Eastern Interconnection Planning Collaborative

Eastern Interconnection Planning Collaborative
Technical Committee

Frequency Response Working Group
2020 Final Report
Public Version

Approved by the EIPC Executive Committee

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Executive Summary

This report details information on the technical analysis, model modifications, and simulations performed by members of the Eastern Interconnection Planning Collaborative (EIPC) Frequency Response Working Group (FRWG) to assess the North American Electric Reliability Corporation (NERC) Essential Reliability Services Working Group (ERSWG) forward looking frequency Measures 1, 2, and 4 for the Eastern Interconnection (EI) for inclusion in the 2021 NERC Long-Term Reliability Assessment (LTRA).

The analysis and simulation of this study demonstrated that the EI would have sufficient system inertia over the next 5 years with the generation resource mix, load, and interchange levels and governor participation modeled. However, with the addition of non-synchronous generation and planned resource retirements, maintaining frequency in the EI is a concern which warrants continued study. The EIPC Technical Committee (TC) has been tasked with identifying and understanding how future generation contingencies could lead to Under Frequency Load Shedding (UFLS) events due to the reduction of frequency support from the changing generation resource mix. In order to study and plan for possible increased non-synchronous generation with reduced inertia, there is a need for improved frequency responsive simulation power flow models. With assistance from all FRWG members, biweekly meetings and collaborative efforts allowed the FRWG to develop, assign, and complete many tasks in support of this effort.

In total, 12 tasks which are described in Section 4 were complete. These tasks include benchmarking historical frequency events with spring light load (SLL) cases to determine how the existing generator governor models perform in response to the frequency events. Improvements to future modeling of governors is expected to supersede the need for limiting generator governor responses. The FRWG also created a list of recommended changes to improve the frequency responsiveness of the planning models for use by the EI Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) in future model development cycles.

As with the study performed in 2018, the FRWG tested two different frequency events and the most severe single contingency (MSSC) for the Eastern Interconnection pulled from 2018. The two historical frequency events include the loss of 4,307 MW event from 2007, and the largest EI frequency event of the last 10 years of 3,852 MW. The EI MSSC selected for this study is the loss of 2,299 MW. The benchmarking analysis for this study resulted in disabling 53% of governors and removing 17% additional governors from the case, resulting in on 30% of governors modeled as responsive. This compares to approximately 45% of governors modeled as responsive in the 2018 study. Building off the benchmark analysis, EI load was scaled to a minimum load forecast level and dispatch changes were applied to model forecasted changes in system inertia over the next 5 years. With these changes applied to the 2018 Series 2023 case, the simulated events and the selected MSSC exhibited satisfactory frequency response with a minimum nadir of 59.80 Hz. While the lowest observed frequency nadir is lower than the lowest nadir observed in the 2018 study of 59.85 Hz, the 2020 study results are still significantly above the initial UFLS set point of 59.6 Hz.

The results of this analysis have been shared with NERC for inclusion in the 2021 LTRA. Through a series of discussions, EIPC has worked with MMWG in shaping a definition for minimum load future year case for inclusion in the 2021 series library cases. The recommendations submitted with the 2018 study remain key areas for improving the MMWG model building process, with particular emphasis on governor modeling. EIPC will continue to work with industry groups to implement these recommendations.

- Recommendation #1: Gross PMax Values
- Recommendation #2: Governor Modeling
- Recommendation #3: Frequency Responsive Dynamics Files

1. Introduction

The EIPC represents an effort that draws Planning Coordinators in the EI together in a collaborative effort to perform the technical analysis of transmission planning and related matters, and to model the impact on the grid of various energy policy options determined to be of interest by state, provincial, and federal policy makers and other stakeholders. The work EIPC undertakes builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Coordinators and associated regional stakeholder groups within the EI. Those processes may be informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various energy policy options.

As part of the EIPC's ongoing work to perform technical analyses of transmission planning issues, the EIPC Technical Committee established the Frequency Response Task Force (FRTF) on July 20, 2017 (later changed to the Frequency Response Working Group (FRWG) in March 2019) to take a leadership role in providing on a biannual basis the frequency response Measures 1, 2, and 4 from the Essential Reliability Services Task Force (ERSTF) Measurements Framework Report[1] for the EI for the North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment (LTRA). The FRWG coordinates its work with NERC.

The quickly evolving resource mix for the EI continues to place importance on ensuring the EI frequency response to loss of generation events will not lead to activation of UFLS. The scope of work outlined in this report include the additional simulation of minimum load forecast which was not included in the 2018 study[2]. Additionally, the EIPC FRWG used an outside contractor, S&C Electric Company, to perform benchmarking analysis, future minimum load/low inertia case, and simulations used to calculate frequency response measures 1, 2, and 4.

[1] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[2] https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5ca541769b747a55f8444c03/1554334072121/EIPC_FRTF_2018_Final_Report_Public_Version_EC_Approved_2019-02-27.pdf

2. Background and Purpose

The FRWG was established by the EIPC Technical Committee to develop a low inertia future planning model of the EI used to analyze the frequency response characteristics and trends of the EI to specified large resource contingencies. The scope of this work will benchmark existing models and simulate conditions on the interconnection when generation inertia is low based on a credible generation dispatch and assumed resource mix for the timeframe being modeled. The FRWG will then use the low inertia case to test that frequency response of the system, calculate Measures 1, 2, and 4, and develop a report on its findings and recommendations.

As the generation resource mix continues to evolve based on new technologies, regulations, and policies, the ability of the EI to maintain system frequency will change. These changes have a potential to degrade the amount of frequency support within the EI. This potential degradation of frequency support within the EI could lead to an increase in the number of Under-Frequency Load Shed (UFLS) events, which would be detrimental to reliability of the system and is therefore a concern to Planning Coordinators in the EI.

Furthermore, accurately assessing the impact of future possible resource mix changes depends on the accuracy of the currently available long-range planning models developed by the Multiregional Model Working Group (MMWG). This linkage to available long-range planning models leads Planning Coordinators to provide constructive feedback on the models to assist MMWG in improving their accuracy and applicability to frequency response analyses under future system conditions. Following presentation and ongoing discussions of the 2018 study recommendations, the MMWG has targeted a minimum load future year case for development in the 2021 model library build. This additional library model will leverage existing model building processes to better enable engineers to simulate EI frequency response to loss of generation events. As demonstrated by the benchmarking analysis from both the 2018 study and the 2020 study, the recommendations from the 2018 study to improve accuracy of governor modeling continues to be a key area for improving the models to predict EI frequency response to loss of generation events.

One focus of the FRWG effort is to establish a baseline confidence in the solutions provided by currently available frequency response models and to provide suggestions to improve those models. The FRWG will develop a model that adequately represents the behavior of the system to contingencies during time periods when the impact on frequency will be the largest. The objective is to benchmark the existing system and simulate the planned system 5 years into the future to calculate the frequency response metrics and trends of the EI to provide Measures 1, 2, and 4 to NERC for inclusion in the NERC LTRA report.

3. Objectives

The objective of this effort is to determine the NERC Measures 1, 2, and 4 from the ERSTF Measures Framework Report for the EI.

- Measure 1: Synchronous Inertial Response (SIR) of EI – Measure of kinetic energy at the interconnection level. It provides both a historical and future (5-years-out) view.
- Measure 2: Initial Frequency Deviation Following Largest Contingency – At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria [RCC] in BAL-003-1 for each interconnection).
- Measure 4: Frequency Response at Interconnection Level – Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to ALR1-12), C:B Ratio, C:C' Ratio as well as three time-based measures (t_0 to t_C, t_C to $t_{C'}$, and t_0 to $t_{C'}$), capturing speed of frequency response and response withdrawal.

The FRWG will continue to work with the MMWG to implement the set of recommendations from both the 2018 report[2] and this report to augment the current model building process to create 'study-ready' cases to calculate frequency measures and develop a procedure manual to conduct these measures on a future ongoing basis. The results of Measures 1, 2, and 4 are provided in Section 6.10.

4. Tasks

As part of this effort, the FRWG developed 12 tasks to be complete. Details for each task are shown below. Volunteers were taken and EIPC members completed 9 of the tasks. Contractors were selected to complete the other 3 tasks (Tasks 8, 9 and 10). In 2018, members of the FRWG performed each of these tasks.

4.1 Task 1 – Develop Procedure Manual

Develop a detailed Procedure Manual to document the process to build the low inertia case and calculate the Frequency Measures 1, 2, and 4. The Procedure Manual was also used for developing the Request for Proposal (RFP) to hire consultants to build the low inertia case with EIPC member supplied data, and perform the contingency analysis.

4.2 Task 2 – EI Inertia/Load Calculator

Work with Eastern Interconnection Data Sharing Network (EIDSN) to provide technical input regarding the dynamics data that is linked to generator status for calculation of EI inertia. Establish process with EIDSN to review updates to the dynamics data to keep the information up-to-date and accurate.

4.3 Task 3 – Formalize EI Inertia Calculation Script

Using python, create a script from the 2018 study to calculate the equivalent system inertia using the MMWG spring light load (SLL) power flow cases. The code was revised and made more user friendly for this year's study. Equivalent inertia can be calculated using the following methods:

- Model Parameter Based
    a. By looking at the case dispatch and maximum capability of the units as well as H the inertia constant [inertia is defined as the product of MVA and H and has the units of MVA-s]
    b. Determine the equivalent r (governor regulation) taking into account the units that are at maximum have a value of r=infinity (meaning no governor gain as the gain is 1/r)

4.4 Task 4 – Implement 2018 Recommendations with MMWG

Based on the 2018 FRWG report[2], work with the MMWG to implement recommendations 1 through 4 from the report. Those recommendations were modeling of gross PMax values in the cases, accurate governor modeling in the cases, update of frequency responsive dynamics files to library, and the need for a low inertia / minimum load MMWG library case.

4.5 Task 5 – Select Historical Low Inertia and Frequency Events

Using the MISO Parallel Flow Visualizations data (the pre-cursor to the upcoming EIDSN calculator described in Task 2) select the minimum inertia time from the last 3 years (2016-2018).

Using historical FNET[3] data, select 2 historical events which had recorded frequency excursions that coincide with the MMWG 2019 Spring Light Load (SLL) model. The frequency events will be used to benchmark the frequency response of the latest MMWG 2018 library case.

4.6 Task 6 – Collect Historical Dispatch Data Associated with the Low Inertia and Frequency Events

Based on the dates selected for the historical low inertia and frequency events, each Planning Coordinator will collect the unit dispatch for those dates. This historical dispatch will be used to identify the overall resource mix and type of generation (including pumped storage as negative generation) participating in the primary frequency response for the Eastern Interconnection and sub-regions during the times selected.

