O‘ahu Grid Study: Validation of Grid Models

Prepared for the

U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability

Under Award No. DE-FC26-06NT42847
Hawai‘i Distributed Energy Resource Technologies for Energy Security

Subtask 7.2 Deliverable

By

GE Global Research
Niskayuna, New York

And

Hawai‘i Natural Energy Institute
School of Ocean and Earth Science and Technology
University of Hawai‘i

September 2009

Acknowledgement: This material is based upon work supported by the United States Department of Energy under Award Number DE-FC-06NT42847.

Table of Contents

List of Figures

List of Tables

1 Introduction

The Oahu Grid Study is a joint study by Hawaiian Electric Company (HECO), the Hawaii Natural Energy Institute (HNEI) and the General Electric Company (GE). The primary objective of this phase of the study is to develop and calibrate dynamic and production cost models for the Oahu Grid. This is the first step in an activity designed to help HECO 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 model and evaluate power system expansion scenarios for the island of Oahu. This program began in October 2008 with the data acquisition and model development. This deliverable highlights the validation of the power systems models for the island of Oahu.

In order to ensure that the model accurately captures HECO's present system operation, the model was calibrated and validated against historical data. Significant iterations with the HECO team were needed to ensure the model accurately captured HECO system operation to a level of fidelity that is sufficient for the next phase of the study. This next phase will be the scenario analysis of the future HECO system (Task 10 under the overall HNEI contract with NETL). Meetings of a Technical Review Committee (TRC) were organized by David Corbus of the National Renewable Energy Laboratory as part of the Hawaii Clean Energy Initiative in which the GE team presented results of the model development and validation. Based on the responses to the questions and the inputs and directions from HECO and the TRC, the GE team implemented the necessary changes to revise and update the model. The project team is now comfortable with the level of accuracy of both the GE PSLF^{TM} and GE MAPS^{TM} models of the HECO system for the application of these tools to system scenario analysis.

This document serves as the deliverable for Task 7.2. This document is intended to present the validation of databases created in GE MAPS^{TM} and GE PSLF^{TM} for the analysis of the electrical systems of HECO. The databases were compiled based on the data provided by HECO.

2 Model Validation

The Oahu grid is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. 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 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. 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
- 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 HECO assets, in each of the timeframes relevant to the performance of HECO'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 that were made day ahead are implemented and refined to meet the changing load. In this 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 (those that 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 HECO, 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 HECO AGC. The model developed is not intended to reproduce every detail of the actual AGC, but to capture behavior relevant for the objective of this study. A HECO system event, which resulted in load being rejected, was chosen and the AGC model was calibrated and validated against the behavior during the event. This type of simulation is referred to as a transient stability simulation.

2.1 Production Cost Modeling (GE MAPS™ analysis)

Production cost modeling of the HECO system was performed with the GE's Multi Area Production Simulation (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 HECO production for 2007. Ultimately, the production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (i.e., GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, and fuel consumption.

The overall simulation algorithm is based on standard least 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 units. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum regulating reserve, stability limits, as well as the physical limitations and characteristics of the power plants. Significant input has been received from HECO 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 HECO system in GE MAPS^{TM}, general operating assumptions were needed. It was understood by both GE and HECO that the actual operating practices vary, depending on unique system events and conditions, such as the load level, the number and types of units on outage, etc; and the model may not capture all the variations in operating practices. To briefly summarize modeling data and assumptions, some of the inputs to the GE MAPS^{TM} model are listed 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, fuel prices, and emissions rates.
- Hourly HPOWER production.
- System and unit constraints.
- System losses due to transmission.
- General operating assumptions (described later in the report).

The incremental heatrate values were compared to the HECO "ABC Heatrate Curves" to verify that the conversion was performed accurately. These heatrate values and fuel cost data, covered by non-disclosure agreements were also an input to the GE MAPS^{TM} model.

The following general modeling assumptions were made to capture the current system operation:

Unit categorization:

- Base-loaded units: AES, HPOWER, Kalaeloa, Kahe, Waiau 7-8.
- Cycling: Waiau 3-6, Honolulu 8-9.
- Peaking: Waiau 9-10, DGs 1-18.

Kalaeloa Modeling:

- Unit 1 (CT + ½ ST) rated for 90 MW. Wash time from 9pm(Fri) to 9am(Sat).
- Unit 2 (CT + ½ ST) rated for 90 MW. Wash time from 9pm(Sat) to 9am(Sun).
- Unit 3 rated for 28 MW. Operates only when Units 1 and 2 are operating at max capacity.

HPOWER: Modeled with actual 2007 production data.

Regulating up-reserve:

- Modeled as the loss of largest unit (AES - 180 MWs).
- All units, except HPOWER, W9-10, and DG's are modeled to account 100% of their rated capacity towards regulating up-reserves.

Other Modeling Assumptions:

- Two hour start up delay between sister units (W3&W4, W5&W6, H8&H9).

- Start-up cost is not included in unit commitment.
- 5 hour downtime for W3, W4, W5, W6, H8, H9.
- Minimum run time of 1 hour and downtime of 1 hour for W9, W10.

These system constraints and assumptions increased the accuracy of the model with respect to the base year of 2007. This allowed the project team to compare the model results to the historical data for the implementation of the HECO 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/GE team, the results of the model were compared to historical data. The GE MAPS™ hourly production data (by unit), and a summary table that outlines 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 period of time (see Figure 2-1). 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 GE MAPS™ that did not historically occur in the same time frame. The model uses five-year average heat rates and forced outage rates, which are different from those observed in 2007. Additionally, any operator intervention is not captured in the GE MAPS™ model. Additional 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.

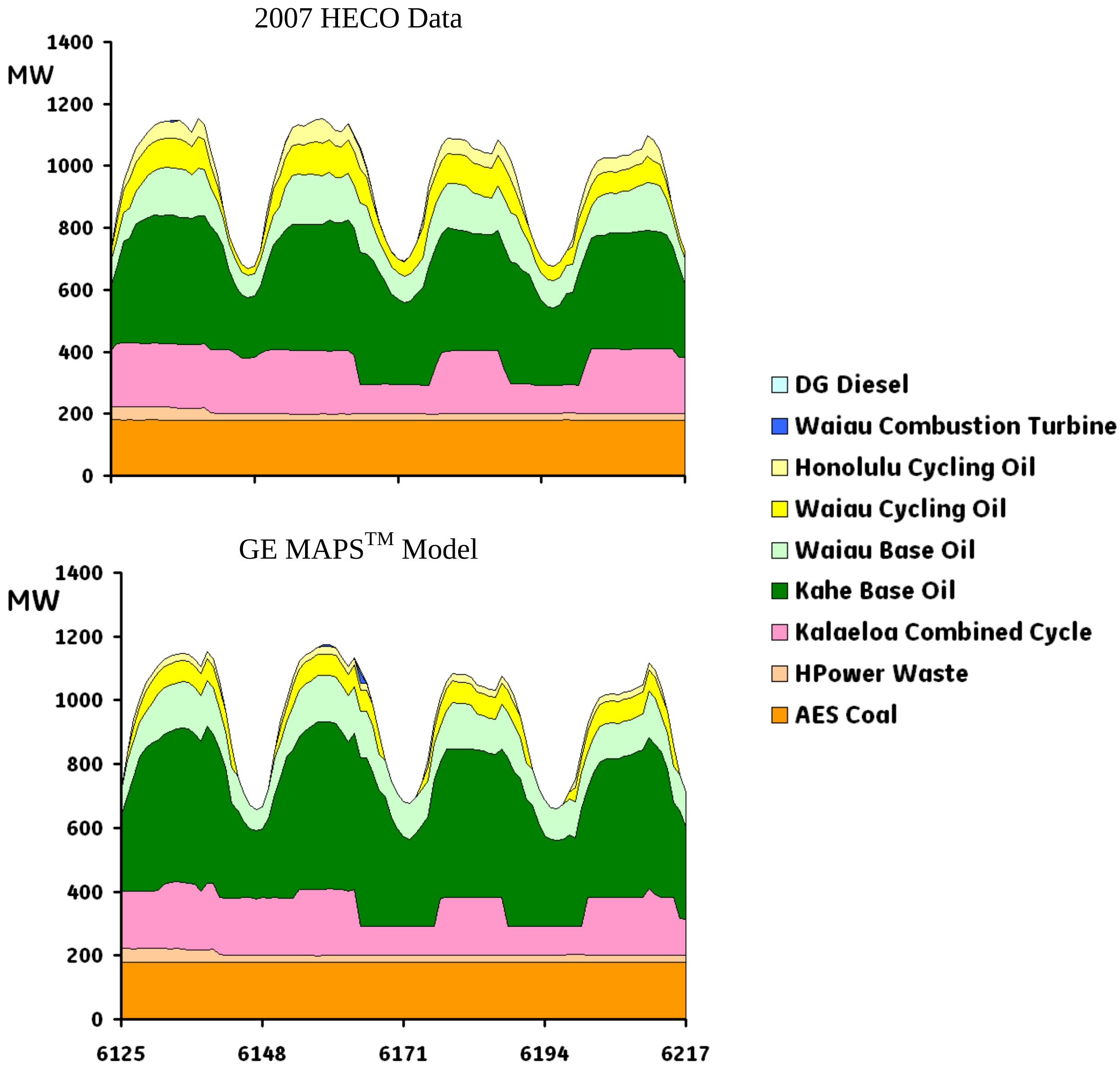

Figure 2-1: GE MAPS™ model results compared to historical hourly generation data for 4 days, starting September 13, 2007 and ending September 16, 2007

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 heatrate as interchangeable, comparisons are generally made on a unit type basis. The model captures the general operating practices of HECO system that are outlined in section 2.1. The annual energy production, by unit type, is shown for the 2007 historical HECO operation and the MAPS model in Figure 2-2.

\

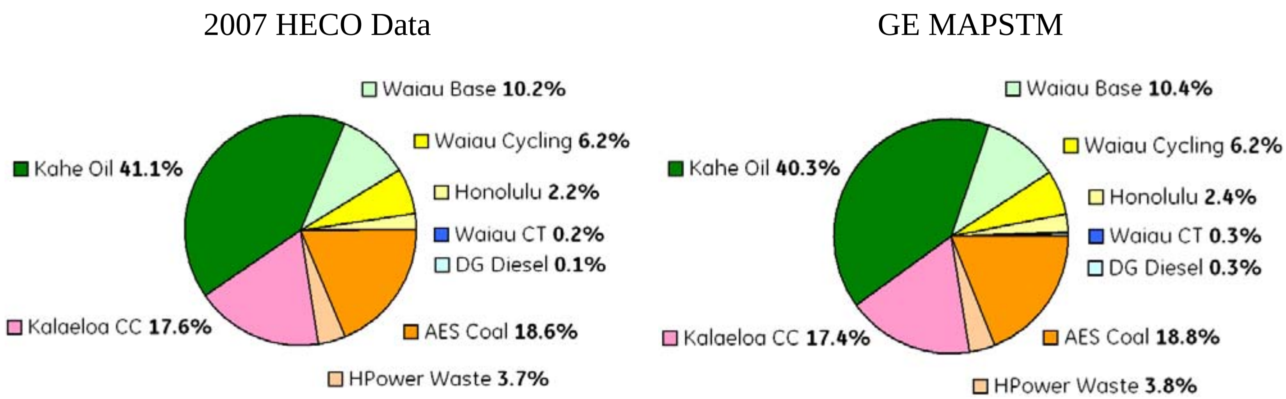

Figure 2-2: Comparison of the annual energy production (MWh), by unit type, between the historical 2007 HECO energy production and the GE MAPS™ model simulation

Recognizing the limitations of the model, the project team was satisfied with the level of fidelity observed on a unit-by-unit basis. The maximum absolute energy difference, by unit type, is seen to be 0.8% (for Kahe units). 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 total fuel consumed by the HECO units and the fuel consumption obtained from GE MAPS™ model. Actual 2007 data on fuel consumption for IPPs were not available; hence the comparison is limited to the HECO units at Kahe, Waiau, and Honolulu. The GE MAPS™ model accurately captures the fuel consumption with the maximum absolute difference of 1.1% (for Kahe units). This is shown in Figure 2-3.

