Maui Electrical System Simulation Model Validation

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Data was provided to GE by HECO and MECO for the purpose of operating under the Maui Grid Study contract. These data were used to build the models and are summarized in this report.

Table of Contents

1. Introduction

The Maui Grid Study is a joint study by Hawaiian Electric Company (HECO), Maui Electric Company (MECO), the Hawaii Natural Energy Institute (HNEI) and the General Electric Company (GE). It is one of the components of the Hawaii Distributed Energy Resource Technologies for Energy Security project.

The primary objective of this study is to develop and calibrate dynamic and production cost models for the MECO electricity grid. This is the first set of steps in an activity designed to help MECO identify technologies or operating strategies that will enable the system to manage higher amounts of as-available renewable energy. These models were validated against a base year and will be used to evaluate power system expansion scenarios for the island of Maui. This program began in January 2008 with the data acquisition and model development. This deliverable highlights the validation of the power systems model for the island of Maui.

In order to ensure the model accurately captures MECO's present system operation, the model was calibrated and validated against historical data. However, some of the operating practices that are presently in place were not in place in 2007. In order to ensure the model is useful for analysis of future scenarios, the present operating conditions were generally modeled, while only some historical operating conditions were captured. Significant iteration with the HECO/MECO team was needed to ensure the model accurately captured MECO system operation to a level of fidelity sufficient for the next phase of this study (scenario analysis of the future MECO system). Weekly meetings were organized to allow the model development and validation team to present the results from each model. Questions were asked of the HECO/MECO team to clarify system-operating practices. Based on their responses to these questions, and their inputs and directions based on questions that HECO/MECO raised, the GE team revisited the model each week, implemented the necessary changes, and presented the latest results at the following meeting. This document represents the Deliverable for Task 9, the Baseline Model Validation results. The modeling, validation, and management team is comfortable with the level of accuracy for both the GE PSLF™ and GE MAPS™ models of the MECO system for the application of these tools to system scenario analysis.

This document is intended to present the validation of databases created in GE MAPS™ and GE PSLF™ for the analysis of the electrical systems of MECO. The databases were compiled based on the data provided by HECO and MECO. These data were described in the Task 8 Deliverable, "Maui Electrical System Model Development: Data and Assumptions," the report on System Model Development. Some of the models were further improved based on the input provided by HECO and MECO after the Task 8 Deliverable was submitted. After HECO and MECO have reviewed this document, an exchange will be held to discuss the model validation and scenarios to be considered in the next task of the project.

A final comment is appropriate. This effort was primarily funded using HECO funding as part of the larger, related project that is funded by DOE. As a result, some information is considered proprietary by the utility and is presented here in this report as qualitative conclusions, although quantitative information has been presented to the utility.

2. Model Validation

The Maui grid is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. From a control perspective, the load and the wind power production are the primary independent variables – the drivers to which all the short-term controllable elements in the power system must be positioned and to which they must respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and nature) of load served by the system. The performance of the power system is highly dependent on the ability of the system to accommodate changes and disturbances while maintaining quality and continuity of service to the customers.

The modeling exercise is aimed at capturing technical aspects of challenges related to regulation, frequency control, load following and unit commitment within the transmission system capabilities associated with the present infrastructure, including intermittent resources such as wind generation. The quantitative analysis covered a broad range of timeframes, including:

- Seconds to minutes (regulation and frequency control) – Dynamic simulation,
- Minutes to hours (load following, balancing) – Dynamic simulation, and
- Hours to days (unit commitment, day-ahead load forecasting and schedules) – Production cost simulation.

There are several timeframes of variability, and each timeframe has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis in the first phase of the project was aimed at quantitatively evaluating the impact of existing MECO assets, including wind resources, in each of the timeframes relevant to the performance of MECO's power system. In the longest timeframe, planners look several years into the future to determine the infrastructure requirements of the system based on capacity (or adequacy) needs. This timeframe includes the time required to permit and build new physical infrastructure. In the next smaller timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this timeframe, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In the shortest timeframe, cycle-to-cycle and second-to-second variations in the system are handled primarily by automated controls. The system's automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e., are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized Automatic Generation Control (AGC), to meet overall system control objectives including system frequency.

In the context of MECO, the infrastructure has been modeled at different levels:

- Transient modeling, in the seconds-to-minutes timescale, to validate stability and transient performance of the island grid, and
- Production cost modeling, in the hours-to-days timescale, to determine the operating economics of the power system.