4.7 Task 7 – Select the Most Severe Single Contingency (MSSC) and the Largest 10-year Historical Event for the EI

To capture the trend of frequency response in the EI, the Planning Coordinators will test three (3) different contingencies. The first is the largest historical event within the past 10 years (2009-2018). The second event will be the most severe single contingency (MSSC) for the EI. The FRWG will use the documented criteria to establish the MSSC and each Planning Coordinator will submit their region's MSSC. The final event will be a 10,000 MW benchmark test to test the EI margin until the under-frequency load shedding threshold of 59.6 Hz[4]. Following more detailed review of the 2018 study which used 59.5 Hz as the threshold for UFLS within the EI, the 2020 study used a UFLS threshold of 59.6 Hz for the EI after changes related to the merging of FRCC into SERC.

4.8 Task 8 – Benchmark Historical Frequency Event

Conduct a benchmark comparison of the historical frequency event using the 2019 spring light load MMWG case from the 2018 library with a focus on identifying the resource mix and amount of generation participating in the frequency response. Specific unit to unit mapping between the historical and MMWG cases is not necessary to achieve similar inertial response between the recorded frequency event and the simulated event.

4.9 Task 9 – Create Low Inertia 5-Years-Out Case

Using the data submitted in Task 5 and any changes to the dynamics model from the benchmarking in Task 7, modify the future 5-years-out MMWG 2023 spring light load case so that it represents an expected future minimum load, low inertia case. Verify that the dynamics case will initialize and solve for the timeframe of primary frequency response for resource contingencies identified in Task 6.

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[3] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable GPS synchronized wide-area frequency measurement network. High-dynamic accuracy FDRs are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

[4] FRCC has historically used a UFLS threshold of 59.7 Hz for local system conditions. Since joining SERC in 2019, FRCC proposed modifying the PRC-006-SERC-02 to align the historical UFLS schemes used in FRCC with the thresholds specified in the standard. The SERC UFLS standard currently in the draft phase, proposes a change in the highest setpoint for UFLS to be set to 59.6 Hz.

4.10 Task 10 – Calculate Frequency Measures 1, 2, and 4

Simulate the frequency response of the EI to postulated resource contingencies and plot frequency versus time for each contingency selected in Task 6. Collect other pertinent information from the dynamics simulations needed to develop a detailed report on the results of the frequency response tests.

4.11 Task 11 – Write a Comprehensive Report

Write a report to document the findings of the effort. The report includes detailed information on the efforts performed by members of the FRWG and references the detail of the results of the Frequency Measures 1, 2, and 4.

4.12 Task 12 – Outreach to Other Interconnections

Communicate with other interconnections and NERC. The purpose of this task is to understand how the other interconnections are developing the same information. Results from the FRWG work will be shared with other interconnections.

5. Schedule

The FRWG met as a whole monthly on WebEx format on the 2nd Wednesday from 9-11 AM Eastern. Face-to-face meetings have been twice a year in April and November to coincide with EIPC TC meetings. However, the face-to-face meeting in April was changed to WebEx only due to COVID-19. The timeline for each task and specific milestones are shown in Table 5-1.

Table 5-1: Milestone Timeline

	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1	2020 Q2	2020 Q3	2020 Q4
Task 1								
Task 2								
Task 3								
Task 4								
Task 5								
Task 6								
Task 7								
Task 8								
Task 9								
Task 10								
Task 11								
Task 12								

6. Results of Each Task

EIPC members completed tasks 1-7. Due to the amount of time required for tasks 8-10, it was decided to solicit bids for the work to be done by contractors. Several bids were received and, following evaluation by the FRWG, S&C Electric (S&C) was chosen to complete these tasks. The results of the work performed on tasks 8-10 is briefly described in this section. The full report written by S&C is in Appendix C.

6.1 Task 1 – Develop Procedure Manual

A detailed Procedure Manual was developed to document the process to build low inertia case and calculate the Frequency Measures 1, 2, and 4. The Procedure Manual was also used for developing the Request for Proposal (RFP) to hire consultants to build the low inertia case with EIPC member supplied data.

6.2 Task 2 – EI Inertia/Load Calculator

EIPC FRWG met with Eastern Interconnection Data Sharing Network (EIDSN) to discuss providing technical input regarding the dynamics data that is linked to generator status for calculation of EI inertia. EIDSN is still in the process of developing real time EI Inertia calculations.

6.3 Task 3 – Formalize EI Inertia Calculation Script

The FRWG updated the inertia calculation python script to calculate the equivalent system inertia of the two MMWG cases. Updates include adding wind provided inertia to the calculation. The following are changes for each revision. Rev 5 is final and was provided to the consultant for use in building the models for this study

Rev 1 : 2019/10/10 - turned each model into a separate function to speed up script
Rev 2 : 2019/10/16 - added offline and gnet inertia values, removed R from spreadsheets
Rev 3 : 2019/10/16 - added additional gen and gov models, added check for PLL for Type 3 WTG, added area to errors
Rev 4 : 2019/11/01 - added load totals to summary tab of results
Rev 5 : 2019/11/25 - excluded Type 3 WTGs from system total inertia calculation and flagged in the "Error" sheet as "Skipped (Type 3 or Type 4 WTG)". fixed fetching the user model GEWTG2 inertia that is given by its turbine module GEWTT1. updated the T_{rate} based on the information in the generator model added several user models (HYGOV4, CIMTSS and GWPM27) for system total inertia calculation

6.4 Task 4 – Implement 2018 Recommendations with MMWG

The following reflect the EIPC FRWG recommendations for improving the simulation study results of the MMWG base cases. The EIPC FRWG recognizes that compliance with the NERC Reliability Standards is the responsibility of the individual Planning Coordinators and Transmission Planners and does not intend to create any conflict with compliance with those standards.

The 4 recommendations from the 2018 report are:
Recommendation #1: Gross PMax Values
Recommendation #2: Governor Modeling
Recommendation #3: Frequency Responsive Dynamics Files
Recommendation #4: Need for a Low Inertia / Minimum Load MMWG Library Case

The EIPC FRWG chair met with MMWG during the Spring and Fall 2019 meetings to discuss implementation of the four recommendations from the 2018 report. Following these meetings, the MMWG agreed to build a Min Load case in place of 5 year out spring light load (SLL) case for the 2021 series case build. The EIPC FRWG believes this is an important step toward improving EI models for use in Frequency Response studies. The Min Load case will serve as a good starting point for these studies, and reduce the number of changes required to dispatch patterns which represent a low inertia condition.

EIPC FRWG created a document titled "EIPC FRWG MMWG Case Build Manual" and submitted to MMWG for consideration. This document describes the process to create a minimum load / low inertia case.

6.5 Task 5 – Select Historical Low Inertia and Frequency Events

A minimum inertia time from 2016-2018 was selected. The FRWG agreed to select 10/28/2018 4:28:00. This event was based on NERC RS data that records the EI inertia and system load throughout time. The inertia from 10/28/2018 is in Table 6-1 below.

Table 6-1: EI Inertia

	Time	EI Inertia (MVA-s)	Delta from Prev
Min Inertia	10/28/18 4:28 AM	1,018,805	-0.2%

Two historical frequency response events were also selected. The event times are shown in Table 6-2. The FNET plots for each event are shown in Figures 6-1 and 6-2.

Table 6-2: Historical Frequency Events

Event #	Event ID	Local Time
Event 1	EI_2019-03-10_050145	03/10/2019 01:01:45
Event 2	EI_2019-03-16_003902	03/15/2019 20:39:02

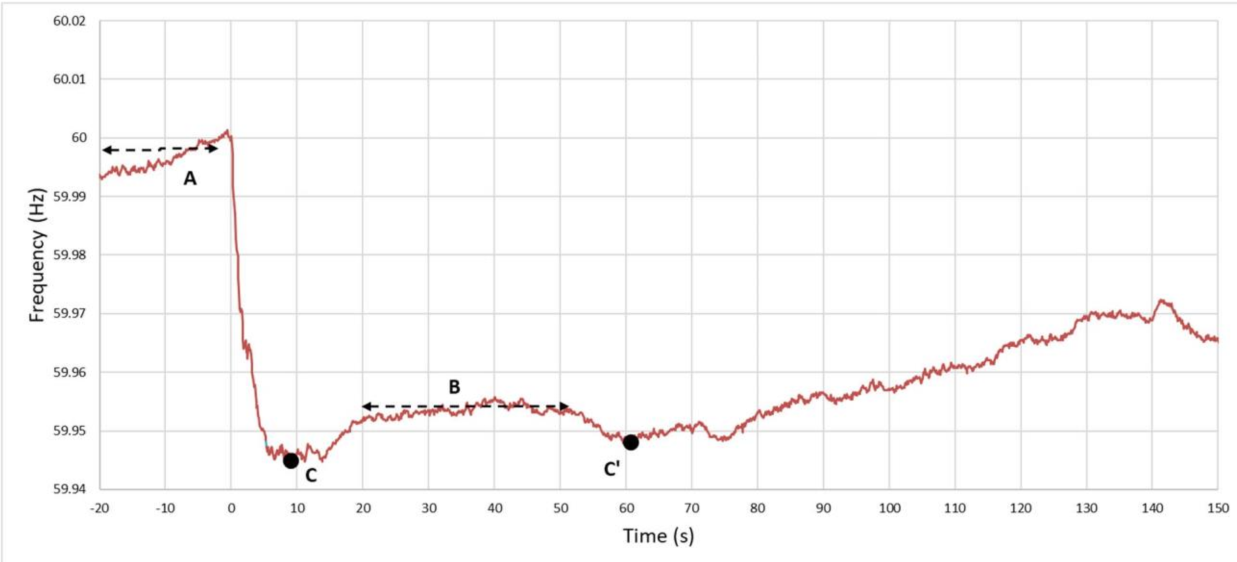

Figure 6-1: EI FNET March 10, 2019 Frequency Event Raw Data Plot (Event 1)