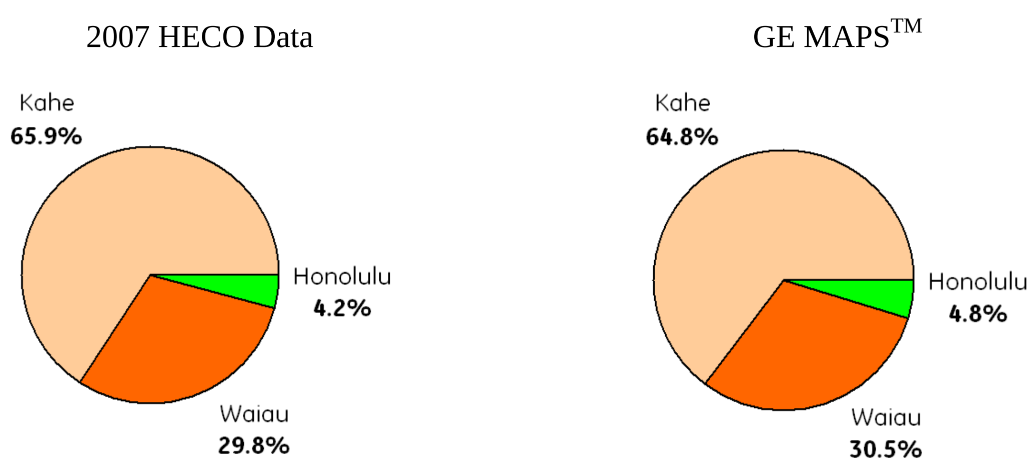

Figure 2-3: Comparison of the fuel consumption (MMBTU), by unit type, between the historical 2007 HECO fuel consumption and the GE MAPS™ model simulation

A third metric was used for validating the production cost model. This is the system heatrate, which is calculated as the total fuel consumption of a unit per kWh produced by that unit. The heatrate from the GEMAPS^{TM} model was compared against the HECO system heatrate that was observed in 2007.

Based on the results of the GE MAPS^{TM} simulation, the system heatrate was 1.2% less than the historical HECO system heatrate. This indicates that GE MAPS^{TM} overestimates the overall system efficiency by 1.2%, similar to the level of fidelity observed in the HECO production cost simulations. The total fuel consumption and total energy production was lower than historical 2007 numbers by 2.86% and 1.67% respectively.

Some of the discrepancy between the model results and the historical 2007 results can be attributed to the following factors:

- Forward-looking heat rates and forced outage rates were used in the model, the values of which are different from those observed in 2007
- GE MAPS^{TM} models the system to carry 180 MW of regulating up-reserves in every hour, but the regulating up-reserves may be higher under light load conditions
- During system outages, HECO may commit/dispatch units in a manner different from normal operating practices, which the model cannot capture
- Temporary unit de-ratings occurred during 2007 historical operation. These de-ratings were not captured in the model.

2.1.3 Conclusions of the Production Cost Modeling

The project team agreed that the production cost model of the HECO system accurately captured the total energy production within a margin of 1.6%, total fuel consumption by HECO within a margin of 2.8%, and the system heatrate within a margin of 1.25%. The project team was satisfied with the level of fidelity of the production cost model and recognized that some of the discrepancy between actual historical production and simulated production can be attributed to the list of factors described above. The GE team is comfortable using this tool to analyze system scenarios on the HECO system.

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 large disturbances and large renewable (wind and/or solar) power variations. In combination with good engineering judgment and with the understanding of the limitations of the model, this type of modeling can be used to understand the impact of system contingencies or wind power variability on system frequency in a seconds timeframe. For example, if a fault results in generation loss in the area, other generators must increase its power output to meet the load demand. Depending on how fast these generators increase their output, 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. Also the impact on fault recovery of the system with renewable resources is assessed with this model.

Long-Term Dynamic Simulations were performed for HECO's grid using GE's Positive-Sequence Load Flow (PSLF™) software. Second-by-second load variability was used to drive the full dynamic simulation of the HECO grid for several hundred seconds in the validation run.

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™. The comparison of GE PSLF™ results and PSS/E results was considered adequate by the project team.

2.2.2 Dynamic Model Data

Transmission Planning Division of HECO provided the dynamic data for the HECO grid, which was also available in PSS/E format. The database included dynamic models and respective parameters of generators, their governors and excitation systems, under frequency load shed scheme and dynamic load characteristics. The PSS/E models from the dynamic database were then subsequently converted to GE PSLF™.

The only modification made in the PSLF data was with respect to the excitation system models of Waiau 7 and 8. As was suggested by HECO, the excitation system models of Waiau 7 and 8 units are identical to those of Kahe 1 and 2. Therefore, the IEEEX1 models of Waiau 7 and 8 have been replaced with EXDC2 models and parameters of the Kahe 1 and 2.

To summarize briefly, the main modifications made to the dynamic database are as follows:

- The gross maximum and minimum generator unit MW limits that HECO had provided has been used to update the Pmax/Pmin limits of the governor models in the dynamic database.
- Droop settings, as proposed, by EPS were used to modify respective governor model parameters.
- Excitation system model parameters for CICT-1 have been added to the dynamic database obtained from manufacturer datasheets.
- The steam turbine-governor model of Kalaeloa ST was replaced with the combined cycle plant steam turbine model (ccst3) available within GE PSLF™.

2.2.3 AGC Model Development

The Automatic Generation Control (AGC) for the Oahu grid was modeled based on information provided by HECO, engineering judgment, and several related discussions with HECO Operations. The proposed model is not intended to reproduce every detail of the actual AGC, but to capture behavior relevant for the objectives of this study. The following are the salient points that have been considered for the development of the AGC model:

- Based on discussions with HECO, Local Frequency Control (LFC) has not been considered in this study. In other words, the Frequency Control Units (FCU) have been switched off.
- Unit ramp rates have been modified to reflect projected improvements to unit ramp rates according to the Power Supply information provided in Table 2-1.
- Unit and Area settings, and economic dispatch representation has been based according to information from HECO.

Table 2-1: Preliminary "Projected" Ramp Rates

Unit Name	**Ramp Rates (MW/min)**	
	"Everyday"	**"Once in a while"**
HON-8 **(H8)**	3.0	5.0
HON-9 **(H9)**	3.0	5.0
KAHE-1 **(K1)**	5.0	7.0
KAHE-2 **(K2)**	5.0	7.0
KAHE-3 **(K3)**	5.0	7.0
KAHE-4 **(K4)**	5.0	7.0
KAHE-5 **(K5)**	7.0	10.0
KAHE-6 **(K6)**	6.0	8.0
WAI-3 **(W3)**	2.5	4.0
WAI-4 **(W4)**	2.5	4.0
WAI-5 **(W5)**	3.0	5.0
WAI-6 **(W6)**	3.0	5.0
WAI-7 **(W7)**	5.0	7.0
WAI-8 **(W8)**	5.0	7.0
WAI-9 **(W9)**	5.0	10.0
WAI-10 **(W10)**	5.0	10.0
AES-1 **(AES)**	2.5	-
KALAE-1 **(Kal1)**	1.25	-
KALAE-2 **(Kal2)**	1.25	-
KALAE-3 **(Kal3)**	Note 1	-
CICT-1	10	13
CICT-2	10	13
HRRV **(HPOWER)**	-	-

The AGC model is divided into two sections: regulation function and pulsating logic. The operation of AGC in different levels of control (normal, permissive, assist, warning and emergency) is captured in the model.

The regulation function is fundamentally a proportional control system and the inherent integral control action of the AGC returns system frequency to its nominal value following a disturbance.

In the pulsating logic, all regulating units under AGC share the power request from the regulation participation factor. Units are assigned regulating duty based on these factors. The relative magnitude of these values determines the unit's responsibility in controlling system area control error (ACE).

Based on the ACE value determined by AGC, all the units are placed on five different levels of control, namely: Normal, Permissive, Assist, Warning and Trip. The level of control is determined by comparing the value of the smoothed ACE against specified pre-determined thresholds.

The unit frequency bias (UFB) function that estimates the governor action is not available in HECO's AGC and is, hence, not considered in the AGC model.

2.2.3.1 AGC Model Validation

The present system may not be representative of the future Oahu system in which faster unit ramp rates and enhanced governor response for each unit is being expected by HECO. Therefore, this did not constitute a relevant baseline for scenario analyses, since the system response of an actual event in the past cannot be compared to a future system with new settings (no LFC, new ramp rates and governor characteristics) in the future. The validation of the Oahu AGC model is therefore performed by comparing a simulated event with the outcome of an EMS/AGC study carried out by KEMA[1].

The simulated event considered for the purpose of validation is a load rejection event. HECO provided GE with the data for this fault-induced event in which about 130 MW of load is rejected. The event was simulated using base line pre-disturbance conditions. Three different simulation scenarios were considered for the same load rejection event in order to properly understand the AGC behavior and the system settings that influence the system response to disturbances. The three scenarios are discussed in the next sub-sections.

2.2.3.1.1 AGC Response with "Everyday" Ramp Rates in AGC

For validation purposes, the system frequency response for the fault-induced 130 MW load rejection event, obtained by KEMA, has been reproduced here and is shown in Figure 2-4.

[1] "EMS Evaluation for High Penetration of Variable Generating Resources, Distributed Resources, Load Management Resources, and Energy Storage". KEMA – June 2009.

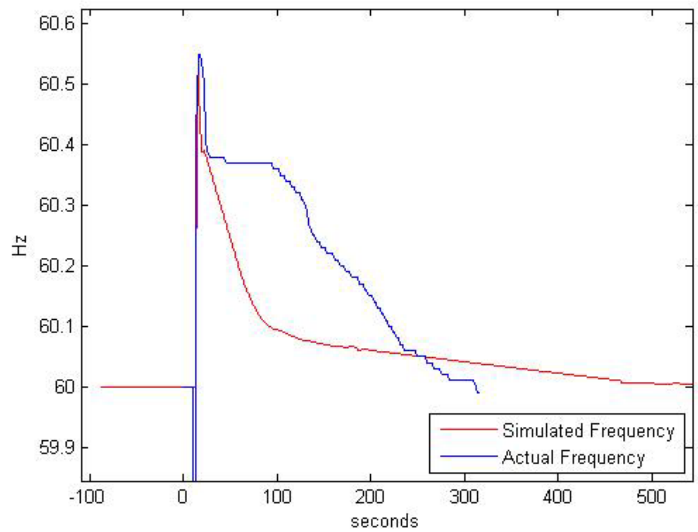

Figure 2-4: Fast AGC Tuning, Simulated vs. Actual Frequency (wide scale)

The GE PSLF^{TM} study for the Oahu AGC model validation for the load rejection event was simulated with historical data and the following considerations:

- Droop and ramp rates according to expected improvements communicated by Power Supply. Area Parameters according to EMS info from HECO.
- "Once in a while" ramp rates NOT used in AGC.
- The simulation is run for only 200 seconds in order to better understand the system's second-by-second behavior.