The production model was developed in GE MAPS™. The results of the production cost model were compared to the 2007 historical operating conditions. The comparison is summarized in this report. The dynamic model was developed in GE PSLF™. The AGC model was developed to represent the MECO AGC. Three "windows" of system operation were chosen and the AGC model was calibrated and validated against these windows. This type of simulation is referred to as a long-term dynamic simulation. Additionally, transient stability simulations were performed. This included simulating load flows and contingencies in GE PSLF™ to ensure the model represented actual system behavior

2.1 Production Cost Modeling (GE MAPS™ analysis)

Production cost modeling of the MECO system was performed with GE's Multi Area Production Simulation (GE MAPS™) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. This tool was used to simulate the MECO production for 2006. Ultimately, the production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on standard least-marginal-cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before higher marginal cost generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum regulating reserve, and stability limits, as well as the physical limitations and characteristics of the power plants. Significant input has been received from HECO and MECO, and multiple model iterations have been performed, to ensure that all physical, contractual, and reliability requirements were met.

2.1.1 Model Data and Assumption

In order to characterize the operation of the MECO system in GE MAPS™, general operating assumptions were needed. It was understood by both GE and HECO/MECO that the actual operating practices vary depending on unique system events and conditions, such as the present and anticipated wind power production, the load level, the number and types of units on outage, etc. The data used in the model are outlined in the Deliverables for Tasks 6 and 7. The model data and assumptions are outlined in the Deliverable for Task 8.

To briefly summarize the Task 8 Deliverable, some of the inputs to the GE MAPS™ model are summarized below:

- Sum of hourly generation as the load profile.

- Unit characteristics, such as heat rate curve over the entire operating range. Maximum power point, minimum power point, planned and forced outages rates, regulating reserve capability, and emissions rates.
- Hourly wind power production.
- Hourly HC&S production.
- System and unit constraints.
- System losses due to transmission.
- General operating assumptions (described later in the report).

The unit-by-unit characteristics are summarized in the GE MAPS™ model. The incremental heat rate values were compared to the MECO "ABC Heat rate Curves" to verify that the conversion was performed accurately. The fuel cost data are an input to the GE MAPS™ model. These data were provided by MECO (see Table 1).

Table 1: MECO thermal plant fuel cost data ($/MMBtu) from "Power Supply Reports ('07)_031708mm.xls".

	RESIDUAL	DISTILLATE
1/1/2007	8.14	14.69
2/1/2007	8.35	16.25
3/1/2007	8.01	15.09
4/1/2007	8.43	15.62
5/1/2007	8.78	15.96
6/1/2007	8.97	17.18
7/1/2007	9.91	16.93
8/1/2007	9.91	17.52
9/1/2007	10.19	18.12
10/1/2007	10.05	17.51
11/1/2007	10.38	17.58
12/1/2007	11.32	18.92

In order to characterize the operation of the MECO system in GE MAPS™, general operating assumptions were made. It was understood by both GE and HECO/MECO that the actual operating practices will change depending on unique system events, such as the present and anticipated wind power production and load condition, as well as the number and types of units on outage, etc.

The following general modeling assumptions were made:

- M14, M15, M16 were modeled as operating in dual-train combined cycle mode.
- M17, M18, M19 were modeled as operating in dual-train combined cycle mode from 6 am to 10 pm.
- M17, M18, M19 were modeled as operating in single-train combined cycle mode from 10 pm to 6 am.
- HC&S was modeled as operating on the following schedule:
  - 9 MW from 9 pm to 7 am, and 13 MW from 7 am to 9 pm, on Monday through Saturday; and 9 MW on Sunday.

- Kaheawa Wind Farm (KWP) was modeled based on 2007 hourly wind power production data (post-historical curtailment).
- K1 was modeled as operating from 6 am to 11 pm.
- K2 was modeled as operating from 7 am to 10 pm.
- M4, M5, M6, M7, M8 and M9 were modeled as being available from 7 am to 10 pm.
- The regulation reserve requirement was modeled as:
    - 6 MW plus half the power production of the Kaheawa wind farm. The regulating reserve requirement calculation was changed to a new methodology in 2008.
    - M4, M5, M6, M7, M8, M9, M10, M11, M12, M13, M14, M15, M16, M17, M18, and M19 were modeled as the units capable of providing regulation.
- There was no power production from Makila hydro plant in 2007; therefore, no power production from the hydro plant was included in the model.
- Outages were simulated in MAPS based on 2007 historical outage duration by unit. In future analyses it is likely that the 5-year average outage data, by unit, would be implemented in the model.
- The general commitment order was obtained from MECO as: K3, K4, M14/15/16, M17/18, K1, K2, M10, M19, M11, M12, M13, M8, M9, M4, M6, M1-3, X1, X2, M5, M7
    - M10, M11, M12, and M13 are interchangeable in commitment order.
    - M4 and M6 are lower in the commitment order than M8 and M9 due to the limit on the operating hours.
    - M5 and M7 are lowest in the commitment order due to the air permits on NOx emissions.
    - M1, M2, and M3 interchangeable in commitment order.
    - X1 and X2 are interchangeable in commitment order.

The incorporation of these system constraints and assumptions increased the accuracy of the model with respect to the 2007 operating year. This allowed the project team to compare the model results to the historical data in order to gain comfort in the implementation of the MECO system data into the GE MAPS™ model.