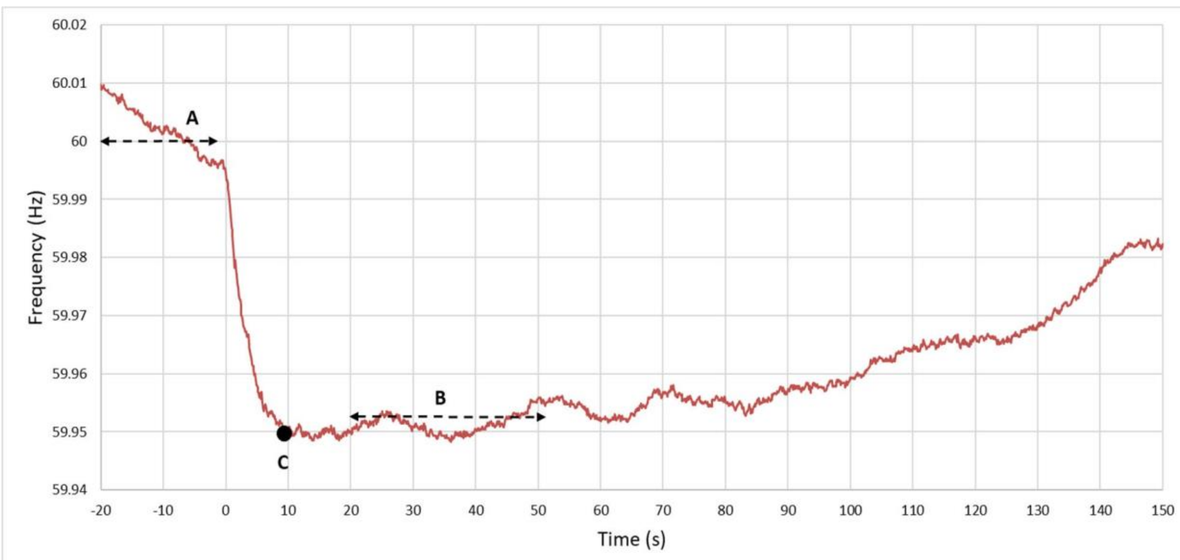

Figure 6-2: EI FNET March 15,2019 Frequency Event Raw Data Plot (Event 2)

6.6 Task 6 – Collect Historical Dispatch Data Associated with the Low Inertia and Frequency Events

Based on the dates selected in Task 5, each PC collected and submitted the unit dispatch for their area. Digital Fault Recorder (DFR) or Phasor Measurement Unit (PMU) data was used and the equivalent system inertia was calculated. FRWG members submitted excel files with information for generation and load for all areas in the EI. Due to confidentiality reasons, the specific dispatch data for each generator was not submitted. In each of these, the resource mix separated into 9 categories (nuclear, coal, natural gas CC, natural gas simple cycle, hydro, wind, solar, pumped storage, and other. Members agreed to include pumped storage as negative generation and include the machine inertia as a positive value in the total inertia calculation. Pumped storage was not counted as load. Details for the minimum inertia event on 10/28/2018 are shown in Table 6-3 below.

Table 6-3: Historical Resource Mix by Type Min Inertia 10/28/2018 04:28:00 AM

Nuclear	Coal	NG CC	NG SC	Hydro	Wind	Solar	Other	Pump
30%	23%	27%	4%	4%	11%	0%	4%	-3%

6.7 Task 7 – Select the Most Severe Single Contingency (MSSC) and the Largest 10-year Historical Event for the EI

The largest event in 10 year history was selected. It is the event where 3,852 MW of generation was lost. This event was in 2011.

The MSSC was selected from the submitted events. This event is where 2,299 MW is lost.

The final benchmark is a 10,000 MW benchmark test to determine the EI margin until the under-frequency load shedding threshold of 59.6 Hz[4].

6.8 Task 8 – Benchmark Historical Frequency Event

S&C performed Tasks 8, 9 and 10. For Task 8, the FRWG provided S&C with MMWG 2018 Series dynamic base cases, Python script, and stability model files. S&C used these files to create the cases. S&C conducted a benchmark comparison of two of the frequency events chosen in Task 5. The two events had similar load levels to the 2019SLL library case. S&C used PSS/E version 33.12.0 to simulate the events. Generation adjustments were made to the cases to simulate the actual dispatch for the two events. For each simulation, S&C provided parameters and frequency response plots to compare the actual events to the simulations. The MMWG cases were provided as “Base Case 1” and “Base Case 2.” In Base Case 1, approximately 39% of governors were modeled as non-responsive. In Base Case 2 approximately 53% of governors were modeled as non-responsive. Summaries of the Responsive and Non-Responsive Governors in each Base Case are shown in figures 6-3 and 6-4. Based on discussions with the FRWG, S&C confirmed that Base Case 2 provided a closer match to the actual events, so it was used for the benchmark simulations. See Figure 6-5 for Event 1 plotted with both base cases and Figure 6-6 for Event 2 plotted with both base cases.

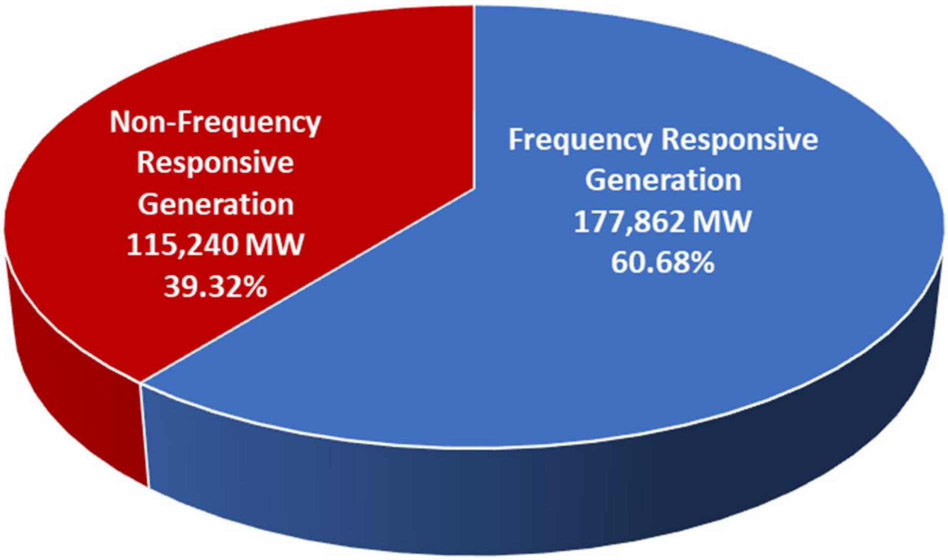

Figure 6-3: Frequency Responsive Governor Modeling Summary for Case 1

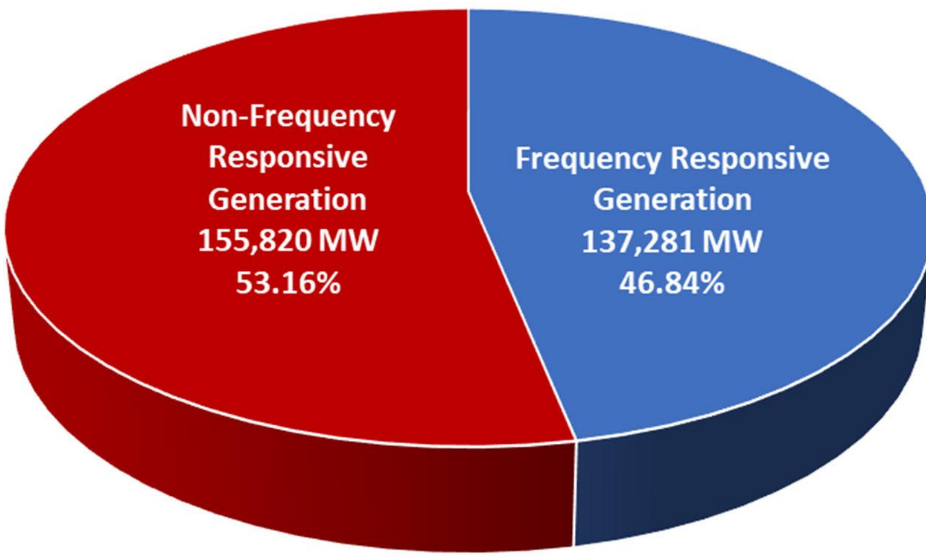

Figure 6-4: Frequency Responsive Governor Modeling Summary for Case 2

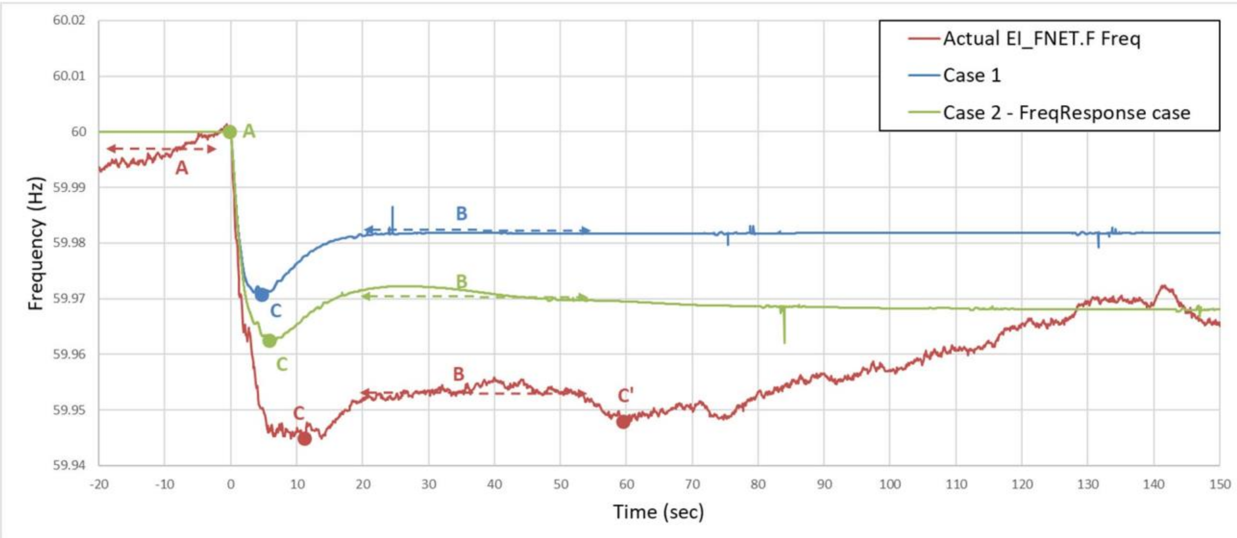

Figure 6-5: EI March 10, 2019 Frequency FNET Raw Data Plot and Simulated Frequency Responses for Both 2019 Base Cases (Event 1)

