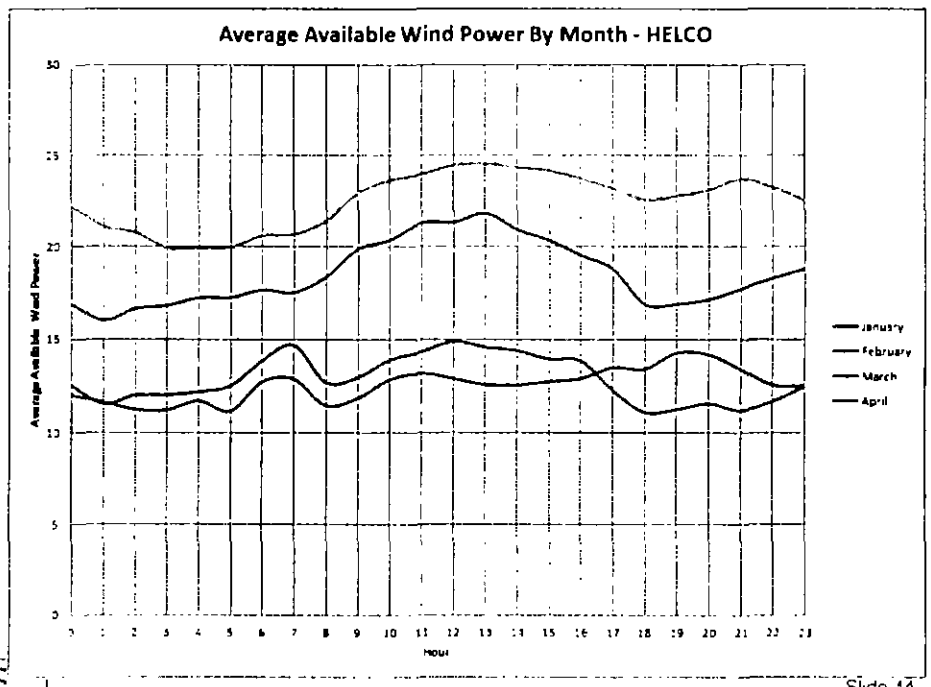
Other Inputs

- Environmental permit constraints on unit starts/hours
- Curtailment priority: evaluated seniority & economic w/in RE group
- HELCO unit cycling costs (provided by APTECH)

Input Data – HELCO Wind Development

- SCADA data used to develop available wind from Tawhiri and HRD
- Spot checked against Tawhiri data and HELCO delivery points
- Estimate matched actual during non-curtailed periods, assume same turbine outage during curtailed periods
- Excess energy curtailments are due to energy above HELCO's ability to consume
- EPS formula passed on to HELCO for future use

HELCO 2011/13 Input: Monthly Wind



2013 – HELCO Renewable Summary

	Total	Wind	Hydro	Geothermal	% RE
Available*	1,217,281	170,950	46,129	275,700	40.5%

* Does not include PV or energy efficiency

Notes:

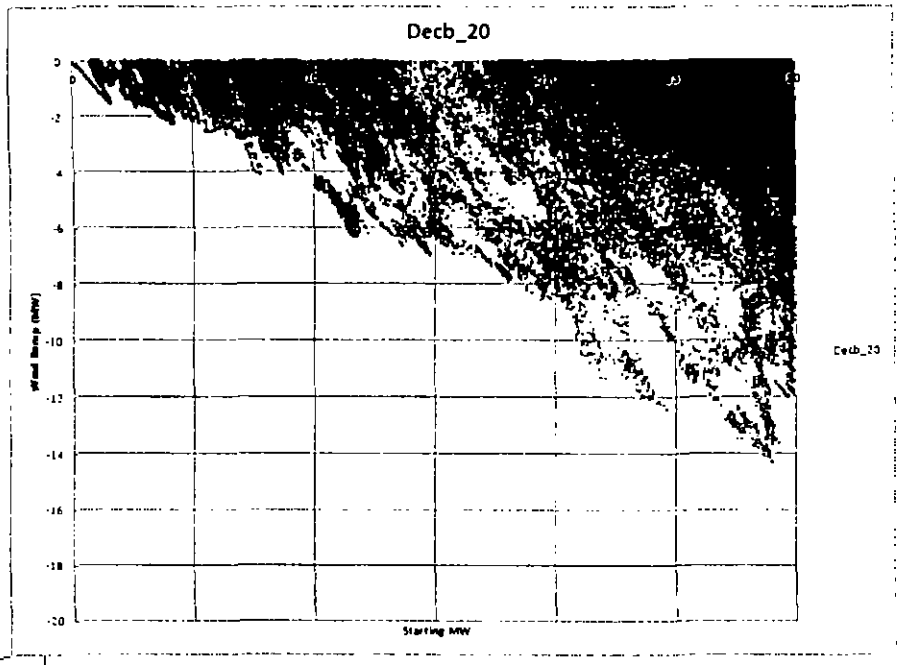
1) "Available" assumes all available RE without curtailments, includes HRD, Tawhiri, PGV plus hydro

Input Constraint – HELCO Regulation

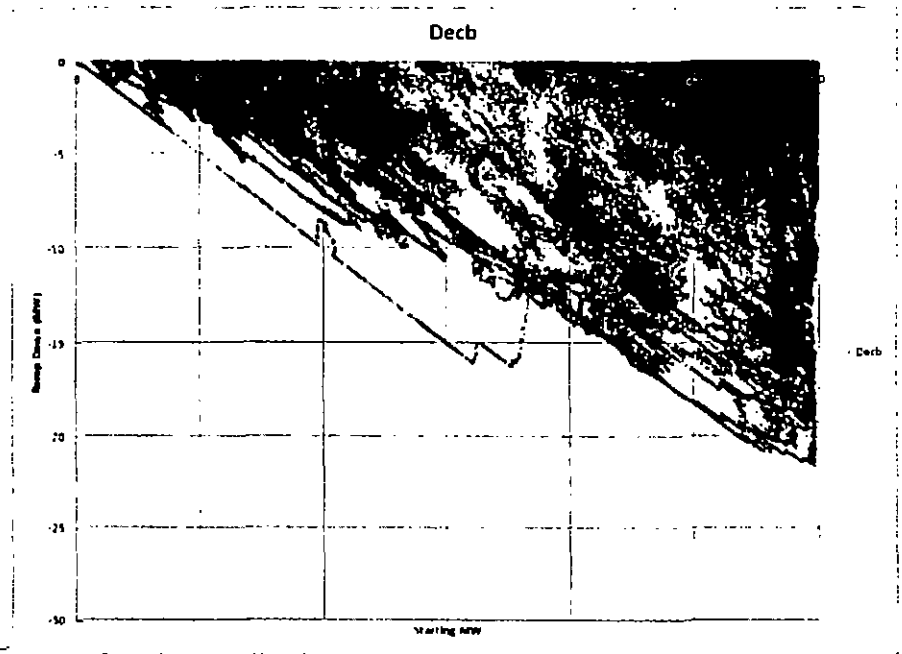
Wind Regulation – 2013

- Use 20-minute scatter plots as basis
- Net load requirements – 6 MW up
- Net load requirements – 9 MW down
- Can be opposite ramps, need additive total
- Wind regulation – 1:1 up to 15 MW, no regulation above 15 MW
- Wind can provide a portion of down regulation; studies indicate no more than 50%

2011 – HELCO Regulation – 20 minutes



2011 – HELCO Regulation – 60 minutes

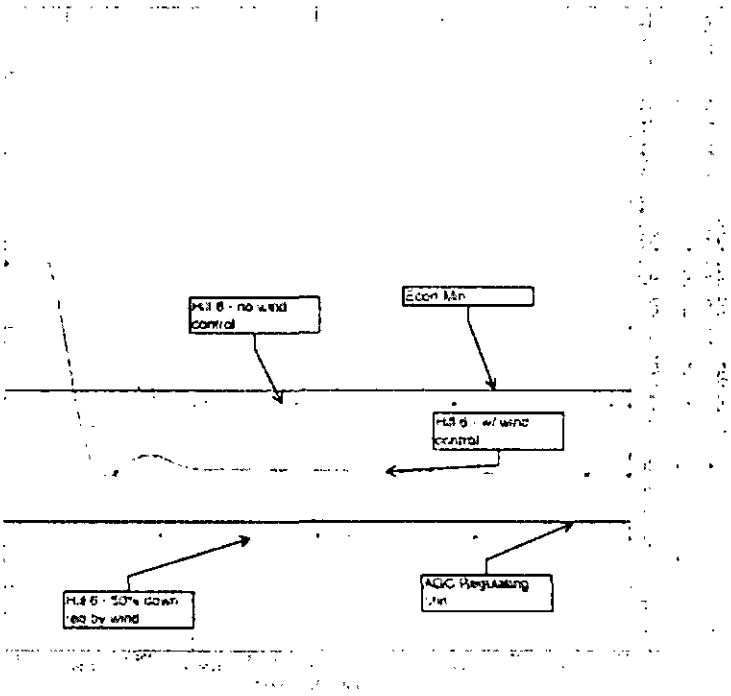


HELCO Down Regulation Studies

Studies completed to determine if wind can provide down regulation for HELCO

- Only Tawhiri was considered technically feasible
- 1% droop and GE recommended wind control parameters used
- Indicates that no more than 50% of down regulation can be supplied by wind
- Wind can supply less down regulation if additional units are on-line
- Down regulation can be beneficial if it reduces curtailments

HELCO Down Regulation Studies



HELCO Production Cost Simulation Cases

Case 1: No system constraints
- 1a – down reg supplied by thermal, curtailment by seniority queue
- 1b – down reg supplied by wind, curtailment by seniority queue

Case 2: Base Case – identified constraints
- 2a – down reg supplied by thermal, curtailment by seniority queue
- 2b – down reg supplied by wind, curtailment by seniority queue

Case 3: Economic Queue Case – all constraints
- 3a – down reg supplied by thermal, curtailment by economic queue
- 3b – down reg supplied by wind, curtailment by economic queue

Case 4: Seniority Queue Case – all constraints
(50% of curtailed wind can provide upward regulation)
- 4a – down reg supplied by thermal, curtailment by seniority queue
- 4b – down reg supplied by wind, curtailment by seniority queue

Case 5: Same as 4 – economic curtailment

Production Simulation Results - HELCO

Comments on Production Simulation Output

- Annual production cost simulation utilized probabilistic method to determine unit production, starts, stops, etc.
- Probabilistic methods are used for estimating long-term forecasting of production costing
- Method provides guidance on how system should be operated over the long-term and gives an indication on unit commitment for short-term
- Short-term unit commitment simulations using deterministic methods will be required prior to implementation by system operators

Example – Probabilistic vs Deterministic

Probabilistic Method

unit has low probability of being dispatched during this hour of the month

unit has higher probability of being dispatched during this hour of the month

GENERATING UNITS - July 2013 - MW

Hour		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
[illegible]	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	14	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

unit has high probability of being dispatched during this hour of the month at some load

unit has almost 100% probability of being dispatched during this hour of the month at max load

Deterministic Method

unit is not on-line

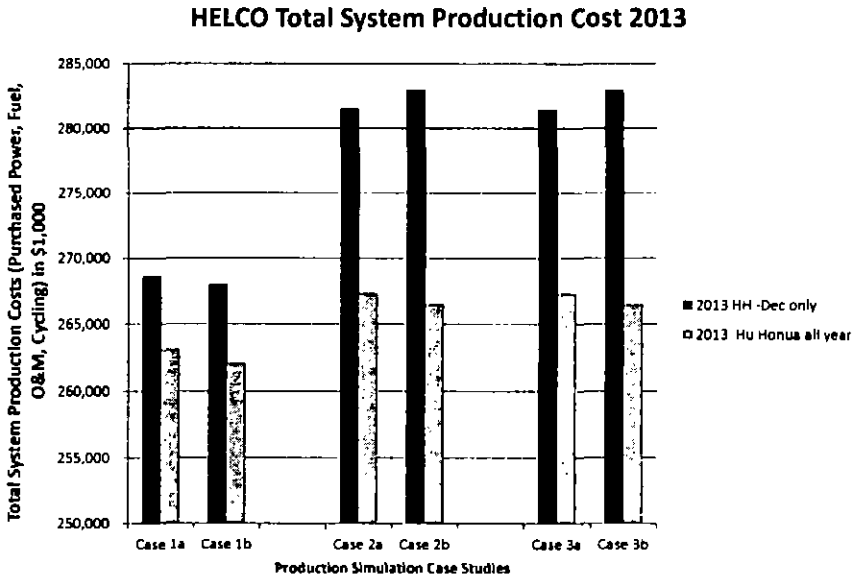
unit is on-line and dispatched at this level

GENERATING UNITS - July 2013 - MW

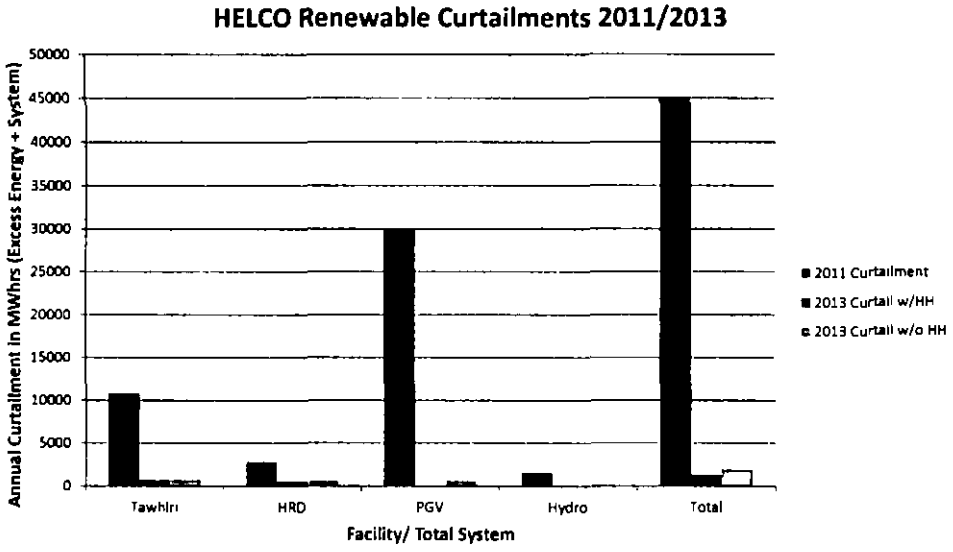
Hour		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
[illegible]	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	14	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

unit is on-line and dispatched at this level

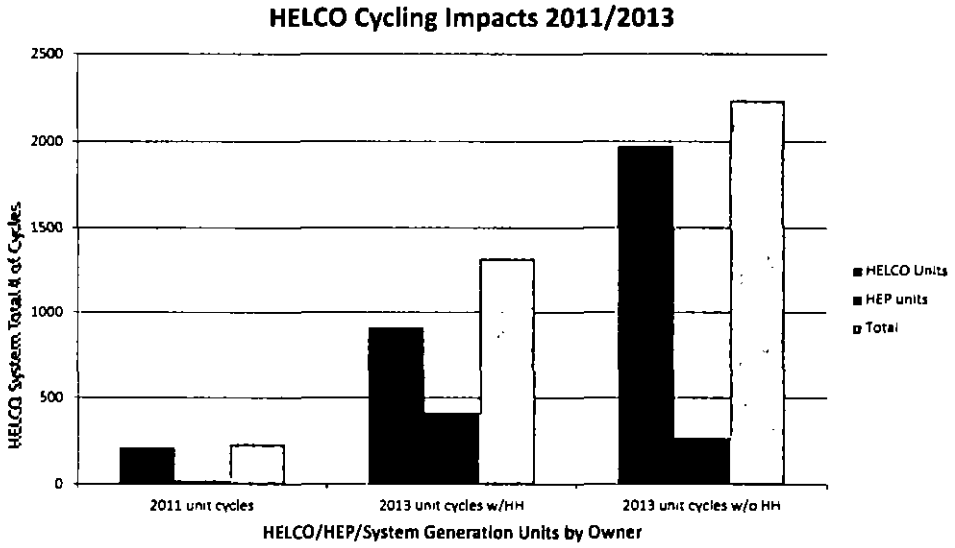
HELCO Production Cost Simulations



Results of 2013 Cycling Study

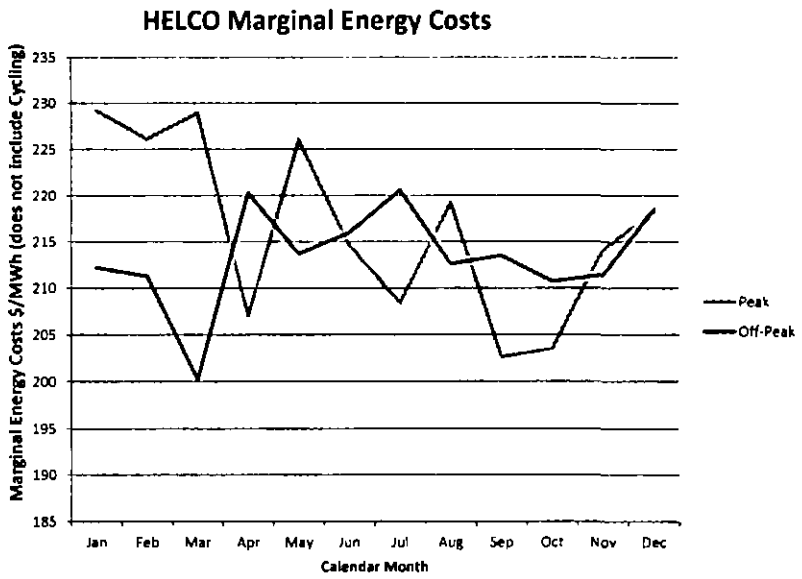


Impact of 2013 Security Constraints



Marginal Energy Costs 2013

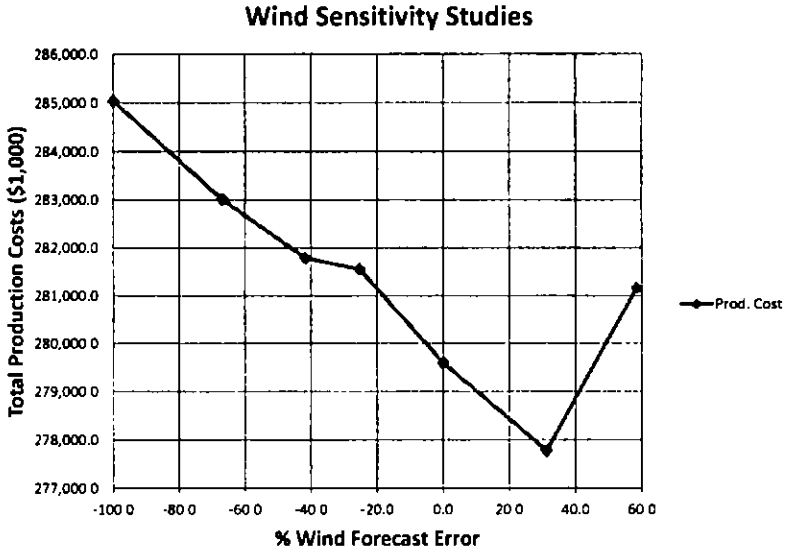
(does not consider cycling or ancillary services costs)



HELCO Sensitivity Analysis

- The production model base case assumed that demand to be served by dispatchable generation could be perfectly forecast in advance
- Review of case studies indicated that unit commitment and dispatch results might be sensitive to wind forecast errors
- Cases were designed to evaluate the impact of wind forecast errors on base case 2a
- Sensitivities were designed for the wind energy to be consistently over or under forecast to evaluate the sensitivity of the simulation to wind forecast error

HELCO Sensitivity Analysis



PUC Requested Analysis - HELCO

- PUC requested an analysis using $0/MWh for marginal cost of variable energy in the production simulations
- HELCO treats all variable energy as "must-take"
- Production simulation results using $0/MWh for variable energy are identical unit commitment and energy cases as 1a, 1b, 2a, 2b and 4a, 4b in the Scope of Work
- $0/MWh modifies the fuel & purchased power cost of the production simulations by the revenue paid to the IPPs as indicated on the following pages

HELCO $0/MWh Results

Case 1 (HH-Dec)		
IPP	GWh	Cost ($000)
HRD	43.2	$ 8,858
Tawhiri	127.8	$ 21,934
Total	171	$ 30,792

Case 2a (HH-Dec)		
IPP	GWh	Cost ($000)
HRD	43.2	$ 8,858
Tawhiri	127.8	$ 21,934
Total	171	$ 30,792

Case 2b (HH-Dec)		
IPP	GWh	Cost ($000)
HRD	43.2	$ 8,858
Tawhiri	127.2	$ 21,754
Total	170.4	$ 30,612

HELCO $0/MWh Results

HELCO SYSTEM PRODUCTION COSTS ($,000) ($0/MWh)			
	2011	2013 HH -Dec only	2013 Hu Honua all year
Case 1a	na	237,883	na
Case 1b	na	237,254	na
Case 2a	na	250,764	na
Case 2b	na	252,403	na
Case 3a	na	na	na
Case 3b	na	na	na
Case 4a	Insufficient Curtailment in Case 2 to warrant analysis		
Case 4b	Insufficient Curtailment in Case 2 to warrant analysis		
Case 5a	na	na	na
Case 5b	na	na	na

Production Simulation Conclusions HELCO

- The production cost simulations provide information as to how the system might be operated
- The value of ancillary services is about $12,900,000/year prior to Hu Honua and about $4,200,000/year following Hu Honua
- Results indicate that curtailment of variable renewables for excess energy could be reduced with increased cycling
- Curtailments are reduced slightly more than the base case after Hu Honua is online

Production Simulation Conclusions HELCO

- Results indicate that although curtailments might be reduced, the annual production cost varies with the accuracy of the net load forecast
  - Further analysis will better quantify the relationship
- Large errors in wind forecast, either over or under, result in increased production cost simulation results
- Similar dependencies might exist for PV forecast
- Results depend on HELCO/HEP units experiencing ***considerable*** offline cycling

Phase 4: Recommendations & Future Tasks

-HELCO-

Recommendations & Future Tasks HELCO

- Review the detailed results of the production cost simulations to determine if they suggest any operational changes in the present time-frame to reduce curtailment and reduce production cost
- Develop additional sensitivity cases and forecast assumptions to determine the best method of using a production cost simulation tool to develop unit commitment strategies and implementation methods
- Identify potential pitfalls and additional items for study
- Develop next-steps implementation plan on the optimized unit commitment/forecasting solution

Action Items (identified to date)
HELCO

Evaluate the impact of the simulation results on HELCO and HEP

- Perform deterministic simulations to evaluate offline cycling requirements
- Identify equipment modifications (capital improvements) to HELCO units for type of offline cycling, including layup
- Work with HEP to understand impacts of routine offline cycling
- Develop operator procedures for routine offline cycling/layup

Action Items (identified to date)
HELCO

Develop Unit Commitment and Load Forecast tools for system operations

- Continue to develop wind and solar forecasting techniques
- Integrate forecast into system operations
- Determine the accuracy of the near term forecast
- Develop an understanding of forecast errors and unit commitment impacts

Develop unit commitment/dispatch procedures incorporating integrated load/variable generation forecasting and offline cycling decisions

Considerations and Concerns
HELCO

- Results depend on PGV/Hu Honua performing to preliminary design: Verify PGV/Hu Honua operational performance
- Cycling costs are preliminary: monitor cycling costs going forward to accurately update production cost simulations
- When capital investments and operational expenses for cycling are identified, review total cost impacts of production cost savings plus required capital/operating expenses; need to assess the value of flexibility
- System would be operating closer to reliability constraints: monitor system performance through faults and contingencies, monitor system performance and reliability impact from running with fewer online units

Considerations and Concerns
HELCO

- Frequency control in sub-minute time frame might require additional ramping capability; monitor impact on system frequency performance
- Collect system and generator data to evaluate ROCOF constraints
- Ramping requirement did not include impact of increased solar PV variability; consider impact of solar PV increases on ramp constraint
- Turbines require testing and verification of ROCOF ability

MECO
Cycling Study

Study Building Blocks: MECO

In 2012, MECO completed the following steps that were utilized to reduce curtailment in the study:

- Implemented alternate day cycling of Kahului Units 1 and 2 in 2012
- Limited upward regulation on the system with three wind farms (72 MW) to 50 MW
  - Allocated 10 MW of upward regulation to the KWP II BESS
  - Allocated 3 MW of downward regulation to the KWP II BESS
- Modified the AGC to incorporate the three wind farms and battery energy storage systems into the AGC system

MECO Study Conclusions

- Significant reductions in curtailment are simulated in the study when compared to previous simulations and historical experience
- Voltage constraint security was reduced by 7.5 MW during curtailment periods
- New volt constraint/increased cycling allows significantly more renewable usage during day and evening peak hours
- Wind/PV & net load forecasting is important
- MECO units will experience significant cycling costs to minimize curtailments with some fuel cost savings; total system costs need to be reduced
- Over-prediction of wind appears to provide better results than under-prediction

Phase 1:
Cycling Costs Study

-MECO-

Cycling Cost Study – Recommendations
MECO

- MECO cost of cycling for typical starts estimated by APTECH
- Layup of more than 7 days requires long-term lay-up measures (will require new equipment and other investments)
- Add plant station service requirements to system loads

Phase 2:
System Security

-MECO-

System Security Constraint Summary
MECO

System Constraint	Existing Practice	Study Recommendations
Stability at minimum	None K3, K4, M14, M15, M16, M17, M18	None required if regulation is met
Load shed	None K3, K4, M14, M15, M16, M17, M18	None if regulation is met
ROCOF	None K3, K4, M14, M15, M16, M17, M18	None if regulation is met
Ramp Rate	None K3, K4, M14, M15, M16, M17, M18	DTCC plus one unit or equivalent to obtain ≥5MW/min
Voltage/ Transmission	K3 and K4 M14, M15, M16, M17, M18	K3 or K4 plus one unit at peak, lesser constraints off-peak

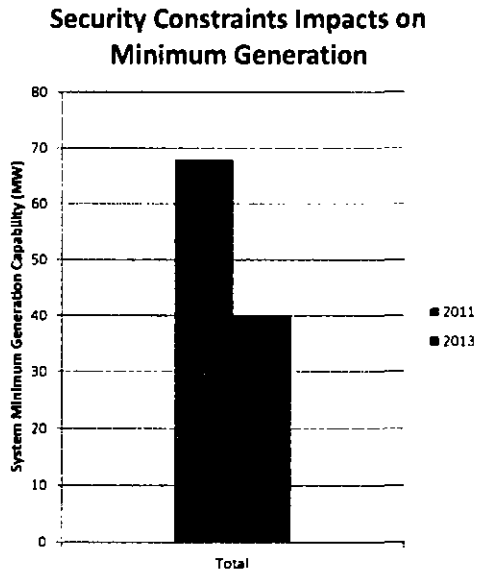
NOTES:
1) Generating units must operate as modeled; for improved performance, fewer units might be required, for poorer performance; additional units might be required
2) Units in blue are typical operating units on the MECO system due to historic cycling policy

Minimum Generation Summary
MECO

- Multiple units are required to meet regulation criteria
- No unit stability restrictions as long as the combination of units meet the regulation criteria
- Either K3 or K4 is required for voltage
- Ramp requirements of 5.0 MW/Minute require at least one dual-train cc plus one unit or equivalent

2013 Security Constraints Impact

(only changes in security constraints, not the economic unit commitment or dispatch)



System Security Analysis

Stability constraint

- No unit stability restrictions as long as the combination of units meet the regulation criteria

Load shed constraint

- Increased regulation reserves/spinning reserves plus BESS decrease UFLS; no load shed constraints so long as regulation requirements are met

System Security Analysis

Load shed requirements

- Worst case condition occurs immediately prior to curtailment
- Loss of wind plant is largest single contingency
- Historical system response generation would be first or second stage UFLS, day/min, 0 UFLS peak
- Increased regulation reserves/spinning reserves plus BESS decrease UFLS

Rate of change of frequency

- No limitations so long as reserves are met

System Security Analysis: MECO Ramp Rate Constraints

- ≥ 5MW/min
- Actual need will increase due to distributed PV; further assessment will be required using current load data

Unit	Ramp Rate (MW/Min)
K1	0.1
K2	0.1
K3	0.1
K4	0.1
M14	2
M15	0.5/1.0
M16	2
M17	2
M18	0.5/1.0
M19	2
M10, M11, M12, M13	1
M4, M5, M6, M7	1
M8, M9	1
M1, M2, M3, X1, X2, X3	0

MECO Ramp Requirements

- Thermal units must be capable of ramp rates when BESS is discharged or not available
- Many times wind down ramps coincide with load up ramps
- 99% of wind ramp rates are less than 2.5 MW/30-seconds
- 30-second ramp rate equates to 5.0 MW/minute requirement, 1-minute ramp rate is 3.0 MW/minute
- Net load ramp rates are approximately 2.0 MW/30 seconds, 1-minute ramp rate is approximately 2.2 MW/minute
- Recommend minimum ramping capability be greater than 5.0 MW/minute which is less than the 9.0 MW/minute equivalent 30-second ramp rate and approximately equal to the 1-minuye ramp rate
- Frequency stability in the subminute timeframe might require increased ramping capability and should be monitored since the ramps rates are calculated from wind models and not actual data
- Note K1, K2, K3 & K4 provide almost no ramp capability although they are on combinations of must-run units for transmission constraints

System Security Analysis: MECO Voltage/Transmission Constraints

All constraints are based on a contingency requirement and are not steady-state transmission constraints. Generation constraint is reduced by at least 7.5 MW by new analysis

- At a load level < 144 MW; no Kahului generation is required
- The 2 small Kahului units or one large unit would be sufficient for load levels 144 < x < 175
- 1 large Kahului unit is required for load levels 175 < x < 186
- 1 large + 1 small Kahului unit is required for load levels 186 < x < 207
- 1 large + 2 small Kahului units are required for load levels 207 < x < 221
- 1 large unit at Kahului plus HC&S would be sufficient at 2013 peak (195 MW) to eliminate all voltage violations

System Security Analysis: MECO Voltage/Transmission Constraints

- Potential transmission solutions to be examined
  - Line reconductoring
  - Load tap changer settings and operation
- Either solution could decrease voltage constraint on generation by another 7.5 MW

Phase 3: Production Cost Simulations

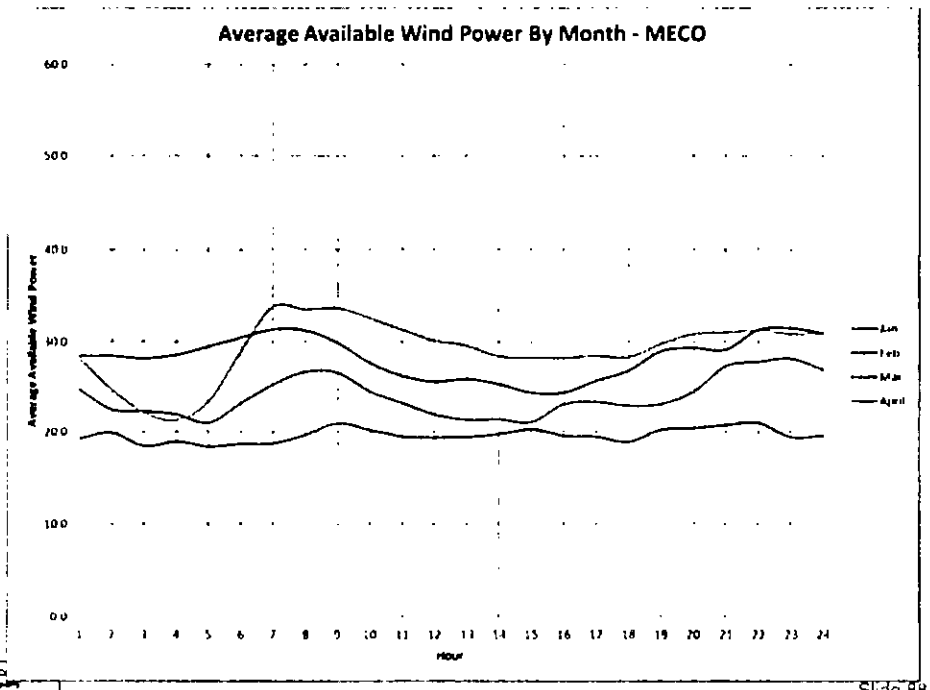
-MECO-

Input Data – MECO Wind Development

2013 wind estimates

- Used AWS Truewind wind model for 2013 2-second wind data
- Developed wind power and wind ramp data from AWS model
- MECO wind models do not utilize actual power measurements to develop wind data

MECO 2013: Wind Estimate



2013 – MECO Renewable Summary

	Total	Wind	HC&S	% Renewable**
Available*	1,214,482	313,181	63,751	31.0%

*From AWS True Wind Integration Study

** does not include PV or Energy Efficiency

MECO Regulation (pre-determined)

Wind regulation

- Based on 2012 requirements
- Wind regulation up – 6 MW or 50% of wind up to first 30 MW of wind, whichever is greater
- Wind > 30 MW, 1 MW for 1 MW wind to a maximum of 50 MW
- Battery can supply up to 10 MW of up regulation and up to 3 MW of down regulation depending on number of CTs online
- Down regulation 6 MW – BESS is already providing portion of down regulation, no additional down regulation is allowed by wind

MECO Cases

Case 1: No system constraints

1a – Down reg supplied by thermal, curtailment by seniority queue

Case 2: Base Case – identified constraints

2a – Down reg supplied by thermal, curtailment by seniority queue

Case 3: Economic Queue Case – all constraints

3a – Down reg supplied by thermal, curtailment by economic queue

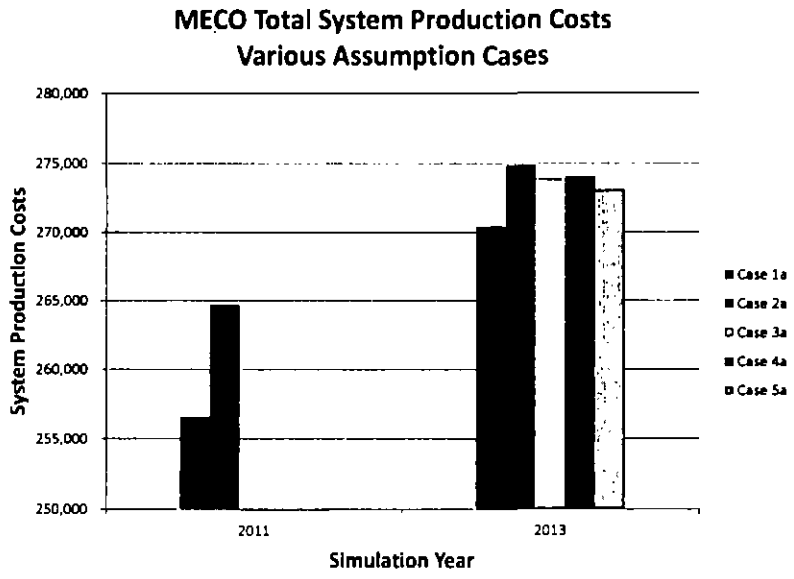
Case 4: Seniority Queue Case – all constraints

(50% of curtailed wind can provide upward regulation)

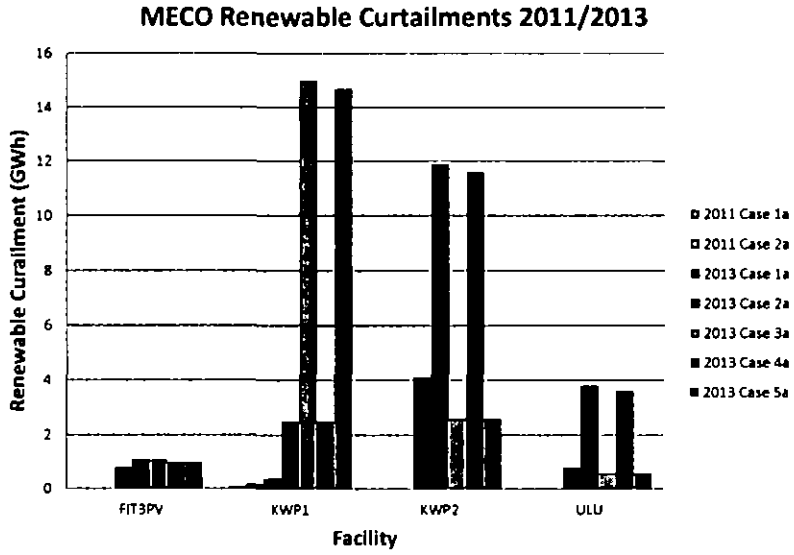
4a – Down reg supplied by thermal, curtailment by seniority queue

Case 5: Same as 4, economic curtailment

MECO Production cost Simulations

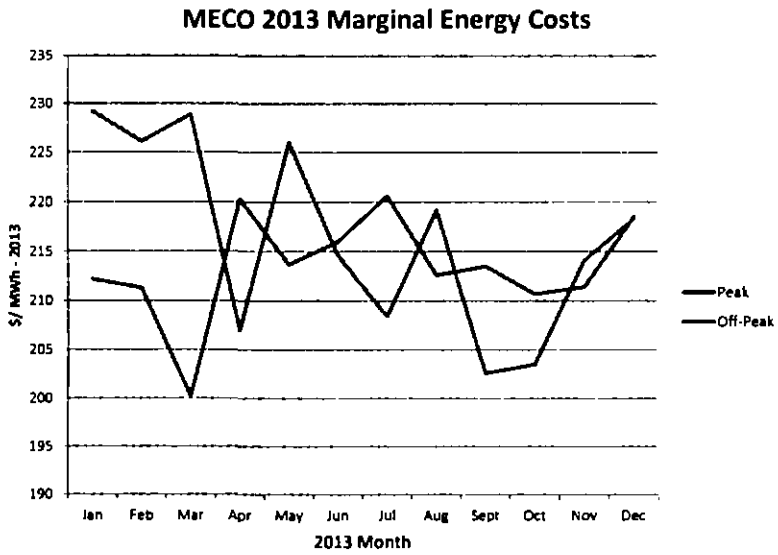


2013 Cycling Study Results



2013 Cycling Study Results

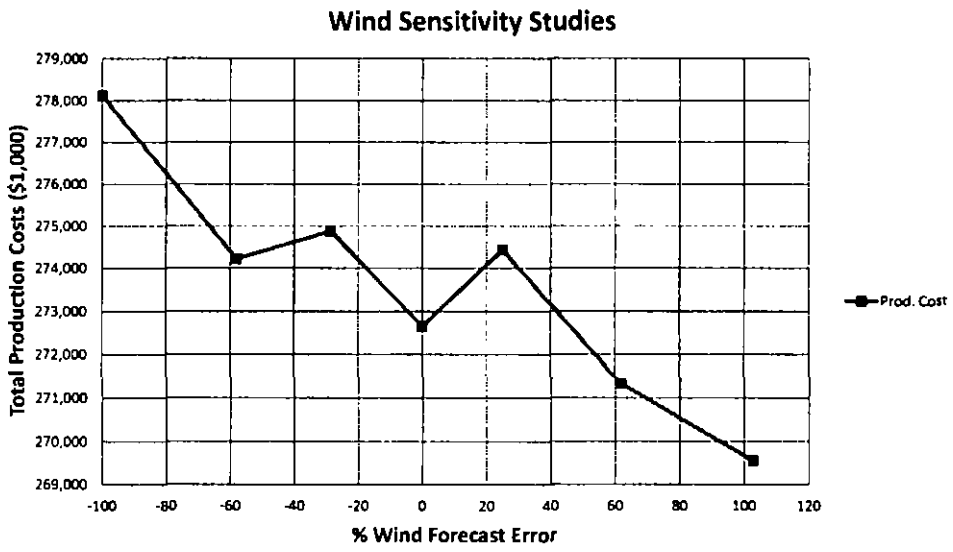
(does not consider cycling costs or ancillary services costs)



MECO Sensitivity Analysis

- Review of case studies indicated that unit commitment and dispatch results might be sensitive to wind forecast errors
- Sensitivities were designed for the wind energy to be consistently over or under forecast to evaluate the sensitivity of the simulation to wind forecast error
- Cases were designed to evaluate the impact of wind forecast errors on base case 2a.

MECO Sensitivity Analysis



PUC Requested Analysis
MECO

- PUC requested an analysis using $0/MWh for the production simulations of all cases
- MECO treats all variable energy as "must-take"
- Production simulation results using $0/MWh are identical unit commitment and energy cases as 1, 2a, 4a in the Scope of Work
- $0/MWh modifies the fuel & purchased power cost of the production simulations by the revenue paid to the IPPs as indicated on the following pages

MECO $0/MWh Results

SYSTEM PRODUCTION COSTS ($,000)	
	2013
Case 1a	223,593
Case 2a	228,830
Case 3a	na
Case 4a	228,002.0
Case 5a	na

Production Simulation Results
MECO

- The results indicate that new security constraints and commitment order can reduce curtailment and reduce costs
- The production cost simulations are not real-time unit commitment/dispatching tools, but provide information as to how the system might be operated
- The value of ancillary services is about $4.4M/year
- MECO units will experience extensive cycling and costs with new commitment order with some fuel cost savings
- MECO results indicate over-prediction might be consistently better than under-prediction
- Development of accurate wind/PV/net load forecasting is important

Phase 4: Recommendations & Future Tasks

-MECO-

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Smart grid market outperforms in 2012 (but the future looks less bright)

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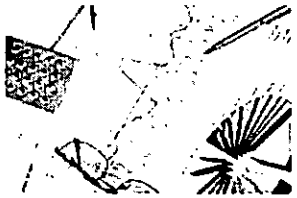
By Allan McHale
Memoori

World smart grid sales at an installed value climbed to $36.5 billion in 2012 - a growth of 30% on 2011 – while M&A activity reached $19.5 billion, almost doubling the value of deals in the previous year. That's according to Memoori's latest report, *The Smart Grid Business 2012 to 2017*.

This confirms that progress has been made over the last few years to move the smart grid out of the embryonic stage into its infancy – a commendable performance given that the world economy has struggled during this time and very few businesses have done more than marked time.



But we forecast that growth will slow down to a more modest 20% over the next three years as the smart meter market, the main engine for growth the last three years, falls off. With an investment of $15 billion in 2012, AMI is currently the largest single segment spend in the smart grid sector. It accounts for some 40% of the investment dollars, yet only accounts for 8% of the technical market potential for delivering a fully working smart grid.

The reason for that is easy to understand. The installation of AMI carries little technical risk and a return on the investment should start immediately as a result of saving operating costs through automatic reading and billing. So it is not surprising that so many utilities have taken the low hanging fruit first.

From our reports store: "Smart Grid Business 2011 to 2016" published by Memoori, analyzes the smart grid market's size, technologies, finance and needed investments, demand forecasts and more.

At the other extreme, current smart grid sales in transmission and distribution are at 53% when its market share of the total investment will be around 61%. This is disappointing because a high proportion of this spend is on incremental improvements to quality and reliability of supply and not comprehensive automated demand response (ADR) systems, at least not full scale ones. As this is the technical heart of a smart grid, until ADR is in place we won't see an integrated system that maximizes the benefits from all of its parts.

Snapshot of the smart grid supply business

We estimate there are at least 2,426 companies in the world manufacturing hardware and software products for the T&D market. This is a conservative estimate because in the developing markets, particularly China, Brazil, Russia and India, we believe there are hundreds of very small operations involved in manufacturing products and components that we have not yet been able to identify.

The structure of the business is currently skewed heavily towards the major international suppliers where 26 companies shared sales of $81.5 billion in 2012. Those 26 averaged $3.125 billion in revenue, but only accounted for 1% of the population of suppliers. The next group, with sales between $100 million and less than $1 billion, shared $31.5 billion, averaging $45 million in revenue.

Over the last three years we have noted a steady trend for those medium-size companies to increase their share of the smart grid market through the introduction of innovative products and systems. We expect this trend to continue, although in time many will be acquired by the major international suppliers.

We estimate there are 1,700 companies with sales of less than $100 million that shared $10 billion in sales in 2012, averaging $6 million each. This would suggest that more than half the companies in the business are too small to be viable.

The "pure" smart grid players

The pure smart grid vendors break down into a number of separate but interconnected businesses. The supply and installation of AMI is clearly one such business and is now well established, but the others less so. They will include:

- Demand response automation
- Communication networks
- Business enterprise management and analytics software
- Consumer interface products

One could argue the smart grid industry would be healthier if it were less dependent on the major international companies, but there are a sufficient number of them to ensure competition – and they do have the financial strength to take on multi-billion dollar projects. The financial and technical muscle of the new players entering from the IT and communications markets will further strengthen the capacity and capability of the smart grid marketplace.

We are confident that the smart grid supply industry has the capacity and capability to deliver smart grids around the world by 2030, but are much less confident that the demand side will get its act together – as you'll read in our next instalment.

Allan P. McHale (CEng, MIMechE, MEI, MInM) has spent 45 years in the energy and building controls industry – from design and commissioning utility power stations in the 1960s to managing global sales and marketing operations, and subsequently starting up three marketing consultancy operations all in energy related businesses during the last 20 years.

Memoori's report – The Smart Grid Business 2012 to 2017 – is a definitive resource for the smart grid industry, combining clearly defined market sizing statistics, a review of the structure of the supply side and financial analyses of M&A and investment opportunities. It is available for purchase in the SGN Research Marketplace.

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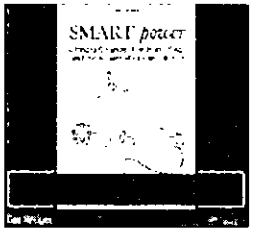

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Recommendations & Future Tasks MECO

- Review the detailed results of the production cost simulations to determine if they suggest any operational changes in the present time-frame to reduce curtailment and reduce production cost
- Develop additional sensitivity cases and forecast assumptions to determine the best method of using a production cost simulation tool to develop unit commitment strategies and implementation methods
- Identify potential pitfalls and additional items for study
- Develop next-steps implementation plan on the optimized unit commitment/forecasting solution

Recommendations & Future Tasks MECO

- Develop Unit Commitment and Load Forecast tools for system operations
  - Continue to develop wind and solar forecasting techniques
  - Integrate forecast into system operations
  - Determine the accuracy of the near term forecast
  - Develop an understanding of forecast errors and unit commitment impacts
- Develop unit commitment/ dispatch procedures incorporating integrated load/variable gen forecasting and offline cycling decisions

Action Items (identified to date)
MECO

- Gather real time wind data and compare results
- Perform deterministic simulations to evaluate offline cycling requirements
- Identify equipment modifications (capital improvements) to MECO units for type of offline cycling, including layup
- Develop operator procedures for routine offline cycling/layup

Considerations and Concerns
MECO

- Results are based on forecast wind data and have not been correlated with real wind data
- Cycling costs are preliminary: monitor cycling costs going forward to accurately update production cost simulations
- When capital investments and operational expenses for cycling are identified, review total cost impacts of production cost savings plus required capital/operating expenses
- System would be operating closer to reliability constraints: monitor system performance through faults and contingencies, monitor system performance and reliability impact from running with fewer online units
- Frequency control in sub-minute time frame might require additional ramping capability; monitor impact on system frequency performance
- Ramping requirement did not include impact of increased solar PV variability; consider impact of solar PV increases on ramp constraint
- Battery testing and verification is critical to system performance

Going Forward with HELCO & MECO

MECO and HELCO Strategy

Continuously identify new or different ways to lower generation costs and synergies with or tradeoffs with reliability / security or renewable energy integration

- "Re-optimize" generation commitment and dispatch for energy and ancillary services as new resources become available, or relative costs of resources change
- Implement new or changing methods as each system evolves
- Add new cost-effective renewable energy resources to displace fossil generation

HELCO Work Plan

- Review HELCO's capital budget to incorporate modifications necessary to facilitate migration to the optimal unit commitment and dispatch identified in the cycling study
  - Equipment modifications for routine cycling or layup
  - Equipment modifications to improve dispatch range, AGC response, ramping
- Verify/improve system dynamic response
  - Verify Hu Honua/PGV dynamic response to confirm assumptions in cycling study through design and operational data
  - Confirm distributed generation ride-through
  - Collect system and generator data to evaluate ROCOF constraints
  - Monitor frequency control in the sub-minute time frame
- Integrate wind and PV forecasting tools into system operations
- Develop unit commitment/dispatch procedures incorporating integrated load/variable generation forecasting and offline cycling decisions

HELCO Work Plan (continued)

- Investigate modifications to existing and new variable generation IPP contracts to reduce ratepayer costs and participate in system grid management (for example, frequency response, regulation, and inertial response)
- Continue plans to acquire new firm, dispatchable renewable generation
- Continue to monitor technology improvements that enable more flexible, secure system operation with high levels variable RE (for example, improved forecasting, storage technologies, smart grid solutions, demand response capabilities, inverter-based generation technical capabilities)

MECO Work Plan

- Review MECO's capital budget to incorporate:
  - Generating unit modifications necessary to: (1) enable Kahului Units 3 and 4 to start up in a shorter timeframe; (2) lower the minimum operating loads on the units; and (3) enable the units to cycle on a daily basis or to be shut down for extended durations (days, weeks, or months) while mitigating any deleterious effects, and maintaining compliance with environmental guidelines
  - Transmission projects to reduce voltage constraint on Kahului generating station operations
- Continue improvements to the AGC system to allocate the combined cycle steam units contribution to regulation reserves

MECO Work Plan (continued)

- Develop unit commitment/ dispatch procedures incorporating integrated load and variable generation forecasting and offline cycling decisions

Closing Remarks

- Continue learning from operational data to understand the impacts of changes to the islands' generation mix and to improve efficiencies and outcomes for all grid partners
- Increase the flexibility of the systems to accommodate the fast-paced changes in the generation mix
- Perform frequent system analysis (load flows, dynamics to identify other methods that improve system flexibility)
- Incorporate operational "lessons learned" using system real-time data into plans
- Continue with generation, T&D, and operational changes to accommodate more renewable energy and lower generation costs

Thank You!

Supplemental

Kirby and EPS Study:

Differences

Kirby and EPS Study Differences

Item	Brendan Analysis	Generation Performance & Reserves Study
Study period	2011 historical	2011 cursory; 2013 w/Hu Honua, PGV8, New Wind
Cycling costs	Estimates from mainland study only applied to select steam units	Based on custom APTECH study for HELCO/MECO units for all units under dispatch control
Hydro	2011 historical, no corrections for curtailment	2011 actual uncurtailed. Average of 2011 peak/morning used for curtailed energy during off-peak
Wind data	Wind data for Tawhiri used for HRD, actual wind for MECO, curtailment # from IPP	Wind data from all IPPs, correlated between utility and IPP, estimated 2013 data for MECO
Geothermal	2011 historical, no corrections for curtailment or derations/maintenance	2011 actual uncurtailed. Peak period assumed available for next day in 2011. 2013: 38 MW with unit maintenance

Kirby and EPS Study Differences

Item	Brendan Analysis	Generation Performance and Reserves Study
Unit Commitment	Unit commitment not optimized, re-dispatch optimized	Re-evaluate unit commitment and dispatch using cycling study costs for all units
Generation Output and Cost Data	Historical unit outputs, one-month fuel and avoided costs provided by utility	Forecast fuel, forecast demand, include future generation additions, distributed PV, anticipated availability
System Security Constraints	Used only 2 steam unit reliability constraint *for HELCO; K3/K4 for MECO*	Assessment of reliability, UFLS, ramping, ROCOF, stability criteria for all conditions
Wind Sensitivity Analysis	Assumed wind was 100% predictable	Assessed the reliability of wind forecast on unit commitment/production costs
Unit Characteristics	Used 2011 unit constraints	Used 2012 unit constraints, generally lower turndown, better response

HELCO

Cycling Study
Additional Information

Input Data 2011 HELCO Fuel Prices

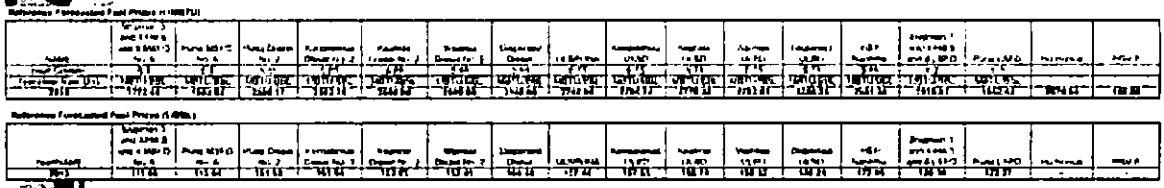
Reference Forecasted Fuel Prices (¢/MBTU)

NAME	Shipman 3 and 4/Hill 5 and 6 MSFO No. 6	Puna MSFO No. 6	Puna Diesel No. 2	Kanoelehua Diesel No. 2	Keahole Diesel No. 2	Waimea Diesel No. 2	Dispersed Diesel	HEP Naphtha
Heat Content	6.3	6.3	5.86	5.86	5.86	5.86	5.86	5.86
2011 Month/Heat Rate Unit	MBTU/BBL	MBTU/BBL	MBTU/BBL	MBTU/BBL	MBTU/BBL	MBTU/BBL	MBTU/BBL	MBTU/BBL
Jan	1341.43	1301.92	1866.36	1873.35	1883.51	1876.73	1551.81	1883.51
Feb	1354.81	1438.69	1913.08	1922.5	1928.3	1925.8	1234.57	1928.3
Mar	1493.95	1512.67	1964.71	1972.68	1980.41	1977.43	1612.75	1980.41
Apr	1554.67	1571.29	2027.99	2036.07	2046.7	2040.77	2134.35	2046.7
May	1759.7	1775.35	2191.74	2200.29	2213.21	2202.41	2152.97	2213.21
Jun	1894.97	1912.6	2438.85	2447.26	2460.59	2448.32	2152.97	2460.59
Jul	1862.93	1886.73	2446.58	2457.57	2469.65	2458.31	2043.45	2469.65
Aug	1831.17	1854.39	2470.98	2479.73	2493.55	2485.5	2696.42	2493.59
Sep	1867.66	1883.55	2452.36	2461.04	2474.43	2468.13	3004.93	2474.43
Oct	1886.42	1897.53	2342.45	2363.24	2376.81	2370.4	3004.26	2376.81
Nov	1861.37	1872.2	2335.63	2342.69	2357.96	2348.62	2968.41	2357.96
Dec	1736.27	1750.97	2373.87	2380.51	2396.45	2388.52	2915.29	2396.45

Reference Forecasted Fuel Prices ($/BBL)

Year/NAME	Shipman 3 and 4/Hill 5 and 6 MSFO No. 6	Puna MSFO No. 6	Puna Diesel No. 2	Kanoelehua Diesel No. 2	Keahole Diesel No. 2	Waimea Diesel No. 2	Dispersed Diesel	HEP Naphtha
	6.3	6.3	5.86	5.86	5.86	5.86	5.86	5.86
2011 Month/Heat Rate Unit	$/BBL	$/BBL	$/BBL	$/BBL	$/BBL	$/BBL	$/BBL	$/BBL
Jan	84.51	85.80	108.37	109.78	110.37	109.98	90.94	110.37
Feb	85.35	90.64	112.11	112.66	113.00	112.85	72.34	113.00
Mar	94.12	95.30	115.11	115.60	116.05	115.88	94.51	116.05
Apr	97.94	98.99	118.84	119.31	119.94	119.59	125.07	119.94
May	110.86	111.85	128.44	128.94	129.69	129.08	126.16	129.69
Jun	119.38	120.49	142.92	143.41	144.19	143.47	126.16	144.19
Jul	117.36	118.86	143.37	144.01	144.72	144.06	119.75	144.72
Aug	115.36	116.83	144.80	145.31	146.12	145.67	158.01	146.12
Sep	117.66	118.66	143.71	144.22	145.00	144.63	176.06	145.00
Oct	118.84	119.54	137.27	138.49	139.28	138.91	176.05	139.28
Nov	117.27	117.95	136.87	137.28	138.18	137.63	173.95	138.18
Dec	109.39	110.31	139.11	139.50	140.43	139.97	170.84	140.43
Avg	107.34	108.77	130.99	131.54	132.25	131.81	134.16	132.25

Input Data 2013 HELCO Fuel Prices



HELCO Production Cost Simulations

HELCO SYSTEM PRODUCTION COSTS ($,000)			
	2011	2013 HH -Dec only	2013 Hu Honua all year
Case 1a	248,907	268,675	263,151
Case 1b	249,168	268,046	262,123
Case 2a	257,805	281,556	267,369
Case 2b	261,272	283,015	266,557
Case 3a	257,734	281,493	267,345
Case 3b	261,249	282,958	266,535
Case 4a	Insufficient Curtailment in Case 2 to warrant analysis		
Case 4b	Insufficient Curtailment in Case 2 to warrant analysis		
Case 5a	Insufficient Curtailment in Case 3 to warrant analysis		
Case 5b	Insufficient Curtailment in Case 3 to warrant analysis		

HELCO Production Cost Simulations

HELCO CURTAILMENT RESULTS												
	2011 Curtailment (GWh)				2013 HH IN DECEMBER Curtailment (GWh)				2013 with Hu Honua all year HH ALL YEAR Curtailment (GWh)			
	HRD	Tawhiri	Wailuku	PGV	HRD	Tawhiri	Wailuku	PGV	HRD	Tawhiri	Wailuku	PGV
Case 1a	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Case 1b	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Case 2a	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
Case 2b	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Case 3a	1.5	1.8	0.5	0.0	2.3	0.0	0.0	0.0	1.9	0.0	0.0	0.0
Case 3b	1.0	1.3	0.4	0.0	2.2	0.0	0.0	0.0	0.8	0.0	0.0	0.0

Case 4a	Insufficient Curtailment in Case 2 to warrant analysis
Case 4b	Insufficient Curtailment in Case 2 to warrant analysis
Case 5a	Insufficient Curtailment in Case 3 to warrant analysis
Case 5b	Insufficient Curtailment in Case 3 to warrant analysis

Does not include nightly system curtailments for HDR

2013 HELCO Production Cost Simulations HH in Service in December											
		Case 1a			Case 2a			Case 3a			
System Cost ($)			268 675			281 556			281 393		
			268 046	(Case 1b)		283 015	(Case 2b)		282 958	(Case 3b)	
PLANT	UNIT	OUTPUT (GWH)	SERVICE HOURS	START UPS	OUTPUT (GWH)	SERVICE HOURS	START UPS	OUTPUT (GWH)	SERVICE HOURS	START UPS	
HEP	11	117.9	5946	307	162.4	8291	28	162.4	8233	28	
HEP	12	27.9	2169	208	29	3374	237	29.3	3404	237	
HEP CT	1	0	0	0	0.2	27	6	0.2	27	6	
HEP CT	2	0	0	0	0.2	28	6	0.2	29	6	
HILL	5	57.4	6804	27	52.4	7840	21	52.4	7840	21	
HILL	6	118.3	7901	2	93.3	7896	4	93.4	7896	4	
HU HONUA	1	11.8	660	1	7.9	620	1	7.9	630	1	
KANOELE	11	0	0	0	0	0	0	0	0	0	
KANOELE	15	0.3	128	25	0.7	334	58	0.7	335	58	
KANOELE	16	0.1	58	12	0.4	190	33	0.4	190	33	
KANOELE	17	0.2	70	13	0.6	265	42	0.6	271	43	
KANOELE	1	0	0	0	0.1	41	9	0.1	41	9	
KAPUA	27	0	9	4	0.1	73	30	0.1	73	30	
KEAHOLE	4	196.4	8246	1	185.9	8246	1	185.8	8246	1	
KEAHOLE	5	121.9	4710	65	113.1	4710	65	113.3	4710	65	
KEAHOLE	2	0.1	14	7	1.1	224	25	1.2	224	25	
KEAHOLE	4	0.2	21	5	0.8	101	11	0.8	101	11	
KEAHOLE	5	0	1	1	0.6	77	10	0.61	77	10	
KEAHOLE	21	1.4	625	121	4.7	2052	238	4.81	2088	241	
KEAHOLE	22	0.7	308	63	3.6	1607	213	3.71	1630	214	
KEAHOLE	23	0.7	303	63	3.8	1672	229	3.8	1689	230	
OULI	25	0.1	80	19	0.4	445	88	0.4	445	88	
PAHAEWA	24	0	30	6	0.2	243	49	0.2	243	49	
PUNA	1	78.6	5291	18	57.4	6664	115	57.4	6665	115	
PUNA	3	0.3	41	4	6.6	1065	105	6.6	1066	105	
PUNALUU	26	0	46	10	0.4	374	71	0.4	374	71	
SHIPMAN	3	0	0	0	0	0	1	0	0	1	
SHIPMAN	4	0	0	0	0	1	1	0	1	1	
WAIMEA D	12	0.4	139	40	3.2	1418	211	3.2	1426	212	
WAIMEA D	13	0.3	152	32	2.5	1134	173	2.5	1118	174	
WAIMEA D	14	0.1	56	16	2.1	952	156	2.1	955	156	

24-hour Dispatch Cycle – Thermal Units

[illegible]

[illegible]

[illegible]

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Marginal Energy Costs 2011 vs 2013

(does not include cycling costs)

HOURLY MARGINAL ENERGY COST SUMMARY

2011 AVERAGES

HOUR	ANNUAL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	181.4	155.5	149.6	157.6	168.1	205.0	204.7	187.5	186.1	183.4	166.5	188.6	199.8
2	187.6	151.3	151.9	156.8	219.7	229.2	209.0	180.1	194.0	177.0	167.1	189.1	199.7
3	190.1	148.2	150.5	161.8	224.2	250.5	230.9	179.4	188.9	183.7	182.1	203.2	200.3
4	187.4	141.4	156.3	172.9	230.3	227.6	250.5	180.9	178.3	204.7	170.5	188.1	203.8
5	181.4	137.6	144.3	163.1	188.4	219.5	202.5	199.7	184.1	210.4	176.7	197.0	183.8
6	189.4	145.1	149.1	165.9	147.8	201.8	231.5	212.0	205.5	215.5	207.8	218.2	202.7
7	214.7	151.9	168.6	183.2	172.1	257.5	255.8	254.9	226.0	270.0	219.7	210.0	206.3
8	236.9	149.9	153.8	179.8	208.0	265.4	330.8	273.0	224.7	270.4	253.1	211.2	238.9
9	250.1	168.5	175.2	190.5	215.0	265.4	334.1	278.0	275.8	298.0	246.1	258.6	254.3
10	254.0	186.8	192.8	196.2	240.9	271.2	291.4	260.3	212.4	284.4	248.4	241.4	241.2
11	261.2	159.5	183.0	197.9	240.4	282.1	328.7	261.3	231.0	275.5	247.5	240.5	243.2
12	280.9	167.8	184.7	196.7	236.8	300.9	365.1	259.7	232.0	268.0	244.1	242.3	242.1
13	227.9	164.7	177.1	184.2	243.5	250.9	261.7	261.1	232.7	263.5	240.7	252.3	242.5
14	224.8	160.5	176.6	184.4	237.9	244.0	239.2	257.5	231.7	255.9	242.0	222.6	240.0
15	225.5	164.1	175.6	187.8	234.3	232.4	232.6	261.6	233.6	230.2	241.4	226.1	241.0
16	232.2	163.5	175.7	187.3	238.3	233.4	239.2	267.2	234.1	232.5	249.7	234.9	238.9
17	241.5	178.7	180.7	191.9	238.5	275.0	259.7	290.6	243.2	297.3	254.2	246.7	267.9
18	247.7	187.7	218.4	199.0	247.8	278.9	254.0	287.4	244.2	297.0	258.5	261.5	277.4
19	249.9	187.8	198.1	202.9	252.7	323.8	255.9	278.3	275.2	327.2	267.3	271.2	240.1
20	248.7	180.3	216.2	195.1	258.2	314.6	277.3	281.0	300.2	273.2	250.1	249.1	270.9
21	231.2	156.0	175.8	185.8	244.0	257.2	257.2	281.2	232.3	298.3	257.7	207.5	246.0
22	218.1	156.4	180.7	195.9	195.9	262.3	253.1	271.0	238.2	232.4	236.7	221.9	204.0
23	192.6	155.2	146.5	151.6	145.5	278.8	229.4	239.3	270.8	248.5	191.7	211.2	189.5
24	175.0	139.9	180.1	145.8	179.7	179.5	180.7	203.0	168.7	223.5	182.1	182.9	178.1
WEEKDAY	234.2	167.5	184.8	191.3	236.0	267.2	280.8	271.5	258.1	281.2	250.6	236.1	244.6
WEEKEND	180.1	150.0	155.4	164.9	186.6	220.7	210.1	208.5	196.4	207.6	189.1	188.8	191.9
WEEKEND	202.7	160.5	160.8	159.7	214.3	251.7	238.3	239.4	201.6	245.4	202.8	214.9	217.9
MONTH	216.5	158.7	171.7	179.8	217.1	249.7	248.8	245.7	227.7	251.9	225.9	221.6	224.2
MAXIMUM	365.1	210.8	344.8	311.4	286.7	368.1	297.4	412.4	407.4	362.0	328.1	318.8	402.8
MINIMUM	121.5	121.5	124.4	127.1	140.4	157.7	165.4	158.4	163.0	140.6	155.8	151.1	155.1

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HELCO Sensitivity Analysis

Sensitivity to day-ahead forecast of wind generation - Underprediction							
All wind case are simple variations of Case2a (Case U-B is Case 2a)							
		Actual Wind GWh	Forecast Wind GWh	Underforecast %	Production Cost $ 000	PGV Curtailment GWh	Loss of Spinning Reserve MW
Case U-A:	Tawhiri 7	56.5	56.5		279,595	0.6	0
	Tawhiri 13.5	71.3	71.3				
	HRD	43.2	43.2				
	Total	171	171.0	0.0			
Case U-B:	Tawhiri 7	56.5	56.5		281,556	0.6	0
	Tawhiri 13.5	71.3	71.3				
	HRD	43.2	0				
	Total	171	127.8	25.3			
Case U-C:	Tawhiri 7	56.5	56.5		281,788	0.6	0
	Tawhiri 13.5	71.3	0				
	HRD	43.2	43.2				
	Total	171	99.7	41.7			
Case U-D:	Tawhiri 7	56.5	56.5		283,015	0.6	0
	Tawhiri 13.5	71.3	0				
	HRD	43.2	0				
	Total	171	56.5	67.0			
Case U-E:	Tawhiri 7	56.5	0		285,040	0.6	0
	Tawhiri 13.5	71.3	0				
	HRD	43.2	0				
	Total	171	0.0	100.0			

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HELCO Sensitivity Analysis

Sensitivity to day-ahead forecast of wind generation - Overprediction							
All wind case are simple variations of Case2a.							
		Actual Wind GWh	Forecast Wind GWh	Overforecast %	Production Cost $,000	PGV Curtailment GWh	Loss of Spinning Reserve MW
Case O-A:	Tawhiri 7	56.5	56.5		279,594.5	0.6	0.0
	Tawhiri 13.5	71.3	71.3				
	HRD	43.2	43.2				
	Total	171	171.0	0.0			
Case O-B:	Tawhiri 7	56.5	61.3		277,779.4	1.6	5.0
	Tawhiri 13.5	71.3	71.3				
	HRD	43.2	92.0				
	Total	171	224.6	31.3			
Case O-C:	Tawhiri 7	56.5	61.3		281,165.6	3.1	8.4
	Tawhiri 13.5	71.3	118.3				
	HRD	43.2	92.0				
	Total	171	271.6	58.8			

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HELCO Sensitivity Analysis

Sensitivity to day-ahead forecast of wind generation - Production Cost Components							
						Variable O&M Costs	
	Production Cost	Fuel	IPP Purchases	Fixed O&M	Cycling Maint. Cost	Per MWh Costs	Hours U/S costs
	$,000	$,000	$,000	$,000	$,000	$,000	$,000
Case O-C:	281,165.6	179,689.80	80,176.0	11,454.1	5,730.0	558.1	3,607.4
Case O-B:	277,779.4	178,784.60	80,254.0	11,454.1	3,283.7	520.3	3,482.7
Case O-A:	279,594.5	181,106.90	80,335.6	11,454.1	2,245.1	494.4	3,958.4
Case U-A'							
Case U-B	283,555.5	182,596.30	80,335.6	11,454.1	2,440.1	496.5	4,232.8
Case U-C	281,787.8	182,844.80	80,335.7	11,454.1	2,394.3	494.9	4,264.0
Case U-D	283,015.4	183,671.60	80,335.7	11,454.1	2,615.4	498.7	4,439.9
Case U-E	285,040.3	185,218.30	80,335.6	11,454.1	2,805.9	493.3	4,737.9

Input Data Tawhiri Power 2013 costs

Cents/kWh

Year	Mon	Tawhiri Payment Rate 16-quarter Average On-Peak	Off-Peak
2013	1	17.580	14.388
	2	17.696	14.456
	3	17.824	14.532
	4	17.989	14.642
	5	18.167	14.764
	6	18.350	14.892
	7	18.544	15.024
	8	18.722	15.142
	9	18.883	15.250
	10	19.041	15.353
	11	19.191	15.449
	12	19.340	15.542

Input Data 2011 HELCO Avoided Costs

Cents/kWh

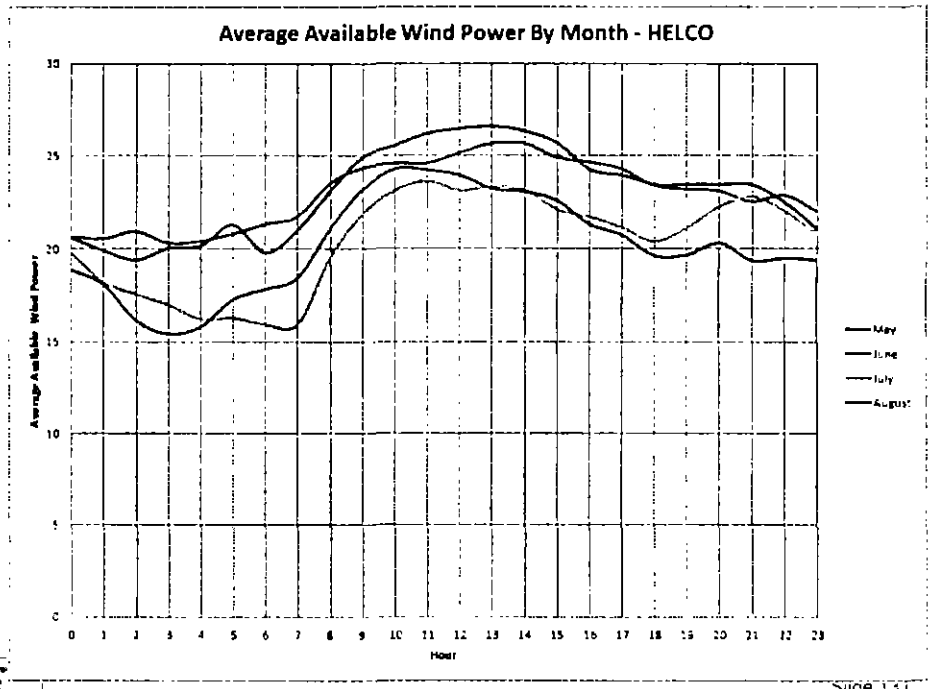
2011	HELCO Avoided Cost		Tawhiri Rates		Schedule Q
Month	On-Peak	Off-Peak	On-Peak	Off-Peak	
1	15.92	13.651	18.4	15.04	14.61
2	16.75	14.447	18.41	15.07	15.42
3	17.928	15.644	18.45	15.12	16.59
4	18.277	15.846	18.48	15.17	16.88
5	22.321	19.995	18.59	15.3	20.93
6	20.677	17.586	18.67	15.38	18.99
7	20.721	17.662	18.67	15.4	19.05
8	21.317	18.318	18.68	15.43	19.66
9	20.881	17.801	18.67	15.45	19.20
10	20.75	17.776	18.67	15.46	19.11
11	21.055	18.18	18.67	15.49	19.45
12	21.027	18.23	18.67	15.52	19.45
	19.802	17.09466667	18.5858333	15.3191667	18.27833333