2.1.2 Results of the Production Cost Model Analysis

Based on the validation objectives developed at the onset of this task by the HECO/MECO/GE team, the results of the model were compared to historical data. The GE MAPS™ hourly production data, by unit, and a summary table, outlining the annual unit-by-unit energy production, annual production cost, annual emissions, annual fuel consumption, etc., were obtained from the model.

One of the qualitative methods for comparing model results to historical data is to visually compare the hourly generation, by unit type, to historical data over a long period of time (see Figure 1). The GE MAPS™ model predicted hourly energy production similar to the historical 2007 production. Some of the discrepancy between the two figures can be attributed to unit outages occurring in MAPS that did not historically occur in the same time frame. Additionally, any operator intervention is not captured in the GE MAPS™ model. Furthermore, discrepancies between the historical system operation and the model results will be discussed later in this section. This qualitative comparison allowed the project team to gauge how accurately some of the operating constraints were being implemented in the model.

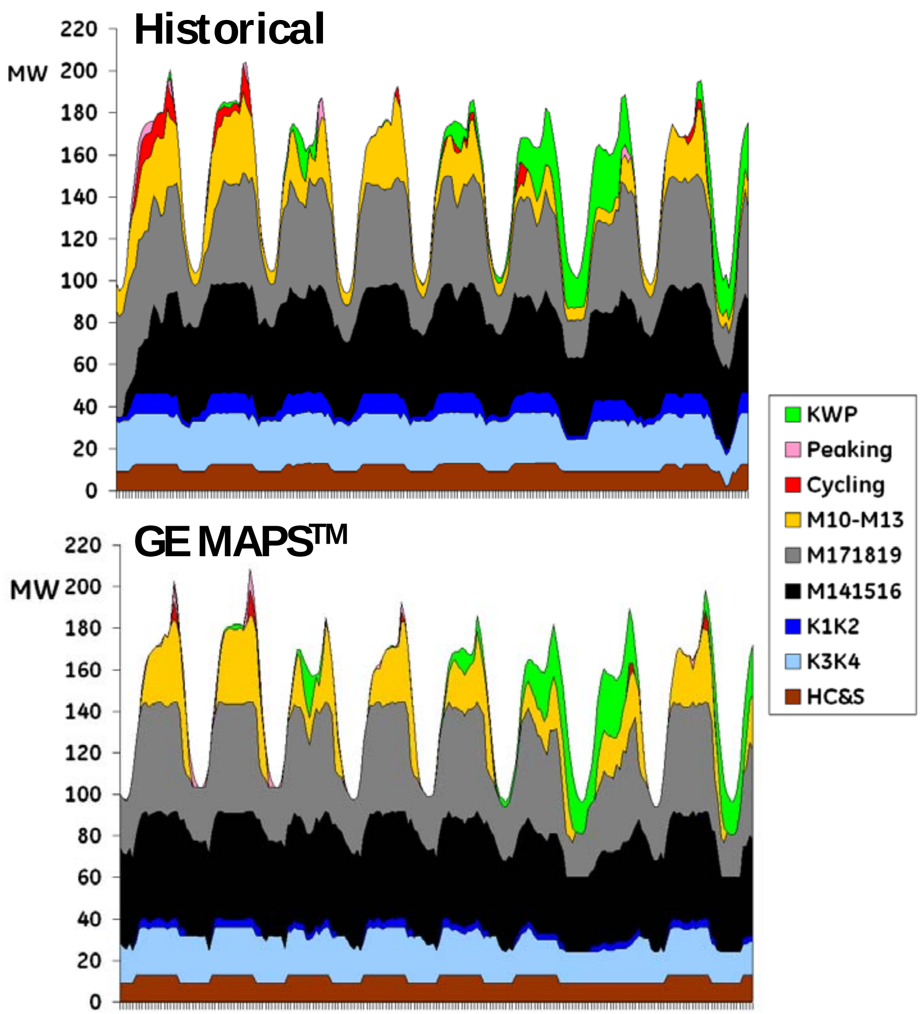

Figure 1: GE MAPS™ model results compared to historical hourly generation data for 200 hours, starting November 26, 2007 and ending December 4, 2007. The MAPS model Did not simulate the exact outage events as they historically occurred in 2007.

A number of quantitative methods for comparing the GE MAPS™ model results to the historical data were performed. The first method considered the annual energy production, by unit type. Since most production cost models consider units of similar type and heat rate as interchangeable, comparisons are generally made on a unit-type basis. The 2007 historical energy production was chosen as the benchmark year. There are notable differences between the way MECO operated the system in 2007 and the way in which it is presently operated. Both some of the present operating strategies and some of the former operating strategies were modeled in GE MAPS™; therefore, a very close comparison to the 2007 historical year may not necessarily reflect how accurately the model would predict system operation while analyzing scenarios for subsequent years (i.e., using post-2007 operating practices only). Where reasonable, the project team modeled some of the operating practices in 2007 in order to demonstrate the validity of the MAPS model to a benchmark year. The annual energy production, by unit type, is shown for both the 2007 historical MECO operation and the MAPS model in Figure 2.