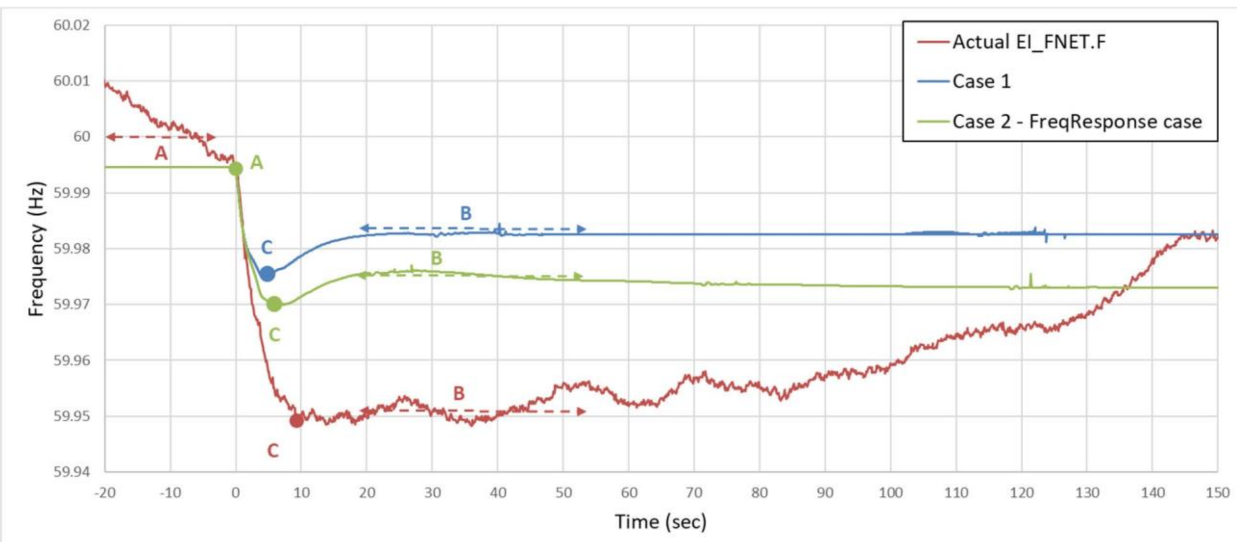

Figure 6-6: EI March 15, 2019 Frequency FNET Raw Data Plot and Simulated Frequency Responses for Both 2019 Base Cases (Event 2)

Since system inertia and generator kinetic energy can have an impact on frequency response immediately after a generator is tripped, S&C decided to perform simulations with adjustments made to the system inertia. The inertia was adjusted in 4 stages to determine how it would impact frequency response for both events. The stages include a decrease in increments of 3%, 4%, 6%, and 9%. In each stage, the results were plotted while Nadir and ROCOF were recorded. Based on the plots, there were no major differences in the simulation results for either stage. Each simulation appeared to provide similar frequency responses during the times recorded. The nadir remained unchanged for both events and ROCOF only varied slightly in each stage. Figures 6-7 (Event 1) and 6-8 (Event 2) show the plots for all 4 stages. There are only minimal changes in the plots in the 4 stages of reduced inertia.

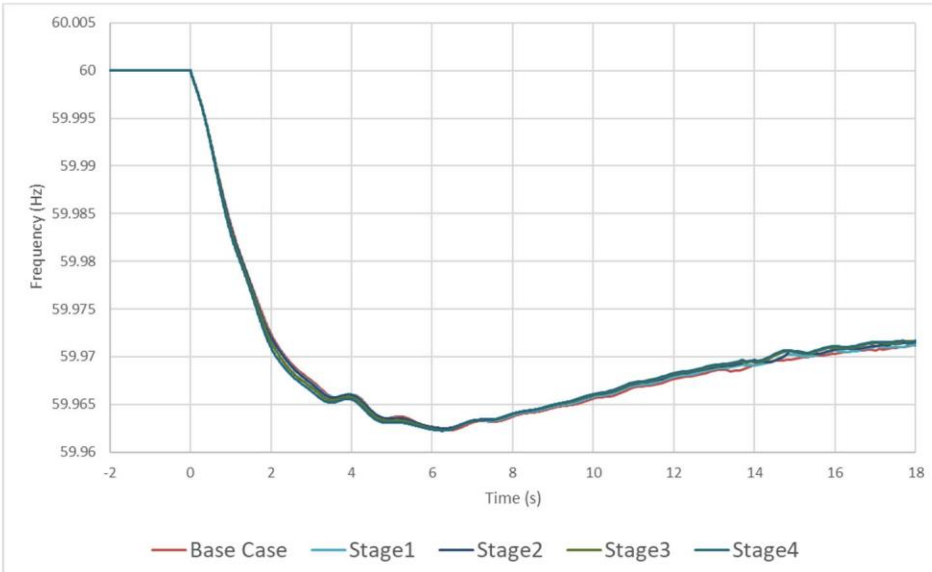

Figure 6-7: Impact of System Inertia Reduction on Frequency Response (Event 1)

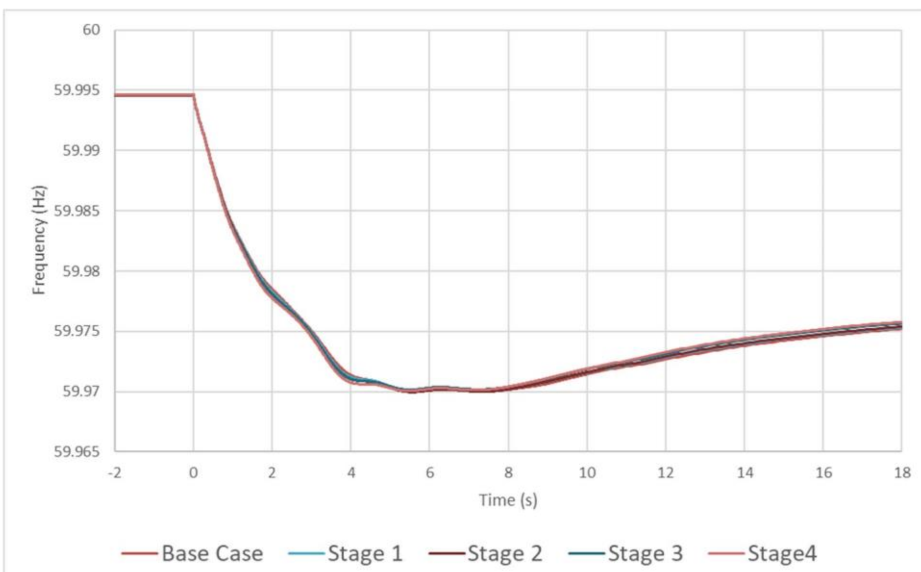

Figure 6-8: Impact of System Inertia Reduction on Frequency Response (Event 2)

Governor response is known to have an impact on system frequency response. This was confirmed in the 2018 studies and also seen by S&C when comparing preliminary simulations of Base Case 1 and Base Case 2. S&C decided to reduce governor responses for online generators. For Event 1, through simulations, it was determined that removing 9% of governors would provide the closest matching plot. For Event 2, it was determined that removing 17% of governors provided the closest matching plot. These percentages are in addition to the governors modeled as non-responsive in the bases cases. This brings the total responsive governors for Event 1 to 38% and the total number of responsive governors for Event 2 to 30%. S&C plotted Event 2 which included 21%, 19%, 17%, 14% and 12% decreases. This is shown in Figure 6-9.

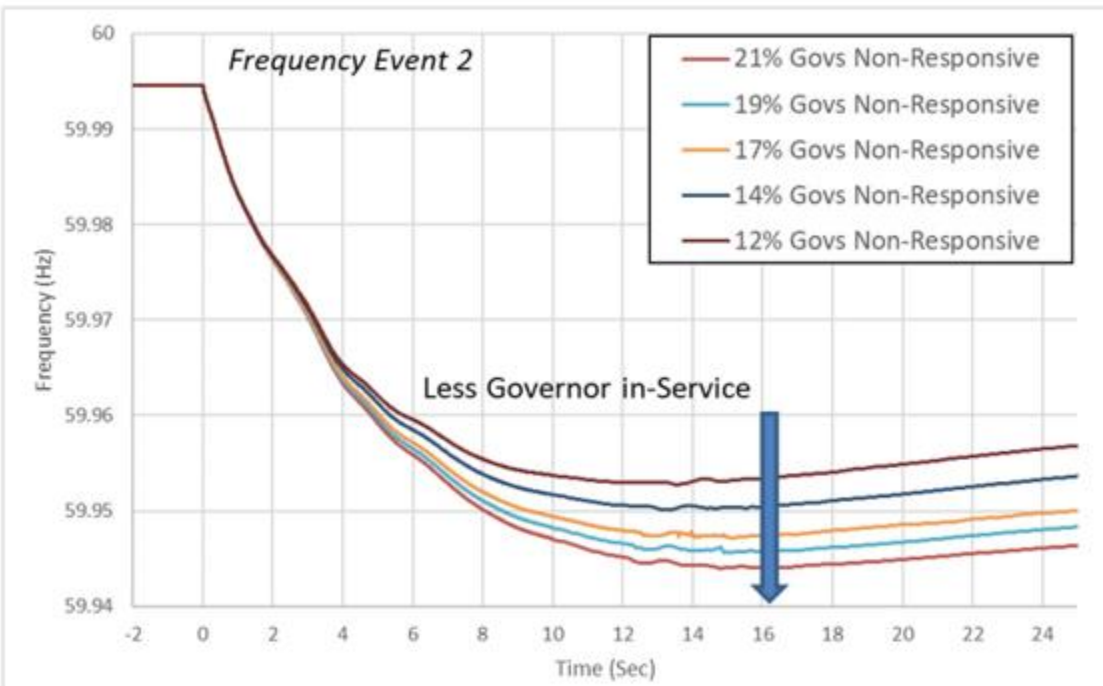

Figure 6-9: Impact of the Amount of Governors Non-Responsive on System Frequency Response in the 2019 Base Case 2 (Event 2)

Benchmarking Event 1 was then performed. The simulation shows a similar frequency response to Event 1 during the arresting period. During the rebound period, the simulation has a slightly better response than the event. During the withdrawal period, the simulation has the frequency recovering towards nominal while Event 1 does not. Also, during the recovery period, the simulation appears to continue flat while Event 1 recovers toward nominal. The plot for Event 1 and the simulation is shown in Figure 6-10.