Input Data 2011 HELCO Avoided Costs

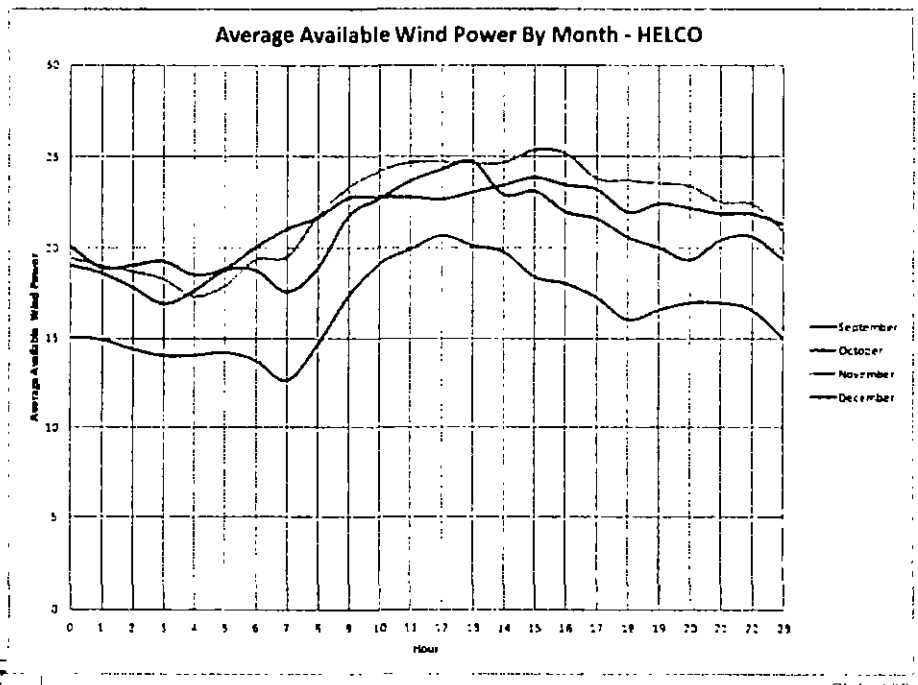
Cents/kWh

		Base		
Year	Mon	On-Peak	Off-Peak	Composite
2013	1	22.137	16.629	19.842
	2	22.137	16.629	19.842
	3	22.137	16.629	19.842
	4	22.137	16.629	19.842
	5	22.137	16.629	19.842
	6	22.137	16.629	19.842
	7	22.137	16.629	19.842
	8	22.137	16.629	19.842
	9	22.137	16.629	19.842
	10	22.137	16.629	19.842
	11	22.137	16.629	19.842
	12	22.137	16.629	19.842

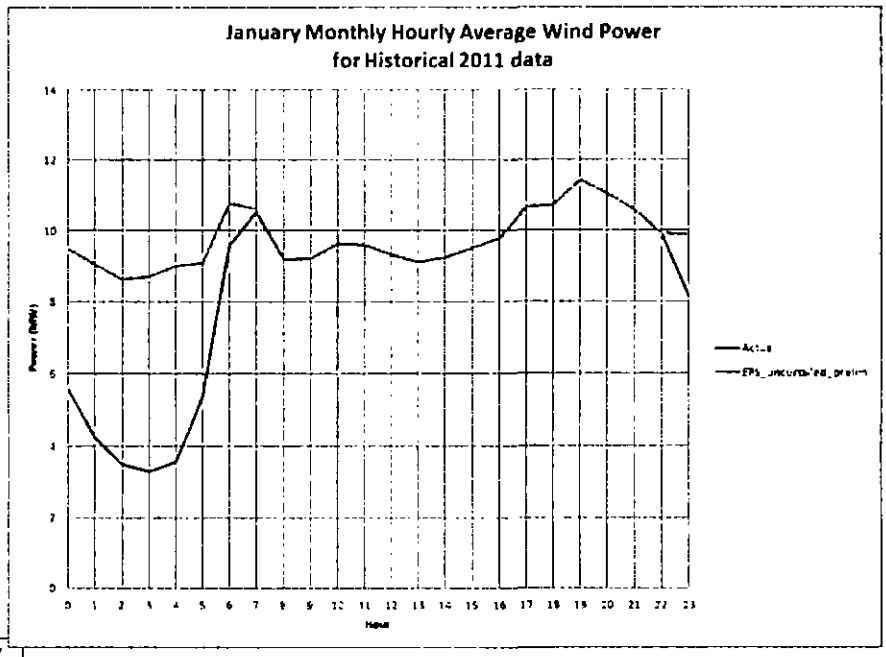
HELCO 2011: Monthly Wind



HELCO 2011: Monthly Wind



HELCO 2011 – EPS MW Calc vs Actual



2011 – HELCO Wind Summary

HRD		% HRD
Available Energy *	43,194 MWh	
System Curtailments	734 MWh	1.7%
Excess Energy Curtailment	2,092 MWh	4.8%
Total Curtailments	2,826 MWh	6.5%
Delivered to HELCO	40,368 MWh	93.5%

Tawhiri		% Tawhiri
Available Energy *	127,756 MWh	
System Curtailments	585 MWh	0.5%
Excess Energy Curtailment	10,210 MWh	8.0 %
Total Curtailments	10,795 MWh	8.5%
Delivered to HELCO	116,961 MWh	91.5%

* Assumes constant turbine availability

2011 – HELCO Non-Wind Summary

PGV		% PGV
Available Energy *	262,847 MWh	
System Curtailments	0 MWh	0%
Excess Energy Curtailment	29,941 MWh	11.4%
Total Curtailments	29,941 MWh	11.4%
Delivered to HELCO	232,906 MWh	88.6%

* Highest daily hour assumed available during night for same 24 hr period

Hydro		% Hydro
Available Energy *	46,129 MWh	
System Curtailments	0 MWh	0.0%
Excess Energy Curtailment	1,532 MWh	3.3 %
Total Curtailments	1,532 MWh	3.3%
Delivered to HELCO	44,597 MWh	96.7%

* Average of 20:00 and 08:00 hydro production used for the night

2011 – HELCO Renewable Summary

	Total	Wind	Hydro	Geothermal	% RE
Actual	1,217,281	157,329	44,597	232,906	35.7%
Available*	1,217,281	170,950	46,129	262,847	39.4%
100% Wind	1,217,281	170,950	44,597	232,906	36.8%
100% Geo	1,217,281	157,329	44,597	262,847	38.2%

* Does not include PV or energy efficiency

Notes:
1) "Actual" relates to 2011 actual production schedule
2) "Available" assumes all available RE without curtailments
3) "100% Wind" assumes no wind curtailment; hydro and geothermal curtailed as 2011
4) "100% Geo" assumes no geothermal curtailment; wind & hydro as 2011

MECO

Cycling Study
Additional Information

Fuel Prices - MECO

(price per barrel)	Reference	High	Low
Kahului Medium Sulfur Fuel Oil No.6	$110.16	$171.35	$67.34
Maalaea High Sulfur Diesel	$152.84	$232.59	$97.04
Maalaea Ultra Low Sulfur Diesel (April 2013)	$158.80	$241.66	$100.82

2012 Fuel Price Forecast – Issued Feb 2012

Avoided Costs- MECO

Cents/kWh

2011	MECO Avoided Cost (Maui Division)		2013 (Oct 1, 2012 Dkt 7310 Filing)	
Month	On-Peak	Off-Peak	On-Peak	Off-Peak
1	16.42	15.74	18.13	17.49
2	16.90	16.21	18.13	17.49
3	17.67	16.95	18.13	17.49
4	18.71	17.95	18.13	17.49
5	20.62	19.79	18.13	17.49
6	22.51	21.62	18.13	17.49
7	21.87	21.00	18.13	17.49
8	21.43	20.58	18.13	17.49
9	20.50	19.68	18.13	17.49
10	20.10	19.30	18.13	17.49
11	20.77	19.94	18.13	17.49
12	20.50	19.68	18.13	17.49

2011 – MECO Wind Summary

KWP		% KWP	%MECO
Available Energy *	131,515 MWh		
System Curtailments	1,397 MWh	6.7%	
Excess Energy Curtailment	8,203 MWh	1.1%	
Total Curtailments	9,601 MWh**	7.9%	
Delivered to MECO	121,652 MWh	92.5%	

*Available energy based on # turbines available with 2% line loss

** Avail. Energy + Curtailments did not exceed delivered energy (loss assumption)

2011 – MECO Renewable Summary

	Total	Wind	HC&S	% Renewable**
Actual	1,214,482	121,652	63,751	15.3%
Available*	1,214,482	131,515	63,751	16.1%

** does not include PV or Energy Efficiency

MECO Production Cost Simulations

SYSTEM PRODUCTION COSTS ($,000)		
	2011	2013
Case 1a	256,565	270,460
Case 2a	264,703	274,877
Case 3a	same as case 2a	273,946
Case 4a	insufficient curtail	274,049.0
Case 5a	insufficient curtail	273,144.0

MECO Production Cost Simulations

CURTAILMENT RESULTS							
	2011				2013		
	Curtailment (GWh)				Curtailment (GWh)		
	KWP1	KWP2	ULU		FIT3PV	KWP1	KWP2	ULU
Case 1a	0.1	0.0	0.0		0.8	0.4	4.1	0.8
Case 2a	0.2	0.0	0.0		1.1	2.5	11.9	3.8
Case 3a	na	na	na		1.1	15.0	2.6	0.6
Case 4a	na	na	na		1.0	2.5	11.6	3.6
Case 5a	na	na	na		1.0	14.7	2.6	0.6

MECO Production Cost Simulations – 2a

GENERATING UNITS - July 2013 - MW

Hour		1	2	3	4	5	6	7	8	9	10	11	12	13	14
KAHU	1	0.09	0.09	0.08	0.06	0.05	0.08	0.15	2.27	2.3	2.86	2.86	2.86	4.71	2.86
KAHU	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KAHU	3	7.69	7.69	7.69	7.69	7.69	7.69	7.69	7.84	7.85	5.75	9.13	9.91	11.72	8.75
KAHU	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	1	0	0	0	0	0	0	0	0	0	0	0	0	0.04	0
MAALA	2	0	0	0	0	0	0	0	0	0	0	0	0	0.04	0
MAALA	3	0	0	0	0	0	0	0	0	0	0	0	0	0.03	0
MAALA	4	0	0	0	0	0	0	0	0	0	0	0.03	0.03	0.04	0
MAALA	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	6	0	0	0	0	0	0	0	0	0	0	0.03	0.03	0.04	0
MAALA	7	0	0	0	0	0	0	0	0	0	0	0	0	0.02	0
MAALA	8	0	0	0	0	0	0	0	0	0	0	0.03	0.03	0.05	0
MAALA	9	0	0	0	0	0	0	0	0	0	0	0.03	0.03	0.04	0.03
MAALA	10	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0	0	0.16	2.01	2.01	2.05	0.94
MAALA	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	12	0.01	0.01	0	0	0	0	0.01	0	0.12	1.54	2.01	2.01	6.51	2.01
MAALA	13	0.01	0.01	0.01	0	0	0.01	0.01	0	0	0.22	1.13	1.42	3.22	0.22
MAALA	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAALA CC	14	15.92	15.92	15.8	15.72	15.71	15.78	15.99	16.83	17.13	25.38	27.56	27.56	27.56	27.56
MAALA CC	16	17.29	17.29	17.27	17.27	17.27	17.27	17.32	17.79	17.79	18.71	23.31	23.49	23.49	18.71
MAALA CC	17	15.6	15.32	11.42	4.83	4.33	10.75	17.84	19.86	20.49	27.06	27.06	27.06	27.06	27.06
MAALA CC	19	2.44	2.29	1.68	0.58	0.5	1.56	3.05	5.17	12.04	18.38	21.61	21.61	21.61	20.1
MAALA x	1	0	0	0	0	0	0	0	0	0	0	0.01	0.01	0.04	0
MAALA x	2	0	0	0	0	0	0	0	0	0	0	0.02	0.03	0.04	0

Hour		15	16	17	18	19	20	21	22	23	24
KAHU	1	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.93	2.28	2.12
KAHU	2	0	0	0	0	0	0	0	0.03	0	0
KAHU	3	8.75	8.75	8.75	8.75	8.75	9.69	8.75	8.94	7.83	7.76
KAHU	4	0	0	0	0	0	0	0	0.01	0	0
MAALA	1	0	0	0	0	0	0	0	0	0	0
MAALA	2	0	0	0	0	0	0	0	0	0	0
MAALA	3	0	0	0	0	0	0	0	0	0	0
MAALA	4	0	0	0	0	0	0.03	0.03	0	0	0
MAALA	5	0	0	0	0	0	0	0	0	0	0
MAALA	6	0.01	0	0.01	0	0	0.03	0.03	0	0	0
MAALA	7	0	0	0	0	0	0	0	0	0	0
MAALA	8	0.02	0	0.02	0	0.01	0.03	0.03	0	0	0
MAALA	9	0.03	0	0.03	0	0.02	0.03	0.03	0	0	0
MAALA	10	1.6	0.15	2.64	0.15	1.23	2.01	2.97	0.41	0.18	0.01
MAALA	11	0	0	0	0	0	0	0	0	0	0
MAALA	12	2.01	1.1	2.01	0.99	2.01	2.01	2.01	1.71	0.3	0.01
MAALA	13	0.24	0.21	0.34	0.21	0.21	1.36	0.53	0.47	0.01	0.01
MAALA	14	0	0	0	0	0	0	0	0	0	0
MAALA	16	0	0	0	0	0	0	0	0	0	0
MAALA	17	0	0	0	0	0	0	0	0	0	0
MAALA	19	0	0	0	0	0	0	0	0	0	0
MAALA CC	14	24.01	27.56	23.67	27.56	27.56	27.56	27.56	23.91	18.3	16.05
MAALA CC	16	18.71	19.56	18.71	18.79	23.49	21.56	18.52	17.86	17.33	
MAALA CC	17	27.06	27.06	27.06	27.06	27.06	27.06	26.4	20.54	18.51	
MAALA CC	19	21.55	18.38	21.55	18.38	21.01	21.61	21.61	18.22	16.74	5.78
MAALA x	1	0	0	0	0	0	0.01	0	0.01	0	0
MAALA x	2	0	0	0	0	0	0.03	0	0.01	0	0

MECO Production Cost Simulations 2a

GENERATING UNITS - July 2013 - MW

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Renewables - July 2013 - MW																								
FIT1&2PV	0	0	0	0	0	0.01	0.77	1.31	1.59	1.72	1.8	1.75	1.75	1.75	1.71	1.66	1.55	1.4	0	0	0	0	0	0
FIT12CSP	0	0	0	0	0	0	0.09	0.16	0.19	0.21	0.22	0.21	0.21	0.21	0.21	0.2	0.19	0.17	0	0	0	0	0	0
HC&S	9	9	9	9	9	9	9	13	13	13	13	13	13	13	13	13	13	13	13	13	9	9	9	9
FIT3PV	0	0	0	0	0	0	0	0	0	0	0	0	0.32	0	0	0	0	0	0	0	0	0	0	0
KWP1	21	15.8	20	22	22	26	25	24	25	11.9	8	5	1	13	5	19	11	25	27	27	28	28.2	27	28
KWP2	18.1	17.8	17	18	18	19	13	17.9	19	13	3.9	7.94	3	13	15.9	19	18	18.9	18.9	13	19	19	19	19
MAUI1A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.5	0.5	0	0	0
ULU	4	5	3.95	8	11	5	3.9	6	8	13	16	16	17	16	16	15	16	14	11	11	9	9	7	6
AVAILABLE RENEWABLES -																								
FIT1&2PV	0	0	0	0	0	0.01478	0.7765	1.3094	1.5864	1.7157	1.7968	1.7531	1.7501	1.752	1.7112	1.6611	1.5514	1.3952	0	0	0	0	0	0
FIT12CSP	0	0	0	0	0	0.0018	0.094	0.1597	0.1935	0.2093	0.2192	0.214	0.2135	0.2137	0.2087	0.2026	0.1892	0.1702	0	0	0	0	0	0
FIT3PV	0	0	0	0	0	0.00268	0.1398	0.2376	0.2878	0.3113	0.326	0.318	0.3175	0.3179	0.3105	0.3014	0.2815	0.2531	0	0	0	0	0	0
HC&S	0	0	0	0	0	0	0	13	13	13	13	13	13	13	13	13	13	13	13	13	0	0	0	0
HC&S OFF	9	9	9	9	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	9	9	9	9
KWP1	0	0	0	0	0	0	0	24	25	11.9	8	5	1	13	9	19	11	25	27	27	28	0	0	0
KWP1 WE	21	15.8	20	22	22	26	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWP1 WN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.2	27	28	28
KWP2	18.1	17.8	17	18	18	19	13	17.9	19	13	3.9	7.94	3	13	15.9	19	18	18.9	18.9	13	19	19	19	19
ULU	4	4	3.95	8	11	5	3.9	6	8	13	16	16	17	16	16	15	16	14	11	11	9	9	7	6
CURTAILMENTS																								
FIT3PV	0	0	0	0	0	0.00268	0.1398	0.2376	0.2878	0.3113	0.326	0.318	0.002	0.3179	0.3105	0.3014	0.2815	0.2531	0	0	0	0	0	0
KWP1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWP1-WE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWP1-WN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWP2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ULU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

MECO Marginal Energy Costs 2a

(does not include cycling costs)

HOURLY MARGINAL ENERGY COST SUMMARY

2012 AVERAGES

HOUR	ANNUAL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
22	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WEEKDAY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WEEKNIT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WEEKEND	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MONTH	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MAXIMUM	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MINIMUM	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

MECO Production Cost Simulations

Underprediction Cases							
		Actual Wind	Forecast Wind	Underforecast	Production Cost	Wind Curtailment	Loss of Spinning Reserve
		GWh	GWh	%	$,000	GWh	MW
Case U-A:	KWP1	128.9	128.9		272,651	0	0
	KWP2	90.5	90.5			4.6	
	ULU	87.9	87.9			0.2	
	Total	307.3	307.3	0.0			
Case U-B:	KWP1	128.9	128.9		274,877	2.5	0
	KWP2	90.5	90.5			11.9	
	ULU	87.9	0			3.8	
	Total	307.3	219.4	28.6			
Case U-C.	KWP1	128.9	128.9		274,218	0.9	0
	KWP2	90.5	0			9.7	
	ULU	87.9	0			2.3	
	Total	307.3	128.9	58.1			
Case U-D:	KWP1	128.9	0		278,125	0.9	0
	KWP2	90.5	0			10.4	
	ULU	87.9	0			2.2	
	Total	307.3	0.0	100.0			

MECO Production Cost Simulations

Overprediction Cases							
		Actual Wind	Forecast Wind	Overforecast	Production Cost	Wind Curtailment	Loss of Spinning Reserve
		GWh	GWh	%	$,000	GWh	MW
Case O-A:	KWP1	128.9	128.9		272,651	0.1	0
	KWP2	90.5	90.5			7.1	
	ULU	87.9	87.9			1.7	
	Total	307.3	307.3	0.0			
Case O-B:	KWP1	128.9	128.9		274,434	5.0	0
	KWP2	90.5	71.3			15.0	
	ULU	87.9	184.0			5.6	
	Total	307.3	384.2	25.0			
Case O-C:	KWP1	128.9	128.9		271,325	0.2	0
	KWP2	90.5	184.0			6.8	
	ULU	87.9	184.0			1.6	
	Total	307.3	496.9	61.7			
Case O-D:	KWP1	128.9	254.9		269,561	0.0	0
	KWP2	90.5	184.0			4.6	
	ULU	87.9	184.0			0.2	
	Total	307.3	622.9	102.7			

MECO Production Cost Simulations

Sansitivity to day-ahead forecast of wind generation - Production Cost Components							
					Variable O&M Costs		
	Production Cost	Fuel	IPP Purchases	Fixed O&M	Cyrling Maint. Cost	Per MWh Costs	Hours I/S costs
	$,000	$,000	$,000	$,000	$,000	$,000	$,000
Case O-D:	269,561	176,598	65,354	18,957	6,581	515	1,555
Case O-C:	271,325	178,565	65,150	18,957	6,437	552	1,664
Case O-B:	274,434	183,048	63,895	18,957	6,101	639	1,794
Case O-A: Case U-A:	272,651	179,197	65,114	18,957	7,205	512	1,666
Case U-B	274,718	181,958	64,431	18,957	6,948	633	1,785
Case U C	274,218	180,317	64,843	18,957	8,012	478	1,611
Case U-D	278,125	181,448	64,802	18,957	10,837	478	1,604

Docket No. 2011-0206 – Reliability Standards Working Group

Comments of the Hawaiian Electric Companies Regarding HELCO/MECO Cycling Study Final Report

During the January 24, 2013 RSWG stakeholder meeting, Colton Ching, Vice-President – Energy Delivery, provided the Hawaiian Electric Companies' comments on the HELCO/MECO Cycling Study Final Report ("Report") prepared by Electric Power Systems Inc. ("EPS") and presented during the meeting. Mr. Ching discussed the Companies' strategies for implementing recommendations contained in the Report, discussed the detailed work plans for HELCO and MECO, and provided the Companies' closing remarks with regard to the Report. Because the content of the January 24, 2013 meeting was not transcribed or otherwise recorded, the Companies respectfully submit the following summary of Mr. Ching's remarks for interested parties' information and for the record.

Mr. Ching noted that there were three "bottom line" conclusions identified as a part of the HELCO/MECO Cycling Study ("Study") work. First, the Study identifies potential methods to achieve lower generation costs for the Maui and Big Island systems. Second, the Study identifies potential methods to reduce excess-energy curtailment of as-available generation. And third, the Study confirms that reliability of the Maui and Big Island electric systems can be maintained while achieving these outcomes.

Mr. Ching discussed a four part strategy to facilitate implementation of the conclusions and recommendations contained in the Report. These included:

(1) Expeditiously incorporate study results into actions. This would include beginning work on both short-term and long term initiatives to put into place the many findings and recommendations of the Study.
(2) Perform system security and production simulation analyses as was done in the Study on a periodic basis. As the Companies encounter changes to their systems (changes in load, generation mix, fuel prices), periodic analysis will help to provide insights on new or different ways to commit and dispatch generation, the maintenance of efficient generation costs and identifying any avoidable instances of as-available generation curtailment.
(3) Continue to add new renewable energy resources to the Maui and Big Island grids focused on displacing fossil fuel generation and to substitute for fossil fuel generators.
(4) Regularly update the PUC on the Companies' progress in implementing the above three items.

Mr. Ching also discussed specific work plans for the HELCO and MECO systems. For HELCO, the Company will continue to cycle and layup certain units, like the Shipman units in Hilo as appropriate and consistent with maintenance of system reliability. HELCO will also revise its work plan and budgets to enable regular cycling of units identified in the study as

being beneficial to system generation costs and a reduction in as-available generation curtailment. The Company would also work to verify the modeled dynamic properties of its generating units, work with Independent Power Producers ("IPPs") to perform similar verifications of their units; and operationalize the wind and solar forecasting work performed to date at HELCO. HELCO will also continue with plans to procure additional dispatchable renewable resources and continue to seek operational and economic provisions in existing as-available contracts that can reduce overall system costs.

For MECO, the Company will revise its work plans and budgets to enable regular cycling and transmission solutions to reduce and eliminate must-run conditions of the Kahului units. A transmission project in the Wailuku-Kahului area has been identified as one way to achieve this. Additionally, MECO will build on its AGC capabilities and subject more units to AGC control. Finally, the Company will work to operationalize the wind and solar forecasting work performed to date at MECO.

Both utilities will also continue to look at new technologies – storage, forecasting, demand response, smart technologies – that can aid in reducing costs into the future.

In closing, Mr. Ching noted that similar to the work at HELCO and MECO, Hawaiian Electric will plan on performing similar analyses on Oahu. Although excess energy curtailment is not yet occurring on Oahu, performing such an analysis now may identify ways to operate the Oahu system at lower costs and focus efforts to avoid any future instances of excess energy curtailment. Mr. Ching committed again to updating the PUC on a regular basis on the Companies' work to operationalize the recommendations in the Study and noted that the studies performed for the HELCO and MECO systems were not a single event but rather will be a part of an ongoing re-assessment process on how best to run the Companies' generation systems in light of changes to the respective grids.

Mr. Ching concluded on a personal note that the cycling study work performed by EPS was borne out of opportunities for improved generation efficiency and excess energy avoidance identified through work done by the Commission's consultant Brendan Kirby. Mr. Ching noted that the RSWG process helped to highlight that utilities do not have all of the answers in this fast changing environment, that there is a lot of knowledge and new ideas which stakeholders can bring to the table, and that collectively, we can do great things if we choose to work together toward a common objective.

GE Energy Management

Ancillary Services Definitions and Capability Study

Part 1, Tasks 1-2, Final Report

For Hawaii Natural Energy Institute

Principal Contributors:

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Rameet Kohli

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Michael O'Connor

Sundar Venkataraman

Revision 1

Date: 12/19/2012

imagination at work

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Foreword

This report was prepared by General Electric International, Inc. acting through its Energy Consulting group based in Schenectady, NY **through the support of the Hawaii Natural Energy Institute and under a contract with the Research Corporation of the University of Hawaii**. Technical and commercial questions and any correspondence concerning this document should be referred to:

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1 Study Background and Objectives

The purpose of this study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems and particularly the Hawaiian Islands. The results of this study may be: incorporated into the Hawaii Reliability Standards Working Group's proposals for new reliability standards; used to develop recommendations for revised generation interconnection technical requirements; provided to the Hawaii Public Utility Commission for consideration and adoption; and used to inform the Hawaii utilities' Integrated Resource Planning process.

The GE team has been deeply involved in analyzing the impact of renewable generation on the HECO systems and has performed 9 system-level studies over the past 5 years. The power output form Variable Generators (VG) such as wind and solar plants, by definition is variable. Also, there is a certain amount of uncertainty associated with this generation in the hours preceding actual operations. The generation from VGs is not only variable within the hour and is also variable on a longer timeframe such as daily, weekly and monthly time frame. The variability of VGs within the hour (along with the variability associated with the load) is handled by the system operator through the use of regulation and load-following (spinning) reserves. This study will leverage the findings of the renewable impact studies performed by GE.

The project focuses on four tasks[1]:

- Task 1: Define a standardized set of ancillary services along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems, and provide for the integration of variable generation technologies.
- Task 2: Assess resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Task 3: Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island).
- Task 4: Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

This report presents the results of Tasks 1 and 2 of the study. The results of Tasks 3 and 4 will be presented in a separate report.

[1] After the study was commenced, it was decided that Task 1 should be generic and address all ancillary services that are in service or under development in the U.S., as well as internationally, regardless of their applicability to the Hawaii system. The applicability of the ancillary services to the Hawaii system was included as a portion of Task 3 of the study. Therefore, in Task 1, the difficulty in adopting some of the researched ancillary services for the Hawaii system will be acknowledged, but not discussed in detail.

2 Summary of Results

Ancillary services are required to maintain reliable operations of the electric power system. With Hawaii Natural Energy Institute (HNEI), in cooperation with the Hawaii Reliability Standards Working Group (RSWG), GE has worked to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for the Hawaiian Islands. This written summary report for Tasks 1-2 and the attached PowerPoint slides in Appendix A documenting Tasks 1-2[2], comprise the Part 1 final report from GE for use by HNEI and the Hawaii RSWG. This portion of the study focuses on ancillary services definitions, interconnection requirements and technologies capable of providing these ancillary services in technology-neutral, functional terms. These definitions may not reflect the current practices on the Hawaiian Islands for delivering ancillary services, but the ancillary services as defined here represent viable options for any electric power system to maintain reliable operations and should be considered as options for the Hawaiian Islands. Table A.2-1 summarizes the ancillary service definitions.

[2] 2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx

Table A.2-1*Ancillary Services Definitions*

Ancillary Service: **Normal and contingency conditions**	**Brief Description:**	**Notes:**
Frequency Responsive Reserves/ Primary Frequency Response:	Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change.	- Immediate response - Typically less than 15 min - Provided continuously - Proportional to frequency deviation
Regulation:	Used continuously during normal operations to correct short-term imbalances between supply and demand Deployed via AGC signals.	- At least every 6 seconds - Typically 5-10 min - Provided continuously - Magnitude varies, proportional to size of imbalance
Load Following:	Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future.	- Response time and duration needs to be established - Anticipated to be continuous - Magnitude varies, proportional to size of imbalance
Contingency Conditions		
Spinning Reserves:	Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately.	- Response is immediate will full response within 10 min - Various durations - Intermittent use, after a disturbance - Magnitude varies

Non-spinning Reserves:	Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate.	- Full response within 10 min - Various durations - Intermittent use, after a disturbance - Magnitude varies
Replacement Reserves:	Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately.	- Response within 30 to 60 min - Various durations - Intermittent use, after a disturbance - Magnitude varies
Additional Services		
Black Start:	Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout.	- Resources available after a black-out - Various durations - Only after a black-out - Magnitude varies
Reactive Power/ Voltage Support:	Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system.	- Response in seconds - Various durations - Provided continuously - Typical power factor range of 0.95 leading to 0.95 lagging

The Part 2 final report documents the GE study results for Tasks 3-4 and provide analysis of Hawaii-specific scenarios including comparison of current practices on the Hawaiian Islands to the ancillary services and interconnection requirements proposed in Part 1. Part 2 offers a number of procedures and methodologies to determine the need for, provide, and value ancillary services for an electric system. While the examples and data used in Part 2 are Hawaii-specific, the procedures and approaches outlined should be applicable and useful for any system.

2.1 Key Terminology

The following definitions for key terminology are relevant throughout the content of this study and should be interpreted as described below.

Area Control Error (ACE):

The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. Source - NERC Glossary (2008)

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

> **NIA** is the algebraic sum of actual flows on all tie lines.
>
> **NIS** is the algebraic sum of scheduled flows on all tie lines.
>
> **B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
>
> **FA** is the actual frequency.
>
> **FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
>
> **IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for **Hawaii, ACE = – 10B (FA – FS).** This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. Source - Revised definition per Hawaii RSWG Glossary

Automatic Generation Control (AGC):

Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule, plus the Frequency Bias (i.e. ACE). Source - NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Droop Response:

Droop response is a near instantaneous means of proportionally adjusting a resource's real-power to resist a change in frequency; allowing a system of resources to operate in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide

100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.

Droop response can be provided by any frequency-sensitive resource.

Resource:

A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning:

Historically, the terms "spinning" and "non-spinning" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

3 Study Results

3.1 Task 1: Identify and define ancillary services needed for integration of new generation resources, including various renewable generation technologies

Every bulk system requires a suite of ancillary services to provide grid reliability today and to integrate variable renewable generation. The objective of Task 1 is to gather information to help define a standard set of ancillary services with functional performance requirements/definitions, interconnection requirements and other system considerations. Although each power system uses the same ancillary services in functional terms, in practice there are significant differences across regions and balancing areas in which entities produce specific ancillary services and how these services are acquired, controlled, delivered and compensated. Thus it is important to distinguish between the functional role of each ancillary service and the local, system-specific practices for its provisioning (for instance, whether a particular service is performed only by a utility-owned generator or included as an operational interconnection requirement of third party generators). Tasks 1 and 2 therefore describe the ancillary services, and include descriptions to distinguish some of the ways by which Hawaii's electric systems name and deliver these services today.

GE identified and defined all of the ancillary services that are currently being used or under development in different parts of the world, in regulated as well as deregulated regions, with a focus on real-power energy balancing services such as regulation, load following and various types of contingency reserves which are impacted more by renewables. The purpose of this task is to gather the most recent information and best practices with respect to ancillary services with the full understanding that some of these ancillary services may not be applicable to the Hawaii utilities.

Ancillary services[3] are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system. In addition to ancillary services, other interconnection requirements are placed on resources to ensure reliable operation of the grid. These ancillary services and interconnection requirements enable the system operator to meet the required operations and reliability standards set by NERC. The ancillary services, interconnection requirements, and reliability standards are dependent on the characteristics of a power system.

[3] FERC defines ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

The set of ancillary services that provide direct support for the reliable and economic operation of the power system are:

Real-Power Energy Balancing Services

- Frequency Responsive Reserve /Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

Additional Services

- Black Start
- Reactive Power/Voltage Support

Generation characteristics that are specified via Interconnection Requirements are:

- Power Factor & Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and minimum response
- Over and Under Frequency Controls
- Inertia

Real power balancing services that come into play during normal and contingency operating conditions are shown in the figures below. ***Figure 3-1*** and ***Figure 3-2*** illustrate the operational timeframes for some services.

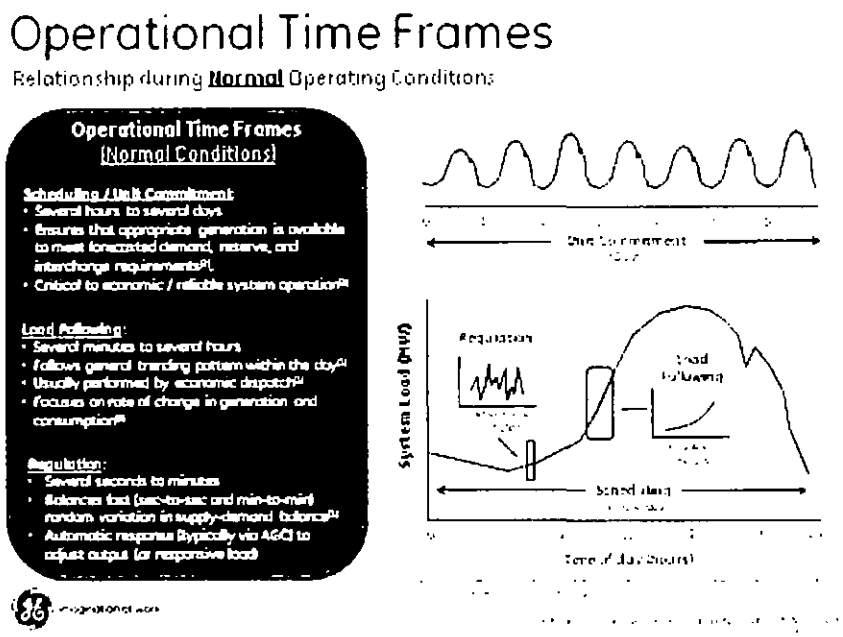

Figure 3-1 *Normal Operating Conditions*

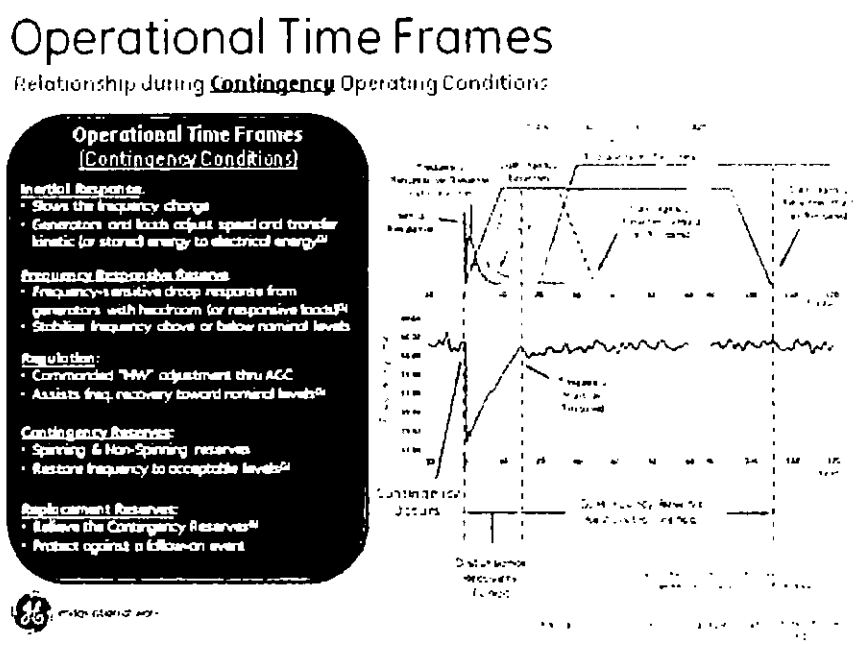

Figure 3-2 *Contingency Operating Conditions*

The purposes of these ancillary services are defined below. See the attached PowerPoint slides in Appendix A entitled "2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx" slides 17-27 for the detailed definition for each ancillary service in functional terms for its performance requirements (e.g., reaction speed for service provision, time duration, deployment frequency, and MW magnitude of response). Differences from these functional definitions and the current practices of the Hawaiian Islands are explored in Part 2 of this study.

For normal and contingency conditions:

Inertial Response: Provides system stability during normal conditions; slows frequency change during contingency events. Provided by synchronized resources (also via power electronics). Inertial response is not obtained as an ancillary service. Rather it is autonomously provided by all synchronous units. It can also be provided by variable generators if they are equipped with synthetic inertia feature. These inertial response requirements for VGs are addressed through the interconnection requirements.

Frequency Responsive Reserves/ Primary Frequency Response: Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change.

Regulation: Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals.

Load Following: Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future.

For contingency conditions:

Spinning Reserves: Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately.

Non-spinning Reserves: Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate.

Replacement Reserves: Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately.

Additional Services:

Black Start: Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout.

Reactive Power/ Voltage Support: Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system.

The definitions and details of these ancillary services are summarized in Table XX below and discussed in further detail in Appendix A.

Table A.3-1*Ancillary Services Definitions*

Ancillary Service: **Normal and contingency conditions**	**Brief Description:**	**Notes:**
Frequency Responsive Reserves/ Primary Frequency Response:	Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change.	- Immediate response - Typically less than 15 min - Provided continuously - Proportional to frequency deviation
Regulation:	Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals.	- At least every 6 seconds - Typically 5-10 min - Provided continuously - Magnitude varies, proportional to size of imbalance
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3.1.1 Developments in Ancillary services – Emerging regulations, services and requirements

Recent developments in ancillary services for several regions in North America were researched to help identify emerging and additional services that may be applicable to Hawaii. As renewable *penetration increases, many systems are challenged to examine existing and future requirements for* reliability. Here are some highlights of the findings of this research.

Inertial Response (ERCOT)[4]

ERCOT is evaluating requirements for inertial response. Introduced tool (2010) to monitor online conventional generation, spinning reserves, and ratio of wind to total generation ... system operator can adjust unit commitment if available inertial response is insufficient.

Primary Frequency Response

Frequency Responsive Reserve (WECC):

A Frequency Responsive Reserve (FRR) procedure was proposed by WECC in 2005[5].

NERC BAL-002-WECC-1 *(2008)* requires 50% of contingency reserves to be spinning AND frequency responsive. NERC BAL-012-WECC-2-CR *(FRR Criterion, 2009)* establishes minimum required FRR to prevent under-freq. load shedding (UFLS) during loss of generation event.

Primary Frequency Response (ERCOT):

ERCOT is the only balancing area that guides its minimum frequency response. The protocols also discuss the required primary frequency response from wind powered generation resources with standard generation interconnection agreements signed after January 1, 2010. Wind units are required to provide primary frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.

Secondary Frequency Response

Load Following (CAISO): Flexible Ramping Revised Draft Proposal – August 2012

In WECC there is a stakeholder effort to develop market-based flexible ramping products. The load following service attempts to provide sufficient ramping and flexibility to handle 5-minute supply/demand changes.

Analogous to Load Following: Flexible ramping product addresses ramping issue before the binding real-time dispatch (RTD) ... Regulation addresses ramping issue after binding RTD.

As part of NERC Project 2010-14.1 standard BAL-012-1 is developed to require a balancing authority to develop and document plants for the appropriate mix of operating reserves. This will include adequate Regulating Reserve, Contingency Reserve and Frequency Responsive

[4] Reference [3] NREL: National Renewable Energy Laboratory, Operating Reserves and Variable Generation, August 2010

[5] See above footnote 5, Reference [3]

Reserve. Comments have been received (period closed July 2012) and are available here: http://www.nerc.com/docs/standards/sar/comments_received_PAL-015_070312.pdf

Hawaii requires 100% of all contingency reserves to be frequency responsive.

Ramp Capability for Load Following (MISO): MISO white-paper - July 2011

MISO is investigating improved Load Following options ... considering several approaches for "pre-ramping" resources for better future interval positioning.

They appear to be gravitating toward a "market product" which prices ramp capability. An incentive is provided to participate to avoid "out of merit" dispatch. The price would be "cleared" based on resource opportunity cost, and "paid-for" thru cost allocation similar to other ancillary products.

Regulation Performance Compensation (FERC Order 755): Issued in October 2011

FERC found "current methods for compensating resources for the provision of regulation are unduly discriminatory". Order 755 requires all RTOs and ISOs to modify their tariffs to provide for a two-part payment to regulation resources:

- 1st Part: Payment for keeping a resource's capacity in reserve in the event that it is needed to provide regulation.
- 2nd Part: Payment shall be a performance payment that reflects the amount of work that each resource performs in real-time.

3.1.2 Interconnection Requirements

Interconnection standards enable the system to meet its reliability standards by requiring generators:

- To have certain capabilities that directly helps with the system reliability
- To have certain capabilities that enable it to provide ancillary services that are required for system reliability.

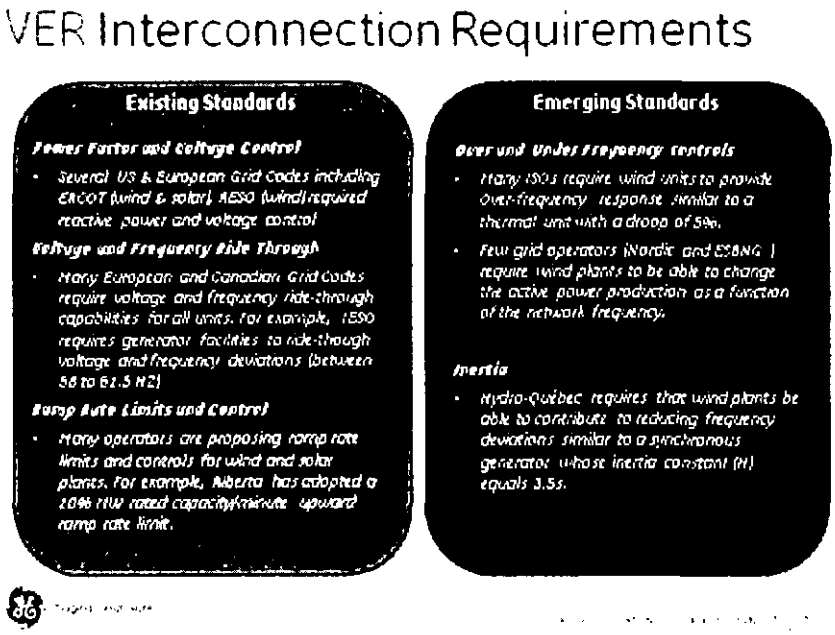

Figure 3-3 *Interconnection requirements for Variable Energy Resources*

More information on these interconnection requirements and example of regions that have implemented some of these interconnection standards can be found in Appendix A slides 44-52. More detail on recommended interconnection requirements can be found in the Part 2 report and are summarized in Table A.3-2 below.

Table A.3-2*Interconnection Requirements*

Interconnection Requirement:	Brief Definition:
Reactive Power & voltage Control	Capability to provide reactive power output within a certain power factor range and the capability to regulate voltage within this range
Fault Ride-through	Capability of the generator to ride-through (predetermined) temporary voltage and *frequency deviations*
Ramp Rate Limits and Control	Capability to ramp limit the output of a generator under certain conditions
Over and under Frequency Control	Capability to automatically increase and decrease (sustained) output under low and high frequency conditions respectively
Inertia	Capability to provide an immediate response to a drop in system frequency

Per a recent NREL paper (spring 2012): common active power control requirements in the US for wind are as follows:

- Curtailment control
- Ramp rate control (for curtailments and startup)
- Regulation UP (for under-frequency)
  - Adjustable droop
- Regulation down for over-frequency
  - Adjustable droop
- High wind shutdown
- Rate variation control
- Inertia
- Primary frequency response

Of the above, a couple of the key developments with respect to interconnection requirements are discussed below.

Inertia Requirement for Hydro Quebec:

Hydro-Québec requires that wind plants be able to contribute to reducing frequency deviations similar to a synchronous generator whose inertia constant (H) equals 3.5s

Primary Frequency Response Requirement for ERCOT:

Many ISOs require wind units to provide Over-frequency response similar to a thermal unit with a droop of 5%. .

Few grid operators (Nordic and ESBNG) require wind plants to be able to change the active power production as a function of the network frequency. In ERCOT, wind units are required to provide primary frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.

Recommendations regarding which of the above-mentioned ancillary services and interconnection requirements are suitable for Hawaii will be discussed in Task 3.

3.1.3 Other Considerations

Several additional considerations affect ancillary service delivery and system economics and the ability to meet renewable energy goals. These considerations cannot be addressed directly by interconnection requirements or ancillary services. There may be a need for other mechanism as listed below.

Reduced Minimum Generation Capability:

Enabling resources to operate with reduced minimum generation capacity increases the potential for increased online reserves and the potential for more granular ancillary service participation. More online reserves may help avoid curtailment of renewable and lower cost generating assets.. This should also improve system-level load following capability and provide options for improved portfolio management to hedge against uncertain conditions. In general, there needs to be a mechanism within power systems such as planning rules or tariffs to incent more flexibility in generators, i.e. lower turndown, faster ramp rate, shorter start time and the ability to cycle.

Short-circuit Strength:

Short-circuit levels on transmission lines may decrease if synchronous generators are replaced by renewables. Synchronous generators may need to be online to maintain minimum short-circuit levels on the system. Relays and protection devices that detect short circuits by monitoring the current and need a minimum current for reliable operation (lower limit for short circuit levels). Since Hawaii anticipates high penetrations of renewables, additional studies are recommended to try and identify any issues with short-circuit strength.

Short-circuit Ratio:

The short circuit ratio as seen at the point of interconnection of non-synchronous generators can decrease. This can happen even at the same level of commitment of synchronous generators but at higher penetration of non-synchronous resources. The decreased short-circuit ratio can lead to controller instability issues in the power electronics control of wind and solar generators.

Load Shaping:

Load shaping considers proactive movement of demand-side resources or non-dispatchable load to provide a more manageable daily load shape, i.e. incentivize / prohibit charging of PEVs at certain times of day. "Load shaping" may provide an opportunity to reduce the amount of other ancillary services that are required. We anticipate that this would be a procedural implementation rather than ancillary-service based approach. System operators need to carefully consider how to monitor, incentivize, and enforce the targeted load adjustments.

3.1.4 Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

The unique characteristics of the Hawaii system needs to be taken into account in order to determine the additional ancillary service and interconnection requirements. These characteristics are discussed below.

- The Hawaiian Islands are comprised of relatively small island systems: HECO~1200 MW, MECO ~200MW, HELCO~195 MW peak load. The relative small island systems make it challenging to maintain frequency.
- There are no interconnections between the Hawaiian Islands or the Mainland. Any imbalance between load and generation affects frequency, a small frequency bias.
- There is a higher Rate of Change of Frequency (ROCOF) due to system events. The ratio of unit size or renewable energy project size to system size is high.
- Hawaii has leaner operations than other systems. There is a relatively high cost of energy and ancillary services (that are currently provided as a bundled service with energy) due to high fuel prices.
- Historical reasons such as existing purchase power agreements, system requirements for UFLS, ROCOF, transmission constraints, ramping, physical and emission limits require the use of some Must run/scheduled units.
- Each Hawaiian Island has a single vertically integrated utility, multiple IPPs and third-party dispersed generation with no centralized power markets to purchase or sell excess generation
- While fewer opportunities for transaction "liquidity", ancillary service value can be calculated/estimated to provide incentives/payments to providers of ancillary services – ancillary services do not need to remain in bundled utility offering.
- The Hawaiian Islands have large amounts of distributed generation.

- Clean Energy Mandate includes RPS target of 40% and 4,300 GWH reduction for Energy Efficiency Portfolio Standards by 2030; high wind and solar generation potential in MECO, geothermal in HELCO.
- Hawaii has specific operating criteria to maintain system frequency and voltage and provide adequate reserves.

The unique characteristics of the Hawaii system will be taken into account while determining the applicability of the researched ancillary services and interconnection requirements.

The current operating criteria of note and the impact on the current provision of ancillary services on the Hawaiian Islands are included in Task 3.

3.2 Task 2: Identify which technologies can provide each ancillary service.

Using the ancillary service definitions developed in Task 1, GE identified and summarized in a table which generation, transmission, storage and demand-side technologies are able to provide each ancillary service given current technology capabilities and fuel availability, without screening or limiting the options with respect to economic cost-effectiveness. As requested, GE generally limited technologies to those that are available in commercial or pilot applications today and provide current deployment cost estimates, but do not speculate about future cost projections.

The generation technologies are broken down by fuel (for example, gas units) and type (for example, simple cycle gas turbine) without focus on the actual make or model. GE Identified the approximate resource size for each technology and each ancillary service. Background and reference citations as available for each technology and ancillary service capability match are provided.

Table A.3-3 *Ancillary Services Capabilities by technology*

Technologies	Ancillary Services Compatibility								
	Inertial Response	Frequency Responsive Reserve	Regulation	Load Following	Spinning Reserve	Non-Spinning Reserve	Replacement Reserve	Voltage Support	Black Start
Generation									
Solar Thermal	A	T	T	T	T	---	---	A	T
Solar Photovoltaic (Transmission Connected)	T	T	T	T	T	T	T	T	---
Wind (non-synchronized / power conversion)	A	A	A	A	A	T	T	A	---
Wind (synchronized)	A	A	A	A	A	T	T	A	T
Hydropower	A	A	A	A	A	A	A	A	A
Geothermal	A	A	A	A	A	---	---	A	T
Biomass	A	A	A	A	A	---	---	A	---
Coal	A	A	A	A	A	---	---	A	---
Combined Cycle (Gas/Oil: Sm. HD/Aero) (1x1)	A	A	A	A	A	A	A	A	A
Combined Cycle (Gas/Oil: Heavy-duty) (1x1)	A	A	A	A	A	A	A	A	A
Simple Cycle (Gas/Oil: Small HD/Aero)	A	A	A	A	A	A	A	A	A
Simple Cycle (Gas/Oil: Heavy-duty)	A	A	A	A	A	A	A	A	A
Reciprocating Engines (Gas/Diesel/Bio)	A	A	A	A	A	A	A	A	A
Energy Storage									
Pumped Hydropower	A	A	A	A	A	A	A	A	A
CAES - Comp. Air Energy Storage	E	E	E	E	E	E	E	E	T
Solid Batteries	E	E	A	E	A	E	E	E	E
Flow Batteries (Redox)	T	T	T	T	T	T	T	T	T
Flywheels	E	E	A	---	---	---	---	T	---
PEV	T	T	E	T	T	T	T	T	T
Fuel Cells (PEM)	T	T	T	T	T	T	T	T	T
Demand Response									
Fast Auto DR	T	A	A	T	A	A	A	---	---
Direct Load Control	T	A	E	T	A	A	A	---	---
Interruptible Load	T	A	T	T	A	A	A	---	---
Price Responsive Demand	T	T	T	T	A	A	A	---	---
Transmission									
Synch. Cond.: Large motor frame	A	---	---	---	---	---	---	A	---
Synch. Cond.: Air-cooled generator frame	A	---	---	---	---	---	---	A	---
Synch. Cond.: H2-cooled generator frame	A	---	---	---	---	---	---	A	---
Shunt FACTS devices (STATCOM, SVCs)*	---	---	---	---	---	---	---	A	---
HVDC Transmission Technologies*	---	---	---	---	---	---	---	A	A
Desirable Attributes / Retrofit Options									
Improved Turndown (MinGen) Capability	✓	✓	✓	✓	✓			✓	
Elevated Ramp-rate Capability		✓	✓	✓	✓	✓	✓		✓
Faster Startup Capability						✓	✓		

*Dynamic voltage support

A	Available commercially
E	Emerging capability in demonstration phase
T	Technically feasible, but not currently being pursued

Note: GE Wind Turbines are capable of providing governor response with a dead-band of up to +/- 36 mHz. For frequency deviations that extend beyond +/- 36 mHz, the default response for the turbine governors is to provide a proportional response back to the droop characteristic. Further, synthetic inertia can also be availed from the wind turbines in events of severe frequency excursions. The stored kinetic energy in the wind blades can be released during such events to assist the grid and arrest the frequency drop and frequency nadir. GE Wind Turbines have a deadband of 200 mHz for provision of synthetic inertia. For AGC-based "MW raise/ MW lower" regulation signals, the governor dead-band does not apply. Wind turbines are also capable of providing sufficient responsiveness for spinning reserve; however, a related factor that needs to be considered is the required duration that the spinning reserve response must be sustained once it is deployed. The required response period is more directly tied to the site-specific wind sustainability than the equipment itself.

Table A.3-4 *Technology characteristics*

Technologies	Plant Size (MW)				Cost Estimates		Flexibility			
	Minimum	Minimum (Typical)	Maximum (Typical)	Maximum	Total Overnight Cost in 2010 (2009 $/kW) for stated size (MW)	Resource Size Assumed in Cost Estimate (MW)	Turndown Load Level	Ramp Rate Capability (thermally stable)	10-Minute Output Available (from offline)	30-Minute Output Available (from offline)
Generation					$/kW	MW	%MW	%MW/min	%MW	%MW
Solar Thermal	0.1	1	100	200	$4600 - 8100	200	12-15%	3-7%*	0%	0%
Solar Photovoltaic (Transmission Connected)	0.001	0.05	5	150	$2100 - 3900	10	---	Rapid*	100%	100%
Wind (non-synchronized / power conversion)	0.001	1	100	450	$1500 - 2500	100	< 10%	Rapid*	100%	100%
Wind (synchronized)	0.001	1	100	450	$1500 - 2500	100	< 10%	Rapid*	100%	100%
Hydropower	0.001	0.5	50	650	$2200 - 4800	500	20-40%	25-100%	100%	100%
Geothermal	0.05	1	30	180	$2500 - 9900	50	12-15%	3-7%	0%	0%
Biomass	0.1	5	50	75	$2900 - 5800	50	35-40%	3-7%	0%	0%
Coal	0.1	10	400	1300	$1900 - 3900	600	35-40%	3-7%	0%	0%
Combined Cycle (Gas/Oil Sm. HD/Aero) (1x1)	10	25	60	120	$1000 - $1800	55	20-40%	20-40%	0-75%	75-100%
Combined Cycle (Gas/Oil Heavy-duty) (1x1)	60	120	300	500	$900 - 1500	615	25-70%	3-11%	0-60%	10-100%
Simple Cycle (Gas/Oil: Small HD/Aero)	1	20	40	100	$800 - 1300	45	25-50%	25-50%	0-100%	100%
Simple Cycle (Gas/Oil: Heavy-duty)	40	80	200	330	$500 - 800	211	15-70%	4-16%	0-75%	100%
Reciprocating Engines (Gas/Diesel/Bio)	0.01	1	5	20	$700 - 1300	10	50%	35%	100%	100%
Energy Storage							Resp. Time	%MW/min	%MW	%MW
Pumped Hydropower	---	100	1000	---	$1000 - 3000	500	10s	25-100%	100%	100%
CAES - Comp. Air Energy Storage	---	50	500	---	$600 - 1600	260	1-10min	4%	100%	100%
Solid Batteries	0.1	1	20	50	$1000 - 4000	50	100ms	500%	100%	100%
Flow Batteries (Redox)	---	0.1	20	50	$1700 - 4200	50	100ms	500%	100%	100%
Flywheels	0.1	1	20	40	$900 - 1100	20	1-4s	1500%	---	---
PEV	---	0.02	0.05	---	---	---	100ms	---	---	---
Fuel Cells (PEM)	1E-04	0.001	0.1	10	$3,000	1	10s	500%	100%	100%
Demand Response										
Fast Auto DR	---	---	---	---	---	---	---	---	---	---
Direct Load Control	---	---	---	---	---	---	---	---	---	---
Interruptible Load	---	---	---	---	---	---	---	---	---	---
Price Responsive Demand	---	---	---	---	---	---	---	---	---	---
Transmission										
Synch. Cond.: Large motor frame	---	0	50	---	---	---	---	---	---	---
Synch. Cond. Air-cooled generator frame	---	38	113	---	---	---	---	---	---	---
Synch. Cond.: H2-cooled generator frame	---	198	478	---	---	---	---	---	---	---
Shunt FACTS devices (STATCOM SVCs)	---	---	---	---	---	---	---	---	---	---
HVDC Transmission Technologies	---	---	---	---	---	---	---	---	---	---
Desirable Attributes / Retrofit Options										
Improved Turndown (MinGen) Capability	---	---	---	---	---	---	---	---	---	---
Elevated Ramp-rate Capability	---	---	---	---	---	---	---	---	---	---
Faster Startup Capability	---	---	---	---	---	---	---	---	---	---

More detailed descriptions of each resource are included on slides 58-87 of Appendix A.

4 Part 1 Summary

Part 1 of the Hawaii Ancillary Services study focuses on ancillary services definitions, interconnection requirements and technologies capable of providing these ancillary services in functional terms. They may not reflect the current practices on the Hawaiian Islands but represent viable options for any electric power system to maintain reliable operations and should be considered as options for the Hawaiian Islands. The ancillary services are currently provided to the Hawaiian Islands under bundled service by the utility operators. Part 2 of the final report will document the GE study results for Task 3-4 and provide analysis of Hawaii specific scenarios including comparison of current practices on the Hawaiian Islands to proposed ancillary services and interconnection requirements. The interconnection requirements can help designate some of the desired capabilities required to deliver ancillary services. These services may be provided by a utility or independent power producer and compensated in accordance to the value that capability brings to the system, to be discussed in Task 3 and 4.

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6 Appendix A - 2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx

Ancillary Services Definitions & Capability Study Part 1, Task 1-2, Final Report

December 10, 2012

Prepared by: GE Energy Consulting

Prepared for: Hawaii Natural Energy Institute (HNEI) and Hawaii Reliability Standards Working Group (RSWG)

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Ancillary Services Definition & Capability Study

Study Background and Objectives

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  - Hawaii Specific Differences/Additions
- Task 2 - Identification of technologies capable of providing each ancillary service: Enabling Technology Details

References

Study Background and Objectives

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Ancillary Services Def. & Cap. Study

Overview of Study

Purpose:

Study sponsored by HNEI with support and guidance from Hawaii RSWG to identify, define, and quantify ancillary services required to support new generation (including renewable generation) for bulk power systems and particularly the Hawaiian islands.

Objectives:

- Define a standardized set of ancillary services along with their associated definitions (in functional, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems.
- Technologies (generation, transmission, storage, and demand response (DR)) will be assessed for their ability to support the respective ancillary services to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island)
- Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

Introduction

Ancillary services & additional functions required for power system operation

- **Ancillary services*** are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system.

- In addition to ancillary services, other **interconnection requirements** are placed on resources to ensure reliable operation of the grid

- These ancillary services and interconnection requirements enable the system operator to meet the required operations **reliability standards** set by NERC.

- The ancillary services, interconnection requirements, and reliability standards are related to the characteristics of a power system.

** FERC defined ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."*

Key Terminology

Key Terminology

The following definitions are relevant throughout the content of this presentation and should be interpreted as described below:

Area Control Error (ACE): The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. *NERC Glossary (2008)*

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

- NIA is the algebraic sum of actual flows on all tie lines.
- NIS is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- FA is the actual frequency.
- FS is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
- IME is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for Hawaii, **ACE = – 10B (FA – FS) – IME.** This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. *Revised definition per Hawaii RSWG Glossary.*

Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

Automatic Generation Control (AGC): Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias (i.e. ACE). *NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices.*

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

Droop Control / Governor: Droop speed control is near instantaneous means of using frequency deviations to distribute load set-point adjustments to a system of resources in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.[3]

Droop response can be provided by any frequency-sensitive resource.

Resource: A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning: Historically, the terms "**spinning**" and "**non-spinning**" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

Study Results

Task 1: Scope & Deliverables

Identification & definition of ancillary services

Objectives:

- Provide a standardized set of ancillary services along with their associated definitions (in functional terms).
  - Highlight emerging ancillary services and the entities pursuing them
  - Scope added by GE: Discussion on interconnection requirements due to inter-relationship w/ ancillary services
- Explain how each ancillary service is used for grid operation
  - Incorporate perspective during normal and contingency conditions
- Identify "Hawaii-specific" differences relative to the standardized definitions
  - Consider how ancillary functionality is currently provided
  - Adjust standardized definitions for Hawaii (finalize during Tasks 3 & 4)

Ancillary Services & Interconnection Requirements

Emphasis on **Ancillary Services** that provide direct support for the reliable and economic operation of the power system:

Real-Power Energy Balancing Services

- Frequency Responsive Reserve/Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

Additional Services

- Black Start
- Reactive Power/ Voltage Support

Generation requirements that are specified via **Interconnection Requirements** are:

Interconnection Requirements

- Power Factor & Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and Control
- Over and Under Frequency Controls
- Inertia

Other Considerations

Real-Power Energy Balancing Services

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Operational Time Frames

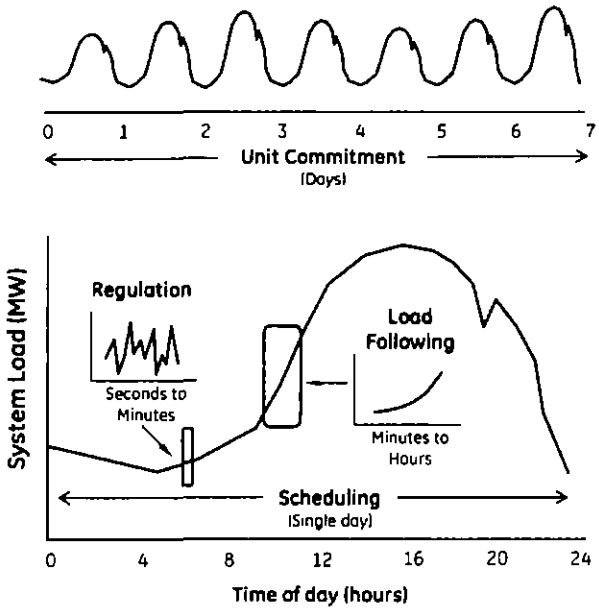
Relationship during **Normal** Operating Conditions

Operational Time Frames
(Normal Conditions)

Scheduling / Unit Commitment:
- Several hours to several days
- Ensures that appropriate generation is available to meet forecasted demand, reserve, and interchange requirements[2].
- Critical to economic / reliable system operation[2]

Load Following:
- Several minutes to several hours
- Follows general trending pattern within the day[3]
- Usually performed by economic dispatch[3]
- Focuses on rate of change in generation and consumption[2]

Regulation:
- Several seconds to minutes
- Balances fast (sec-to-sec and min-to-min) random variation in supply-demand balance[3]
- Automatic response (typically via AGC) to adjust output (or responsive load)



Illustrations based on NREL - National Renewable Energy Laboratory, Renewable Electricity Futures Study (Vol. 3 of 4), Bulk Electric Power Systems, Operations and Transmission Planning, 2012

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Operational Time Frames

Relationship during **Contingency** Operating Conditions

Operational Time Frames (Contingency Conditions)

Inertial Response:
- Arrests the frequency change
- Generators and loads adjust speed and transfer kinetic (or stored) energy to electrical energy[3]

Frequency Responsive Reserve:
- Frequency-sensitive droop response from generators with headroom (or responsive loads)[3]
- Stabilize frequency at or below nominal levels

Regulation:
- Commanded "MW" adjustment thru AGC
- Assists freq. recovery toward nominal levels[3]

Contingency Reserves:
- Spinning & Non-Spinning reserves
- Restore frequency to nominal levels[3]

Replacement Reserves:
- Relieve the Contingency Reserves[3]
- Protect against a follow-on event

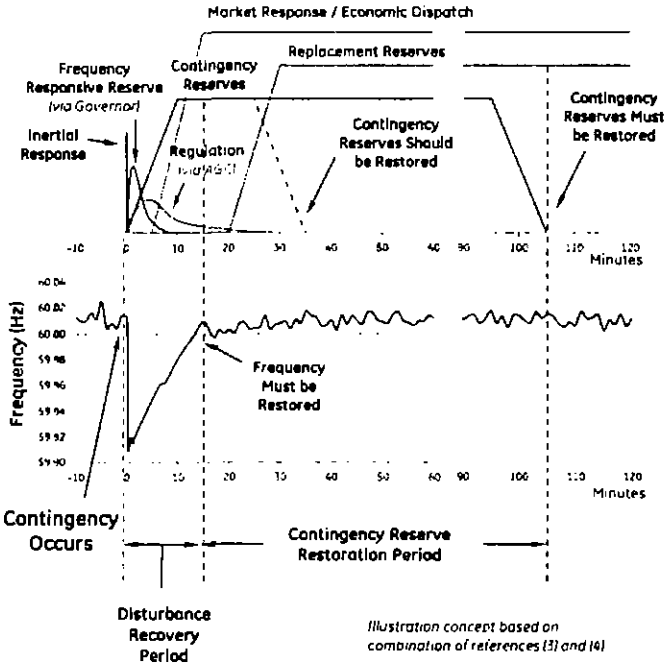


Illustration concept based on combination of references (3) and (4)

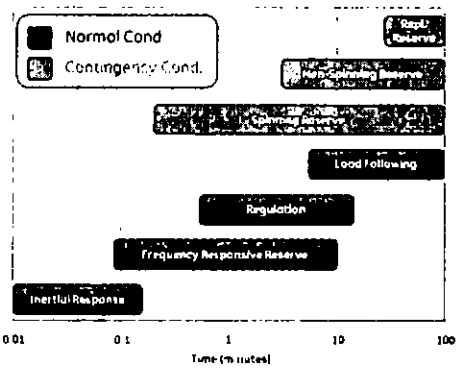
Continuous Spectrum of Protection

Progressive series of inter-related responses to ensure system reliability

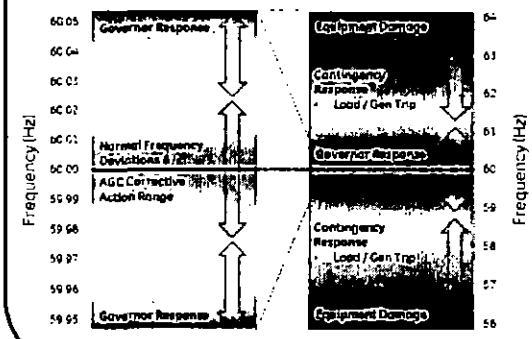
Combination of automated and manual actions link Normal and Contingency Conditions

- Inertial Response provided autonomously from synchronized generation (or synthesized via power electronics)
- Frequency Responsive Reserve/ Primary Frequency Response automatically driven by frequency deviations (droop governor response, etc.)
- Regulation drives automatic output adjustments thru Automatic Generation Control (AGC), precipitated by changes in Area Control Error (ACE)
- Automatic and Manually deployed reserves (Spinning / Non-Spinning / Replacement)

Response Times and Durations[5]



Progression from Normal to Contingency Conditions[5]



Ancillary Service Definitions

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Ancillary Services

Functions Required to Maintain System Flexibility & Reliability

- Normal Cond.
- Contingency Cond
- Additional Services

Frequency Responsive Reserve/ Primary Frequency Response	Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency fall-off.
Regulation	Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals.
Load Following	Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future.
Spinning Reserve	Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately.
Non-Spinning Reserve	Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate.
Replacement Reserve	Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately.
Black Start	Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout.
Reactive Power/ Voltage Support	Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system

Inertial Response

Emerging Ancillary Service

- **Definition**: Inertial response is the autonomous and immediate[3]:
  (1) Transfer of kinetic (or stored) energy into electrical energy during a frequency reduction
  (2) Transfer of electrical energy into kinetic (or stored) energy during a frequency increase

  Inertial response is not obtained as an ancillary service. Rather, Inertial response is provided by synchronized resources and variable generation (VG) resources with power converters that can provide synthesized inertia[4]. These inertial response requirements for VGs are addressed through the interconnection requirements. The immediate injection/ consumption of real power reduces the rate of change of frequency (ROCOF) and assists in stabilizing the frequency of the power system.

- **Reaction Speed**: Inertial response is initiated and fully deployed within seconds[2].
- **Response Duration**: Response is only effective during the first few seconds following a disturbance and, *with the exception of power converters*, is not directly controlled / purposefully sustained.
- **Frequency of Use**: For synchronous resources, the inertial response is continuously active and providing stability to the power system. Resources connected with power electronics may utilize a dead-band to withhold the response during normal operation and deploy only during major disturbances.
- **Magnitude of Response**: Resources will autonomously consume/inject until they reach their respective over/under-frequency trip set-points OR until system frequency stabilizes.

Frequency Responsive Reserve/ Primary Frequency Response

Emerging Ancillary Service

- **Definition**: Frequency responsive reserve is the immediate and automatic increase/decrease in real power output provided by frequency-sensitive resources[3],[4].
- **Reaction Speed**: Response should begin immediately and is typically fully deployed within a few seconds.
- **Response Duration**: Varies. Often defined as part of grid compliance / interconnection requirements and in-proportion to the magnitude of the frequency deviation. Typically, the response is less than 15 minutes* to ensure compliance with NERC BAL-002 which states that ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.
- **Frequency of Use**: For all resources which have upward/downward operating range available (relative to their current set-point), and are connected with governors, the frequency responsive reserve is continuously provided. In many cases, a small 10-50 mHz dead-band is applied so that small frequency deviations are ignored[3].
- **Magnitude of Response**: Magnitude of the response is proportional to the frequency deviation and typically characterized by "x%" droop response. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capacity.[3]

* Represents the mainland and might be different for Hawaii

Regulation

Well-established Ancillary Service

- **Definition**: Regulation service is the capability to adjust real power by resources capable of responding appropriately to a system operator's AGC signal in order to correct for actual or expected Area Control Error (ACE) needs. Regulation is distinguishable from Frequency Responsive Reserve. *Updated definition per FERC Order 755, but also recognized as an official ancillary service per FERC Order 888.*
- **Reaction Speed**: Regulation signal provided to participating resources must be updated at least every six (6) seconds (per NERC BAL-005, Requirement 8). Resources should begin to respond immediately with full response achieved in five (5) to ten (10) minutes for most locations (assuming a sustained AGC signal).
- **Response Duration**: Varies – full response typically required to be sustainable for a minimum of the economic dispatch interval (typically five (5) to ten (10) minutes).
- **Frequency of Use**: Continuous. Energy neutral service with up/down fluctuation balancing out in reasonably short-time.
- **Magnitude of Response**: Varies – typically distributed to participating resources in proportion to the size of the imbalance and the allocation of regulation MW's each resource is responsible for.

Note. NERC (per BAL-001) requires an amount of regulation required to satisfy control performance standards (CPS1 and CPS2) Lack of interconnection reduces CPS1 and CPS2 to statistical measures May be appropriate to define statistical frequency control requirements (for each Hawaiian island) to provide basis for determining regulation amount - Kirby Proposed Ancillary Services (10/31/2011)

Load Following

Emerging Ancillary Service

- **Definition**: Load following is similar to Regulation, but on a slower time-scale.[4] It focuses on the rate of change in supply and demand and is intended to correct for anticipated imbalances that will occur in the next several minutes to hours.[3] Load following can be provided by any resource type capable of adjusting its real-power set-point in this time-frame.

  Increased penetrations of VG can increase net-load ramping requirements. Load Following can be used to address sustained ramps and periods when preferred low-cost resources cannot ramp quickly enough. Can also use to bridge-gap between Regulation and Contingency Reserves.[3],[4],[5],[6]

- **Reaction Speed**: Requirements for reaction speed, duration, accuracy measurement, and a mechanism for communicating set-points to participating resources would need to be established. It is anticipated that economic dispatch algorithms would be used to communicate set-points and resources would be remunerated for committing to more stringent response requirements.
- **Response Duration**: Similar to economic dispatch. Sustainable response at given set-point.
- **Frequency of Use**: Anticipated to be continuous, similar to economic dispatch.
- **Magnitude of Response**: Similar to economic dispatch and proportional to the anticipated future imbalance between supply and demand.

Spinning Reserve

Well-established Ancillary Service

- **Definition**: Spinning Reserve is a type of contingency reserve and consists of resources that are connected to the power system and poised, ready to respond immediately.[2] One of the officially recognized ancillary services per FERC Order 888.

- **Reaction Speed**: Spinning reserve begins to respond immediately and must achieve full response within ten (10) minutes.[2] Per NERC BAL-002, ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.

- **Response Duration**: Varies. Per NERC Disturbance Control Standard (DCS) BAL-002, all contingency reserves must be fully restored (replenished) 90 minutes* after the end of the disturbance recovery period (or 105 minutes* after the start of a reportable disturbance).

- **Frequency of Use**: Intermittent, but typically deployed following a reportable disturbance.

- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure compliance with NERC Disturbance Control Standard (DCS) requirements.

* Represents the mainland and might be different for Hawaii

Non-Spinning Reserve

Well-established Ancillary Service

- **Definition**: Non-Spinning Reserve is a type of contingency reserve and consists of resources that are capable of providing full response within a specified time; however, the response does not need be begin immediately.[2] One of the officially recognized ancillary services per FERC Order 888 (referred to as Operating Reserve - Supplemental Reserve by FERC).

- **Reaction Speed**: Non-Spinning Reserve must achieve full response within ten (10) minutes. Per NERC BAL-002, ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.

- **Response Duration**: Varies. Per NERC Disturbance Control Standard BAL-002, all contingency reserves must be fully restored (replenished) 90 minutes* after the end of the disturbance recovery period (or 105 minutes* after the start of a reportable disturbance).

- **Frequency of Use**: Intermittent, but typically deployed following a reportable disturbance.

- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure compliance with NERC DCS requirements.

* Represents the mainland and might be different for Hawaii

Replacement Reserve

Well-established Ancillary Service

- **Definition**: Replacement Reserve consists of resources that are capable of providing full response within a specified time; however, the response does not need be begin immediately. Replacement Reserve is not one of the officially recognized ancillary services per FERC Order 888.
- **Reaction Speed**: Replacement Reserve begins responding in thirty (30) to sixty (60) minutes and is intended to replenish contingency reserves in order to protect against a second event or reportable disturbance.[2],[3] NERC BAL-002 does not explicitly require Replacement Reserves.
- **Response Duration**: Varies.
- **Frequency of Use**: Intermittent, but typically deployed to restore Contingency Reserves following a reportable disturbance.
- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure Contingency Reserves are replenished in accordance with NERC DCS requirements.