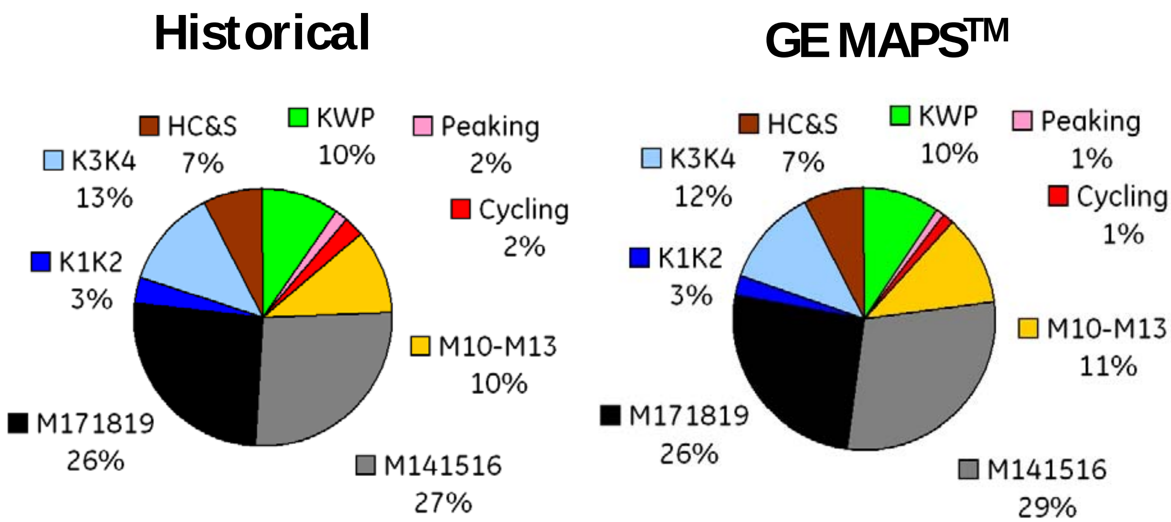

Figure 2: Comparison of the annual energy production (MWh), by unit type, between the Historical 2007 Maui energy production and the GE MAPS^{TM} model simulation. Note that The Cycling units refers to M4, M5, M6, and M9, and the Peaking units refers to X1, X2, M1, M2, M3, M5, and M7.

Recognizing the limitations of the model, the project team was satisfied with the level of fidelity observed on a unit-by-unit basis. The annual energy production, by unit type, compared within 1% of historical energy production. Later in this section, the differences between the model and the historical data are discussed in further detail.

The second quantitative method for validating the production cost model was a comparison between the average MECO system heat rate, based on 2007 historical data, and the system heat rate obtained from the GE MAPS^{TM} model. The heat rate is calculated as the total fuel consumption on a fuel-type basis per kWh produced by those units.

Based on the results of the MAPS simulation, the heat rate was ~5% less than the historical MECO system heat rate. This indicates that GE MAPS^{TM} overestimates the overall system efficiency by ~5%; similar to the level of fidelity observed in the HECO/MECO production cost simulations.

The model results captured the historical energy production, by unit type and the historical system heat rate, within 5%. Some of the discrepancy between the model results and the historical 2007 results can be attributed to the following factors:

- Intra-hour variability of wind/load was not captured in the hour-to-hour simulation tool. Natural imperfect dispatch of generation due to the present wind production and the wind power production trend was not captured in the model.
- The amount of regulating-up reserve available to address the decrease in wind production and increase in load varies within an hour. In the hour-to-hour simulation, the inter-hour changes in regulating reserve were not captured.
- Changes in the regulating reserve requirement may lead or lag the changes in the load and actual wind power production. For example, the amount of reserve also depends on the load level and the anticipated rate of change in load. Additionally, if the wind power is steady, MECO may decide to decrease the reserve requirements. These decisions are made at the discretion of the operator and could not be systematically captured in the model.
- After starting some units, they do not count towards the regulating reserve requirement until a specific period of time has passed. The model counts this unit in the regulating reserve requirement once it has been started.
- Differences in commitment/dispatch during outages were not captured. For example, K1 or K2 was operated as baseload when K3 or K4 was on outage.
- Temporary unit de-ratings occurred during 2007 historical operation. These de-ratings were not captured in the model.
- A detailed list of the unique operating conditions, generally not captured in production models, is provided in Docket No. 2006-0387. For example, performance tests were performed on M18 in 2007, M13 was only in operation for half of 2007 and returned to operation on July 9, 2007, and biodiesel fuel testing was performed on some of the diesel-fired units in 2007.
- HC&S was modeled on a fixed schedule, not on the actual historical production from 2007. This was done to ensure the validity of the model for scenarios.