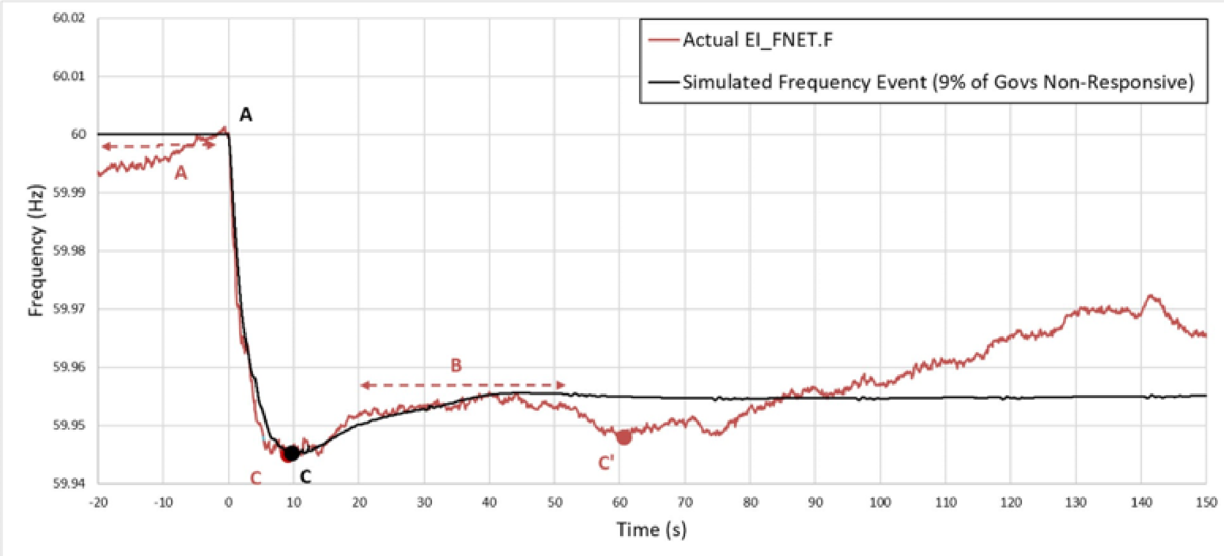

Figure 6-10: Benchmark Simulation of Event 1

The Event 2 simulation was then performed. The shape of the plot is similar to Event 1. During the arresting period, the plots match very closely but during the rebound, withdrawal, and recovery period, the simulation plot is slightly different than Event 2. The plot for Event 2 and the simulation are shown in Figure 6-11.

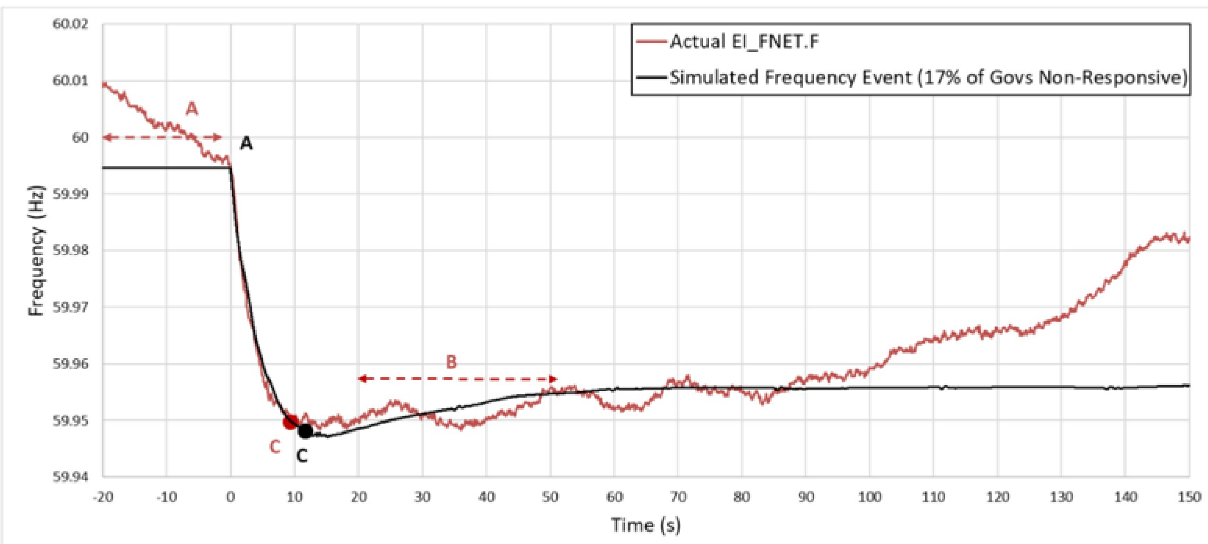

Figure 6-11: Benchmark Simulation of Event 2

Figure 6-12 illustrates the dispatch of frequency responsive governors in the Case 2 model broken down by governor type. It should be noted that the governor models with low percentage are not shown in this figure.

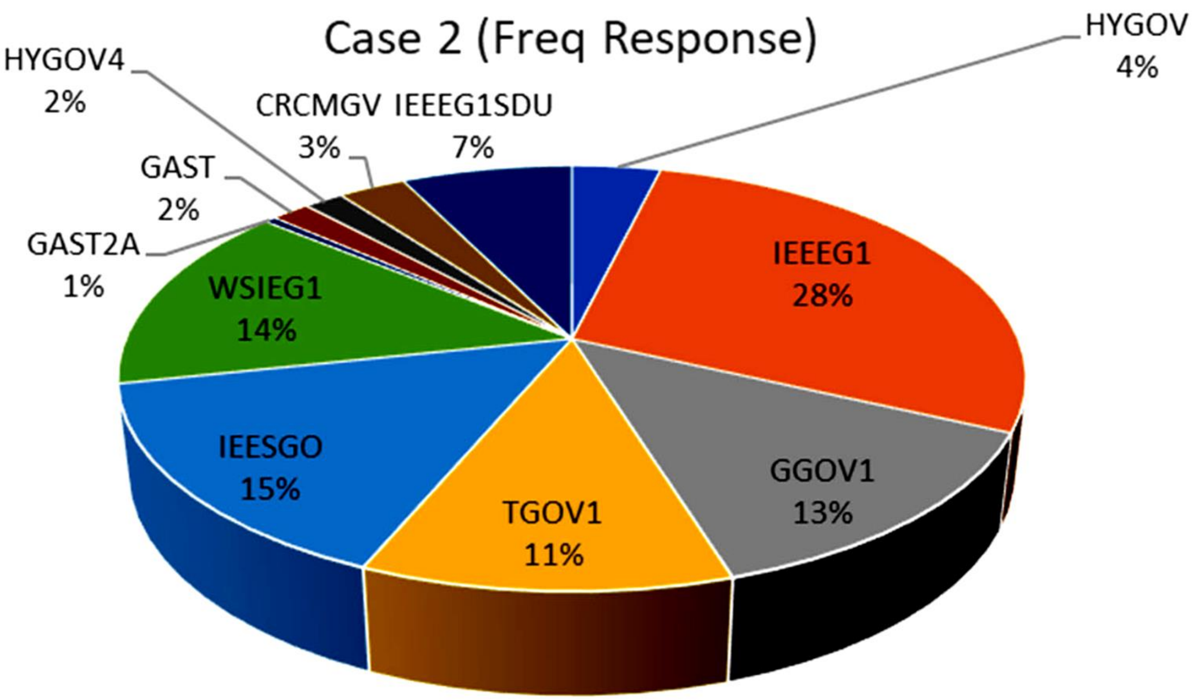

Figure 6-12: Dispatch of Frequency Responsive Governors in Case 2 by Governor Type

6.9 Task 9 - Low Inertia 5-Year-Out Case

S&C developed the low inertia 5-year out case using the MMWG 2018 Series 2023 SLL case. During the model build process, it was discovered that a number of units had been reduced to negative load equivalents. Subsequent to discussions with the MMWG model builder, a revised case was produced in December 2019 which included the full dynamic models for these units. The MMWG Base Case 2 was used again to develop this case. The FRWG members provided the generation mix, load, and interchange levels to S&C projected to occur in 2023 in IDV or Python script. The information provided included power flow and dynamic modeling changes. Once provided, S&C merged all the files and applied the changes to the 2023 SLL Base Case 2 and tested it. This is the case with the additional governor reduction of 17%. The case was initialized and tested. The historic events (03/10/2019 01:01:45 and 03/15/2019 20:39:02) were simulated. Calculated parameters are shown in Table 6-4. The governors in the case are shown in Table 6-5. Figures 6-13 and 6-14 provide modeling summaries of the dispatch of frequency responsive governors and online governors by model type.

Table 6-4: Calculated Parameters of the Low Inertia 5-Year Out Case with 17% of Governors Non-Responsive and the 2023 Base Case

Parameter	2023 Spring Light Load Base Case	Low Inertia 5-Year Out Study Case	Change in Study Case (%)
Sum of PMax (MW)	383,443.88	337,158.74	-12.07%
Sum of PGen (MW)	295,867.96	250,371.27	-15.38%
Equivalent H (s)	3.59	3.59	0.00%
Equivalent R (pu)	0.19	0.20	5.26%
Spinning Reserve (%)	29.60	34.70	17.23%
Sum of MBase (MVA)	471,648.61	411,158.49	-12.83%
System Inertia (MVA-s) (Frequency Measure 1)	1,694,098.28	1,476,165.65	-12.86%
Beta in pu of MBase	5.28	5.04	-4.55%

Table 6-5: Generation Dispatch and Headroom by Governor Model Type in the Low Inertia 5-Year Out Case (17% of Governors Non-Responsive)

Governor Model	Total Dispatched Generation (MW)	Total Headroom (MW)
HYGOV	3,691.2	2,691.8
TGOV1	8,497.0	1,721.0
GGOV1	15,996.2	4,169.7
IEESGO	6,816.3	2,215.4
IEEEG1	13,524.3	3,277.6
GAST	3,136.5	790.2
WEHGOV	1,063.5	759.2
HYGOV4	-20.0	36.4
IEEEG2	272.3	1,972.9
WSIEG1	11,414.5	2,767.2
CRCMGV	1,096.3	152.7
All Generators with Governors	**70,450.9**	**28,417.0**
All Generators without Governors	**179,920.3**	**58,369.8**
All Generators	250,371.2	86,786.8