Black Start

Well-established Ancillary Service

- **Definition**: Black start is an ancillary service acquired for the benefit of all loads provided by resources capable of starting themselves quickly without support of an external electricity source.[5],[7] Black start resources must have sufficient real and reactive power capability to be able to energize transmission lines and restart other generators.[5]
- **Reaction Speed**: Resources must be available to begin re-energizing the power system immediately following a major blackout.
- **Response Duration**: Varies, but is required until the power system has been fully restored.
- **Frequency of Use**: Deployed following a major blackout of the power system.
- **Magnitude of Response**: Participating resources must be able to withstand off-nominal frequency and voltage during the restoration and have the ability to accept block-load increases on the order of 10% (or more) of the individual black start resource's full capacity.

Reactive Power/ Voltage Support

Well-established Ancillary Service

- **Definition**: Voltage support is an ancillary service that is provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system.[5]
- **Reaction Speed**: Reactive power can be adjusted very rapidly (seconds).
- **Response Duration**: Varies, but is typically provided continuously.
- **Frequency of Use**: Continuous.
- **Magnitude of Response**: Participating resources will typically be deployed to provide reactive power within a power factor range of 0.95 leading to 0.95 lagging.

Note: Interconnection requirements can be used as a mechanism for sourcing voltage support. Specifically, resources are often required to have a specified reactive power capability which is controlled by the power system operator.

Developments in Ancillary Services

Emerging Regulations, Services, and Requirements

Inertial Response (ERCOT):[3]

- Evaluating requirements for inertial response.
- Inertial Frequency Response Estimator Tool (IFRET) introduced in February 2010
  - Monitors system load, online conventional generation, spinning reserves and ratio of wind to total generation.
  - If insufficient inertial response available, system operator can adjust unit commitment

Frequency Responsive Reserve/ Primary Frequency Response (WECC):

- Frequency Responsive Reserve (FRR) procedure proposed by WECC in 2005[3]
- NERC BAL-002-WECC-1 *(Version 1: April 2008)* requires 50% of contingency reserves:
  - To be spinning **AND** able to "immediately and automatically respond proportionally to frequency deviations ... through the action of a governor or other control systems."
- NERC BAL-012-WECC-2-CR *(Frequency Responsive Reserve Criterion, May 2013)*
  - Purpose: Ensure reliable operation during freq. deviation from a loss of generation
  - Applies to: WECC balancing authorities, Reserve Sharing Groups, and Reliability Coords.
  - Establishes minimum required FRR to prevent under-freq. load shed (UFLS) for simultaneous loss of two largest generators in WECC
  - Includes performance measurement criterion to gauge how generation adjusts to support the interconnection

Developments in Ancillary Services

Emerging Regulations, Services, and Requirements

Regulation Performance Compensation (FERC Order 755): Issued in October 2011

- Commission found "current methods for compensating resources for the provision of regulation are unduly discriminatory".
- Require all RTOs and ISOs to modify their tariffs to provide for a two-part payment to regulation resources:
  - 1st Part: Payment for keeping a resource's capacity in reserve in the event that it is needed to provide regulation.
  - 2nd Part: Payment shall be a performance payment that reflects the amount of work that each resource performs in real-time.

Secondary Frequency Response and Load Following (CAISO): Flexible Ramping Revised Draft Proposal – August 2012

- Stakeholder effort to develop market-based flexible ramping products
- CAISO currently deploys 10-min. Regulation service and 5-min. Real-time Dispatch (RTD)
- Flex-Ramping product addresses "lack of sufficient ramping and flexibility" to handle 5-minute supply/demand changes
- Increases in renewable penetration will drive need for increased ramping capability.
- Analogous to Load Following: Flexible ramping product addresses ramping issue before the binding real-time dispatch (RTD) ... Regulation addresses ramping issue after binding RTD.
- Purpose is to have resources poised to cover the variation and uncertainty in net system demand following the current RTD interval under consideration.

Developments in Ancillary Services

Emerging Regulations, Services, and Requirements

Secondary Frequency Response and Ramp Capability for Load Following (MISO): MISO white-paper - July 2011

- Investigating improved Load Following options
- Current practice: Use economic dispatch for "load following" ... coverage of any additional unexpected variation in net load is provided by residual resource flexibility.
- MISO recognizes variability of the net load will likely increase in the future (due to intermittent resources)
  - Strains the ramp response of controllable resources
  - Potential for increase in the frequency of short-term scarcity events ... due to ramping capacity shortage.
- Solution requires balance between increased op costs and avoided scarcity event cost
- Appear to be gravitating toward "market product" which prices for ramp capability:
  - Provides incentive to participate
  - Avoids "out of merit" dispatch which is not consistent w/ location-based marginal price
  - Load following product would be "cleared" based on resource opportunity cost and "paid-for" thru cost allocation similar to other ancillary products
- Several approaches proposed:
  - Single-interval: Ramp-capability would be considered for future 10-min. (2 RTD intervals)
  - Multi-interval: Similar to single-interval, but also identifies opportunities in future intervals to "pre-ramp" resources ... early interval adjustment for better future interval positioning.

Ancillary Service Allocations (On the Mainland)

imagination at work

Inertial Response

As implemented on the mainland

CAISO/NYISO:

- Inertial Response is not a stand-alone ancillary service product

ERCOT:

- ERCOT requirement that new wind plants supply primary frequency response for over-frequency events

PJM:

- Inertial Response is not a stand-alone ancillary service product

ISO-NE:

- Inertial Response is not a stand-alone ancillary service product

Frequency Responsive Reserve/ Primary Frequency Response

As implemented on the mainland

ERCOT:
- FRR is not a stand-alone ancillary service product
- All online generation resources must have governors in-service and unblocked

NYISO/IESO:
- FRR is not a stand-alone ancillary service product

PJM:
- FRR is not a stand-alone ancillary service product
- All resources providing spinning reserve must be synchronized to the grid and frequency responsive.

WECC:
- In process of developing FRR criteria [NERC BAL-012-WECC-2-CR - May 2009]
- Unclear if new criteria would replace spinning reserve or be a subset of spinning reserve
  - Current proposal is to base FRR criteria on NERC Category "C" event
- Criteria (as proposed) would share the total obligation among the respective balancing authorities (BA's) and would be proportional to BA's load and generation.

Extracted from Reference [6] NERC. North American Electric Reliability Corporation, Special Report Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011

Regulation

As implemented on the mainland

ERCOT:
- Market-based and deployed via AGC
- MW requirement is a function of the month and daily hour number
  - Based on the amount historically deployed and amount of time it was exhausted
  - Considers additional wind penetration relative to the historically benchmarked levels
    - i.e. + "x" MW of additional regulation per 1000 MW of additional wind (also assessed monthly and hourly)
- All online generation resources must have governors in-service and unblocked

IESO:
- IESO contracts for regulation service.
- Terms / Conditions of the contract include:
  - Minimum of +/- 100 MW of regulation must be scheduled (system-level) at all-times
  - Minimum overall system ramp rate requirement is 50 MW / min

NYISO:
- Market-based product and deployed via AGC (every 6 seconds)
- MW requirement is a function of the month and daily hour number
- All resources providing spinning reserve must be synchronized to the grid and frequency responsive.

Extracted from Reference [6] NERC. North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011

Regulation (cont'd)

As implemented on the mainland

MISO:
- Market-based and deployed via AGC (every 4 seconds)
- No fixed "MW" requirement; however, must carry sufficient reserve which is responsive to AGC to comply w/ NERC's Control Performance Criteria

PJM:
- Regulation service is scheduled via two (2) methods:
  - Self-scheduled
  - PJM RTO Regulation Market
- Resources providing regulation receive two (2) signals:
  - AReg (Assigned Regulation): Assigned regulation for hour. Typically constant for the hour, but adjusted on a 10 second scan rate.
  - RegA (Real-time Instantaneous Target): +/- MW signal deployed via AGC every 2 sec.
- MW requirement determined for two (2) daily periods
  - On-Peak (0500 – 2359): 1% of the forecast peak load for the day
  - Off-Peak (000-0459): 1% of the forecast valley load for the day

SPP / WECC:
- Deployed via AGC.
- No fixed "MW" requirement; however, must carry sufficient reserve which is responsive to AGC to comply w/ NERC's Control Performance Criteria

Extracted from Reference [6] NERC North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation March 2011

Spinning Reserve

As implemented on the mainland

ERCOT:
- Market-based 10-minute spinning reserve product
- Minimum "MW" requirement is 2300 MW (~3.5% peak demand) and can go up to 2800 MW (~4.3% peak demand).
- May be provided by:
  - Unloaded generation resources
  - Demand-side resources (up to 50% of the total spinning reserve MW)
  - Resources controlled by under-frequency relays
  - Direct Current (DC) tie-line response (must be fully deployed in 15 seconds)
- Load following / spin deployed as necessary to minimize use of 10-minute reserves

IESO:
- IESO has two market-based 10-minute products: (1) Spinning and (2) Non-spinning
- Spinning reserve must be provided by resources synchronized to the power system
- 10-min Spin/Non-Spin MW requirement is based on largest single contingency on the system
  - Minimum of 25% of the 10-minute reserve requirement must be spinning
  - Could be more based on historical ACE performance during contingency events

Extracted from Reference [6] NERC North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011

Spinning Reserve (cont'd)

As implemented on the mainland

Extracted from Reference [6] NERC, North American Electric Reliability Corporation, Special Report, Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011

NYISO:

- Market-based 10-minute spinning reserve product
- 50% of the 10-minute contingency reserve requirement must be sourced from synchronized resources (including load reductions, curtailed resource capacity, or canceled off-system energy sales)
- Total 10-minute contingency reserve must be greater than the operating capacity loss caused by the most severe observed contingency OR the largest energy loss caused by the cancellation of an interruptible off-system energy purchase.

MISO:

- Market-based ancillary service product.
- Provided by synchronized generation resources which are capable of achieving response within the NERC Disturbance Recovery Period (15 min.)
- Residual regulating reserves (in excess of the requirement) may be applied to Spinning Reserve
- 40% of the contingency reserves must be spinning

SPP:

- Provided by frequency-sensitive synchronized resources
- 50% of the contingency reserve must be spinning reserve
- Spinning Reserve allocation (per resource) is limited to the increase in output associated w/ a frequency drop to 59.5 Hz. Under 5% droop, this is 16.7% of the individual resource capacity.

Spinning Reserve (cont'd)

As implemented on the mainland

Extracted from Reference [6] NERC, North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011

PJM:

- Market-based 10-minute ancillary product
- PJM consists of two (2) zones:

  ReliabilityFirst Corporation (RFC) Reserve Zone:
  - Consists of all PJM companies except for SERC-based companies
  - Total contingency reserve must be able to cover the minimum imposed RFC requirement (150% largest generator) or largest contingency on the system.
  - Per NERC BAL-002-RFC-02, at least 50% of the contingency reserves must be spinning and no more than 25% should be interruptible load.

  Southern Reserve Zone:
  - Consists of the Dominion load share of VACAR (NERC Sub-region: VA/NC/SC)
  - Total contingency reserve req's for Southern Zone determined annually (~430 MW)
  - Spinning reserves must be able to cover the largest contingency within the zone less the 15-minute quick-start capability in the zone.

WECC:

- Requires 50% of its contingency reserves to be spinning reserves; unloaded generation that can be loaded in 10-min. can be considered spinning reserve.
- Contingency reserves shall be sufficient meet the NERC Disturbance Control Standard (DCS) and be at least greater than:
  - Most severe single contingency
  - Sum of 5% of hydro generation load responsibility and 7% of thermal generation load responsibility

Non-Spinning Reserve

As implemented on the mainland

ERCOT:
- Market-based 30-minute ancillary service product
- Calculated for each hour of the day each month
- Can be provided by off-line generation resources or loads capable of being interrupted within 30-minutes for a duration of at least 1-hour.

NYISO
- Market-based 10-minute ancillary service product
- Represents the residual portion of the 10-minute contingency reserve (which is not covered by spinning reserve)
- Total 10-minute operating reserve must be greater than the operating capacity loss caused by the most severe observed contingency OR the largest energy loss caused by the cancellation of an interruptible off-system energy purchase.

MISO:
- Consists of off-line generation able to be loaded or interruptible load able to be removed within the NERC DCS period (15-minutes).

Extracted from Reference (6) NERC: North American Electric Reliability Corporation, Special Report Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation March 2011

Non-Spinning Reserve (cont'd)

As implemented on the mainland

PJM:
- Not a formalized ancillary service product
- Consists of any resource capable of providing full response in 10-min (RFC Zone) or 15-min. (Southern Zone).
- Represents the residual portion of the 10-minute contingency reserve (which is not covered by spinning reserve)

SPP:
- Provided by any resource (which does not have to be connected to the network), but can be connected and applied to meet NERC DCS requirements (15-min.).

WECC:
- Represents 50% of the total contingency reserve obligation
- Consists of any resource capable of providing full response in 10-min, including:
  - Load which can be interrupted within 10 minutes
  - Interruptible exports
  - On-demand rights from other Balancing Areas (BA's)
  - Spinning Reserve in excess of requirement
  - Off-line generation that qualifies as non-spinning reserve

Extracted from Reference (6) NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation March 2011

Replacement Reserve

As implemented on the mainland

IESO:
- Market-based 30-minute reserve product
- Replacement reserve addresses the residual portion of the largest single contingency plus half of the second largest contingency (typically, this is the loss of the two largest generators), which is not covered by 10-minute spinning and non-spinning reserves.

NYISO:
- Market-based 30-minute reserve product
- Equivalent to 50% of the total 10-minute contingency reserve (including both spinning and non-spinning resources)

PJM:
- Not a formalized ancillary service product
- Consists of any resource capable of providing full response within a 10 – 30 minute notification.

Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation March 2011

Reactive Power/ Voltage Support

As implemented on the mainland

CAISO:
- Maintains acceptable voltage levels and VAR flow on the Controlled Grid using all voltage control support equipment required to meet the operating criteria specified in the NERC and WECC Minimum Operating Reliability Criteria
- If notified of the loss of an automatic voltage regulator control (AVR),and the Scheduling Coordinator (SC) has not notified the PTO then notify the applicable PTO of the status of the device (the TO will direct the Generator Operator to maintain or change either its voltage Schedule or its Reactive Power Schedule as appropriate)

NYISO:
- Resource must be able to produce and absorb Reactive Power within its tested reactive capability range
- Resource must be able to automatically respond to voltage control signals; for a generator, a functioning Automatic Voltage Regulator (AVR) is required
- Resource must be under the operational control of the NYISO or a Transmission Owner

PJM:
- Not a formalized ancillary service product

ERCOT:
- As provided by ERCOT to the QSEs: The coordinated scheduling of voltage profiles at transmission busses to maintain transmission voltages on the ERCOT System in accordance with Operating Guides
- As provided by a QSE to ERCOT: The provision of Generation Resource capacity whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits throughout the ERCOT System in accordance with Operating Guides

Black Start

As implemented on the mainland

CAISO:

- Cost of Service - units are identified for black start and their documented costs are then funded and rolled into a tariff for cost recovery

PJM/NYISO:

- Cost of Service - units are identified for black start and their documented costs are then funded and rolled into a tariff for cost recovery
- NYISO selects the generating resources with black start capability by considering the following operating characteristics: electrical location in the NYCA; startup time: from NYISO order to start to minimum output; maximum response rate (MW/minute) above minimum output; and maximum power output

ISO-NE:

- Flat Rate Payment which increases black start remuneration to encourage provision - the monthly compensation paid to a generator is determined by multiplying a flat rate (in $/KWyr and referred to as the $Y value) by the unit's Monthly Claimed Capability for that month

ERCOT:

- Competitive Procurement - under this approach ERCOT runs a market for black start services and each black start unit must be able to demonstrate that it can startup another unit in close proximity to begin the islanding and synchronization of the grid
- As provided by ERCOT to QSEs: The procurement by ERCOT through Agreements, pursuant to emergency dispatch by ERCOT and emergency restoration plans of Resources which are capable of self-starting without support from the ERCOT System in the event of a blackout, in order to begin restoration of the ERCOT System to a secure operating state
- As provided by a Generator or a QSE to ERCOT: The provision of Resources under a Black Start Agreement, pursuant to emergency dispatch, which are capable of self-starting without support from the ERCOT System in the event of a blackout

Interconnection Requirements

Interconnection Requirements

Interconnection Standards* (Grid Codes)

- *Power Factor and Voltage Control*
- *Voltage and Frequency Ride Through*
- *Ramp Rate Limits and Control*
- *Over and Under Frequency controls*
- *Inertia*

*Related to the control requirements for generators

Reliability Standards

- *BAL- Resource and Demand Balancing*
- *FAC- Facilities Design, Connection & Maintenance*
- *TPL - Transmission Planning*
- *VAR – Voltage and Reactive*

Ancillary Services

- *Voltage regulation*
- *Regulation*
- *Reserves*
- *Black Start*

Interconnection Standards enables the system to meet its reliability standards by requiring all generators:

- To have certain capabilities that directly helps with the system reliability
- To have certain capabilities that enables it to provide ancillary services that are required for system reliability

VER Interconnection Requirements

Existing Standards

Power Factor and Voltage Control

- *Several US & European Grid Codes including ERCOT (wind & solar), AESO (wind) required reactive power and voltage control*

Voltage and Frequency Ride Through

- *Many European and Canadian Grid Codes require voltage and frequency ride-through capabilities for all units. For example, IESO requires generator facilities to ride-though voltage and frequency deviations (between 58 to 61.5 HZ)*

Ramp Rate Limits and Control

- *Many operators are proposing ramp rate limits and controls for wind and solar plants. For example, Alberta has adopted a 10% MW rated capacity/minute upward ramp rate limit.*

Emerging Standards

Over and Under Frequency controls

- *Many ISOs require wind units to provide Over-frequency response similar to a thermal unit with a droop of 5%.*
- *Few grid operators (Nordic and ESBNG) require wind plants to be able to change the active power production as a function of the network frequency.*

Inertia

- *Hydro-Québec requires that wind plants be able to contribute to reducing frequency deviations similar to a synchronous generator whose inertia constant (H) equals 3.5s.*

Reactive Power & Voltage Control

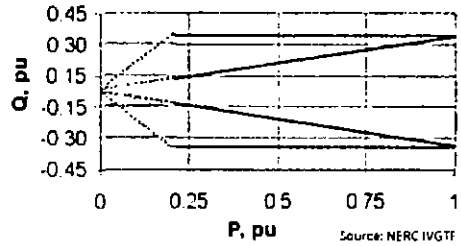
Capability to provide reactive power output within a certain power factor range and the capability to regulate voltage within this range

- Required for reliable operations
- Synchronous generators required to have 0.95 lead/**0.90 lag** capability. Automatic Voltage Regulator (AVR) required.
- Capable units participate in voltage support ancillary service
  - assumed to provide (and compensated)- NYISO
  - Only units that operate outside their PF range are paid opportunity cost - CAISO

Requirements for Wind and/or Solar Plants

- Order 661-A requires study by TO to justify the reactive capability requirement up to 0.95 lag to lead at POI
- ERCOT (wind & solar), AESO (wind), several European Grid Codes required reactive power and voltage control
- Typically, baseline capability of 0.95 lag to lead at full output (POI) and permissive reactive power range
- Some grid codes require a certain portion of the reactive power range be dynamic.

Reactive Power Capability Specification at the POI for 0.95 pf at Rated Output, Reduced Capability or Permissive Range Below 0.2 pu



Source: NERC IVGTF

Fault Ride-through

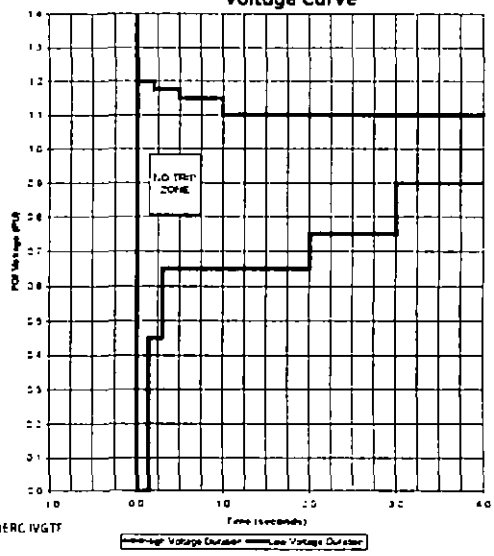
Capability of the generator to ride-through (predetermined) temporary voltage and frequency deviations

- Inadvertent loss of generators after a fault compounds frequency and voltage problems
- No explicit ride through requirement specified for conventional generators

Requirements for Wind and Solar Plants

- FERC Order 661-A requires that wind plants remain connected for three phase faults with normal clearing
- NERC PRC-024-1 (draft) proposes voltage and frequency curves for all units
- Many European and Canadian Grid Codes require voltage and frequency ride-through capabilities for all units.
- For example, IESO requires generator facilities (10MW/50MW) to ride-though voltage and frequency deviations (between 58 to 61.5 HZ)
- In the U.S., most regions have voltage ride-through requirements for wind

Voltage Curve



Source: NERC IVGTF

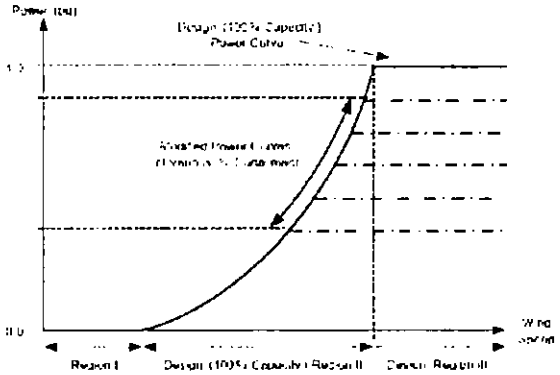
Ramp Rate Limits and Control

Capability to ramp the output of a generator under certain conditions

- Sudden changes in the output that are otherwise controllable may have a negative impact on system reliability
- No specific ramp rate and control requirements for synchronous generators ... conventional generator have "gradual" ramp rates

Requirements for Wind and Solar Plants

- Many operators are proposing ramp rate limits and controls for wind and solar plants
- Alberta ISO has adopted a 10% MW rated capacity/minute upward ramp rate limit.
- ERCOT and NYISO have the capability to dispatch wind generation



Source: NERC IVGTF

Over and Under Frequency Control

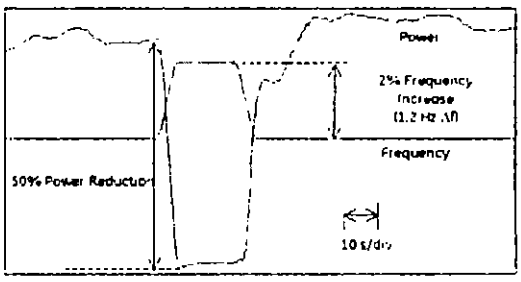
Capability to automatically increase and decrease (sustained) output under low and high frequency conditions respectively

- System frequency should be maintained around nominal value
- Synchronous generators are required to have governors with droop control
- Provide MWs in response to a drop in frequency... however, need "headroom"
- Reduce MWs in response to an increase in frequency... however, need to be operating above their minimum generation level

Requirements for Wind and Solar Plants

- Capable of providing over-frequency response (by pitch control or inverter control)
- Can provide under-frequency response... however, need to spill energy which has high opportunity cost
- Many ISOs require wind units to provide Over-frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.
- Few grid operators (Nordic and ESBNG) require wind plants to be able to change the active power production as a function of the network frequency.

Over-frequency Response (test) of Wind Plant



Source: NERC IVGTF

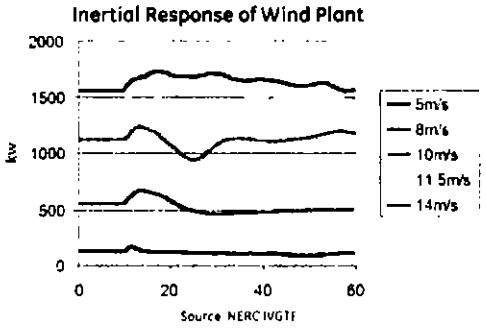
Inertia

Capability to provide an immediate response to a drop in system frequency

- Conventional generating units give up a portion of their stored kinetic energy as increased power output, which helps to retard the frequency decline after a fault.
- No specific inertia requirement for synchronous generators

Requirements for Wind and Solar Plants

- Stored kinetic energy from the turbine-generator rotors can be temporarily donated to the grid in the form of MWs
- Response depends on wind speed and is tunable
- For PV spilling is required to provide this response
- Hydro-Québec requires that wind plants be able to contribute to reducing large (> 0.5 Hz), short-term (< 10 s) frequency deviations on the power system, as does the inertial response of a conventional synchronous generator whose inertia constant (H) equals 3.5s.



Other Considerations

Items not addressed directly thru Ancillary Services or Interconnection Requirements

Reduced Minimum Generation Capability:

- Potential to avoid curtailment of renewable and economically preferred generating assets
- Enables more online reserve ... potential for more granular ancillary service participation
- Improved system-level load following capability
- Provides options for improved portfolio management ... hedge against uncertain conditions

Short-circuit Strength:

- Short-circuit levels may decrease if synchronous generators are replaced by renewables
- Synchronous generators may need to be online to maintain minimum short-circuit levels
- Additional studies are required

Load Shaping:

- Consider proactive movement of demand-side resources or non-dispatchable load to provide a more manageable daily load shape
  - i.e. incentivize / prohibit charging of PEV's at certain times of day
- "Load shaping" may provide an opportunity to reduce the amount of other ancillary services that are required.
- Anticipate that this would be a procedural implementation rather than ancillary-service based approach ... need to carefully consider how to monitor, incentivize, and enforce the targeted load adjustments.

Hawaii-Specific Differences / Additions

imagination at work

Ancillary Services – Hawaii

Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

- Relatively small island systems: HECO~1200 MW, MECO ~200MW, HELCO~195 MW peak load... challenge to maintain frequency
- No interconnections ... imbalance between load and generation affects frequency, a small frequency bias
- High Rate of Change of Frequency (ROCOF)... units are large compared to the size of the system
- High cost of energy and ancillary services due to high fuel import prices... lean operations
- Many must run/scheduled units... historical operations
- Small system with few units... single vertically integrated utility, multiple IPPs and third-party dispersed generation on each island with no centralized power markets

Ancillary Services – Hawaii (con't)

Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

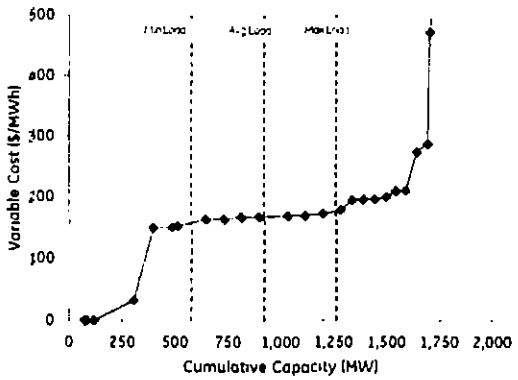
- While fewer opportunities for transaction "liquidity", ancillary service value can be calculated/estimated to provide incentives/payments to providers of ancillary services - does not need to remain in bundled utility offering
- Large amounts of distributed generation
- Clean Energy Mandate includes RPS target of 40% and 4,300 GWH reduction for Energy Efficiency Portfolio Standards by 2030; high wind and solar generation potential in MECO, geothermal in HELCO
- Hawaii specific operating criteria to maintain system frequency and voltage and provide adequate reserves

Ancillary Services – Hawaii

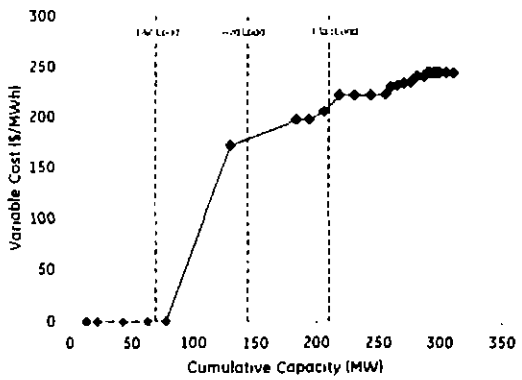
Characteristics of the Hawaii Grids

Size (MW) of power grids and resource size and mix result in limited options to serve demand and noticeable dispatch stack step changes

HECO (Oahu) Dispatch Stack



MECO (Maui) Dispatch Stack



* Renewable capacity is derated per ongoing Stage 2 interconnection study

System Operating Criteria

Hawaii specific operating criteria to maintain system frequency and voltage and provide adequate reserves

- A few criteria of note:
  - Under Frequency Load Shed is used to maintain frequency: instantaneous load shed occurs at 58.9 Hz, 58.7 Hz and 58.8 Hz for the three islands respectively. Both HECO and HELCO also have time delay blocks starting at 59 Hz and 59.3 Hz respectively
  - Each Island has several "must run" units for stability and contractual reasons
  - HECO carries spinning reserves for large single contingency while MECO and HELCO do not

- GE recognizes that understanding the current system operating criteria and practices is important to the study recommendations and therefore will confirm understanding while working through Tasks 3&4

Enabling Technologies

Task 2: Scope & Deliverables

Identification of technologies capable of providing each ancillary service

Objectives:

- Develop a summary table which identifies which technologies can supply each ancillary service. Consider:
  - Generation (including both conventional and variable renewable), storage, demand-response, and transmission technologies
  - Identify the approximate resource sizes
  - Include perspective on product attributes which can be used to assess ancillary compatibility

- Adhere to the following constraints:
  - Limit discussion to technologies in commercial or pilot applications today
  - Focus on current deployment costs – do not speculate about future costs
  - Avoid screening technologies based on cost-effectiveness

- Provide reference citations (as available) for each technology / ancillary match-up

Enabling Technologies

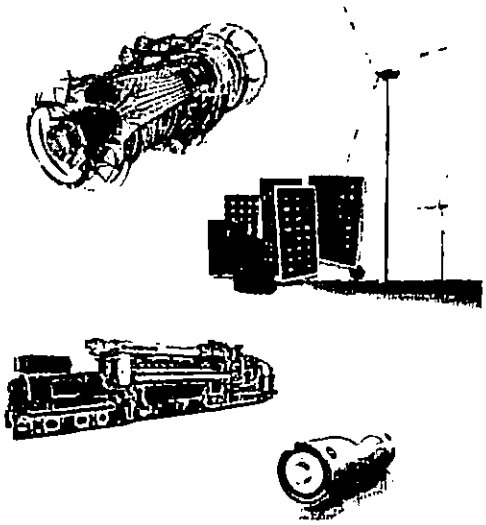
Aligning Technologies with Ancillary Service Capability

Approach:

- Spectrum of generation, transmission, storage, and demand-response technologies considered for their ability to support the defined ancillary services.

- Focus was placed on technologies in commercial or pilot applications today.

- Each resource-type was evaluated based on its capital cost, response capability, and degree of commercial penetration / experience providing each type of ancillary service.



Technology Capability Table

Screening Resources for their Ancillary Service Compatibility

Technologies	Inertial Response	Frequency Responsive Reserve	Regulation	Load Following	Spinning Reserve	Non-Spinning Reserve	Replacement Reserve	Voltage Support	Black Start
	Ancillary Services Compatibility								
Generation									
Solar Thermal	A	T	T	T	T	...	-	A	T
Solar Photovoltaic (Transmission Connected)	T	T	T	T	T	T	T	T	—
Wind (non-synchronized / power conversion)	A	A	A	A	A	T	T	A	—
Wind (synchronized)	A	A	A	A	A	T	T	A	T
Hydropower	A	A	A	A	A	A	A	A	A
Geothermal	A	A	A	A	A	...	-	A	T
Biomass	A	A	A	A	A	—	—	A	...
Coal	A	A	A	A	A	...	—	A	...
Combined Cycle (Gas/Oil Sm HD/Aero)(1+1)	A	A	A	A	A	A	A	A	A
Combined Cycle (Gas/Oil Heavy duty)(1+1)	A	A	A	A	A	A	A	A	A
Simple Cycle (Gas/Oil Small HD/Aero)	A	A	A	A	A	A	A	A	A
Simple Cycle (Gas/Oil Heavy duty)	A	A	A	A	A	A	A	A	A
Reciprocating Engines (Gas/Diesel/Bio)	A	A	A	A	A	A	A	A	A
Energy Storage									
Pumped Hydropower	A	A	A	A	A	A	A	A	A
CAES - Comp Air Energy Storage	E	E	E	E	E	E	E	E	T
Solid Batteries	E	E	A	E	A	E	E	E	E
Flow Batteries (Redox)	E	T	T	T	T	T	T	T	T
Flywheels	E	E	A	.			...	T	...
PEV	T	T	E	T	T	T	T	T	T
Fuel Cells (PEM)	T	T	T	T	T	T	T	T	T
Demand Response									
Fast Auto DR	T	A	A	T	A	A	A	...	...
Direct Load Control	T	A	E	T	A	A	A		...
Interruptible Load	T	A	T	T	A	A	A	.	...
Price Responsive Demand	T	T	T	T	A	A	A		...
Transmission									
Synch Cond Large motor frame	A	.	...	.		...	...	A	...
Synch Cond Air cooled generator frame	A	...	...			...	...	A	...
Synch Cond H2-cooled generator frame	A	...	...			...	...	A	...
Shunt FACTS devices (STATCOM, SVCs)*	.	...	...	.		...	...	A	...
HVDC Transmission Technologies*		.	...	...	..	...	...	A	A
Desirable Attributes / Retrofit Options									
Improved Turndown (MinGen) Capability	✓	✓	✓	✓	✓			✓	
Elevated Ramp-rate Capability		✓	✓	✓	✓	✓	✓		✓
Faster Startup Capability						✓	✓		

A	Available commercially
E	Emerging capability in demonstration phase
T	Technically feasible, but not currently being pursued

*Dynamic voltage support

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Technology Capability Table (cont'd)

Screening Resources for their Ancillary Service Compatibility

Technologies	Plant Size (MW)				Cost Estimates		Flexibility			
	Minimum	Minimum (Typical)	Maximum (Typical)	Maximum	Total Overnight Cost in 2010 ($2009 $/MW) for stated size (MW)	Resource Size Assumed in Cost Estimate (MW)	Turndown Load Level	Ramp Rate Capability (%/minute) (stated)	10-minute Output Available from offline	30-minute Output Available from offline
Generation					$/MW	MW	Max/Min	Max/Min	% MW	% MW
Solar Thermal	0.1	1	100	200	$4800 - 8100	210	12-15%	3-7%*	0%	0%
Solar Photovoltaic (Transmission Connected)	0.001	0.05	5	150	$2100 - 3900	10	—	Rapid*	100%	100%
Wind (non-synchronized / power conversion)	0.001	1	100	450	$1500 - 2500	100	< 10%	Rapid*	100%	100%
Wind (synchronized)	0.001	1	100	450	$1500 - 2500	100	< 10%	Rapid*	100%	100%
Hydropower	0.001	0.5	50	650	$2200 - 4800	500	20-40%	25-100%	100%	100%
Geothermal	0.05	1	30	180	$4500 - 9900	50	12-15%	3-7%	0%	0%
Biomass	0.1	5	50	75	$2900 - 5200	50	35-40%	3-7%	0%	0%
Coal	0.1	10	400	1300	$1900 - 3900	600	35-40%	3-7%	0%	0%
Combined Cycle (Gas/Oil Sm HD/Aero)(1+1)	10	25	60	120	$1000 - $1800	55	20-40%	20-40%	0-75%	75-100%
Combined Cycle (Gas/Oil Heavy-duty)(1+1)	50	120	300	500	$900 - 1500	615	25-70%	5-11%	0-80%	10-100%
Simple Cycle (Gas/Oil Small HD/Aero)	1	20	40	100	$800 - 1300	45	25-50%	25-50%	0-100%	100%
Simple Cycle (Gas/Oil Heavy-duty)	40	80	200	330	$500 - 800	211	15-70%	4-16%	0-75%	100%
Reciprocating Engines (Gas/Diesel/Bio)	0.01	1	5	20	$700 - 1300	10	50%	35%	100%	100%
Energy Storage							Max / Min	%/min	% MW	% MW
Pumped Hydropower	—	100	1000	—	$1000 - 3000	500	10%	25-100%	100%	100%
CAES - Comp Air Energy Storage	—	50	500	—	$600 - 1600	260	3-10min	8%	100%	100%
Solid Batteries	0.1	1	20	50	$1000 - 4000	50	100ms	500%	100%	100%
Flow Batteries (Redox)	—	0.1	20	50	$1700 - 4200	50	100ms	500%	100%	100%
Flywheels	0.1	1	20	40	$900 - 1100	20	1-4s	1500%	—	—
PEV	—	0.02	0.05	—	—	—	100ms	—	—	—
Fuel Cells (PEM)	1E-06	0.001	0.1	10	$5000	1	10%	500%	100%	100%
Demand Response										
Fast Auto DR	—	—	—	—	—	—	—	—	—	—
Direct Load Control	—	—	—	—	—	—	—	—	—	—
Interruptible Load	—	—	—	—	—	—	—	—	—	—
Price Responsive Demand	—	—	—	—	—	—	—	—	—	—
Transmission										
Synch Cond Large motor frame	—	0	50	—	—	—	—	—	—	—
Synch Cond Air-cooled generator frame	—	38	113	—	—	—	—	—	—	—
Synch Cond H2-cooled generator frame	—	198	278	—	—	—	—	—	—	—
Shunt FACTS devices (STATCOM, SVCs)	—	—	—	—	—	—	—	—	—	—
HVDC Transmission Technologies	—	—	—	—	—	—	—	—	—	—
Desirable Attributes / Retrofit Options										
Improved Turndown (MinGen) Capability	—	—	—	—	—	—	—	—	—	—
Elevated Ramp-rate Capability	—	—	—	—	—	—	—	—	—	—
Faster Startup Capability	—	—	—	—	—	—	—	—	—	—

imagination at work

Generation Technologies

Heavy-duty (HD) Gas Turbines / Combined Cycles:
- Well-positioned to provide all of the defined ancillary services
- Continued advancements in flexibility will enable greater penetration & reduce curtailment of renewable generation
    - Turndown, ramp-rates, part-load efficiency, hot-day output, daily cycling capability, etc.
- Much focus from both Aero and Heavy-duty GT/CC manufacturers on improved flexibility, reduced footprint, and lower startup/running emissions

Aero-derivative Gas Turbines / Combined Cycles:
- Similar ancillary capabilities as HD options; however, typically include more efficient simple cycle operation, minimal cycling penalties and improved quick-start / ramping capabilities.
- Reduced footprint, quick-delivery, and typically smaller block-sizes.

Reciprocating Engines:
- Able to provide 'full-spectrum' of ancillary services
- Effectiveness of inertial response (due to lower rotating mass) is less-than other conventional thermal generators
- Typically provide some of the fastest startup times and ramp-rates of all generation technologies.
    - Most offer full output (from offline) inside 10-minutes and more than 30% / min ramp rate
- Ideal for black start, particularly on smaller power systems

Generation Technologies

Coal / Biomass:
- Available to provide all "on-line" ancillary services
- ST-based generation ... operating range & ramping capability typically less-than GT/CC assets
- Not well-suited for applications which require startups inside 1-hr
    - Non-spinning reserve, Replacement reserves, Black start
- Excellent for inertial response

Geothermal:
- Similar ancillary capabilities as Coal / Biomass
- Improved operating range relative to coal / biomass (enabled by deeper turndown)
    - Lack of combustion process reduces limitations to ST aero / mechanical limits.
- Natural / continuously available fuel source enables potential for use as a black start resource
- Ancillary service potential not limited by fuel supply interruptions

Hydropower:
- Excellent resource-type for providing ancillary services ... used extensively on mainland.
- Superior operating range, ramp-rates, and startup times relative to other generation technologies
- Only restrictions would include release schedules (environmental / wildlife / recreational) and/or availability of water ... particularly for "run-of-river" applications

Generation Technologies

Solar Thermal[8]:
- Capable of providing inertial response similar to conventional steam generators
- Requires curtailment* to establish required headroom for services such as frequency responsive reserve, regulation, load following, and spinning reserve.
- Technically feasible to develop facilities capable of providing both black start and particularly voltage support services

Solar PV[8]:
- Not yet capable of providing inertial response, but feasible
  - Inverters likely possess the required response speed, however, on-site energy storage mechanism would be required.
- Curtailment* required for frequency responsive reserve, regulation, load following, and spinning reserve
- Response speed/accuracy better than most conventional generators can supply
- Voltage support services technically feasible

Wind[8]:
- Synthetic inertia from wind turbines is commercially available.
  - Energy extracted from the wind turbine rotor OR head-room provided by operation at curtailed output level
- Curtailment* required for frequency responsive reserve, regulation, load following, and spinning reserve
- Response speed/accuracy better than most conventional generators can supply
- Voltage support services technically feasible

*Curtailment only required for upward movement. Downward movement can be provided without curtailment.

Emerging Req's / Opportunities

Specific to Variable Generation (VG)

CAISO:
- Exploring incentives to encourage greater participation in economic dispatch by wind and solar resources.[8]
- Considering reduction in the continuous energy requirements for ancillary services ... would benefit VG resources[8]
  - Spinning and Non-Spinning Reserve: From 2 hours down to 30 minutes
  - Regulation: 60 minutes for DAH and 30 minutes for RT

ERCOT:
- New requirements for wind generators – applicability based on the date of signing the Generation Interconnect Agreement *[3]
  - New generators required to provide "governor-like" response to frequency deviations[8] : Requires adjustable dead-bands and droop response of 5%(3)
  - Includes Voltage Ride-Through (VRT) requirements[8]
- Wind generators must be capable of producing reactive power equal to ±95 percent power factor (based on current load set-point) down to 10% of nameplate capacity. [8]
- Variable generation resources expected to respond to dispatch instructions[8]

*Required for all wind generators with standard generation interconnection agreements signed after January 1, 2010. Wind generation resources with interconnection agreements signed on or before January 1, 2010, shall have primary frequency response capabilities by December 1, 2010, if ERCOT believes this is physically practical.[3]

Emerging Req's / Opportunities

Specific to Variable Generation (VG)

NYISO:

- Wind scheduled / dispatched similar to other generation[8]
  - Bids a price-curve (based on operating costs only) ... required for RT and optional for DAH market
  - Must be able to accept electronic base-point signals ... penalties assessed for non-compliance
    - Equivalent to MW-deviation multiplied by regulation clearing price (3% tolerance allowed)
- VG allowed to provide reserves if all technical requirements are met[8]
  - Limited energy storage resources (LESR) allowed to provide regulation service. Rule change accepted by FERC to allow 15-minute continuous reserve (vs. 1-hour).[3]
  - Energy Management System (EMS) modified to monitor LESR energy levels & adjust regulating range to allow for charging (if required).[3]

Hydro Quebec:

- Wind plants larger than 10 MW must provide emulated inertial response similar to conventional synchronous generator (3.5s)[3]
- Demonstrations conducted with wind turbines supplying regulation service[8]

Desirable Attributes / Retrofit Options

Preferred Characteristics for New or Existing Generation Technologies

Improved Turndown (Minimum Generation) Capability:

- Enhances ability to provide all online ancillary services
  - Inertial Response, FRR, Regulation, Load Following, Spinning Reserve, Voltage Support
- Minimizes fuel cost during off-peak periods
- Potential to avoid curtailment of renewable and economically preferred resources

Elevated Ramp-Rate Capability:

- Increases the amount of available Regulation, Load Following and Spinning Reserve
- Potential to improve the quality of the response for smaller "MW" swings
- Aids in allowing offline reserves to contribute more quickly during contingency events

Faster Startup Capability:

- Enables Non-Spinning and Replacement Reserves to be delivered more quickly
- Opportunity to reduce fuel consumption thru replacement of some online reserves
- Typically accompanied by reduced startup emissions

Improved Cycling Capability:

- Ability to accommodate daily (and sometimes multi-daily) startups with minimal variable operation & maintenance penalties along w/ reduced minimum up/down time req's.
- Enables more options at the power system level and further limits required curtailments

Energy Storage – Flywheels

Technology Overview

- Mass rotating about an axis to store mechanical energy
- Mechanical energy converted to electrical energy via generator
- Practical for short charge-discharge cycles (less than 15 minutes)
- Flywheel energy storage provides >10 seconds of ride-through power to protect the load from that 99% of disturbances
- Backup gen-sets typically provides the other 1%

Energy Storage – Flywheels

Impact on Ancillary Services

- **Inertial Response:** Flywheels are coupled to the grid through a power electronic interface that should allow for emulation of inertial response
- **Regulation:** In regards to regulation, flywheels can use their power electronic front ends to accurately respond to automatic generation control (AGC) signals faster and more efficiently than traditional conventional generators, potentially reducing the total amount of comparable regulating reserve carried on traditional units
- **Load Following:** Some flywheel technology can apparently provide load following capability above the capacity rating of the distribution generation (DG) asset as well as voltage and reactive power support and control; For Combined Heat and Power (CHP) systems, this technology has the potential to facilitate the use of gas turbines as part of a CHP system, by improving these systems' ability to follow fast-changing loads
- **Spinning/Non-Spinning Reserve:** All energy storage technologies except for flywheels are well suited to provide spinning/non-spinning reserve; The only limiting factor for flywheels is the duration of the response required; However the introduction of energy storage can act to further reduce diesel fuel consumption by using the stored energy to provide both load following and supplying the occasional shortfall, while leaving the generator turned off - some flywheel energy storage technology could be ideal for this application due to its low maintenance, long design life, high cycling capability without any degradation in storage value, its ability to respond almost instantaneously (thus improving load following), and its ability to provide real and/or reactive power
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

Energy Storage – Batteries

Technology Overview (applies to both Solid State and Flow types)

- A Battery Energy Storage System (BESS) system can cover a wide range making them suitable for almost all energy storage applications; One installation can be used for multiple applications such as spinning reserve and voltage & frequency control
- Lithium-Ion batteries are good for inertial/frequency response, regulation, reserves
- Energy batteries good for load following but could also be good for response
- Energy batteries (some sodium based batteries, flow batteries) can also provide power

Energy Storage – Batteries

Impact on Ancillary Services (applies to both Solid State and Flow types)

- **Inertial Response:** BESS do not include any rotating mass, but rather they interface to the grid through a power electronic front-end and the power electronic controls should be configurable to provide an emulation of inertial response over very short durations of up to a few seconds
- **Frequency Responsive Reserve:** The power electronics for battery energy storage can be controlled to provide frequency response
- **Regulation:** If BESS are used to provide regulation, then cycle life (number of charge/discharge cycles in the life of the battery), the round-trip energy efficiency and O&M costs will play a major role; On the other hand, these factors will be less important than the capital and replacement costs when BESS are used in black start applications - this is particularly true considering that these batteries will only be discharged and recharged when a major black out occurs and black start is required - shelf life, rather than cycle life will be important and round-trip efficiency will be of little or no concern
- **Load Following:** BESS can provide dispatched balance, with flow batteries potentially having the capability to provide the longer duration load following
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

Energy Storage – PSH

Technology Overview (PSH - Pumped Storage Hydropower or Pumped Storage)

- Pumped Storage Hydropower (PSH) can quickly accommodate disturbances that occur on transmission grids – loss of generators, failure of transmission lines, instant demands (or cessation of demands) Low operating cost, reliable, long lifetime, can have large power ratings
- Fast response – can go from full load pumping to full load generation in minutes (as little as 10s). Additionally, a configuration with two penstocks could be deployed for pumping water and generating electricity simultaneously.
- Efficiency: >70-75% round trip (and may be upto 85%)

Energy Storage – PSH

Impact on Ancillary Services (PSH - Pumped Storage Hydropower or Pumped Storage)

- **Inertial Response:** PSH interface with the grid through a rotating machine that allows them to provide inertial response just like any conventional synchronous generator
- **Frequency Responsive Reserve:** PSH can provide primary frequency response and is available while the plant is generating but they must be designed with variable pumping control if they are to provide primary frequency response while pumping
- **Regulation:** In regards to regulation, PSH can respond to AGC Controls in the same manner as traditional hydro and gas turbine plants while generating and can provide regulation when pumping if they are initially designed to do
- **Load Following:** When it comes to load following, PSH can follow system operator dispatch commands to provide sub-hourly to multi-hour energy balancing in the generating mode; As with primary frequency response, pumped hydro plants can provide load following or ramping when pumping if they are initially designed to do so
- **Spinning Reserves:** PSH is well suited to provide spinning reserve; The amount of response available from a pumped storage plant while pumping depends on the plant design
- **Non-Spinning Reserves:** Because non-spinning reserves do not need to respond as quickly as spinning reserves, PSH is well suited to provide non-spinning reserve
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

Note additional comments form the Hawaiian companies on this technology will be addressed in Task 3 and 4

Energy Storage – CAES

Technology Overview (CAES – Compressed Air Energy Storage)

- Gas Turbine (GT) that uses 40% less fuel - 2/3 of GT fuel is used to compress air
- Air is pre-compressed (using off-peak energy) in an underground chamber
- The pre-compressed air supplements gas turbine
- Shorter construction time, greater site flexibility, lower capital costs than PSH
- Low operating costs, reliable, long lifetime, can have large power ratings
- Fast response – can go from full load pumping to full load generation in minutes
- Efficiency: >70-75% round trip

Energy Storage – CAES

Impact on Ancillary Services (CAES – Compressed Air Energy Storage)

- **Inertial Response:** CAES plants interface with the grid through a rotating machine that allows them to provide inertial response just like any conventional synchronous generator
- **Frequency Response:** CAES plants can provide primary frequency response and is available while the plant is generating
- **Regulation:** When it comes to regulation, CAES plants can respond to AGC Controls in the same manner as traditional hydro and gas turbine plants while generating
- **Load Following:** In regards to load following, CAES plants can follow system operator dispatch commands to provide sub-hourly to multi-hour energy balancing in the generating mode
- **Spinning Reserves:** CAES is well suited to provide spinning reserve - the fast response is easily met by CAES
- **Non-Spinning Reserves:** Because non-spinning reserves do not need to respond as quickly as spinning reserves, CAES is well suited to provide non-spinning reserve
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

Plug-in Electric Vehicle (PEV)

Technology Overview

- Very low capital cost
- Very fast response
- High power/low energy (per vehicle)
- Capable of storing electricity from an intermittent generator such as PV or wind (wind is the cheapest, low-CO2 emissions energy source, but is intermittent)
- Potential to supply energy back to the grid on demand
- Day time opportunity charging could go really well with high PV penetration since the HSIS is showing daytime PV curtailment

Plug-in Electric Vehicle (PEV)

Impact on Ancillary Services

- **Inertial Response:** PEV chargers have the advantage that they can both increase and decrease consumption, providing the opportunity for full inertial response
- **Frequency Responsive Reserve:** The solid-state control capability of PEV chargers make providing primary frequency response feasible
- **Regulation:** PEV solid-state charger control potentially allows for the provision of regulation; Communications will be required to deliver the system operator's AGC signals to the PEV chargers every few seconds
- **Load Following:** PEV chargers can supply load following and ramping response well and are better suited for this service if the balancing requirements are more or less neutral and are not in one direction for a sustained period of time, such as when the load or variable generation forecast errs significantly
- **Spinning Reserves:** PEVs could provide spinning reserves and can respond immediately after receiving a control signal, particularly by reducing its charging though reserve capabilities may be limited in certain circumstances such as in the final hours of the night to honor requirements to PEV owners of a full overnight charge
- **Non-Spinning Reserves:** PEVs can supply non-spinning reserves though reserve capabilities may be limited in certain circumstances such as in the final hours of the night to honor requirements to PEV owners of a full overnight charge
- **Voltage Support:** The interface of the PEVs to the power system is through inverters that have the ability to provide reactive power to the grid and support system voltage

Demand Response (DR)

Impact on Ancillary Services

- **Inertial Response:** Distributed resources' contributions to system inertial response needs is not anticipated to be significant
- **Frequency Responsive Reserve:** The potential contribution of DR to system primary frequency response has been low so far
- **Regulation:** Regulation is the most difficult ancillary service to provide (though fast DR can), requiring the load to adjust consumption every few seconds in response to the system operator's AGC commands; Responsive load is beginning to provide Regulation Reserve
- **Spinning Reserves:** Appropriately responsive load can provide any of the contingency reserves; Technically, demand can provide better reliability response than generation since full response is usually achieved immediately by tripping the load
- **Non-Spinning Reserves:** Appropriately responsive load can provide any of the contingency reserves, including non-spinning reserve; ERCOT's "Loads acting as a Resource" (LaaR) are capable of being interrupted within 30 minutes and are capable of running (or being interrupted) at a specified output level for at least 1 hour (small loads can be used for spin as well)
- **Supplemental Reserves:** Supplemental reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within a 10-to-30 minute interval following the request of the an ISO dispatcher (i.e. PJM)
- **Voltage Support:** DR is not well suited for supporting system voltage or reactive needs; Reducing loads may have a small localized impact on system voltage, but the ability to supply reactive power to support bulk system voltages is limited

Demand Response (DR)

Available DR Programs Cross-referenced with Ancillary Service Potential

DR Programs	Ancillary Services
Direct Load Control (DLC)	Frequency Resp. Reserve & Regulation (w/ enhanced communication and control), Spinning Reserve, Non-Spinning Reserve
Interruptible Load	Spinning reserve, Non-Spinning Reserve
Load as a Capacity Resource	Non-Spinning Reserve
Demand-side Spinning Reserves	Spinning Reserve
Demand-side Non-Spinning Reserves	Non-Spinning Reserve
Demand-side Regulation Service	Frequency Responsive Reserve, Regulation, Load Following
Peak Time Rebate (PTR) and also Critical Peak Rebate (CPR)	Spinning Reserve, Non-Spinning Reserve
Real-Time Pricing (RTP)	Not a traditional A/S function but can be used for "Load Leveling/Load Shifting"
Critical Peak Pricing (CPP)	Spinning reserve, Non-Spinning Reserve
Time of Use Pricing (TOU)	Not a traditional A/S function but can be used for "Load Leveling/Load Shifting"
Fast Auto-DR / Aggregated DR / Integrated DR	Frequency Responsive Reserve, Regulation, Load Following, Spinning Reserves, Non-Spinning Reserves

Demand Response (DR)

Program Details

- **Direct Load Control (DLC):** In a DLC Program, the program sponsor remotely shuts down or cycles a customer's electrical equipment, e.g. air conditioner, water heater, lighting, on short notice; DLC programs are primarily offered to residential or small commercial customers
- **Interruptible Load:** In an interruptible load program, electric consumption is subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies; In some instances, the demand reduction may be effected by action of the system operator, called 'remote tripping', after notice to the customer in accordance with contractual provisions
- **Load as a Capacity Resource:** A Load as Capacity Resource commits to make pre-specified load reductions when system contingencies arise
- **Demand-side Spinning Reserves:** Spinning Reserves are demand-side resources synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an emergency event
- **Demand-side Non-Spinning Reserves:** Non-Spinning Reserves are demand-side resources that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more
- **Fast Auto-DR and also Aggregated DR/Integrated DR:** Aggregated and Integrated DR capable of managing load via high-speed, automated EMS that can deliver second-to-second and minute-to-minute variations in load under grid operator or load scheduler direction

Demand Response (DR)

Program Details (cont'd)

- **Demand-side Regulation Service:** Regulation Service is a type of demand response service in which a demand resource increases and decreases load in response to real-time signals from the system operator; Demand resources providing Regulation Service are subject to dispatch continuously during a commitment period; This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin; Also known as regulation or regulating reserves, up-regulation and down-regulation
- **Peak Time Rebate (PTR) and also Critical Peak Rebate (CPR):** Peak Time Rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days; Like CPP, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices
- **Real-Time Pricing (RTP):** In RTP rate and price structures, the retail price for electricity typically fluctuates hourly or more often to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis
- **Critical Peak Pricing (CPP):** CPP is the rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours
- **Time-of-Use Pricing (TOU):** TOU Pricing is a rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day; TOU rates reflect the average cost of generating and delivering power during those time periods

Demand Response (DR)

Available Resources and Processes that can be used for Demand Response

Residential/Small Comm. End-uses

- A/C Cycling & PCT
- Water Heating
- Space Heating
- Lighting
- Smart Appliances
- Refrigeration
- Fans
- Pumps (Fountain, Pool, Irrigation)
- Thermal Storage (Heat & Cool)
- Battery Storage
- Building Thermal Mass
- EV Charging

C&I Customer Type / Process Uses

- Water Utilities and Water Pumping
- Wastewater Treatment
- Pulp & Paper Product Making
- Fruit + Vegetable Preserving
- Evaporative Processes
- Water Desalination
- Bakeries + Food Manufacturing
- Chemical Manufacturing
- Batch Operations: Hammer Mills
- Air Liquefaction/Separation
- Dairy Product Manufacturing
- Fabricated Metal Product Manufacturing
- Beverage Manufacturing
- Cold Storage & Refrigerated Warehouses
- Arc Furnace & Induction Processes
- Electrolysis and Electroplating
- Oil Pipelines and Pump Stations
- Smelting Processes

Demand Response (DR)

Additional Comments

- All these end-use devices and processes can be aggregated into a larger DR grouping which with proper sizing and integration; With the required communication, command, and control systems, they can provide any of the needed A/S functions, as long as the system architecture and technical characteristics meet the A/S functionality requirements in terms of size, metering, speed and timing of response

- Virtual DR Plants with Energy Management System, Demand Response Management Systems, and Fast Auto-DR all could refer to such an aggregated and integrated system; Large loads can participate individually, but smaller loads are most likely to participate in an Aggregated DR system managed either by the utility or by third party DR aggregators; Suitability of the end-uses and processes would depend on the underlying DR program

Fuel Cells

Technology Overview

- Fuel cells are playing an increasing role in energy storage
- PEM Fuel Cells are currently common for storage but Solid Oxide Fuel Cells (SOFCs), which use natural gas as a fuel and would be viewed more as power generation as opposed to storage, are being researched and tested - there currently is not sufficient information at the system level for this technology but some are targeting 1-10MW at <$2000/kW – baseload
- The Naval Air Warfare Center in China Lake, California, is developing a system that will use solar power to create hydrogen for use in a fuel cell during periods with insufficient sunlight
- In Canada, a partnership between the federal government, BC Hydro, Powertech, and General Electric is converting excess off-peak electricity into hydrogen, reducing diesel consumption by an estimated 200,000 liters per year and greenhouse gas (GHG) emissions by an estimated 600 tons per year
- Germany's Enertrag AG, one of the world's largest wind power companies, is building a facility to use excess wind energy to produce hydrogen for energy storage and for transport applications

Transmission Technologies

- The following data applies to new 60 Hz GE synchronous condensers* only

Frame	Rotor	+ MVArs	H Range
Large motor frame	4 or 6 poles (salient design)	Up to +50	~1.50 to ~2.0
Air-cooled generator frame	Round rotor	+38 to +113	~3.0 to ~2.3
Hydrogen-cooled generator frame	Round rotor	+198 to +478	~1.28 to ~0.88

*-inertia is relatively low for these machines

HVDC and Shunt FACTS for Grid Support

- HVDC technology can be a more economically feasible option for integration of off-island wind power.
  - There are two types of technologies: (1). Conventional line commutated converter (LCC) HVDC, and (2). Voltage-source converter (VSC) technology
  - Voltage source converter technology is capable of providing dynamic voltage support to the grid and is flexible to connect with weak AC systems
  - World's first Ultra high voltage DC solution: Southern power grid China, Conventional LCC HVDC project 5000 MW +/- 800 kV, 1418 km
  - World's first off-shore VSC HVDC: North Sea, 88MW (in 2005) being expanded to additional 100 MW in 2015, 66kV, 70 km,

- Shunt FACTS devices (such as SVC's, STATCOMS) have been deployed worldwide to provide voltage support to the grid.
  - These devices are capable of providing dynamic reactive VAR and voltage support
  - Typical STATCOM ratings for grid applications: 10's – 100's of MVA
  - Energy storage can also be coupled with such devices to provide dynamic real power compensation

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GE Energy Management

Ancillary Services Definitions and Capability Study

Part 2, Tasks 3-4, Final Report

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imagination at work

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Table 3.1 Scenarios of renewable development 8

Foreword

This report was prepared by General Electric International, Inc. acting through its Energy Consulting group based in Schenectady, NY through the support of the Hawaii Natural Energy Institute and under a contract with the Research Corporation of the University of Hawaii.

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1 Study Background and Objectives

The purpose of this study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems and particularly the Hawaiian Islands. The results of this study may be: incorporated into the Hawaii Reliability Standards Working Group's proposals for new reliability standards; used to develop recommendations for revised generation interconnection technical requirements; provided to the Hawaii Public Utility Commission for consideration and adoption; and used to inform the Hawaii utilities' Integrated Resource Planning process.

The GE team has been deeply involved in analyzing the impact of renewable generation on the HECO systems and has performed 9 system-level studies over the past 5 years. The power output form Variable Generators (VG) such as wind and solar plants, by definition is variable. Also, there is a certain amount of uncertainty associated with this generation in the hours preceding actual operations. The generation from VGs is not only variable within the hour and is also variable on a longer timeframe such as daily, weekly and monthly time frame. The variability of VGs within the hour (along with the variability associated with the load) is handled by the system operator through the use of regulation and load-following (spinning) reserves. This study will leverage the findings of the renewable impact studies performed by GE.

The project focuses on four tasks[1]:

- Task 1: Define a standardized set of ancillary services along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems, and provide for the integration of variable generation technologies.
- Task 2: Assess resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Task 3: Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island).
- Task 4: Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

This report presents the results of Tasks 3 and 4 of the study. The results of Tasks 1 and 2 were presented in a separate report, GEA30441 Hawaii Ancillary Services Study PART 1 REPORT and PRESENTATION_12192912r1.pdf.

[1] After the study commenced, it was decided that Task 1 should be generic and address all ancillary services that are in service or under development in the U.S., as well as internationally, regardless of their applicability to the Hawaii system. The applicability of the ancillary services to the Hawaii system was included as a portion of Task 3 of the study. Therefore, in Task 1, the difficulty in adopting some of the researched ancillary services for the Hawaii system was acknowledged, but not discussed in detail.

2 Summary of Results

Ancillary services are required to maintain reliable operations of the electric power system. With Hawaii Natural Energy Institute (HNEI), in cooperation with the Hawaii Reliability Standards Working Group (RSWG), GE has worked to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for the Hawaiian Islands. This written summary report for Tasks 3-4 and the attached PowerPoint slides documenting Tasks 3-4, comprise the Part 2 final report from GE for use by HNEI and the Hawaii RSWG.

The purpose of a companion report on Part 1 of the study was to define a standardized set of ancillary services along with their associated definitions that can be used to meet the operational needs of any bulk power systems, and provide for the integration of variable generation technologies. Part 1 also provided an assessment of resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.

The purpose of the Part 2 study was to identify the physical requirements of the ancillary services needed for each Hawaiian island and to outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs[2]. The Part 2 study was performed under two tasks – Task 3 and Task 4.

The primary focus of Task 3 was to investigate the need for additional ancillary services and interconnection requirements under a couple of different renewable generation scenarios for the three Hawaii electric power systems. The results of past renewable integration studies performed for the Hawaii utilities, where available, were used to understand the impact of renewables on operations under the different scenarios. This information along with the lessons learnt from Part 1 on the best practices in the industry was used to determine the additional ancillary services and interconnection requirements for Hawaii. The unique characteristics of the Hawaii systems were taken into account in determining these additional ancillary services and interconnection requirements. Another important deliverable of Task 3 was to develop a process for evaluating various resource options that were summarized in the technology section (Part 1 - Task 2) for providing the ancillary services required under future system conditions.

The purpose of Task 4 of the report was to outline considerations for promoting a least-cost portfolio of resources that can supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs.

The major recommendations related to ancillary services and interconnection requirements are given below.

[2] Production costs include all costs associated with the operation of a power system. These costs include (but are not limited to): fuel costs, variable O&M costs, fixed O&M costs, startup/shutdown & cycling costs, impact of transmission losses, environmental compliance costs, and any explicit compensation which is paid to resources. Production costs do not include capital expenditure associated with the initial purchase of a resource or associated upgrades costs. Consumer cost is highly correlated with Production cost; however, the primary differentiator is that that Consumer cost includes the impact of capital expenditure on the price rate-payers are exposed to. In addition, consumer cost also includes other distribution-related expenses which are not typically included in the production cost.

- Require synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements.
- Require droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to the requirement for dispatchable generators.
- Variable Generation (VG) should be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. Recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. Need to design and employ forecasting methodology/tool to calculate the amount of down reserves that VGs can reliably provide based on actual and forecasted generation from VGs.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are already curtailed.
- Recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- Recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation.
- In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical.

As mentioned before, another important deliverable of Task 3 was to develop a process for evaluating various resource options. A methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements was developed. Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a "least-cost" portfolio while observing system reliability needs. Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure. There are 10 specific steps included in the body of the report and corresponding presentation material.

The objective of Task 3 was also to evaluate methods for procuring the recommended ancillary services. Four potential approaches for obtaining, compensating, and incentivizing ancillary services were included the report. The details of each approach along with their respective pros/cons are discussed further in the report body and corresponding presentation material. Specifically, the four approaches are:

1. Market Clearing Price

2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources. Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements. As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive could likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for (some of/all of) the ancillary services. Careful consideration is required before introducing such remuneration methods or unbundling the ancillary services.

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources. Relative to the current environment, in which dispatchable resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be considered as an equitable option. Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are more expensive to operate than some non-renewable resources on the system (i.e. periods where the energy contract price is higher than the marginal system cost). During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation", to explicitly compensate for costs (including opportunity costs) associated with providing ancillary services, would be recommended. It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration.[3] Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource

[3] The provisions which preclude economic curtailment of renewable VG have not been extended to dispatchable renewables such as hydropower or biomass.

Mix" developed in Task 3 and discussed earlier, could be leveraged to help quantify these potential benefits. Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services. To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

Ancillary service participation from DR, transmission, and retrofit options has the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure. Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies. To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types. In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have [typically] low variable operating cost and have the have the potential to reduce the overall production cost for the system. As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized. Instead, it is recommended that the impact on overall consumer cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

2.1 Key Terminology

The following definitions for key terminology are relevant throughout the content of this study and should be interpreted as described below.

Area Control Error (ACE):

The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. Source - NERC Glossary (2008)

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

> **NIA** is the algebraic sum of actual flows on all tie lines.
>
> **NIS** is the algebraic sum of scheduled flows on all tie lines.
>
> **B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
>
> **FA** is the actual frequency.
>
> **FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
>
> **IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for **Hawaii, ACE = – 10B (FA – FS).** This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. Source - Revised definition per Hawaii RSWG Glossary

Automatic Generation Control (AGC):

Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule, plus the Frequency Bias (i.e. ACE). Source - NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Droop Response:

Droop response is a near instantaneous means of proportionally adjusting a resource's real-power to resist a change in frequency; allowing a system of resources to operate in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide

100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.

Droop response can be provided by any frequency-sensitive resource.

Resource:

A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning:

Historically, the terms "spinning" and "non-spinning" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

3 Study Results

3.1 **Task 3:** Identify the physical requirements of ancillary services needed for each Hawaiian island.

The objective of this task was to answer the following questions:

1. How much additional quantity of existing ancillary services (example, additional MWs of spinning reserves) may be required in the future under high renewable generation scenarios?
2. What new ancillary services and interconnection requirements may be needed in the future under high renewable generation scenarios?
3. What is the process to determine a cost-effective way of using existing as well as new technology to meet the additional ancillary service requirements?

Drawing on recent Hawaii renewables integration studies conducted by GE, the project teams' expertise from these and similar large scale renewable integration studies, and other sources, GE and the HPUC and HECO companies hypothesized the following scenarios of renewables development for the three utilities.

Table 3.1 *Scenarios of renewable development*

	HECO (Oahu)	MECO (Maui)	HELCO (Big Island)
Most Recent IRP	HECO IRP 2009-2028 (Sep 2008)	MECO IRP 2007-2026 (April 2007)	HELCO IRP 2007-2026 (May 2007)
Resource Planning Study to support future IRP	?	Available from MECO	HELCO Resource Planning Study (June 2012)
Other renewable integration studies	OWIST & HSIS (Available from GE)	HSIS (Available from GE)	
Load Forecast	From OWIST and HSIS	Base Line From HSIS	Base Line From Resource Planning Study
Scenario 1: Moderate penetration Renewables or mix definition	HSIS Scenario 4A 360 MW Dist Solar PV 400 MW Cent Solar PV 100 MW On-shore Wind No Off-Shore Wind	HSIS Base Line (2012 system) 15 MW Dist Solar PV 0 MW Cent Solar PV 72 MW On-shore Wind	HELCO 100% renewables intermittent - heavy **22 MW Biomass** **100 MW Wind (centralized)** **100 MW PV (centralized or distributed)** **50 MW Geothermal**
Scenario 2: High penetration Renewables or mix definition	HSIS Scenario 4B 160 MW Dist Solar PV 200 MW Cent Solar PV 100 MW On-shore Wind 200 Off-Shore Wind (same solar & wind MWH as 4A)	HSIS Scenario 3 30 MW Dist Solar PV 15 MW Cent Solar PV 72 MW On-shore Wind **Scenario 3: Heavy Intermittent Renewables** **22 MW Biomass** **100 MW Wind, 100 MW PV** **50 MW Geothermal**	HELCO 100% renewables geothermal/ dispatchable - heavy **42 MW Biomass** **50 MW Wind (centralized)** **50 MW PV (centralized or distributed)** **100 MW Geothermal**

Details regarding existing interconnection requirements and ancillary services were gathered and summarized by GE using various sources such as typical design criteria for new units, model PPAs etc. GE also reviewed pertinent documents from HPUC and Hawaii utilities such as Docket 2008-0273 Feed-in Tariff ("FIT") and the updates to the information contained in the docket provided by the HECO utilities.

The attached workbooks[4] include the details regarding existing interconnection requirements and ancillary services for all three HECO utilities as well as forecasted ancillary services (primarily increase in MWs of operating reserves) for the chosen scenarios where available. To the extent that the scenarios had been previously studied by the GE teams as part of the renewable integration studies, the additional reserve requirements (HECO and MECO Scenarios 1&2) were available. For MECO Scenario 3 and HELCO Scenarios 1&2, more detailed studies would need to be performed to determine the additional reserve requirements. The process for determining the additional reserve requirements is included in Appendix A (Methodology for Determining Operating Reserves). For the purposes of this study, GE worked with the MECO and HELCO to try and define the directional change and magnitude of ancillary services for those scenarios. Where practical, GE estimated the amount of ancillary services required based on studies performed in Hawaii and the mainland.

The results from the primary frequency response simulations were available for some of the selected scenarios from the HSIS and OWIS study performed by GE. These simulations were also used in the determination of the need for new ancillary services.

HECO Ancillary Services for Scenario MECO Ancillary Services for Scenario HELCO Ancillary Services for Scenario

[4]

HECO Workbook: HECO Ancillary Services for Scenarios_DRAFT_Rev7.xlsx
MECO Workbook: MECO Ancillary Services for Scenarios_DRAFT_rev6.xlsx
HELCO Workbook: HELCO Ancillary Services for Scenarios_DRAFT_Rev4.xlsx

3.1.1 Additional Quantities of Existing Ancillary Services Required Under Study Scenarios

This section discusses the additional quantities of existing ancillary services required under the study scenarios for each HECO utility, where available.

3.1.1.1 HECO

The following two scenarios were studied:

Scenario 1 - HSIS Scenario 4A

360 MW Dist. Solar PV

400 MW Cent Solar PV

100 MW On-shore Wind

No Off-Shore Wind

Scenario 2HSIS-Scenario 4B

160 MW Dist. Solar PV

200 MW Cent Solar PV

100 MW On-shore Wind

200 Off-Shore Wind

(same solar & wind MWH as 4A)

Inertia and Primary Frequency Response

Results of HSIS study show that 1) enforcing no trip of Distributed PV on under-frequency excursion helped to reduce the frequency drop by 2.2-3.4 Hz (if UFLS is not active), 2) use of frequency responsive load (50MW @ 59.5 Hz trip), and synthetic inertia from off-shore wind plants can support the system during loss of generation contingency by reducing the frequency drop (raising the nadir) by up to 0.3 Hz, in cases where synchronous generators are displaced by renewables. Please see figures.