The "Once in a while" ramp rates are for events when ACE exceeds the Assist limit, all the regulating units will be pulsed at their maximum ramp rate to reduce ACE. The system frequency responses for the GE PSLF^{TM} runs are shown in Figures 2-5, 2-6, and 2-7.

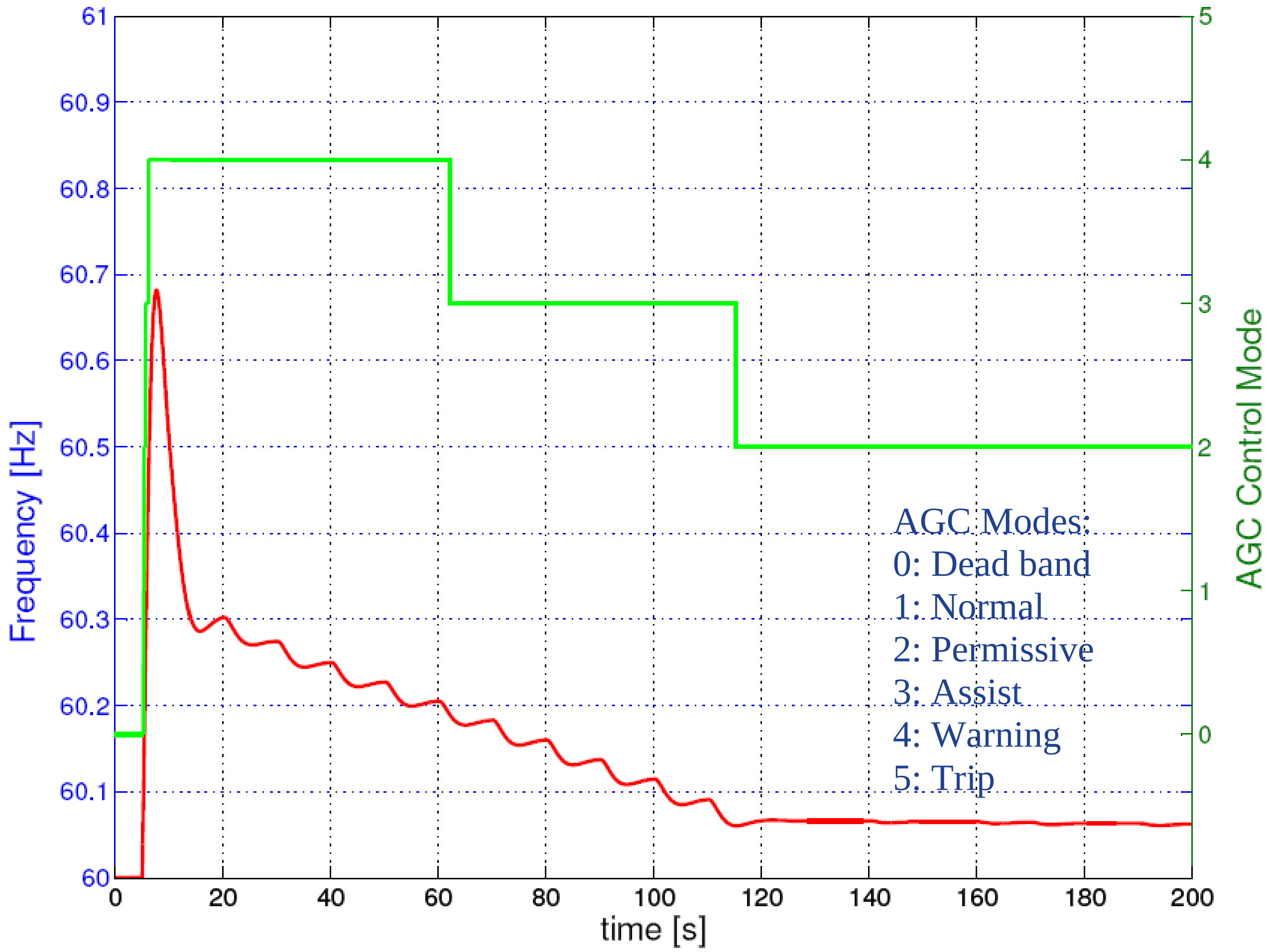

Figure 2-5: System Frequency Response without "Once in a while" ramp rates in AGC

The following are the observations made:

- The maximum value of frequency deviation is higher than that of the actual event. This may be due to the fact that 130 MW of load was rejected at once rather than in a sequence of load rejection events which would have resulted in a slightly lower frequency deviation.
- The system inertia and the governor action of the units play a significant role in bringing the system frequency close to the nominal soon after the disturbance and the post-disturbance governor response (after 20 seconds in the figure) is similar to KEMA's response.
- The AGC response in Assist and higher ACE modes is a little bit sluggish when compared to KEMA's response. It is estimated that this is due to no "Once in a while" ramp rates.
- Appendix 1 provides a detailed overview of the system response for a few units namely Kahe 1 & 4, Waiau 6 & 8, Kalaeloa 1, AES-1 and Honolulu 9 in terms of the angles

responses, generator terminal voltages, generator field voltages, generator active power, mechanical power and reactive power outputs.

2.2.3.1.2 AGC Response with "Once in a while" Ramp Rates in AGC

Based on the observation in the previous section, a second run was performed with "Once in a while" ramp rates enabled (see Figure 2-6). That is, "Once in a while" ramp rates were used in AGC.

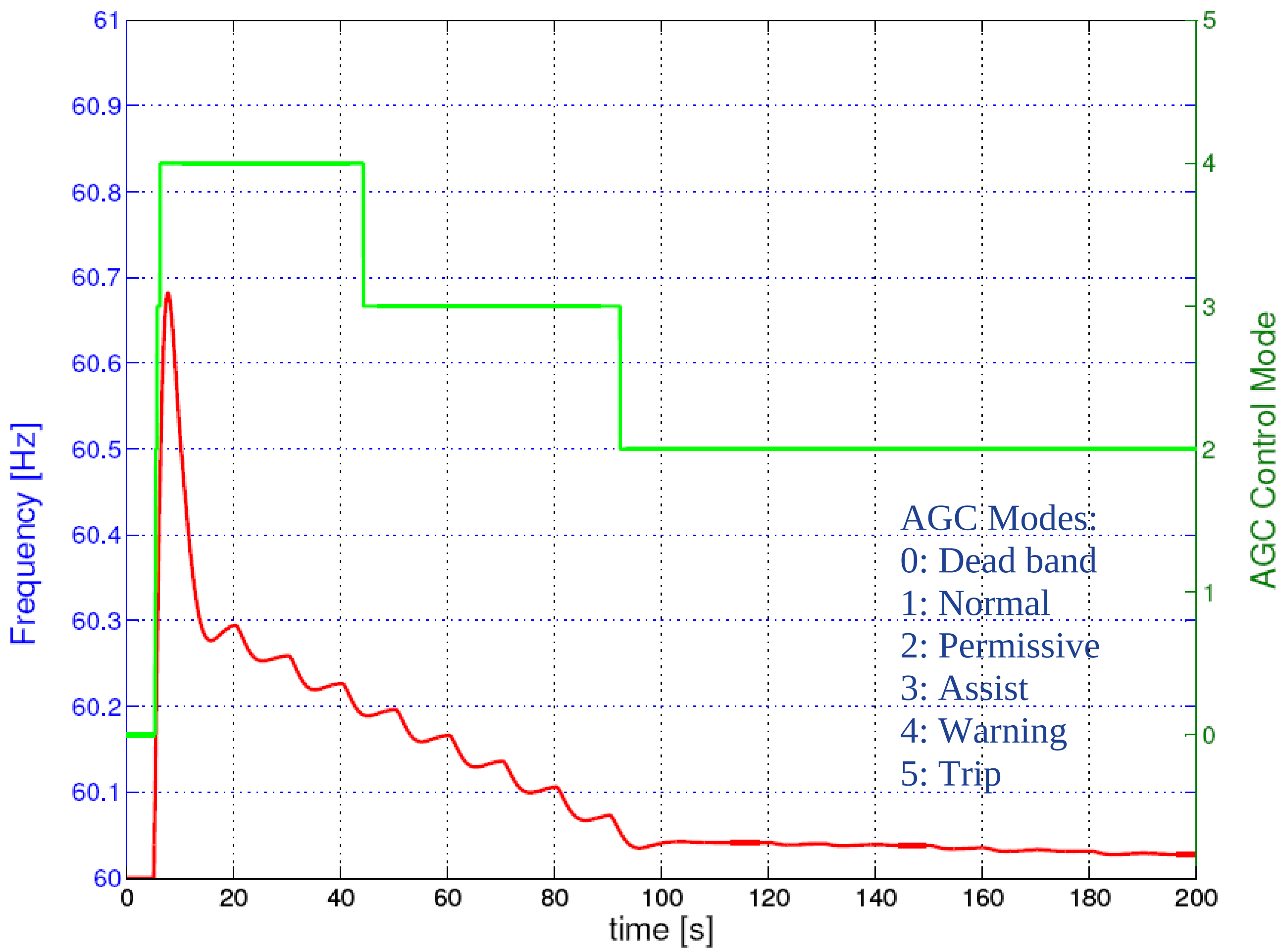

Figure 2-6: System Frequency Response with "Once in a while" ramp rates in AGC

The following are the observations made:

- The maximum value of frequency deviation is still the same as in previous case.
- The system inertia and the governor action of the units play a significant role in bringing the system frequency close to the nominal as was observed in the previous case. The post-disturbance AGC response is similar to the KEMA's response.

- The AGC response in Assist and higher ACE modes behaves similarly when compared to KEMA's response in this scenario when "Once in a while" ramp rates were used in AGC.
- Appendix 2 provides a detailed overview of the system response for this run in terms of the angles responses, generator terminal voltages, generator field voltages, generator active power, mechanical power and reactive power outputs.

2.2.3.1.3 AGC Response with "Once in a while" Ramp Rates in AGC and Less Responsive Governors

In order to obtain a much smoother transition of the system response from the initial governor action to the AGC response (at around 20 sec of Figure 2-6), and to better understand how the system responds to various system or unit settings, a third run was simulated as follows (Figure 2-7):

- Faster unit ramp rates according to expected improvements communicated by Power Supply.
- Higher governor droops than communicated (less responsive governors).
- Area Parameters according to EMS info from HECO except for ACE value for transition Assist to Permissive (slightly higher).

Appendix 3 provides a detailed overview of the system response for this run in terms of the angles responses, generator terminal voltages, generator field voltages, generator active power, mechanical power and reactive power outputs.