2.1.3 Conclusions of the Production Cost Modeling

The project team agreed that the production cost model of the MECO system accurately captured the energy production, by unit type, within 1% and the system heat rate within 5%. The GE team is satisfied with the level of fidelity of the production cost model and recognizes that some of the discrepancy between actual historical production and simulate production can be attributed to a list of factors described above. The project team believes that the use of this tool to analyze system scenarios on the MECO system is appropriate for future phases of the project

2.2 Transient Stability and Long-Term Simulations (GE PSLF™ analysis)

Transient and long-term dynamics simulations are used to estimate system behavior (such as frequency) during wind power fluctuations and system events. In combination with good engineering judgment with the understanding of the limitations of the model, this type of modeling can be used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe, and can be used by utilities to ensure that the system frequency remains stable and within acceptable limits during critical operating conditions. For example, if wind power production suddenly decreases due to a sudden calming of wind in the area, another generator must increase its electricity production as quickly as the windfarm decreased its production. Depending on how fast the generator increases its production, the system frequency will deviate from 60 Hz. The dynamic simulation tool can be used to estimate the frequency excursion associated with this type of an event.

Long-Term Dynamic Simulations were performed for MECO's grid using GE's Positive-Sequence Load Flow (GE PSLF^{TM}) software. Second-by-second load and wind variability were used to drive the full dynamic simulation of the MECO grid for several thousand seconds (approximately one hour).

2.2.1 Load Flow Database conversion

The Transmission Planning Division of HECO provided load-flow databases in PSS/E format. The PSS/E datasets were converted to GE PSLF^{TM}. The comparison of GE PSLF^{TM} results and PSS/E results was adequate and presented in the Task 8 deliverable.

2.2.2 Steady State Contingency Simulations

2.2.2.1 N-1 Contingencies in the 69 kV System

Based on the breaker locations in the single-line diagram of the MECO 69 KV system, an N-1 outage of all 69 KV lines was considered for both minimum and peak load cases. Constant power loads, generator terminal voltage control, no tap changer action and no automatic cap switching were assumed. The list of lines considered for the N-1 contingencies is given in Table 2.

Table 2: Contingency list of lines.

Outage name	Outage description
line_1	Line MAALAEA 69.0 to LAHAINA 69.0 Circuit 1
line_2	Line LAHAINA 69.0 to PUUKA 69 69.0 Circuit 1
line_3	Line LAHALUNA 69.0 to PUUKB 69 69.0 Circuit 1
line_4	Line LAHAINA 69.0 to LAHALUNA 69.0 Circuit 1
line_5	Line MAALAEA 69.0 to KWP 69.0 Circuit 1
line_6	Line LAHAINA 69.0 to KWP 69.0 Circuit 1
line_7	Line MAALAEA 69.0 to LAHALUNA 69.0 Circuit 1
line_8	Line MAALAEA 69.0 to WAIINU 69.0 Circuit 1
line_9	Line MAALAEA 69.0 to PUUNENE 69.0 Circuit 1
line_10	Line PUUNENE 69.0 to KANAHA69 69.0 Circuit 1
line_11	Line KANAHA69 69.0 to PUKLN69 69.0 Circuit 1
line_12	Line KULA 69 69.0 to PUKLN69 69.0 Circuit 1
line_13	Line KEALAHOU 69.0 to KULA 69 69.0 Circuit 1
line_14	Line MAALAEA 69.0 to KEALAHOU 69.0 Circuit 1
line_15	Line MAALAEA 69.0 to KIHEI 69.0 Circuit 1
line_16	Line KIHEI 69.0 to WAILEA 69.0 Circuit 1
line_17	Line WAILEA 69.0 to KEALAHOU 69.0 Circuit 1

2.2.2.1.1 Minimum Load Conditions

The maximum and minimum per unit bus voltages for all contingencies during minimum load conditions were evaluated and modeled, where necessary. This also includes the maximum per unit branch loading for all contingencies during minimum load conditions. One-line diagrams of the base case and the contingencies are also developed. No salient overloading or low voltage problems were observed for minimum load conditions, in line with collected information of the MECO system.

2.2.2.1.2 Peak Load Conditions

The maximum and minimum per unit bus voltages for all contingencies in the peak load case were also modeled and evaluated. Maximum per unit branch loading for all contingencies during peak load conditions and one-line diagrams of the base case and the contingencies were also developed.

The pre-contingency load flow during peak load conditions demonstrate low voltage conditions in the radial system between PUKLN69 and Hana. Any contingencies due to a line outage in the 69 kV system between Maalaea and PUKLN69 lead to either severe under voltage conditions in the radial 23 kV system to Hana or to voltage collapse.

Voltage collapse in this long 23 kV radial system was observed in N-1 outage of lines PUUNENE-KANAHA69 (line_10) and MAALAEA-KIHEI (line_15). Load flows did not solve with constant power load characteristics.

The voltage issues observed in the 23 kV system to HANA are in line with the information shared by MECO and HECO during the weekly discussions. Under system conditions that result in low voltages in Hana, MECO operators start small diesel units close to Hana.