Figure 3.1 *HECO Scenario 4A – Loss of AES (with frequency ride through of Dist PV)*

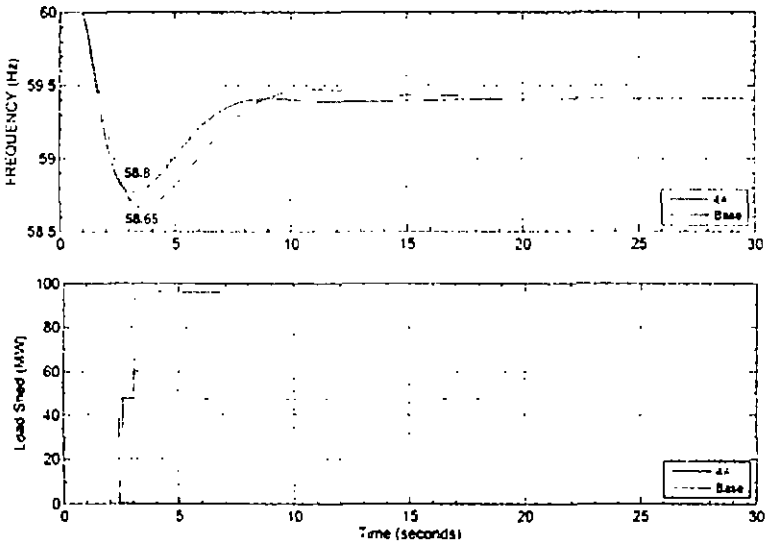


Figure 3.2 *HECO Scenario 4A – Loss of AES (without frequency ride through of Dist PV)*

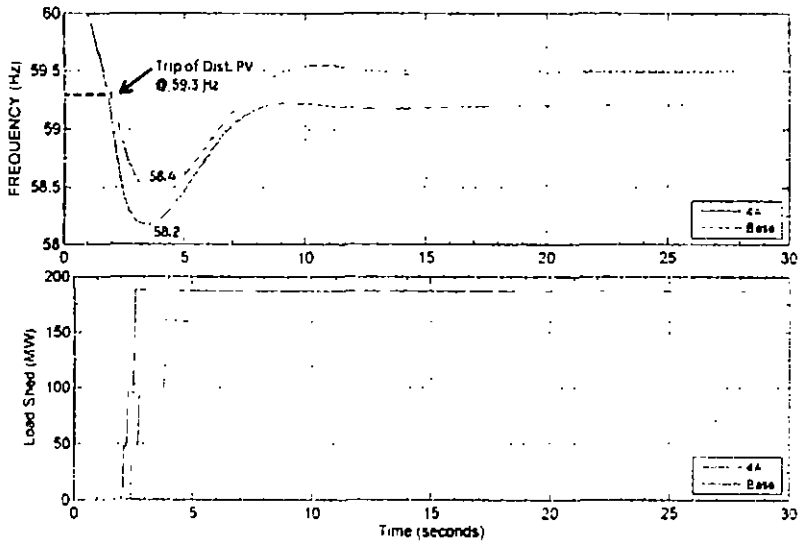
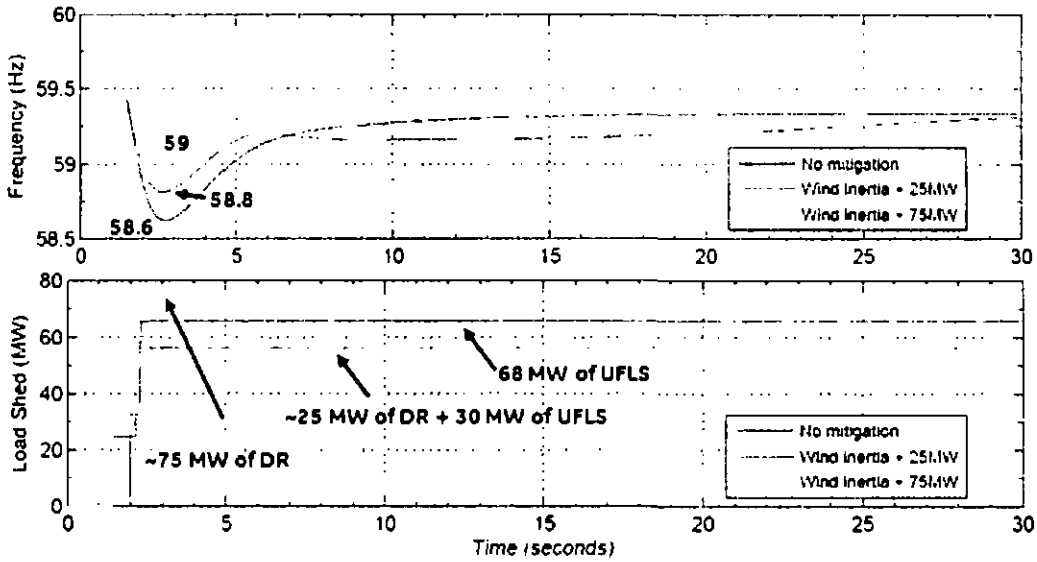
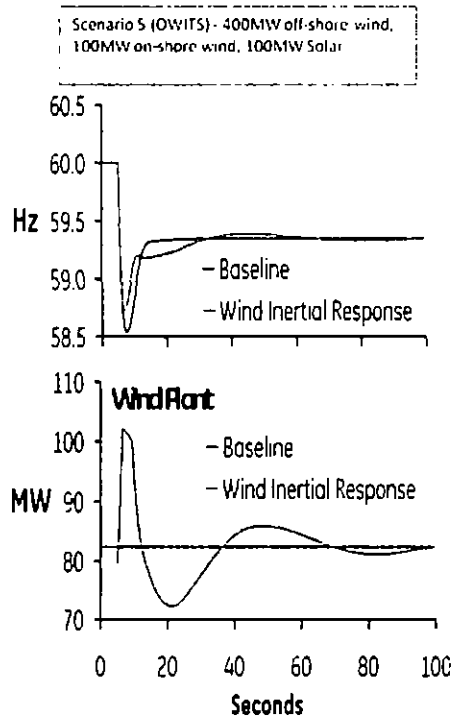


Figure 3.3 *HECO Scenario 4B - Synthetic Inertia from Online Wind Plants & Frequency Responsive Load Reserves*



Preventing distributed PV trips has the most beneficial effect on the frequency response. The frequency nadir without distributed PV trip is 58.1 Hz, 0.9 below the first stage of UFLS. For a safe margin, other recommendations (i.e., synthetic inertia and frequency responsive load) should also be implemented.

Figure 3.4 *HECO Scenario 5 - Synthetic Inertia from Online Wind Plants*



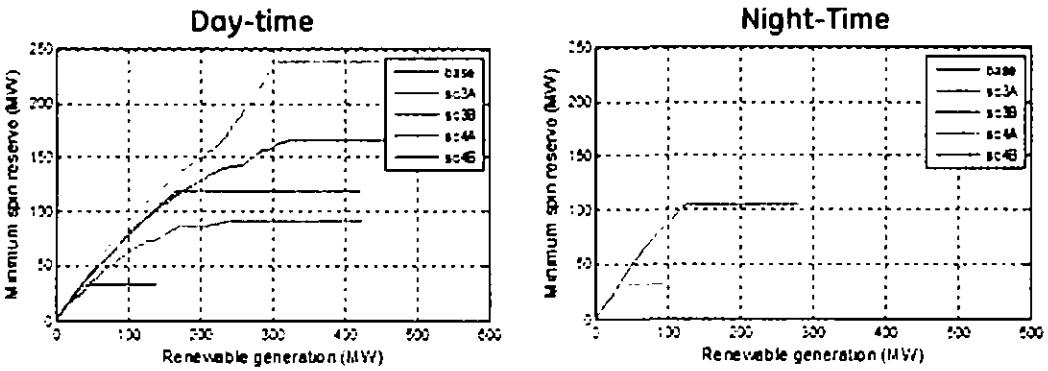
Regulation

The additional regulation reserves required to accommodate variability in wind and solar generation is given below.

Scenario 1 - HSIS Scenario 4A: Max Day-time (6am-8pm) = 239MW; Night-time (8pm-6am) = 32MW.

Scenario 2HSIS-Scenario 4B: Day-time (max) = 166MW; Night-time (max) = 104MW

Figure 3.5 *HECO Spinning Reserve Requirement as a Function of Online Renewable Generation*



Inter-hour results from the simulation of these scenarios confirm that the operating reserves requirement helps the system (in Scenarios 4A and 4B) to carry enough reserves to sustain the worst sub-hourly event in each hour of the year as well as to ride the system through forecast error/uncertainty. Further analysis is required to determine the economics of the existing capacity meeting the additional reserve requirement. If the existing capacity is insufficient or uneconomic, then other means of obtaining spinning reserves (for example, from battery storage and DR) should be explored. This is further discussed in the next section on the methodology to estimate technology mix.

3.1.1.2 MECO

The following two scenarios were studied:

Scenario 1 – Maui Baseline

15 MW Dist Solar PV
0 MW Cent Solar PV
72 MW On-shore Wind

Scenario 2- Maui Scenario 3

30 MW Dist Solar PV
15 MW Cent Solar PV
72 MW On-shore Wind

Scenario 3- Heavy Intermittent Renewables Scenario

22 MW Biomass
100 MW Wind
100 MW PV
50 MW Geothermal

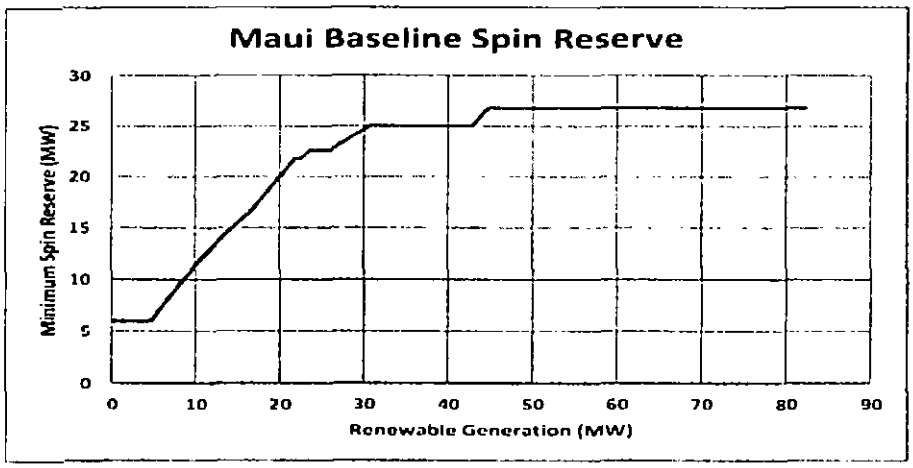
Inertia and Primary Frequency Response

Regulation

Scenario 1 & 2: As a function of forecast of wind+solar power. Max Reserves approximately 27 MW as shown in the figure.

Scenario 3: As a function of forecast of wind+solar power. Max Reserves estimated to be approximately 50 MW.

Figure 3.6 *MECO Spinning Reserve Requirement as a Function of Online Renewable Generation*



3.1.1.3 HELCO

The following two scenarios were studied:

Scenario 1 – Heavy Intermittent

Geothermal - 50MW

ROR Hydro - 16.85MW

Wind - 100MW

Distributed PV - 12MW

Central/Dist PV - 88MW

Biomass - 22MW

Scenario 2- Heavy Dispatchable

Geothermal - 100MW

ROR Hydro - 16.85MW

Wind - 50MW

Distributed PV - 12MW

Central/Dist PV - 38MW

Biomass - 42MW

Inertia and Primary Frequency Response

(No data available)

Regulation

(No data available)

3.1.2 Recommendations for New Ancillary Services and Interconnection Requirements

Task 1 (Part 1 study) researched the ancillary services and interconnection requirements that are currently being employed or under consideration globally. The ancillary services are as follows:

- Frequency Responsive Reserve/Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

The emerging interconnection requirements fall in the categories below:

- Power Factor and Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and Control
- Over and Under Frequency controls
- AGC Response Capability
- Inertia

It should be noted that the above-mentioned ancillary services and interconnection requirements have been employed in various parts of the world and may or may not be applicable to the Hawaii system. These ancillary services and interconnection requirements were discussed in detail in the Part 1 report. The information presented in Section 3.1.1 along with the lessons learnt from the Part 1 study on the best practices in the industry were used to determine the additional ancillary services and interconnection requirements for Hawaii. The unique characteristics of the Hawaii systems were taken into account in determining these additional ancillary services and interconnection requirements. Below is a list of the recommendations.

3.1.2.1 Inertial Response

Inertial response is very important for the Hawaii utilities since they are small islanded systems with relatively high Rate-of-Change-of-Frequency (ROCOF) due to system events. Currently, the desired inertial response from dispatchable synchronous renewable generation (RE) resources such as geothermal plants is obtained as a condition of contract. There is no synthetic inertia requirement in the interconnection requirements for Variable Generation (VG) resources such as wind and solar plants. However, recent PPAs for renewable generation have included inertia requirement.

Based on the information gathered in Part 1, it can be concluded that, at present, there is no ancillary service or market associated with inertial response anywhere in the world. Where implemented, the inertial response requirements have been through interconnection requirements. For example, Hydro Quebec[5] requires wind power to provide an emulated inertial response. Based on the Part 1 study, we have also determined that with the current technology, it is possible for wind plants to provide synthetic inertial response, which if designed properly can help the system ride through

[5] Hydro-Québec requires that wind plants be able to contribute to reducing large (> 0.5 Hz), short-term (< 10 s) frequency deviations on the power system, as does the inertial response of a conventional synchronous generator whose inertia constant (H) equals 3.5s

frequency events. Therefore, we recommend synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements. The utilities should also perform offline studies to determine the impact of synthetic inertia on inertial and primary frequency response and how it impacts inertia requirements from other (future) interconnecting resources, Under Frequency Load Shedding (UFLS) practices, and spinning reserve requirements. The offline studies should be used to guide for determining combinations of resources that need to be online.

3.1.2.2 Primary Frequency Response

Primary frequency control involves the autonomous, automatic, and rapid action (i.e., within seconds) of a generator to change its output to oppose large changes in frequency. Primary frequency control actions are especially important during the period following the sudden loss of generation to prevent the frequency from collapsing. Primary frequency response is provided by units that are selected to provide spinning reserves.

HECO uses spinning reserves to cover 100% of its largest single contingency (185MW). The units providing spinning reserves are on governor and AGC control. In addition, HECO also carries spinning reserves to meet the variations in load and renewable energy within the hour. These units are also on governor and AGC control and provide frequency response.

In MECO, no separate spinning reserves are carried for contingencies. The units that provide regulation are on governor and AGC control and also provide frequency response and provide spinning reserves for contingencies. The regulating reserves are a function of forecast of wind and solar generation - minimum of 6MW and a maximum of 50MW in the up direction and up to 9 MW in the down direction. Under Frequency Load Shedding (ULFS) is used to prevent the frequency from collapsing. Fast-starting offline resources are used to restore shed load.

In HELCO, the units that provide regulation are on governor and AGC control and also provide frequency response and spinning reserve. The regulating reserves are a function of forecast of wind and solar generation with a minimum of 6 MW plus up to 15 MW to account for the wind regulation. ULFS is used to prevent the frequency from collapsing. Fast-starting offline resources are used to restore shed load.

Currently, the interconnection requirements for HECO utilities require all dispatchable generators (conventional, as well as synchronous RE) to have a 4% droop that is adjustable. HECO utilities also have the capability to dispatch units to provide reserves as needed. As such, the HECO utilities currently obtain primary frequency response as a condition of interconnection.

Based on our research in the Part 1 study, Primary Frequency Response ancillary service is an emerging ancillary service that is being investigated in the U.S. mainland systems[6]. FRR (Frequency

[6] All systems carry contingency reserves (spinning and non-spinning) to help bring the frequency to its original value after the loss of a generator or transmission line. However, having sufficient contingency reserves in itself does not guarantee adequate primate frequency response. Currently, NERC is investigating the need for Frequency Responsive Reserves to ensure adequate primary frequency response This is because the speed of response of resources that can provide

Responsive Reserves) is already being used in the markets in Australia[7]. However, in Hawaii all the dispatchable generators are on both governor and AGC control and are already required to have fast response (100% response within 30 seconds) in emergency situations. This fact needs to be considered in determining if there is a need for an additional primary frequency response ancillary service. Also, how such an ancillary service would work in a non-market environment should be investigated.

Based on the research performed on technical capabilities of resources in the Part 1 study, wind and solar plants are capable of providing primary frequency response improving the reliability of the grid.

Our recommendations with respect to primary frequency response are as follows:

- We recommend droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to this requirement for dispatchable generators.
- We also recommend that VG be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. The payment mechanism will be discussed later in the section on ancillary service procurement. We also recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. In many instances, using VG to provide reserves also reduces their curtailment. For example, using wind generation to provide down reserves (instead of carrying the down reserves by dispatching up a thermal generator) reduces the curtailment of wind generation. Tools to determine the amount of down reserves that VGs can reliably provide should be developed.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are curtailed.

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contingency reserve is driven by NERC standard BAL-002 requirement R4 requires that the ACE be returned to zero (or to its pre-disturbance level if its pre-disturbance level is originally negative) within 15 minutes. In FERC Order 693, FERC ordered NERC to revise its standard so that it "defines the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved." NERC is pursuing a frequency response initiative that is looking at what types of requirements are needed. A frequency responsive reserve (FRR) procedure has been proposed in a WECC whitepaper. The proposal suggests a FRR amount for all of WECC that is based on the largest credible contingency the system is prepared to deal with without activating UFLS (a 3200 MW Category C double generator contingency) allocated to each balancing authority based on peak load.

[7] In Australia, the NEM has 6 FCAS (Frequency Control Ancillary Services) related to primary frequency response
Fast Raise (6 Second Raise)
Fast Lower (6 Second Lower)
Slow Raise (60 Second Raise)
Slow Lower (60 Second Lower)
Delayed Raise (5 Minute Raise)
Delayed Lower (5 Minute Lower)

- Allowing VG to provide primary frequency response as suggested above can help reduce the production cost of the system, improve the reliability and lower curtailment. It should also be noted that the above provisions are similar to those used in the ERCOT[8] market.

3.1.2.3 Frequency Regulation Ancillary Service (Secondary Frequency Response)

Regulation is very important for Hawaii utilities unlike the mainland where shortages may only result in CPS violations and do not show up in the system frequency. This ancillary service is required to follow the changes in load, as well as renewable generation. Regulation is not only required under normal operations, but also after an event to restore the frequency after primary frequency response has been provided.

- Currently, HECO does not quantify up regulation but it is carried as part of its spinning reserve requirement. The generators selected for providing primary frequency response (that are also on AGC) provide up regulation.
- The amount of up regulation carried by MECO is a function of forecast of wind and solar generation, with a minimum of 6MW and a maximum of 50MW. 6-8 MW of down regulation is also held depending on number of CTs online.
- In HELCO, the regulating reserve requirement is determined by the anticipated near-term balancing needs, which the system operator determines by observing the variability of apparent demand (due to wind variability, solar PV) and forecasted customer demand. HELCO also carries sufficient down regulating reserve to cover largest off-peak load loss due to a single contingency.
- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to be on AGC. All the existing wind contracts also include active power control (APC) provision to enable automatic curtailment.
- In Hawaii, the AGC signal is sent to generators every 4 seconds. There are two components to a generator signal: a regulation component, and an economic component. The regulation component has larger gains and more aggressive time of implementation and therefore will override the economic signals when frequency is off-normal (HELCO).

Based on the findings in the Part 1 study, markets such as California ISO are looking into a separate load-following ancillary service product to handle changes in variable generation that are sustained. However, this is an artifact of the CAISO (and other) markets where regulation is only used to handle variations in net load within the dispatch interval, typically 5 minutes. In Hawaii, regulating reserves are maintained to manage anticipated variability within the hour in the apparent demand, which includes forecast changes in load and the imbalances caused by changes in variable generation[9]. Therefore, there is no need for a separate load-following

[8] The wind generation plants should have adjustable dead bands to match those of other conventional resources or that which is provided in the operating guides, and a similar droop to the other resources of 5%. In ERCOT, wind generators are required to provide down response all the time and up response when curtailed.

[9] Regulating reserves are designed to meet the inter-hour variability of wind and solar. The nature of the fleet is such that there are abundant up-reserves to sustain forecast uncertainty (in load and renewables). Also, load variability in shorter time scales is smaller than the renewable variability and in the high penetration scenarios it is not at all visible. With

reserve in Hawaii. However, higher amounts of regulation reserves will be required to integrate higher amounts of variable generation as shown later through the scenarios. Variable generation resources and other emerging technologies should be allowed to provide regulation. Based on the research performed in the Part 1 study, wind plants have the capability[10] to provide regulation.

Our recommendations with respect to secondary frequency response are as follows:

- We recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- We recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of regulation that VG can provide.
- VG should be required to provide down regulation without any explicit compensation similar to other dispatchable units in the system. Need tools to determine the amount of down regulation that VGs can reliably provide.
- VG should be required to provide up regulation without any explicit compensation when they are curtailed for reasons other than providing up regulation since their opportunity cost is zero when they are curtailed.
- Allowing VG to provide regulation as suggested above can help reduce the production cost of the system, improve the reliability and lower curtailment.

3.1.2.4 Non-Spinning Reserves

Non-spinning reserves in the form of quick start resources serve a number of purposes. Following an outage or unexpected loss of generation, diesels are initially used (offline contingency reserves) to replace lost generation and/or UFLS restoration; following this intermediate and/or more efficient generation is started to replace the diesels. Quick start units are also used to offset regulating requirements within the hour. All three utilities carry varying amounts of QS resources. No changes to non-spinning reserves ancillary services are proposed. However, faster/more contribution from non-spinning assets may help to reduce the spinning regulation reserves requirement and should be evaluated.

3.1.2.5 Black Start Service

All three utilities have a number of units with black start capability. No changes to black start service proposed.

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changes to the operating practices or in baseload fleet, it maybe required to assess reserves requirement for forecast uncertainty (in net load).

[10] Grid codes in Ireland and Denmark require Active Power Control (APC) for wind farms which give them the capability of responding to operator power set-point commands (equivalent to AGC)

3.1.3 Storage and Demand Response

In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical. However, the following need to be considered:

- Need to consider the interaction between DR response and UFLS since UFLS uses 75-80% of all load. The interaction of UFLS and DR must be developed and coordinated to ensure adequate protection for the UFLS system.
- The modification of PV to being required to trip on lower frequency set-points than standard IEEE 1547 trip settings, which are higher than UFLS trip settings, to mitigate loss of PV during a system low-frequency events was completed by the recent modification to Hi Rule 14h. However, there are still legacy installations that trip in accordance with IEEE 1547 and will compound the impact of unit trips. HECO uses 57.3 Hz for low frequency trip of distributed PV (not sure about other utilities). Legacy PV trips at 59.3 Hz and still must be considered in all studies. Since the 1547 standard and, similarly, Rule 14H specify in terms of a must-trip instead of ride-through, confirmation that the existing change results in the desired ride-through is important - a future change to a ride-through requirement may be necessary.
- Need to consider feeder net load for UFLS system as distributed PV increases and feeder net load decreases during some hours.

3.1.4 Changes to Interconnection Requirements

Below are the suggested changes to the interconnection requirements.

3.1.4.1 Reactive Power and Voltage Regulation

- Hawaii utilities have voltage regulation and control requirements for dispatchable and variable generation. No changes proposed.

3.1.4.2 Voltage and Frequency Ride-thru

- Hawaii utilities have voltage and frequency ride-thru requirements for dispatchable and variable generation. Utilities should develop requirements for unbalanced ride thru requirements. *Unbalanced voltage capability is required in weak systems and is currently a* much larger issue than LVRT since turbine manufacturers do not currently have a standard to meet and the current technology of WTG is much less than conventional generation.

3.1.4.3 Ramp Rate Limits and Control

- Hawaii utilities have ramp rate limits in the up direction for variable generation. Ramping requirements in the up and down direction are included as requirements for dispatchable generation. No changes proposed.

3.1.4.4 Over and Under Frequency Controls

- Per recommendation before, require wind and solar plants to have primary frequency response capabilities.

3.1.4.5 Inertia

- Per recommendation before, require wind plants to have inertial response capabilities.

3.1.4.6 AGC Capability

- Per recommendations before, require all generators including wind and solar plants to have the ability to accept and respond to AGC commands. Active power set-point is a current requirement for VG to enable curtailment. This would require modifications to the AGC program.

3.1.5 Fundamentals of Power System Operation

This section is intended to serve as a primer which provides a common foundation for the general terminology and concepts that will be referred to throughout the balance of this report. In addition, it is intended to provide insight into the processes and considerations that are required to leverage available power system resources to "serve the load" in the most cost effective and reliable manner. Downstream sections of this report will contain more Hawaii-specific discussion, considerations, and where possible, recommendations which reference these concepts. The "fundamentals" are outlined here and in the PowerPoint presentation for Tasks 3&4 in Appendix A.

In a power system, resources are committed and dispatched based on their ability to:

1. Directly provide energy
2. Support the reliable delivery of energy

Often, the same resource may serve both functions. The degree to which this occurs depends upon the attributes of the individual resource, resource mix, and the respective needs of the power system. To supply "energy", a resource is primarily evaluated based on its variable cost structure:

- Startup Cost: Typically on a "$/startup" basis. Represents the cost incurred for bringing a resource to a state where it is available for dispatch.
- Minimum Generation Cost: Typically on a "$/hr" basis. Represents the variable cost required to sustain operation at the minimum permissible "real-power" operating level.
- Incremental Variable Cost: Typically on a "$/MWh" basis. This represents the cost for the next incremental adjustment in the real-power set-point.

To support the "reliable delivery of energy", a resource is considered based on additional attributes that characterize its flexibility. Examples include, but are not limited to:

- Inertial Response: Typically measured by a resource's inertial constant "H" (in seconds). This is a normalized value that relates a resource's kinetic energy to its respective capacity.
- Ramp-rate: Typically on a "MW/min" basis. Characterizes the rate at which a resource is able to adjust it's real-power set-point. This rate can be set "tuned" differently dependent upon whether the need is for frequency response (i.e. FRR), regulation, (i.e. AGC), load following, spinning reserve, and/or startup periods.
- Quick-start capability: Typically on a "minutes or hours" basis. Characterizes the time-delay required for a unit that is offline or disconnected from the power system to become available for the purposes of providing energy or supporting the reliable delivery of energy.
- Operating Range: Characterized on a "real-power" and "reactive power" basis.
- Real-power range: Characterizes the range over which a resource is able to inject or consume actual "MW" to support the load on the power system.

- Reactive-power range: Characterizes the range over which a resource is able to provide "MVAR" to assist with maintaining system voltage levels.
- Minimum Operating Period:
- Minimum up-time: The minimum time for which the unit needs to be online once started
- Minimum down-time: The minimum time for which the unit needs to be offline once shutdown
- Black-start capability: Ability to start a unit without support from the grid

Determining the balance between using a resource for its "energy" vs. its ability to support the "reliable delivery of energy" often requires sophisticated algorithms. Typically, this balance is achieved through "security-constrained unit-commitment (SCUC)" and "security-constrained economic dispatch (SCED)" algorithms. For long-term power system planning, a production cost model is often leveraged to execute the SCUC and SCED algorithms. For day-to-day and week-to-week operations, similar algorithms are used in energy management system (EMS) software. The objective of the algorithms is to ensure that sufficient resources will be online (i.e. committed) to meet the anticipated load forecast (including variability) and satisfy reserve requirements in the most economical manner (i.e. lowest system cost) while observing reliability constraints. Emphasis is placed on leveraging assets with the lowest variable operating costs. More expensive resources are only selected if their flexibility is required to ensure reliable delivery of the energy, relieve system constraints, or they benefit increased renewables penetration, etc.

Once a resource is "committed", the "security-constrained economic-dispatch" algorithms are then utilized to obtain a resource's load set-point (i.e. "dispatch-point"). To achieve a solution, these algorithms attempt to "park" all committed resources at the same incremental variable cost (additional details in following slides). Typically, the "most-economical" manner for operating the system is for all committed resources to be dispatched to the same "incremental variable cost" (provided the resource is not at the extremes of its operating range). This is referred to as "economic dispatch". The resource which will provide the "next most economical MW" is referred to as the marginal unit. And, at that instant, the "system marginal cost" is equivalent to the incremental variable cost of that resource. Often, there are multiple units "on or near the margin".

To satisfy the reliability needs of the power system, it is often necessary to adjust the dispatch of the resources away from their economic optimum set-point. This movement creates additional "headroom/legroom" and increases the available reserves to satisfy system requirements. To ensure that these adjustments are made in the most economical manner, a process referred to as "co-optimization" is often deployed. This process assists in identifying which resources to adjust, and by how much. Specifically, it attempts to minimize the "opportunity costs" associated with moving a resource away from its economic optimum to meet the reliability needs of the system.

The concept of using opportunity costs to rank/prioritize resources and make system-level trade-offs between energy vs. ancillary capability is still applicable regardless of whether an explicit payment is made to the resources for their ancillary participation.

Typically, ancillary service needs are "best-served" by marginal resources. This is driven by the fact that they often have the lowest opportunity cost for providing the service. For example, a wind farm[11] typically has a very low variable operating cost. Curtailing the wind for the specific purpose of providing an ancillary service would [typically] result in very high opportunity cost (for both the plant and the power system). However, during periods where renewables are curtailed, due to must-run resources and/or corresponding over-supply, allocation of ancillary services to the renewables would likely be very cost-effective. In situation where renewables are not curtailed, selecting a combustion turbine or storage device[12] would likely result in lower opportunity cost and lower system cost.

[11] In Hawaii, during off-peak periods, wind energy contract prices can higher than the variable cost of other thermal generation. For these circumstances (and while wind contracts do not separate fixed & variable costs), curtailing wind for the purposes of providing ancillary services may be recommended

[12] Storage devices are unique. Such resources are often "energy-neutral" (i.e. zero net-output on a nominal basis). As a result, storage devices do not have an "opportunity cost" per se. The variable cost to provide ancillary services from a storage device is typically driven by the cost to initiate the devices operation (i.e. startup) and the corresponding variable O&M during operation. As a result of their energy-neutral / zero-opportunity cost, storage devices are typically prioritized ahead of other resources for providing ancillary services.

The following illustrations are intended to provide further clarification on some of the key tools and concepts that were discussed in this section. Specifically, Figure 3-7 and Figure 3-8 illustrate the calculations for opportunity costs and co-optimization. The accompanying PowerPoint presentation in Appendix A has additional details on production cost modeling, average vs. incremental variable cost, and economic dispatch.

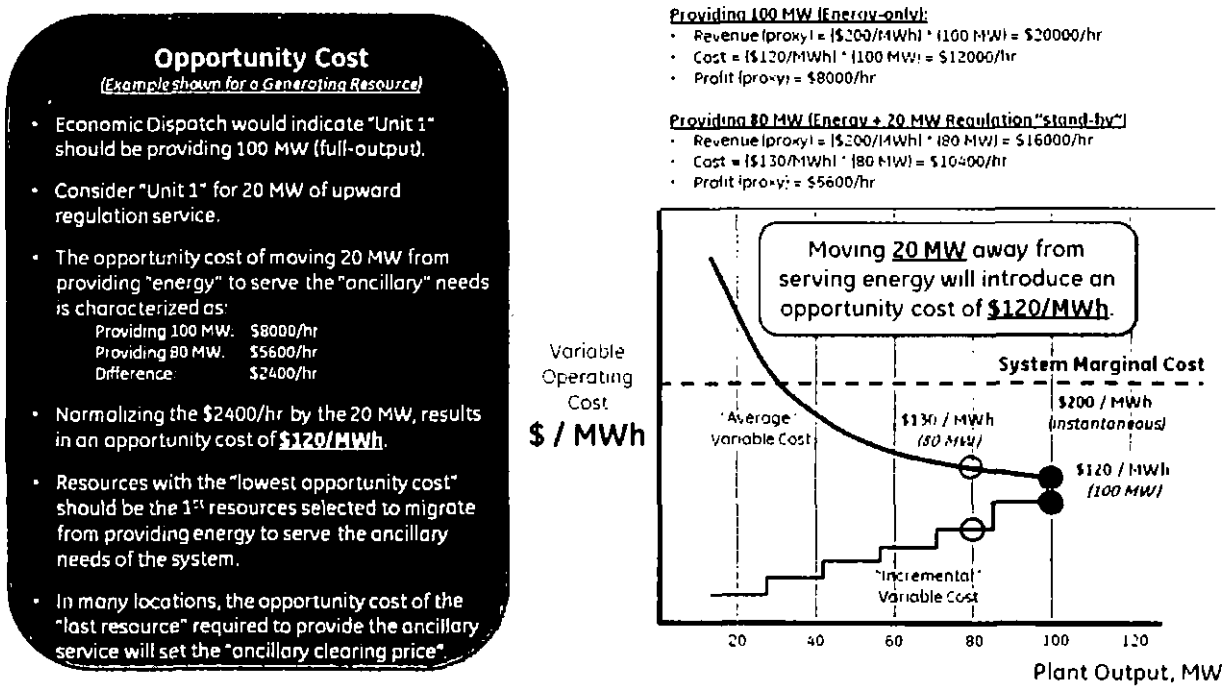

Figure 3.7 *Opportunity Cost illustration*

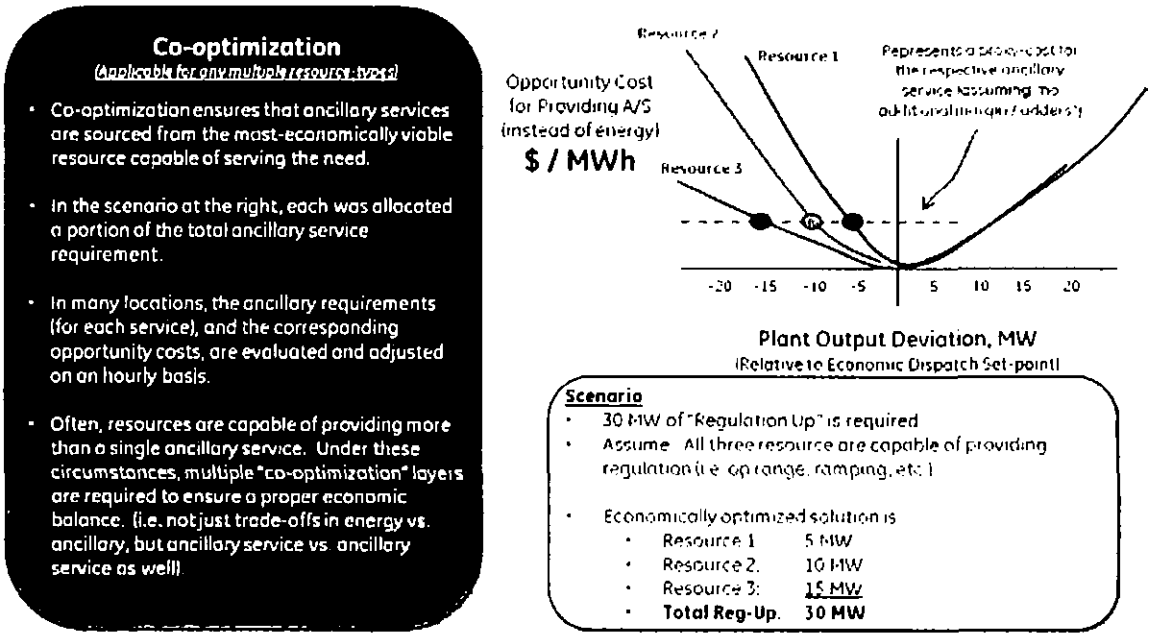

Figure 3.8 *Co-optimization illustration*

In an effort to place the preceding material in context, the accompanying PowerPoint presentation provides some HECO-specific perspective on the opportunity cost associated with migrating a resource away from providing energy and into ancillary participation. For the following example, which is an excerpt from the PowerPoint in Appendix A, we'll be assuming an instantaneous marginal system level cost of $190 / MWh.

Figure 3.9 shows the instantaneous opportunity cost for ancillary service for HECO based on the data available in the HSIS study. Figure 3.10 shows the Opportunity cost as the deviation from the economic dispatch set-point is increased for the HECO units.

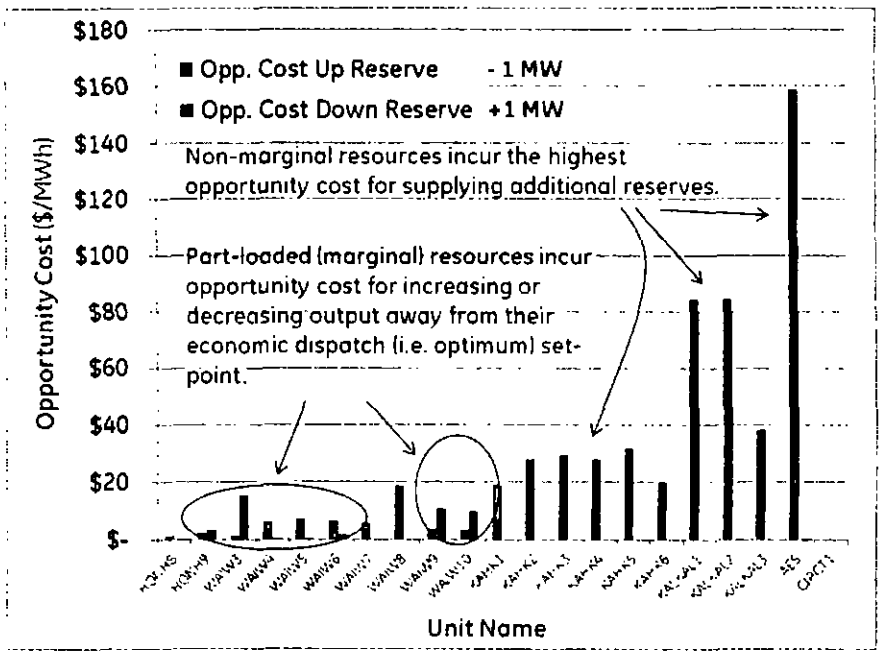

Figure 3.9 *Instantaneous opportunity cost for shifting capability from energy to A/S*

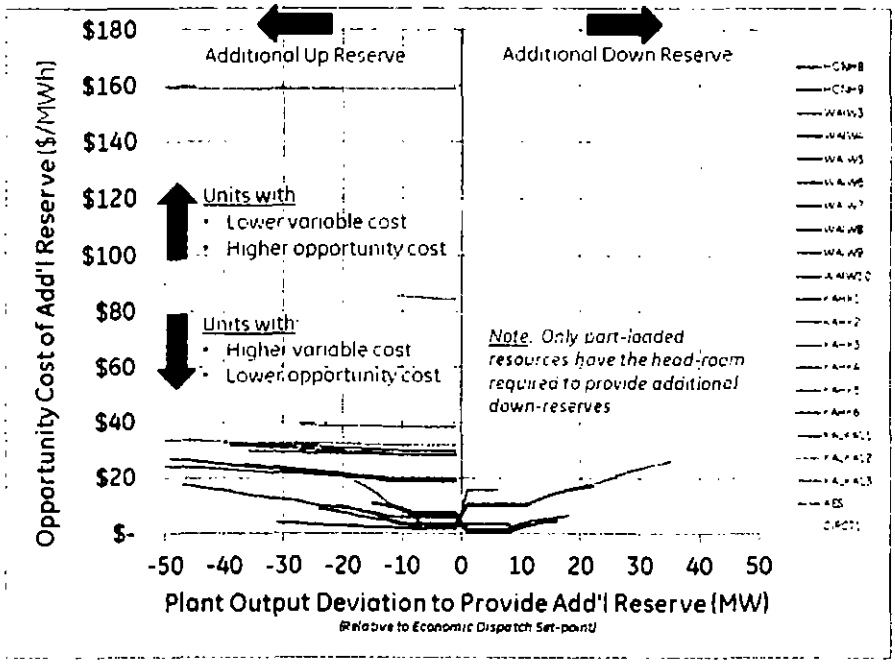

Figure 3.9 *Opportunity cost as the deviation from the economic dispatch increases*

3.1.6 Process for Evaluating and Selecting a Potential Future Technology Mix

This section outlines a methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements. Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a "least-cost" portfolio while observing system reliability needs. Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure.

Using HECO Scenario 4A (as an example), each of the steps outlined in the above-mentioned process will are placed in context (see PowerPoint in Appendix A). It should be noted that many options are available to fulfill any observed ancillary service deficiencies, such as: new generation, energy storage, demand response programs, transmission technologies, and existing generation modifications/retrofits. To ensure that an optimal (economic, risk, environmental) solution is achieved, it is recommended that a series of options be developed and analyzed via the following process.

Due to the complexity of the simulations required to generate the data that would be required to perform this analysis, the following process will not be able to be demonstrated in its entirety. A separate study would be required to calibrate a suitable simulation and fully execute the process.

The process is outlined here and in the PowerPoint presentation for Tasks 3&4 in Appendix A.

1. **Identify Current or Future Scenario**: Begin with an established current or future scenario. It is assumed that the resource-specific variable cost characteristics (i.e. heat rate curves, variable O&M cost, startup costs), min-up/down times, ramp-rates, storage capacity, DR availability/activation thresholds, and system-level future economic scenario (i.e. fuel cost/availability, system load forecast, etc.) are known values.

   To provide a comprehensive evaluation, it may be necessary to perform an uncertainty analysis of the key parameters which influence the characterization of a given future scenario.[13] The results of the uncertainty analysis would yield the relevant bounds for each key parameter. With the uncertainty bounds understood, a matrix of the desired evaluation conditions for a parametric sensitivity analysis could be established. This process would be executed for each evaluation condition to ensure a robust analysis of the potential resource mix.

[13] A contemporary example of why the up-front uncertainty analysis would be beneficial is the increased adoption of distributed solar PV on the Hawaiian islands. The increase in the use of distributed solar PV has a tendency to change the system load forecast (i.e. net-load shape) which will be served by the centralized resource technologies targeted by this report. Without an uncertainty analysis, an inaccurate representation of the load forecast could result; this would have the potential to drive a sub-optimal resource mix.

Similar uncertainty analysis of the resource-specific variable cost characteristics, operability constraints, storage/DR characteristics, fuel cost/availability, etc. may be required to develop a robust evaluation matrix to guide the sensitivity analysis.

2. **Obtain Production Cost Simulation**: Obtain a production cost simulation that is capable of performing security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED)
    a. The production cost simulation (or post-processing algorithms) should be capable of analyzing intra-hour behavior to fully evaluate the ancillary service performance.
    b. Simulation needs to be able to "co-optimize" the energy and ancillary services.
3. **Estimate required "system-level" amounts for each ancillary service**: Assess/anticipate the required amount (and minimal level of acceptable responsiveness) that is required for each ancillary service. Provide these ancillary requirements to the production cost simulation and corresponding post-processing algorithms. These ancillary requirements will be interpreted as constraints by the simulation so that it can reserve the respective ancillary capability from each of the available resources. Note: Iteration will be required to optimize.
4. **Identify "resource-level" ancillary service capability**: Identify the amount of each ancillary service that can be performed by each resource. This establishes the subset of the respective resource's capability that could be allocated to the given ancillary service. Items such as operating range, startup times, ramp-rates, min-up/down times, inertial response, black start capability, etc. are key considerations.
5. **Execute the Production Cost Simulation**: Execute the production cost simulation for the respective scenario. Review the hourly (and sub-hourly data as applicable) to ensure that all ancillary services requirements (plus other relevant system constraints) were observed. i.e. sufficient system-level regulation, spinning reserve, etc. was reserved.
6. **Identify Trends in the Results**: If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider the trends in the deficiencies (or excess):
    a. Are the deficiencies (or excess) driven by inadequate responsiveness from the available resources?
    b. Are the deficiencies (or excess) driven by inadequate operating range?
    c. Are the deficiencies (or excess) present in all hours or only some hours?

7. **Consider potential solutions to alleviate deficiencies and improve system efficiency.** To assist in identifying solutions, consider the trends in the deficiencies (or excess):

   Adjustments to operating procedures:

   - Adjusted minimum run-times
   - Relaxed qualifications/requirements for respective A/S participation
   - Activation thresholds for DR,
   - storage device charging procedures
   - Relaxed "must-run" rules

   Retrofits of existing resources:

   - Increased plant output
   - Improved turndown on thermal units
   - Elevated ramp-rates
   - Reduced start times
   - Synthetic inertia & governor response from renewables

   New resources:

   - Fossil
   - Storage
   - Demand response
   - Renewable assets
   - Inter-island connectivity

8. **Evaluate the economic viability of each potential solution**:

   a. Consider/evaluate the change in total cost required to serve the anticipated system load profile.

   b. Potential for the respective solution to facilitate the desired trajectory of renewables penetration over-time.

9. **Perform a cost-benefit analysis**: This analysis evaluates the year-over-year (YOY) system-level benefit (typically in the form of reduced production cost) of the proposed solution relative to the capital cost required to achieve the respective solution. Rank the solutions according to their economic viability (i.e. NPV, IRR, etc.)

10. **Evaluate the risks associated of each potential solution**: A comprehensive risk assessment of the potential options should also be conducted and weighted against to the economic viability to ensure that the selected solution is robust and reliable:

    Potential Risks to consider (not limited to the following):

    - Inadequate response from renewables due to instantaneous availability
    - Available down-reserves and stable operating region of thermal units during loss of load events
    - Voltage/VAR support sufficiency
    - Reductions in inertial response capability
    - Unfavorable impacts to "system-level" variable cost of operation
    - Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes
    - Challenges associated with monitoring / controlling DR participation on a centralized basis

3.2 Task 4: Outline considerations for specifying and acquiring A/S

3.2.1 Procuring Ancillary Services – Overview of Approaches for Obtaining, Compensating, and Incentivizing

This section puts forth some potential approaches and mechanisms which can be used to obtain, compensate, and incentivize resources for providing ancillary services. The following four approaches will be highlighted in this section:

1. Market Clearing Price
2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

The above listing is not intended to be exhaustive; however, the GE team believes that it contains a representative subset of the most viable techniques which could be considered. Further, it should be noted that each option is not mutually exclusive and may incorporate aspects of the surrounding approaches.

Method #1: Market Clearing Price

The Marketing Clearing Price approach is leveraged primarily by wholesale power markets. For this method, each resource submits (or is assigned) an offer price for the respective ancillary service. Most often, resources submit offer prices that are based on their opportunity cost to reserve the headroom or legroom required to provide the service. Some resources, such as storage devices, do not have an opportunity cost because they do not directly provide energy. Instead, their offer price may be based on startup, variable O&M, charging costs, or other expenses associated with providing the respective A/S.

In addition to the cost to provide the service, many markets allow resources to include "additional margin" in their offer price. In some cases, the resource may use to the additional margin to hedge against increased variable O&M costs (i.e. cycling wear & tear). In other cases, the resources may simply leverage the additional margin to cover "cost uncertainty" and/or attempt to enhance their ancillary profitability.

In some markets, the offer price is capped. The cap is often derived by calculating the cost for a unit to provide the service and adding (up to) a maximum allowable margin. The lesser of the submitted price and the capped price is then used as the offer price in the market clearing algorithms.

The "market clearing price" for the ancillary service is driven by the offer price of the last rank-ordered[14] resource required to satisfy the system-level ancillary requirement (for the respective ancillary service). For this approach, all participating resources will receive the "same price" for the

[14] A "low to high" ranking of the offer prices for each participating resource.

given period (typically 1-hour increments).[15] To incentivize "no risk" participation, some markets will compensate for "actual incurred" costs which are larger than the revenues derived from the ancillary market clearing price via "make-whole" payments. This ensures that resources are "no worse off" for having provided ancillary services.

Due to the fact that all participating resources receive the same price for a given ancillary service, it is important to note that most resources, with the exception of the marginal ancillary resource, will earn a financial benefit (i.e. profit) for providing the respective A/S.

Method #2: Reimbursement of Offer Price

The Reimbursement of Offer Price is an alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. It is a logical compromise between the "market clearing price" and "make-whole compensation" approach. Instead of a "clearing price" for the ancillary service, each resource is compensated on an individual basis for providing the service. The offer price for each resource would likely be derived in a similar fashion to the Market Clearing Price methodology. Specifically, the resource's "cost to provide + margin" (including opportunity costs) would serve as a rational basis for the offer price. If the agreement is between a utility and IPP, the offer price could be based on the anticipated production cost savings for the utility. The final ancillary service price would be based on a negotiated value between the respective parties.

The period for which this contractually agreed to price is valid could be varied (i.e. hourly, daily, monthly, annually, or simply set at a constant rate for contract period, etc.). Similar to the Market Clearing Price approach, it is recommended that the Reimbursement of Offer Price incentivize participation by providing a "no-risk" contract architecture through the reimbursement of "actual incurred" costs (i.e. if incurred costs are higher than the compensation that would be derived via the offer-price).

Due to the fact that resources are compensated on an individual basis, profitability (for the resource providing the service) is limited to the margin included in the offer price.

Method #3: Make-whole Compensation

The Make-whole Compensation approach is another alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. Most wholesale markets include "make-whole compensation" provisions in their architecture. This method extracts the "spirit & intent" of those provisions. At its core, the rationale for "Make-whole Compensation" is to explicitly compensate participating resources for their costs (including opportunity costs) associated with providing A/S. This method is designed to make the participating resource indifferent toward providing ancillary services. Instead of negotiating an offer-price, the resource-specific cost

[15] In many wholesale markets, there exists both a day-ahead clearing price and a real-time (or supplemental) clearing price (as-required) to ensure sufficient ancillary availability.

structure would be shared between the contracting parties so that an accurate assessment of incurred costs could be obtained.

Due to the fact that resources are compensated on an individual basis, and only for their cost to provide the service, there is no additional profitability potential for participating in A/S. For the three approaches discussed thus far, this method will typically result in the lowest overall production cost to reliably serve the load. It is important to note that while this approach adequately and explicitly compensates resources for their A/S participation, it does not incentivize that participation.

Method #4: Condition of Interconnection

It is important to note that all power systems (historical, existing, and future) require the use of certain interconnection requirements and ancillary services to ensure the system reliability is maintained. In many cases, such as with regulated utilities, the explicit compensation of resources for ancillary participation has not been required to maintain a reliable system. For this reason, the Condition of Interconnection approach was included in this list of options. The "Condition of Interconnection" approach would simply require ancillary service capability and participation from interconnecting resources. Resources would not be explicitly remunerated for providing ancillary service capability or for the associated costs incurred.

The incentive for resources to provide ancillary service capability would be driven by the accompanying right to participate in selling energy. For this type of agreement, it is implied that the participating resources would derive financial benefit from the sale of energy alone that was sufficiently large enough to cover both the cost to provide energy and the cost to provide A/S. Due to the lack of explicit compensation, the "Condition of Interconnection" approach has the potential to offer the lowest production cost of the four methods described.

3.2.2 Forward Planning Approach to Derive Rational Ancillary Service Contract Prices

Much attention has been focused on obtaining ancillary services from resources with the lowest offer price and/or lowest "cost to provide" (including opportunity costs).

One potential method for assessing the basis of a "rational" ancillary service offer price would be to leverage a production cost simulation with the capability to co-optimize energy and ancillary services. For a given future scenario, with a known resource mix, the simulation could be exercised and evaluated at both a resource-level and a system-level to draw conclusions about a rational offer price for the respective resource:

- At a **resource-level**, the results of the simulation could be interrogated to identify the perceived cost (including opportunity cost) for each resource to provide a given ancillary service. To develop an offer price, the hourly observations for each resource could then be aggregated and averaged over a period that aligned w/ the desired contractual period.

- At a **system-level**, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price for each particular resource.

To adequately bound the offer price, it is recommended that both the resource-level and system-level assessments be conducted.

3.2.3 Hawaii-specific Ancillary Service Procurement

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources. Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements. As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive could likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for [some of/all of] the ancillary services. Careful consideration is required before introducing such remuneration methods or unbundling the ancillary services.

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources. Relative to the current environment, in which dispatchable resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be considered as an equitable option. Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are more expensive to operate than some non-renewable resources on the system (i.e. periods where the energy contract price is higher than the marginal system cost). During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation", to explicitly compensate for costs (including opportunity costs) associated with providing ancillary services, would be recommended. It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration. Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would likely be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource Mix" developed in Task 3 and discussed earlier, could be leveraged to help quantify these potential benefits. Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services. To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

Ancillary service participation from DR, transmission, and retrofit options have the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure. Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies. To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types. In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have (typically) low variable operating cost and have the have the potential to reduce the overall production cost for the system. As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized. Instead, it is recommended that the impact on overall consumer cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

3.2.4 Risk Considerations

The process and methodologies developed in this study can help promote a least-cost portfolio of resources to supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs. The process to specify technologies for ancillary resources is outlined in Task 3. The technology combination is not unique.

For each scenario, the risks associated with the recommended ancillary services and potential technology mix may include:

- Hawaii specific resource costs and economics should be considered in any least cost planning exercises. Task 3 outlines the system operation cost considerations and the capital costs can be accounted for in resource planning and/or competitive resource solicitations.
- New/emerging technology availability such as batteries should be considered in future plans to account for potential difference in time of ancillary server requirements and technology implementation timeline.
- Ability to uprate/upgrade existing resources to provide additional capacity, energy and/or ancillary services must be considered. For instance, an existing resource may not have physical space to uprate or may not be able to permit increased capabilities.
- Fuel availability and fuel infrastructure will dictate the ability to get certain fuels to the resources. While build out of the fuel delivery systems should be considered in the total system planning to accommodate increased need due to load growth or change in purpose, potential for interruptions in emergency situations should also be considered along with the ability to provide ancillary services. Production and delivery of biofuels may also need to be considered along with more traditional oil and natural gas.
- Wind and solar forecasting should be implemented in system operations to more accurately predict when these resources will be available. And in the case of wind, energy production must be available to provide frequency response and down regulation.
- Interconnection costs of the resources should be considered if new resources are being added to provide ancillary services.
- Inter-Island transmission connections, if in place, can be used to provide ancillary services between islands, but must be monitored for flow and outages to ensure that service is not interrupted. A minimum amount of certain ancillary services should be specified locally, as is the case is in other island/peninsular systems such as Long Island, in case the inter-island transmission connection is lost.
- Demand-side participation and programs can be used to provide certain ancillary services, like operating reserves, but the grid operator needs to have control over those resources on a centralized basis. Preferably via physical control such as demand response switches.
- Load shaping programs such as electric vehicle charging schedules, may be implemented to help shape the system load and thereby make planning for ancillary service deployment easier.
- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- Reductions in inertial response capability
- Unfavorable impacts to "system-level" variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes such as with must run units

Additional details on the individual "technology-specific" risks are included in the PowerPoint Presentation in Appendix A which accompanies this report.

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5 Appendix A: Power Point Presentation

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Ancillary Services Definitions & Capability Study Part 2, Task 3-4, Final Report

December 19, 2012

Prepared by: GE Energy Consulting

Prepared for: Hawaii Natural Energy Institute (HNEI) and Hawaii Reliability Standards Working Group (RSWG)

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Appendix A – Methodology for Determining Operating Reserves

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Study Background and Objectives

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Ancillary Services Def. & Cap. Study

Overview of Study

Purpose:

Study sponsored by HNEI with support and guidance from Hawaii RSWG to identify, define, and quantify ancillary services required to support new generation (including renewable generation) for bulk power systems and particularly the Hawaiian islands.

Objectives:

- Define a standardized set of ancillary services along with their associated definitions (in functional, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems.
- Technologies (generation, transmission, storage, and demand response (DR)) will be assessed for their ability to support the respective ancillary services to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island)
- Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

Introduction

Ancillary services & additional functions required for power system operation

- **Ancillary services*** are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system.

- In addition to ancillary services, other **interconnection requirements** are placed on resources to ensure reliable operation of the grid

- These ancillary services and interconnection requirements enable the system operator to meet the required operations **reliability standards** set by NERC.

- The ancillary services, interconnection requirements, and reliability standards are dependent on the characteristics of a power system.

** FERC defined ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."*

Key Terminology

Key Terminology

The following definitions are relevant throughout the content of this presentation and should be interpreted as described below:

Area Control Error (ACE): The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. *NERC Glossary (2008)*

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

- NIA is the algebraic sum of actual flows on all tie lines.
- NIS is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- FA is the actual frequency.
- FS is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections
- IME is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for Hawaii, **ACE = – 10B (FA – FS) – IME**. This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. *Revised definition per Hawaii RSWG Glossary.*

Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

Automatic Generation Control (AGC): Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias (i.e. ACE). *NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices.*

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

Droop Control / Governor: Droop speed control is near instantaneous means of using frequency deviations to distribute load set-point adjustments to a system of resources in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.[3]

Droop response can be provided by any frequency-sensitive resource.

Resource: A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning: Historically, the terms "**spinning**" and "**non-spinning**" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

Study Results

Identify Physical Requirements of Ancillary Services

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Task 3: Scope & Deliverables

Identify physical requirements of ancillary services

Objectives:

- From recent renewable integration and planning studies, develop two future scenarios
- With HPUC and Hawaiian utilities, specify basic level of required bulk power system reliability for each island (Oahu, Maui, Big Island) [Task 1 and Task 3]
- Propose methodology to estimate required ancillary services and interconnection requirements (under the future scenarios) while taking into account other system considerations
- Suggest a process to determine a set of technologies and associated features

Scenario Development

Approach:

- From recent renewable integration and planning studies, develop two future scenarios with HECO companies and HPUC

Observations:

- The HECO companies required to conduct a 20-year time horizon IRP study every three years.
- In May 2009, the HPUC proposed amendments to the framework for IRP based on the proposal of a new Clean Energy Scenario Planning (CESP) process.
- The revised goal of IRP is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.
- Some of the Hawaiian utilities (HELCO and MECO) have conducted resource planning studies. These studies are not intended to serve as IRPs. Rather, they seek to identify resource needs for Hawaii Island and identify resource options for consideration in a future IRP cycle.

Scenario Development

Sources for scenario planning

	HECO (Oahu)	MECO (Maui)	HELCO (Big Island)
Most Recent IRP	HECO IRP 2009-2028 (Sep 2008)	MECO IRP 2007-2026 (April 2007)	HELCO IRP 2007-2026 (May 2007)
Resource Planning Study to support future IRP	?	Available from MECO	HELCO Resource Planning Study (June 2012)
Other renewable integration studies	OWIST & HSIS (Available from GE)	HSIS (Available from GE)	
Load Forecast	From OWIST and HSIS	Base Line From HSIS	Base Line From Resource Planning Study
Scenario 1: Moderate penetration Renewables or mix definition	HSIS Scenario 4A 360 MW Dist Solar PV 400 MW Cent Solar PV 100 MW On-shore Wind No Off-Shore Wind	HSIS Base Line (2012 system) 15 MW Dist Solar PV 0 MW Cent Solar PV 72 MW On-shore Wind	HELCO 100% renewables intermittent - heavy **22 MW Biomass** **100 MW Wind (centralized)** **100 MW PV (centralized or distributed)** **50 MW Geothermal**
Scenario 2: High penetration Renewables or mix definition	HSIS Scenario 4B 160 MW Dist Solar PV 200 MW Cent Solar PV 100 MW On-shore Wind 200 Off-Shore Wind (same solar & wind MWH as 4A)	HSIS Scenario 3 30 MW Dist Solar PV 15 MW Cent Solar PV 72 MW On-shore Wind **Scenario 3: Heavy Intermittent Renewables** **22 MW Biomass** **100 MW Wind, 100 MW PV** **50 MW Geothermal**	HELCO 100% renewables geothermal/ dispatchable - heavy **42 MW Biomass** **50 MW Wind (centralized)** **50 MW PV (centralized or distributed)** **100 MW Geothermal**

Ancillary Services for Existing System and Future Scenarios

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Level of Bulk Power System Reliability

Approach:

- Review pertinent documents from HPUC and Hawaii utilities to identify current specifications required for bulk power system reliability for each island (Oahu, Maui, Big Island) such as:
  - Docket 2008-0273 Feed-in Tariff ("FIT")
- Confirm findings and reliability levels to be used for this study with Hawaiian utilities and HPUC and identify any areas that may require further study beyond this project

Observations:

- The HECO Companies currently plan and operate their systems in accordance with reliability principles that are very much aligned with the NERC Reliability Standards
- FIT Reliability Standards were filed in Docket 2008-0273 Feed-in Tariff ("FIT") Proceeding HECO Companies Report on Reliability Standards per the direction of HPUC

Methodology to Determine A/S

Applied to future scenarios

Approach:

- Propose methodology to estimate required ancillary services and interconnection requirements (under the future scenarios) while taking into account other system considerations and using the basic level of bulk system reliability as the performance target
- Refer to renewable integration studies, both in Hawaii and on the mainland

Observations:

- The results from the simulation of the selected scenarios from the HSIS and OWIS study performed by GE were used to determine the need for additional ancillary services (for HECO and MECO).

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Inertial Response

- Currently, the desired inertial response from dispatchable synchronous renewable generation (RE) resources such as geothermal plants is obtained as a condition of contract. Currently, there is no synthetic inertia requirement in the interconnection requirements for Variable Generation (VG) resources such as wind and solar plants.
- With the current technology, it is possible for wind plants to provide synthetic inertial response, which if designed properly can help the system ride through frequency events.
- We recommend synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements.
- The utilities should also perform offline studies to determine the impact of synthetic inertia on inertial and primary frequency response and how it impacts inertia requirements from other (future) interconnecting resources, UFLS practices, and spinning reserve requirements. The offline studies should be used to guide for determining combinations of resources that need to be online.

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Primary Frequency Response

- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to have a 4% droop that is adjustable. HECO utilities also have the capability to dispatch units to provide reserves as needed. As such, the HECO utilities currently obtain primary frequency response as a condition of interconnection.
- Wind and solar plants are capable of providing primary frequency response improving the reliability of the grid. In many instances, using VG to provide reserves also reduces their curtailment. For example, using wind generation to provide down reserves (instead of carrying the down reserves by dispatching up a thermal generator) reduces the curtailment of wind generation.
- We recommend droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to the requirement for dispatchable generators.
- We recommend that VG be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. Need tools to amount of down reserves that VGs can reliably provide.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are curtailed.
- The above provisions are similar to those used in the ERCOT market.

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Secondary Frequency Response

- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to be on AGC.
- All the existing wind contracts also include active power control (APC) provision to enable automatic curtailment.
- We recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- We recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of regulation that VG can provide.
- VG should be required to provide down regulation without any explicit compensation similar to other dispatchable units in the system. Need tools to amount of down regulation that VGs can reliably provide.
- VG should be required to provide up regulation without any explicit compensation when they are curtailed for reasons other than providing up regulation since their opportunity cost is zero when they are curtailed.

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Storage and Demand Response

- In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical. However, the following need to be considered:
- Need to consider DR response and UFLS interaction. UFLS uses 75-80% of all load. The interaction of UFLS and DR must be developed and coordinated to ensure adequate protection for the UFLS system.
- The modification of PV to being required to trip on lower frequency set-points than standard IEEE 1547 trip settings, which are higher than UFLS trip settings, to mitigate loss of PV during a system low-frequency events was completed by the recent modification to Hi Rule 14h. However, there are still legacy installations that trip in accordance with IEEE 1547 and will compound the impact of unit trips. HECO uses 57.3 Hz for low frequency trip of distributed PV (not sure about other utilities). Legacy PV trips at 59.3 Hz and still must be considered in all studies. Since the 1547 standard and, similarly, Rule 14H specify in terms of a must-trip instead of ride-through, confirmation that the existing change results in the desired ride-through is important - a future change to a ride-through requirement may be necessary.
- Need to consider feeder net load for UFLS system as distributed PV increases and feeder net load during some hours reduces.

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Changes to Interconnection Requirements

Reactive Power and Voltage Regulation

Hawaii utilities have voltage regulation and control requirements for dispatchable and variable generation. No changes proposed.

Voltage and Frequency Ride-thru

Hawaii utilities have voltage and frequency ride-thru requirements for dispatchable and variable generation. Utilities should develop requirements for unbalanced ride thru requirements. Unbalanced voltage capability is required in weak systems and is currently a much larger issue than LVRT since turbine manufacturers do not currently have a standard to meet and the current technology of WTG is much less than conventional generation.

Ramp Rate Limits and Control

Hawaii utilities have ramp rate limits in the up direction for variable generation. Ramping requirements in the up and down direction are included as requirements for dispatchable generation. No changes proposed.

Over and Under Frequency Controls

Per recommendation before, require wind and solar plants to have primary frequency response capabilities.

Recommendations Regarding New Ancillary Services and Interconnection Requirements

Changes to Interconnection Requirements

Inertia

Per recommendation before, require wind plants to have inertial response capabilities. Inertia response should be defined by utility based on system needs.

AGC Capability

Per recommendations before, require all generators including wind and solar plants to have the ability to accept and respond to AGC commands. Active power set-point is a current requirement for VG to enable curtailment. This would require modifications to the AGC program.

Fundamentals of Power System Operation

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Power System Operation

Identifying the balancing point between resource capability and system needs

This section is intended to serve as a primer which provides a common foundation for the general terminology and concepts that will be referred to throughout the balance of this report.

In addition, it is intended to provide insight into the processes and considerations that are required to leverage available power system resources to "serve the load" in the most cost effective and reliable manner.

Downstream sections of this report will contain more Hawaii-specific discussion, considerations, and where possible, recommendations which reference these concepts.

Power System Operation

Identifying the balancing point between resource capability and system needs

In a power system, resources are committed and dispatched based on their ability to:

1. Directly provide energy
2. Support the reliable delivery of energy

- Often, the same resource may serve both functions. The degree to which this occurs depends upon the attributes of the individual resource, resource mix, and the respective needs of the power system.

To supply "energy", a resource is *primarily* evaluated based on its ***variable cost*** structure:

Startup Cost:

- Typically on a "$/startup" basis. Represents the cost incurred for bringing a resource to a state where it is available for dispatch.

Minimum Generation Cost:

- Typically on a "$/hr" basis. Represents the variable cost required to sustain operation at the minimum permissible "real-power" operating level.

Incremental Variable Cost:

- Typically on a "$/MWh" basis. This represents the cost for the next incremental adjustment in the real-power set-point.

Power System Operation (cont'd)

Identifying the balancing point between resource capability and system needs

To support the "reliable delivery of energy", a resource is considered based on additional attributes that characterize its ***flexibility***. Examples include, but are not limited to:

Inertial Response:

- Typically measured by a resource's inertial constant "H" (in seconds). This is a normalized value that relates a resource's kinetic energy to its respective capacity.

Ramp-rate:

- Typically on a "MW/min" basis. Characterizes the rate at which a resource is able to adjust it's real-power set-point. This rate can be set "tuned" differently dependent upon whether the need is for frequency response (i.e. FRR), regulation, (i.e. AGC), load following, spinning reserve, and/or startup periods.

Quick-start capability:

- Typically on a "minutes or hours" basis. Characterizes the time-delay required for a unit that is offline or disconnected from the power system to become available for the purposes of providing energy or supporting the reliable delivery of energy.

Operating Range:

- Characterized on a "real-power" and "reactive power" basis.
- Real-power range: Characterizes the range over which a resource is able to inject or consume actual "MW" to support the load on the power system.
- Reactive-power range: Characterizes the range over which a resource is able to provide "MVAR" to assist with maintaining system voltage levels.

Power System Operation (cont'd)

Identifying the balancing point between resource capability and system needs

To support the "reliable delivery of energy", a resource is considered based on additional attributes. Examples include, but are not limited to:

- Minimum Operating Period:
  - Minimum up-time: The minimum time for which the unit needs to be online once started
  - Minimum down-time: The minimum time for which the unit needs to be offline once shutdown
- Black-start capability:
  - Ability to start a unit without support from the grid

Power System Operation (cont'd)

Identifying the balancing point between resource capability and system needs

Determining the balance between using a resource for its "energy" vs. its ability to support the "reliable delivery of energy" often requires sophisticated algorithms. Typically, this balance is achieved through *"security-constrained unit-commitment (SCUC)"* and *"security-constrained economic dispatch (SCED)"* algorithms. For long-term power system planning, a ***production cost model*** is often leveraged to execute the SCUC and SCED algorithms. For day-to-day and week-to-week operations, similar algorithms are used in energy management system (EMS) software.

The objective of the algorithms is to ensure that sufficient resources will be online (i.e. committed) to meet the anticipated load forecast (including variability) and satisfy reserve requirements in the most economical manner (i.e. lowest system cost) while observing reliability constraints.

Emphasis is placed on leveraging assets with the lowest ***variable operating costs***. More expensive resources are only selected if their ***flexibility*** is required to ensure reliable delivery of the energy, relieve system constraints, or they benefit increased renewables penetration, etc.

Once a resource is "committed", the "security-constrained economic-dispatch" algorithms are then utilized to obtain a resource's load set-point (i.e. "dispatch-point"). To achieve a solution, these algorithms attempt to "park" all committed resources at the same incremental variable cost (*additional details in following slides*).

Power System Operation (cont'd)

Identifying the balancing point between resource capability and system needs

Typically, the "most-economical" manner for operating the system is for all committed resources to be dispatched to the same "incremental variable cost" (provided the resource is not at the extremes of its operating range). This is referred to as "*economic dispatch*".

The resource which will provide the "next most economical MW" is referred to as the marginal unit. And, at that instant, the "system marginal cost" is equivalent to the incremental variable cost of that resource. Often, there are multiple units "on or near the margin".

To satisfy the reliability needs of the power system, it is often necessary to adjust the dispatch of the resources away from their economic optimum set-point. This movement creates additional "headroom/legroom" and increases the available reserves to satisfy system req's.

To ensure that these adjustments are made in the most economical manner, a process referred to as "*co-optimization*" is often deployed. This process assists in identifying which resources to adjust, and by how much. Specifically, it attempts to minimize the "*opportunity costs*" associated with moving a resource away from its economic optimum to meet the reliability needs of the system.

The concept of using opportunity costs to rank/prioritize resources and make system-level trade-offs between energy vs. ancillary capability is still applicable regardless of whether an explicit payment is made to the resources for their ancillary participation.

Power System Operation (cont'd)

Identifying the balancing point between resource capability and system needs

Typically, ancillary service needs are "best-served" by marginal resources. This is driven by the fact that they often have the lowest opportunity cost for providing the service.

- For example, a wind farm* typically has a very low variable operating cost. Curtailing the wind for the specific purpose of providing an ancillary service would [typically] result in very high opportunity cost (for both the plant and the power system).
- However, during periods where renewables are curtailed (due to must-run resources and/or corresponding over-supply), allocation of ancillary services to the renewables would likely be very cost-effective.
- In situation where renewables are not curtailed, selecting a combustion turbine or storage device** would likely result in lower opportunity cost and lower system cost.