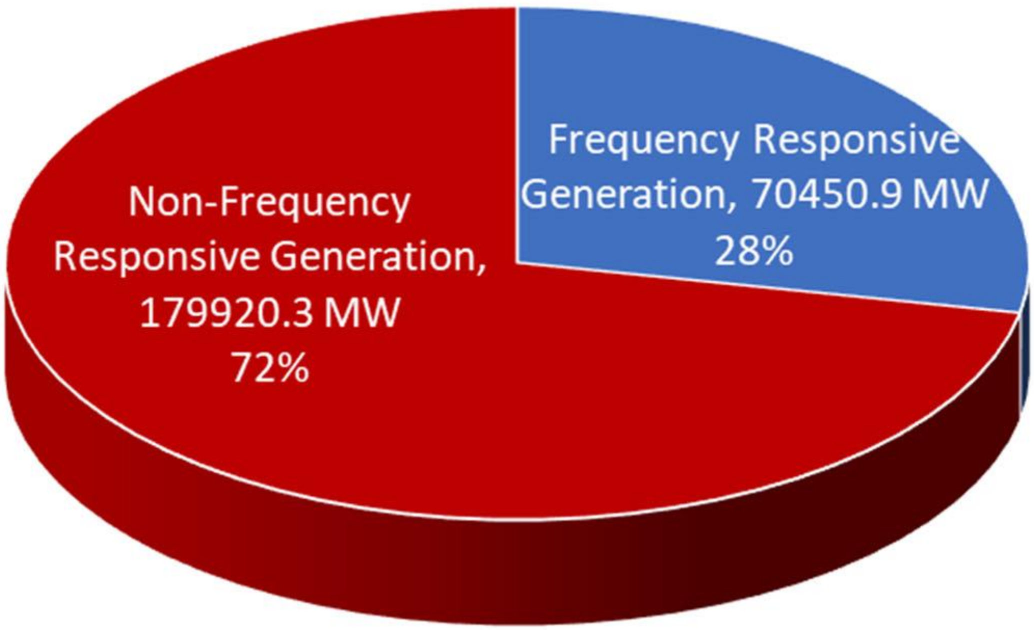

Figure 6-13: Frequency Responsive Governor Modeling Summary for Future Year case

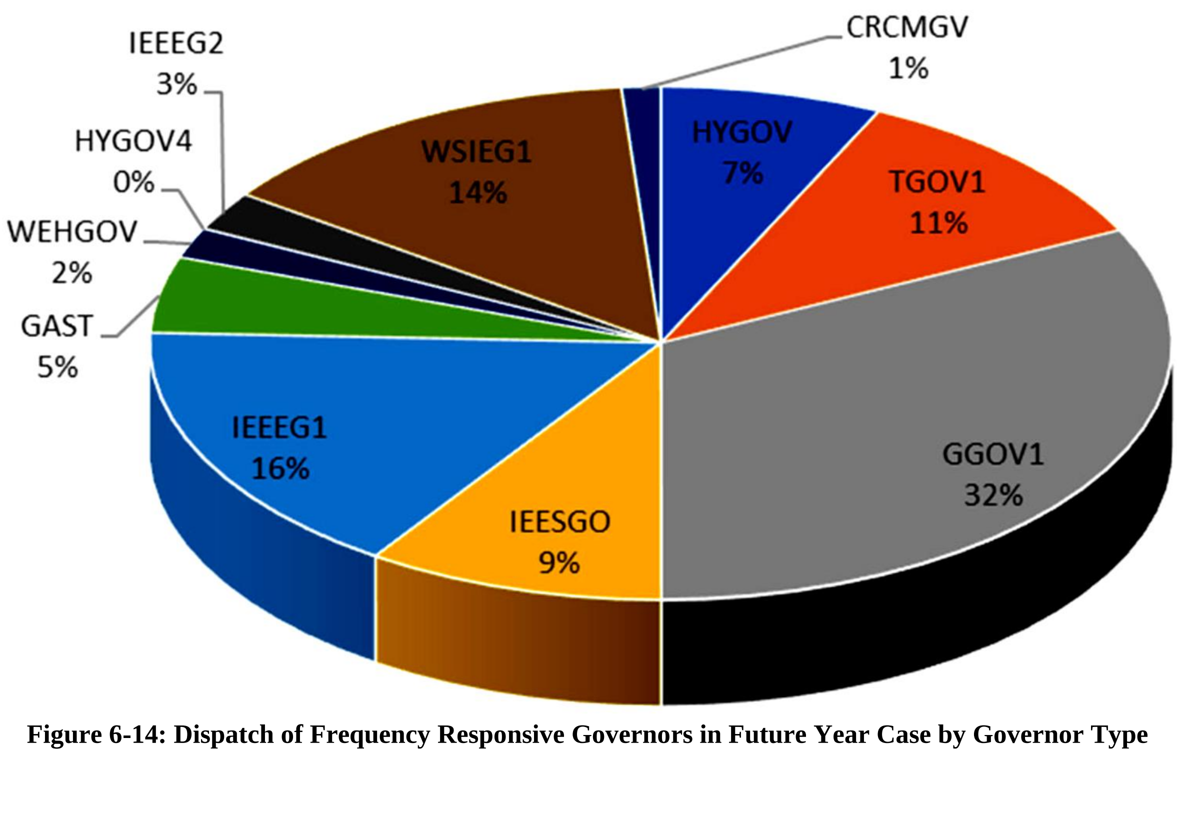

Figure 6-14: Dispatch of Frequency Responsive Governors in Future Year Case by Governor Type

6.10 Task 10 – Calculate Frequency Measures 1, 2, and 4

Figure 6-15 includes a sample frequency response plot from the ERSTF report[1] which shows how frequency response is calculated and frequency deviation due to generation loss. Values A, B, and C are each described in Figure 6-15.

This figure illustrates a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. **The event starts at time t0**. **Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency point observed in the first 12 seconds and Value B is the average from t+20 to t+52 seconds. Point C' occurs when the frequency after 52 seconds falls below either the Point C (12 seconds) or average Value B (20 – 52 seconds).**

The difference between Value A and Value B is the change in frequency used for calculating primary frequency response. Frequency response is calculated as the ratio of the megawatts lost when a resource trips and the frequency deviation. For convenience, frequency response is expressed in this report as an absolute value. A large absolute value of frequency response, measured in MW/0.1Hz, is better than a small value.

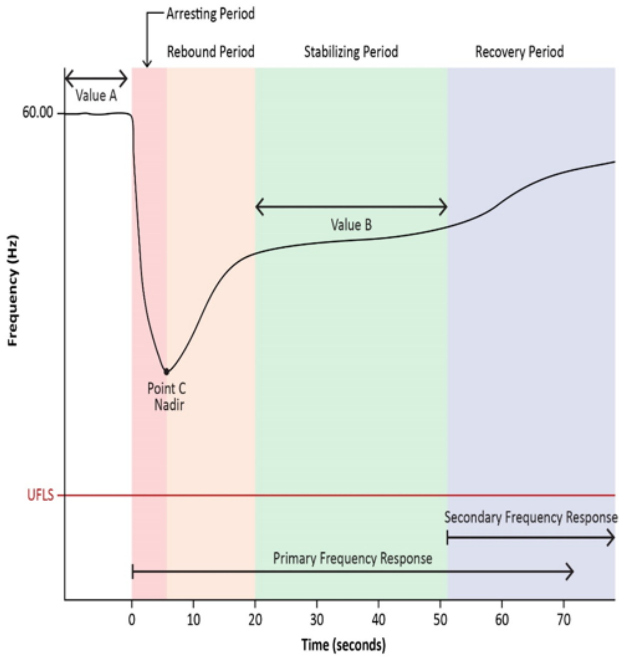

Figure 6-15: Frequency Response Data Point Explanations

S&C simulated the frequency response of the EI to postulated resource contingencies. Other pertinent information from the dynamic simulations needed was also collected. Frequency versus time was plotted for each contingency defined in Task 7.

The frequency values were modeled in a manner consistent with the methodology utilized by FNET. S&C collected other pertinent information from the dynamics simulations needed to calculate the frequency response tests outlined in Measures 1, 2, and 4 of the ERSTF report.

6.10.1 MSSC Trip Event

The simulation results for the MSSC are shown in Figure 6-16.

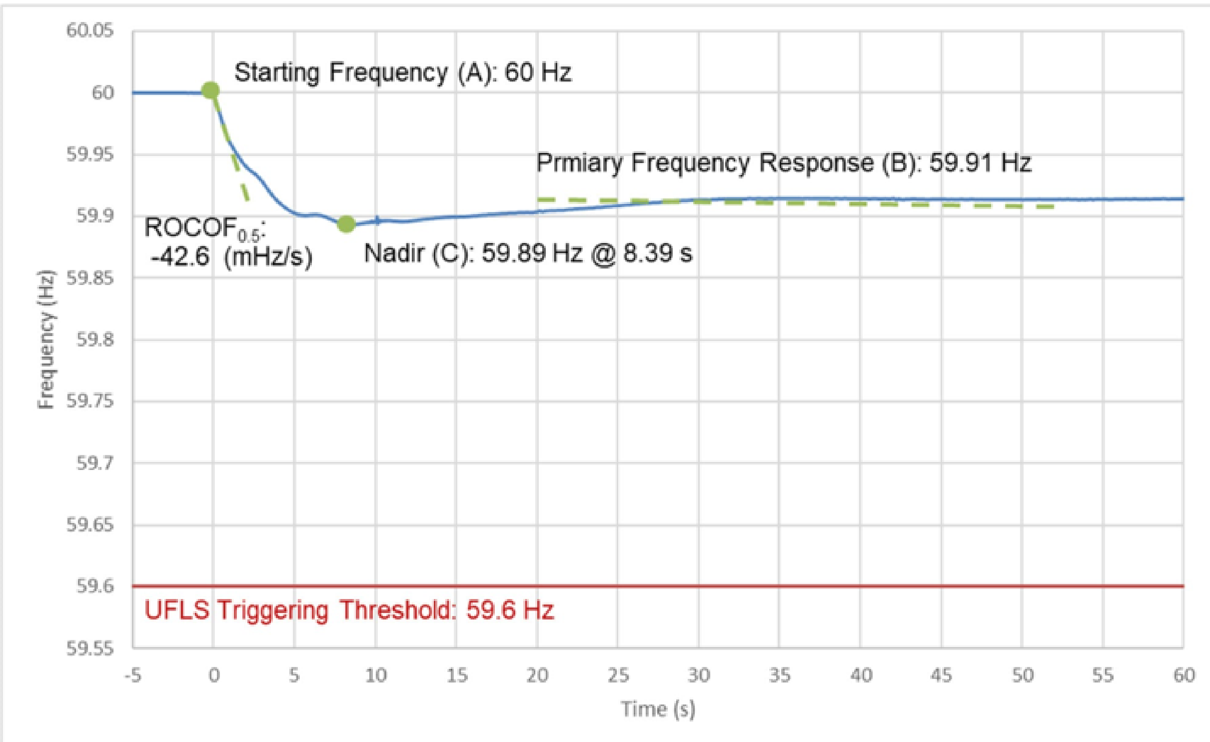

Figure 6-16: Frequency Response Following MSSC

6.10.2 The Largest 10-Year Event

The largest generation trip in 10 years was simulated. The frequency response plot is shown in Figure 6-17.