2.2.2.2 Critical Contingencies

In addition to the N-1 contingency analysis of all 69 kV transmission lines, further analysis was performed based on the list of critical cases provided by MECO and HECO (Table 3).

Table 3: List of critical cases.

Outage name	Outage Description	Remarks
fnl-crtcase-01	Lost of MPP-Waiinu line(39-636)	line_8
fnl-crtcase-02	Lost of MPP-Kihei line (39-35)	line_15
fnl-crtcase-03	Lost of MPP-Puunene (39-402)	line_9
fnl-crtcase-04	Lost of Waiinu tie transformer (636-236) and Lost of Puunene tie transformer (4-4002)	transformer outages (N-2)
fnl-crtcase-05	Lost of MPP-Lahaina (39-34) and Lost of KWP-Lahaina (97-34)	line_1 & line_6 (N-2)
fnl-crtcase-06	Lost of MPP-Kealahou (39-655) and Lost of MPP-Kihei (39-35)	line_14 & line_15 (N-2)
fnl-crtcase-07	Lost of KPP-Kanaha 1,2,3 (200-202,1,2,3)	lines in 23 kv system
fnl-crtcase-08	Lost of Waiinu-Wailuku 23 (236-3)	line in 23 kv system
fnl-crtcase-09	During minimum load, lost of KPP (K3 and K4)	generator outage

The first eight critical cases occur during peak load conditions, whereas the ninth case is during the minimum load conditions. The first three cases are identical to N-1contingency cases considered in the previous section. The corresponding contingency cases are shown in the remarks column. Case 4 is an N-2 outage of transformers, and cases 5 and 6 are N-2 outages of lines. Cases 7 and 8 are N-1 outage of lines in the 23 kV system.

Case 9 is loss of K3 and K4 units at KPP during minimum load conditions. The total amount of lost generation due to the loss of units K3 and K4 is re-dispatched on the three CT units in service during minimum load conditions, which are M14, M16 and M17. This is associated with priority levels in regulation function of the AGC application in EMS. Each of the three units picks up a fraction of the total lost generation, proportionally to the amount of its reserve. The percentage of the lost generation each of the three units picks up is as follows: M14 27%, M16 27% and M17 46%.

The maximum and minimum per unit bus voltages for all critical cases were evaluated as were the maximum per unit branch loading for all critical cases and the one-line diagrams of the base case and the contingencies. Cases 2 and 6 did not converge due to low voltages in 23 kV radial system to Hana, as described in the previous section.

2.2.3 Dynamic Contingency Analysis

2.2.3.1 Critical Clearing Times

Dynamic contingency analysis was performed on the critical cases provided by MECO (Table 3). According to the information provided by MECO, typical clearing times for zone 1 faults are between 6 to 9 cycles, and typical clearing times for zone 2 faults are 20 to 50 cycles, depending on the line. Based on this information, four clearing time combinations were chosen for the dynamic contingency analysis

Angle stability is maintained in all critical cases for the first three clearing-time combinations. The last clearing-time combination (150ms-833ms) leads to loss of synchronism for the critical cases 1,2,3,5 and 6. Critical case 6 leads to very low voltages in the radial system between PUKLN69 and Hana.

Loss of KPP in case 9 leads to a minimum frequency of around 58.5 Hz and results in under-frequency load-shedding operation. Loads at KIHEI B, PUKLN A, LAHAINA1 and NAPILB12 (11.6MW) trip at 58.7 Hz. Many other loads would trip at 58.5 Hz.

2.2.3.2 Definition of Contingencies and Clearing Times

Based on the critical clearing-time calculations of the previous section and after further consultation with MECO and HECO, contingency cases were chosen and analyzed. Critical case 2 does not present transient instability. However, even though the simulation reaches a stable steady state after the fault, the system is likely to evolve to significant load disconnections due voltage collapse. In the transient simulations it can be observed that reactive power and the field current in MPP units are high and sustained for many seconds. There is significant risk of these units experiencing reduced field current due to over-excitation limiter (OEL) operation and consequently further reducing voltages. In case OEL limiters are not available in the units, the units may trip on over-excitation protection. This situation is also aggravated by the OLTC operation that tends to increase the load consumption of active and reactive power during low voltage conditions in the 69 kV system. Critical case 6 does not present transient instability, but would result in voltage collapse.

2.2.4 Governor/Turbine Models

Historical data of a fault at a 23 kV system on March 15, 2008 was provided to verify that the proposed governor models are representative of the performance of the different turbines. The event was recorded on the MECO system on March 15, 2008.

The data (unit power output) is sampled every 4 seconds. The sampling data are less than optimal for capturing the dynamic performance of governor response in detail. The steady state and slow dynamics response of the governor models were improved based on the historical data.

A frequency excursion similar to the EMS recorded signal was imposed to the governor and generator models of the different units in service. The simulated electrical power was used to compare the performance of the model and the recorded data.