* *In Hawaii, during off-peak periods, wind energy contract prices can higher than the variable cost of other thermal generation. For these circumstances (and while wind contracts do not separate fixed & variable costs), curtailing wind for the purposes of providing ancillary services may be recommended.*

** Storage devices are unique. Such resources are often "energy-neutral" (i.e. zero net-output on a nominal basis). *As a result, storage devices do not have an "opportunity cost" per se. The variable cost to provide ancillary services from a storage device is typically driven by the cost to initiate the devices operation (i.e. startup) and the corresponding variable O&M during operation. As a result of their energy-neutral / zero-opportunity cost, storage devices are typically prioritized ahead of other resources for providing ancillary services.*

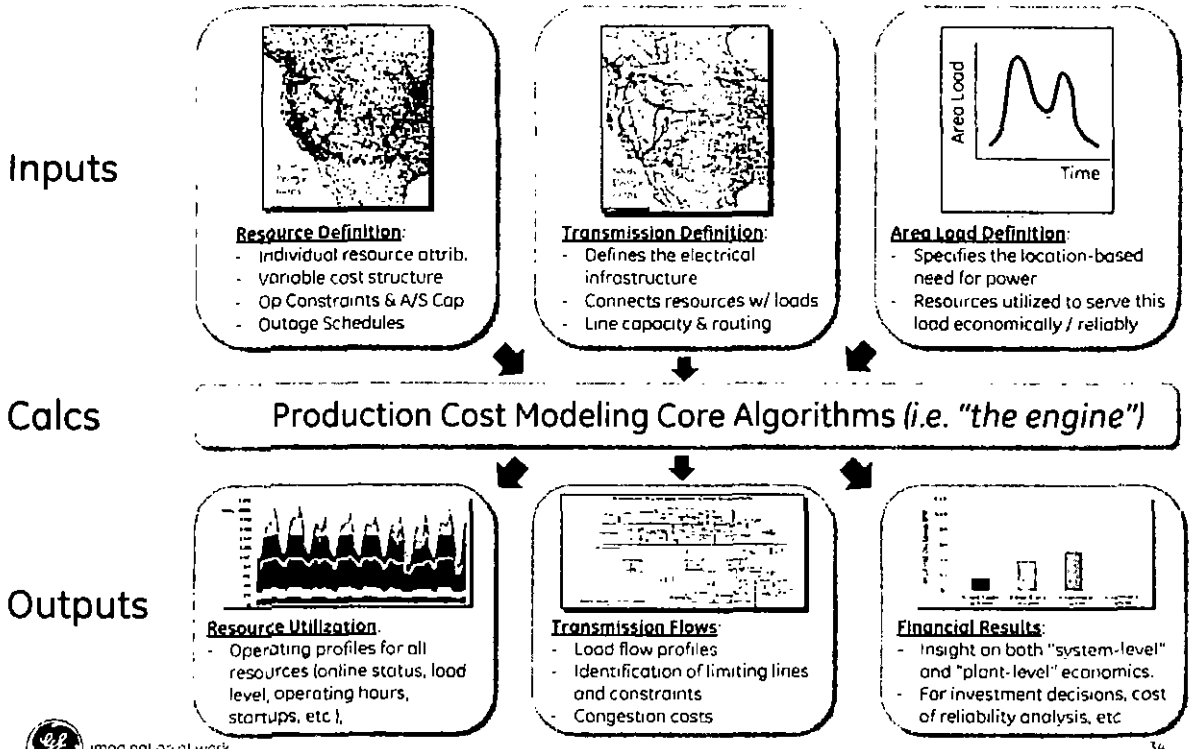
Power System Operation (cont'd)

Illustration of the key concepts & tools which facilitate the analysis

The illustrations on the following pages are intended to provide further clarification of some of the key tools & concepts that were discussed in the preceding slides:

- Production Cost Modeling
- Average vs. Incremental Variable Cost
- Economic Dispatch
- Opportunity Cost
- Co-optimization of Energy and Ancillary Services

Production Cost Modeling



Variable Operating Costs

Incremental vs. Average Variable Cost

Variable Operating Costs

(Example shown for a Generating Resource)

Variable Operating Cost ($/hr):

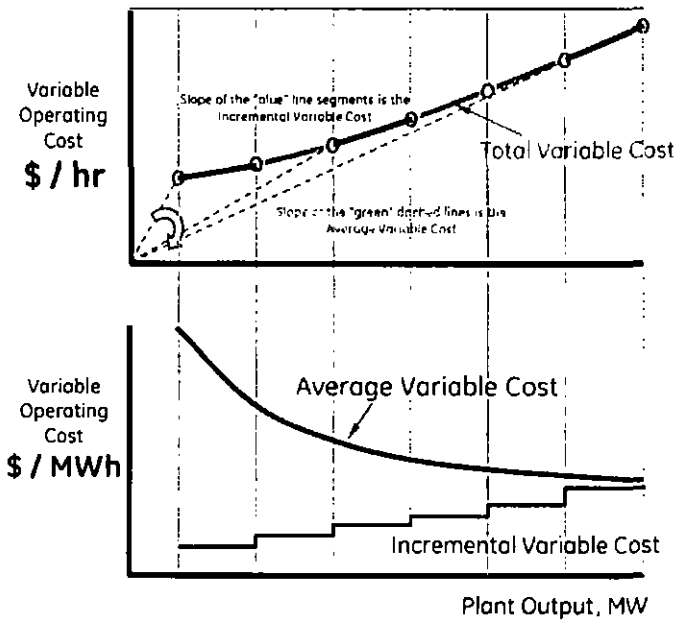
- Hourly cost required to sustain operation at a given load set-point.
- Driven by costs which are a function of utilization
- Typically consists of (but not limited to):
  - Fuel cost
  - Variable O&M
  - Emissions (i.e. environmental compliance)

Average Variable Cost ($/MWh):

- Calculated by dividing the Variable Operating Cost by the respective output level
- Provides a normalized representation of the "actual" operating cost incurred at a given set-point.

Incremental Variable Cost ($/MWh):

- Represents the "additional cost" for the "next "MW" provided by the resource. Trend is "downward" sloping for DR resources.
- Critical to "economic dispatch"



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Economic Dispatch

Provides an "economically optimized" operating point for each resource

Economic Dispatch

(Example shown for a Generating Resource)

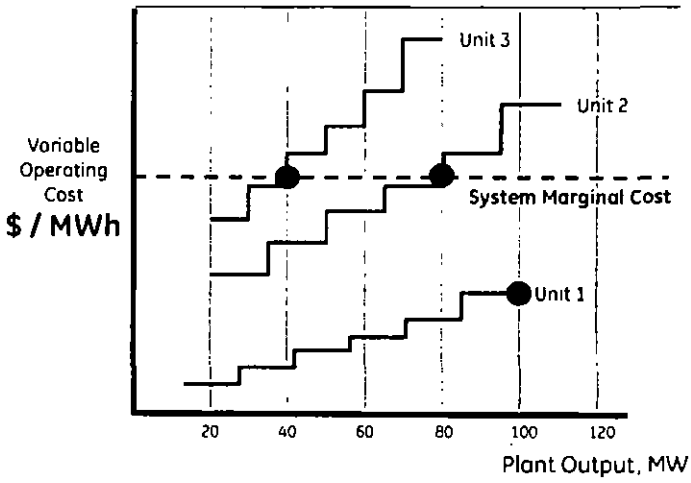
- Economic Dispatch is the process used to move the real-power set-point for resources upward and downward.
- At the power system-level, the cost to "serve the load" is minimized when committed resources are dispatched to the same "incremental variable cost".
- The "system marginal cost" is analogous to the "clearing price" in a power market.
- Exceptions for resources that are at the extremes of their operating range.
- Deviations from the economic optimum may be necessary to meet the reliability needs of the power system.
- Trade-offs are typically driven by the "opportunity cost" of migrating a resource away from its economic optimum.

Scenario (for illustration only):

- Instantaneous system need is 220 MW
- Assume Units 1-3 are committed

Principles of economic dispatch would yield:

Unit 1 Set-point: 100 MW (upper extreme of op range)
Unit 2 Set-point: 80 MW (on the margin)
Unit 3 Set-point: 40 MW (on the margin)
Total Supply: 220 MW



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Opportunity Cost

Represents the cost for deviating from economic dispatch

Opportunity Cost

(Example shown for a Generating Resource)

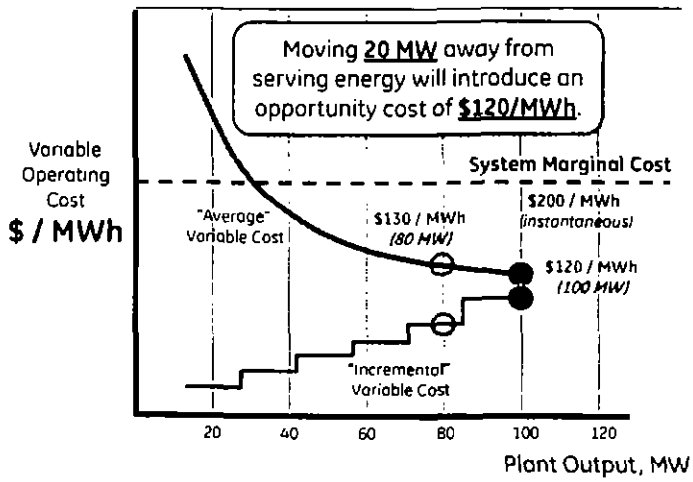
- Economic Dispatch would indicate "Unit 1" should be providing 100 MW (full-output).
- Consider "Unit 1" for 20 MW of upward regulation service.
- The opportunity cost of moving 20 MW from providing "energy" to serve the "ancillary" needs is characterized as:
  - Providing 100 MW: $8000/hr
  - Providing 80 MW: $5600/hr
  - Difference: $2400/hr
- Normalizing the $2400/hr by the 20 MW, results in an opportunity cost of **$120/MWh**.
- Resources with the "lowest opportunity cost" should be the 1st resources selected to migrate from providing energy to serve the ancillary needs of the system.
- In many locations, the opportunity cost of the "last resource" required to provide the ancillary service will set the "ancillary clearing price".

Providing 100 MW (Energy-only):

- Revenue (proxy) = ($200/MWh) * (100 MW) = $20000/hr
- Cost = ($120/MWh) * (100 MW) = $12000/hr
- Profit (proxy) = $8000/hr

Providing 80 MW (Energy + 20 MW Regulation "stand-by")

- Revenue (proxy) = ($200/MWh) * (80 MW) = $16000/hr
- Cost = ($130/MWh) * (80 MW) = $10400/hr
- Profit (proxy) = $5600/hr



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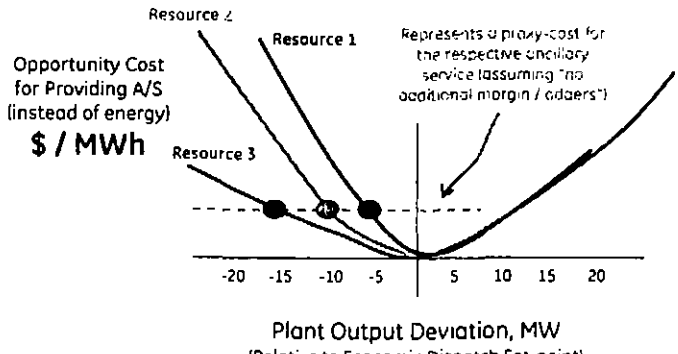
Co-optimization

A mechanism for minimizing the opportunity cost at a system-level

Co-optimization

(Applicable for any multiple resource-types)

- Co-optimization ensures that ancillary services are sourced from the most-economically viable resource capable of serving the need.
- In the scenario at the right, each was allocated a portion of the total ancillary service requirement.
- In many locations, the ancillary requirements (for each service), and the corresponding opportunity costs, are evaluated and adjusted on an hourly basis.
- Often, resources are capable of providing more than a single ancillary service. Under these circumstances, multiple "co-optimization" layers are required to ensure a proper economic balance. (i.e. not just trade-offs in energy vs. ancillary, but ancillary service vs. ancillary service as well).



Scenario:

- 30 MW of "Regulation Up" is required
- Assume: All three resource are capable of providing regulation (i.e. op range, ramping, etc.)
- Economically optimized solution is:
  - Resource 1: 5 MW
  - Resource 2: 10 MW
  - Resource 3: 15 MW
  - **Total Reg-Up: 30 MW**

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Opportunity Cost Illustration for HECO

HECO-specific Opportunity Cost

In an effort to place the preceding material in context, the following slides will provide some HECO-specific perspective on the opportunity cost associated with migrating a resource away from providing energy and into ancillary participation.

On an individual basis, the incremental variable cost structure for each of the HECO resources will be compared to the marginal system level cost to identify the appropriate economic dispatch if that resource had been online and available. *Note: For this illustration, each resource will be individually compared to a proxy system cost. Therefore, the summation of the load set-points for each resource does not necessarily constitute a valid system solution.*

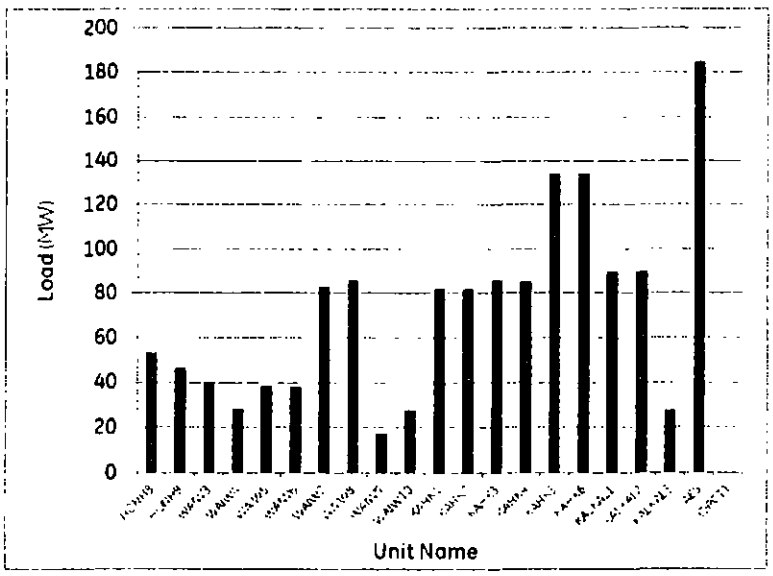
With an understanding of the economic dispatch set-point, each resource will then be perturbed away from this set-point to determine the associated opportunity cost of transferring capability away from providing energy.

Resources with the lowest opportunity cost should be the first resources transferred away from providing energy to fulfill ancillary requirements.

For this example, we'll be assuming an instantaneous marginal system level cost of $190 / MWh.

Opportunity Cost Illustration for HECO

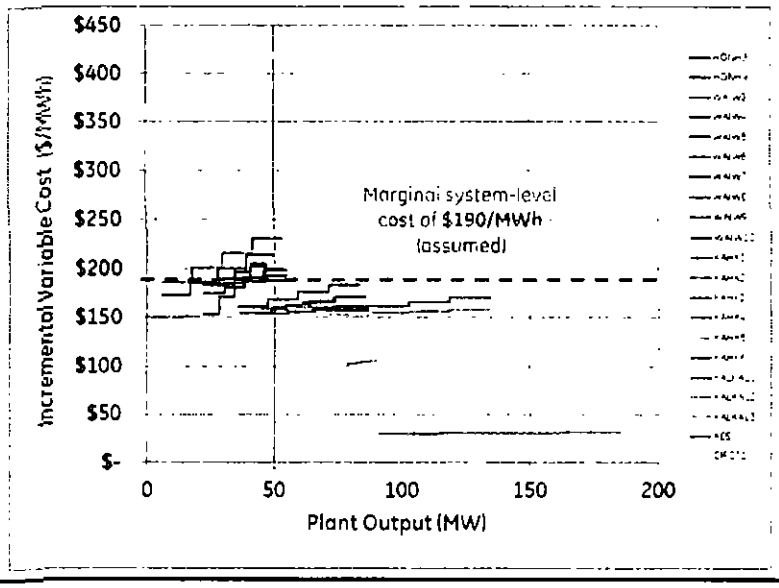
Intersection of the marginal system cost and incremental cost establishes load level



For a $190 / MWh marginal system cost, the respective load level for each resource (if committed) would be as shown.

Opportunity Cost Illustration for HECO

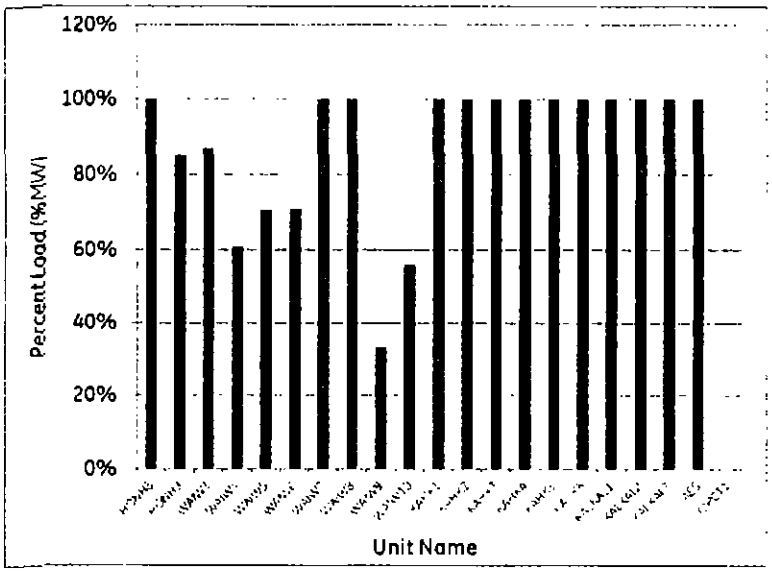
Intersection of the marginal system cost and incremental cost establishes load level



All resources shown are initially dispatched economically per their incremental variable cost structure

Opportunity Cost Illustration for HECO

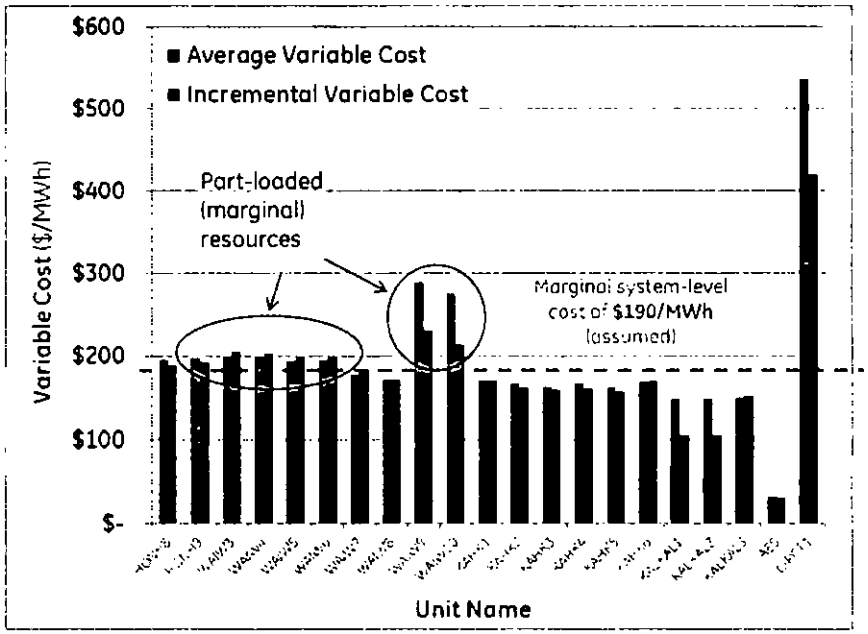
Intersection of the marginal system cost and incremental cost establishes load level



For a $190 / MWh marginal system cost, the respective load level for each resource (if committed) would be as shown.

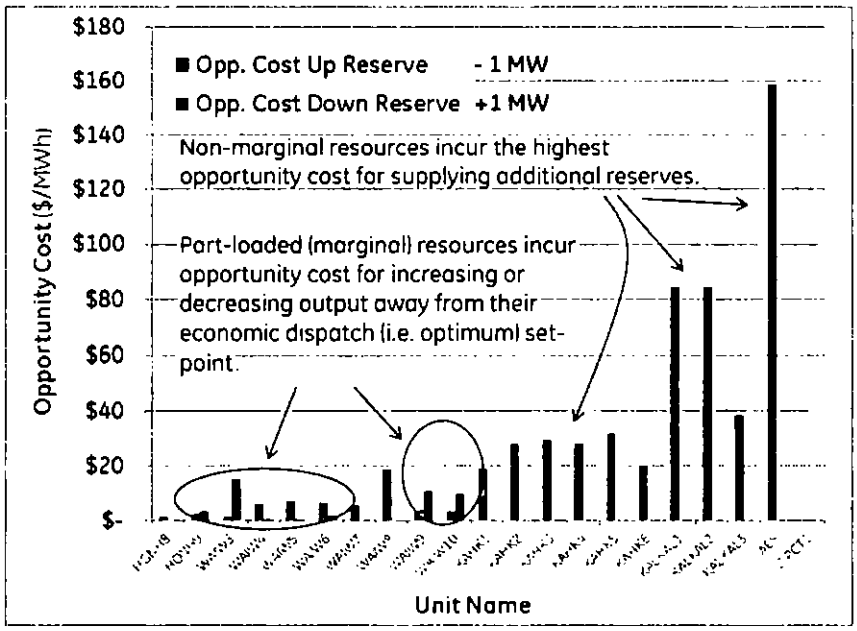
Opportunity Cost Illustration for HECO

Incremental and Average Variable Cost compared w/ the System Marginal Cost



Opportunity Cost Illustration for HECO

Instantaneous opportunity cost for shifting capability from energy to A/S

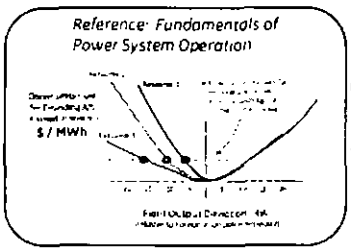


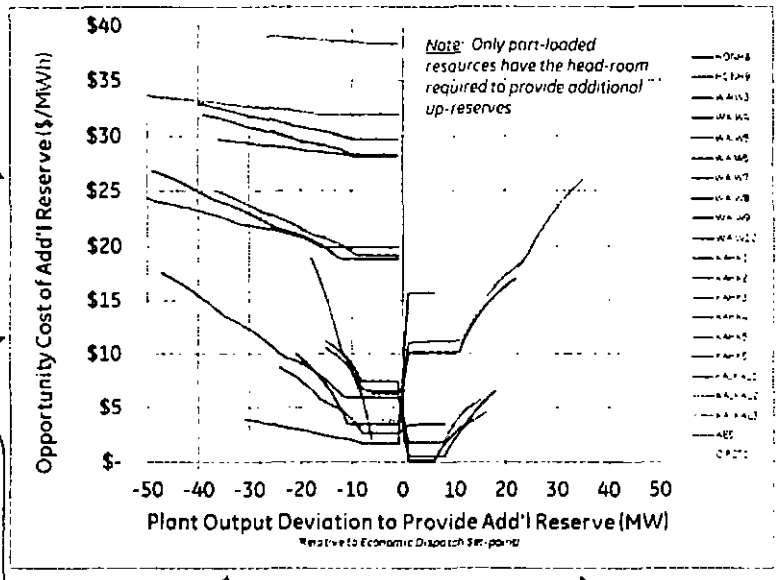
Opportunity Cost Illustration for HECO

Opportunity cost as the deviation from the economic dispatch set-point is increased

Units with:
- Lower variable cost
- Higher opportunity cost

Units with:
- Higher variable cost
- Lower opportunity cost





Increasing Up Reserve

Increasing Down Reserve

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Process for Evaluating and Selecting a Potential Future Technology Mix

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Process for Evaluating a Resource Mix

Overview

This section outlines a methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements.

Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a "least-cost" portfolio while observing system reliability needs.

Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure.

Process for Evaluating a Resource Mix

Description of Approach

Using HECO Scenario 4A (as an example), each of the steps outlined in the above-mentioned process will be placed in context.

It should be noted that many options are available to fulfill any observed ancillary service deficiencies, such as: *New generation, Energy storage, Demand response programs, Transmission technologies, and Existing generation modifications/retrofits*

To ensure that an optimal (*economic, risk, environmental*) solution is achieved, it is recommended that a series of options be developed and analyzed via the process described on the following slides.

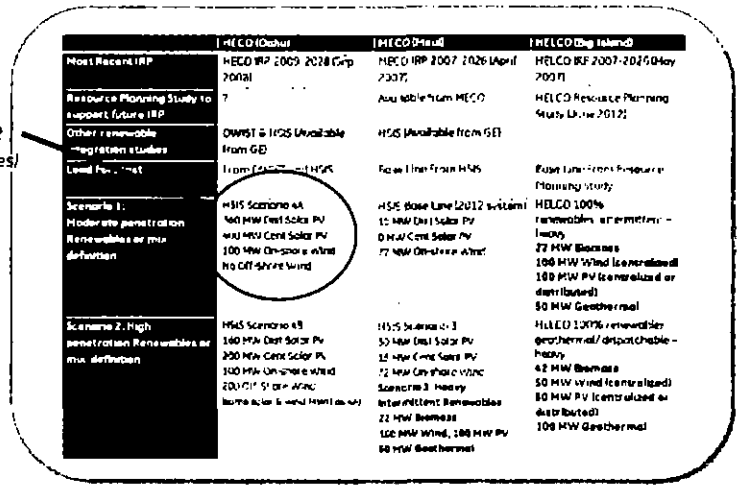
Due to the complexity of the simulations required to generate the data that would be required to perform this analysis, the following process will not be able to be demonstrated in its entirety. A separate study would be required to calibrate a suitable simulation and fully execute the process.

Step 1: (Example)

Identify Current or Future Scenario

Begin with an established current or future scenario. It is assumed that the resource-specific variable cost characteristics (i.e. heat rate curves, variable O&M cost, startup costs), min-up/down times, ramp-rates, storage capacity, DR availability/activation thresholds, and system-level future economic scenario (i.e. fuel cost/availability, system load forecast, etc.) are known values.

Select HECO 4A for this Example
(including subsequent slides)



	HECO (Oahu)	HECO (Maui)	HELCO (Big Island)
Most Recent IRP	HECO IRP 2009-2028 (Grp 2008)	HECO IRP 2007-2026 (April 2007)	HELCO IRP 2007-2026 (May 2007)
Resource Planning Study to support future IRP	?	Available from HECO	HELCO Resource Planning Study (June 2012)
Other renewable integration studies	DWIST & HSIS (Available from GE)	HSIS (Available from GE)	
Load Forecast	From [illegible] and HSIS	Base Line from HSIS	Base Line from Resource Planning Study
Scenario 1: Moderate penetration Renewables or mix definition	HSIS Scenario 4A 140 MW Dist Solar PV 400 MW Cent Solar PV 100 MW On-shore wind No Off-Shore Wind	HSIS (Base Line 2012 system) 15 MW Dist Solar PV 0 MW Cent Solar PV 72 MW On-shore Wind	HELCO 100% renewables or mix – heavy 72 MW Biomass 100 MW Wind (centralized) 100 MW PV (centralized or distributed) 50 MW Geothermal
Scenario 2: High penetration Renewables or mix definition	HSIS Scenario 4B 140 MW Dist Solar PV 200 MW Cent Solar PV 100 MW On-shore Wind 200 MW Off-Shore Wind (some solar & wind [illegible])	HSIS Scenario 3 55 MW Dist Solar PV 14 MW Cent Solar PV 72 MW On-shore Wind Scenario 3 Heavy Intermittent Renewables 72 MW Biomass 100 MW Wind, 100 MW PV 50 MW Geothermal	HELCO 100% renewables geothermal/ dispatchable – heavy 42 MW Biomass 50 MW Wind (centralized) 50 MW PV (centralized or distributed) 100 MW Geothermal

Step 1: (cont'd)

Identify Current or Future Scenario

To provide a comprehensive evaluation, it may be necessary to perform an uncertainty analysis of the key parameters which influence the characterization of a given future scenario. The results of the uncertainty analysis would yield the relevant bounds for each key parameter. With the uncertainty bounds understood, a matrix of the desired evaluation conditions for a parametric sensitivity analysis could be established. This process would be executed for each evaluation condition to ensure a robust analysis of the potential resource mix.

- *A contemporary example of why the up-front uncertainty analysis would be beneficial is the increased adoption of distributed solar PV on the Hawaiian islands. The increase in the use of distributed solar PV has a tendency to change the system load forecast (i.e. net-load shape) which will be served by the centralized resource technologies targeted by this report. Without an uncertainty analysis, an inaccurate representation of the load forecast could result; this would have the potential to drive a sub-optimal resource mix.*

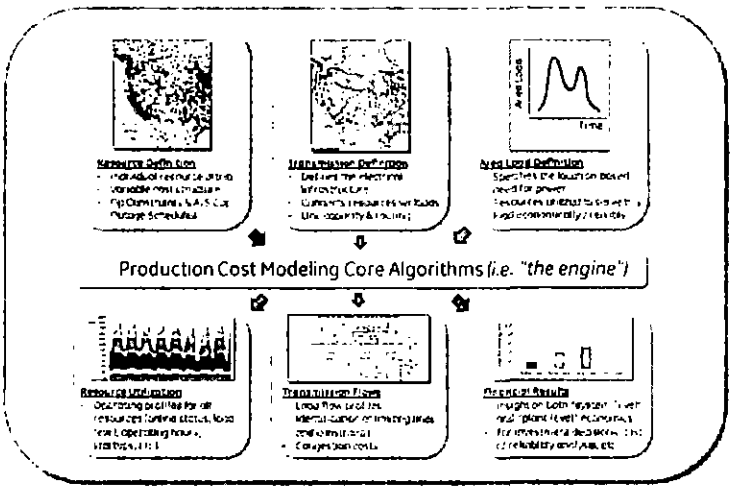
Similar uncertainty analysis of the resource-specific variable cost characteristics, operability constraints, storage/DR characteristics, fuel cost/availability, etc. may be required to develop a robust evaluation matrix to guide the sensitivity analysis.

Step 2:

Obtain Production Cost Simulation

Obtain a production cost simulation that is capable of performing security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED)

- The production cost simulation (or post-processing algorithms) should be capable of analyzing intra-hour behavior to fully evaluate the ancillary service performance
- Simulation needs to be able to "co-optimize" the energy and ancillary services.



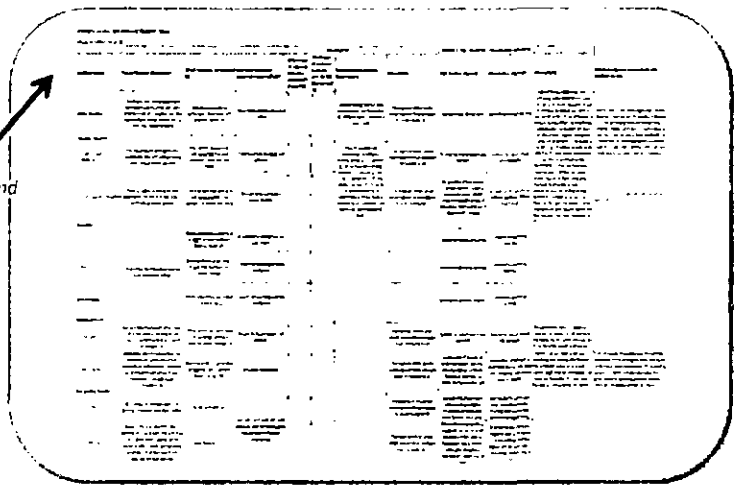
Step 3:

Estimate required "system-level" amounts for each ancillary service

Assess/Anticipate the required amount (and minimal level of acceptable responsiveness) that is required for each ancillary service. Provide these ancillary requirements to the production cost simulation and corresponding post-processing algorithms. These ancillary requirements will be interpreted as constraints by the simulation so that it can reserve the respective ancillary capability from each of the available resources. *Note: Iteration will be required to optimize.*

HECO Ancillary Service Matrix

(Actual HECO spreadsheet accompanies this report and covers Scenarios 4A & 4B)



Step 4:

Identify "resource-level" ancillary service capability

Identify the amount of each ancillary service that can be performed by each resource. This establishes the subset of the respective resource's capability that could be allocated to the given ancillary service. Items such as operating range, startup times, ramp-rates, min-up/down times, inertial response, black start capability, etc. are key considerations.

Example: Representative Ramp Rate Capability for HECO Resources

(other attributes would require similar definition for each resource)

Unit	Actual 2012	Target Upward	Target Downward	Maximum Upward
	(MW/min)	(MW/min)	(MW/min)	(MW/min)
HCNH8	1.6	1.6	1.6	5.0
HCNH9	1.3	1.3	1.3	5.0
WAIW3	1.4	1.4	1.4	5.0
WAIW4	2.7	2.7	2.7	4.0
WAIW5	3.0	3.0	3.0	5.0
WAIW6	3.0	3.0	3.0	5.0
WAIW7	3.0	5.0	3.0	7.0
WAIW8	3.0	5.0	3.0	7.0
WAIW9	3.0	5.0	3.0	10.0
WAIW10	3.0	5.0	3.0	10.0
KAHK1	3.0	5.0	3.0	7.0
KAHK2	1.6	3.0	3.0	7.0
KAHK3	3.0	5.0	3.0	7.0
KAHK4	3.0	5.0	3.0	7.0
KAHK5	3.0	7.0	3.0	10.0
KAHK6	3.0	6.0	3.0	8.0
CIP_CT-1	5.0	10.0	10.0	13.0
AES	2.5			

Step 4: (cont'd)

Identify "resource-level" ancillary service capability

The following table provides an overview of the ancillary service compatibility *that would be assumed* for each HECO resource if a detailed ancillary service assessment of Scenario 4A were performed. *Note: Previous simulations and analysis of Scenario 4A have not explicitly considered the ancillary service obligations with the granularity depicted in the table below.*

						Ancillary Services Compatibility								
HECO Resources - Scenario 4A	Duty	Fuel	Frame	Model	GRD	Inertial Response	Frequency Response Reserve	Regulation	Load Following	Spinning Reserve	Non-Spinning Reserve	Replacement Reserve	Voltage Support	Black Start
AES	Base load	Coal			168	✓	✓	✓	✓	✓	—	—	✓	—
H POWER	Base load	Biomass/Waste			72	✓	—	—	—	—	—	—	✓	—
HONUA WATT. ANT	Base load	Biomass/Waste			8	✓	—	—	—	—	—	—	✓	—
KAHE 1	Base load	LSFO			82	✓	✓	✓	✓	✓	—	—	✓	✓
KAHE 2	Base load	LSFO			82	✓	✓	✓	✓	✓	—	—	✓	✓
KAHE 3	Base load	LSFO			86	✓	✓	✓	✓	✓	—	—	✓	✓
KAHE 4	Base load	LSFO			85	✓	✓	✓	✓	✓	—	—	✓	✓
KAHE 5	Base load	LSFO			224	✓	✓	✓	✓	✓	—	—	✓	—
KAHE 6	Baseload	LSFO			224	✓	✓	✓	✓	✓	—	—	✓	—
KALAELOA CC	Base load	LSFO			90	✓	✓	✓	✓	✓	—	—	✓	—
KALAELOA CC	Base load	LSFO			90	✓	✓	✓	✓	✓	—	—	✓	—
WAIAU 7	Base load	LSFO			33	✓	✓	✓	✓	✓	—	—	✓	—
WAIAU 8	Base load	LSFO			68	✓	✓	✓	✓	✓	—	—	✓	—
HONOLULU 8	Cycling	LSFO			53	✓	✓	✓	✓	✓	—	✓	✓	—
HONOLULU 9	Cycling	LSFO			54	✓	✓	✓	✓	✓	—	✓	✓	—
WAIAU 5	Cycling	LSFO			37	✓	✓	✓	✓	✓	—	✓	✓	—
WAIAU 6	Cycling	LSFO			37	✓	✓	✓	✓	✓	—	✓	✓	—
WAIAU 9	Cycling	LSFO			35	✓	✓	✓	✓	✓	—	✓	✓	—
WAIAU 10	Cycling	LSFO			46	✓	✓	✓	✓	✓	—	✓	✓	—
KALAELOA CC 5 MW	Peaking	Biomass/Waste			8	✓	✓	✓	✓	✓	✓	✓	✓	—
CIP CT BIODIESEL	Peaking	Biomass/Waste			153	✓	✓	✓	✓	✓	✓	✓	✓	—
WAIAU 10	Peaking	Diesel			55	✓	✓	✓	✓	✓	✓	✓	✓	✓
WAIAU 9	Peaking	Diesel			55	✓	✓	✓	✓	✓	✓	✓	✓	✓
OAHU CENTRALIZED SOLAR	Solar	Solar	Solar PV		150	—	—	—	—	—	—	—	✓	—
OAHU DISTRIBUTED SOLAR	Solar	Solar	Solar PV		340	—	—	—	—	—	—	—	✓	—
OAHU WIND TERM	Wind	Wind	Wind		72	—	—	—	—	—	—	—	✓	—
OAHU WIND TERM	Wind	Wind	Wind		72	—	—	—	—	—	—	—	✓	—

Step 5:

Execute the Production Cost Simulation

Execute the production cost simulation for the respective scenario. Review the hourly (and sub-hourly data as applicable) to ensure that all ancillary services requirements (plus other relevant system constraints) were observed. *i.e. sufficient system-level regulation, spinning reserve, etc. was reserved.*

Step 6:

Identify Trends in the Results

If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider the trends in the deficiencies (or excess):

- Are the deficiencies (or excess) driven by inadequate responsiveness from the available resources?
- Are the deficiencies (or excess) driven by inadequate operating range?
- Are the deficiencies (or excess) present in all hours or only some hours?

Step 7:

Consider potential solutions to alleviate deficiencies and improve system efficiency

Adjustments to operating procedures:
- Adjusted minimum run-times
- Relaxed qualifications/requirements for respective A/S participation
- Activation thresholds for DR,
- storage device charging procedures
- Relaxed "must-run" rules

Retrofits of existing resources:
- Increased plant output
- Improved turndown on thermal units
- Elevated ramp-rates
- Reduced start times
- Synthetic inertia & governor response from renewables

New resources:
- Fossil
- Storage
- Demand response
- Renewable assets
- Inter-island connectivity

Coupled Benefits

Are there resource adjustments (or new resources) that would alleviate multiple deficiencies (or excess)?

i.e. Re-tuning the synthetic inertia of a wind-turbine in conjunction with pitch-control enhancement might facilitate improvements to both inertia and regulation capabilities.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios".

Identify Trends / Consider Solutions: **Inertial Response** – Scenario 4A

Observations
- The inertial response of the system appears to be adequate in Scenario 4A.

Recommendations
- Consider requiring interconnecting wind and solar plants to provide synthetic inertia to further strengthen the inertial response capability.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios"

Identify Trends / Consider Solutions : **Frequency Responsive Reserve** – Scenario 4A

Amount Required

- Under-frequency response: Needs to be able to cover loss of largest unit (185 MW)
- Over-frequency response: To cover loss of load events: 140MW (daytime) under a transmission fault; 90MW (night-time) under the loss of 80MVA transformer and loss of adjacent 46kV feeders.

Observations

- For under-frequency*, the results of HSIS study show that:
  - Enforcing "no trip" of distributed PV on under-frequency excursion helped to reduce the frequency drop by 2.2-3.4 Hz (if UFLS is not active).
  - Use of frequency responsive load (50MW @ 59.5 Hz trip), and synthetic inertia from wind plants can support the system during loss of generation contingency by reducing the frequency nadir by up to 0.3 Hz, in cases where synchronous generators are displaced by renewables.
- For over-frequency*:
  - Over-frequency control (5% droop, 36mHz dead-band) from renewables seems to improve the system performance under 140MW of load rejection in a challenging hour. The burden on the thermal units gets reduced by 43% and the frequency excursion decreases by 0.7 Hz.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios".

Identify Trends / Consider Solutions : **Frequency Responsive Reserve** – Scenario 4A

Recommendations

- For under-frequency, *one or more of the following changes may be required under Scenario 4A and 4B (additional simulation / analysis would be required to confirm):*
  - *Obtain primary frequency response from frequency responsive load*
  - *Prevent distributed PV from tripping (not an ancillary service... more to do with IEEE 1547)*
  - *Permit curtailed wind and solar resources to provide under-frequency response*
- *For over-frequency:*
  - *Consider allowing wind and solar resources plants to provide over-frequency response.*

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios"

Identify Trends / Consider Solutions : **Regulation & Load Following** – Scenario 4A

Observations

- The regulation and load following needs of the system are currently covered by operating reserves and deemed to be adequate.

Recommendations

- No firm recommendations at this time. Further analysis may yield a more economically optimal means of obtaining the regulation & load following services.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios"

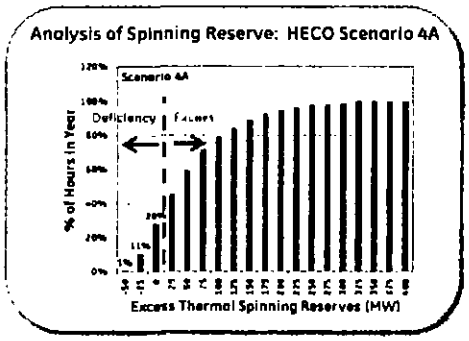
Identify Trends / Consider Solutions : **Spinning Reserve** – Scenario 4A

Amount Required

- Contingency Reserves: Needs to be able to cover loss of largest unit (185 MW)
- Operating Reserves: No explicit requirement, but required to cover statistical variation in load and renewable generation in the 1 minute to 1 hour timeframe. Quick start capability is taken into account when calculating spinning reserve requirements.
  - Max variation: Day-time (6am-8pm) = 239MW; Night-time (8pm-6am) = 32MW.

Observations

- In Scenario 4A, a deficiency of Spinning Reserves is anticipated 28% of the time (up to 50 MW maximum)
- Due to sufficient reserve participation from baseload units, the full 50 MW would only be required 1% of the time.
- However, in some hours, cycling units are committed to meet the higher operating reserves requirement & net load.



Steps 6/7: (cont'd)

Note: Comprehensive validation of the [illegible] relations in this step require additional simulation runs and analysis which are presently determined to be outside the scope of this study

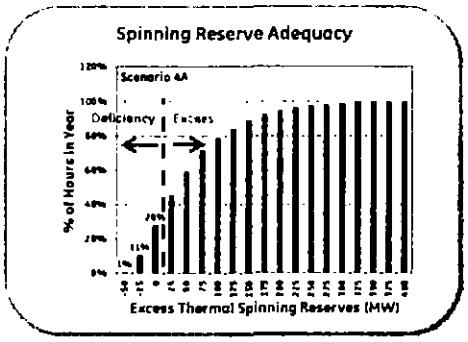
Identify Trends / Consider Solutions : **Spinning Reserve** – Scenario 4A

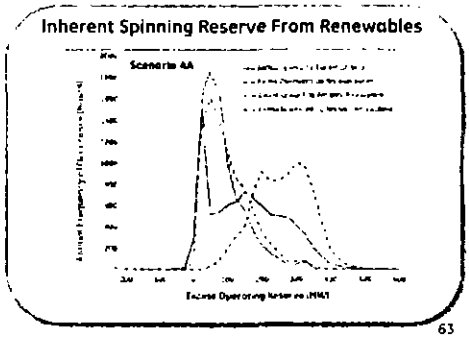
Recommendations

Multiple options exist to relieve the anticipated Spinning Reserve issues. Two options will be presented below:

Option #1: To alleviate the deficiency, consider the addition of 50-MW BESS or DR resource. Beyond relieving the shortage, this option could potentially lower the reserves requirement on thermal units and help to de-commit cycling generation which would allow the system to absorb more solar & wind energy.

Option #2: To relieve the excess spinning reserve, consider allowing curtailed renewables to provide reserves. Modern Wind / Solar facilities are capable of responding quickly to load set-point adjustments. This action may reduce commitment on thermal units (reducing excess reserves), and potentially provide for increased penetration of renewable resources.





Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios"

Identify Trends / Consider Solutions : **Non-Spinning Reserve** – Scenario 4A

Amount Required

- Contingency Reserves: All contingency reserves are required to be spinning on an island system.
- Operating Reserves: No explicit requirement for non-spinning operating reserves.

Observations

- The response of the current system appears to be adequate.

Recommendations

- None.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios"

Identify Trends / Consider Solutions : **Black Start** - Scenario 4A

Amount Required

- The MWs and location of black start units are determined based on a planning study
- Currently provided by the Kahe, Waiau, and Campbell units.

Observations

- Black start capability of the system is probably sufficient since there is no significant load growth in Scenario 4A. Further analysis may be required to confirm.

Recommendations

- None.

Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled "HECO Ancillary Services for Scenarios".

Identify Trends / Consider Solutions : **Voltage Support** - Scenario 4A

Observations

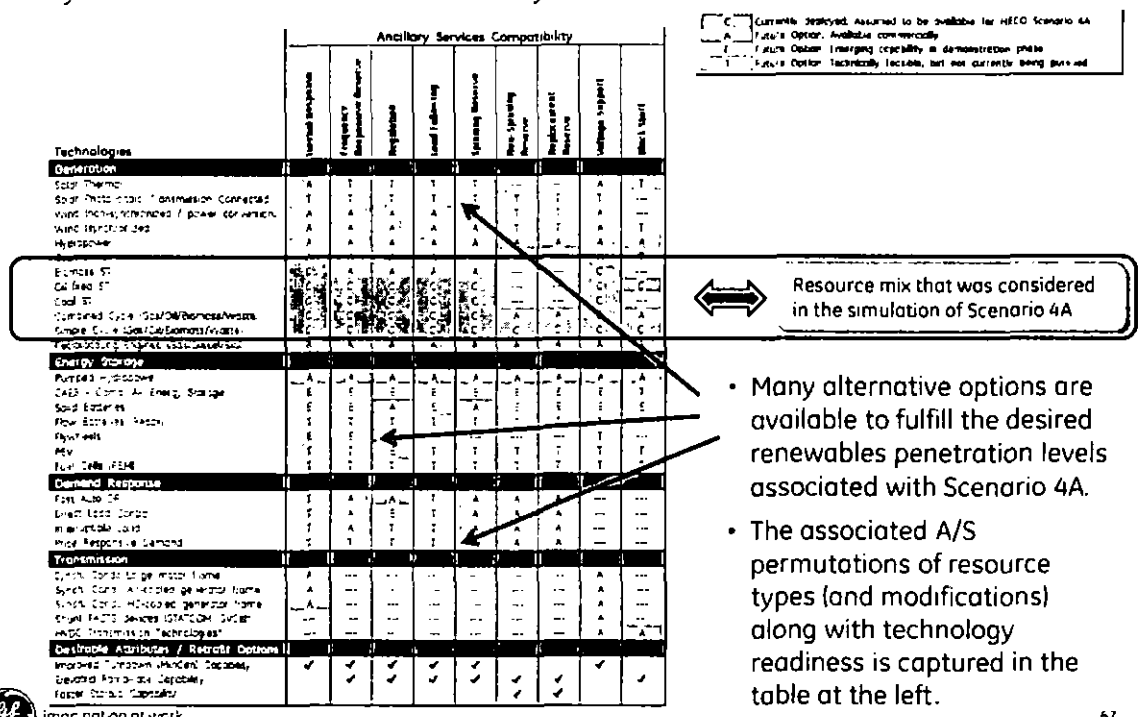
- Currently provided by all online generators with voltage and reactive power controls (including Wind, Solar, and Sync. Condensers)
- The response of the current system appears to be adequate.

Recommendations

- There may a need for additional voltage support if the "must-run" rules on existing thermal units is relaxed.

Steps 6/7: (cont'd)

Identify Trends / Consider Solutions : Many Permutations of Solutions are Available



- Many alternative options are available to fulfill the desired renewables penetration levels associated with Scenario 4A.
- The associated A/S permutations of resource types (and modifications) along with technology readiness is captured in the table at the left.

Steps 6/7: (cont'd)

Identify Trends / Consider Solutions : Synergies between technology types

When selecting new resources and/or resource modifications to alleviate ancillary constraints, there may be synergies available. For example:

- When allowing VG (solar/wind) to participate in A/S, the addition of a moderate amount of storage may have the potential enable more periods where VG can provide the A/S needs. Further, the availability of the storage may help to cover a portion of the A/S requirements that would have otherwise been provided by dispatchable thermal generation ... further increasing renewables penetration objectives. DR may offer benefits which are analogous to those of storage.
- As additional "non-synchronous" generation is added to the power system for the purposes of providing both energy and ancillary services, there may be a need for the addition of transmission technologies such as synchronous condensing units to be added to ensure sufficient reactive power.

It should be noted that the degree to which synergies will available and their corresponding benefit is highly dependent upon the respective scenario being considered. The current process being described provides a method for evaluating a technology mix in a given scenario. As each scenario/mix combination is evaluated, other potential synergies between technologies may emerge.

Steps 8/9:

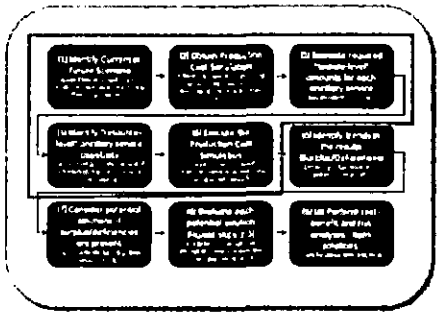
Evaluate the economic viability of each potential solution

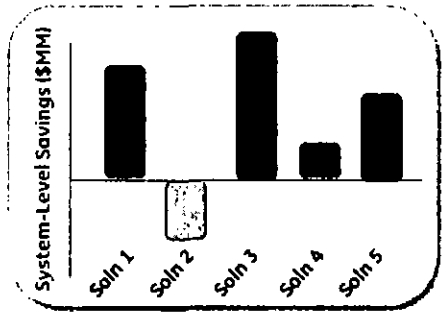
Note: Completion of this step requires additional simulation runs and analysis which are presently determined to be outside the scope of this study. Conceptual illustration only.

Step 8: For each potential solution identified, repeat steps 1-5:

- Consider/evaluate the change in total cost required to serve the anticipated system load profile.
- Potential for the respective solution to facilitate the desired trajectory of renewables penetration over-time.

Step 9: Perform a cost-benefit analysis which evaluates the year-over-year (YOY) system-level benefit (typically in the form of reduced production cost) of the proposed solution relative to the capital cost required to achieve the respective solution. Rank the solutions according to their economic viability (i.e. NPV, IRR, etc.)





Step 10:

Evaluate the risks associated of each potential solution

Note: Completion of this step requires additional simulation runs and analysis which are presently determined to be outside the scope of this study. Conceptual illustration only.

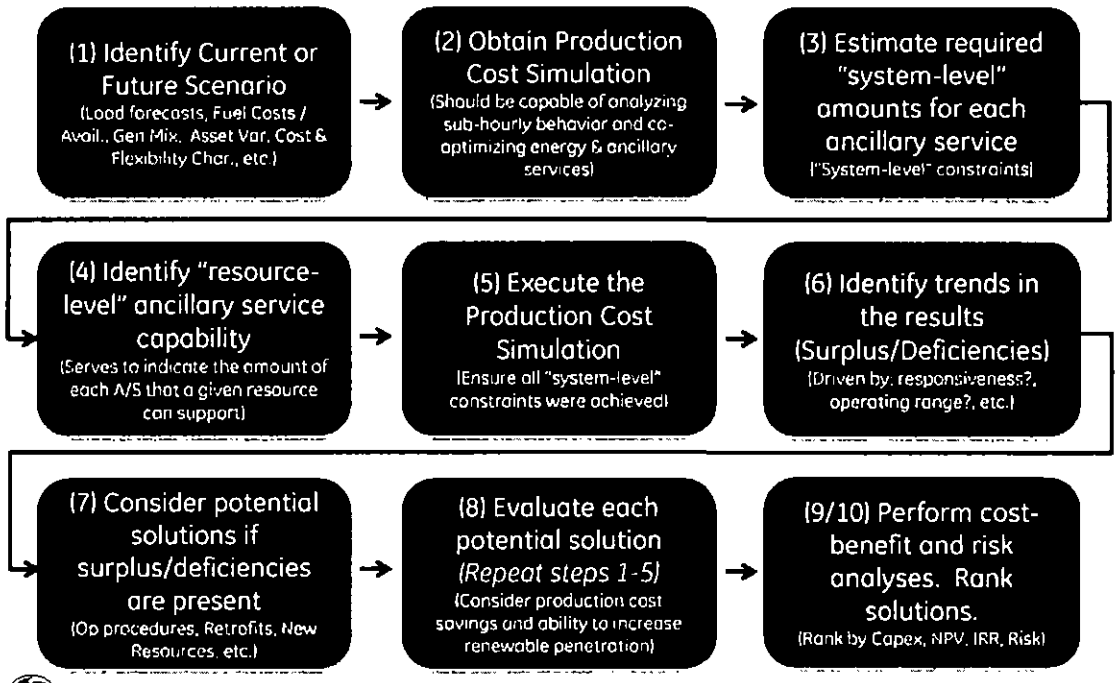
A comprehensive risk assessment of the potential options should also be conducted and weighted against to the economic viability to ensure that the selected solution is robust and reliable.

Potential Risks to consider (not limited to the following):

- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- *Reductions in inertial response capability*
- Unfavorable impacts to "system-level" variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes
- Challenges associated with monitoring / controlling DR participation on a centralized basis

Process to Estimate Technology Mix

Summary



imagination at work

Considerations for Specifying and Acquiring Ancillary Services

imagination at work

Task 4: Scope & Deliverables

Outline considerations for specifying and acquiring ancillary services

Objectives:

- Promote a least-cost portfolio of resources that can supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs
- Highlight costs, technology availability, fuel availability or other risks associated with the recommended ancillary services and potential technology mix, with contributions from HPUC and HECO
- Outline factors and provisions to consider for future resources:
  - Type of ancillary services and performance requirements (Task 1)
  - Technology/manufacturer neutral response capabilities for interconnection requirements for new generators (Task 2)
  - Risk, cost and cost-effectiveness methods explored in other power systems
  - Process to compare alternative ancillary service offerings
- Describe any additional study work, including estimated timeline and cost, that may be required to identify the type and amount of ancillary services required

Task 4: Scope & Deliverables

Outline considerations for specifying and acquiring ancillary services

Approach:

- Summarize findings in Tasks 1-3
- Identify potential risks such as Hawaii specific resource costs, technology availability, fuel availability, and other that may impact the ability of the Hawaiian utilities and HPUC to build an effective portfolio of resources to provide ancillary services, fulfill interconnection requirements or address other system considerations

Methods for Procuring Ancillary Services

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Procuring Ancillary Services

Overview of Approaches for Obtaining, Compensating, and Incentivizing

This section puts forth some potential approaches and mechanisms which can be used to obtain, compensate, and incentivize resources for providing ancillary services.

The following **four** approaches will be highlighted in this section:

1. Market Clearing Price
2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

The above listing is not intended to be exhaustive; however, the GE team believes that it contains a representative subset of the most viable techniques which could be considered. Further, it should be noted that each option is not mutually exclusive and may incorporate aspects of the surrounding approaches.

Procuring Ancillary Services

Method 1: Market Clearing Price

The Marketing Clearing Price approach is leveraged primarily by wholesale power markets:

- For this method, each resource submits (or is assigned) an offer price for the respective ancillary service.
  - Most often, resources submit offer prices that are based on their opportunity cost to reserve the headroom or legroom required to provide the service.
  - Some resources, such as storage devices, do not have an opportunity cost because they do not directly provide energy. Instead, their offer price may be based on startup, variable O&M, charging costs, or other expenses associated with providing the respective A/S.
  - In addition to the cost to provide the service, many markets allow resources to include "additional margin" in their offer price. In some cases, the resource may use to the additional margin to hedge against increased variable O&M costs (i.e. cycling wear & tear). In other cases, the resources may simply leverage the additional margin to cover "cost uncertainty" and/or attempt to enhance their ancillary profitability.
  - In some markets, the offer price is capped. The cap is often derived by calculating the cost for a unit to provide the service and adding (up to) a maximum allowable margin. The lesser of the submitted price and the capped price is then used as the offer price in the market clearing algorithms.

Procuring Ancillary Services

Method 1: Market Clearing Price (cont'd)

- The "market clearing price" for the ancillary service is driven by the *offer price of the last rank-ordered* resource required* to satisfy the system-level ancillary requirement (for the respective ancillary service). For this approach, all participating resources will receive the "same price" for the given period (typically 1-hour increments).
  - *In many wholesale markets, there exists both a day-ahead clearing price and a real-time (or supplemental) clearing price (as-required) to ensure sufficient ancillary availability.*
- To incentivize "no risk" participation, some markets will compensate for "actual incurred" costs which are larger than the revenues derived from the ancillary market clearing price via "make-whole" payments. This ensures that resources are "no worse off" for having provided ancillary services.
- Due to the fact that all participating resources receive the same price for a given ancillary service, it is important to note that most resources, with the exception of the marginal ancillary resource, will earn a financial benefit (i.e. profit) for providing the respective A/S.

** A "low to high" ranking of the offer prices for each participating resource*

Procuring Ancillary Services

Method 2: Reimbursement of Offer Price

The Reimbursement of Offer Price is an alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. It is a logical compromise between the "market clearing price" and "make-whole compensation" approach.

- Instead of a "clearing price" for the ancillary service, each resource is compensated on an individual basis for providing the service.
- The offer price for each resource would likely be derived in a similar fashion to the Market Clearing Price methodology. Specifically, the resource's "cost to provide + margin" (including opportunity costs) would serve as a rational basis for the offer price. If the agreement is between a utility and IPP, the offer price could be based on the anticipated production cost savings for the utility. The final ancillary service price would be based on a negotiated value between the respective parties.
- The period for which this contractually agreed to price is valid could be varied (i.e. hourly, daily, monthly, annually, or simply set at a constant rate for contract period, etc.)
- Similar to the Market Clearing Price approach, it is recommended that the Reimbursement of Offer Price incentivize participation by providing a "no-risk" contract architecture through the reimbursement of "actual incurred" costs (i.e. if incurred costs are higher than the compensation that would be derived via the offer-price).
- Due to the fact that resources are compensated on an individual basis, profitability (for the resource providing the service) is limited to the margin included in the offer price.

Procuring Ancillary Services

Method 3: Make-whole Compensation

The Make-whole Compensation approach is another alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. Most wholesale markets include "make-whole compensation" provisions in their architecture. This method extracts the "spirit & intent" of those provisions.

- At its core, the rationale for "Make-whole Compensation" is to explicitly compensate participating resources for their costs (including opportunity costs) associated with providing A/S. This method is designed to make the participating resource indifferent toward providing ancillary services.
- Instead of negotiating an offer-price, the resource-specific cost structure would be shared between the contracting parties so that an accurate assessment of incurred costs could be obtained.
- Due to the fact that resources are compensated on an individual basis, and only for their cost to provide the service, there is no additional profitability potential for participating in A/S. For the three approaches discussed thus far, this method will typically result in the lowest overall production cost to reliably serve the load.
- It is important to note that while this approach adequately and explicitly compensates resources for their A/S participation, it does not incentivize that participation.

Procuring Ancillary Services

Method 4: Condition of Interconnection

It is important to note that all power systems (historical, existing, and future) require the use of certain interconnection requirements and ancillary services to ensure the system reliability is maintained. In many cases, such as with regulated utilities, the explicit compensation of resources for ancillary participation has not been required to maintain a reliable system. For this reason, the Condition of Interconnection approach was included in this list of options.

- The "Condition of Interconnection" approach would simply require ancillary service capability and participation from interconnecting resources.
- Resources would not be explicitly remunerated for providing ancillary service capability or for the associated costs incurred.
- The incentive for resources to provide ancillary service capability would be driven by the accompanying right to participate in selling energy.
- For this type of agreement, it is implied that the participating resources would derive financial benefit from the sale of energy alone that was sufficiently large enough to cover both the cost to provide energy and the cost to provide A/S.
- Due to the lack of explicit compensation, the "Condition of Interconnection" approach has the potential to offer the lowest production cost of the four methods described.

Procuring Ancillary Services

Forward Planning Approach to Derive Rational Ancillary Service Contract Prices

Much attention has been focused on obtaining ancillary services from resources with the lowest offer price and/or lowest "cost to provide" (including opportunity costs).

One potential method for assessing the basis of a "rational" ancillary service offer price would be to leverage a production cost simulation with the capability to co-optimize energy and ancillary services. For a given future scenario, with a known resource mix, the simulation could be exercised and evaluated at both a resource-level and a system-level to draw conclusions about a rational offer price for the respective resource:

- At a resource-level, the results of the simulation could be interrogated to identify the perceived cost (including opportunity cost) for each resource to provide a given ancillary service. To develop an offer price, the hourly observations for each resource could then be aggregated and averaged over a period that aligned w/ the desired contractual period.
- At a system-level, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price for each particular resource.

To adequately bound the offer price, it is recommended that both the resource-level and system-level assessments be conducted.

Hawaii-Specific Ancillary Service Procurement

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Procuring Ancillary Services

Methods for Obtaining Ancillary Services in Hawaii

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources.

Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements.

As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive would likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for [some of/all of] the ancillary services. Careful consideration is required before integrating such remuneration methods.

Procuring Ancillary Services

Methods for Obtaining Ancillary Services in Hawaii

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources.

Relative to the current environment, in which resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be an equitable option.

Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are *more expensive* to operate than some non-renewable resources on the system *(i.e. periods where the energy contract price is higher than the marginal system cost).* During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation" would be recommended.

Procuring Ancillary Services

Methods for Obtaining Ancillary Services in Hawaii

It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration. Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would likely be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource Mix" could be leveraged to help quantify these potential benefits.

Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services.

To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

Procuring Ancillary Services

Methods for Obtaining Ancillary Services in Hawaii

Ancillary service participation from DR, transmission, and retrofit options have the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure.

Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies.

To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

Procuring Ancillary Services

Methods for Obtaining Ancillary Services in Hawaii

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types.

In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have [typically] low variable operating cost and have the have the potential to reduce the overall production cost for the system.

As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized.

Instead, it is recommended that the impact on overall production cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

Risk Assessment and Other Considerations

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Risk Considerations

Outline considerations for specifying and acquiring ancillary services

- Hawaii specific resource costs
- New/emerging technology availability
- Ability to uprate/upgrade existing resources
- Fuel availability and fuel infrastructure
- Wind and solar forecasting process
- Interconnection costs
- Inter-Island transmission connections
- Challenges associated with monitoring / controlling Demand Response participation on a centralized basis
- Load shaping programs
- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- Reductions in inertial response capability
- Unfavorable impacts to "system-level" variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes

Risks are highlighted in the "Observations" column of the scenario workbooks for each system

Technology Risks

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Generation Technology Risks

- Wind Turbines:
  - Variable generation
  - Unstable incentive structures (i.e. government tax credits)
- Gas Turbines / Combined Cycles:
  - Volatile fuel prices
  - Fuel transport costs
- Simple Cycles:
  - Volatile fuel prices
  - Fuel transport costs
- Reciprocating Engines:
  - To be added

Generation Technology Risks

- Solar Thermal:
  - Unstable incentive structures (i.e. government tax credits)
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

- Solar PV:
  - Variable generation
  - Unstable incentive structures (i.e. government tax credits)

- Hydropower:
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

- Geothermal:
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

Generation Technology Risks

- Biomass:
  - Unstable incentive structures (i.e. government tax credits
  - Cost of collecting biomass

- Coal:
  - Negative environmental impact
  - Fuel transport costs

Storage Technology Risks

- PHS:
  - Energy naturally wants to spread out, so compressing water behind a dam creates the risk of an uncontrolled energy release
  - High costs/market liquidity/market price uncertainty (revenues from ancillary services hugely volatile)
  - Arbitrage revenue - after efficiency is taken into account this is not a huge money spinner at some market prices
  - Market risk (i.e. change in ISO rules)
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii
  - There is a real option value that may not be captured unless risk is explicitly identified and quantified - plant operations decisions must incorporate these risks
  - A serious disadvantage is dependence on specific geological formations or man-made reservoirs
  - Difficult construction – depends on topography

Storage Technology Risks (Comments)

Comments from HREA:

- Risk of Structural Failure: We understand with proper design and installation, the risks of dam or reservoir failures are very low. In addition, a Pumped Storage facility using advanced Roller-Compacted Concrete ("RCC") technology would mitigate structural risk with a design that incorporates a deep reservoir with most of its capacity below ground level. See also the Division of Safety of Dams ("DSOD"), Department of Water Resources in California for additional information (http://www.water.ca.gov/damsafety/).
- High costs/market liquidity/market price uncertainty: All renewable projects in Hawaii face similar costs/market risks. Re Pumped Storage, we understand construction costs would be similar to those for a wind farm of similar MW capacity. We agree that there could be risks associated with Pumped Storage that operates in the "classic" duty cycle for pumping during off-peak hours and generating during peak hours. However, we believe additional revenues for a number of ancillary services, such as load following, frequency response, spinning reserve, inertial stability (Wr2), voltage support, VAR generation/control, and black start capability, can reduce that risk significantly. The key will be ability to negotiate a PPA that helps meet system needs and provides an adequate revenue stream such that investors can make an acceptable return on their investment.
- Arbitrage revenue: As discussed previously, Pumped Storage may not be able to accomplish the primary goal of energy arbitrage, i.e., buy low, sell high or higher, in Hawaii. However, we believe a Pumped Storage facility with PPA that includes appropriate payment for generation and ancillary services can be financially viable.

Docket No. 2011-0206 – Reliability Standards Working Group

Comments of the Hawaiian Electric Companies Regarding General Electric Ancillary Services Definitions and Capability Study

During the January 24, 2013 RSWG stakeholder meeting, representatives of General Electric Energy Consulting ("GE") provided their final briefing on the Ancillary Services Definitions and Capability Study – Parts I and II ("Study") produced for and with the support of the Hawaii Natural Energy Institute. The following provides the Hawaiian Electric Companies' general comments on the Study for the Commission's information and consideration as further process is contemplated for the evaluation and assessment of the Study's recommendations.[1]

The Study correctly acknowledges that the utilities presently obtain ancillary services from dispatchable resources through a method which is similar to the "Condition of Interconnection" approach identified in the Study. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources. The Study states that relative to the current environment, in which dispatchable resources are not explicitly compensated for fulfilling system-level ancillary services obligations, requiring wind or solar resources to provide ancillary services via the "condition of interconnection" approach would certainly be considered an equitable option. The Hawaiian Electric Companies continue to include provisions for required ancillary services in recently negotiated contracts for dispatchable, firm capacity, renewable energy resources (e.g. Hu Honua, PGV expansion, geothermal RFP), and variable generation (e.g. Kawailoa Wind, Kalaeloa Solar Two, Auwahi Wind, Kaheawa Wind Power II) and propose to continue doing so pending an analysis and study which indicates that a contrary course would be preferable.

The Study takes the position that to the extent the penetration of variable resources increases beyond the ability of existing resources (including the ancillary services capabilities obtained by continuing to require certain services for future variable resources) to economically provide the ancillary services required to support these resources, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) ancillary service capabilities. The Study notes however that the use of methods to incentivize ancillary service capabilities, including explicit compensation for some or all of the ancillary services, has the potential to increase the overall production cost as a result of explicit compensation for [some of/all of] the ancillary services and therefore, careful consideration is required before introducing such remuneration methods or unbundling ancillary services.

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[1] Hawaiian Electric Company, Inc., Maui Electric Company, Limited and Hawaii Electric Light Company, Inc. (collectively "Hawaiian Electric Companies" or "Companies").

This caution is worth emphasizing, as the cost of energy is a major concern to ratepayers. The Hawaiian Electric Companies therefore recommend that any proposed incentives to facilitate the provision of ancillary services from new or existing resources, be thoroughly analyzed against the following objectives:

a) Maintain or improve present levels of system reliability and security
b) Maintain or reduce overall system costs
c) Ensure that resource capabilities needed for system security will be made available
d) Provide flexibility for the system operator to change use of resources in response to changing relative costs, system operational needs, and resource availability

To meet this objective, the Companies are prepared to undertake a study utilizing the proposed methodology in the Study to determine the required level of ancillary services and then assess costs under a variety of options. The Companies suggest that this approach be based on two phases of analysis:

1) For each of the base case systems, identify the value of ancillary services for the HELCO, MECO and Hawaiian Electric systems in a given study year. This value of ancillary services would be derived by completing an annual production cost simulation assuming that transmission is unconstrained and comparing the annual production cost simulation against the constrained system.

2) Identify the potential to reduce annual production cost by providing various ancillary services from facilities which are not currently supplying the services as part of a bundled energy rate. For instance, battery systems located at key transmission constraints may alleviate certain generation requirements. Identify the cost differences between the possible ancillary service facilities and the energy facilities in annual production cost simulations.

3) Based on the findings of the acceptable combinations of resources in the first and second phases, perform a cost assessment to evaluate the least-cost portfolio of resources using an iterative solution to provide the best method of providing the required services. The method could also identify the energy rate reductions required from IPP contracts that would be required to facilitate the provision of ancillary services incentives.

This approach is similar to that used in the recently conducted EPS cycling study for the HELCO and MECO systems, which first examined acceptable resource combinations for system security based on existing and near-term resources and also evaluated the potential for down-regulation from wind. The set of resources required for security constraints were then incorporated into a production cost assessment.

The first two phases could incorporate existing and potential (new) resources, or new capabilities on existing resources. By completing the work in this manner, the risk of increasing overall production costs can be adequately assessed and identified. It is recommended that such analysis be based on recognized industry system planning tools to evaluate system performance under dynamic and steady state conditions and incorporate modeling to capture impacts of variable and distributed generation. As recommended in the Study, the production cost assessment would evaluate the potential combinations of resources to determine a lowest-cost portfolio, including production cost and capital expenditures, while observing system reliability needs identified in the first phase. It is also recommended that such analysis must be based on industry accepted methods which capture all variable production costs, including impacts of variable and distributed generation, in order to accurately assess the relative costs of various scenarios. With the evolution of the island power systems to incorporate greater amounts of distributed and variable generation, both the security analysis and production cost analysis must become more sophisticated. Due to the significant cost and reliability impacts associated with these types of decisions on future power systems, investment in the required detailed modeling and analysis is necessary.

The final determination of future resource portfolios should also incorporate Risk Considerations such as those identified in Section 3.2.4 of the GE Study.

Docket No. 2011-0206 – Reliability Standards Working Group

RDM Subgroup Comments on the
General Electric Ancillary Services Study
January 14, 2013

The purpose of this paper is to provide comments by the Reliability Definitions and Metrics Subgroup ("RDM Subgroup")[1] of the Reliability Standards Working Group ("RSWG") on the study prepared by General Electric International, Inc., acting through its Energy Consulting group ("GE"), titled, "Ancillary Services Definitions and Capability Study" and dated December 19, 2012 ("GE Study").

1.0 Background

As described by GE, the purpose of the GE Study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems in Hawaii and elsewhere. GE suggests the study results may be proposed for consideration and adoption by the Hawaii Public Utilities Commission and used for RSWG standards proposals, revised generation interconnection technical requirements, and the Integrated Resource Planning process.

The RDM Subgroup offers these comments consistent with the understanding that the GE Study is RSWG-associated work product. As noted in the Independent Facilitator's submittal to the Commission filed December 24, 2012, the GE Study, which was facilitated by funding and contract management provided by the Hawaii Natural Energy Institute, is not formal RSWG work product and not subject to approval by the RSWG, but is rather "RSWG-associated work product."[2] The RDM Subgroup, which helped define the scope of the study and reviewed and commented on various drafts, offers the following comments with that understanding.

The comments in this paper are intended to complement and supplement (i) the paper prepared by the RSWG Minimum Load and Curtailment Subgroup, and approved by that subgroup and the RSWG, titled, "RSWG Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities in a Renewable Based Grid" ("MLC Subgroup ancillary services paper"), and (ii) the paper prepared by the RSWG Demand Side Options Subgroup, titled, "Demand Response as a Flexible Operating Resource" ("DSO Subgroup ancillary services paper").

In addition, the RSWG process contemplates further opportunities for individual RSWG members to submit comments on this paper and on the GE Study. This paper is not intended to foreclose or prejudice any such comments and each member of the RDM Subgroup reserves its rights to submit further comments.

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[1] Members of the RDM Subgroup include the following RSWG parties: Blue Planet Foundation; Department of Business, Economic Development and Tourism; Department of Commerce and Consumer Affairs, Division of Consumer Advocacy; HECO Companies; Hawaii Renewable Energy Alliance; Interstate Renewable Energy Council; Life of the Land; and Tawhiri.

[2] *See* Independent Facilitator, Reliability Standards Working Group Independent Facilitator's Submittal, Progress Report, and RSWG Work Product Submittal filed Dec. 24, 2012 ("IF Submittal") at 5, 6.

2.0 General Support for GE Study

Although the GE Study is not subject to approval by the RSWG (or any RSWG subgroup, including the RDM Subgroup), the RDM Subgroup wishes to indicate to the Commission that it views the GE Study as providing a useful and valuable contribution to the RSWG process and to Hawaii's efforts to increase the use of renewable energy while maintaining electric system reliability. The RDM Subgroup appreciates the opportunity it has had to collaborate with GE on the study and believes the study provides information and analysis that is supportive of and consistent with the general goal of the RSWG process.

The GE Study sets forth the following eight bullet point major recommendations:

- "Require synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements.

- Require droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to the requirement for dispatchable generators.

- Variable Generation (VG) should be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. Recommend the development of tools to reliably calculate the amount of reserves that VG can provide.[3]

- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. Need to design and employ forecasting methodology/tool to calculate the amount of down reserves that VGs can reliably provide based on actual and forecasted generation from VGs.

- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are already curtailed.

- AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability should be made a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.

- VG should be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation.

[3] It is noted that this bullet point concerning "reserves" may be duplicative insofar as the seventh bullet point, which contains nearly identical language, concerns "regulation" and reserves are a form of regulation.

- Storage and demand response should be allowed to provide regulation and reserves as long as they are economical."[4]

RDM Subgroup members hold differing views on certain aspects of the GE Study, including the foregoing major recommendations, due in part to the study's length, level of detail, and the complexity of the technical and policy issues it addresses, as well as the diverse interests and perspectives of the individual subgroup members. Consistent with the overarching purpose of the RSWG process to aid the Commission in assessing key issues such as ancillary services, the RDM Subgroup wishes to indicate to the Commission that it generally supports the information and analyses developed through the GE Study and, at the same time, respectfully offers comments, clarifications, corrections and further suggestions to the study by means of this paper, and also by means of anticipated future submissions to the Commission by individual subgroup members.

3.0 Comments on GE Study

3.1 Future Docketed Proceeding

The RDM Subgroup supports Commission consideration of a further docketed proceeding, upon the conclusion of the RSWG process or otherwise as deemed by the Commission, concerning ancillary services and ancillary services-related interconnection requirements for utility-scale renewable energy generators. The RDM Subgroup suggests that the scope of this proceeding could specifically include, but not necessarily be limited to, the following specific topics:

(1) assessment of the ability of the electric utilities to achieve the GE Study's eight major recommendations;

(2) cost/benefit analysis concerning any modifications to electric utility procurement of ancillary services consistent with certain aspects of the GE Study's eight major recommendations;

(3) feasibility of and risks associated with restructuring existing power purchase contracts to allow for the purchase and acquisition of ancillary services from these facilities as unbundled service providers;

(4) further development and implementation of a methodology for identifying the type, quantifying the amount, and establishing the method of supplying and procuring any necessary ancillary services;

(5) valuing ancillary services for purposes of compensating and imposing costs on generators, storage and demand response (including the use of fixed price over and above specified performance requirements versus real-time pricing based on system need, condition of interconnection, etc.); and

(6) whether and to what extent production cost modeling should or should not be used to quantify needed ancillary services, impacts to total system costs, and ratepayer impacts.