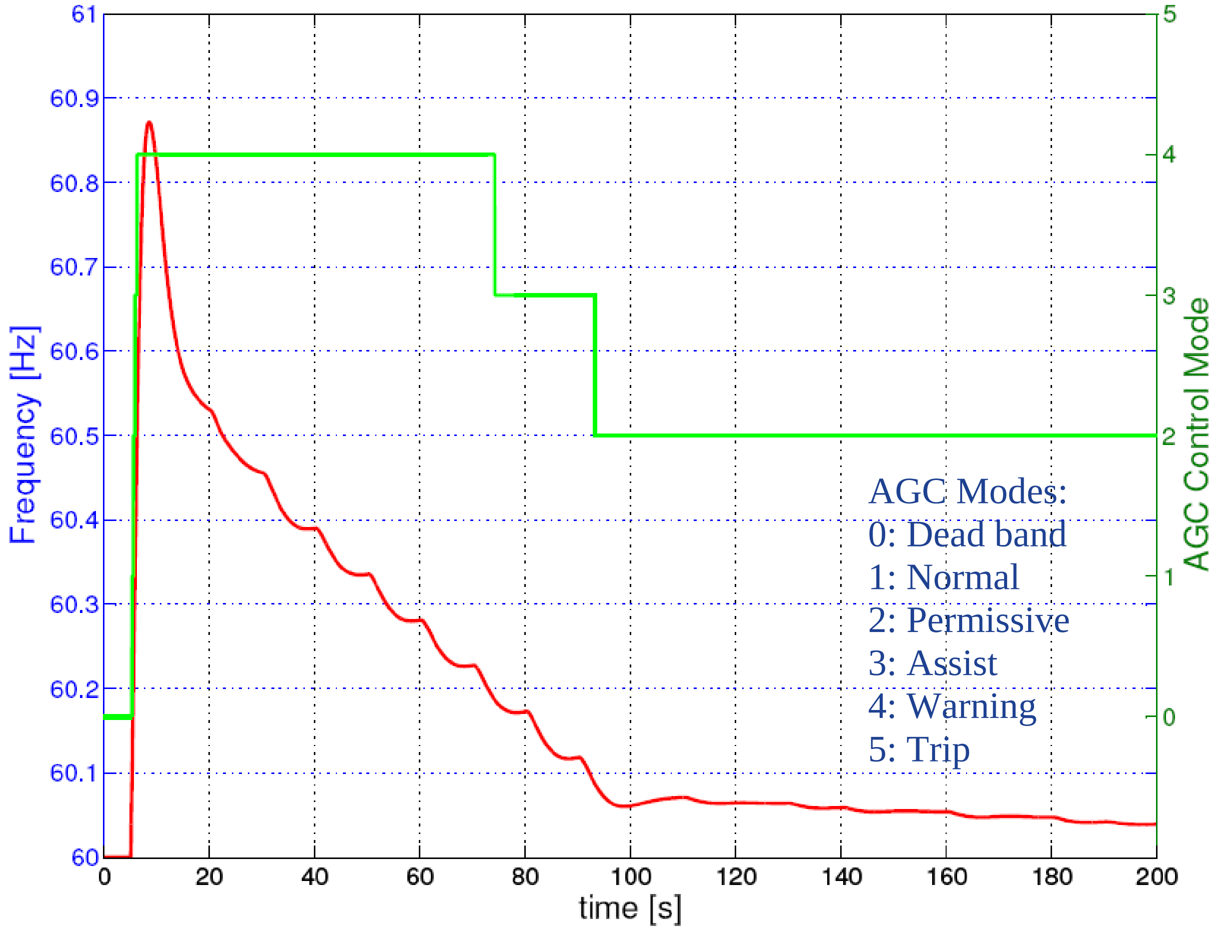

Figure 2-7: System Frequency Response with "Once in a while" ramp rates in AGC and less responsive governors

2.2.4 Conclusions of the Dynamic Modeling

Various aspects of understanding the system behavior for change in system settings were addressed with PSLF modeling.

The load flow database was successfully created from the data provided for the event considered in the study. Transient simulation models of the considered fault-induced load rejection event were setup and the event was simulated for comparison with the same event in the KEMA study. The differences of the PSLF simulations with KEMA study are understood and mostly associated to governor responses. The GE model incorporates the planned improvements in governor responses at HECO units. The use of the more aggressive ramp rates indicated as "Once in a while" ramp rates in AGC may also be a difference with the KEMA report. As requested by HECO Power Supply, the "Once in a while" ramp rates will initially not be used as the emergency AGC ratings in the GE model for Phase 2. The resulting system model (AGC, governors, generators, network, etc.) captures the relevant dynamics of the actual system in the recorded data. The project team is comfortable with the fidelity of the dynamic models and is prepared to use these models in the subsequent phase of this study.