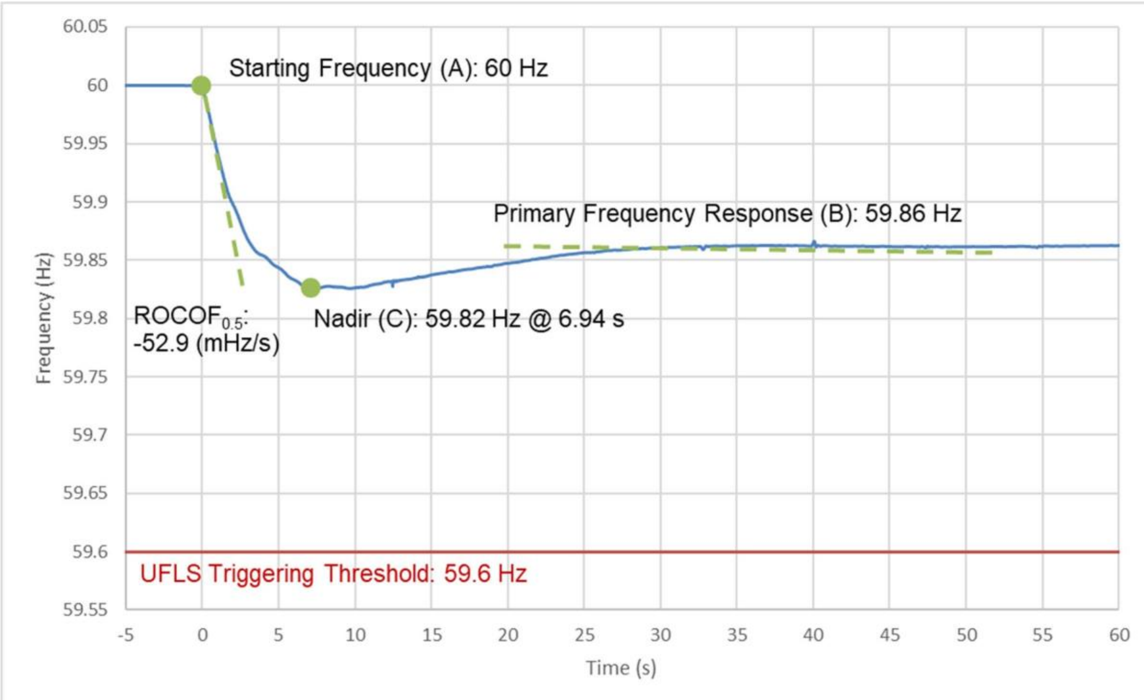

Figure 6-17: Frequency Response Following the Largest 10-Year Generation Trip Event

6.10.3 Historic 4,500 MW Generation Trip Event

The historic 4,500 MW Generation trip event was simulated next. Some of the generating units involved in the historical event are no longer modeled in the case due to unit retirements, and the original contingency is no longer credible due to changes in the transmission system. In this simulation an approximate event was created by tripping a similar total, 4,307.6 MW of generation.

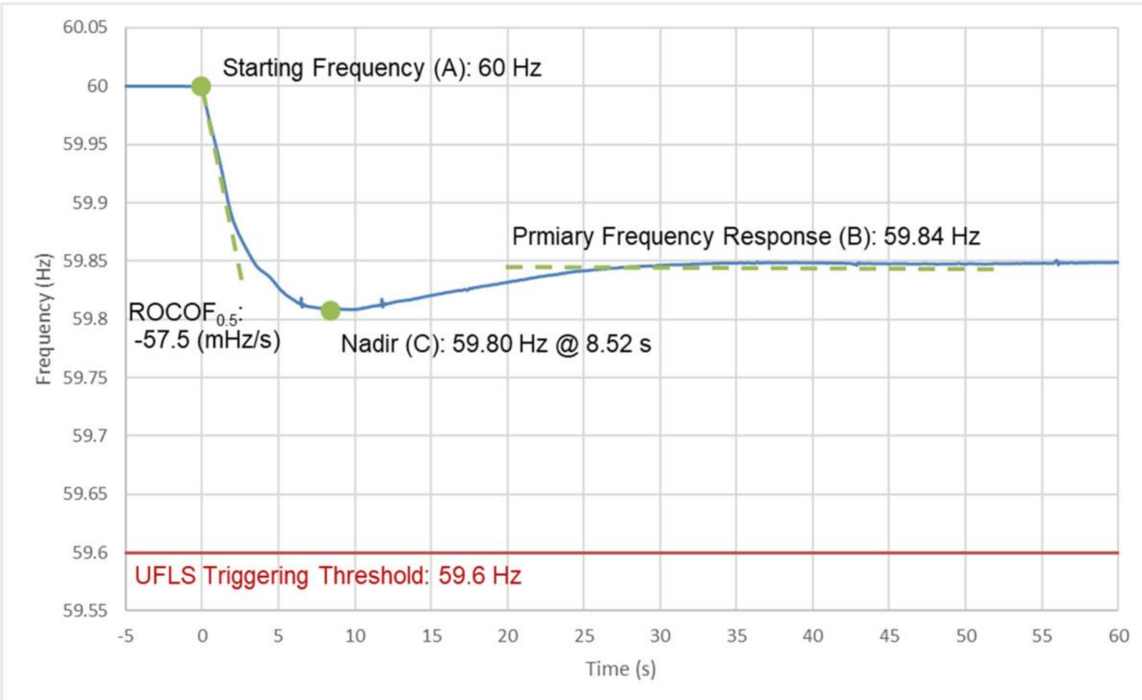

Figure 6-18: Frequency Response Following the 4,307.6 MW Generation Trip Event

6.10.4 10,000 MW Benchmark Test

The 10,000 MW benchmark test frequency response simulation is shown in Figure 6-19.

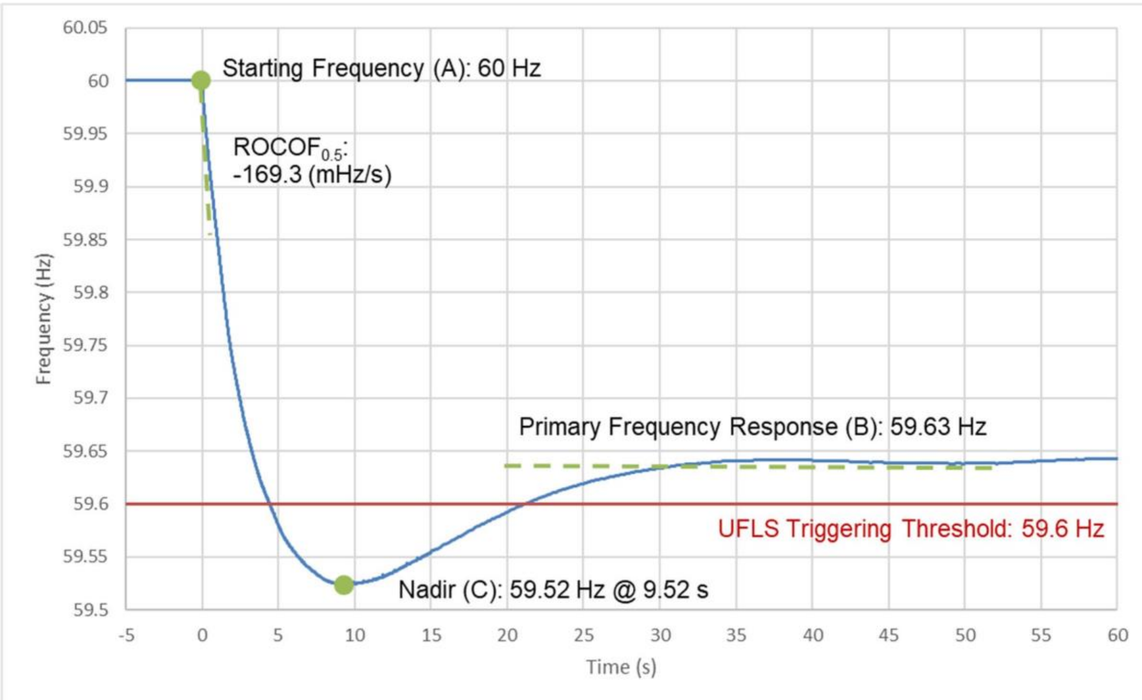

Figure 6-19: Frequency Response For the 10,000 MW Benchmark Test

There were issues with the 10,000 MW benchmark test. S&C confirmed the issues were related to network nonconvergence. The issues were resolved by converting a generator to an equivalent negative load without a dynamic model.

6.10.5 Calculation of Measures and Sensitivity Analysis

Table 6-10 shows the calculated Frequency Measure 1, i.e., Synchronous Inertial Response (SIR), as well as other system parameters for both the benchmarking case and the 5-year out case. Table 6-11 shows the calculated Frequency Measure 2 for each resource contingency event simulated in the 5-year out case, including initial frequency deviation and the ROCOF during the first 0.5 second following the initiation of the event. The average frequency values from multiple frequency channels spread across the EI were used to calculate Measure 4 for each generation loss event simulation. Table 6-12 shows the calculated Frequency Measure 4 including frequency performance ratios and time measures.

Table 6-6: Frequency Measure 1: Synchronous Inertial Response (SIR)

Case #	Case Name	Total System's Synchronous Inertia (MVA-s)	Total Non-synchronous Generation Dispatched (Pgen [%])	Total Synchronous Generation Dispatched (Pgen [%])	Total DC Tie-Line Imports (MW)	Total System Load (MW)
1	Benchmarking Case (2019 Spring Light Load)	1,680,291	5.7%	94.3%	637	286,950
2	5-Year Out Case (2023 Spring Light Load Post-Adjustments by EIPC/FRWG Members)	1,476,166	9.4%	90.6%	3,123	247,574

Table 6-7: Frequency Measure 2 for Resource Contingency Events Tested

Event #	Event Name	Initial Frequency Deviation (Hz) within First 0.5 Second)	Rate of Change of Frequency ($ROCOF_{0.5}$) (mHz/s)
1	Most Severe Single Contingency Event	-0.0213	-42.6
2	Largest 10-Year Generation Trip Event	-0.0265	-52.9
3	Historic 4,500 MW Generation Trip Event	-0.0288	-57.5
4	10,000 MW Benchmark Test	-0.0847	-169.3

Table 6-8: Frequency Measure 4 for Resource Contingency Events Tested

Event #	Event Name	Frequency Performance Ratios				Time Measures			
		A:B (MW/0.1Hz)	A:C (MW/0.1Hz)	C:B	C':C	t_C-t_0 (s)	$t_{C'}-t_C$ (s)	$t_{C'}-t_0$ (s)	Time to UFLS (s)
1	Most Severe Single Contingency Event	2,612.588	2,143.604	1.219	NaN*	8.400	NaN*	NaN*	9.390
2	Largest 10-Year Generation Trip Event	2,756.191	2,201.405	1.252	NaN	6.946	NaN	NaN	7.561
3	Historic 4,500 MW Generation Trip Event	2,794.326	2,250.781	1.241	NaN	8.521	NaN	NaN	6.957
4	10,000 MW Benchmark Test	2,723.756	2,102.748	1.295	NaN	9.530	NaN	NaN	2.363

* The frequency simulation event did not exhibit absolute minimum frequency value (C'); i.e. the frequency after 52 seconds did not fall below either Point C or average Value B. Hence, there are no Point C' and its associated frequency and time measures in the frequency simulation.