[4] *See* GE Study Part 2, Tasks 3-4 at 2-3.

3.2 Requirements for Utility-Scale Projects

The GE Study's major recommendations include requiring synthetic inertia, droop control and automatic generation control ("AGC"), among other attributes, for "utility-scale" wind plants, and droop control and AGC for utility-scale solar plants, as a condition to interconnecting such plants to the electric system. The RDM Subgroup notes that it generally agrees with the GE Study's recommendations in this regard and adds that, at this time, these attributes should generally be required as a condition of interconnection only for utility-scale plants interconnecting at the transmission or sub-transmission level. Due to technical limitations and economic cost, and the potential advantages associated with a proactive approach to integrating distributed generation,[5] *it may not be appropriate at this time to require such capabilities from distributed* generators interconnecting at the distribution level (e.g., through net energy metering, feed-in tariff, standard interconnection agreement, etc.).

3.3 Procuring and Incentivizing Ancillary Services

At present, Hawaii electric utilities are able to obtain ancillary services from utility owned and controlled resources and dispatchable non-fossil fuel resources. The ancillary services cost is built into the total cost of energy. The utilities procure and dispatch these ancillary services without incentivizing or compensating the non-utility resources. The GE Study suggests that, if the system-need for ancillary services increases to accommodate increased penetration of variable renewable resources, it may be necessary and desirable to incentivize and compensate new and existing resources. These resources must have sufficient flexibility to provide ancillary services to optimize the services based upon recognition of their cost. The RDM Subgroup acknowledges that the procurement and incentivizing of ancillary services from variable resources, as discussed in the GE Study, will require future study (on cost and other related *issues) prior to implementation.*

3.4 Production Cost Modeling

The GE Study recommends the use of production cost modeling to quantify the amounts of necessary ancillary services. The RDM Subgroup members have been unable to reach consensus on this recommendation. It has been suggested that the complexity, time and cost associated with production cost modeling may not be justified given that Hawaii has a relatively limited number of options for obtaining ancillary services (primarily existing fossil generation, demand response and storage). It has also been suggested, however, that production cost modeling need not be complex or extensive, may be relatively low cost (especially in a high fuel cost setting), and modeling may be necessary to support ongoing adjustments to ancillary services requirements based upon changes in system requirements.

3.5 Resource Planning Processes

The RDM Subgroup notes that, in general, resource planning processes should determine the nature and quantity of ancillary services necessary to maintain system reliability. System stability assessments may be required and such aspects of the resource planning process will likely influence potential modifications concerning ancillary services.

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[5] *See* IF Submittal at Attachment 17 ("Summary of Proposal for Proactive Review Approach").

3.6 Technical Feasibility of Storage and Demand Response

The final bullet point of the GE Study's major recommendations states that storage and demand response should be allowed to provide regulation and reserves "as long as they are economical." The RDM Subgroup agrees with this recommendation and notes that, in addition to economic cost considerations, technical considerations should also be assessed, as discussed in detail in the MLC Subgroup and DSO Subgroup ancillary services papers. Demand response may be an important source of ancillary services and storage may contribute to integrating variable generation, notwithstanding an initial cost that may be marginally higher than other technologies, insofar as those other technologies may be subject to unpredictable changes in variable cost inputs over time.

3.7 Wind Energy Opportunity Cost for Up Reserves

The GE Study recommends that "VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are already curtailed." As a clarification, the RDM Subgroup suggests that it may be more appropriate to characterize the opportunity cost as low or very low, rather than "zero," insofar as running wind turbines (for example) to provide up reserves when they would otherwise be offline under curtailment does not have zero cost.

RSWG Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities in a Renewable Based Grid

Background

Ancillary services are necessary for reliable power system operation which includes such functions for routine system operation, responding to contingencies, ensuring secure operation following contingencies, and supporting re-starting of the grid following blackouts. This paper provides a general discussion of how ancillary services meet these needs and the capabilities of utility-scale generators to provide ancillary services.[1]

Power system ancillary service requirements change from hour to hour and from year to year depending on the overall load and generation mix. Without sufficient ancillary service capabilities some otherwise desirable generators may be curtailed in favor of generators with greater ancillary service capabilities.

The decision of how much of each ancillary service is required to maintain reliability and the optimal mix of resources to provide those ancillary services from the available responsive load, storage, and generation resources is a real-time operating decision. This paper does not specifically address the real-time choice of how much of each ancillary service is required or which resources should supply each ancillary service at a specific time. Instead, this paper addresses decisions associated with assuring that there is sufficient ancillary service supply capability available to maintain power system reliability without unnecessarily curtailing renewable generation.

If generators are not designed with ancillary service capabilities they will not be available as potential ancillary service resources for inclusion in the real-time optimization. Four factors make including ancillary service capabilities in the design of new generator wise (in most cases):

- The cost of providing ancillary services from most generators is dominated by the opportunity costs of not producing energy as opposed to the capital cost of including the ancillary service capability in the initial plant design.
- The cost of adding ancillary service capabilities to an existing generator is typically much greater than the cost of including the capability in the initial design.
- Generators have long lives and future ancillary service requirements are uncertain.

[1] Utility scale generators are connected to the transmission system. The recommendations in this paper apply to those generators. Some generators on the distribution system may be able to provide some useful ancillary services to the bulk power system but many will be limited by constraints imposed by the distribution system.

- Installing ancillary service capabilities in all generators (conventional and renewable) can provide the system operator with additional dispatch flexibility to help alleviate or eliminate curtailing environmentally friendly or lower cost generation in order to operate non-renewable or more expensive generation that is more flexible.

While adding ancillary service capabilities or increasing the ancillary service capabilities of existing generators is usually more expensive than including those capabilities in the original design, exceptions may occur and the recommendations herein are intended to include this possibility.

The RSWG through the RDM subgroup has initiated a study by General Electric Energy (GEE) to explore the nature of and requirements for Ancillary Services to support the HECO Companies grid operations. Efforts were initiated to define the types of Ancillary Services available, assess deployment of such services based on various renewable resource penetration on the HECO Companies' grids and determine a methodology to predict future Ancillary Services requirements.

The RSWG recognizes that additional analysis and evaluation must be conducted before implementing the recommendations. Although the paper discusses each ancillary service individually, an analysis must be conducted to holistically assess the technical requirements and secure the ancillary services at the lowest cost.

The RSWG recommends each utility establish an analytical process to define the ancillary service requirements necessary for reliable and efficient operations and a mechanism for securing them at the lowest cost. The process and mechanism should be defined in a first year report to the PUC. Implementation results should be documented annually.

The discussion that follows summarizes key Ancillary Services and is presented as an adjunct to the GEE study along with key recommendations for consideration by the Hawaii Public Utilities Commission.

Inertia

An electric power system needs inertia to function reliably. Inertia provides short-term (cycles to seconds) stored energy to help slow frequency decline or rise upon the sudden loss of demand or generation. Inertia is also important to angular and oscillatory system stability. Inertia is provided by the rotating mass of generators and their prime movers (e.g., turbines) and, to a lesser extent, by motors in load devices not connected through adjustable speed drives. In conventional synchronous generators this inertia is inherently coupled to the grid and any change in grid frequency is associated with a corresponding change in turbine-generator rotor speeds.

Upon loss (trip) of a generator, frequency drops and demand in excess of remaining generation pulls energy from inertia thereby slowing the frequency decline. In systems where there is sufficient inertia, inertia limits the rate of frequency decay to an extent that the drop in frequency can be addressed by the governors on the remaining generators that are carrying spinning reserve and/or load shedding. Inertia and governor response in combination determine the frequency response of the power system. To the extent that certain types of generators can provide relatively fast response to a change in frequency, they can make the frequency response of a lower inertia system acceptable. Likewise, advancing demand-response and storage technologies may provide sufficiently fast response to assist with arresting frequency decay caused by a demand-generation unbalance and thereby also may make the frequency response of a system with lower inertia acceptable.

Inertia is inherently provided by synchronous and induction generators directly coupled to the grid, and by certain motor loads. Inertia cannot currently be provided by PV plants because there is no source of additional energy that can be tapped for a short time though future designs may provide "synthetic" inertia, for instance by incorporating a small amount of storage and momentarily overloading of the inverters. Similarly, battery storage plants can be designed to provide synthetic inertia.

Inertia is not inherently provided by rotating generators that are coupled to the grid through power electronics, for example the widely used doubly fed 1.5 or 1.6 MW wind turbine generators. However, such advanced power electronic controlled wind generators can deliver "synthetic inertia" to the grid through controls that sense a drop in system frequency and respond by increasing power output through the inverter. The extra energy comes either from the rotational energy stored in the blades and/or from unused wind energy if available. To the extent the energy comes from rotating energy, the rotating machine speed will drop modestly. The turbine's speed is returned to normal when frequency is back to normal by using a portion of the turbine's wind produced power to accelerate the wind turbine to its optimum speed. While the machine speed is low, power production will be reduced slightly due to reduced efficiency. In the case where wind is available to produce the energy there is no reduction in turbine speed and no need to reaccelerate the machine later. While there is a capital cost associated with the wind turbine control system required to provide synthetic inertia there is no opportunity cost when the service is provided.

Synthetic inertia as might be provided by a battery and inertia provided by modern wind farms differs from inertia provided by conventional synchronous generators in that it is provided through control logic. An advantage of this form of inertia is that its response to the frequency drop can be tailored for maximum benefit. For instance, the response can be delayed so that thermal plant governors see rapid frequency decay and thus respond more strongly than they would if the controlled inertia were applied

quickly. The amount of inertia also varies widely. On a MW for MW plant rating basis, batteries offer the potential of very large amounts of synthetic inertia, particularly with a small incremental investment in the inverter. Modern windfarms, because of their active power control, offer greater inertia contribution than thermal plants.[2] These attributes and differences between the various types of inertia require analysis to assess the potential contribution of each and optimize their combined use. Further, field tests are needed to confirm field performance matches planning models, particularly where the control technology has not been well proven.

Rotating generators and pump storage plant pumps can be designed to provide higher inertia by machine design or the addition of a flywheel.

Further inertial response could be realized from conversion of existing thermal generators to synchronous condensers.

Inertia is most likely to be lowest at night when demand is low and some generating plants that provide inertia during the day are cycled off. Hence inertia from plants remaining online during minimum load periods becomes particularly important. Inertia from resources available during lower demand periods that have not historically provided inertial response may be a useful enhancement to system frequency response. Examples include synthetic inertia from wind plants, demand side resources, and charging of storage plants. Special attention to the lowest available inertial response periods is necessary in evaluating system options to meet system inertial response requirements and for minimizing or reducing requirements for online conventional plants solely required to fulfill these inertial response requirements.

Generator inertia cannot be evaluated in isolation. The power system's reliable response to the sudden loss of generation or load depends on both inertia and governor response. The move to lighter, aero-derivative turbines, for example, results in a lower system inertia, but the faster response of the governors and turbines makes the overall impact of the system response very close to a higher inertia, slower responding turbine/governor system.

Recommendations

1) The available combination of inertia and governor response and current and future requirements of inertia and governor response should be tracked and evaluated by the utility to ensure new generation fulfills frequency recovery needs and that needed response is provided at minimum cost.[3]
2) All power plants using rotating machines including those based on power electronics should be encouraged to provide maximum cost effective inertia to the power system.
3) Emerging demand-response and storage technologies that provide sufficiently fast response to assist with arresting frequency decay should be encouraged to provide maximum cost effective inertia-like response to the power system.

[2] Windfarms offer an inertia-produced output of about 5% for 5 seconds, or up to 10% for a shorter time period while a typical thermal plant of an equivalent size with an inertia constant of 3 kW-s per kVA offers about half this amount in a typical spinning reserve event.

[3] It may be cost effective to add synthetic inertia capability to some existing wind plants and storage facilities.

4) When the ability to provide adequate frequency recovery has been identified, utilities should endeavor to secure additional frequency recovery capability from new generating or storage plants or synthetic response from plants or storage systems where that is practicable.
5) Compensation for direct costs for resources providing increased inertia should be considered.
6) Engineering test procedures should be developed to perform field testing and measurement of synthetic or actual inertial capabilities for new or existing plants.

Frequency Response

When the demand on the system changes or the power output of a variable generator changes; the result is an immediate unbalance between demand and generation and a resulting rise or drop in frequency. The initial response to a change in frequency comes automatically from governors that increase or decrease power production in inverse proportion to the change in frequency (this is called primary frequency response). Appropriately equipped storage devices and some responsive loads can also respond to a change in frequency. Because frequency is nearly the same at all points on the system, all resources with frequency response capability will respond regardless of where the demand-generator output unbalance occurs.

When a system's frequency response cannot keep up with an increase in apparent demand, frequency declines. A rapid decline in frequency can occur upon loss of generation, an increase in demand, or an extended wind down ramp that exhausts reserves. In an extreme case frequency can decline to the level where underfrequency load-shedding occurs. Planning an adequate amount of frequency response means either planning to avoid load shedding for routine disturbances or limiting the stage or block of load shedding to an acceptable level. Similarly, a loss of load event causes a frequency rise and must be accommodated in planning and operations to ensure adequate frequency response to the condition, without the loss of on-line generation.

While inertia and governor response provides the initial response to a change in frequency, referred to as the "primary frequency response", the AGC system follows up with adjustments to the various governor systems to restore frequency to nominal, referred to as "secondary frequency response." The role of AGC is discussed in the next section.

All rotating generators connected directly to the grid and most modern power-electronics based generators will or can have a governor and provide frequency response.[4] This includes pump-hydro storage plants which can provide regulation in both pumping (if the pumped storage plant has an adjustable speed pump) and generating modes.

There is an important distinction between having ancillary service response capability (a decision made when the generator is designed) and operating such that the response capability is available (a decision made by the system operator in real time). Generators can only provide upward response to a drop in power system frequency if they are operating below their maximum power level.[5] Similarly, generators can only provide downward response to an increase in power system frequency if they are operating above their minimum power level. Generators, and rate payers, will typically incur an opportunity cost when generators are operated out of economic order in order to reserve upward or downward room for response. The system operator must continuously determine the least cost mix of generation, storage, and demand response resources to reliably supply energy and ancillary services. Opportunity costs are particularly large for wind and solar plants because they have no fuel cost so there is no fuel cost savings

[4] Frequency response from wind plants is commercially available. PV plants may also be able to provide frequency response.

[5] In some cases, governor droop response may be permitted to drive the unit beyond minimum and maximum capabilities at some risk to the plant's stable operation.

if they are dispatched down in order to create up reserves. This cost should be included in the system operator's optimization of energy and ancillary service resources. No potential production will be sacrificed to supply frequency up-regulation if it is utilized at times when a facility is operating at less than full output due to system constraints (i.e.; is curtailed).[6] Downward frequency response does not require reduction in energy production to ensure the reserve energy is available, except for a few moments while responding to a rise in frequency. Frequency response from wind and solar plants can supplement system frequency down-response. In some systems the frequency response capability from renewables is a requirement but is utilized only when necessary.

The ability of storage to contribute to frequency response depends on the cycling capability of the storage technology. Pumped storage hydro can typically provide frequency response while generating. Pumped storage hydro can provide frequency response while pumping if it is equipped with adjustable speed pumps.[7] Battery storage can provide frequency response if the batteries can withstand second-to-second cycling duty. Flywheel storage is explicitly designed to only provide frequency regulation and AGC response. The frequency response from storage may be faster and more accurate than that provided by thermal generation and less total frequency response from other resources may be required when storage is used.

Some responsive loads may provide frequency response, either individually or collectively. This capability is highly dependent on the specific loads available for this service. While this technology is not commonplace today, opportunities may arise in the Islands for its development and use.

Frequency response is reduced when fewer responsive generators are online. Where responsive generation is taken offline to accommodate variable generation, frequency response (and AGC dispatch capability) may be insufficient to ensure the power system will remain operable through faults and contingencies. If frequency-responsive plants must remain online to support system frequency, or if reserves must be held on frequency-responsive plants to ensure there is head-room for frequency response, the system may be unable to accommodate the available energy from variable generation. The result can be curtailments of variable generation to allow the frequency-responsive plants to remain on-line. Such curtailments can be minimized by ensuring that all on-line units are frequency responsive including variable renewables. Regulation from wind plants and geothermal plants, along with storage and demand response, thus becomes important to avoid or minimize curtailments and ensure efficient system dispatch. Integrating any new generator into the system requires that the resources be coordinated to avoid individual resources being overburdened or unstable frequency response during disturbances.

Recommendations

1) All generators (thermal, hydro, geothermal, wind, solar, etc.) should be required to be capable of frequency response to the extent economically feasible.

[6] For instance, PV and wind might provide up regulation in a high penetration scenario where curtailment is necessary. During curtailment energy is being dumped by these plants and could be used for up regulation.
[7] Adjustable speed pump-hydro plant pumps or pump-generators significantly improve efficiency and stability and provide other benefits so are likely to be used in the Islands.

2) Frequency response should be specified in terms of droop. The time frame of the response should be defined.
3) Storage and demand response should be encouraged to provide frequency response capability to the extent that they are physically capable of doing so. System operators should utilize the least cost frequency response resources which may vary from hour to hour.
4) Compensation for direct and opportunity costs from resources providing frequency response should be considered.

AGC Dispatch Capability

Automatic Generation Control (AGC) sends signals every 4-6 seconds from the system operator to raise or lower the MW output of generators, storage devices, and (potentially) consumption of responsive loads in order to balance the system to within the control tolerance.[8] Maintaining frequency within acceptable bounds of the target value (generally 60 Hz) requires that AGC have sufficient resources under its control, with enough reserve capability, to increase or decrease the production to match demand on the system. AGC is used to control frequency while also optimizing the cost of generation by allocating energy requirements optimally among the dispatchable online resources. This optimization of costs is referred to as "Economic Dispatch".

A resource needs to accept the AGC control signals and respond in a predictable manner which can be modeled within the AGC program. AGC can keep the system within balance (i.e.; system within the desired frequency) only when there is sufficient responsive reserve capacity under its control to respond to any imbalance between generation and demand. For instance, when demand rises rapidly in the morning hours, generator outputs may need to increase fairly rapidly. Generator ramp rate capability is determined primarily by constraints such as long-term thermal fatigue, boiler control design combustion control design, and/or fuel constraints. Storage and demand response often have faster and more accurate ramping capabilities than thermal generators if designed to provide these services.

Advanced wind turbine generators and PV plants[9] can be designed to accept signals from an AGC system to reduce power output. Having an AGC system reduce wind or PV plant power output would be of great value during times where variable generation production is available and dispatchable plants are operating at low output to accommodate the variable generation and thus unable to provide significant down reserve. Up AGC response can be provided by advanced wind turbine plants and PV plants if they are operated below the maximum power that is available from the wind or sun. Normally, up AGC response from wind plants and PV plants would only be used under unusual circumstances and during certain times of day, such as high renewables output and relatively low demand and the resource is operating under a curtailment.

The ability of storage to provide AGC response depends on the cycling capability of the storage technology. Pumped hydro storage[10] can typically provide AGC response while generating. Pumped storage hydro may provide AGC response while pumping if equipped with adjustable speed pumps. Battery storage can provide AGC response if the batteries can withstand the minute-to-minute cycling duty and the controls incorporate this requirement. Flywheel storage is explicitly designed to only provide frequency regulation and AGC response.

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[8] The existing AGC systems may require modifications to be able to control storage and demand response resources.

[9] AGC from wind plants is commercially available. AGC from centralized PV plants could be implemented relatively easily. Retrofit cost, time frames, and capabilities need to be further examined.

[10] Deployment of a Pumped storage Hydro facility including planning, siting, permitting and construction will typically range from 4 to 6 years before operational.

Some responsive loads can provide AGC response, either individually or collectively. The capability is very dependent on the specific loads. Providing AGC response capability requires a remote telemetry and control interface between the control center's SCADA/EMS system and the resource. Wind and solar generators with appropriate control capability can accept power output set points from the AGC and hold those outputs so long as the setpoint is for a power output below the capability of the available wind or sunshine. An AGC system could "dispatch" wind turbine or PV generators during curtailment to maximize energy production from wind and solar while maintaining regulating reserve on thermal units and/or the wind plant itself.

Recommendations

1) All generators (thermal, hydro, geothermal, wind, solar, etc.) should be required to be capable of responding to AGC commands.
2) Each utility's AGC system should be modified to be able to utilize the full range of responsive resources (conventional generators, variable renewable generators, storage, and demand response) unless detailed studies demonstrate that this is not economically justified.
3) Storage and demand response should be allowed to provide AGC response to the extent that they are physically capable. If the device or generator interface and response capabilities support the necessary AGC response (i.e.; AGC interface is provided, the response is predictable, and within the appropriate time frame) the device or generator should participate in frequency regulation as well as economic dispatch under AGC control.
4) System operators should utilize the least cost AGC resources which will likely change from hour to hour during conditions when frequency is within specified tolerances.
5) Compensation for direct and opportunity costs for resources providing frequency regulation should be considered.

Spinning Reserve

Spinning reserve is fast-responding generating capability that is on-line and operating below its maximum output, or demand response or storage with similar capability, that is ready to respond to a sudden large mismatch in generation and load, typically caused by the sudden failure of a generator. Spinning reserve is discussed separately from regulation reserve and reserves that respond to AGC because it is unique in requiring a very large and fast change in generator power output. This requires that generators tolerate occasional large changes in power output. It also tends to require uneconomic operation of generators when the reserve is spread across multiple generators because multiple generators responding simultaneously can produce the needed power more quickly than can fewer generators each providing a larger share of the needed power.

Demand response is increasingly being used for spinning reserve in many regions of the mainland. In Hawaii, under frequency load shedding (UFLS) is often used very effectively to perform the spinning reserve function.[11] Spinning Reserve and Replacement Reserve are the two components of Contingency Reserves.

Spinning reserve is activated in either of two ways: through direct measurement of frequency and governor action or through response to system operator command. When the generator governor measures a significant drop in frequency, the output of the generator is increased quickly by the governor, in the primary response time frame, at a rate that is typically higher than the normal ramp rate available to AGC. Spinning reserve can also be deployed by the system operator. Because spinning reserve events are infrequent, the higher duty of a fast ramp is acceptable. Similarly, the relatively infrequent nature of contingency reserve response, coupled with the relatively short required response duration, makes it a good match for some responsive loads and storage.

Recommendations

1) All generators (thermal, hydro, geothermal, wind, solar, etc.) should be designed with spinning reserve capability with the best response practicable.
2) Storage and demand response should be allowed to provide spinning reserve to the extent that they are physically and economically capable.
3) System operators should utilize the least cost available resources for spinning reserves, which will likely change from hour to hour.
3) Compensation for direct and opportunity costs for resources providing spinning reserve should be considered.
4) The amount of spinning reserve required is generally determined by the largest single contingency (i.e.; largest online generator). Larger units or installations, while less expensive for the initial installer, will increase contingency reserve requirements and costs for the BA. Any added reserve cost should be considered when evaluating any new generation project.

[11] Historically the term "spinning reserve" has been used to refer to partially loaded generation that was online and "spinning". As new technologies have evolved that provide the same or superior response the term has changed to refer to the function being performed (reserves held for fast response) rather than to the technology (generation that is online and unloaded).

Replacement Reserve (Non-spinning and Supplemental Reserve)

Replacement reserve can be put on-line and ramped up quickly in the event of a generation shortage. In most power systems a portion of the contingency reserve may be carried as replacement reserves in lieu of spinning reserves. RSWG has defined two categories of such reserve: non-spinning reserve that can be on-line within 10 minutes and supplemental reserve that can be on-line within 30 minutes.

Some diesel generators can be started quickly and make excellent ten minute or 30 minute reserve. Combustion turbines can start and ramp up well within the time frame of supplemental reserve. Combined cycle plants may be designed to achieve a significant level of output within the supplemental reserve time limit, or started in simple-cycle mode to achieve the necessary replacement reserve startup time[12]

Ideally, some existing generation will be available to provide this service thereby avoiding the need to invest in generating equipment specifically for this purpose. For instance, older generators that are approaching retirement can be kept in a standby mode that allows for quick start-up. Older combustion turbines are a good example because of their relatively short start-up times. Backup generators can also be a good replacement resource. Demand response and storage can also be used for replacement reserve providing that it is available for the duration the replacement reserve will be needed.

While replacement reserve is typically activated relatively infrequently it may be required to operate for long periods. For instance, when spinning reserve is exhausted by a loss-of-generation event, the system no longer has protection against a second event and needs replacement reserve to be activated. Further, if load is shed to help cover a loss-of-generation event, that load will need to be restored as soon as possible through activation of replacement reserve. Demand response and storage resources used for replacement reserve must have sufficient response duration capability and be available in the same time frame as generation providing replacement reserves.

Recommendations

1) Utilities should consider the need for non-spinning and supplemental reserve in their routine generation planning.
2) All generators should be encouraged to provide non-spinning and supplemental reserve to the extent that they are physically capable (i.e.; ability to come online quickly or operate in standby mode).
3) Storage and demand response should be encouraged to provide non-spinning and supplemental reserve to the extent that they are physically and economically capable.
4) System operators should utilize the least cost replacement reserve resources which will likely change from hour to hour. Recognize that the total cost for providing replacement reserve is typically dominated by the standby cost rather than by the activation cost.
5) Consider compensation direct and opportunity costs for resources providing replacement reserve should be considered.

[12] Such plants may not reach full power within 30 minutes, but can provide significant and helpful output within that time frame.

Reactive Power and Voltage Regulation

The transmission system requires reactive power to control power system voltages. Reactive power must be injected at multiple locations across the system to assure an acceptable voltage profile; voltages cannot be effectively controlled by injecting reactive power into electrically remote locations. The amount of reactive power required at a given location increases when transmission lines in that area are heavily loaded and determines the voltage at that location. Reactive power requirements change as power system conditions change. Voltage profiles within acceptable limits are essential to reliability and power quality thus requiring the reactive power injection to be controllable.

Reactive power can be supplied by a number of different resources. Capacitors can be switched on and off to adjust the reactive power injection for voltage support or reactors can be switched on or off to help control over voltages. However, mechanically switched capacitors/reactors cannot be switched quickly and frequently and create large switching transients in weak systems because they are discrete controls for relatively large blocks of reactive power. The effective reactive power will be dependent upon the voltage level of the system. Where quick and/or continuous changes in reactive power are needed, a variable (continuous) source of reactive power is required. Conventional generators and most advanced utility scale wind generators can provide controllable reactive power and are ideal reactive power sources because the incremental cost of providing reactive power is modest. Many storage devices and inverters can be designed to provide controllable reactive power.

Where controllable reactive power injection is needed to regulate voltage and there is no generation in the area, a combination of switched capacitors and a static var compensator (SVC), static synchronous compensator (STATCOM), or synchronous condenser can be installed. The SVC or STATCOM uses power electronics to control the reactive power it injects into the system. A synchronous condenser is essentially a conventional synchronous generator without the prime mover (engine or turbine).

The ability of storage to provide reactive power and voltage regulation depends on the storage technology.[13] Pumped hydro storage typically utilizes synchronous generators and can provide the same reactive power and voltage regulation capabilities as other conventional generators while it is generating. Pumped storage hydro can also provide the same reactive power and voltage regulation capabilities while pumping if it utilizes a directly connected synchronous motor to drive the pump. Storage technologies that utilize power electronics (battery, flywheel, and variable speed pumped hydro storage, for example) can provide reactive power and voltage regulation capabilities similar to that available from a STATCOM if they are designed to do so.[14] The technical ability to provide reactive power and voltage regulation capabilities from power electronics based storage at any instant in time is typically independent of the real-power charging or discharging that is simultaneously occurring. Many pumped storage hydro plants can also provide reactive power and voltage regulation capabilities when they are not either pumping or generating by allowing the turbine to spin in air (dewatering the turbine)

[13] Some loads may also be capable of providing reactive power and voltage regulation capabilities. These would typically be large adjustable speed motor drives.

[14] The power electronics typically need to be somewhat oversized (and somewhat more expensive) so that the storage device can provide full reactive capability at the same time it is either fully charging or fully discharging.

and operating the generator as a synchronous condenser. Providing reactive power and voltage regulation capabilities while not either charging or discharging does require that the storage device remain on line when it might otherwise shut down completely and this may incur additional costs.

Because reactive power requirements are much more location specific than real power requirements it may be appropriate to site storage devices based on where the reactive power and voltage regulation capabilities are required even if the storage device will primarily be used for energy arbitrage, frequency regulation, AGC, or spinning reserve.

When a generator is "must-run" because it is needed to provide controllable reactive power at its location, capacitors and an SVC or STATCOM (or appropriate storage device) should be evaluated as an alternative to cover that need and allow the generator to be dispatched in merit order.[15] This may reduce overall system cost and avoid curtailment of as-available generation.

Recommendations

1) *All generators (thermal, hydro, geothermal, wind, solar, etc.) should be required to be capable* of providing reactive power and controlling voltage in response to system operator commands.
2) Storage should be encouraged to provide reactive power and voltage regulation. This may influence where storage is installed on the power system to make best use of the reactive power and voltage regulation capabilities. If storage must remain on line just to provide reactive power and voltage regulation is should be compensated for doing so.
3) Alternative sources of controllable reactive power should be considered to reduce operating cost where reactive power needs would otherwise require out-of-merit order or must-run operation.

[15] In some cases it makes economic sense to install a clutch to disconnect the generator from the engine or turbine and operate the generator as a synchronous condenser thus saving the fuel costs for the must run generator.

Short-Circuit Current

Faults or "short-circuits" on transmission lines and in transformers must be detected quickly so protection can remove the faulted element before grid instability occurs, generators trip, or additional equipment is damaged. Protection is done with "relays" that monitor current or current and voltage. Short-circuit current must be sufficient to operate the protection. In addition, systems with low short-circuit current experience low voltage or dips during motor starting and have difficulty providing starting energy for large motors such as water pumps and pumped storage facilities.

Where short-circuit currents are low, certain protection types that require less current can be used to ensure fast detection of short-circuits. For instance, "distance" or "impedance" protection can operate securely at much lower currents than "overcurrent" protection. These types of relays are only useful on transmission or sub-transmission circuits. However, there are short-circuit levels in both transmission and distribution systems below which protection will become difficult.

Conventional generating plants that use synchronous machines provide short-circuit current that is about five times their maximum load current. Fossil and biofuel plants fall into this category as do geothermal plants that use synchronous generators. Standard design PV plants provide little more than their full load current and then only for remote faults that do not cause them to shut down. Most current wind plants provide very little short-circuit current.

Storage plants that use conventional synchronous machines will provide short-circuit current while in both pumping and generating modes. However, the most efficient and responsive pump hydro plants use adjustable speed technology much like some advanced wind turbine generators and as typically designed provide very little short-circuit current. The Adjustable speed converter can be designed to deliver some short-circuit current. Synchronous condensers, essentially a synchronous generator without a turbine, can provide short-circuit current.[16] Battery and flywheel based storage devices use power electronics and provide similar short circuit performance as PV and wind.

Recommendations

1) Low short-circuit current problems due to increased penetration of renewable resources should be monitored and appropriate remedial action taken.
2) As more generators that provide little or no short-circuit current are installed, problematic protection should be changed to a type that requires lower short-circuit current.
3) Motor-starting or voltage flicker should be monitored at both the transmission and distribution levels for adverse impacts due to the increased penetration of renewables.
4) When energy storage is considered for its many benefits, the short-circuit contribution of pump-hydro systems should be taken into consideration.

[16] Pump hydro generators or pump-generators are often designed to operate as synchronous condensers to provide inertial and reactive power and voltage regulation. Water in the turbine cavity is pushed below the turbine blades with compressed air to allow the blades to spin freely.

Black Start (System Restoration Service)

Grid restoration following a complete blackout depends on generating plants that can start and energize transmission lines and provide start-up power to other plants. In order to provide system restoration capabilities, a generator must be able to self-start (i.e.; provide its own startup power without requiring power from the grid), energize a "dead" bus, and have sufficient response capabilities to control frequency and voltage during the restoration process. The number of black start plants necessary in a system will depend on the system configuration and location of the plants relative to larger generating resources to which power needs to be provided. Utility studies are conducted to plan grid restoration and determine the equipment requirements necessary for prompt restoration. This includes the location, capability, and number of black start generators. For reliability purposes the minimum number of generators with black start capability is three to allow for forced outage of one plant while another is down for overhaul. The re-start time of generators that will be used for system start-up is important. Other considerations such as weather-related events, geologic events, etc may factor into the decision as to the prudent number and location of black-start generating units.

Conventional wind and PV plants cannot presently provide black start service but have the advantage that they require little or no power from black start plants for their own start-up.[17]

Central energy storage plants based on pump-hydro or batteries are potential candidates for black start service if appropriately located and designed.

Recommendations

1) Utilities should file their restoration plans with the PUC.
2) System black start capability needs should be based upon the utility's restoration plan
3) When energy storage is considered, its black start benefit should be evaluated.

[17] Such plants generally require only that the grid be energized at their location by black start plants.

Excess Energy

High penetrations of wind and solar generation can result in times when generation exceeds demand. This already occurs at night on the HELCO and MECO systems due to excess wind generation and minimum load constraints from the thermal generators. Daytime excess energy is also possible in the future if there is high solar generation penetration. Excess wind and solar generation does not pose a reliability problem since the excess energy can always be curtailed (this however, is not presently true for the majority of distributed PV installations). Curtailment represents an economic loss to both the owner and utility customer and also an economic opportunity with three potential solution areas. First, the conventional generation fleet can be designed and operated to minimize wind and solar curtailment through low minimum demand and increased ability to cycle off. Second, storage can be used to absorb the excess wind and solar generation and return it to the power system when net demand increases and ideally during the hours when demand is highest. Third, some loads may be able to be designed to utilize the excess energy by increasing consumption during times of low net demand. The economic viability of both the storage and demand response solutions depends in part on the expected amounts and timing of excess energy, along with the costs of each storage and demand response technology. It may be useful to publicize excess energy expectations for years in the future to provide an opportunity for storage and DR developers to propose solutions.

Recommendations

1) Evaluate and publicize excess energy expectations based on demand and generation forecasts for five to ten years into the future.
2) Consider developing energy pricing tariffs for both storage and demand response to encourage investment in technologies that reduce or eliminate power system minimum demand problems.
3) Consider developing energy pricing that reflects the true marginal cost of energy, especially during curtailment periods.

December 18, 2012

Consumer Advocate's Comments to the RSWG Work Products and Recommendations Presented at the December 11, 2012 Meeting

The Consumer Advocate respectfully offers the following comments to the RSWG work products and recommendations presented and voted on at the December 11, 2012 meeting. In general, the Consumer Advocate supported a majority of the work products and recommendations presented at that meeting, as it has been acknowledged that although much *work has been conducted within the RSWG process, additional work is still necessary to further* develop these work products and recommendations to address various issues.

The two RSWG work products and recommendations that the Consumer Advocate abstained upon are related to: (1) the Reliability Standards Drafting ("RSD") Subgroup recommendations for the Standards development framework; and (2) the Minimum Load and Curtailment ("MLC") Subgroup recommendations concerning central generator station ancillary service supply capabilities in a renewable based grid.

1. RSD Recommendations for the Standards Development Framework.

Primarily, the Consumer Advocate abstained from voting on this RSD recommendation, as the issues relating to the Framework extends beyond the scope of the RSWG proceeding. The Consumer Advocate recognizes that a process will need to be considered related to the proposed standards developed in the RSWG process, as well as the relationship of those standards to the functions of the Hawaii Electricity Reliability Administrator ("HERA"). However, when the role of HERA is considered in relationship to the proposed standards, issues such as ratepayer costs, identification of who will be responsible and accountable when the standards are implemented, to name a few examples, will need to be addressed and such considerations will be the subject of another proceeding.

2. MLC Recommendations Concerning Central Generator Station Ancillary Service Supply Capabilities.

Primarily, the Consumer Advocate abstained from voting on the MLC recommendation, as it believes that the paper did not evenly address the issue of compensation to the developers as offered by the Consumer Advocate's suggested language to the draft paper. The Consumer Advocate appreciates the efforts of the MLC Subgroup and the drafters of the paper to include several of the Consumer Advocate's proposed revisions and comments, especially the inclusion of language recognizing that additional analysis and evaluation must be conducted before implementing the recommendations. However, the Consumer Advocate contends that any consideration of compensation of direct and opportunity costs for ancillary services must include consideration of system charges to those resources that are only able to provide individual ancillary services or can only provide these services on an intermittent basis. The consideration of systems charges is necessary to mitigate impacts to ratepayer cost and quality of service to provision the other ancillary services that resource is unable to provide or cannot provide on demand.

Reliability Standards Working Group
Hawaii PUC Docket No. 2011-0206

DEMAND RESPONSE AS A FLEXIBLE OPERATING RESOURCE

By: The RSWG Demand Side Options Subgroup [1]

I. Introduction

This white paper reviews the opportunity for Hawai`i's utilities to obtain additional operating flexibility via the use of flexible demand-side programs. The use of loads to provide electric utility market products (e.g. capacity, energy, and ancillary services) is known as "demand response." The capital cost associated with demand response is typically much less than the capital cost associated with constructing new generating plant. For Hawai`i in particular, where construction costs for new capacity are very high relative to the U.S. mainland, demand response resources' capital costs may be an order of magnitude less expensive than new generation (i.e. 100's of dollars per kilowatt for demand response, versus 1000's of dollars per kilowatt for incremental generation additions). The cost to use the reserves (dominated by the energy opportunity cost) may be much lower as well, especially for ancillary services. Further, demand response resources can provide a high level of operating flexibility, which when combined with the existing generation mix, can allow greater penetration of intermittent renewable energy resources. Thus, a thorough and aggressive investigation of the potential for all types of demand-response should be a priority for all stakeholders.

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This white paper provides a potential path that would allow a rollout of demand-side programs with increasing complexity as time goes on. One possible next step for the Commission would be to open another investigatory docket that is designed to make specific recommendations regarding demand response as discussed herein. However, there may also be opportunities for stakeholders to jointly present to the Commission demand-side type programs that could be implemented quickly.[2]

II. Goals for Demand Response in Hawai`i

The Hawai`i utilities and third party providers seek to significantly increase the amount of renewable energy produced in the state, reduce renewable energy curtailments, and maintain a

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[2] This could also include the upgrading of existing demand response programs to enhance the speed of communication and bandwidth for 2-way control.

high level of system reliability at affordable prices. To this end, they need to use all available energy options to manage supply, demand, system operations and energy costs effectively. Demand response could play a role in meeting Hawai`i's electric system operational objectives:

1) Reduce total kWh consumed to reduce oil imports (e.g., through efficiency including always-on building commissioning and more efficient, rationalized end-use operation with flatter load factors);
2) Reduce peak loads (in 5-9 pm period) to reduce the amount of fossil generation required for contingencies and demand or PV variability (e.g. through lower on-peak AC, water heater, refrigeration and pool pump usage);
3) Build off-peak loads to increase consumption of minimum load generation and reduce wind curtailments (e.g., through building and device pre-cooling or pre-heating);
4) As distributed PV generation and penetration increases on many feeders and expands across the HI island grids, reduce the impact of variability and volatility of PV ramps by integrating PV operation with end use loads, offsetting and absorbing much of the fast ramps against host building or same-feeder loads and distributed storage (possibly including end uses as storage media), so the bulk power system sees slower net ramps with less magnitude and speed;
5) Use utility-dispatchable and automatic (e.g., demand-side equivalent of Automatic Generator Control and frequency droop response), automated load control to deliver fast ancillary services (frequency management, up-regulation and down-regulation, spinning reserve) without burning fossil fuels in a boiler;
6) Use utility-dispatchable and automatic, automated load control (responding in the same frequency range as generator governor response and ahead of, but coordinated with, the utility's current under-frequency load shedding schemes), and eventually, spinning reserve to protect system frequency;
7) Use utility-dispatchable demand response as a bridge under contingency conditions while waiting for utility emergency diesel generators to come on-line.

Keep in mind that demand response is only a tool and does not always lower cost or increase renewable energy usage. However, demand response options have the potential to create value for Hawai`i's ratepayers and therefore should be investigated to meet the objectives listed above.

III. Pre-Requisites for Demand Response Programs

There are several prerequisites for tapping demand response:

The prerequisites for accessing demand response as a resource include a clear system objective and need, loads that are responsive, a control scheme, measurement and verification (and baseline) methodology, and adequate customer/program participant compensation.

1) *Define the Objectives*: The demand response program resource must serve the utility system objectives (as reviewed above) and customers' energy management and/or economic needs.
2) *Identify Responsive Loads*: the ability of demand side programs to deliver the reliability products required in Hawai`i will depend upon the types of customer end-use loads and customer-owned generators in Hawai`i and whether those can

feasibly be used to respond to relevant price and/or system conditions.

3) *Control Scheme*: There must be an ability to use these resources in the manner required to achieve the desired objectives (i.e., manage, control, and coordinate). The level of technical sophistication required to achieve a specific objective can vary from very simple (e.g. phone call, text message, email) to very complex (e.g. under-frequency relays, full supervisory control and data acquisition ("SCADA") or SCADA-like control and communication functionality). It is also possible to achieve automation of demand response via installation of a control interface between the utility demand-response automation system and the customer's existing Building Management System ("BMS").
4) *Measurement and Verification ("M&V")*: It is necessary to quantify or measure the contribution of the demand-side resources in meeting the program objectives. Required solutions may range in complexity from interval meters that can record 15-minute consumption and store the data for later analysis, to near-real time, two-way communication between the resources and the system operator via utility-grade telemetry. The M&V scheme also needs to identify a "baseline" load profile for the customer, against which the customer's actual demand during a demand response "event" can be compared in order to determine performance. Statistical sampling may be appropriate for some types if demand response verification.[3]
5) *Compensation to the Customer/Program Participant*: Finally, demand response program design and compensation should be based on the value of specific capacity, energy and ancillary service products, or the cost of providing such capacity, energy or ancillary services by other means. Many demand response options can be competitive – including both program implementation and customer compensation costs – when compared to the costs of generation or storage options for capacity or ancillary services.

While not a prerequisite per se, the adoption of advanced meters, communications systems, and smart grid technologies can facilitate real-time demand-side options for Hawai'i. Large and small loads offer different load profiles and flexibility options and should be tapped to provide differing demand response services; these possibilities could be unlocked with smart meter systems.

IV. Implementation of Demand Response

There are several mechanisms for implementing a change in customer loads in a way that provides value within a power system. Three will be discussed here: pricing, manual demand response, and automated demand response.

a. Time-Based Pricing Programs

Time-based pricing programs can influence customer behavior.

One of the easiest ways to induce the behavior of customer demand is through electricity pricing. If the utility wants the customer to use less during a certain time period, the utility would charge more for electricity during that period; to encourage higher consumption in other periods, the electricity rate would be lower in those periods. These retail rates are tailored for different classes of customers.

[3] DR resources used to provide ancillary services may not need the baseline if the events are fast and short.

There are three basic types of pricing models[4] that can be used to incentivize customer behavior:

1) *On-Peak / Off-Peak Pricing*: In this model, the customer sees two prices, one price for "on-peak" time periods and another price for "off-peak" time periods. The time periods vary depending on the system load characteristics. Another variation of on-peak / off-peak pricing is "critical peak pricing" ("CPP"), in which the "on-peak" period is very short (usually temperature-driven) and the Critical Peak price is very high. These prices can vary according to system conditions, with day-ahead or hour-ahead warnings of extreme peak conditions and prices.
2) *Time of Use Pricing ("TOU")*: TOU pricing is similar to on-peak/off-peak pricing, but with several time periods across the day. TOU pricing applies to fixed periods with fixed prices that do not change (other than by season). TOU pricing may also be used to encourage the use of curtailed energy at a reduced price to customers who are willing to increase loads at the time of potential curtailment.
3) *Dynamic or Real-Time Pricing ("RTP")*: In an RTP program, energy prices change hourly as a function of power system load and generation conditions, with some limited notice of price levels to the customer. RTP programs vary in terms of notice provided to the customer, but a typical program might determine the day-ahead price schedule as the system operator plans unit commitments for the following day, and send that price schedule to the customer before the start of the day when it applies. Other programs allow prices to vary hourly or every ten minutes in near-immediate response to current operating conditions with hour-ahead or ten-minute-ahead notice.

If Hawai`i chooses to use pricing programs as one method to drive its demand response programs, those price patterns should be tailored to each island's load and generation patterns and the incremental costs of utility-owned and purchased generation. Interval metering ("smart-meters") is the tool that is almost always used to measure the customer's electricity usage during the various pricing periods in time-based pricing programs, with the usage in appropriate pricing period applied to the time-based rate for that same time period to compute the bill. And while it is proven that customers modify their electricity usage in response to well-designed time-of-use and dynamic rates, it may take some time to determine the most appropriate rates for Hawai`i. Details of production costing, generation contracting, and retail price design complicate developing economically efficient pricing programs. Note also that time-based rates do not give system operators any direct control over customers' energy usage.

If Hawaii chooses to use pricing programs as one method to drive its demand response programs, those price patterns should be tailored to each island's load and generation patterns and the incremental costs of utility-owned and purchased generation.

[4] In a presentation to the RSWG group on October 23, 2012, time based pricing was divided into dynamic and static TOU pricing. The category "on-peak/off-peak pricing" (e.g., CPP) may be confused with TOU pricing which is also on-peak/off-peak pricing. However, CPP is dynamic, meaning that the price and timing during the day are dependent upon system conditions and not set daily periods, as is TOU pricing.

There is typically no penalty associated with a customer's failure to reduce loads in the desired time periods, other than the higher price that the customer incurs for having demand during the higher priced time periods.

b. Manual Demand Response Programs

In a manual demand response program, the system operator asks the customer to take a specific, pre-agreed curtailment action via some kind of communication (e.g. phone call, text message, email, fax, etc.) when the system operator requires the response for reliability or economic reasons. Based on the scheduled demand response "event", it is then up to the customer to take action necessary to comply with the system operator request. The advance notice for a program of this type can range from day-ahead, hours, or minutes. In this instance, the utility does not have any direct control over the customer's actions.

In a manual demand response program, the system operator asks the customer to take a specific, pre-agreed curtailment action. It is up to the customer to take action necessary to comply with the system operator request.

In a program of this type, there is typically an after-the-fact verification that the load responded as desired (using interval metering with remote communication capabilities). There is typically a baseline of some type established for the customer, against which the actual load is compared for purposes of determining the customer's performance during an event. This type of program can be designed to include penalties for non-compliance, which might range from reduced compensation all the way to making the customer ineligible for continued participation in the program.

An important consideration of a manual demand response program is customer compensation. The amount of compensation is a balance between the value of the customer's response during an event, versus an amount of compensation that will make it worth the customer's time and effort to participate and implement curtailment during called events. In some areas, the customer is paid a reservation fee (essentially a capacity charge) whether an event is called or not, with additional compensation for responding adequately to an actual event. Few demand response programs pay customers only for responding to events.

c. Automated Demand Response Programs

In an automated demand response program, the particular load that is participating in the demand response program is outfitted with communications and control equipment that allows the utility system operator to signal the load to automatically cut back or turn off (and later, to turn on again). In an automated demand response program, manual action on the part of the customer is not required. The load curtailment can also be automated to respond directly to price signals, frequency or voltage levels.[5] The above measures could be tied to an Interruptible Rate schedule to promote participation.

[5] Manual and automated demand response programs can exist in the same program. For example, the Fast DR pilot program currently being implemented at HECO and MECO has both an auto DR and a semi-auto DR phase. The semi-auto DR phase involves sending a DR signal via phone, text, or e-mail message to the facility manager who

In an automated demand response program, the particular load that is participating in the demand response program is outfitted with communications and control equipment that allows the utility system operator to signal the load to automatically cut back or turn off (and later, to turn on again).

Direct load control of retail loads such as air conditioners, water heaters and pool pumps are the long-standing examples of simple automated demand response; more sophisticated programs have been developed to exploit commercial and industrial customers' energy management systems. Simple direct load control programs do not require interval meters nor extensive measurement and verification programs, and customer compensation could be as simple as a standing discount to the participant's monthly electric bill.

HECO has successfully implemented several automated demand response programs, including a residential hot water heater program that has under-frequency responsive capabilities. Further, as was reported to the RSWG in its meeting on September 18-19, 2012, HECO is actively working with Honeywell to put into place the architecture to implement additional automated demand response capabilities.[6] HECO and MECO programs are pilot project efforts.

The logical rollout sequence for demand-side programs is to first go after customers who offer the largest amount of flexible load. However, a comprehensive smart grid deployment strategy should also consider the potential for the aggregation of smaller flexible loads (this speaks only to the *ability* to aggregate those loads, not *who* aggregates those loads). Smaller flexible loads, aggregated into demand-side programs may actually offer greater flexibility than do larger loads. The opportunity cost for many small loads to provide spinning reserve is very low so they often are a very attractive source for aggregation to provide spinning reserve.

V. Customer-Side Implementation of Demand-Response

a. Load Control

Industrial customers (most of which in Hawaii would be located in the HECO system) and municipal and agricultural pumping loads (located throughout the islands) may have extensive DR capabilities.

The types of demand response best suited to a system depend on the system objectives for demand response, the types of customer loads, and the customers' level of sophistication about energy costs and management options. Customers who actively manage their operations are usually better candidates for more sophisticated time-based programs because these customers are accustomed to scheduling their operations in a way that

manually activates the building automation system (BAS), which automatically initiates load reductions via a Schema programmed into the BAS.

[6] As of the date of this white paper, HECO has signed contracts with 13 Fast DR Pilot program participants. MECO has 4 semi-auto DR participants. Total = 17.

reduces their energy costs and improves their profit margins. Industrial customers (most of which in Hawai`i would be located in the HECO system) and municipal and agricultural pumping loads (located throughout the islands) may have extensive DR capabilities. More simplified time based pricing programs may or may not be effective among residential customers and can't be offered until advanced meters have been deployed. Fully automated programs can be effective for residential customers, especially for providing ancillary service where the required response duration is typically relatively short.

As one moves into manual programs, again the level of sophistication is correlated to the sophistication of the customer. In Hawai`i, candidates for manual demand response might include water pumping customers and perhaps resorts and hotels, to the extent that they have some degree of flexibility with their loads (e.g. laundry operations).

Automated programs can be more broadly applied, provided that there are end-uses embedded in the load curve that can be modified using active control by the system operator. Water heaters, pumps, air conditioners, refrigeration and those types of loads may be candidates for active control in Hawai`i. Automated response to frequency events can be especially attractive since the response can be very rapid and yet the required response duration is typically shorter (minutes rather than hours). Because Hawai`i's electric systems are isolated and all imbalance results in frequency error, reconnection or restoration of frequency-responsive demand should be coordinated by the system operator to ensure reserve generation is on-line and available to serve it, (which cannot be determined solely by the system frequency measurement). If reconnection occurs before generation is available to serve it, there could be additional low-frequency events.

b. On-Site Generation and Energy Storage

Customers can also provide demand response through operation of on-site, behind-the-meter generating and storage resources, provided that such generators can be controlled in a manner consistent with the demand-response program parameters, and that they comply with environmental and other applicable regulations. For example, some customers may operate fleets of standby generators that could operate within a demand response program as part of the standby generator's periodic testing program. Energy storage technologies such as batteries can also provide demand response. Eventually electric vehicles may provide significant opportunities for storage, demand response, and/or price response. Automatic or scheduled demand response can be used for thermal energy storage by pre-heating water heaters, pre-cooling buildings, or pre-cooling freezers and refrigeration units, to shift load to off-peak periods and absorb a portion of minimum load generation. An additional emerging customer-side resource option is the microgrid. In a microgrid, the customer load, energy generating resources and storage resources are operated as a contained system (in effect by creating a mini balancing area). A microgrid operated in parallel with the larger utility system can in certain circumstances, in addition to allowing for scheduled interchange between the utility and the customer microgrid, provide demand response and ancillary services.

VI. Use of Demand Response and Storage to Provide Ancillary Services

The RSWG Ancillary Services study being performed by General Electric ("GE") through Hawaii Natural Energy Institute ("HNEI") points out the potential for using demand response and energy storage to provide ancillary services. According to the November 20, 2012 draft GE report: "... GE identified and summarized in a table which generation, transmission, ***storage and demand-side*** technologies are able to provide each ancillary service given current technology capabilities and fuel availability, without screening or limiting the options with respect to economic cost-effectiveness. As requested, GE generally limited technologies to those that are available in commercial or pilot applications today ..."[7] (emphasis supplied). Table A.3-3[8] of the GE draft report identifies commercially available demand response technologies that can provide the following ancillary services: frequency response, regulation, spinning reserves, non-spinning reserves and replacement reserves. The same table shows emerging energy storage technologies that can provide multiple types of ancillary services as well.

The RSWG Ancillary Services study being performed by GE points out the potential for using demand response and energy storage to provide ancillary services.

Specific points and recommendations from the November 17, 2012 draft of the GE report include:

1) Many [system] operators such as ERCOT allow storage to participate in arresting the frequency decline (ERCOT FRRS). Many [system] operators including PJM and ERCOT allow demand response (ERCOT LAaR) to participate in frequency response." [9]
2) "... storage as well as DR should be allowed to provide primary frequency response and spinning reserve."[10]
3) "Operators (for example, PJM) allow Curtailment Service Providers (CSP's) that bid demand reductions into the Regulation Market. Demand response also provides regulation in MISO. Enbala Power Networks enables large electricity user to participate in the regulation market." [11]
4) "[..] a recommendation is to allow LESRs [Limited Energy Storage Resources] and DRs [demand response] to provide frequency regulation service."[12]
5) "If the existing capacity is insufficient or uneconomic [to provide spinning reserves], then other means of obtaining spinning reserves (for example, from battery storage and DR) should be explored."[13]

GE: "Storage as well as DR should be allowed to provide primary frequency response and spinning reserve."

[7] *Ancillary Services Definitions and Capability Study*, Draft Final Report For Hawaii Natural Energy Institute, GE Energy Consulting, November 20, 2012, p 12.
[8] Ibid. p 13.
[9] Ibid p 19.
[10] Ibid p 20.
[11] Ibid p 21.
[12] Ibid p 21.
[13] Ibid p 27.

6) "If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider potential solutions that could alleviate the deficiency or allow the system to operate in a more efficient manner. Solutions may include ... New resources ... storage, demand response ..."[14]
7) "Consider potential solutions to alleviate deficiencies and improve system efficiency [...] Adjustments to operating procedures: Activation thresholds for DR, [...] New resources: [...] storage, demand response ..."[15]
8) "In addition to the economic viability, consider the risks associated with pursuing the respective path. Consider items such as: [...] Challenges associated with monitoring / controlling DR participation on a centralized basis." [16]
9) "Demand-side participation and programs can be used to provide certain ancillary services, like operating reserves, but the grid operator needs to have control over those resources on a centralized basis. Preferably [this is accomplished] via physical control such as demand response switches." [17]
10) "Load shaping programs such as electric vehicle charging schedules, may be implemented to help shape the system load and thereby make planning for ancillary service deployment easier."[18]
11) The GE report references a presentation entitled "Opportunities for Mass Market Demand Response to Provide Ancillary Services, October 2011, by Robb Pratt (Pacific Northwest National Laboratory) and Dave Najewicz (GE Appliances). [19]

Frequency responsive demand response can be faster and more reliable that obtaining reserves from generation and does not necessarily require high-speed communications. Obtaining ancillary services from demand response can also reduce renewable generation curtailment by allowing conventional generators to operate at lower loads or to be turned off during low net-load periods.

VII. Demand Response Program Components

There are several business components common to all demand response programs. These affect the business models available to deliver DR.

The design of a demand response program is driven by the system's need for resources (e.g. energy, capacity, and/or ancillary services) and the potential of the system's customers and end use loads to provide demand response of differing types.

1) *Program Design*: Prior to designing a program, there should be a clear understanding of the system objectives. Therefore, the program proposal should include an assessment of the potential ability of the demand response program to meet these objectives, and if program

[14] Ibid p 31.
[15] Ibid p 31.
[16] Ibid p 32.
[17] Ibid p 36.
[18] Ibid p 37.
[19] Ibid Appendix H, Reference No. 20. This presentation can be found at: http://www1.eere.energy.gov/analysis/pdfs/opportunities_for_mass_market_dr_for_as_rob_pratt_pnnl_and_dave_najewicz_ge.pdf

costs can be reasonably estimated (e.g., based on the results of a pilot program), program cost-effectiveness should also be presented. The design of a demand response program is driven by the system's need for resources (e.g. energy, capacity, and/or ancillary services) and the potential of the system's customers and end use loads to provide demand response of differing types. This is a decision that is best made involving as many stakeholders as possible and is one that ultimately must receive regulatory approval. One of the tasks of the ongoing Reliability Standards Working Group is to develop recommendations to the Public Utilities Commission regarding the type of resources that are needed in Hawai`i power markets in order to meet the State's energy policy goals of larger penetration of renewables.

2) *Customer recruiting*: Once a demand response program is designed and approved, customers must be recruited to participate in the program. This is largely a marketing function that could be performed by the utility, by third party curtailment service providers, or possibly by a third party administrator. For maximum participation, it is important that this role be filled by someone with both the understanding of the benefits and obligations associated with a demand response program *and* the requisite marketing and sales skills.

Almost all of the demand response program components could be outsourced to third parties.

3) *Customer program enrollment and customer relationship management*: When a customer agrees to sign up for a demand response program, there must be a way to register the customer into the program, to register the responsive load that the customer is providing and to record the details that will be required to ensure timely settlement with the customer for successful participation. Further, after enrollment the customer needs a point of contact with respect to the demand response program. Several types of parties can perform these tasks. To the extent that the utility performs this task, then appropriate changes must be made to the utility's Customer Information System ("CIS"), Customer Relationship Management ("CRM") and billing systems. To the extent that a third party performs this function, if the third party brings its own CIS and CRM platforms into play, then there must be appropriate integration between the third party systems and the utility systems. There are a number of third party providers that provide these capabilities.

4) *Load Provisioning*: After the customer is enrolled, the customer's load must be provisioned to participate in the demand response program. For a time-based pricing program or a manual demand response program, provisioning might be as simple as providing the customer a web-based platform for monitoring its own performance. In the case of an automated program, provisioning consists of installation of hardware (e.g. relays, load shedding equipment, interfaces with customer-owned building management systems, under-frequency relays) and communications capabilities at the customer site. Provided that the technology specifications and communications protocols are open

Because demand response is an active, operational resource, the operator of the balancing area must be the entity that performs the scheduling and control of demand response events.

and non-proprietary, there are a number of third parties that perform these provisioning tasks as a service to utilities and load-side aggregators.

5) *Scheduling / Operations*: Because demand response is an active, operational resource, there must be centralized control and coordination of the operation of demand response programs to ensure their coordination with grid needs. The operator of the balancing area typically calls demand response events to meet specific system needs, particularly with respect to use of the loads to provide ancillary services. Thus, the scheduling and operation of demand response programs must remain with the system operator – although third-party intermediaries can receive that curtailment signal and deliver aggregated customer curtailments consistent with the parameters of the program. Indeed, in demand response programs that provide real-time products (e.g. ancillary services like operating reserves, frequency response, etc.) a decision must be made to as the minimum size load that can participate in the program, or if smaller loads can be aggregated into larger groups that can participate. To a large extent, the minimum load size is a function of the technical provisioning requirements for the load and the cost of meeting those requirements.
6) *Measurement and Verification ("M&V")*: After a demand response event has been called, there must be a way to measure and verify that the customer did actually provide the desired response. In the case of real-time demand response products, the M&V may be provided via telemetry and the system operator has the ability to see the performance of a customer in real time.[20] In the case of time-based pricing programs and manual demand response programs, the M&V function will most likely be performed after the fact. This function can be performed by the utility, using its meter data management ("MDM") system to automate the collection, validation, and analysis of the metered data. However, the M&V function can also be performed by qualified third party "meter data management agents." In fact, it is quite common (especially in energy efficiency performance contracts) to have a third party perform the M&V function. In some cases, the M&V function may be based on a simulation using actual after-the-fact data but applied to the class or type of load to determine customers' DR responses.
7) *Settlement*: The final function in a typical demand response program is settlement with the customer. In some cases, the settlement with the customer may be in the form of a credit against a power bill. In other situations, settlement may require an actual separate payment to the customer. For most DR programs, the utility can perform all DR settlement calculations. Ultimately, there must be a central clearing authority for these settlements. In Hawai'i, that function best resides with the system operator. However, in some circumstance, it may be acceptable to have intermediaries between the central clearing agent and the participating customer.

All of these DR program components can, in principal, be outsourced with the exception of the Scheduling/Operations component.

[20] In the case of a program with multiple participants, it is unlikely that the system operator would want to see anything other than the aggregate response from the demand side resource. Statistical or other aggregate monitoring techniques may prove to be the most reliable and cost effective means to monitor the aggregate response. There would also likely be a need to audit, after the fact, the actual response of the individual loads.

VIII. Demand Response Business Model Options

It follows from the inherent flexibility in the delivery of demand response functions, that there are a number of different business models that can be utilized. Business models are not mutually exclusive. It is a matter of policy and efficiency as to the appropriate business model for a program and/or service territory. Several business models are discussed here.

1) *Utility Managed*: Under this model the utility provides all program functions and roles internally.
2) *Utility Managed – Outsourced to Third Party:* Some utilities are outsourcing the management of demand response programs to a third party contractor – for instance, curtailment services providers deliver direct load control and diverse energy management services across much of the Northeast, Southwest and California. The Hawaiian Electric Companies currently outsource much of the recruiting, enrollment, and provisioning elements of its existing programs. The exception is the Direct Load Control ("DLC") program element of the Commercial and Industrial Direct Load Control ("CIDLC") Program for which Hawaiian Electric currently performs all of the functions itself.

Demand response business models are not mutually exclusive. It is a matter of policy and efficiency as to the appropriate business model for a program and/or service territory.

3) *Curtailment Administrator*: Hawai`i has separated energy efficiency programs and utility operations, creating a third party Energy Efficiency Administrator. A similar model could conceivably be deployed for demand response programs, although the costs of doing so and effectiveness of real-time coordination would require further investigation because the functions required to deliver demand response are quite different from the functions that are being provided by the existing Public Benefits Fund Administrator (PBFA).
4) *Curtailment Service Providers ("CSP's)*: A completely new class of load aggregators has arisen over the past ten years or so in response to the expansion of demand response programs across various power markets both in the US and internationally. These aggregators, known as Curtailment Service Providers or CSP's, perform most of the functions identified above. Typically, the CSP enters into a contract with the system operator (a utility or independent system operator) to deliver a block of demand response resource that meets the specific program criteria. The CSP is required to meet all of the technical requirements of the specific program. The market-clearing entity pays the CSP directly for the delivery of the demand-side resource, and in turn the CSP is responsible for compensating the individual customers who are participants in the program. A CSP shares its compensation with participating customers. Typical splits are in the range of 60% to 80% of the payment going to the customer, with the balance going to the CSP. CSPs are not necessarily regulated entities although they would be subject to general contract law and consumer protection

A Curtailment Service Provider ("CSP") enters into a contract with the utility to deliver a resource in accordance with the DR program. The CSP must meet all of the technical requirements of the specific DR program. The utility pays the CSP, which in turns compensates the customer.

regulations that apply to any other business. If the CSP model is utilized, a set of consumer protection rules many be desirable; however this would be a legislative issue, not a Commission issue.

Regardless of which business model is used to administer demand response programs, since DR is so intimately responsive to system operational needs, DR programs should be designed to meet the system's operational needs, and DR events should be initiated by the system operator rather than any third party.

IX. RSWG & RSWG Demand Side Options Subgroup Discussions to Date

In early 2012, the RSWG Demand Side Options (DSO) subgroup identified a process to determine if demand side options (including but not limited to demand response and energy storage) could be viable resources for the HECO Companies in terms of providing additional system flexibility and allowing greater penetration of renewable resources. The DSO working group's process included:

1) Identification of existing demand response programs in the HECO Companies' service areas;
2) Determination of loads available in the system that are flexible or which have characteristics conducive to dispatch (on or off) in some manner;
3) Determination of ancillary services products required in the HECO Companies' systems;
4) Match potential demand response programs with required products, including each of the ancillary services.

As part of the HECO Companies' participation in the RSWG docket, the HECO Companies produced a "Roadmap" for demand response programs prepared by Lawrence Berkeley National Laboratory. This roadmap document laid out a process for determining programs and technologies conducive to demand response. The roadmap process, if implemented, will take several years to complete.

The DSO subgroup has determined that there has been no load research studies performed in some time that would help determine the types and levels of penetrations of particular end-use loads that would be candidates for demand response.[21] HECO is however working with the Commission's Public Benefits Fund Administrator (PBFA) evaluation consultant to conduct on-site and mail/telephone surveys to obtain end-use data that will be used for energy efficiency and demand response potential studies.

There have been no load research studies performed in some time to determine end-use loads that are candidates for DR in Hawaii. HECO is working with the Commission's consultant to obtain end-use data that would provide this information.

[21] However, a Global Energy Partners DR potential study conducted on behalf of the Hawaiian Electric Companies in 2010 did identify DR potential categorized by control mechanism (e.g., direct load control, dynamic pricing), but not by end-use.

On April 13, 2012, the HECO Companies filed an application (Docket No. 2012-0079) for expansion of the Residential Direct Load Control ("RDLC") program for the HECO service area (i.e. Oahu only). The application summarized the demand response programs in place in the HECO systems. MECO participates in the Fast DR Pilot Program.[22] There are no demand response programs in the HELCO service area at the present time (although in PUC Docket 2010-0165 and PUC Docket 2007-0341 HELCO pledged to undertake a study of the potential for such programs). HECO included in its application in Docket No. 2012-0079 a plan for expanding and/or extending demand response programs and a dynamic pricing program. HECO's timeframes with respect to rollout of these programs on a permanent basis range from 2013 to 2017.[23]

General Electric, working through the Hawaii Natural Energy Institute ("HNEI") at the direction of the RSWG, is delivering a report on ancillary services requirements in Hawai'i. The report identifies the specific ancillary services that are required in each of the HECO company systems, the report clearly identifies demand response and energy storage as potential resources for providing certain ancillary services.

HECO has contracted with Honeywell to implement automated demand response programs in the HECO service territory over the next 2 to 3 years.

In September 2012, in a conference call meeting of the DSO subgroup, the HECO Companies stated that the Commission is now contracting for end-use load research studies that can be used to identify loads that are capable of responding to dispatch signals (manual, automatic or otherwise). The HECO Companies indicated that information of this type would be available in 2013, after which the load research data can be used for demand response and energy efficiency EE potential studies.

At the September 19, 2012 RSWG meeting, Honeywell presented an overview of the technology that they are deploying with HECO to implement automated demand response programs in the HECO service territory. The deployment of this system is to take place over the next two to three years.

On October 3, 2012 a call was held among some members of the DSO working group and HELCO. In that call we learned that the utilities currently have a pricing program in place through a tariff known as "Rider M." Rider M is available only to certain customers who are subject to demand charges. The purpose of Rider M is to incentivize loads to shift their demands from on-peak to off-peak periods. Thus, the "product" that this delivers is peaking power and perhaps a modest level of minimum load mitigation. Under Rider M, the customer is compensated through an elimination of the demand charge; if the customer does not shift the load, then it is penalized by a demand charge that is the tariffed demand charge plus $1.00 per kilowatt-month per unit of billing demand. Using the HELCO version of Rider M, a low load factor customer who complies with the Rider M terms and conditions receives at most a benefit that is approximately 2 – 3 cents per KWH (spread over all of its energy usage in a month) for a savings of, at most, approximately 5 – 10% of its total energy.

[22] MECO will also be testing DR in the Wailea Smart Grid project – residential water heaters and PCTs.
[23] See HECO's Application in Docket No. 2012-0079, Exhibit B, page 3 of 3 (pdf page 62).

X. Status of Demand-Side Initiatives in the HECO Companies' Systems

Demand-side resources can play a role as an operational resource and should therefore be considered as a resource option in the HECO Companies' systems. A fundamental task of a system operator is to match aggregate generation and aggregate load on an instantaneous and continuous basis. Inside RSWG, and elsewhere, much discussion has gone into determining the "right" generation resource mix to fulfill this task. Permanent reductions on the load side of the equation are being carried out by the PBFA in its energy efficiency work. In addition, there have been HECO Company initiatives with respect to modifying load behavior in operating time frames (e.g. less than one day and/or providing ancillary services) in response to power system needs. Table 1 shows the existing HECO demand response programs as of September 2012. MECO has a pilot demand response program. There are currently no demand response programs offered in the HELCO service territory. The objective of the Fast DR Pilot program is to obtain DR resources available within 10 minutes to provide a "bridge" between when the need for a generating unit to be started is identified and when the unit is available on-line. In addition, the RDLC and CIDLC programs, which have been in place since 2005, provide under-frequency protection via their under-frequency relays (UFRs) embedded in the load control receivers provided by HECO and installed at customer premises. The UFRs respond nearly instantaneously when the frequency thresholds are attained.

Table 1

Hawaiian Electric Existing and Proposed Demand Response Programs

Program Name	Existing or Proposed?	Customer Segment*	MW Nov. 2012	Customers Nov. 2012
Fast DR Pilot **	Existing	C&I>50 kW	2	17
CIDLC (DLC) #	Existing	C&I>50 kW	18	42
CIDLC (SBDLC) #	Existing	C&I > 3 kW	1	161
RDLC #	Existing	Res	17	≈36,000
Rider I #	Existing	C&I	3	4
CIDP Pilot ⊕	Proposed	C&I > 50 kW	0	0

* C&I = Commercial and Industrial, Res = Residential

** Includes Fast DR Pilot on Maui. Cumulative MW program goal is 7 MW (total on Maui + Oahu) in 2013.

\# Program currently not expanding.

⊕ Cumulative MW program goal is 2 MW within two years.

The HECO Companies are working on new demand-side programs such as the Fast DR Pilot Program, the Commercial and Industrial Dynamic Pricing (CIDP) Pilot Program, and are seeking approval from the Commission to expand the RDLC and CIDLC programs. However, as presented to the RSWG on September 18, 2012, the timeframe for some of these initiatives are relatively long, i.e., well beyond the current Integrated Resource Planning (IRP) process. Notwithstanding some of the longer term program initiatives, the CIDP pilot and the RDLC and

CIDP program expansions are awaiting Commission approval and could be in place and available for customer enrollment in 2013, i.e., possibly before the completion of the IRP process. In the meantime, there may be additional loads in the HECO Companies' systems that could provide meaningful capacity, energy and ancillary service resources via demand response resources that are not being accessed. As noted above, there are pricing programs and manual demand response programs that could be put into place without waiting on the automated technology and those programs should be further explored.

This paper proposes that the Commission consider allowing the HECO Companies, end users and possibly curtailment service providers, to explore and develop demand response programs that can be implemented in the near term. In particular, the DSO subgroup believes that it may be possible to launch new demand response programs that would precede the automated programs by as much as two years.[24] These programs, which would initially be aimed at commercial customers, would allow customers to become accustomed to the benefits that would accrue to them for changing their operation, while getting comfortable enough over time to allow the automated control over some of their operations when the automated systems are ready. These programs would also allow the utility operators to get comfortable with the use of demand response for reliability requirements.

The DSO subgroup recommends that the Commission consider allowing the utilities and other market participants to develop DR programs that can be implemented in the near term. It may be possible to launch new DR programs that would precede the automated programs by as much as 2 years.

Additionally, with the concerns expressed repeatedly in the RSWG (and particularly the MLC working group) regarding the curtailment of non-firm renewable energy resources from time to time, we recommend that the utilities and non-firm renewable generators develop demand-side programs that build load in periods when curtailment would otherwise occur or to provide reserves that are currently required to be supplied by thermal generation. This of course is not a zero sum proposition. In order to provide the incentive for the customer to move its load to off-peak periods or to provide reserves, there must be a source of funding to pay the customer for doing so. One possible mechanism for doing this would be for the non-firm generator to take less compensation during periods when it would otherwise be curtailed (during which time periods it currently receives nothing). The arbitrage between the existing contractual price and the reduced price would allow for a pool of funds to be collected which would then be used to pay customers to shift their demands. In such a scenario, everyone wins. The renewable generators would get paid when otherwise they would be curtailed.

[24] Note that the CIDP pilot program that is awaiting PUC approval is a pricing program and it also has a semi-auto (i.e., manual) DR component, in addition to an auto DR component.