Appendix 1

AGC Response with "Everyday" ramp rates in AGC

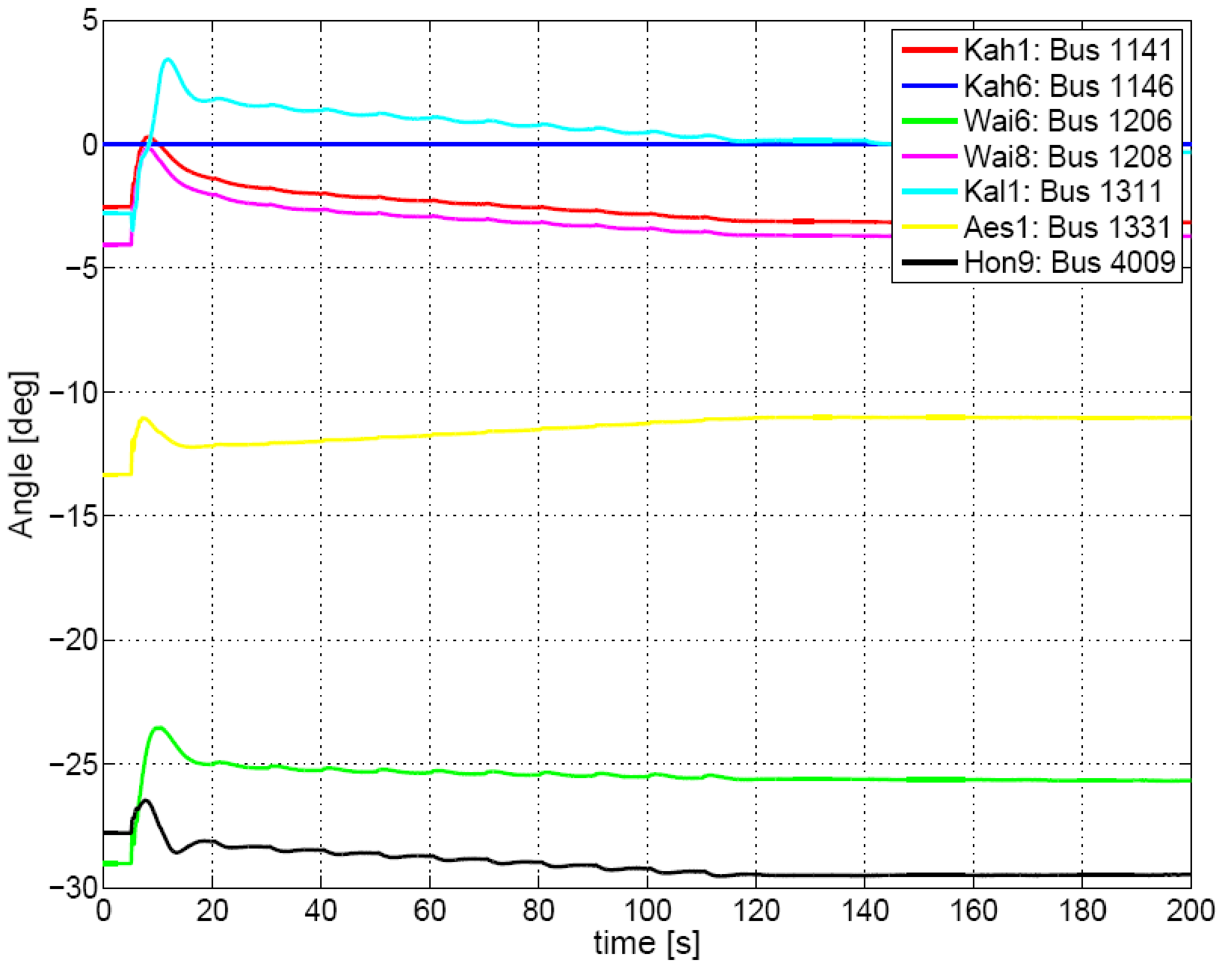

Figure A1-1: Generator angle response

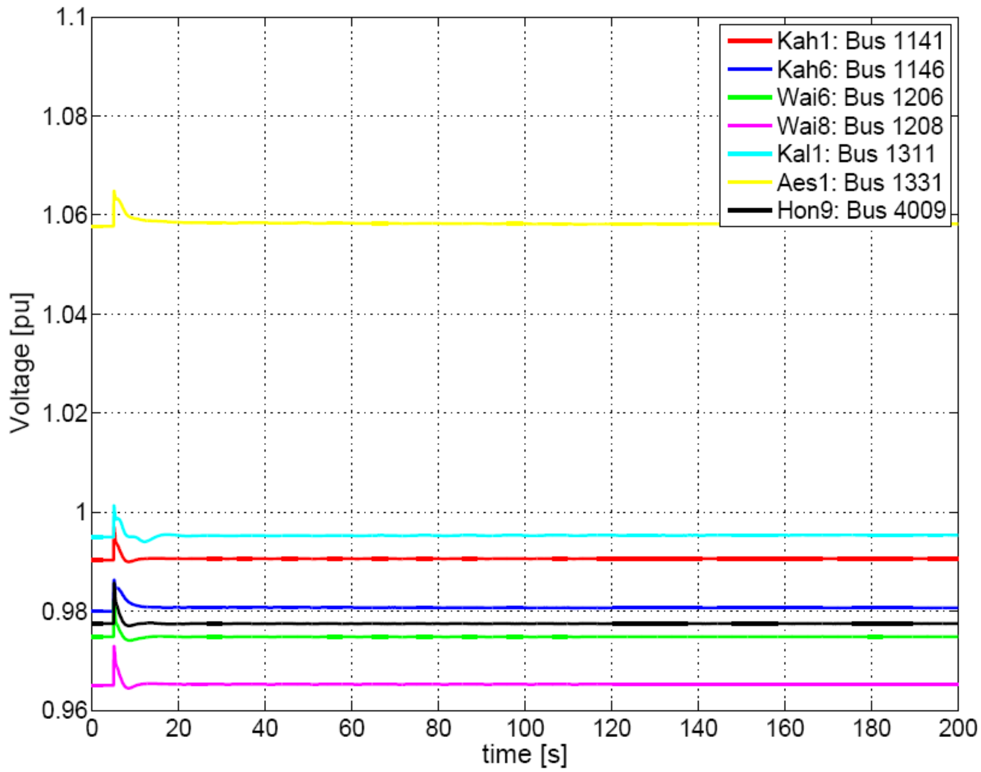

Figure A1-2: Generator Terminal Voltages

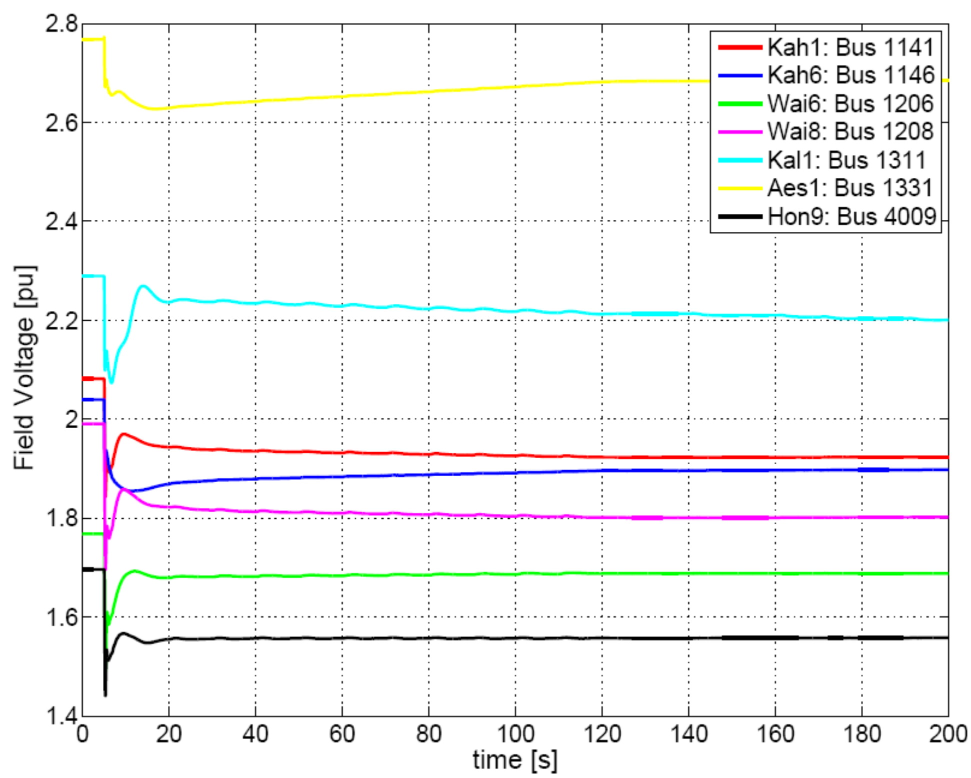

Figure A1-3: Generator Field Voltages

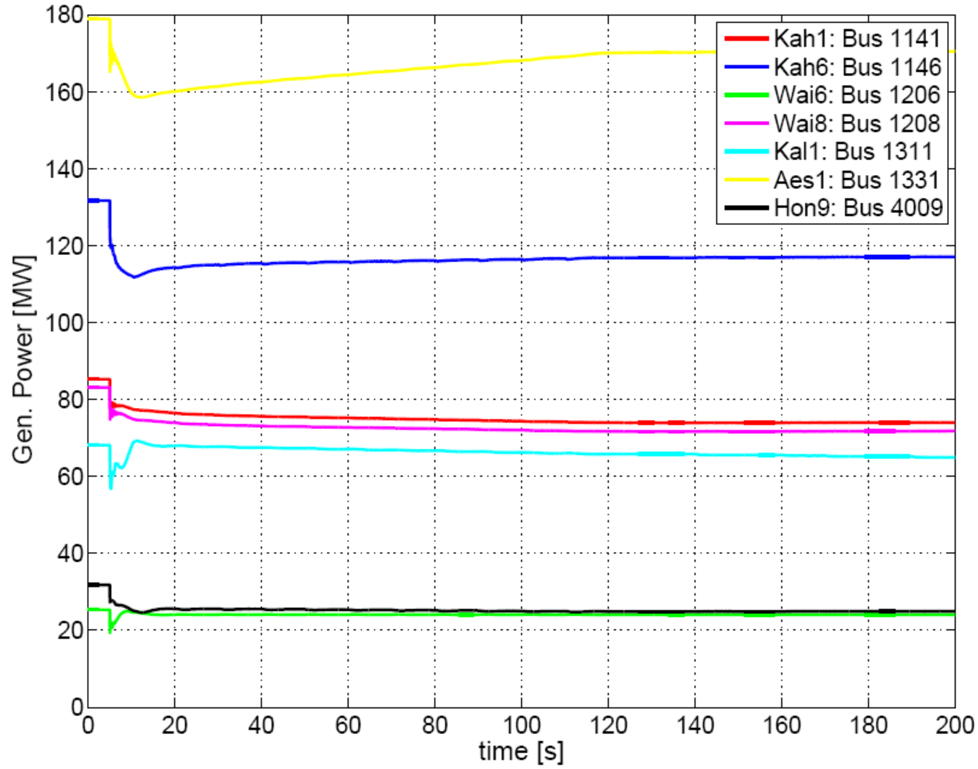

Figure A1-4: Generator Active Power Output