Modifications were made to the database reported in the Task 8 Deliverable, mostly on droop settings. Most salient changes are:

- Unit K4 is less responsive than initially reported (governor with 10% droop). Due to 4 second sampling data it is not possible to differentiate between accelerating power and potential operation with dead band. It is evident, however, that there is no significant change in steady state power output during operation at 0.8 Hz above nominal. This unit will be assumed not to perform any significant contribution to primary frequency control. The same assumption will be made for K1, K2 and K3.
- The droop of unit M6 was increased from initially assumed 4% to 5.5% (5.6 MW base). The same will be used for M7 and M9.
- The droop of unit M11 was increased from initially assumed 4% to 4.5% (11.5 MW base). The same will be used for M11.
- The droop of unit M13 was increased from initially assumed 4% to 5.5% (11.5 MW base). The same will be used for M12.
- The droop of unit X2 was increased from initially assumed 4% to 10% (2.5 MW base). The same will be used for X1.

2.2.5 Steam Turbines on Combined Cycle Plant

Based on historical data sets for AGC validation, the models of the steam turbines in combined cycle were modified from previously reported models. System frequency, CTs and ST power output recorded on February 11 2008 were modeled. The ST output smoothly follows CT operation. At the time the frequency reaches 59.9 Hz, there is no transient increase of ST power. Similar behavior is observed in other combined cycle (M17, M18 and M19) and in other periods of recorded data. It can be concluded that both combined cycles operate with steam turbine admission valves fully open. The parameters for these models are different if the heat recovery steam generator has one or two CTs in service.

2.2.6 AGC Model Improvement

Different windows of historical data were evaluated with MECO and HECO. The list of data periods is presented in Table 4. The three windows highlighted in yellow were selected for the purpose of improving the AGC model. The main and challenging objective of this section is to understand the natural response of the system without operator action in the time frame of minutes, where AGC is most relevant.

Table 4: List of windows for AGC model improvement.

Date	Time	General Conditions	Notes
1/19/2008	0830-1030	Morning Ramp	M19 not on AGC while being step loaded up during event
2/3/08	2100-2300	High Load	Unit shut down during KWP drop. Good wind power fluctuation Modest frequency fluctuation M12 seems to be manually ramping down during relevant part of the recording HC&S does not seem to respond with droop, origin of power variations is unknown
2/6/08	0900-1100	After Morning Ramp	Units Started. - Good wind power fluctuation Considerable frequency fluctuation. Seems to trigger assist mode in AGC M10 and M11 seems to react to AGC assist mode request.M11 seems to be limiting (operations commented the fact that due to torsional concerns the units is limited) Various unit starts after frequency drop
2/7/08	0430-0630	Low Load/Morning Ramp	Units started late in event. Good wind power fluctuation Modest frequency fluctuation KPP seems to be manually ramping up during relevant part of the recording
2/11/08	1630-1830	High Load	Units started late in event. -Good wind power fluctuation Modest frequency fluctuation M13 seems to be manually ramping up during relevant part of the recording. Hard to differentiate from "natural system" response
2/11/08	2000-2200	After Peak	Good wind power fluctuation Modest frequency fluctuation. M10, M11 and M13 seem to shortly react to AGC assist mode request. K2 and HC&S seem to respond to manual operation
2/29/08	0430-0630	Morning Ramp	Fast Drop off, units started. Window was provided earlier for validation Good wind power fluctuation Significant frequency fluctuation. CTs are only units reacting to AGC request K3 and K4 manually pick up power Several units manually started outside box
5/1/08	1245-1315	Loss of HC&S	HC&S drops more than 15 MW in about 100sec. Comparatively fast frequency drop with UFLS operation. AGC seems to enter assist and emergency modes. M5 response is reducing power before the event without clear reason.

The block diagram of the AGC model was already presented in the earlier report. The historical data were used to set or confirm the parameters of the AGC model. The priority levels of the different units on AGC are presented in Table 5. Parameters of PSLF models were modified to better represent the behavior of the actual system. Several iterations were done to tune the parameters in a way that had acceptable results with the same model for three selected windows.

Table 5: Units under AGC control and priority levels.

Bus	Unit	ID	ID	Priority
106	MGS-458	4	M4	2
106	MGS-458	5	M5	3
106	MGS-458	8	M6	3
107	MGS-679	6	M7	3
107	MGS-679	7	M8	3
107	MGS-679	9	M9	3
108	MGS-1011	0	M10	2
108	MGS-1011	1	M11	2
109	MGS-1213	2	M12	2
109	MGS-1213	3	M13	2
301	CT-1 M14	1	M14	1
302	CT-2 M16	2	M16	1
304	CT-3 M17	4	M17	1
305	CT-4 M19	5	M19	1
303	ST-1 M15	3	M15	
306	ST-2 M18	6	M18	
101	KGS-1	1	K1	Basepoint
102	KGS-2	2	K2	Basepoint
103	KGS-3	3	K3	Basepoint
104	KGS-4	4	K4	Basepoint

2.2.6.1 Window 02/29/2008

The project team selected the 02/29/2008 validation window as the first window to validate. In this window, the units initially in service are:

- Wind Farm.
- K3 and K4 (did not respond to frequency fluctuations).
- M14, M16, M15, M18 and M19. M16 power output is flat as the recording is from before the controls upgrade.
- HC&S (did not respond to frequency fluctuations).