XI. Specific Proposal for a Demand Response Program

There are at least several water pumping loads in each of the HECO Companies' service areas worth evaluating and exploring. Domestic water providers such as County and privately-owned water utilities employ many horsepower worth of electric-powered pumps. Also, any demand-response program developed for water pumps would be repeatable to other water systems – which may comprise 5-15% of each Island's load. These should be considered the primary loads to explore for generation-load matching and the start of a smarter and more flexible grid. Agricultural water users routinely operate their own water systems for irrigation and livestock operations. Both private and public entities operate electric-powered wastewater lift stations. From an operational perspective, these pumps have significant flexibility in terms of when they operate, and in a significant number of cases, water storage facilities are available that can store several days' worth of water without operating these electric powered pumps. At the current time, there is no coordination of the operation of these pumps to match generating resources that may be available at any given time (e.g. to operate off-peak to absorb high levels of wind generation) or to provide ancillary services to the power system (regulation, load-following, or contingency reserves). Though conceptually feasible and while each type of load may provide benefits to the grid or local area, each load and respective water usage need as well as any water management rights or issues need to be further investigated for appropriateness and fit.[25]

At times there may be arbitrage opportunities between the value of renewable resources being curtailed and an incentive to customers for shifting load into hours when curtailment would otherwise occur. Taking advantage of this arbitrage opportunity could increase renewable energy generation and provide a source of funding to pay customers for the value of shifting load.

a. Concept

To illustrate how these loads could immediately be utilized, consider the curtailment of available wind generation. Let's call the wind generator "Wind 1" and a generic pumping load called "Pump A". Let's call the hypothetical utility "Utility." Pump A is a 1 MW pumping load and it has a choice to pump water today at noon, or tonight at midnight. Pump A is on a general service rate schedule with a rate of $0.35 per KWH, regardless of the time it runs. The utility's marginal cost is $0.25 per KWH regardless of the time of day (a simplifying assumption for purposes of this "thought experiment") and its marginal cost is based on burning oil to generate electricity. Let's assume that Wind 1 is compensated at $0.20 per KWH.[26] From a water operations perspective, Pump A is ambivalent as to which time it runs. Utility is operating its system and through its daily and hourly load forecasting processes, it determines

[25] Several investigative studies were conducted in California as part of linking the state water irrigation management and large pumping loads with electric utility and renewable integration. However, in light of real-time operations and water management needs, recreational use and fish management constraints, overall energy value and demand response opportunities and value were not as significant as originally expected. Proper tailoring of program with appropriate and available loads will need to be further investigated.

[26] This assumes that Wind energy cost is lower than the utility's marginal cost. While this is generally true, it may not always be true. E.g., during certain times of the day, HELCO's and Maui's wind energy costs are sometimes higher than HELCO's and Maui's marginal cost of generation.

that a system low load condition will occur at midnight. Wind 1 is forecasting strong trade winds overnight and expects to be available to produce its full output. Because of constraints around thermal unit commitment, the Utility expects that it may need to curtail Wind 1's generation overnight.

In the current situation, the operating decisions made by the owner of Pump A are totally divorced from the operating decisions of the Utility. Therefore if the pump chooses to run at noon, the following economic outcome occurs (cash outflows for the relevant entity are shown as negative, cash inflows are shown as positive):

Cost of power for Pump A:	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Utility Marginal Cost to Supply Pump A:	$0.25 per KWH * 1 MW * 1 hour =	($250.00)
Wind 1 Revenue at Midnight (curtailed)		$ 0.00

However, if the pump chooses to run at midnight, the following economic outcome occurs:

Cost of power for Pump A:	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
PUMP A INCREMENTAL SAVINGS		$0.00
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
RATEPAYER INCREMENTAL SAVINGS[27]		$50.00
Wind 1 Revenue at Midnight (not curtailed)	$0.20 per KWH * 1 MW * 1 hour =	$200.00
WIND 1 INCREMENTAL REVENUE		$200.00

In the example above, Pump A is not compensated for the option value of running at midnight rather than at noon; rather the example assumes that Pump A simply made a choice to run and it happened to coincide when wind curtailment would have otherwise occurred. However, if the optionality of Pump A is recognized by all parties, Pump A would receive a payment in recognition of its willingness to coordinate its operations with Utility's operations. Assume that that policy is for the ratepayer to split the benefits with the individual customer on a 50-50 basis. Now the economics would look like this:

Cost of power for Pump A (per tariff):	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Split system fuel cost with ratepayers		$25.00
PUMP A INCREMENTAL Power Cost		(325.00)
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
Split fuel savings with Pump A		($25.00)
RATEPAYER INCREMENTAL SAVINGS		$25.00
Wind 1 Revenue at Midnight (not curtailed)	$0.20 per KWH * 1 MW * 1 hour =	$200.00
WIND 1 INCREMENTAL REVENUE		$200.00

In this example, all parties would benefit from the arrangement. By shifting its operation from noon until midnight, with no adverse consequences on its operations, Pump A reduces its power cost by $25, ratepayers benefit by $25, and the Wind A gains $200 in revenue that it would not otherwise have realized. *Of note, the utility is not harmed in this arrangement*.

[27] These savings accrue to all Utility's ratepayers since fuel is a pass-through.

Since the need for thermal units to meet on-peak loads in the 5 pm to 9 pm time period contributes to the need for off-peak minimum load generator operation, it is useful to consider whether and how to modify water and waste water pumping loads to minimize their operation during electric system peak hours; again, if these loads pay a flat rate per KWH regardless of the utility's cost to generate or acquire each KWH, there may be significant cost savings and net benefit to all parties by paying pumping loads to not operate during system peak hours (or providing reduced energy rates for pumping loads that operate off-peak).

Another way to do this that could provide a more meaningful level of compensation to incentivize customers would be for the wind generator (in this example) to share some of its revenue with the customer. The situation might look something like this:

Cost of power for Pump A (per tariff):	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Split system fuel cost with ratepayers		$25.00
Split 25% of wind plants windfall with ratepayer		$50.00
PUMP A INCREMENTAL Power Cost		(275.00)
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
Split fuel savings with Pump A		($25.00)
RATEPAYER INCREMENTAL SAVINGS		$25.00
Wind 1 Revenue at Midnight (not curtailed)	$0.15 per KWH * 1 MW * 1 hour =	$150.00
WIND 1 INCREMENTAL REVENUE		$150.00

Again, the utility is not harmed and the wind plant still receives revenues from that it would not have otherwise received but for the customer's willingness to change its behavior. Within the confines of existing contracts and regulation, this last example may or may not be achievable, however, the point is that a substantial arbitrage opportunity exists that would allow more renewable energy, avoid burning oil, and that would result in economic benefit (or no harm) to all parties except the oil suppliers, assuming there are no limitations/constraints to the water pumping and management needs.

b. Implementation

The implementation of an arrangement described above would be straightforward and relatively simple. The components of such a program would consist of the following:

1) *Scheduling notifications to loads*: The utility control operator should be able to provide, on a daily basis, a schedule for the operation of the flexible loads. This schedule could be communicated to the owner of the load via a phone call, fax, text message, email or other means. No additional technology is required to provide these notices.
2) *Ability of the load to implement the schedule*: a load that participates in this program must have the operational wherewithal to execute the schedule, i.e. operate its loads according to the schedule. With less sophisticated customers, this might require a manual operation, but with sufficient advance notice (e.g. an hour or longer) this does not necessarily represent an obstacle. More sophisticated customers (e.g. county water systems) may have already implemented SCADA systems that would allow scheduling of multiple loads from a central remote location.

3) *Interval metering with communications*: The measurement and verification of performance of the loads is an important consideration. For purposes of starting such a program, the only M&V technology that would be required is interval metering with recording capability. The verification of the load's performance could be established after the fact and settlement with the load could take place based on the load's actual performance against a baseline (in this case a simple baseline is all that is required – was the load on when the utility scheduled it on, and was it off when it was scheduled off). The metering preferably has remote data collection capabilities via a POTS line or (even better a cellular IP addressable modem) installed with the meter. This would allow access to the customer's performance on a next day basis.
4) *Payment mechanism*: the customer would presumably earn a credit on their electric bill, or a separate fee, in return for agreeing to this flexibility. The amount of compensation needs to be a balance between a level that will incentivize the load to participate and a level that will provide benefits to ratepayers and other ratepayers.

This relatively simple program could immediately result in less curtailment of renewable loads and provide additional operating flexibility with respect to commitment of other utility generating assets and dispatchable contracts. After refinement of this program and education of participating customers, and interest by non-participating customers, the program could then be refined and upgraded to include controls and telemetry on loads that would be dispatched directly by the utility. Such a program would offer real-time M&V. Such a program might also provide numerous ancillary services including regulation, load following, spinning reserve and non-spinning reserve. Provision of ancillary services requires much less water or energy storage capabilities (tens of minutes versus hours or days) than rescheduling operations and many more MW of response are potentially available.

This relatively simple program of shifting flexible loads into hours when curtailment is forecasted to occur, could immediately result in less curtailment of renewable loads and provide additional operating flexibility with respect to commitment of other utility generating assets and dispatchable contracts.

Since there are only a few water and waste-water pumping loads per island, and their characteristics are already well-known, it should be feasible to estimate the operational and cost impacts of the changes proposed above and develop appropriate incentive offerings relatively quickly without waiting until 2014 for completion of a DR potential study. What may be less well-known is whether the existing pumping loads have other operational constraints due to permits, water flow rate, seasonal concerns, technology limits or other use concerns which may limit their ability to participate in aspects of demand response as envisioned. Upgrades to technology, communication and other un-intended consequence risks of coupling two critical infrastructures such as water and electricity delivery infrastructures for islanded grids may also need to be considered (though coordination of two critical infrastructures should lead to greater reliability if it is done correctly). It may also be feasible for the Commission to adopt these proposed changes through a tariff rather than going through a fully-litigated rate case.

XII. Conclusions and Recommendations

In conclusion, there are very real opportunities to affect the demand side of the supply-demand balance in a way that will produce economic benefit for ratepayers, and that will allow greater penetration of renewable energy. Further, there are loads today that could, with incentives, shift their demand patterns in ways that would be beneficial to many if not all of the stakeholders represented in the RSWG process. Accordingly, this paper recommends to the RSWG and to the Commission the following proactive steps to move on a quicker pace towards implementing demand-side programs:

In conclusion, there are very real opportunities to affect the demand side of the supply-demand balance in a way that will produce economic benefit for ratepayers, and that will allow greater penetration of renewable energy.

1) Investigate pricing programs and manual and automated demand response programs that will incentivize customers to change their consumption patterns in ways that are beneficial for stakeholders. Included in this investigation would be an analysis of the benefits of increasing demand during minimum load periods (i.e., examining the cost reductions that could be incurred and the impact on renewable energy purchases during the entire 24-hour day);
2) Encourage the use of demand response and energy storage to provide ancillary services whenever technically possible and economically justified;
3) Allow the utilities and other interested stakeholders to develop specific pricing and/or manual demand response programs, with expedited regulatory review and approval to get these programs in place as soon as possible;
4) As the Commission reviews new DR programs, it should consider the appropriate role of third party agents and aggregators (i.e. curtailment service providers) to deliver demand response programs effectively and efficiently;
5) Ensure that demand response programs are considered in the Integrated Resource Planning process;
6) Direct the energy efficiency potential study contractor to perform specific load research data collection that will allow the utility to better estimate the demand response potential in Hawai`i.
7) Require Hawaii Energy work with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa).

Reliability Standards Drafting Group
Appendix E
Recommended Generator Interconnection Procedures

HAWAIIAN ELECTRIC COMPANY, INC.

GENERATOR INTERCONNECTION PROCEDURES

INTERCONNECTION REQUIREMENTS STUDY PROCESS

Section 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Base Case shall mean the base case power flow, short circuit, stability and electromagnetic transient databases used for the Interconnection Studies by Company or Interconnection Customer.

Commission shall mean the Public Utilities Commission of the State of Hawaii.

Company shall mean Hawaiian Electric Company, Inc.

Company's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Company from the Point of Change of Ownership to the Point of Interconnection, including any modifications, additions or upgrades to such facilities and equipment. Company's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Confidential Information shall mean (i) any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, or (ii) the term as defined in the confidentiality agreement executed by the Parties.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean Company facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with the Transmission System.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Company's Distribution System at or beyond the Point of Interconnection to facilitate

interconnection of the Generating Facility. Distribution Upgrades do not include Interconnection Facilities.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Company, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Distribution System, the Company's Interconnection Facilities, or the electric systems of others to which the Transmission System or Distribution System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Company to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Facilities.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure. Economic hardship is not considered a Force Majeure event.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request or IRS Request, but shall not include Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

GIP or **Generator Interconnection Procedures** shall mean the interconnection procedures set forth herein. [*This documentation is under development in addition to IRS process.*]

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method,

or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, the Company, or any Affiliate thereof.

In-Service Date shall mean the date upon which Interconnection Customer reasonably expects it will be ready to begin use of Company's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Company or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System or Distribution System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System or Distribution System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean Company's Interconnection Facilities and Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System or Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted to determine a list of facilities (including Company's Interconnection Facilities, System Protection Facilities, and if required, Network Upgrades or Distribution Upgrades, as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System or Distribution System. The scope of the study is defined in Section 8 of the GIP. The Interconnection Facilities Study is included within the scope of an IRS under a single IRS Agreement.

Interconnection Request shall mean an Interconnection Customer's request to interconnect a new Generating Facility, or to increase the capacity of, or make a modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission System or Distribution System. Interconnection Request includes any application

relating to a Standard Interconnection Agreement, Net Energy Metering, Feed-In Tariff, bilateral negotiated project proposal or competitive bidding project proposal.

Interconnection Requirements Study or **IRS** shall mean the combined Interconnection System Impact Study and Interconnection Facilities Study described in the GIP.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System or Distribution System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, and shall identify potential impacts, including but not limited to those identified in the IRS Kickoff Meeting. The Interconnection System Impact Study is included within the scope of an IRS under a single IRS Agreement.

IRS Agreement shall mean the form of agreement contained in Appendix 1 of the GIP.

IRS Queue Position shall mean the order of a valid IRS Request, relative to all other pending valid IRS Requests, that is established based upon the date and time of receipt of the valid IRS Request by the Company. IRS Queue Position is primarily a reference to determine the sequence to start and track IRS work among multiple projects, subject to readiness to proceed with the particular IRS work that may be required for a given project size, type and location. The purposes, rights and requirements of IRS Queue Position are addressed in Section 4.

IRS Request shall mean, together with a submission of all required Generating Facility data, a written request by an Interconnection Customer for an IRS, whether (a) by operation of any application that is subject Tariff Rules 14H, 18, or 19, or (b) expressly requested pursuant to bilateral negotiations.

IRS Scoping Meeting shall mean the meeting between representatives of Interconnection Customer and the Company conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission and distribution data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Material Modification shall mean any modification that has a material impact on the cost or timing of any other Interconnection Request.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility and at the Point of Interconnection including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System or Distribution System to accommodate the interconnection of the Generating Facility to the Transmission System or Distribution System.

Party or Parties shall mean the Company, Interconnection Customer or a combination of the above.

Point of Change of Ownership shall mean the point where Interconnection Customer's Interconnection Facilities connect to Company's Interconnection Facilities.

Point of Interconnection shall mean the point where the Interconnection Facilities connect to the Transmission System or Distribution System.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of Interconnection Customer and the Company conducted for the purpose of discussing alternative interconnection options, to exchange information including any system data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System or Distribution System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or Distribution System or on other delivery systems or other generating systems to which the Transmission System or Distribution System is directly connected.

Transmission System shall mean all the facilities and equipment at or above 46 kV that are owned, controlled or operated by the Company and are used to transmit energy from generation to load. For the purposes herein, the Transmission System includes all radially operated sub-transmission facilities and equipment.

Section 2. Scope and Application

2.1 Application of Generator Interconnection Procedures.

Sections 2 through 13 apply to processing an Interconnection Request that involves an IRS pertaining to a Generating Facility interconnecting to the Transmission System or Distribution System. All timelines specified herein shall be subject to more restrictive or expansive timelines that may be established pursuant to Tariff Rules 14H, 18 and 19.

2.2 Comparability.

The Company shall receive, process and analyze all Interconnection Requests that involve an IRS in a timely manner as set forth in this GIP. The Company will use the same Reasonable Efforts in processing and analyzing all Interconnection

Requests that involve an IRS, whether the Generating Facilities are owned by the Company, its subsidiaries or Affiliates or others.

2.3 Base Case Data.

The Company shall provide base power flow, stability, and short circuit databases, including all underlying assumptions, and contingency lists, upon request subject to confidentiality provisions. The Company shall require Interconnection Customer or its study consultant to sign a confidentiality agreement prior to the release of Base Case data, including switching diagrams and system maps. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission or distribution projects.

Section 3. IRS Requests

3.1 General.

An Interconnection Customer is understood to have submitted to the Company an IRS Request as part of (a) any Net Energy Metering, Standard Interconnection Agreement, Feed-in Tariff or competitive bidding application for which an IRS determination has been made in accordance with Tariff Rule 14H, 18 or 19, or (b) completion of an application for bilateral negotiation of a power purchase agreement and a written request to proceed with an IRS. [*These forms are under development to update and standardize the data collection process.*]

3.2 The Studies.

The IRS shall assure that Interconnection Customer's Generating Facility meets the requirements for interconnection to the Transmission System or Distribution System. The Interconnection Request will be studied with the Transmission System or Distribution System at peak load, minimum load or other load conditions so as to simulate a variety of severely stressed conditions, and to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the Transmission System or Distribution System, consistent with the Company's reliability criteria and procedures. An IRS may include one additional set of relevant analyses to determine the maximum allowed output at the time the study is performed, of the Generating Facility without requiring additional Distribution Upgrades or Network Upgrades, to identify a final project size with equal or less than the proposed full output.

3.3 Valid IRS Request.

3.3.1 Initiating an IRS Request.

To initiate an IRS Request, Interconnection Customer must submit all of the following: data requested on forms provided in the SIA NUG, FIT,

competitive bidding and bilateral negotiation processes and any additional data identified in an IRS determination. [*This documentation, to be attached hereto, is under development to update and standardize all requests for technical data.*]

3.3.2 Deficiencies in IRS Request.

An IRS Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by the Company. If an IRS Request fails to meet the requirements set forth in Section 3.4, the Company shall notify Interconnection Customer within 14 days of receipt of the initial IRS Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the additional requested information needed to constitute a valid request within 14 days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.4.3 shall be treated in accordance with Section 3.7.

3.4. Scoping.

The Company will make Reasonable Efforts to conduct a Scoping Meeting with each Interconnection Customer that has a valid IRS Request within 21 days after an IRS determination under Rule 14H or similar review and finding of data completeness. The Company shall establish a date agreeable to Interconnection Customer for the Scoping Meeting, which may be conducted in person or by telephone.

The purpose of the Scoping Meeting shall be to exchange information including any transmission data that would reasonably be expected to impact such Interconnection Customer's interconnection options, to analyze such information and to review the requested Point of Interconnection. The Company and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general system stability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. The Company and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection for purposes of the Interconnection System Impact Study portion of the IRS.

3.5 IRS Queue Tracking, Posting on the Company's Website.

The Company will maintain on its website a publicly available list of all IRS Requests. The list will identify, for each IRS Request: (i) the maximum megawatt electrical output; (ii) the location; (iii) the station or transmission or distribution line or lines where the interconnection will be made; (iv) the proposed In-Service Date; (v) the status of the IRS Request, including IRS Queue Position;

(vi) the availability of any studies related to the IRS Request; (vii) the date of the IRS Request; (viii) the type of Generating Facility to be constructed; and (ix) for IRS Requests that have not resulted in a completed IRS, an explanation as to why it was not completed. Except in the case of the Company or an Affiliate of Company, the list will not disclose the identity of Interconnection Customer. IRS reports shall be available to others upon request subsequent to the meeting between Interconnection Customer and the Company to discuss the applicable study results. [*This is under development pending resolution of NDA policy issues.*] The Company shall also post any known changes in the Generating Facility's proposed project size and In-Service Date.

3.6 Withdrawal.

Interconnection Customer may withdraw its IRS at any time by written notice of such withdrawal to the Company. In addition, if Interconnection Customer fails to adhere to all requirements of this GIP, except as provided in Section 13.5 (Disputes), the Company shall deem the IRS Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have 21 days in which to either respond with information or actions that cure the deficiency or to notify the Company of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's IRS Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its IRS Queue Position, then during Dispute Resolution, Interconnection Customer's IRS Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its IRS Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its IRS Request shall pay to the Company all costs that the Company reasonably incurs with respect to the processing of that IRS Request prior to the Company's receipt of notice described above. Interconnection Customer must pay all monies due to the Company before it is allowed to obtain any further Interconnection Study data or results.

The Company shall (i) update the Company's website IRS Queue Position posting and (ii) refund any Interconnection Customer's unused payment, including interest computed based on [*under development*]. In the event of such withdrawal, the Company, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that the Company developed for any completed study conducted up to the date of withdrawal of the IRS Request, upon payment of any remaining balance owed by Interconnection Customer.

Section 4. IRS Queue Position

4.1 General.

The Company shall assign an IRS Queue Position based upon the date and time of receipt of the valid IRS Request. If the sole reason an IRS Request is not valid is the lack of required information on the [*application data forms under development*] and Interconnection Customer provides such information in accordance with Section 3.3.2, then the Company shall assign Interconnection Customer an IRS Queue Position based on the date the corrected application form was filed. Moving a Point of Interconnection shall result in a change of IRS Queue Position to the end of the queue if it is deemed a Material Modification under Section 4.4.

The IRS Queue Position of each IRS Request will be used to determine the order to commence Interconnection System Impact Studies, subject to Section 7.1.1. If performing the Interconnection System Impact Study in order of IRS Queue Position will delay the study of IRS Requests that are otherwise ready for study, the Company may sequence the start of Interconnection System Impact Studies on the basis of an IRS Request's location by region. IRS Queue Position does not govern the time to complete an IRS relative to any other IRS Requests.

The IRS Queue Position shall govern the order of priority only through completion of an Interconnection System Impact Study component of the IRS and only to the extent that study work can proceed with Reasonable Efforts in light of data, technical constraints, consultant availability or other issues that may arise on a case by case or by location basis. Thereafter, Interconnection Customers with IRS Requests that meet the requirements set forth in Section 8.1.1 shall proceed to the Interconnection Facilities Study component of the IRS on a first ready, first served basis. Further processing of each IRS Request shall be queued consecutively based on the order in which all pending IRS Requests have met the requirements of Section 8.1.1.

The Company may allocate the cost of common upgrades on a prorated basis in relation to periodic group studies that may be conducted for process efficiency without regard to IRS Queue Position.

4.2 Group Studies.

At the Company's option, IRS Requests may be studied serially or in groups for the purpose of the Interconnection System Impact Study portion of the IRS. Grouping of IRS Requests may be implemented on a per circuit basis as well as on the basis of IRS Queue Position for process efficiency. The Company may study an IRS Request separately to the extent warranted by Good Utility Practice based upon the location or size of the proposed Generating Facility. If system upgrades are determined to be necessary to accommodate the full capacity of the projects in the group study, the Company shall provide a description of the proposed upgrade along with a rough estimate of the cost and time to complete, so that each Interconnection Customer in the group study will have an opportunity to withdraw or proceed with the group Interconnection Facilities Study portion of the IRS.

4.3 Transferability of IRS Queue Position.

An Interconnection Customer may transfer its IRS Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the IRS Request and the Point of Interconnection does not change. At the time of transfer the new Interconnection Customer shall provide documentation of the change in ownership.

4.4 Modifications.

Interconnection Customer shall submit to the Company, in writing, modifications to any information provided in the IRS Request, include to provide revised drawings and data sheets with clouding to identify revisions. Interconnection Customer shall retain its IRS Queue Position if the modifications are determined not to be Material Modifications pursuant to Section 4.4.1.

Notwithstanding the above, during the course of the Interconnection System Impact Study, either Interconnection Customer or the Company may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the IRS Request. To the extent the identified changes are acceptable to the Company and Interconnection Customer, such acceptance not to be unreasonably withheld, the Company shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 7.6 and Interconnection Customer shall retain its IRS Queue Position.

4.4.1 Interconnection Customer may request that the Company evaluate whether such modification is a Material Modification. The Company shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Section 7.2, shall constitute a Material Modification and shall result in a change IRS Queue Position to the end of the queue as set forth in Section 4.1.

4.4.2 Within 21 days after receipt of Interconnection Customer's request for modification permitted under this Section 4.4, the Company shall tender a revised IRS Agreement including any additional deposit required to cover the cost of the revised scope of work or restudy. The Company shall commence such studies within 21 days after receipt of the signed IRS Agreement and deposit.

Section 5. Procedures for Interconnection Requests Submitted Prior to the Effective Date of this GIP

An Interconnection Customer assigned a Queue Position prior to the effective date of this GIP shall retain that Queue Position. Interconnection Requests submitted prior to the effective date of this GIP shall be administered under this GIP, subject to the following:

5.1 [*TBD depending on stage of System Impact Study completion.*]

5.2 [*TBD depending on middle stage of Facilities Study completion.*]

5.3 If a power purchase agreement has been entered into prior to the effective date of this GIP, then Interconnection Customer and the Company shall proceed in accordance with the terms of that agreement.

Section 6. [Reserved]

Section 7. Interconnection System Impact Study Portion of IRS

7.1 IRS Agreement with Scope and Technical Data.
Within 14 days following the Scoping Meeting, Interconnection Customer shall specify for inclusion in the scope of the IRS Agreement the Point of Interconnection and any reasonable alternative Point(s) of Interconnection. Interconnection Customer may also specify an alternative study level to identify the maximum generation available without system upgrades or in the alternative the maximum generation available with a particular upgrade or set of upgrades only. Interconnection Customer also shall provide updated technical data as required in the original data requests. Within 14 days following the Company's receipt of such designations and data, the Company shall tender to Interconnection Customer the IRS Agreement in the form of Appendix 1 [*under development*] which shall include a description of the scope and a good faith estimate of the cost and schedule for completing the Interconnection System Impact Study.

The IRS Agreement shall provide that Interconnection Customer shall compensate the Company for the actual cost of the IRS and that the Company will draw on Interconnection Customer's deposit to perform the study. In the event that the deposit is not sufficient to cover the costs, including potential re-study in accordance with Section 7.6, the Company shall invoice Interconnection Customer for the estimated balance to complete the study. Interconnection Customer shall submit payment no later than 14 days after receipt of invoice. After completion of the Interconnection System Impact Study portion of the IRS any remaining deposit shall be applied to the deposit requirement for the Interconnection Facilities Study portion of the IRS, or refunded in accordance with Section 3.6 if Interconnection Customer withdraws its request.

7.1.1 The Company shall commence the Interconnection System Impact Study portion of the IRS on an expedited basis, regardless of Queue Position, in

line with work already in progress, for an Interconnection Customer who, prior to commencement of the Interconnection System Impact Study, provides a power purchase agreement or letter of intent between Interconnection Customer and the Company to enter into a power purchase agreement.

7.2 Execution of IRS Agreement.
Interconnection Customer shall sign and return the Interconnection System Impact Study Agreement and any applicable deposit to the Company no later than 21 days after its receipt.

If Interconnection Customer does not provide all technical data required under Section 7.1 when it delivers the IRS Agreement, the Company shall notify Interconnection Customer of the deficiency within 14 days of the receipt of the signed IRS Agreement and Interconnection Customer shall cure the deficiency within 14 days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the signed IRS Agreement or deposit. Upon receipt of the signed IRS Agreement and verification of receipt of all technical data, the Company shall promptly execute the IRS Agreement.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting an alternative Point of Interconnection identified by either Interconnection Customer or the Company, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if the Company and Interconnection Customer cannot agree on the alternative Point of Interconnection, then the Parties shall submit the matter to Dispute Resolution in accordance with Section 13.5.

7.3 Scope of Interconnection System Impact Study portion of the IRS.
The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System or Distribution System. The Company will study the Interconnection Request at the Generating Facility's proposed maximum level of output and at a lower level of output that would not require additional Network Upgrades. At Interconnection Customer's request, the Company will study the Interconnection Request at one alternative level as set forth in Section 7.1. The Interconnection System Impact Study will consider the Base Case as well as generating facilities and Network Upgrades that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System or Distribution System; or (ii) may be interconnected in view of a demonstrated likelihood of construction. The Company will use engineering judgment based on Good Utility Practice to determine which facilities should be included in the study.

The Interconnection System Impact Study will consist of a power flow analysis, a

stability analysis, a short circuit analysis and/or electromagnetic transient analysis, each to the extent required by Good Utility Practice. The Interconnection System Impact Study will state the assumptions upon which it is based; explain the results of the analyses; and identify the requirements or potential impediments to providing the requested interconnection, including a preliminary indication of the cost and time required to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a preliminary non-binding good faith estimate of cost responsibility and time to construct.

7.3.1 Within 14 days after completion of the power flow analysis, or at such other stage in the sequence of analyses as is mutually agreeable, the Company will meet with Interconnection Customer to review the initial findings with respect to the original study scope, in the form of a preliminary summary of results or draft report. Within 14 days after receipt of the preliminary summary of results or draft report, Interconnection Customer or several Interconnection Customers in a group study shall narrow the scope to one level of generation output for completion of the study, or withdraw the project or one or more of multiple projects if the likely cost or timeline for system upgrades appears to be prohibitive.

7.4 Interconnection System Impact Study Procedures

7.4.1 The Company shall utilize existing studies to the extent practicable when it performs the study. In the event that the Company determines that a single upgrade may benefit more than one Interconnection Request, the Company may propose or require that the Interconnection Requests be studied on a combined basis.

7.4.2 The Company shall use Reasonable Efforts to complete the Interconnection System Impact Study portion of the IRS within the time frame specified in the IRS Agreement in accordance with Section 7.1.

7.4.3 At the request of Interconnection Customer or at any time The Company determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the Company shall notify Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the Company is unable to complete the Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, the Company shall provide Interconnection Customer all supporting documentation and relevant power flow, stability and short

circuit databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

7.5 Meeting with the Company.
The Company shall have an opportunity to review a first draft of the Interconnection System Impact Study report from its study consultant and provide comments to be incorporated by the study consultant prior to providing a copy of the draft to Interconnection Customer. Within 14 days of providing a draft Interconnection System Impact Study report to Interconnection Customer, the Company shall schedule a meeting with Interconnection Customer at a mutually agreeable date to discuss the results of the draft Interconnection System Impact Study. Within 14 days after this meeting, the Company shall tender the final Interconnection System Impact Study report, unless further study is required.

7.6 Re-Study.
If re-study of the Interconnection System Impact Study is required due to a higher queued project withdrawing from the queue, or a modification of a higher queued project subject to Section 4.4, and such higher queued project was included in the Base Case, Company shall notify Interconnection Customer in writing. Such re-study shall take no longer than 90 days from the date of notice. In accordance with Section 7.1, Interconnection Customer shall pay the estimated cost of re-study in advance and shall pay for the actual cost of the re-study.

Section 8. Interconnection Facilities Study Portion of IRS

8.1 Continuation or Amendment of IRS Agreement and Updated Data.
Within 14 days after delivery of the final Interconnection System Impact Study report to Interconnection Customer, the Company shall provide to Interconnection Customer an update of the expected cost and time to complete for Interconnection Facilities Study portion of the IRS Agreement, or a proposed amendment to the IRS Agreement if a reduced scope or no cost and time to complete was included in the IRS Agreement for an Interconnection Facilities Study, to be referenced in the description of scope attached to the amended IRS Agreement. The IRS Agreement shall provide that Interconnection Customer shall compensate the Company for the actual cost of the Interconnection Facilities Study, and that the Company will draw on Interconnection Customer's deposit to perform the study and continue administration of the Interconnection Request. In the event that Interconnection Customer's remaining deposit will not cover the estimated costs, the Company shall invoice Interconnection Customer for the additional deposit to complete the study and related work.

8.1.1 Interconnection Customer shall sign and return any amendment to the IRS Agreement pursuant to Section 8.1 along with any additional deposit to the Company within 21 days after its receipt, together with any additional required technical data that may be identified by the Company as necessary to complete the Interconnection Facilities Study.

8.1.2 The Company will commence Interconnection Facilities Studies for Interconnection Customers in the order in which it receives completed Interconnection System Impact Study reports and, as applicable, executed amendments to IRS Agreements if an Interconnection Facilities Study was not included in the scope of the original IRS Agreements.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System or Distribution System, including any Network Upgrades identified as necessary in the Interconnection System Impact Studies. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Company Interconnection Facilities and any Network Upgrades necessary to accomplish the interconnection, and an estimate of the time required to complete the construction and installation of such facilities. The Company will not perform an Interconnection Facilities Study for more than one generating output level.

8.3 Interconnection Facilities Study Procedures.

The Company shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. The Company shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within 60 days after the final Interconnection System Impact Study report and, as applicable, receipt of an executed amendment to the IRS Agreement and additional deposit. At the request of Interconnection Customer or at any time the Company determines that it will not meet the required time frame for completing the Interconnection Facilities Study, the Company shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If the Company is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

8.4 Meeting with The Company.

Interconnection Customer may, within 14 days after receipt of the draft Facilities Study report, provide written comments to the Company. Within 14 days of receipt of Interconnection Customer comments on the draft report, or upon receiving Interconnection Customer's written statement that it will not provide comments, the Company shall schedule a meeting with Interconnection Customer at a mutually agreeable date to discuss the results of the Interconnection Facilities Study. The Company shall incorporate Interconnection Customer comments

received at the meeting into the final report. The Company shall issue the final Interconnection Facilities Study report within 14 days after meeting with Interconnection Customer. The Company may reasonably extend such period upon notice to Interconnection Customer if Interconnection Customer's comments require the Company to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Study report. Upon request, the Company shall provide Interconnection Customer supporting documentation and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1.

8.5 Re-Study.
If re-study of the Interconnection Facilities Study is required due to a material change relating to prior study assumptions, the Company shall so notify Interconnection Customer in writing. Such re-study shall take no longer than 60 days from the date of notice. In accordance with Section 8.1, Interconnection Customer shall pay the estimated cost of re-study in advance and shall pay for the actual cost of the re-study.

Section 9. Engineering and Procurement ('E&P') Agreement.

9.1 Availability and Purpose of E&P Agreement. [*Under development.*]

9.2 Termination of E&P Agreement. [*Under development.*]

Section 10. [Reserved]

Section 11. Appendix to Power Purchase Agreements re Interconnection Facilities and Related Requirements.
[*This section is under development.*]

Section 12. [Reserved - Construction of Company's Interconnection Facilities, Distribution Upgrades and Network Upgrades are addressed in power purchase agreements]

Section 13. Miscellaneous

13.1 Confidentiality.
In the event the Parties have executed a confidentiality agreement, the provisions of such agreement shall apply to Confidential Information under this GIP. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of a GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. As soon as reasonably possible, oral designation of Confidential Information shall be confirmed in writing by the designating Party to the other Party.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information.

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates , employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1. The release of Confidential Information shall be subject to Applicable Laws and Regulations and Applicable Reliability Standards.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed

an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to the PUC, or the State.
[*Under development.*]

13.1.9 Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIP including disclosing the Confidential Information to the PUC. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11 The Company shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.
The Company may use the services of subcontractors as it deems appropriate to perform its obligations under this GIP. The Company shall remain primarily responsible to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this GIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and for no other purpose.

13.3 Obligation for Study Costs.

The Company shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies and administration of the Interconnection Requests. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within 21 days of receipt of an invoice therefore. The Company shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.

13.4 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 7.4 or 8.3 that The Company will not complete an Interconnection Study within the applicable time frame for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 7.4 or 8.3 within the applicable time frame for such Interconnection Study, then Interconnection Customer may require the Company to utilize a third party consultant reasonably acceptable to Interconnection Customer and the Company to perform such Interconnection Study under the direction of the Company. At other times, the Company may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

The Company shall convey all databases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or the Company at the Company's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this GIP and the relevant Tariff procedures and protocols as would apply if the Company were to conduct the Interconnection Study, and shall use the information provided to it solely for purposes of performing such services and for no other purposes. The Company shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

13.5.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the GIP, or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within 21 days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this GIP.

13.5.2 External Arbitration Procedures.

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within 14 days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within 21 days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and applicable PUC regulations; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 13, the terms of this Section 13 shall prevail.

13.5.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within 90 days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the GIP and shall have no power to modify or change any provision of the GIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having

jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. Substantive standards for the resolution of disputes resolved hereunder shall reflect applicable legal precedent.

13.5.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Docket No. 2011-0206 – Reliability Standards Working Group

Comments of the Hawaiian Electric Companies Regarding Reliability Standards Drafting Subgroup – Final Report and Recommendations

The January 14, 2013 Final Report and Recommendations ("Report") of the Reliability Standards Drafting Subgroup ("RSDG") includes discussion regarding potential interconnection processes and procedures and attaches as Appendix E a draft document entitled "Hawaiian Electric Company, Inc. Generator Interconnection Procedures – Interconnection Requirements Study Process". The Report expressly acknowledges that Appendix E should be subject to additional review and lists with particularity issues identified by the RSDG which may require further deliberation and consideration in a subsequent proceeding. The Report also recognizes that Hawaiian Electric has already initiated actions to address many of these issues and update their current interconnection procedures, and that accordingly, the Company will file a work plan as a part of its comments on the Report.

The Hawaiian Electric Companies respectfully submit the following comments on the Report for the Commission's consideration. These comments include the Companies' responses to the issues identified in the Report and Hawaiian Electric's work plan for the comprehensive development of interconnection procedures for sub-transmission and transmission level generators which would include necessary modifications to Appendix E to the Report.

Introduction

For project developers on Oahu, the best purpose of a comprehensive set of Generation Interconnection Procedures ("GIP") is to promote an understandable and transparent work flow that will identify the system impacts, interconnection facilities, and cost and schedule considerations that must be known to successfully bring projects through a Power Purchase Agreement (PPA) to construction and commercial operation. The main deliverable of the GIP is the Interconnection Requirements Study ("IRS"). Thus, for meaningful process improvement, the first priorities are to:

(a) clarify what is needed to commence an IRS;

(b) provide a consistent IRS work process and products;

(c) establish durable and reasonably flexible procedures;

(d) coordinate a high volume of projects in an IRS queue;

(e) align the IRS products to directly support a coherent build-out of the remaining grid capacity for distributed generation; and

(f) apply fair principles of cost allocation to add new infrastructure that will be needed.

From the perspective of power system analyses, IRS resource deployment is complicated by a rapidly growing demand to accommodate a wide variety of generation types and sizes. These presently enter and exit the IRS process by way of several existing Tariff Rules with potentially different PPA implications, including net metering ("NEM"), feed-in tariff ("FIT"), a standard interconnection agreement for load customers ("SIA"), bilateral negotiated non-utility generation ("NUG"), and RFP solicitations under Tariff Rule 19. Preferably, the various Rules, application criteria and associated data forms and work timelines can be harmonized to enable a more efficient and predictable GIP process, of which the IRS would be the center piece.

In addition, on Oahu, the entire grid was originally designed for load service with centralized generation interconnected at the 138 kV transmission system. From there, the operating concept was to have one-directional flow through multiple radial 46 kV sub-transmission lines and out to numerous small substations that serve multiple radial 12 kV distribution systems. Today, many proposed renewable generation projects seek to interconnect to the distribution system or the sub-transmission system that happens to run near the proposed project sites. This reverses the predominant flow and turns the grid capacity study process into an effort to fill radial lines to maximum capacity with inbound generation. In this context, at some point there will be limited capacity to interconnect distributed generation projects.

For example, consider inbound generation from the Kahuku region to the 138 kV system at Wahiawa: Accumulated NEM and SIA projects reduce the net load on the 12 kV circuits, multiple existing FIT Tier 1 and 2 applications on any single 12 kV circuit will flow onto the 46 kV lines, the Kahuku and Kawailoa wind projects already fill the 46 kV lines close to thermal capacity, and at the same time one or more FIT Tier 3 applications and one or more NUG projects propose to further compete for the last capacity on the 46 kV lines. In the meantime, any future RFP-selected project in that region will likely result in construction of one or more new lines at a presently-unknown size, cost and in-service date, with an unknown quantity of remaining capacity headroom depending on the size of the generation projects that are selected for a PPA.

A GIP for Oahu needs to be practical and implemented with care. GIP provisions from other jurisdictions need to be carefully considered to apply in the Oahu context. This is why, in part, the Company has initially focused on developing the IRS portion of its proposed GIP. That IRS process is based on actual practice, successful innovations from other jurisdictions, and adaptation to circumstances where there is an overlap among existing Tariff Rules. The IRS process is being documented and issued to meet immediate RSWG deadlines for new deliverables. At the same time the Company

recognizes that meaningful stakeholder review is needed, and this can be facilitated more effectively when the front, middle and back ends of a complete GIP process are presented together, with all of the associated forms updated and revised to promote greater consistency and transparency for the entire IRS and PPA business practice.

"Stand Alone" and "First Ready First Served" Principles for IRS Analyses

As has been successful in other jurisdictions, Hawaiian Electric manages its IRS base cases and dispatch lists so as to compare system impacts on a pre-project and post-project basis. To minimize restudies due to speculative projects dropping out, the preferred approach is to make no presumption of realness from queue seniority alone, and to set the benchmark pre-project condition with only real projects in the base case model. The best measure of realness is having a PPA. This means at the time of commencement of IRS work every similarly situated project will be tested on its own for impacts against known conditions instead of hypothetical multiple project conditions. As a result, the first to obtain a PPA secures the results of the IRS in terms of remaining system capacity and others that delay in becoming real bear the risk of having to be restudied.

This allows the IRS queue to serve as a transparent tracking device, and as a means to promote the principle of first ready first served for resource allocation during the study process. It also reduces any perceived advantage in loading up a queue with projects just to obtain study results ahead of others. In turn, the PPA serves as the best measure of first ready first served with respect to the end objective of an enforceable commitment to allocate limited system capacity in favor of a particular project.

Stand-alone studies greatly improve the validity of study assumptions and reduce the importance of queue position. Moreover, stand-alone studies incent developers to provide complete data as early as possible for the purpose of getting study resources deployed for projects that are ready to proceed. As a practical matter, however, when multiple projects apply in electrical proximity and reasonably close in time, sensitivity analyses may be appropriate to also consider projects that are likely to become real. Group studies also may be appropriate to consolidate the IRS work and pro-rate any expected system upgrades among multiple projects that individually are not likely to afford the cost of upgrades on a stand-alone basis. In addition, portfolio analyses may be appropriate in the context of an RFP. These considerations require a GIP with a reasonable amount of flexibility, including for organization of consultant work plans on a regional basis. Therefore queue position provides no assurance that every project will get through the process at the same pace.

Hawaiian Electric Work Plan

To develop a complete GIP over the next few to several months, Hawaiian Electric proposes to undertake the following action items:

1. Finalize Hawaiian Electric's proposed documentation of IRS process. Complete the necessary internal review and tuning of the draft documentation of the IRS process and provide an updated draft.

2. Harmonize the application and data review processes. Evaluate all applicable existing Rules and recommend possible modifications to develop consistent provisions for the entire range of types and sizes of projects that may require IRS work, ideally to address distribution, sub-transmission, and transmission system interconnections with uniform defined terms and realistic timelines given the comparative technical scope and context. This must take into consideration that (a) small projects are not necessarily easier, cheaper or faster to study than large projects, and (b) RFP projects may have to be studied on a compressed timeline with portfolio analyses to narrow a short list to a final bidders' list.

3. Improve and standardize data collection forms. Review and revise all existing data forms to either one form (or multiple logically similar forms) that will be more understandable to the project developers and the study consultants.

4. Improve and standardize contract instruments for IRS work. Review and revise existing (a) confidentiality principles and related non-disclosure agreement ("NDA") forms, and (b) terms and conditions and related IRS agreement forms. This combined exercise could result in making IRS reports available on a non-confidential basis so that the IRS analyses can become more readily understood by all participants, early in the process. At the same time, it could help to streamline the IRS contracting process and improve transparency of scope and cost expectations, on the basis of a single set of forms to the extent practicable.

5. Develop a standard set of Interconnection Guidelines. Compile, update and explain the relevant (a) planning-based reliability design criteria, (b) engineering-based general facilities requirements, and (c) operations-based procedures for system management. This will require substantial interdepartmental coordination to produce a resilient product for all applications.

6. Clarify the Interconnection-related elements of the Model PPA. Review existing terms and appendices in the Hawaiian Electric Model PPA and revise to locate the presentation of interconnection topics in one place and in a logical sequence. This is intended to simplify the transition from IRS results to PPA requirements, and to make all items clear and reasonably easy to identify across the life of a project, including with

respect to construction, operations and maintenance. As part of this review, Hawaiian Electric proposes to consider the manner of presentation and any relevant and useful terms from Generator Interconnection Agreements from other jurisdictions, to the extent that such could strengthen the Model PPA, for example by developing a single comprehensive appendix.

7. Submit the proposed Hawaiian Electric GIP to an appropriate stakeholder process. Upon completing the assembly of the above items into a comprehensive GIP, conduct an appropriate stakeholder process for review and comments. Hawaiian Electric recommends a docket or stakeholder process to be convened upon receipt of guidance from the Commission with respect to format and timeline.

8. Obtain Commission approval of a Hawaiian Electric GIP. The Company proposes to tender its complete GIP for stakeholder review and comments, make any appropriate revisions to achieve consensus on the reasonableness of a final GIP, and submit that to the Commission for its consideration and approval.

Hawaiian Electric's Preliminary Positions on the Issues Identified in the Report

This summary of issues follows the list that is identified in the RSDG Final Report:

1. Whether a formal Interconnection Request application is appropriate in the context of existing Tariff Rules and should accompanying deposits be required to cover HECO administrative costs.

Necessary improvements can be gained through coordination of the existing array of Rules, data forms, and timelines to facilitate entry into an IRS queue for the purpose of getting studies started, but not as if an IRS is an end in itself, or as if queue position suggests any vested rights of one project over another. At all times the appropriate goal is to obtain a PPA through reasonably efficient process. Queue administration therefore should be limited to activities that contribute to a more effective PPA process. At this time the Company recommends sticking with the cost allocation principles that are stated in existing Rules, subject to any proposed amendments that may derive from the review proposed herein.

2. Whether to include study cost estimates by project size (either fixed or estimated).

Based on IRS experience in 2012, there is very low correlation between project size and complexity and cost of study. With additional observation of trends in 2013, it may be possible to develop general cost ranges with a qualified reference to project size or location on the system. This would have to be calculated on the basis of what

types of analysis are included in an IRS scope. The resulting usable knowledge would relate more to the number and types of reliability concerns than project size per se. For reference, the complexity and cost of a study for a project with a proposed point of interconnection on a 12 kV distribution line may be equal or greater than for a study on a 46 kV sub-transmission line. Therefore, the Company recommends that a range of costs could be shared with developers for comparison from experience with similarly situated projects, rather than setting forth fixed or generalized costs without having first considered the likely study scope in a given context. .

3. Attachment of a standard form Interconnection Request and or NUG Application.

Hawaiian Electric is in agreement as noted in the above discussion for item 1. The Company proposes to establish improved access to commence the IRS process by way of improved data forms, limited applications for NDA, and improved standard IRS agreements, rather than creating a new application form that could conflict with application processes under existing Rules.

4. Whether to specify requirements for site control in relation to IRS work flow.

Requirements for site control help to deter speculative projects and have been implemented in the processes that lead up to an RFP. At this time additional site control requirements have not been needed to control the volume of projects seeking to obtain an IRS. In addition, requirements for partial site control can be controversial in relation to some generation technologies such as wind power, and can impose an administrative burden on the IRS process. The Company proposes to examine whether to implement various IRS readiness milestones when a need may become apparent, but not at this time. The proposed GIP can be subject to periodic revision and reconvened stakeholder process whenever the learning process calls for new and improved queue management tactics.

5. Attachment of a standard IRS Agreement and NDA.

The Company proposes to add these to the draft GIP after internal update and review.

6. Whether and to what extent is an NDA is needed.

The Company proposes to review confidentiality principles and NDA practice as part of developing a complete GIP, bearing in mind principles of transparency and nondiscriminatory grid access. For example, it may be appropriate to require an NDA to obtain base cases and switching diagrams, and it may be appropriate to limit the contents of IRS reports to matters that realistically do not implicate critical infrastructure

concerns. In that context, bona fide study engineers may require an NDA to evaluate system impacts, whereas developers may not need an NDA to obtain an IRS report. Developers need to understand their project impacts and requirements, and that does not call for the same level of detailed information about the overall system. In addition, an NDA may protect pricing and other proprietary information relating to negotiation of a PPA but that kind of information is not required to produce an IRS. IRS reports that discuss reliability compliance should not be held confidential just to serve the competitive interests of individual developers seeking to reduce the transparency of grid access information for others.

7. Resolution of bracketed items, including due dates and performance timelines, and whether to post IRS results.

Hawaiian Electric has removed brackets and inserted tentative timelines for conceptual purposes pending internal review and completion of the remaining GIP components. Qualifying provisions have been added to subordinate GIP timelines to timelines in existing Rules.

8. Whether to include a Standard Engineering and Procurement Agreement.

At this time the Company does not see a need for a standard E&P agreement. The experience to date is that the urgency, scope and commitment to funding to proceed on an E&P basis are project specific and typically involve contract matters well beyond boiler plate provisions.

9. Whether to add a pro forma Generation Interconnection Agreement (GIA) or comparable terms and conditions to be incorporated into PPAs.

Hawaiian Electric is proposing to develop a complete GIP that is aligned with the PPA process to obtain practical results, considering that in this jurisdiction a GIA by itself is not likely to result in the construction of any project. All of the useful benefits of a GIP could be incorporated into the Model PPA by way of improved organization and thoughtful development of the subject matter relating to interconnections. This would simplify the contract negotiation process, reduce any potential for unrealistic expectations of priority from the IRS process, and save the contracting parties from entering into multiple, potentially conflicting agreements. Because the fundamental relationship of the parties is governed by a PPA, the Company does not agree that a GIA would have any value as an instrument that is separate from a PPA.

10. Resolution of Section 13.1.8, Disclosures to the PUC or the State.

This can be addressed in the course of completing the GIP.

11. What is the appropriate venue to address funding/ cost allocation for Network Upgrades and Betterment.

Hawaiian Electric proposes to develop a complete GIP and submit it to an appropriate stakeholder process. Cost allocation principles have been addressed to some extent in other Rules and in other dockets, and there may be some basic processes that can be stated in the GIP. This requires further internal consideration in the course of completing the GIP.

12. Whether the HECO GIP format can be extended to develop comparable GIP work product applicable to MECO and HELCO.

Hawaiian Electric proposes to develop its own complete GIP and then work on means to adapt the same to the IRS environments relating to MECO and HELCO, based upon inter-company communications that will be initiated in the course of developing the Hawaiian Electric GIP.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited	DOCKET NO. 2011-0206

FINAL REPORT OF THE PV SUB-GROUP FOR THE RELIABILITY STANDARDS WORKING GROUP

January 18, 2013

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited	DOCKET NO. 2011-0206

FINAL REPORT OF THE PV SUB-GROUP
FOR THE RELIABILITY STANDARDS WORKING GROUP

The Photovoltaics (PV) Sub-Group (PV Sub-Group) submits this report (Final Report) and its associated attachments to the Hawaii Public Utilities Commission (HPUC or Commission) as the PV Sub-Group's final work product in the Reliability Standards Working Group (RSWG). The RSWG unanimously adopted the PV Sub-Group recommendations referenced in this Final Report at the December 11, 2012 meeting. Pursuant to Orders 30371 (May Order) and 30694 (October Order), the PV Sub-Group respectfully requests the Commission accept this work product as part of the record in the above-captioned proceeding and enact its procedural recommendation to open a new proceeding to consider and integrate the substantive recommendations set forth herein.[1]

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[1] *Order No. 3 0371 Relating to Various Matter in RSWG Process*, filed on May 4, 2012, in Docket 2011-0206, at 1-3 ("Order No. 30371"); *Order No. 3 0694 Clarifying Certain Procedural Matters*, filed on October 18, 2012, in Docket 2011-0206, at 3 ("Order No. 30694").

I. INTRODUCTION AND SUMMARY

Over the past few years, Hawaii has taken a collaborative approach to developing procedures aimed at allowing efficient interconnection and ensuring safe and reliable operation of the utility-owned distribution systems.[2] This collaborative approach resulted in important revisions to the Hawaiian Electric Companies' (HECO's) distribution-level interconnection tariffs in 2011.[3] The work completed in the PV Sub-Group has been a continuation of these efforts to address remaining technical and procedural issues associated with interconnecting distributed generation (DG) under Rule 14H.

The PV Sub-Group members (Members) have worked diligently, conducting frequent and lengthy meetings throughout 2012, to craft the recommendations now presented to the Commission. The Members represent a diverse group of utility, ratepayer, distributed generation advocate, environmental and developer interests. This diverse membership has differing perspectives on how best to balance the need to maintain the safety, reliability and power quality of the state's electric power systems with the need to provide a timely, cost-effective and transparent process for interconnection to the distribution system under Rule 14H. The PV Sub-Group members have worked intensively throughout the RSWG process to discuss and resolve these differences. As an outcome of these meetings, Members made a number of concessions relative to their initial positions on the issues of concern to them in order to reach

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[2] *See Decision and Order No. 3 0027*, filed on December 20, 2011, in Docket No. 2010-0015, at 6-7 ("Order No. 30027"). Appendix I of Rule 14H defines the "distribution system" as "[a]ll electrical wires, equipment, and other facilities at the distribution voltage levels (such as 25kV-HECO only, 12kV, or 4kV) owned or provided by the utility, through which the utility provides electrical service to its customers." HECO Tariff Rule 14H, Appendix I § 1(e).

[3] Order No. 30027 at 68-69.

agreement with the recognition that remaining issues and concerns may be addressed in a subsequent proceeding. The PV Sub-Group is pleased to submit this Final Report with the *unanimous support* of its members.

The PV Sub-Group's efforts have resulted in recommendations that would significantly revise portions of Rule 14H (Attachment 16), identify a proactive approach to integrate DG interconnection and distribution system planning (Attachment 17) (Proactive Approach), and propose creating a distribution-level interconnection queue (Attachment 15). These recommendations are anticipated to maintain the safety, reliability and power quality of the distribution grid while balancing the need for a more timely, efficient and transparent interconnection process. The Final Report provides both proposed tariff revisions and a clear and appropriate path for further improvements to be considered in a subsequent proceeding. In addition, the Final Report includes a summary of an on-going, collaborative effort to share data between the PV industry and the HECO utilities (Attachment 19).

II. THE PV SUB-GROUP'S MANDATE UNDER COMMISSION ORDER NO. 30371

The Commission provided guidance to RSWG members through its May Order, which laid out a list of subject areas to be considered within the working group.[4] A number of those matters fell within the purview of the PV Sub-Group, including improving interconnection screening processes for DG.[5] More specifically, the Commission requested the RSWG "craft recommendations on new, streamlined

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[4] Order No. 30371 at 1-3.

[5] *Id.* at 12.

interconnection screening processes for DG for the HECO Companies" using three resources:[6]

- A National Renewable Energy Laboratory Report entitled *Updating Interconnection Screens for PV System Integration* (NREL Report);
- A California Public Utilities Commission settlement agreement revising Rule 21, California's distribution-level interconnection tariff (Revised Rule 21); and
- The DG screening processes used by the Kaua'i Island Utility Cooperative (KIUC).[7]

The Commission's May Order also notes that parties disputed the "appropriate requirements for monitoring and control of DG" during the Rule 14H docket and requests the RSWG consider this issue again in the instant proceeding.[8] More specifically, the May Order asks whether enhancements to "the monitoring and controllability of PV production" can be used to streamline the interconnection screening process such that "greater penetration of PV systems is possible."[9]

Finally, the May Order directs the RSWG to consider the differences between the interconnection requirements for DG facilities interconnecting under Rule 14H and net-energy metering facilities interconnecting under Rule 18.[10] The RSWG is asked to "resolve any present inconsistencies or ambiguities" between the two rules such that DG interconnection requirements are "consistent regardless of energy procurement method."[11]

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6 *Id.* at 12-13.
7 *Id.*
8 *Id.* at 14.
9 *Id.*
10 *Id.*
11 *Id.*

III. SUBSTANTIVE RECOMMENDATIONS

The substantive recommendations in this Final Report squarely respond to the Commission's directives. All three PV Sub-Group work products are anticipated to streamline the interconnection process for DG without sacrificing the technical rigor that currently exists in Rule 14H. The Proactive Approach and the collaborative data sharing efforts between the PV industry and HECO will leverage existing PV monitoring data to enhance distribution and transmission modeling and increase the penetration of DG on the distribution system. While the relatively short RSWG timeframe has prevented the PV Sub-Group from proposing specific recommendations to resolve discrepancies between Rule 14H and Rule 18, the discussions between Members regarding revisions to Rule 14H and the development of the Proactive Approach have laid a strong foundation upon which to efficiently achieve that task in any subsequent proceeding.

A. Revisions to Rule 14H

The PV Sub-Group makes a number of recommendations to revise the interconnection screens in Rule 14H, Appendix III, Sections 2 and 3 (Revised Rule 14H) in a manner that is anticipated to allow more projects to interconnect more expeditiously without sacrificing safety, reliability and power quality. As explained below, these recommendations are derived from, and informed by, the three sources the Commission asked the PV Sub-Group to consider.

1. Flow Chart

The Revised Rule 14H includes a modified flow chart diagram, which is based on California's Revised Rule 21, to reflect the PV Sub-Group's proposed modifications to Sections 2 and 3. The new flow chart is cleaner and easier to follow than the previous version and should improve transparency and ease communication between HECO and

new interconnection applicants. An improvement in developers' upfront understanding of the Rule 14H process will allow for more timely and cost-effective interconnection.

The flow chart shows the new screens, modified screens, unmodified screens, three new gateway provisions and "quick review" boxes after initial and supplemental review, all of which are explained in detail below. It also re-labels some screens to more accurately align the title of the screen in the flow chart with the title of the screen in the tariff language. The flow chart adds headings to clarify which of the screens are Initial Technical Review Screens and which are Supplemental Review Screens. Further, the flow chart groups Initial Technical Review Screens 1-9 together to reflect the comprehensive, rather than numerically sequential, manner in which HECO engineers apply these screens. Finally, the flow chart combines the three "end zones" in the existing Rule 14H flow chart into two "end zones" and includes new text within each, and a footnote, to better explain the potential results of applying the technical review screens to a project. The first "end zone" denotes interconnection through initial or supplemental review, and the second "end zone" denotes the need for a project to proceed to an Interconnection Requirements Study (IRS).

2. Gateway Provisions

The Revised Rule 14H includes three new gateway provisions to clarify which projects qualify for expedited interconnection and which must proceed through an IRS. Two of the new gateway provisions reflect existing HECO practices regarding the point on the utility system to which an applicant requests interconnection and the type of equipment an applicant will interconnect. An applicant shall proceed directly to an IRS if it is not connecting to the Company's distribution system. This gateway provision

reflects existing Initial Technical Review Screen 1. In addition, a project shall proceed directly to an IRS if it is interconnecting with equipment that is not UL 1741 certified. This gateway provision reflects the existing technical requirements located in Appendix I of Rule 14H.[12] The addition of these two new provisions will increase transparency by better communicating the requirements for interconnection while maintaining the technical rigor of the existing rule.

A third gateway provision will allow applicants to request to proceed directly to an IRS. Experienced developers familiar with the Hawaii interconnection process may already know whether an IRS will be required based on the location and size of a proposed project. This gateway provision allows applicants to make a request to move forward with an IRS more expeditiously. However, the utilities maintain their existing discretion with regard to conducting an IRS, including the provisions in existing Rule 14H, Section 1 that govern the completeness of a project's documentation and the provisions in existing Rule 14H, Section 4 that govern the IRS process itself.

3. Initial Technical Review

The Initial Technical Review Screens allow for the expedited interconnection of projects that are unlikely to cause system impacts that require detailed study. The Revised Rule 14H imports three new screens from California's Rule 21, modifies three existing Rule 14H screens, leaves four existing Rule 14H screens unmodified and deletes two existing screens that are no longer needed. The objective of these changes is to maximize transparency and expediency while maintaining the safety, reliability and power quality of the Company's electric distribution systems.

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[12] *See* HECO Tariff Rule 14H, Appendix I, §§ 5(c), 6(a), and 6(b).

a. New Screens

Screens 1, 6 and 11 are new screens adopted from California's Revised Rule 21. Screen 1 is taken from Revised Rule 21 Screen E and considers potential reliability issues when generators are connected to a single-phase transformer. Screen 1 from the current Rule 14H, which asks if a project's point of interconnection is to a distribution system, has been deleted and replaced by the gateway provision discussed above. Screen 6 is taken from Revised Rule 21 Screen D and considers potential secondary transformer or conductor overloads. Screen 6 from the existing Rule 14H, which is a bypass screen, allowing projects 10 kW or less to bypass other screens, has been moved in its entirety to become Screen 10. Screen 11 is taken from Revised Rule 21 Screen L and considers the potential transmission impacts the interconnection of a DG facility may cause. There is no Screen 11 in the existing Rule 14H.

b. Modified Screens

The PV Sub-Group modified existing Screen 4 to better align it with the recommended Proactive Approach proposal, Attachment 17. In some cases, that approach will allow HECO to determine, or plan upgrades to accommodate, an allowable DG penetration level greater than the 15% of peak load currently used in Screen 4. If the Proactive Approach has already determined an allowable penetration level greater than 15% of peak load on a feeder, or has resulted in planned upgrades that would accommodate a higher penetration level on a feeder, it may no longer be necessary for applicants on that feeder to go through Supplemental Review. The revised language in Screen 4 gives HECO the discretion to allow a project to avoid Supplemental Review in

such instances. Similar language can be found in Note 1 of Supplemental Review Screen 12, which also addresses DG penetration levels.

Since Screen 4 is a penetration screen, it requires HECO to compare the amount of aggregate generation on a distribution feeder with existing metrics for peak load on that feeder. The PV Sub-Group added Note 1 in Screen 4 to better communicate how HECO calculates the aggregate generation on a distribution feeder and how the addition of a proposed generating facility will count towards aggregate generation. Similar language can also be found in Note 3 in Supplemental Review Screen 12, which also addresses DG penetration levels.

Existing Screen 8 asks two questions. The first is whether the short circuit current contribution ratio of the cumulative generating facilities on a line is within acceptable limits for the equipment on the utility's side of the point of interconnection. The second is whether the applicant's short circuit contribution is within acceptable limits for the equipment on the customer's side of the point of interconnection. The Revised Rule 14H splits the two questions embedded in existing Screen 8 into two new screens, Screen 7 and Screen 8, to reflect the approach in Revised Rule 21.

The language in revised Screens 7 and 8 is almost identical to that in the existing Screen 8. An exception for both screens is new language labeled "Note 1", which states that neither Screen 7 nor Screen 8 will be applied to generating facilities less than 10 kW. This new note maintains an existing exemption in the current Rule 14H, which is contained in existing Screen 6. The reconfiguration of the flow chart requires existing Screen 6 to be relabeled as Screen 10, but Note 1 in revised Screens 7 and 8 maintains the small-facilities exemption for these screens.

The same Note 1 has also been added to existing Screen 9, from which generating facilities less than 10 kW are also exempted. Apart from the addition of Note 1 to maintain this exemption, Screen 9 remains unmodified from its original Rule 14H language.

c. Unmodified Language and Screens

The existing Rule 14H represents the cumulative experience of Hawaii's generators and distribution companies in meeting the state's interconnection needs. The Revised 14H Tariff preserves this knowledge and maintains a number of provisions, and much of the language, from the existing interconnection procedures. Screen 2, Screen 3, and Screen 5 remain unmodified from their existing versions. The existing Screen 6 maintains its current language but has simply been renumbered Screen 10, as discussed above. Attachment 16 sets forth the other sections of the revised rule that remain unaltered.

4. Supplemental Review

Supplemental Review allows projects that fail Initial Technical Review to proceed to interconnection without an IRS if the Supplemental Review screens are passed. The Revised Rule 14H deletes the language in existing Subsection 3(d) that governs which projects may interconnect without an IRS. The PV Sub-Group replaces that language with three new screens based on California's Revised Rule 21 and tailored to HECO's systems, the Penetration Test, the Power Quality and Voltage Test, and the Safety and Reliability Test.

The Screen 12 Penetration Test is derived from California's Revised Rule 21 Screen N and is informed by the conclusions in the NREL Report and the KIUC

interconnection procedures. When generating facility capacity on a distribution feeder is less than 100% of the feeder's minimum load, it is less likely to result in power flow from the generating facility back toward the substation and will have a minimal impact on the utility's distribution system. Under the new Screen 12, and the screen's corresponding Note 1, the need for an IRS will be determined by whether the aggregate generating capacity on a line is less than 100% of minimum load, 75% of minimum load or 15% of peak load, depending on the data available for the studied distribution feeder. Note 1 also includes a provision discussing when HECO will begin measuring minimum load on a distribution feeder when no such data is currently available.

Since Screen 12 is a penetration screen, it requires HECO to measure the amount of generation on a distribution feeder in comparison with the feeder's minimum load. Two new Notes describe the methodology HECO will use to measure these characteristics. Note 2 in Screen 12 describes the time of day used to calculate minimum load for different generation types. Note 3 describes an innovative, "cloudy day" methodology to calculate minimum load on feeders with existing PV generation. Note 3 also includes a methodology to calculate the aggregate generation on a distribution feeder and describes how the addition of a proposed generating facility will count towards aggregate generation. Similar language can also be found in Note 1 in Initial Technical Review Screen 4.

The Screen 13 Power Quality and Voltage Test considers the potential adverse voltage and undesirable interference that an interconnecting generator can cause to the distribution system. The Screen 14 Safety and Reliability Test considers a number of

factors that may affect the nature and performance of an interconnection. These two screens are derived from Revised Rule 21 Screen O and Screen P, respectively.

The revised Supplemental Review Section 3 retains, but reorganizes, most of the language in existing Subsections 3(a) through 3(e), except for the deleted language in Subsection 3(d) discussed above. The Revised Section 3 retains the existing explanations of the process when a Supplemental Review Screen is failed (Revised Subsection 3(a)), the potential results from application of the Supplemental Review Screens (Revised Subsection 3(b)), the Supplemental Review timeframes (Revised Subsection 3(d)), and the instances when a facility equipment list is required (Revised Subsection 3(e)). Revised Subsections 3(a) and 3(c) also contain new language discussing the "Quick Review" provisions addressed in the next section of this Final Report.

The revised Supplemental Review Section is anticipated to allow more projects that do not require a full IRS to interconnect on a shorter timeframe. A decrease in the number of projects that require a full IRS could also benefit ratepayers by decreasing the resources HECO must expend to contract with outside consultants to conduct those studies to the extent such expenditures are not compensated by the developer. Moreover, the section increases developers' knowledge of the specific technical issues HECO will take into consideration during Supplemental Review. The section balances this increase in expediency, cost-effectiveness and transparency with additional screens for safety, reliability and power quality to ensure these important objectives are maintained.

5. Opportunity to Avoid Detailed Study Through a Quick Review of Failed Screens

The PV Sub-Group also recommends including an opportunity for HECO to conduct an expedited review of a failed screen (Quick Review) after both Initial

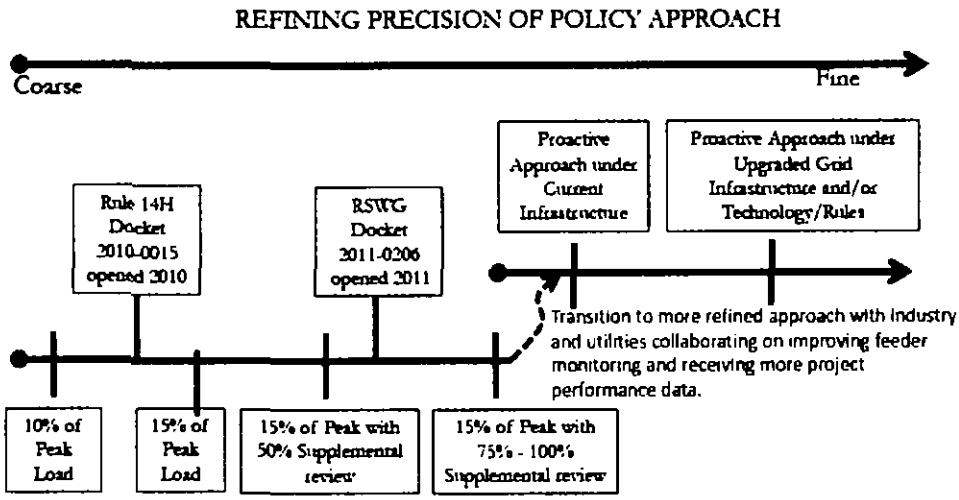
Technical Review and Supplemental Review. Derived from provisions in California's Revised Rule 21, the purpose of a Quick Review is to give HECO the discretion to allow the interconnection of a generator that has failed a screen without requiring the generator to go through detailed study. HECO engineers may be able to identify a solution to address a failed screen based on prior experience, and allowing the applicant to agree to that solution without the need for more study can save time and resources for both the developer and the utility. In this way, the Quick Review provisions will allow interconnections to move forward in a more expedient and cost effective manner, while ensuring the system's safety, reliability and power quality will be maintained.

The Quick Review after the Initial Technical Review Screens (Subsection 2(d)) helps prevent the need for Supplemental Review, while the Quick Review after Supplemental Review Screens (Subsection 3(c)) helps prevent the need for an IRS. The PV Sub-Group intends a "Quick Review" to take place within the existing 15-Business Day timeframe for Initial Technical Review and within the existing 20-Business Day timeframe for Supplemental Review. The Revised Rule 14H language in Subsections 2(d) and 3(c) also includes examples of potential solutions. If a Quick Review does identify a solution, Revised Rule 14H Subsections 2(e) and 3(e), which are almost identical to the language in existing Subsection 3(e), explain the process for the applicant to complete a facility equipment list, if one is necessary to accommodate the identified solution.

B. Proactive Approach

The PV Sub-Group has worked collaboratively to develop a first-of-its-kind utility Proactive Approach that responds directly to the Commission's request to explore

how HECO can utilize PV production data to streamline the screening process such that "greater penetration of PV systems is possible."[13] The Proactive Approach proposal (Attachment 17) coordinates, and mutually enhances, HECO's interconnection and distribution and transmission planning functions. As shown in the image below, which is taken from Attachment 17, the Proactive Approach is a large step forward in refining Hawaii's interconnection procedures:



HECO will utilize the interconnection queue and other data points to establish a reasonable base case of anticipated DG development. Through its distribution and transmission planning effort, it will proactively plan for the aggregate system impacts from expected DG development in order to accommodate higher penetration levels. The coordination of interconnection and planning will identify opportunities where infrastructure upgrades can accommodate both DG and load such that a number of generators and customers can benefit from the upgrades.

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[13] Order No. 30371 at 14.

Specifically, HECO will employ enhanced tools for modeling DG to inform both system and distribution-level planning and operations. Those models will leverage PV production data from individual DG systems, which members of the PV industry recently made available to HECO, to supplement utility monitoring tools. This improved modeling capability will, in turn, enhance a number of areas related to the interconnection of high penetrations of DG, including:

- Assessing potential system and region-level impacts due to high penetrations;
- Evaluating impacts to dispatch and generation, reserve planning, and response to ramping events;
- Informing and streamlining the distribution level interconnection process; and
- Helping to identify circuit penetration capabilities, potential issues, and necessary upgrades.

The overall goal of this collaborative approach is to create a more transparent and efficient process for interconnecting higher levels of DG while maintaining safety, reliability, and power quality across the transmission and distribution infrastructure. The approach will benefit all parties involved, including customers, developers and utilities, as well as the broader public.

C. Distribution-Level Interconnection Queue Proposal

The third PV Sub-Group work product, included as Attachment 15, is an interconnection queue proposal for all distribution-level interconnections. The interconnection queue will give developers a window into the interconnection procedures and the status of projects within that process. Moreover, it will act as an indicator of expected interconnection upgrades, since a developer will be able to ascertain the size, timing and location of projects near its point(s) of interconnection. Further, it will reduce

congestion in the interconnection process by reducing the resources HECO must spend responding to developers' requests for information. By increasing the information available to developers, the interconnection queue will improve timeliness, enhance transparency and defuse the potential for conflicts in the interconnection process. The PV Sub-Group recognizes the HECO Companies' Feed-In Tariff program has its own discrete queue process approved by the Commission in an October 2012 order, which is subject to review at the end of 2012.[14]

D. Solar PV Monitoring

The Members have worked in a remarkably collaborative manner to act upon the Commission's request for the RSWG to explore enhancements to "the monitoring and controllability of PV production."[15] The PV industry has already accommodated during the RSWG, and plans to accommodate in the future, HECO requests for production data. Additionally, HECO will continue to develop its PV monitoring network and identify additional needs for monitoring data from feeders or regions of the distribution grid. HECO will also look for opportunities to obtain needed data by deploying additional utility field monitors or gathering owner or customer-collected data and engaging developers and customers to facilitate any necessary cooperation to gather that data. Attachment 19 summarizes these efforts, discusses how these efforts will continue in the future, and explains the relationship between these efforts and the Proactive Approach.

IV. PROCEDURAL RECOMMENDATION

The PV Sub-Group has been a successful continuation of Hawaii's collaborative

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[14] *Order Approving FIT Tiers 1 and 2 Tariffs, Standard Agreement, and Queuing and Interconnection Procedures and Concurring Opinion of Leslie H. Kondo, Commissioner*, filed on October 13, 2012, in Docket 2008-0273, at 8.