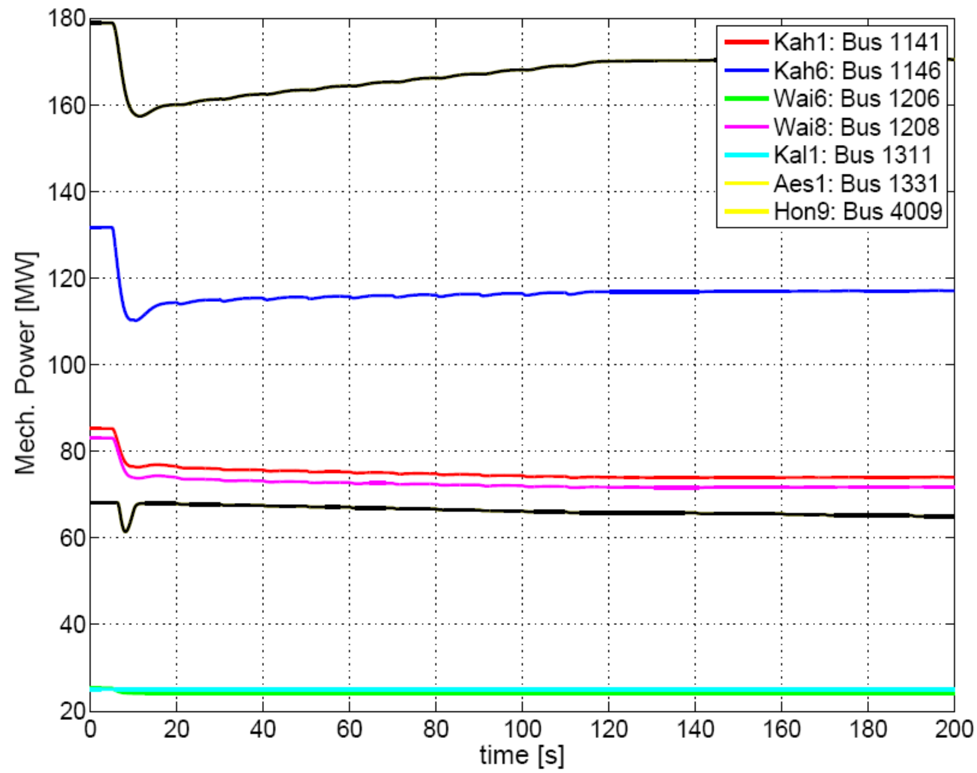

Figure A1-5: Generator Mechanical Power

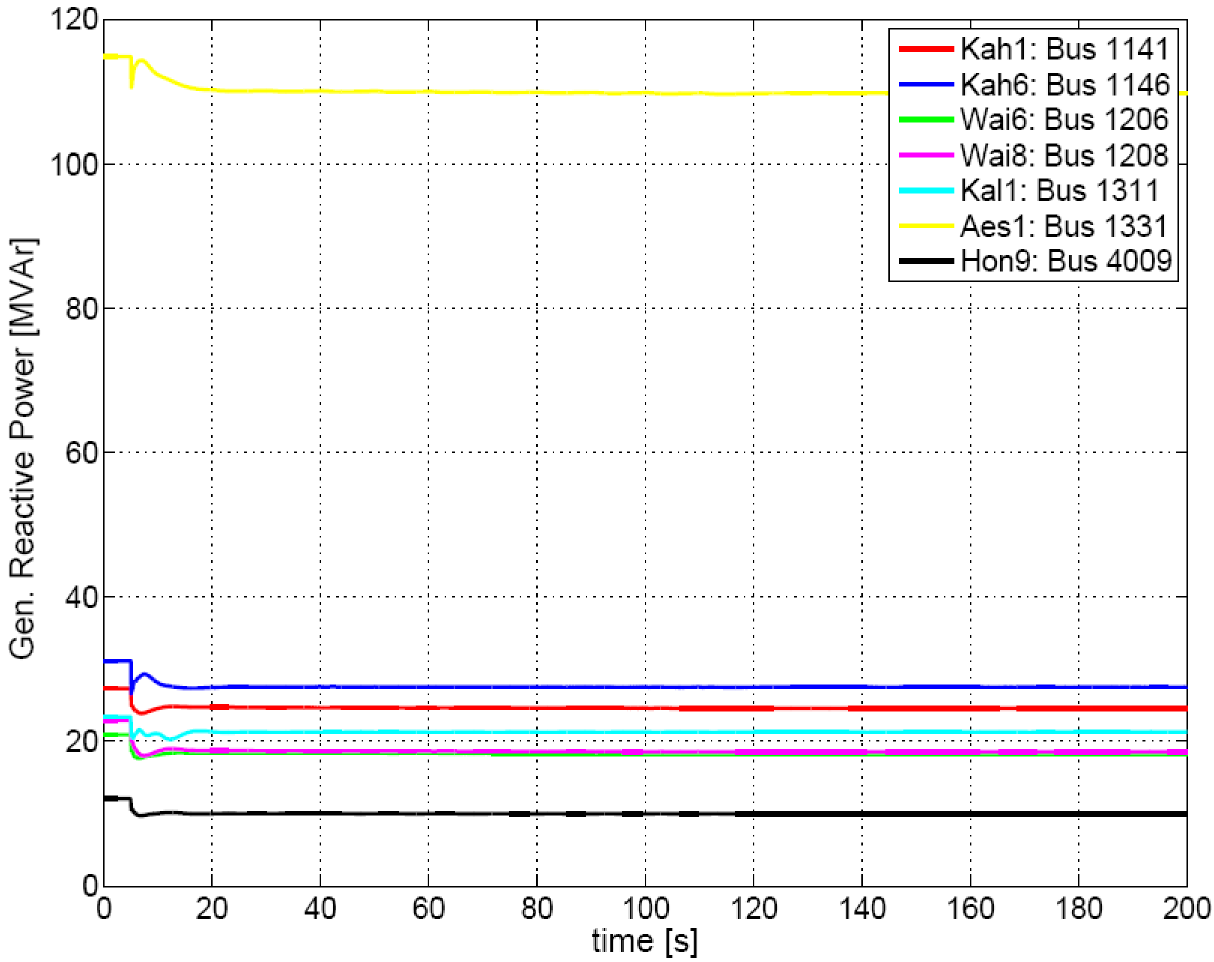

Figure A1-6: Generator Reactive Power Output

Appendix 2

AGC Response with “Once in a while” ramp rates in AGC

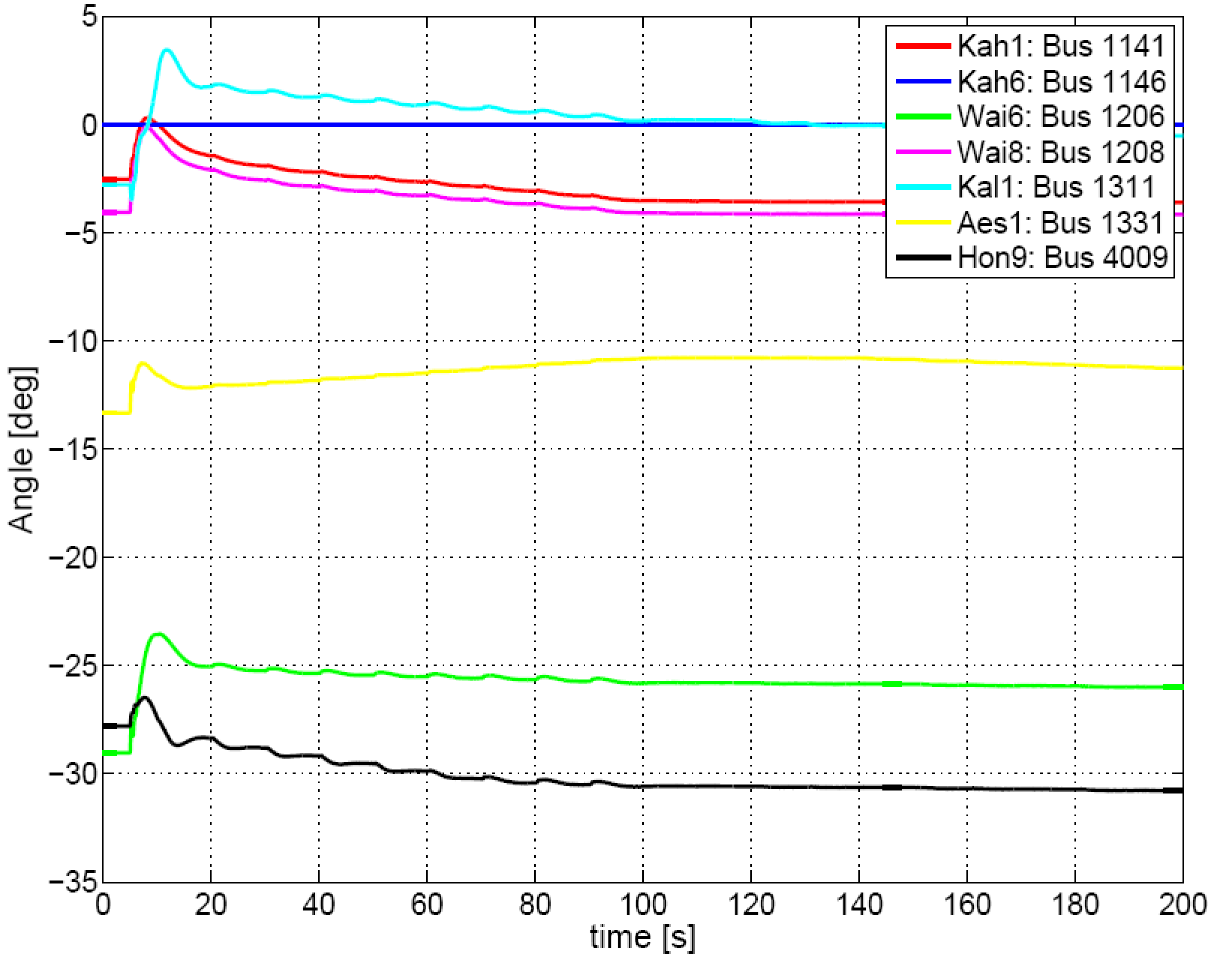

Figure A2-1: Generator angle response

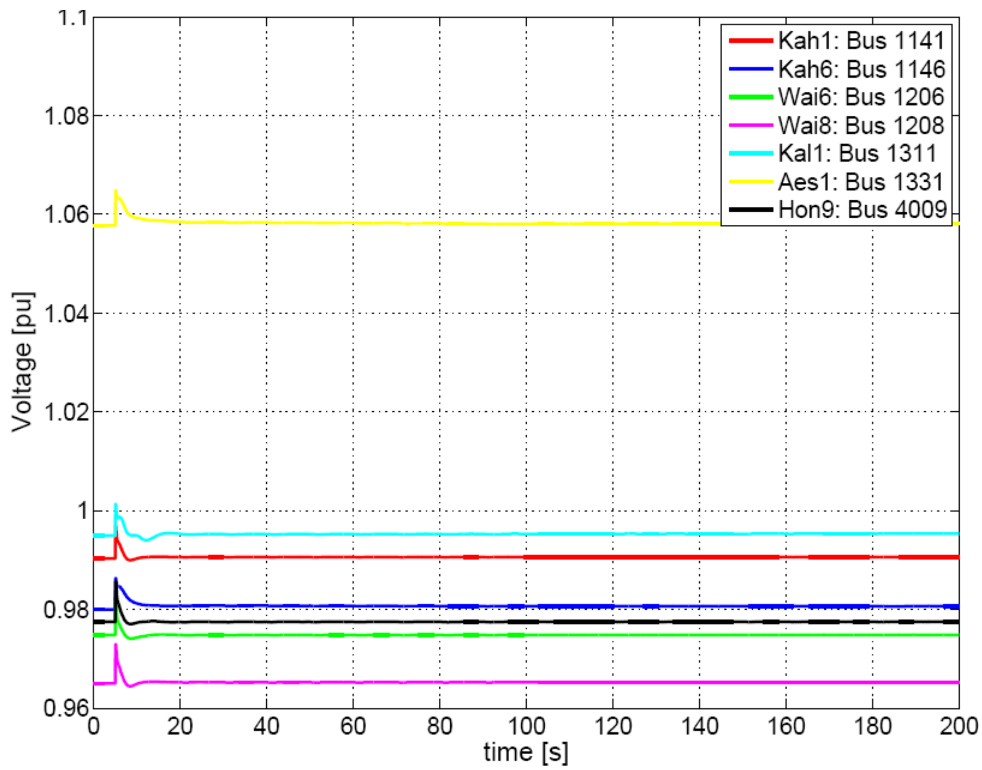

Figure A2-2: Generator Terminal Voltages

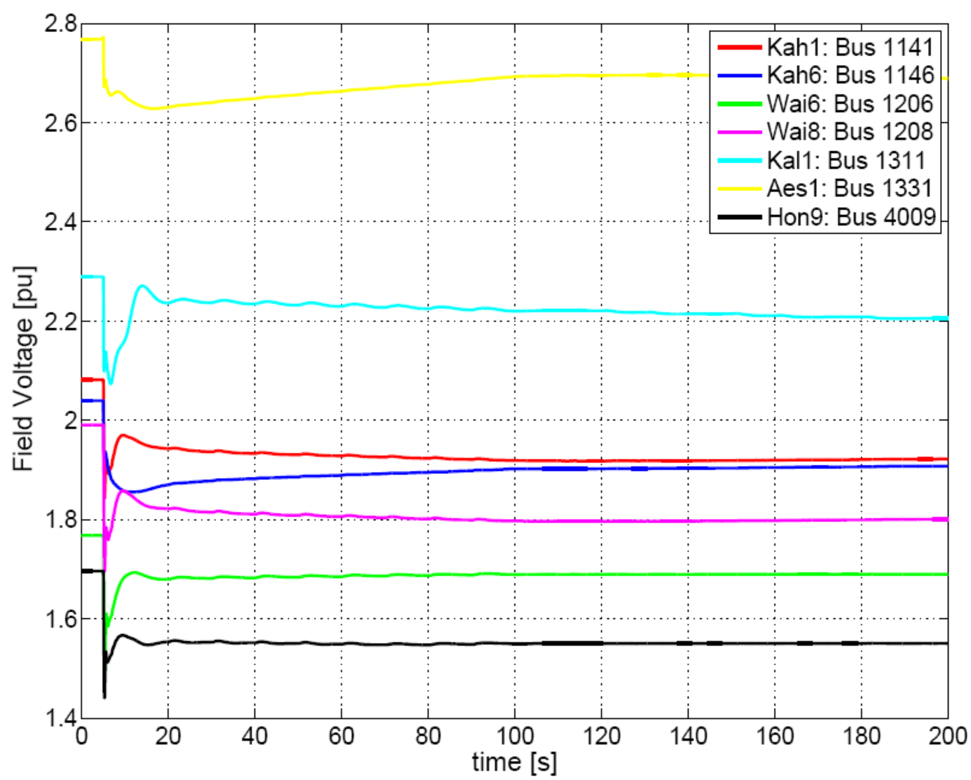