The main disturbance to the system is the wind power fluctuation that was imposed in the simulation. CTs are performing all regulation. Frequency excursions do trigger a few normal to assist mode transitions in the AGC. After the shown data, units were manually started. This window assisted the project team in setting AGC regulation gains for ACE and ACE integral as well as pulsating logic for CTs.

2.2.6.2 Window 02/11/2008

The project team selected the 02/11/2008 validation window as the second window to validate. In this window the units initially in service are:

- Wind Farm with significant variations.
- K2, K3 and K4. K2 was manually ramped down..
- M10, M11 and M13. Units are very responsive.
- Both combined cycles are in service. M16 responds to AGC regulation requests.

- HC&S. Generation did not seem to respond to frequency. The power output also had some oscillations that were most likely related to steam generation/use in the plant.

The main disturbance to the system is the wind power fluctuation that was imposed in the simulation. HC&S was also imposed in the simulations because the fluctuations of the power output cannot be controlled directly by the MECO operators. CTs and large diesels performed regulation. Frequency excursions trigger a few normal to assist mode transitions in the AGC.

Unlike the prior window, the large diesels were in service (M10, M11 and M13). These units are set to priority level 2 in the AGC and operate in Assist/Emergency Mode. It can be seen from the recording that once the frequency error is large enough to cause a normal-to-assist transition, these units react aggressively to recover system frequency. The AGC parameters associated with Assist mode and the pulsating logic of M10, M11 and M13 were improved, based on this recording. In the recording, M10 reacts somewhat differently than M11 and M13. This difference was discussed with the HECO/MECO team. There is no known reason for the differences. The most relevant characteristics of the response are similar among units and well represented in the proposed simulation model.

2.2.6.3 Window 05/01/2008

The project team selected the 05/01/2008 validation window as the third window to validate. In this window the units initially in service are:

- Wind Farm with modest variations.
- K2, K3 and K4 were manually operated.
- M1, M2 and M3. The sum of the three units was provided in the recorded data. These units were ramped up manually.
- M5. The power output does not fully respond to expected regulations request.
- M10, M11, M12 and M13. Units are very responsive.
- X2. Unit was manually ramped up.
- M16 was out of service; all other units in combined cycles were on line.
- HC&S. Dropped about 20 MW in about 150 seconds

The main disturbance to the system is HC&S power reduction. The 58.7 Hz UFLS stage operated. In the simulation, HC&S and units manually operated were imposed.

There are a few challenges associated to this window:

- HC&S switched from exporting to importing power during the window. After the HC&S switched from exporting to importing, only 1-min data were available. Most of the system dynamics are exercised in less than a 100-second period, where HC&S power drops from +7 to –7 MW. During this period, there are insufficient measurements to characterize the HC&S variation. Additional data points were added to the recorded measurements, assuming that HC&S decreased power production at a constant MW/sec rate until it reached its lowest value. This assumption is closer than assuming linear interpolation between every 1-minute sample.

- Many units reacted about 5 to 10 seconds before HC&S dropped, causing these units to increase power production (i.e., they appeared to “anticipate” HC&S’s dropping out). In discussions with MECO/HECO, it was confirmed that small synchronization inaccuracies between signals could be expected. This result had a significant effect in the frequency excursion observed in this window. These synchronization inaccuracies were less relevant for slower frequency excursions observed in previous windows.
- M12 and M13 increased power before the 100 sec in recordings. The frequency at that time was not significantly off nominal to justify this power increase in these units.
- M11 does not seem to modify power according to an AGC request. It can be seen that the unit reduced power at around 400 sec even though the frequency is still below nominal after the event.

This historical window did not necessarily help in improving the simulation model, but showcased the model’s ability to recreate this event within the mentioned limitations.

2.2.7 Conclusions of the Dynamic Modeling

Various aspects of the system behavior were addressed with PSLF modeling. The load flow database was successfully converted from the HECO planning tool. The steady-state contingency analysis of the system presented conditions with voltage challenges in the 23 kV radial system out of Pukalani. These simulation results were confirmed by HECO/MECO as similar challenges in the actual system operation. Transient simulation models of fast system events (faults and generation trips) were also setup. Critical events were simulated as a baseline for future scenario analysis. To the extent possible using available data, governor model parameters were improved based on historical data of 03/15/2008. The validation windows of historical data were used to tune the AGC model parameters. The resulting system model (AGC, governors, generators, network, etc.) captures the relevant dynamics of the actual system in the recorded data. The project team believes that the fidelity of these dynamic models is of sufficient quality to be used in the subsequent phase of this study.