[15] Order No. 30371 at 14.

approach to developing procedures aimed at allowing efficient interconnection and ensuring safe and reliable operation of the utility-owned distribution systems. The October Order gives guidance to the subgroup on the next steps for implementing the attached work products:

> [T]he commission expects to transmit the work product to the commission's Technical Review Committee ("TRC") for review and comment. The commission next expects to open new dockets, if necessary, or incorporate RSWG work product into currently existing dockets, to further refine and/or implement recommendations put forth by the RSWG. To the extent possible, the commission intends to use RSWG work product as a starting point for consideration and possible adoption in any new or currently existing proceedings to best utilize the RSWG's work product and streamline and focus the review of the work product in any secondary proceedings.
>
> "In particular the commission is cognizant that reliability standards and interconnection terms and conditions for large generators, developed as a part of the RSWG process, will require further input from a larger group of stakeholders that would include independent power producers. The commission anticipates using a similar process for proposals relating to distributed generation, net energy metering and photovoltaic interconnection screening processes." [16]

This section outlines the subgroup's procedural recommendations regarding the additional efforts envisioned by the October Order to implement, or, in some cases, more fully develop, the PV Sub-Group's work products.

The PV Sub-Group submits the revisions to Rule 14H in Attachment 16 as a recommendation but acknowledges that more work is required to harmonize these suggested revisions with other parts of Rule 14H as well as include broader participation

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[16] Order No. 30694 at 3.

by stakeholders. It therefore agrees with the Commission's guidance to establish a new proceeding to allow further review before the Commission adopts the suggested revisions.

The Proactive Approach summary describes a series of efforts in which HECO will engage to be more proactive in planning for high penetrations of DG. The comprehensive nature of the Proactive Approach means that it may require revisions to both HECO's tariffs and its internal, non-tariffed business practices. A new docket will provide the PV Sub-Group Members and other potential stakeholders the time and forum needed to develop specific recommendations on where within the Company's tariffs the Proactive Approach should be implemented, if it should be implemented in those tariffs at all. A new docket will also allow for further discussion and evaluation with regard to how the Company may be able to solicit the comments of interested stakeholders in a transparent manner while also preserving efficiencies in interconnecting higher levels of distributed renewable generation and maintaining safety, reliability, and power quality across the transmission and distribution infrastructure.

The interconnection queue proposal in Attachment 15 contains language similar to the language in HECO's Rule 14H. However, it has not yet been determined whether the proposal should be incorporated within the text of Appendix III or as an exhibit to Appendix III. If the former is chosen, other revisions elsewhere in Rule 14H may be required to harmonize the proposal with the existing tariff. For these reasons, the PV Sub-Group respectfully requests a new docket to allow further review to more comprehensively integrate the proposal.

V. OUTSTANDING ISSUES TO BE CONSIDERED IN A SUBSEQUENT PROCEEDING

The PV Sub-Group further recommends that the Commission include the issues discussed in this section within the scope of the subsequent proceeding "to streamline and focus the review of the work product." [17]

A. Incorporation of the Revised Rule 14H, the Proactive Approach and the Interconnection Queue Proposal into Existing HECO Tariffs.

The three major PV Sub-Group work products may need to be integrated into HECO's existing tariff framework, as necessary. The revisions to Rule 14H in Attachment 16 require more work to harmonize the suggested revisions with other parts of Rule 14H to ensure consistency throughout the tariff. An example of these suggested revisions is contained in Section 1 of Appendix III, which describes the "Steps" required for interconnection. The PV Sub-Group anticipates the "Steps", in addition to other parts of Rule 14H, will need to be revised to ensure compatibility with the Revised Rule 14H attached to this report.

Moreover, as explained above, the Proactive Approach may require revisions to both HECO's tariffs and its internal, non-tariffed business practices. The interconnection queue proposal may need to be added to Appendix III and/or require revisions elsewhere in Rule 14H to harmonize it with the existing tariff. The PV Sub-Group recommends that these issues be included in within the scope of the subsequent proceeding.

B. The Allocation of Potential Upgrade Costs Within the Proactive Approach

The Proactive Approach contemplates utility planning and potential construction of upgrades to the distribution system to accommodate anticipated DG growth. The issue

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[17] *Id.* at 3.

of allocating the costs of those upgrades is the main unresolved issue in the proposal. The issue includes the clarification of how costs resulting from upgrades identified in the utility's distribution planning study will be allocated to new generators that seek interconnection and the tariff changes that may be required to implement the approach. The cost allocation issue is similar to, and could potentially expand upon, the existing Rule 14H's consideration of upgrades for consolidated IRSs, discussed in Appendix III, Section 4(g). The PV Sub-Group did not draft a detailed recommendation on this issue because it may require changes to the HECO tariffs and embodies policy choices that may be more appropriate for consideration in a non-confidential proceeding that is open to more stakeholders.

Nonetheless, the PV Sub-Group is able to recommend a general framework for cost allocation. We believe the best path forward is an approach that recognizes the special circumstances that exist for interconnecting small net metered and non-exporting generators. Those customer-generators have little choice about where to locate behind-the-meter systems and, unlike wholesale generators, cannot respond to signals to locate their projects in areas that would minimize interconnection costs. Moreover, the upgrades necessary to accommodate small residential and commercial generators are more likely to be shared such that a number of customers will benefit from upgrades that facilitate a number of small generators.

The PV Sub-Group's recommendation for the next steps in implementing the Proactive Approach, and to integrate the Proactive Approach more fully into Rule 14H interconnection procedures, is to construct a methodology that recognizes these special circumstances and creates mechanisms to ensure the efficient and expedient

interconnection of small residential and commercial net metered and non-exporting generators. The process for stakeholder engagement, and the methodology for allocating the costs of constructing those upgrades and potential cost recovery mechanisms, will need to be determined in the subsequent proceeding.

C. Revisions to the Interconnection Requirements Study Process

Section 4 of Appendix III to Rule 14H discusses the IRS process. A number of revisions will need to be made in that section to better align it with the proposed revisions to Sections 2 and 3 included in this Final Report. Beyond this issue, PV Sub-Group discussions late in the RSWG process centered around other issues pertaining to the IRS that the PV Sub-Group believes should be considered in a subsequent proceeding. Issues *for possible consideration for the IRS process include:*

- The need for, and applicability of, an IRS Letter Agreement and Non-Disclosure Agreement;
- The re-examination of the timelines and interactions between the utilities and the project interconnection applicants;
- Whether the interconnection process should be tightened with regard to providing complete project information in a timely manner in order to meet IRS deadlines, and the consequences if a project proponent does not comply with those deadlines;
- The need for a scoping meeting, or other mechanism, to provide a delineation of the scope, cost and schedule of an IRS;
- Whether an IRS's cost and schedule can be differentiated based on size, technology, intent to serve on-site load, and circuit penetration levels; and, if so, which projects should qualify for a "minor IRS" with a standardized cost;
- Whether the results of an IRS should be made publicly available and/or posted on the HECO website;
- Whether small net metering and non-export generators can be interconnected to the distribution system without having to go through an IRS; and

- The need for Group Studies and the details of a Group Study process.

D. Other Outstanding Issues

The Members also request that a subsequent proceeding include the following within scope:

- Parties should consider modifications to make the Rule 14H proposed revisions compatible with non-PV technologies. For example, both Initial Technical Review Screen 4 and Supplemental Technical Review Screen 12 include a footnote regarding the degree to which existing and proposed generating facilities should count towards aggregate generation on a distribution feeder. The footnote explains that "further discussions are required in the future to substantiate a 10% de-rate factor." Because the PV Sub-Group's focus to date has been on integrating inverter-based PV technologies, the Members believe a review of the Revised Rule 14H is prudent to ensure it is compatible with non-PV technologies.

- Parties should draft revisions to Rule 14H to allow its use by all distribution-level procurement programs, including net-energy metering and feed-in tariff generators. One example of existing issues in the interconnection procedures that need to be resolved is the inconsistent use of the term "interconnection agreement" throughout each program's tariffs.

- HECO should address the footnote in the interconnection queue proposal explaining that the Company is still determining the timeframe for being able to implement the publication of interconnection queue data on its website. HECO is continuing work in this area and was unable to resolve the timing within the RSWG time period. If necessary, it can be addressed in a subsequent proceeding.

- Parties should discuss the customer transformer sizing ratios to better understand the utilities' process for determining when a transformer change out should be required.

VI. CONCLUSION

For the reasons stated above, the PV Sub-Group respectfully requests the Commission adopt this final report as part of the record in Docket 2011-0206. It further requests the Commission initiate a new proceeding that will be necessary to incorporate the PV Sub-Group's three major work products in Rule 14H and include in the scope of the new proceeding the issues set forth in this Final Report. The PV Sub-Group believes that following these recommendations will continue the cooperative spirit of improving

the transparency, efficiency and cost-effectiveness of HECO's interconnection procedures while maintaining the safety, reliability and power quality of its electrical distribution systems.

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DBEDT COMMENTS ON PV SUBGROUP FINAL REPORT

The Department of Business, Economic Development and Tourism ("DBEDT") believes that the Photovoltaics ("PV") Subgroup of the Reliability Standards Working Group ("RSWG") has finalized three significant work products that will accelerate the reliable integration of renewable resources on to the Hawaiian Electric Companies' ("HECO") systems, namely: (1) revisions to portions of Rule 14H pertaining to the interconnection of distributed generation ("DG"); (2) a Proactive Approach process to integrate DG interconnection and distribution system planning and to coordinate HECO's interconnection, distribution and transmission planning functions; and (3) a proposal for creating a distribution-level interconnection queue. DBEDT's comments herein are intended to focus on the timing associated with the recommendations related to these work products.

With respect to the Rule 14H revisions, the PV Subgroup has proposed "a number of recommendations to revise the interconnection screens in Rule 14H, Appendix III, Sections 2 and 3 in a manner that is anticipated to allow more projects to interconnect more expeditiously without sacrificing safety, reliability and power quality." PV Subgroup Final Report at 5. In this regard, DBEDT supports expedited identification and implementation of revised interconnection screens that would immediately and reliably permit greater PV (and to the extent possible, other renewable resource) penetration into the HECO systems.

DBEDT is mindful of the Hawaii Public Utilities Commission's ("Commission") guidance in its October 18, 2012 Order concerning the Commission's expectation to open new dockets as necessary to implement or refine RSWG recommendations and the Commission's recognition of the need for further input related to "proposals relating to distributed generation, net energy metering and photovoltaic interconnection screening processes." Order No. 30694 *Clarifying Certain Procedural Matters*, Docket No. 2011-0206 (filed Oct. 18, 2012) at 3. DBEDT respects these views and supports the PV Subgroup's recommendation that the Commission open a new proceeding to consider and integrate the substantive recommendations set forth in the PV Subgroup's Final Report. Indeed, as identified in DBEDT's separate comments submitted today in response to the Independent Facilitator's request for additional work, DBEDT believes that the Commission should open a new "Interconnection Procedures" docket to address such issues on a coordinated basis.

At the same time, given the number of significant issues that have been identified by the various RSWG subgroups on important proceedings that should be opened, DBEDT believes it is consistent with the Commission's guidance in Order No. 30694 (as well as administrative efficiency and achievement of the State's renewable goals) for the RSWG parties to provide the Commission with clear recommendations on those issues that can be reliably and cost-effectively implemented on a more accelerated basis subject to full vetting and administrative process. To that end, DBEDT believes the Commission should issue an expedited Order directing the PV Subgroup to identify the revised screens or other revisions that can be immediately implemented in a reliable fashion, even if the revisions are implemented on an interim basis, subject to review by all interested parties and the Commission. Given the Independent Facilitator's encouragement, DBEDT respectfully submits that, to the extent they agree and believe it is within their purview, the Commission's consultant, Brendan Kirby, members of the Technical Review Committee ("TRC") or the Independent Facilitator could also work through the Commission to identify the screens that can be implemented immediately in furtherance of expedited Commission action on such issues.

In a similar vein, DBEDT supports the PV Subgroup's recommendation pertaining to the Proactive Approach, particularly with respect to exploration of procedures that will promote transparency in the Proactive Approach process. In this regard, DBEDT believes that such procedures should provide appropriate information sharing and comment opportunities for interested stakeholders as well as reporting requirements. DBEDT understands that the HECO Companies are already moving ahead with some of the Proactive Approach processes, such as using a new cluster-based methodology and enhanced planning models. Summary of Proposal for Proactive Review Approach at 6. These activities are consistent with DBEDT's view that the RSWG should implement as many best practices that do not have adverse cost or reliability impacts in furtherance of maximizing the reliable integration of renewable resources into the HECO systems. Similarly, some members of the PV Subgroup have publicly acknowledged the Proactive Approach developed during the RSWG process as a means to encourage greater use of rooftop solar systems. We support that view, and given the broader goals of the Proactive Approach, DBEDT believes more can and should be done on an expedited basis.

DBEDT thus supports Commission direction on the identification of additional tasks or procedures associated with the Rule 14H revisions and Proactive Approach that can be accomplished on an accelerated basis, including a commitment from HECO to immediately allow expanded stakeholder interaction and reporting of its Proactive Approach analyses.

Draft Interconnection Queue Language

Any applicant for Interconnection to the Company's Distribution System must submit a complete and valid Interconnection Application. An Interconnection Application will be considered complete and valid when all items required for an Interconnection Application have been received by the Company and deemed valid by the Company. An Applicant shall provide the Company any additional requested information needed to constitute a complete and valid request within twenty (20) business days from the date of written notification from the Company that an Application is incomplete or invalid.

The Company shall date stamp each Interconnection Application on the day the Interconnection Application is received and assign a queue position to all applicants. If there are no deficiencies in the Interconnection Application, the queue position will be based on the date the Company received the Interconnection Application. If there are deficiencies in the Interconnection Application, the queue position will be based on the date the Company determines the Interconnection Application to be complete and valid. Should the Company provide written notification to an applicant regarding an incomplete Interconnection Application after the 15-business day deadline for providing such written notification, and the applicant submits any additional information required for a valid Interconnection Application within the 20-business day deadline to respond to such notification, the applicant's queue position shall be set on the final day of the period in which the Company was obligated to provide written notification, provided that the Company determines the Interconnection Application is complete and valid.

The Company shall maintain a single queue for all applications governed by this Rule 14H with a Point of Interconnection on the Company's Distribution System.

1. Publication of the Interconnection Queue

The Company shall publish and update monthly on its website the interconnection queue for all Interconnection Applications governed by this Rule 14H with a Point of Interconnection on the Company's Distribution System that have been assigned a queue position.[1] The published interconnection queue shall include the following information for each Interconnection Application governed by this Rule 14H:

a) Interconnection Application and Queue Position Data

(i) The project number;

(ii) The queue position;

[1] HECO is still reviewing the timeframe of publishing and updating the interconnection queue on its website each month.

(iii) The project developer's ID (by contractor license number);

(iv) The date the Interconnection Application was received by the Company;

(v) The date the Interconnection Application was determined to be complete and valid;

(vi) The procurement program to which the Applicant applied;

(vii) The IRS initiation date, as applicable;

(viii) The IRS completion date, as applicable; and

(ix) The date by which the project must be completed.

b) Applicant Generating Facility/Storage System and Point of Interconnection Data

(i) The project's maximum MW electrical output;

(ii) The type of generating or storage facility to be constructed;

(iii) The proposed project location by island region; and

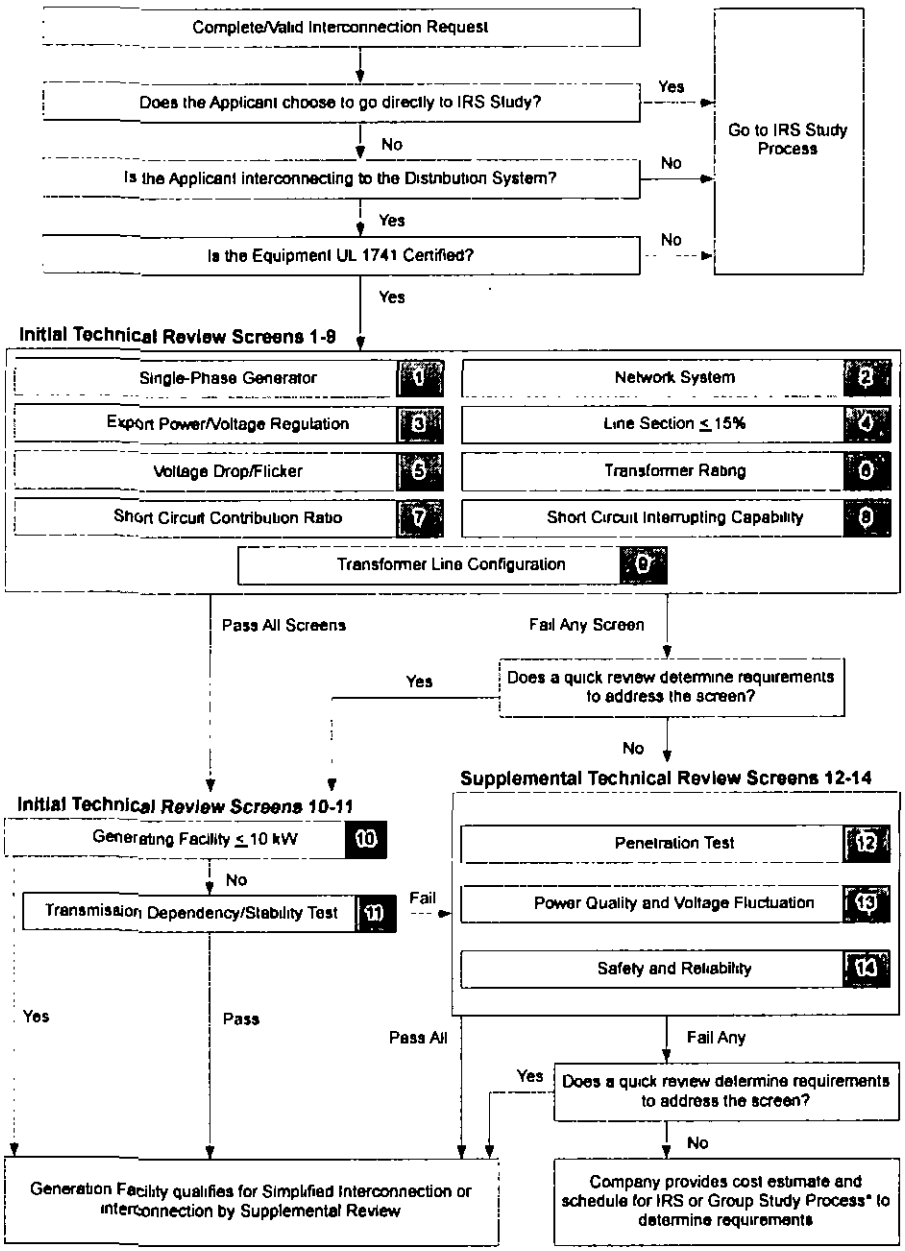
(iv) The proposed Point of Interconnection location by substation/area and, if applicable, circuit.

RSWG PV-DG Subgroup
Rule 14H Sections 2-3 Recommendation

2. Technical Review Process

a. The following flowchart provides, for illustrative purposes, the major steps in the technical review process:

TECHNICAL REVIEW PROCESS FLOW CHART



- "Group Study Process" may include a consolidated IRS or a proactive utility determination of interconnection requirements covering multiple Generating Facilities.

b. Explanation of the screens used in the technical review process:

Introduction:

The technical review process allows for the timely approval for the interconnection of Generating Facilities to the Company's Distribution System that will operate in parallel with the Company's Distribution System. The technical review process includes a screening to determine if a Generating Facility qualifies for Simplified Interconnection, or if Supplemental Review is needed to determine requirements, if any, beyond those of a Simplified Interconnection, or if an Interconnection Requirement Study (IRS) is needed to determine interconnection requirements. The Company will perform an Initial Technical Review unless (1) an Applicant applies for an IRS directly, (2) an Applicant is not connecting to the Company's Distribution System, or (3) an Applicant is interconnecting with equipment that is not UL 1741 certified. If (1), (2), or (3) applies, the Applicant will proceed directly to an IRS.

Note: Failure to pass any screen of the Initial Technical Review process or Supplemental Review process means only that further review may be required to determine additional requirements, if any, or if an IRS is needed before the Generating Facility can be approved for interconnection with the Company's Distribution System. It does not mean that the Generating Facility cannot be interconnected. Though not explicitly covered in the review process, the Generation Facility shall be designed to meet all of the applicable requirements in Appendix I of Rule 14H.

Purpose:

The technical review process determines the following:

1) If a Generating Facility qualifies for Simplified Interconnection,

2) If a Generating Facility can be made to qualify for interconnection by performing a Supplemental Review that will be able to determine additional requirements, if any, or

3) If an IRS is required, the cost estimates and rough schedule for performing the IRS.

Initial Technical Review Screens:

Screen 1: If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, does it cause unacceptable imbalance between the two phases of the 240 volt service?

If Yes, perform Supplemental Review.

If No, continue to Screen 2.

Significance: Generating Facilities connected to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 volt service.

Screen 2: Is the Point of Interconnection to a Network System?

If Yes, perform Supplemental Review.

If No, continue to Screen 3.

Significance: Special considerations must be given to Generating Facilities proposed to be installed on a Network System because of the design and operational

aspects of network protectors. There are no such considerations for radial Distribution Systems.

Screen 3: If exporting power across the Point of Interconnection, can the power export cause a reversal of power flow at any voltage regulation device that is not bi-directional?

If Yes, perform Supplemental Review.

If No, continue to Screen 4.

Significance: If it can be assured that the Generating Facility will not export power, or if exported power will not cause a reversal of power flow at a voltage regulation device that is not designed to handle reverse power flow, the Company's Distribution System does not need to be studied for load-carrying capability or Generating Facility power flow effects on the Company's voltage regulators.

Screen 4: Is the aggregate Generating Facility capacity on the Line Section less than or equal to the greater of 15% of Line Section peak load or a percentage of minimum load predetermined and posted by the utility for that feeder?

If Yes, continue to Screen 5.

If No, perform Supplemental Review.

Significance: 1) Low penetration of Generating Facility installations will have a minimal impact on the operation and load restoration efforts of the Company's Distribution System.

2) The operating requirements for a high penetration of Generating Facilities may be different since the impact on the Company's Distribution System will no longer be minimal, therefore requiring additional study or controls.

Note 1: For an inverter-based Generating Facility (e.g., a photovoltaic facility), the facility capacity for purposes of this screen shall be a number calculated by taking either project size in kW or AC inverter rating (whichever is lower) and applying to it a de-rating factor of 10%** to account for equipment inefficiencies, non-optimal installation conditions, and related factors. The same method shall be applied to determine the aggregate capacity of all inverter-based existing Generating Facilities on the feeder.

Screen 5: Is the voltage flicker and/or drops associated with the Generating Facility within IEEE 519 or IEEE 1453 limits?

If Yes, continue to Screen 6.

If No, perform Supplemental Review.

Significance: 1) This screen addresses potential voltage fluctuation problems for Generating Facilities that start by motoring.

2) When starting, Generating Facilities should have minimal impact on the service voltage to other Customers.

3) This screen addresses voltage flicker at the Point of Interconnection caused by the Generating Facility. Passing this screen does not relieve the Customer from ensuring that its Generating Facility complies with the flicker requirements of Rule 14H.

Screen 6: Do the maximum aggregated gross ratings for all the Generating Facilities connected to a secondary distribution transformer exceed the transformer or secondary conductor rating, absent the Applicant's generators?

If Yes, go to Supplemental Review.

** Parties recognize that further discussions are required in the future to substantiate a 10% de-rate factor.

If No, continue to Screen 7.

Significance: This screen addresses potential secondary transformer or secondary conductor overloads.

Screen 7: Is the Short Circuit Current Contribution Ratio within acceptable limits?

If Yes, continue to Screen 8.

If No, perform Supplemental Review.

When measured at primary side (high side) of a Dedicated Distribution Transformer serving a Generating Facility, the sum of the short circuit contribution ratios of all generating facilities connected to the Company's Distribution System circuit that serves the Generating Facility must be less than or equal to 0.1 (10%).

Significance: If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Company's Distribution System's short circuit duty, fault detection sensitivity, relay coordination or fuse-saving schemes.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Note 2: The ampere rating of the Customer's service equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this provision to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

Screen 8: Is the Short Circuit interrupting capability exceeded?

If Yes, perform Supplemental Review.

If No, continue to Screen 9.

When measured at the secondary side (low side) of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the Customer's service equipment.

Significance: If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Customer's service equipment.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Note 2: The ampere rating of the Customer's service equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this provision to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

Screen 9: Is the Line Configuration Screen (see below) acceptable for Simplified Interconnection?

If Yes, continue to Screen 10.

If No, perform Supplemental Review.

Line Configuration Screen: Identify primary distribution line configuration that will serve the Generating Facility. Based on the type of interconnection to be used for the

Generating Facility, determine from the table below if the proposed Generating Facility passes the screen.

Table I

Primary Distribution Line Type Configuration	Type of Interconnection to be Made to Primary Distribution Line	Results/Criteria
Three-phase, three wire	Any type	Pass Screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four wire (For any line that has such a section OR mixed three wire and four wire)	All others	To pass, aggregate Generating Facility nameplate rating must be less than or equal to 10% of Line Section peak load

Significance: If the primary distribution line serving the Generating Facility is of a "three-wire" configuration, or if the Generating Facility's distribution transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about overvoltages to the Company's or other Customer's equipment caused by loss of system neutral grounding during the operating time of the non-islanding protective function.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Screen 10: Is the gross rating of the Generating Facility 10 kW or less?

If Yes, the Generating Facility qualifies for Simplified Interconnection. Skip remaining screens.

If No, continue to Screen 11.

Significance: The Generating Facility will have a minimal impact on fault current levels and any potential line over-voltages from loss of the Company's Distribution System neutral grounding.

Screen 11: Is the Interconnection Request for an area where: (i) there are known, or posted, transient stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to the Company, with Transmission System interconnection requests? Where (i) or (ii) above are met, could the impacts of the proposed Generating Facility to the Transmission System require an IRS?

If Yes, perform Supplemental Review.

If No, the Generating Facility qualifies for Simplified Interconnection.

Significance: Special consideration must be given to those areas identified as having current or future (due to currently pending interconnection requests) system dependency and stability concerns.

c. Within fifteen (15) business days of the date the Customer's Interconnection Application is deemed complete, the Company will complete the Initial Technical Review and notify the Customer of the results. The Company, for good cause, may modify the time limits to conduct the Initial Technical Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

d. In the event that Supplemental Review is triggered by a failure of Screens 1 through 11, a quick review of the failed Screen(s) within the timeframe established for Initial Technical Review, or any modified time limits, may determine the requirements to address the failure(s), in which case Supplemental Review may not be necessary. Otherwise, Supplemental Review is required. Some examples of requirements that may be available

to address the failure of Screens 1 through 11 without the need for Supplemental Review include:

1. Replace an overloaded distribution transformer with a larger transformer.
2. Replace overloaded secondary conductors with larger conductor.
3. Installation of an appropriately sized grounding transformer or other means to effectively ground a generator.
4. Determine if phase balancing on the transformer is possible with minimal review.
5. If possible without further study, check if the Generating Facility will actually overstress equipment.

e. If a quick review of the failed Screen(s) results in interconnection requirements of equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities, the Customer must also complete a Facility Equipment List, which will identify such equipment, space and/or data. The Facility Equipment List will be included as Exhibit B to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

f. The Initial Technical Review will result in the Company providing either: (a) if all of the Initial Technical Review Screens are passed, the Generating Facility qualifies for Simplified Interconnection, and an executable interconnection agreement for the Customer's signature; or, (b) if one or more screens are not passed, notification whether Supplemental Review will be required and the results, in writing, of all Initial Technical Review screenings.

3. Supplemental Review

a. If a Generating Facility has failed to meet one or more of the Initial Technical Review screens for Simplified Interconnection as proposed, and a quick review of the failed screen(s) cannot determine the requirement(s) to address the failure(s), the Company will notify the Customer upon completing Initial Technical Review that a Supplemental Review as described in this section is needed.

b. The Supplemental Review will result in the Company providing either: (a) Simplified Interconnection, (b) interconnection requirements beyond those for a Simplified Interconnection, and a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirements identified by the Supplemental Review, or (c) a determination that an IRS is required and a good faith cost estimate and schedule for the completion of the IRS, including an identification of the specific analysis and/or reviews that will be performed as part of the IRS.

c. The Supplemental Review consists of Screens 12 through 14. If any of the Screens are not passed, a quick review of the failed Screen(s) within the timeframe established for Supplemental Review, or any modified time limits, may determine the requirements to address the failure(s), in which case an IRS may not be necessary. Otherwise, an IRS is required. Some examples of requirements that may be available to address the failure of Screens 12 through 14 without the need for an IRS include:

   1. Replacing a fixed capacitor bank with a switched capacitor bank.
   2. Adjustment of line regulation settings.
   3. Simple reconfiguration of the distribution circuit.

Supplemental Review Screens:

Screen 12 (Penetration Test): Where 12 months of Line Section minimum load data is available, as measured (or observed) at the feeder or substation, is the aggregate Generating Facility capacity for the Line Section less than 100% of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

If Yes, continue to Screen 13.

If No, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required. Continue to Screen 13. (Note: If an IRS is required, applicants will continue to the IRS after review of the remaining Supplemental Review Screens.)

Significance: Aggregate Generating Facility capacity that is less than 100% of minimum load is less likely to result in power flow from the Generating Facility back toward the substation and will have a minimal impact on equipment loading, voltage, system operational impacts, and protection of the Company's System.

Note 1: If measured (or observed) minimum load is not available for a feeder or substation, the utility shall use reasonable efforts to calculate or estimate minimum load from existing data or models. If minimum load data is not available and must be calculated or estimated, Screen 12 defaults to the higher of either 75% of the estimated/calculated minimum load or a percentage of minimum load predetermined and posted by the utility for that feeder. If minimum load on a feeder cannot be measured, observed, calculated or estimated despite reasonable efforts, this screen

defaults to 15% of Line Section peak load, and the Company shall promptly undertake efforts to begin measuring minimum load for that feeder.

Note 2: The type of generation will be taken into account when calculating, estimating, or determining feeder or Line Section minimum load relevant for the application of this screen. Solar generation systems with no battery storage shall use the daytime minimum load that is coincident with optimal output of the generator (as may occur during 10 am to 2 pm for fixed panel systems). Other generation uses feeder or Line Section minimum load over the entire day or a timeframe coincident with its output.

Note 3: For an inverter-based Generating Facility (e.g., a photovoltaic facility), the facility capacity for purposes of this screen shall be a number calculated by taking either project size in kW or AC inverter rating (whichever is lower) and applying to it a de-rating factor of 10%** to account for equipment inefficiencies, non-optimal installation conditions, and related factors. The same method shall be applied to determine the aggregate capacity of all inverter-based existing Generating Facilities on the feeder. Minimum load shall be established on feeders with existing photovoltaic generation by the measured "cloudy" day conditions which will likely represent the load with limited photovoltaic generation (20-30% irradiance).

Screen 13 (Power Quality and Voltage Tests): In aggregate with existing generation on the Line Section,

a) Can it be determined within the Supplemental Review that the voltage regulation on the Line Section can be maintained in compliance with

** Parties recognize that further discussions are required in the future to substantiate a 10% de-rate factor.

Conservation Voltage Regulation requirements under all system conditions?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE 1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the point of common coupling?

If Yes to all, continue to Screen 14.

If No, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required. Continue to Screen 14. (Note: If an IRS is required, applicants will continue to the IRS after review of the remaining Supplemental Review Screens.)

Significance: Adverse voltages and undesirable interference may be experienced by other customers on the Company's Distribution System caused by operation of the Generating Facility.

Screen 14 (Safety and Reliability Tests): Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without an IRS?

If Yes, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required.

If No, Supplemental Review is complete.

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an interconnection. These include, but are not limited to:

1. Generation energy source

2. Modes of synchronization

3. Unique system topology

4. Possible impacts to critical load customers

5. Possible safety impacts

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (*i.e.*, several large commercial customers)?

2. Is there an even or uneven distribution of loading along the feeder?

3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (*i.e.*, 600A class cable)?

4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?

5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility

to a neighboring distribution circuit/substation may trigger overloads or voltage issues?

6. Does the Generating Facility utilize certified anti-islanding functions and equipment?

d. The Supplemental Review shall be completed, absent any extraordinary circumstances, within twenty (20) business days of completion of Initial Technical Review. The Company, for good cause, without extraordinary circumstances, may modify the time limits to conduct the Supplemental Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

e. If the Supplemental Review results in interconnection requirements beyond those for a Simplified Interconnection, the Customer must also complete a Facility Equipment List, which will identify equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities. The Facility Equipment List will be included as Exhibit B to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

2. Technical Review Process

a The following flowchart provides, for illustrative purposes, the major steps in the technical review process:

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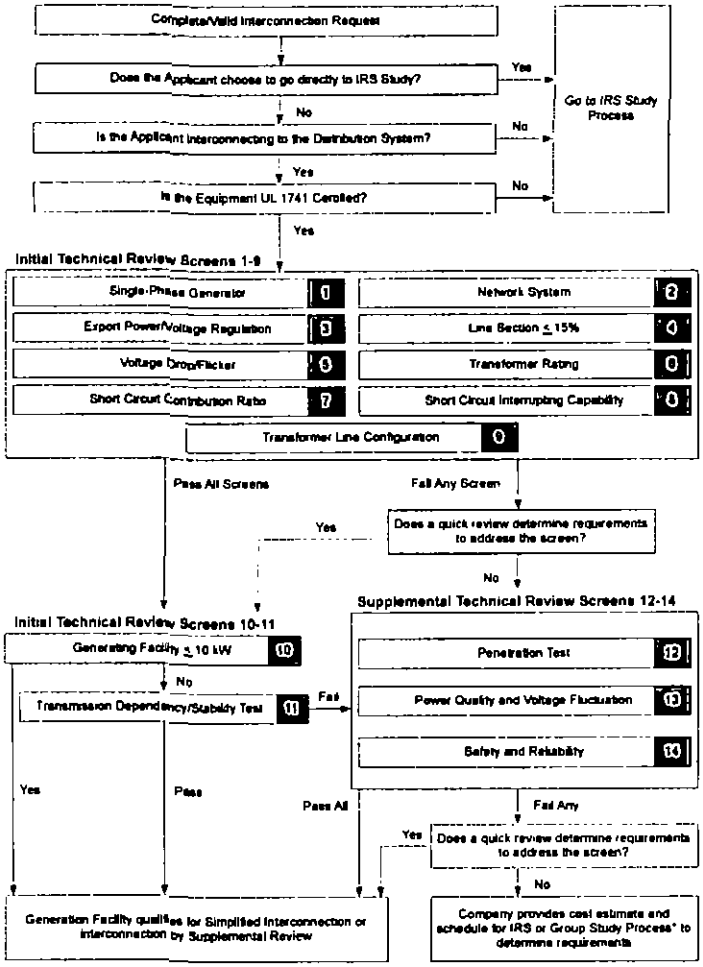
TECHNICAL REVIEW PROCESS FLOW CHART



* "Group Study Process" may include a consolidated IRS or a proactive utility determination of interconnection requirements covering multiple Generating Facilities.

b. Explanation of the screens used in the technical review process:

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Introduction:

The technical review process allows for the timely approval for the interconnection of Generating Facilities to the Company's Distribution System that will operate in parallel with the Company's Distribution System. The technical review process includes a screening to determine if a Generating Facility qualifies for Simplified Interconnection, or if Supplemental Review is needed to determine requirements, if any, beyond those of a Simplified Interconnection, or if an Interconnection Requirement Study (IRS) is needed to determine interconnection requirements. The Company will perform an Initial Technical Review unless (1) an Applicant applies for an IRS directly, (2) an Applicant is not connecting to the Company's Distribution System, or (3) an Applicant is interconnecting with equipment that is not UL 1741 certified. If (1), (2), or (3) applies, the Applicant will proceed directly to an IRS.

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Note: Failure to pass any screen of the Initial Technical Review process or Supplemental Review process means only that further review may be required to determine additional requirements, if any, or if an IRS is needed before the Generating Facility can be approved for interconnection with the Company's Distribution System. It does not mean that the Generating Facility cannot be interconnected. Though not explicitly covered in the review process, the Generation Facility shall be designed to meet all of the applicable requirements in Appendix I of Rule 14H.

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Purpose:

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The technical review process determines the following:

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1) If a Generating Facility qualifies for Simplified Interconnection,

2) If a Generating Facility can be made to qualify for interconnection by performing a Supplemental Review that will be able to determine additional requirements, if any, or

3) If an IRS is required, the cost estimates and rough schedule for performing the IRS.

Initial Technical Review Screens:

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Screen 1: If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, does it cause unacceptable imbalance between the two phases of the 240 volt service?

If Yes, perform Supplemental Review.

If No, continue to Screen 2.

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Significance: Generating Facilities connected to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 volt service.

Screen 2: Is the Point of Interconnection to a Network System?

If Yes, perform Supplemental Review.

If No, continue to Screen 3.

Significance: Special considerations must be given to Generating Facilities proposed to be installed on a Network System because of the design and operational aspects of network protectors. There are no such considerations for radial Distribution Systems.

Screen 3: If exporting power across the Point of Interconnection, can the power export cause a reversal of power flow at any voltage regulation device that is not bi-directional?

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If Yes, perform Supplemental Review.

If No, continue to Screen 4.

Significance: If it can be assured that the Generating Facility will not export power, or if exported power will not cause a reversal of power flow at a voltage regulation device that is not designed to handle reverse power flow, the Company's Distribution System does not need to be studied for load-carrying capability or Generating Facility power flow effects on the Company's voltage regulators.

Screen 4: Is the aggregate Generating Facility capacity on the Line Section less than or equal to the greater of 15% of Line Section peak load or a percentage of minimum load predetermined and posted by the utility for that feeder?

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If Yes, continue to Screen 5.

If No, perform Supplemental Review.

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Deleted: *If No*, perform Supplemental Review to determine cumulative impact on Line Section .

Significance: 1) Low penetration of Generating Facility installations will have a minimal impact on the operation and load restoration efforts of the Company's Distribution System.

2) The operating requirements for a high penetration of Generating Facilities may be different since the impact on the Company's Distribution System will no longer be minimal, therefore requiring additional study or controls.

Note 1: For an inverter-based Generating Facility (e.g., a photovoltaic facility), the facility capacity for purposes of this screen shall be a number calculated by taking

either project size in kW or AC inverter rating (whichever is lower) and applying to it a de-rating factor of 10%** to account for equipment inefficiencies, non-optimal installation conditions, and related factors. The same method shall be applied to determine the aggregate capacity of all inverter-based existing Generating Facilities on the feeder

Screen 5: Is the voltage flicker and/or drops associated with the Generating Facility within IEEE 519 or IEEE 1453 limits?

If Yes, continue to Screen 6.

If No, perform Supplemental Review.

Significance: 1) This screen addresses potential voltage fluctuation problems for Generating Facilities that start by motoring.

2) When starting, Generating Facilities should have minimal impact on the service voltage to other Customers.

3) This screen addresses voltage flicker at the Point of Interconnection caused by the Generating Facility. Passing this screen does not relieve the Customer from ensuring that its Generating Facility complies with the flicker requirements of Rule 14H.

Screen 6: Do the maximum aggregated gross ratings for all the Generating Facilities connected to a secondary distribution transformer exceed the transformer or secondary conductor rating, absent the Applicant's generators?

** Parties recognize that further discussions are required in the future to substantiate a 10% de-rate factor

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If Yes, go to Supplemental Review.

If No, continue to Screen 7.

Significance: This screen addresses potential secondary transformer or secondary conductor overloads.

Screen 7: Is the Short Circuit Current Contribution Ratio within acceptable limits?

If Yes, continue to Screen 8.

If No, perform Supplemental Review.

When measured at primary side (high side) of a Dedicated Distribution Transformer serving a Generating Facility, the sum of the short circuit contribution ratios of all generating facilities connected to the Company's Distribution System circuit that serves the Generating Facility must be less than or equal to 0.1 (10%).

Significance: If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Company's Distribution System's short circuit duty, fault detection sensitivity, relay coordination or fuse-saving schemes.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Note 2: The ampere rating of the Customer's service equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this provision

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Deleted: Significance: . Inverter-based generating facilities less than 250 kW interconnecting through inverters that meet UL 1741, or latest version (the Standard for Inverters, Converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources) and IEEE 1547, or latest version (the IEEE Standard for Interconnecting Distribution Resources with Electric Power Systems) have minimal impact to the short circuit currents Self excited synchronous generators present more interconnection issues. .

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to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

Screen 8: Is the Short Circuit interrupting capability exceeded?

If Yes, perform Supplemental Review.

If No, continue to Screen 9.

When measured at the secondary side (low side) of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the Customer's service equipment.

Significance: If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Customer's service equipment.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Note 2: The ampere rating of the Customer's service equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this provision to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

Screen 9: Is the Line Configuration Screen (see below) acceptable for Simplified Interconnection?

If Yes, continue to Screen 10.

If No, perform Supplemental Review.

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Line Configuration Screen: Identify primary distribution line configuration that will serve the Generating Facility. Based on the type of interconnection to be used for the Generating Facility, determine from the table below if the proposed Generating Facility passes the screen.

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Table I

Primary Distribution Line Type Configuration	Type of Interconnection to be Made to Primary Distribution Line	Results/Criteria
Three-phase, three wire	Any type	Pass Screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four wire (For any line that has such a section OR mixed three wire and four wire)	All others	To pass, aggregate Generating Facility nameplate rating must be less than or equal to 10% of Line Section peak load

Significance: If the primary distribution line serving the Generating Facility is of a "three-wire" configuration, or if the Generating Facility's distribution transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about overvoltages to the Company's or other Customer's equipment caused by loss of system neutral grounding during the operating time of the non-islanding protective function.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Screen 10: *Is the gross rating of the Generating Facility 10 kW or less?*

If Yes, the Generating Facility qualifies for Simplified Interconnection. Skip remaining screens.

If No, continue to Screen 11.

Significance: The Generating Facility will have a minimal impact on fault current levels and any potential line over-voltages from loss of the Company's Distribution System neutral grounding.

Screen 11: Is the Interconnection Request for an area where: (i) there are known, or posted, transient stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to the Company, with Transmission System interconnection requests? Where (i) or (ii) above are met, could the impacts of the proposed Generating Facility to the Transmission System require an IRS?

If Yes, perform Supplemental Review.

If No, the Generating Facility qualifies for Simplified Interconnection.

Significance: Special consideration must be given to those areas identified as having current or future (due to currently pending interconnection requests) system dependency and stability concerns.

c. Within fifteen (15) business days of the date the Customer's Interconnection Application is deemed complete, the Company will complete the Initial Technical Review and notify the Customer of the results. The Company, for good cause, may modify the time limits to conduct the Initial Technical Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

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d. *In the event that Supplemental Review is triggered by a failure of Screens 1 through 11, a quick review of the failed Screen(s) within the timeframe established for Initial Technical Review, or any modified time limits, may determine the requirements to address the failure(s), in which case Supplemental Review may not be necessary. Otherwise,*

Supplemental Review is required. Some examples of requirements that may be available to address the failure of Screens 1 through 11 without the need for Supplemental Review include:

1. Replace an overloaded distribution transformer with a larger transformer.
2. Replace overloaded secondary conductors with larger conductor.
3. Installation of an appropriately sized grounding transformer or other means to effectively ground a generator.
4. Determine if phase balancing on the transformer is possible with minimal review.
5. If possible without further study, check if the Generating Facility will actually overstress equipment.

e. If a quick review of the failed Screen(s) results in interconnection requirements of equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities, the Customer must also complete a Facility Equipment List, which will identify such equipment, space and/or data. The Facility Equipment List will be included as Exhibit B to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

f. The Initial Technical Review will result in the Company providing either: (a) if all of the Initial Technical Review Screens are passed, the Generating Facility qualifies for Simplified Interconnection, and an executable interconnection agreement for the Customer's signature; or, (b) if one or more screens are not passed, notification whether

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Supplemental Review will be required and the results, in writing, of all Initial Technical Review screenings.

3. **Supplemental Review**

a. If a Generating Facility has failed to meet one or more of the Initial Technical Review screens for Simplified Interconnection as proposed, and a quick review of the failed screen(s) cannot determine the requirement(s) to address the failure(s), the Company will notify the Customer upon completing Initial Technical Review that a Supplemental Review as described in this section is needed.

b. The Supplemental Review will result in the Company providing either: (a) Simplified Interconnection, (b) interconnection requirements beyond those for a Simplified Interconnection, and a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirements identified by the Supplemental Review, or (c) a determination that an IRS is required and a good faith cost estimate and schedule for the completion of the IRS, including an identification of the specific analysis and/or reviews that will be performed as part of the IRS.

c. The Supplemental Review consists of Screens 12 through 14. If any of the Screens are not passed, a quick review of the failed Screen(s) within the timeframe established for Supplemental Review, or any modified time limits, may determine the requirements to address the failure(s), in which case an IRS may not be necessary. Otherwise, an IRS is required. Some examples of requirements that may be available to address the failure of Screens 12 through 14 without the need for an IRS include:

1. Replacing a fixed capacitor bank with a switched capacitor bank.

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<#>The Supplemental Review shall be

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Deleted: <#> The Company, for good cause, without extraordinary circumstances, may *modify the time limits to conduct the* Supplemental Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

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Deleted: An IRS shall not be required for UL 1741 inverter systems when (1) in the event that Supplemental Review is triggered by Screen 4 above, the aggregate generating capacity per Line Section is below 50% of the Line Section minimum kW load during the period when the proposed generation is available (including noon on Sunday for solar photovoltaic systems), and (2) in the event that Supplemental Review is triggered by Screen 9 above, a feasible solution from a pre-identified list of solutions maintained by the Company has been identified and agreed upon bet ... [2]

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2. Adjustment of line regulation settings.

3. Simple reconfiguration of the distribution circuit.

Supplemental Review Screens:

Screen 12 (Penetration Test): Where 12 months of Line Section minimum load data is available, as measured (or observed) at the feeder or substation, is the aggregate Generating Facility capacity for the Line Section less than 100% of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

If Yes, continue to Screen 13.

If No, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required. Continue to Screen 13. (Note: If an IRS is required, applicants will continue to the IRS after review of the remaining Supplemental Review Screens.)

Significance: Aggregate Generating Facility capacity that is less than 100% of minimum load is less likely to result in power flow from the Generating Facility back toward the substation and will have a minimal impact on equipment loading, voltage, system operational impacts, and protection of the Company's System.

Note 1: If measured (or observed) minimum load is not available for a feeder or substation, the utility shall use reasonable efforts to calculate or estimate minimum load from existing data or models. If minimum load data is not available and must be calculated or estimated, Screen 12 defaults to the higher of either 75% of the estimated/calculated minimum load or a percentage of minimum load predetermined and posted by the utility for that feeder. If minimum load on a feeder cannot be

measured, observed, calculated or estimated despite reasonable efforts, this screen defaults to 15% of Line Section peak load, and the Company shall promptly undertake efforts to begin measuring minimum load for that feeder.

Note 2: The type of generation will be taken into account when calculating, estimating, or determining feeder or Line Section minimum load relevant for the application of this screen. Solar generation systems with no battery storage shall use the daytime minimum load that is coincident with optimal output of the generator (as may occur during 10 am to 2 pm for fixed panel systems). Other generation uses feeder or Line Section minimum load over the entire day or a timeframe coincident with its output.

Note 3: For an inverter-based Generating Facility (e.g., a photovoltaic facility), the facility capacity for purposes of this screen shall be a number calculated by taking either project size in kW or AC inverter rating (whichever is lower) and applying to it a de-rating factor of 10%[**] to account for equipment inefficiencies, non-optimal installation conditions, and related factors. The same method shall be applied to determine the aggregate capacity of all inverter-based existing Generating Facilities on the feeder. Minimum load shall be established on feeders with existing photovoltaic generation by the measured "cloudy" day conditions which will likely represent the load with limited photovoltaic generation (20-30% irradiance).

[**] Parties recognize that further discussions are required in the future to substantiate a 10% de-rate factor.

Screen 13 (Power Quality and Voltage Tests): In aggregate with existing generation on the Line Section,

a) Can it be determined within the Supplemental Review that the voltage regulation on the Line Section can be maintained in compliance with Conservation Voltage Regulation requirements under all system conditions?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE 1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the point of common coupling?

If Yes to all, continue to Screen 14.

If No, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required. Continue to Screen 14. (Note: If an IRS is required, applicants will continue to the IRS after review of the remaining Supplemental Review Screens.)

Significance: Adverse voltages and undesirable interference may be experienced by other customers on the Company's Distribution System caused by operation of the Generating Facility.

Screen 14 (Safety and Reliability Tests): Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without an IRS?

If Yes, a quick review of the failure may determine the requirements to address the failure; otherwise, an IRS is required.

If No, Supplemental Review is complete.

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an interconnection. These include, but are not limited to:

1. Generation energy source
2. Modes of synchronization
3. Unique system topology
4. Possible impacts to critical load customers
5. Possible safety impacts

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (*i.e.*, several large commercial customers)?
2. Is there an even or uneven distribution of loading along the feeder?
3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (*i.e.*, 600A class cable)?
4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?

5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?

6. Does the Generating Facility utilize certified anti-islanding functions and equipment?

d. The Supplemental Review shall be completed, absent any extraordinary circumstances, within twenty (20) business days of completion of Initial Technical Review. The Company, for good cause, without extraordinary circumstances, may modify the time limits to conduct the Supplemental Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

e. If the Supplemental Review results in interconnection requirements beyond those for a *Simplified Interconnection*, the Customer must also complete a *Facility Equipment List*, which will identify equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities. The Facility Equipment List will be included as Exhibit B to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

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If Yes, the Generating Facility qualifies for Simplified Interconnection.

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An IRS shall not be required for UL 1741 inverter systems when (1) in the event that Supplemental Review is triggered by Screen 4 above, the aggregate generating capacity per Line Section is below 50% of the Line Section minimum kW load during the period when the proposed generation is available (including noon on Sunday for solar photovoltaic systems); and (2) in the event that Supplemental Review is triggered by Screen 9 above, a feasible solution from a pre-identified list of solutions maintained by the Company has been identified and agreed upon between the Company and the Customer. The exclusions from the IRS process, when conditions (1) or (2) above are met, shall not exclude review under the other Initial Technical Review screens, and shall not apply if there are exceptional circumstances, such as impacts to reliability and/or safety that cannot feasibly be addressed without an IRS.

RSWG PV Subgroup
Distributed Photovoltaic Monitoring

Introduction And Summary

In Order No. 30371, Relating To Various Matters In RSWG Process, the Commission directed the RSWG to consider issues related to distributed generation ("DG"), particularly solar photovoltaic ("PV"). See id. at 12-14. The Commission stated it:

> believes that the time is now ripe for the RSWG to look closely at enhancements to the monitoring and controllability of PV production that could be added to interconnection requirements and support overall grid reliability. In particular, the group should consider whether the distribution screening process for PV could be further enhanced and streamlined to reflect any potential changes to the requirements for monitoring PV systems so that greater penetration of PV systems is possible.

The PV Subgroup, including the HECO Companies and solar industry and clean energy stakeholders, extensively discussed these and other issues in seeking solutions for integrating PV while maintaining reliability. As discussed below, the consensus and recommendation of the PV Subgroup are that issues of monitoring and controllability of smaller, distributed (predominantly rooftop) PV are best addressed via the HECO Companies' ongoing proactive efforts on PV integration, which are collectively described in the accompanying written submission as the "Proactive Approach." The monitoring component of this Proactive Approach employs improved utility monitoring and modeling tools supplemented with available monitoring data from PV facilities. The goal is to provide the enhanced visibility of PV generation that is necessary for utility planning and operations by making maximum use of available PV monitoring resources and supplementing those resources on a selective, as-needed basis, rather than incurring extra burdens and costs for the utilities and PV developers and customers by requiring monitoring and control of smaller PV systems on a blanket, obligatory basis.

Monitoring Under The Proactive Approach

As part of the Proactive Approach, the utility will use available field data from utility and PV developer and customer sources to validate and enhance utility models for calculating, forecasting, and tracking PV production as a generation resource versus simply a load modifier. The utility need not require blanket monitoring and control of individual distributed PV sites, which can lead to an overflow of information beyond what is necessary, manageable, and cost-effective. Rather, by monitoring solar irradiance and PV generation at select locations for each feeder or cluster of electrically connected feeders, the utility is able to model, via "nodal and cluster" methodologies, aggregate PV production at levels of accuracy that are relevant and necessary to support utility planning and operations.

The utility can conduct such nodal and cluster analysis based on at least two monitoring points for each feeder or cluster, starting with the utility's monitoring point at its distribution substation. More reference points may be needed for feeders or clusters that cover longer distances and encompass a variety of micro-climates.

The existing PV monitoring network primarily includes the monitoring equipment the utility has been installing at its distribution substations and other locations, and the SCADA (supervisory control and data acquisition) equipment larger PV facilities have installed as a requirement for interconnection.[1] It also may include the available data that smaller PV systems collect for their customers, some of which the utility has already obtained through collaboration with solar industry representatives and customers. The utility may also install monitoring equipment at select additional locations on its own initiative, depending on the needs in certain areas of the grid.

These PV monitoring efforts will support the broader Proactive Approach to PV integration. In summary, the monitoring data will initially help validate the utility models for tracking distributed PV production, and this enhanced modeling capability will in turn inform both system and distribution level planning and operations. Enhancement areas include: assessing potential system and regional level impacts due to high penetrations; evaluating impacts to dispatch and generation, reserve planning, and response to ramping events; informing and streamlining the distribution level interconnection process, including interconnection requirement studies (IRS); and helping to identify penetration capabilities, potential issues, and necessary upgrades.

Summary Of Work To Date

The HECO Companies have already taken the initiative to install sensors in the field in a number of more highly penetrated circuits and have developed the Locational Value Map tool ("LVM") to track development and growth on the distribution system. Monitoring devices include solar irradiance monitors and solar availability sensors (LM-1 and LM-2 monitors), which provide a proxy for the level of solar production. These sensors are located at utility substations and schools participating in HECO's "Sun Power For Schools" program. The HECO Companies have also incorporated into their PV monitoring system the data output from the SCADA equipment installed at larger PV facilities.

In addition, the HECO Companies and PV industry representatives in the PV Subgroup have worked together to provide the HECO Companies with the available monitoring data from selected smaller PV systems, especially in areas of high PV penetration. The inverters of PV systems collect various data for the system owners or customers, which may not be at the time resolutions necessary for some utility applications, but can still help to supplement and validate

[1] The HECO Companies' Tariff Rule 14H: requires SCADA for systems above 250 kW for the MECO and HELCO utilities; requires SCADA for systems above 1 MW and allows SCADA for systems between 1 MW and 250 kW for the HECO utility; and disallows SCADA for systems at or below 250 kW.

the utility's monitoring and modeling tools. PV Subgroup members pursued various efforts to facilitate such added beneficial use of this data, including: contacting solar companies and inverter manufacturers to survey the monitoring capabilities of PV systems; helping to identify specific PV systems with favorable datasets (in terms of quality of data and length of record) in the priority, high-penetration areas the HECO Companies identified; drafting a waiver form for customers and developers to agree to provide the data; initiating the contact and conversation with the customers and developers; engaging PV data experts to check and process the data; and facilitating the delivery of data to the HECO Companies.

Work Going Forward

The HECO Companies, in collaboration with industry and other stakeholders, will continue to develop the HECO Companies' PV monitoring network by identifying (1) additional needs for monitoring data in feeders or regions and (2) opportunities to obtain that data by deploying additional utility field monitors or gathering owner- or customer-collected data and engaging developers and customers to facilitate any necessary cooperation.

The latest amendments to HECO Companies' Tariff Rule 14H in December 2011 included a provision, Appendix I, § 2.g, which reserves the utility's right, after the interconnection of a generating facility

> to require the installation of, or modifications to, equipment determined by the utility to be necessary to facilitate the delivery of reliable electric service to its customers, provided that the costs associated with such post interconnection installation or modifications shall be paid by the utility or through other mechanisms approved by the Commission.

The PV Subgroup believes that this provision affords the utility appropriate authority to install additional monitoring equipment at specific PV system sites as necessary to improve its monitoring coverage for a feeder or region.

In sum, the approach described above of installing monitoring equipment at individual sites as needed to support broader utility monitoring and modeling efforts under the Proactive Approach offers a practical, productive, and prudent way forward to facilitate the integration of distributed PV resources, which the PV Subgroup supports and recommends.

RSWG PV-DG Subgroup
Summary of Proposal for Proactive Review Approach

Background and Basis for Recommendations: As a result of dynamic market trends and technological advances, the HECO Companies are responding to increasing levels of distributed generation (DG) on their distribution systems. To contend with the pace of DG requests, a new proactive and holistic approach to interconnections and distribution system planning is needed for Hawai'i utilities to safely and reliably address high penetrations of DG resources.

Currently, the HECO Companies' Interconnection Tariff Rule 14H uses the proxies "15% of peak load" and "50% of minimum load" (recently increased to 75% of minimum daytime load for certain systems as part of NEM Express) to screen Interconnection Applications for potential impacts to safety, reliability and power quality. Such proxies may unintentionally create the appearance of artificial caps on interconnection and may impact customer expectations about the ability to install DG systems, like solar photovoltaic (PV). The 2008 Energy Agreement between the HECO Companies and State of Hawai'i representatives recognized the need to move beyond proxies in providing that "for those circuits where interconnection requests (particularly for PV) approach the 15% limit, the utility will perform . . . analysis to determine whether the limit can be increased." Id. at 28.

Interconnection reviews traditionally proceed in response to interconnection applications being submitted for specific proposed projects. At the same time, the utilities also traditionally conduct transmission and distribution system planning reviews to provide a more comprehensive view of system changes. Such distribution planning, however, traditionally views DG as "negative load" rather than generation resources to be considered in planning and equipment upgrade decisions. This approach contributes to the reactive nature of DG interconnection and is becoming increasingly unfeasible as Hawai'i reaches higher levels of DG penetration.

Since 2009, the HECO Companies have been continuing to take steps towards facilitating interconnection reviews through improved monitoring and modeling and implementing various proactive planning measures discussed herein, collectively referred to as the Proactive Review Approach, or Proactive Approach.

The RSWG PV Subgroup supports and recommends this Proactive Approach to the larger RSWG and the PUC as the next evolutionary step in renewable DG interconnection, and towards the clean energy grid of the future. (See attached conceptual figure.) The PV Subgroup recognizes that the Proactive Approach may require time to implement within the utility processes and consideration of additional proposals including: modifications of program and interconnection tariffs, selective deployment of monitoring equipment, staff training, public outreach, and determinations of reasonable cost recovery by the utility.

The PV Subgroup recommends that the PUC consider such approvals as may be necessary and prudent to enable reliable adoption of distributed resources and successful implementation of the Proactive Approach.

Purpose: The Proactive Approach aims to coordinate and mutually enhance the utilities' functions of (1) interconnection and (2) transmission and distribution planning in order to anticipate and plan for the interconnection of higher penetration levels of DG and account for their aggregated impacts on the system. Specifically, the utility will employ enhanced tools for modeling distributed PV to inform both system and distribution level planning and operations. Enhancement areas include: assessing potential system and regional level impacts due to high penetrations; evaluating impacts to dispatch and generation, reserve planning, and response to ramping events; informing and streamlining the distribution level interconnection process; and helping to identify circuit penetration capabilities, potential issues, and necessary upgrades.

The overall goal is to create a more transparent and efficient process for interconnecting higher levels of DG while maintaining safety, reliability, and power quality across the transmission and distribution infrastructure. This will benefit all parties involved, including customers, developers, utilities, as well as the broader public.

The Proactive Approach will enable numerous advancements, including:

- More accurate understanding of the currently feasible penetration capability of the distribution system, including any engineering safety margins, based on actual measured (or observed) feeder conditions instead of proxy figures;

- Greater and more reliable facilitation of renewable DG interconnection and attendant progress towards the state's clean energy goals;

- Better informed and engaged customers and developers with the ability to check online the updated, current feeder availability (kWs or MWs of available capacity remaining) to interconnect DG;

- More transparent and accessible interconnection process, where customers and developers will be able to understand the opportunities for interconnection, or anticipate the need for additional review such as an interconnection requirements study (IRS), before submitting an Interconnection Application;

- Streamlined interconnection, where the utility "gets ahead of" potential circuit and system issues that may arise resulting from high penetrations at a more comprehensive level rather than the traditional, piecemeal approach;

- More systematic interconnection review, where the utility conducts forward-looking analysis based on field-monitored data, including data gathered from customers and industry, to inform the interconnection review process, assess and

narrow potential issues, and develop any mitigation options and solutions, as required;

- More cost-effective interconnections, where enhanced modeling and monitoring capabilities supported by customer and industry data provide a more efficient and consistent method to evaluate high feeder penetrations and aggregated system impacts and devise cost-effective options that can address systemic issues and broad benefits for many projects;

- Increased visibility into the location and impacts of DG on the utilities' systems, which carries a number of benefits, including, for example, more targeted solutions and intelligences in applying solutions such as load shedding.

Proactive Approach Review Process:

1. **Coordination with 14H Process**: The Proactive Approach will supplement, and not supplant, the HECO Companies' 14H interconnection review process. The Proactive Approach will provide insight into the penetration capabilities of the distribution system, solutions and strategies to facilitate higher penetration capabilities, and outstanding issues for further project-specific review. This will inform the project-specific interconnection review process under 14H, which may continue to proceed on a parallel course. The Proactive Approach is not a "group or cluster study" or project-specific study, where the utility requires specific details in response to proposed projects. Rather, the Proactive Approach will work alongside the 14H interconnection process to facilitate and inform the interconnection process through proactive monitoring and tracking of high penetration and system reliability issues in order to better highlight potential issues and alleviate delays and burdens.

2. **Enhanced Modeling**: The Proactive Approach uses enhanced utility models currently being developed and validated to account for DG, particularly PV, on the distribution system. These models utilize field-monitored information incorporating the solar resource and PV generation at key "nodal" locations to refine and validate assessment of impacts. To support the modeling efforts, the utilities are installing monitoring devices, gathering SCADA data on PV production from large projects, and requesting available monitoring from customers and developers. Information will provide greater visibility to distributed PV generation characteristics and enable more accurate analysis under the Proactive Approach.

3. **Interconnection Queue**: As part of the Proactive Approach, the utility shall, in consultation with stakeholders, work to establish and utilize a single interconnection queue for all projects seeking interconnection to the distribution system. The interconnection queue will help establish an annual "Base Case" for consideration in the proactive analysis to understand potential distribution upgrades that may be needed.

4. **Base Case**: During a designated period each year generally correlating with the timeframe for annual distribution planning (see "Timing of Annual Review," *infra*), utility will establish a Base Case of anticipated DG development for each cluster of distribution feeders on their grids. A cluster is a group of electrically related distribution feeders in a particular geographic area.

   The Base Case will consider projects from all programs under which projects are seeking interconnection affecting the distribution system (*i.e.*, those projects already in the interconnection queue, including any transmission-level projects that may impact the DG interconnection capabilities in the region). This recognizes that the proposed projects in the interconnection queue may not all be ultimately installed, but nonetheless provides a useful starting point for gauging interconnection demand. The Base Case establishes a planning baseline and does not constitute a detailed project study.

   The Base Case may also include an anticipated number of distribution projects that may enter the queue during the planning period, which under annual distribution planning looks ahead about a year. The anticipated increase in installed capacity may be based on the utility's Integrated Resource Plan or other forecasts of the expected growth in distribution-interconnected projects in a particular year's distribution planning period. The Base Case may also include any anticipated demand response programs, energy efficiency installations, changes in load profiles or other issues that may affect the loading of a particular cluster or line (*e.g.*, entry of electric vehicle loads).

5. **Application of the Base Case to Feeder Clusters**: The utility shall analyze the penetration capabilities for each feeder cluster, using the Base Case along with the models utilities are developing to account for PV generation on their distribution systems. Among other information, the utility shall conduct simulations to help assess the penetration level of DG, particularly PV, that the cluster can accommodate without upgrades, specific issues for that cluster that require further review under the project-specific interconnection process, and upgrade option(s) appropriate for the cluster to enable higher penetrations. Additionally, the utility shall analyze the effect of the base case on safety, reliability, and power quality of the grid, and curtailment to the existing and proposed renewable projects.

6. **Penetration Capabilities**: The utility will establish the existing capability of each feeder cluster to absorb additional PV without upgrades. The penetration capability for PV will be stated as a percentage of the highest (or "peak") minimum daytime load. This recognizes that existing PV generation decreases the net minimum daytime load, and that the highest minimum daytime load most closely equates to the actual gross minimum load without the effects of the existing PV. The penetration capability for other generation technologies will be stated as a percentage of minimum load during the period that the generation is available. The penetration capability for feeder clusters may include an engineering safety factor.

Distinct from the current proxy levels in interconnection procedures (*e.g.*, 15% of peak load and 50% of minimum load), the penetration capability will establish, based on actual analysis, the feeder availability. The feeder availability is the maximum kW or MW value of DG, particularly PV, that can be interconnected to a feeder with the existing equipment on that feeder, including protection and control equipment.

In order for this system of measuring penetration capabilities in terms of percentages of minimum load to work, the utilities must establish and maintain the ability to measure minimum loads on their distribution systems. The HECO Companies have largely, but not completely, installed such capability. To this end, the utility shall continue to install the necessary equipment to measure load profiles on feeders with priority focus on existing high penetration feeders and moving to feeders with DG at or above a threshold of 10% of peak feeder load.

7. **Informing of Upgrades**: Where application of the Base Case results in an amount of generation that exceeds the penetration capability of a feeder cluster without upgrades, the Proactive Approach may be used to help evaluate options to upgrade the distribution infrastructure in order to accommodate the Base Case amount of growth of projected DG. Note: IRS studies may still be necessary for project specific needs, as determined by the utility. If upgrades are needed, the utility shall determine the best way to implement such upgrades and allocate the costs, as allowed by law and tariff. In any event, the utility should inform the customers and developers in the Interconnection Queue for the Base Case of its determination of any necessary upgrades and provide appropriate opportunities to proceed with interconnections through the interconnection process.

   [There are a number of open issues yet to be resolved in this proposal. These issues include clarification of how costs will be allocated to the new generators that seek interconnection and the tariff changes that may be required to implement the approach.]

8. **Online Information**: The utility shall provide appropriate online information where customers and developers can input addresses and view their interconnection status, feeder penetration range and known upgrades using online utility DG tracking tools such as the location value maps (LVM). The goal is to provide customers and developers with a publicly accessible and transparent system of understanding present and potential penetration capabilities and minimize misinterpretation of any perceived or arbitrary feeder caps.

9. **Narrowing of Issues**: In addition to the penetration capabilities and upgrades above, the Proactive Approach will help identify any issues requiring further review in the project-specific interconnection process under Rule 14H. This will facilitate the Rule 14H process by narrowing the scope of interconnection review to an already previewed set of issues. This preview under the Proactive Approach may inform each stage of the Rule 14H interconnection process, including Initial Technical Review, Supplemental Review, and the Interconnection Requirements Study.

10. **Timing of Annual Review**: The Proactive Approach review process will occur in a consistent timeframe each year, targeted around May through July, which dovetails with the HECO Companies' process for transmission and distribution planning reviews conducted during 1st quarter of each year (January through April) and the PV industry's end-of-year tax deadlines. The HECO Companies shall work to make the timeframe for the Proactive Approach review consistent across all the utilities. The completion of this process by June conforms with the timeframes for renewable development, under which the viability of projects must be known sufficiently far in advance of the tax deadlines at the end of the year.

11. **Timing of Rollout**: The Proactive Approach will take time to implement and put into practice, realizing that it is in everyone's best interests to achieve this goal under an expeditious timeframe. The HECO Companies are already moving ahead with conducting cluster studies in key areas of current or anticipated high penetration and DG growth, using the new cluster-based methodology, additional field data, and enhanced planning models. Since the Proactive Approach process is designed to work in parallel with the Rule 14H interconnection process, as the feeder cluster evaluations are completed for each of the islands, the information shall be made available to support the Rule 14H process. Solutions such as improved penetration capabilities or upgrade options shall be applied on an ongoing basis as they are identified.

    The following outlines the basic timeframe for establishing and implementing the framework for the Proactive Approach:

    a. HECO:
        i. 2013 1st Q proactive review for 3-4 clusters in O'ahu complete, inclusive of feeder monitoring device installations
        ii. 2013 3rd Q, completion for all clusters (estimated 15-20) by summer 2013 with ongoing installation of monitoring devices at priority locations.

    b. MECO:
        i. 2013 1st Q proactive review for 1-2 high demand feeders on Maui complete, inclusive of feeder monitoring device installations
        ii. 2014 2nd Q completion for all clusters on Maui (estimated 8-10) with ongoing installations of monitoring devices at priority locations
        iii. 2013 4th Q begin Molokai and Lanai modeling efforts to initiate cluster evaluations with completion of islands by 2015 1st Q.

    c. HELCO:
        i. 2013 1st Q proactive review for 1-2 high demand feeders on Hawai'i complete. Inclusive of feeder monitoring device installations

ii. 2015 2nd Q completion of all clusters (estimated 10-15) with ongoing installations of monitoring devices at priority locations

d. 2015 3rd Q, all islands on Proactive Approach track and annual review cycle.

The Department of Business, Economic Development, and Tourism's Comments Regarding the Proactive Approach

At the December 11, 2012 Reliability Standards Working Group ("RSWG") meeting, the Department of Business, Economic Development, and Tourism ("DBEDT") voted in favor of the Photovoltaics ("PV") Subgroup's Proactive Approach. Pursuant to the procedures outlined in the Independent Facilitator's December 12, 2012 email, DBEDT offers the following written comments to memorialize the comments it made at the October 24, 2012 and December 11, 2012 RSWG meetings on the need to ensure transparency in the Proactive Approach process.

DBEDT voted in favor of the Proactive Approach because DBEDT supports its goal of coordinating, on a forward-looking basis, the HECO Companies' interconnection, distribution and transmission planning functions. DBEDT believes that proactively planning for higher penetration levels of Distributed Generation, load and proposed renewable projects is consistent with the State's interest in reliably integrating the maximum amount of renewable resources into the Hawaii systems.

DBEDT's support for the Proactive Approach is premised on the understanding that the Proactive Approach will be an open and transparent process that provides all interested parties an opportunity to participate, review the information produced during such processes, and submit comments. In fact, prior to voting in favor of the Proactive Approach, DBEDT noted that the proposal provides some assurances on the transparency and collaborative nature of some Proactive Approach activities, but is silent as to others, and asked for assurances in this regard. From the response DBEDT received, and the associated discussion, DBEDT understood that the Proactive Approach proposed by the HECO Companies would be an open process and may follow a process similar to that used for transmission planning by the Western Electricity Coordinating Council ("WECC"), while recognizing the distinction between the level of information shared by transmission planning and distribution planning organizations. DBEDT is not wedded to strict adhesion to the WECC process so long as the process meets the larger goal of ensuring a meaningfully open and collaborative information sharing and planning process. A process that allows all interested parties an opportunity to receive information and provide meaningful comment on activities such as the development of the base case, penetration capability analysis, and analysis of the effect of the base case on reliability and curtailment related to existing and proposed renewable projects, will promote the collaborative review and transparency that the renewable grid of the future requires. It may also reduce concerns of unbridled discretion with respect to the HECO Companies' determination on related issues noted in the Proactive Approach, such as to the best method for implementing upgrades.

DBEDT believes that the Proactive Approach process should also be formalized, either as part of a utility tariff or other order of the Hawaii Public Utilities Commission ("PUC"). Some of the procedures that DBEDT believes should be considered as part of this formalized process include procedures for interested parties to receive information regarding, and comment on, the base case developed by the HECO Companies. Parties should also be permitted to receive information regarding, and comment on, identified opportunities where infrastructure upgrades can accommodate Distributed Generation and load. In addition to the opportunity to comment, reporting requirements are necessary to provide parties confidence that the Proactive Approach meets the stated goal of benefitting all parties involved, including customers, developers and utilities, as well as the broader public. Reasonable measures could also be adopted to protect confidential data produced as part of the Proactive Approach process. While DBEDT appreciates that the Proactive Approach proposes periodic updates to the PUC on the progress in implementing the Proactive Approach, timeliness of other processes, such as for the annual review and information sharing, would need to be considered to ensure adequate notice and opportunity to plan based on and/or comment on the information developed.

If properly implemented, DBEDT submits that the PV Subgroup's Proactive Approach could serve as a useful tool in continuing the State's efforts to use a collaborative approach to developing procedures aimed at allowing efficient interconnection and ensuring safe and reliable operation of the utility-owned distribution systems. Therefore, for the reasons set forth above, DBEDT voted in support of the Proactive Approach. DBEDT recommends that the PUC consider the procedures DBEDT identified in determining whether to approve the Proactive Approach.