Figure A2-3: Generator Field Voltages

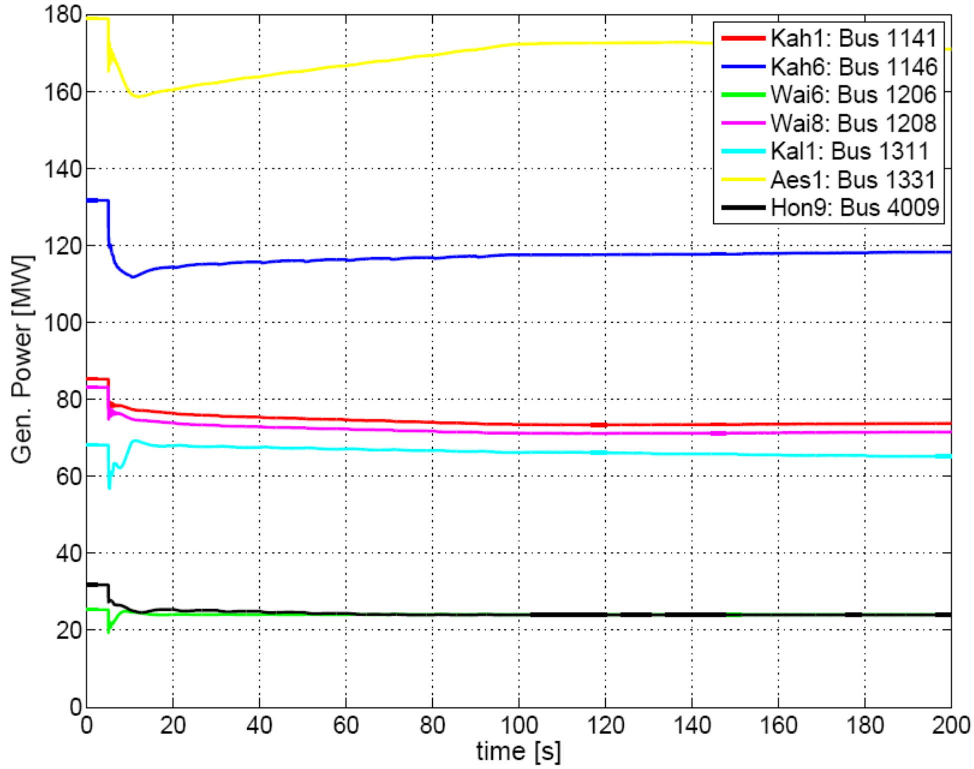

Figure A2-4: Generator Active Power Output

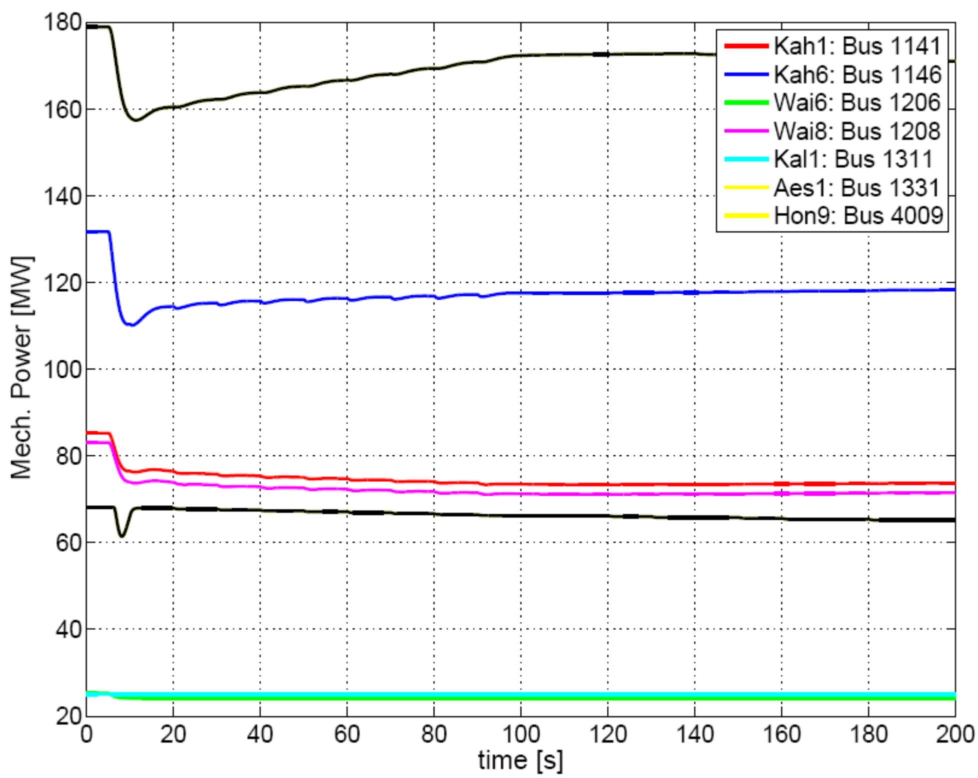

Figure A2-5: Generator Mechanical Power

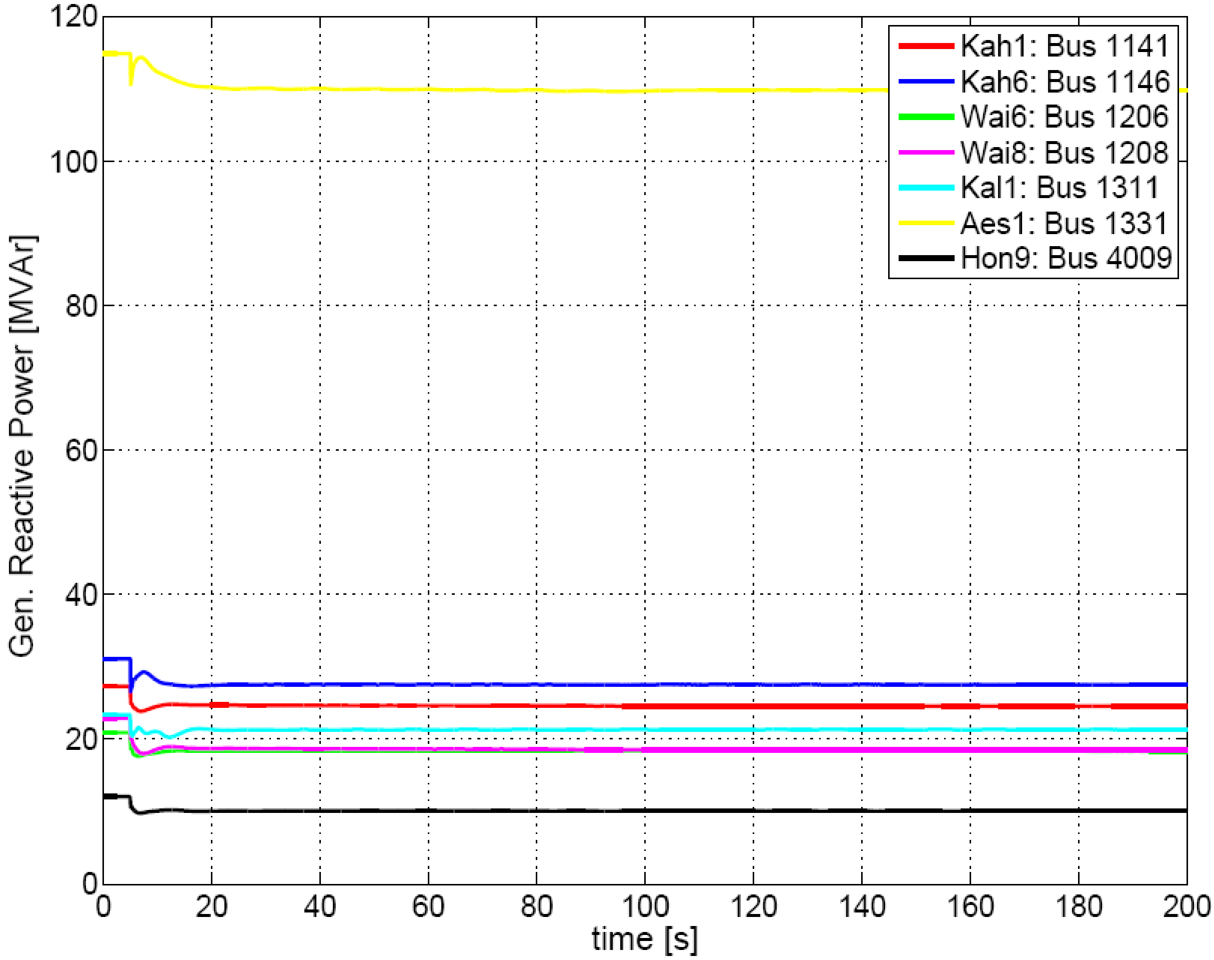

Figure A2-6: Generator Reactive Power Output

Appendix 3

AGC Response with “Once in a while” ramp rates in AGC and less responsive governors

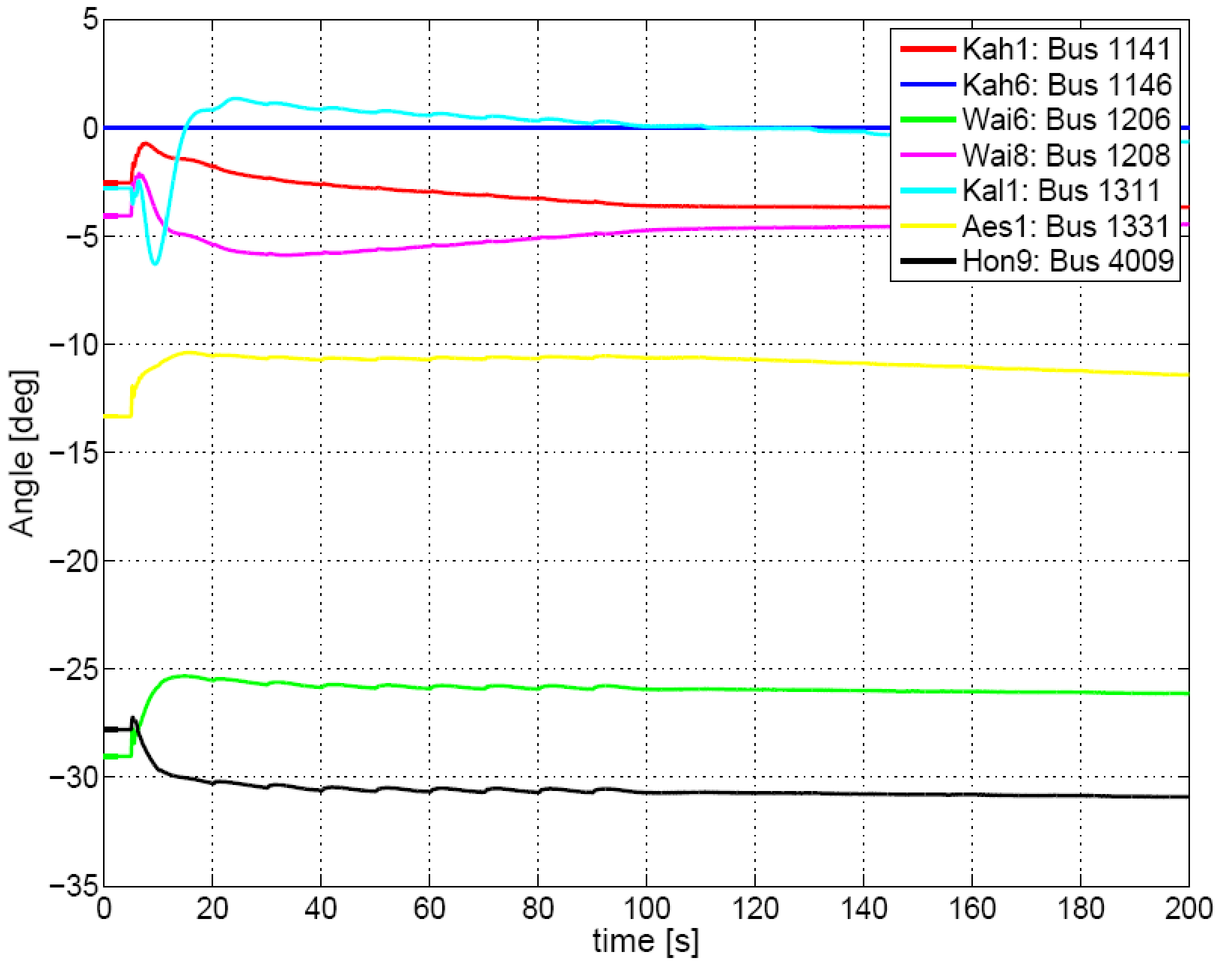

Figure A3-1: Generator angle response

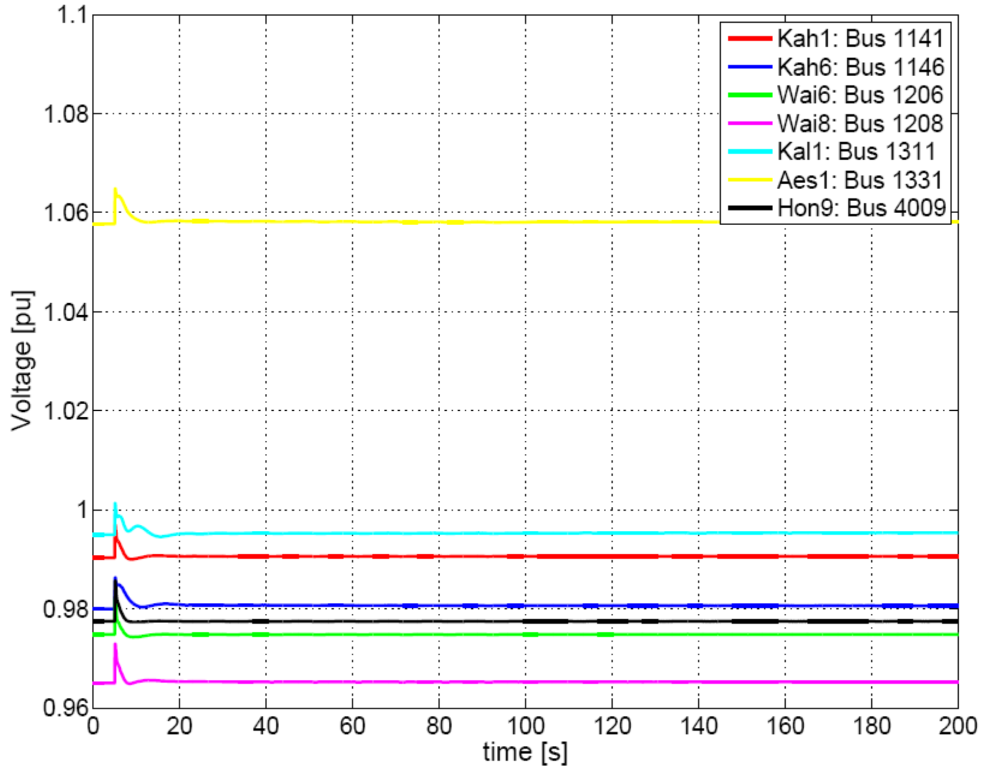

Figure A3-2: Generator Terminal Voltages

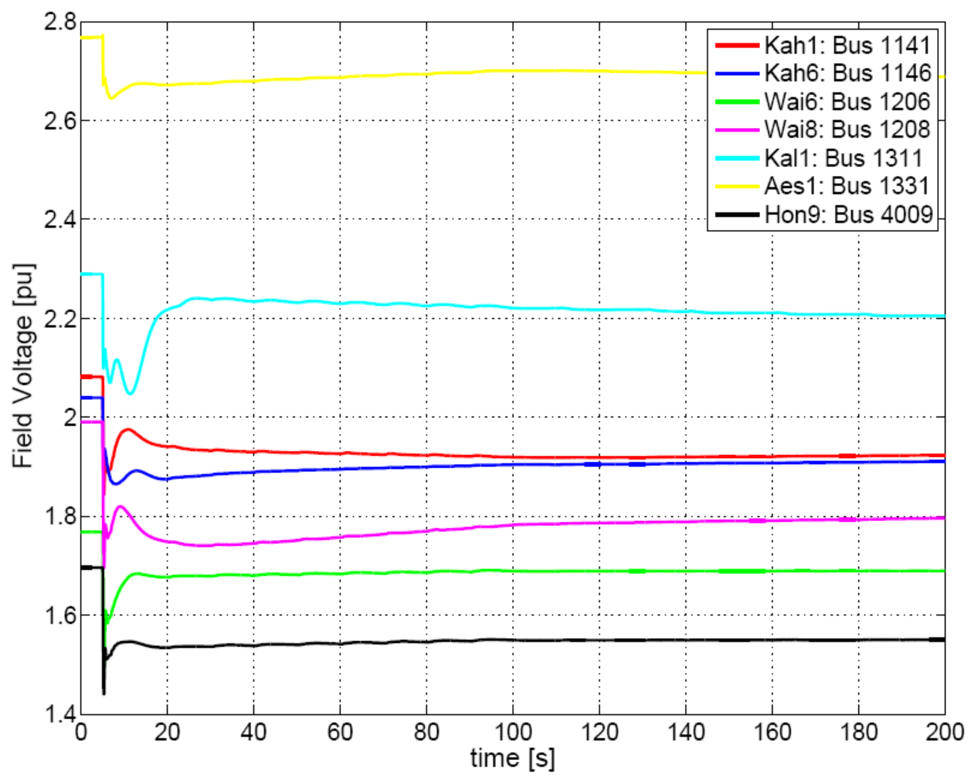

Figure A3-3: Generator Field Voltages

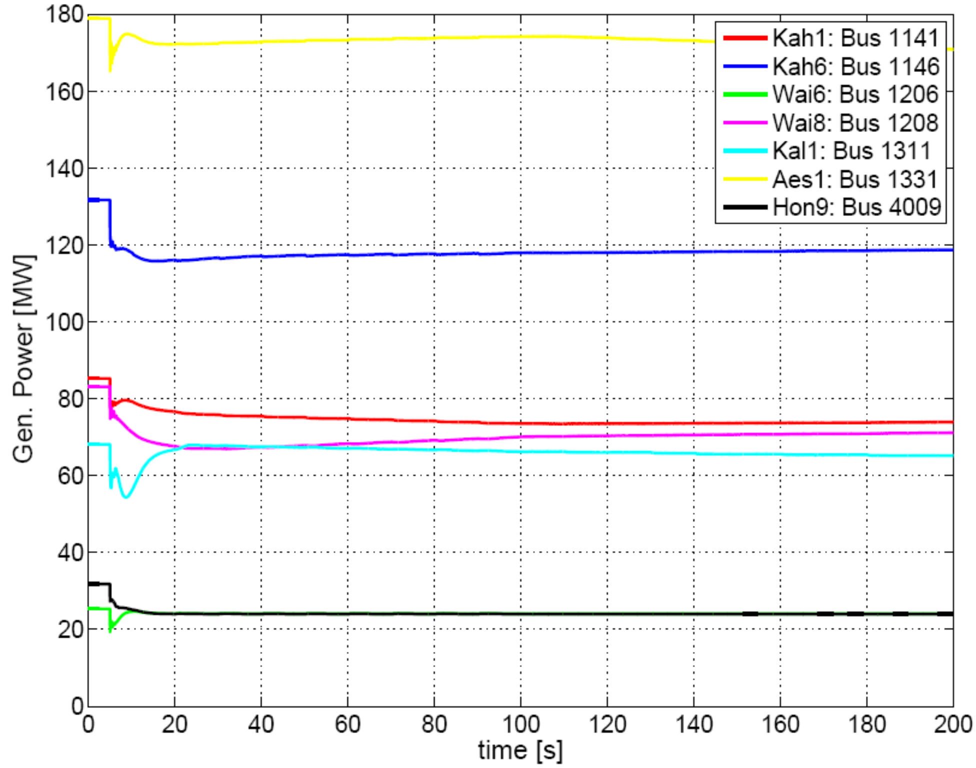

Figure A3-4: Generator Active Power Output

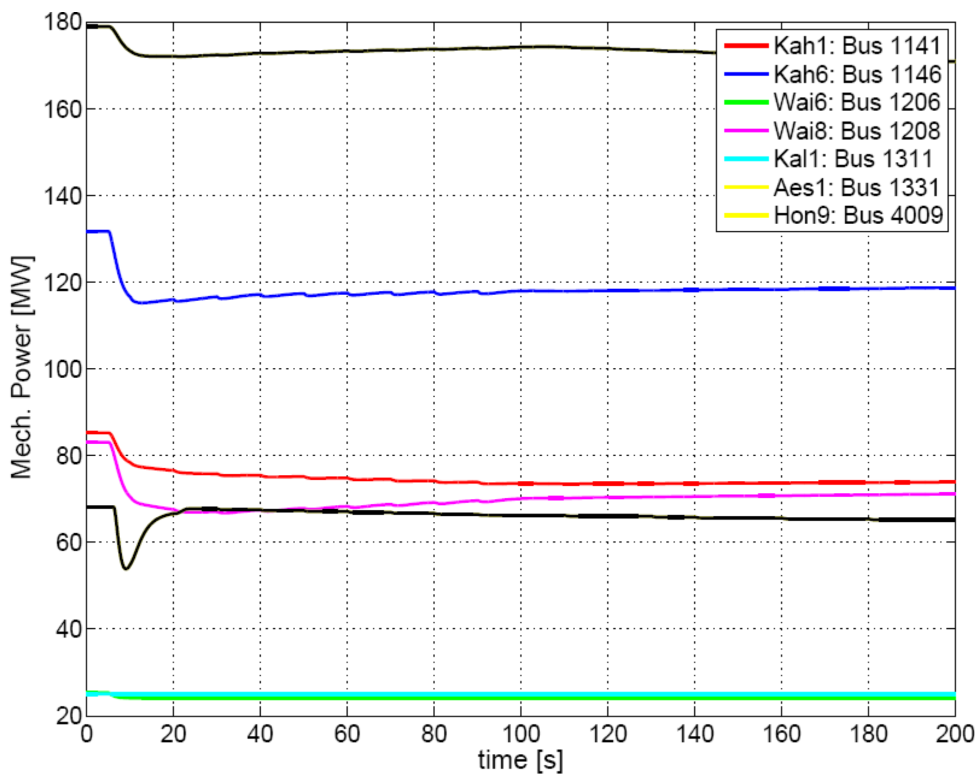

Figure A3-5: Generator Mechanical Power

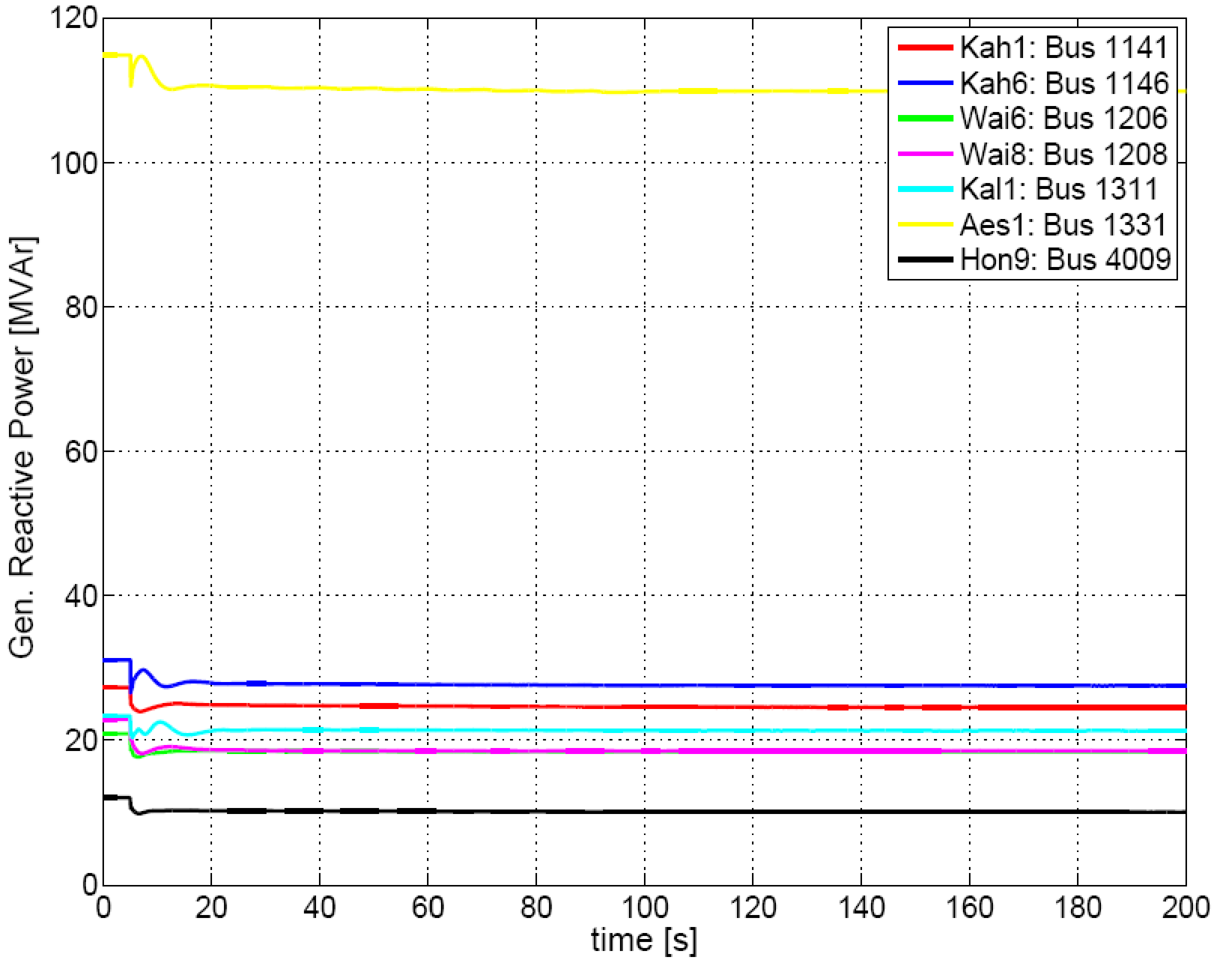

Figure A3-6: Generator Reactive Power Output