Mitigation Solution 1: Governor Participation Reduction

Following the 10,000 MW benchmark test, the frequency nadir is approximately 59.52 Hz which is below the UFLS triggering threshold 59.6 Hz. Mitigation of this condition was tested by reducing non-responsive governor participation in the 5-year out case. The test indicates that changing non-responsive governor participation from 17% to 7% in the 5-year out case would raise the frequency nadir above 59.6 Hz following the 10,000 MW benchmark test. This is shown in Figure 6-20.

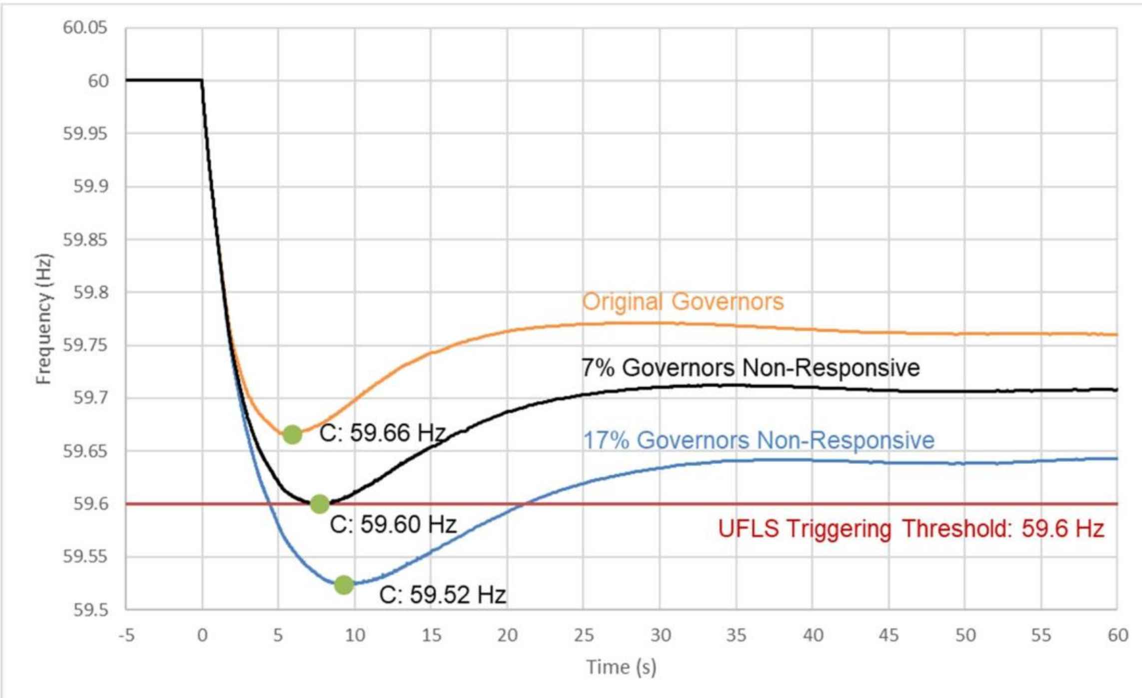

Figure 6-20: Test of Mitigation Option 1: Reducing the Number of Non-Responsive Governors

Mitigation Solution 2: Generation MW Loss Reduction

Mitigation of the low frequency nadir was also tested by reducing the amount of generation MW loss in the 5-year out case for the 10,000 MW benchmark test. The test indicates that reducing generation MW loss from 10,001 MW to 8,597 MW[5] would raise the frequency nadir above 59.6 Hz following the 10,000 MW benchmark test. This is shown in Figure 6-21.

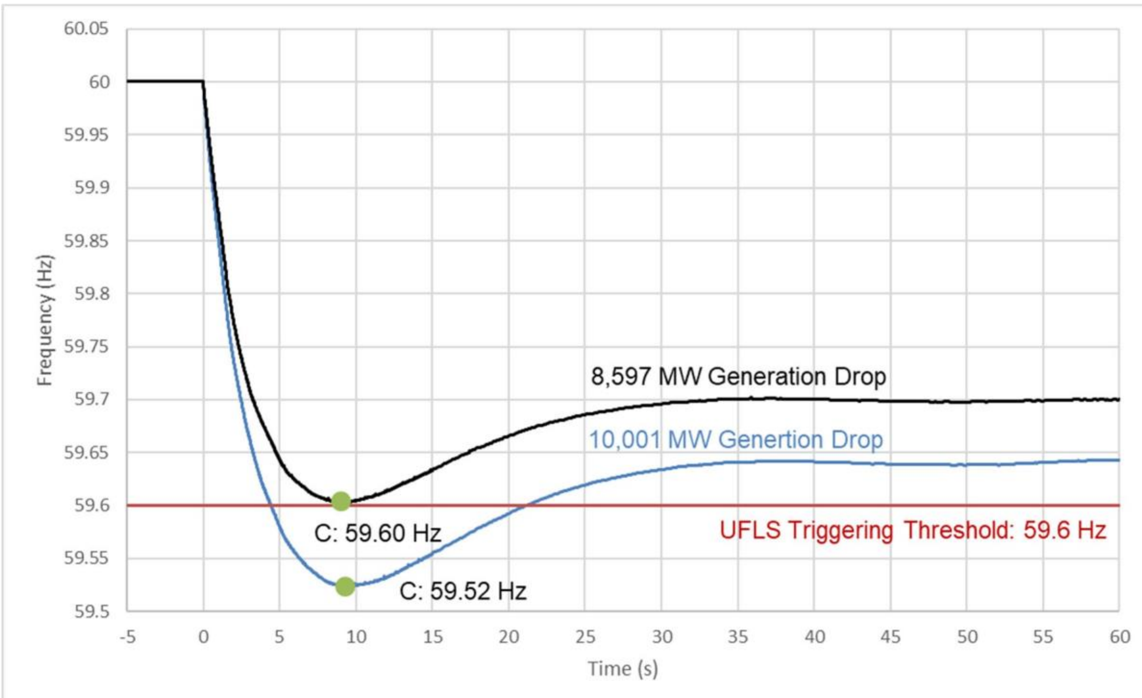

Figure 6-21: Test of Mitigation Option 2: Reducing the Amount of Generation MW Loss

Results of this study are found in Table 6-13. Comparisons to the 2018 study is in Table 6-14 and 6-15.

Table 6-9: Summary of Resource Contingency Events Simulations

Event/Mitigation	% of Gov Non-Responsive *	Gen Loss (MW)	Inertia Dropped **	Point C - Nadir (Hz)	Time C (sec)	Point B (Hz)	$ROCOF_{0.5}$ (mHz/sec)
MSSC	17%	2,299	1.00%	59.89	8.40	59.91	-42.59
Largest 10-Year Gen Trip Event	17%	3,852	1.07%	59.82	6.94	59.86	-52.91
Historical 4,500 MW Trip Event	17%	4,307	1.53%	59.80	8.52	59.85	-57.52
10,000 MW Benchmark Test	17%	10,001	3.38%	59.52	9.53	59.63	-169.31
Mitigation Option 1 (Governor Participation Reduction)	7%	10,001	3.38%	59.60	7.86	59.70	-168.91
Mitigation Option 2 (Generation Reduction)	17%	8,597	2.78%	59.60	9.26	59.69	-133.57

* Total Number of Online Governors in the 5-Year Out Case: 943

** System Inertia of the 5-Year Out Case before the Event: 1,476,166 MVA-s (Frequency Measure 1)

Table 6-10: Comparison of the 5-Year Out Cases: 2022 vs 2023

Study Case	5-Year Out Case (2022 Spring Light Load) for 2018 Study	5-Year Out Case (2023 Spring Light Load) for this (2020) Study	% Change from 2022 to 2023
Case Year	2022	2023	
Total System's Synchronous Inertia (MVA-s)	1,628,796	1,476,166	-9.4%
Total Non-synchronous Generation Dispatched (Pgen [%])	8.70%	9.40%	8.0%
Total Synchronous Generation Dispatched (Pgen [%])	91.30%	90.60%	-0.8%
Total DC Tie-Line Imports (MW)	3,393	3,123	-8.0%
Total System Load (MW)	288,143	247,574	-14.1%

Table 6-11: Comparison with 2018 Frequency Response Study Findings

Event/Mitigation	Study Year	Gen Loss (MW)	Point C - Nadir (Hz)	Point B (Hz)	$ROCOF_{0.5}$ (mHz/sec)
MSSC	2018	2,513	59.91	59.92	-28.00
	2020	2,299	59.89	59.91	-42.59
	Change (%)	-8.52%	-0.03%	-0.02%	51.79%
Largest 10-Year Gen Trip Event	2018	3,120	59.89	59.9	-38.00
	2020	3,853	59.82	59.86	-52.91
	Change (%)	23.46%	-0.12%	-0.07%	39.21%
Historical 4,500 MW Trip Event	2018	4,567	59.84	59.86	-57.00
	2020	4,307.6	59.80	59.84	-57.50
	Change (%)	-5.68%	-0.07%	-0.03%	0.88%

6.11 Task 11 – Write a Comprehensive Report

This internal report has been written to document the process and findings of the FRWG's efforts. In addition, the FRWG submitted the ERSTF Measures 1, 2, and 4 to NERC for inclusion in the 2020 LTRA.

6.12 Task 12 – Outreach to Other Interconnections

The chair of the FRWG has been on regular conference calls with NERC to discussion submission of results for the ERSTF Measures 1, 2, and 4 for the 2021 LTRA.

7. Recommendations

The following reflect the EIPC Frequency Response Working Group's (FRWG) recommendations for improving the simulation study results of the MMWG base cases. The EIPC FRWG recognizes that compliance with the NERC Reliability Standards is the responsibility of the individual Planning Coordinators and Transmission Planners and does not intend to create any conflict with compliance with those standards. The base case benchmarking analysis performed for this study included looking at the sensitivity of disabling governors against reducing system inertia. The results of this sensitivity analysis shown in figures 6-7, 6-8, and 6-9 points to governor action as having a greater impact to overall frequency response. Given the need to disable or remove a significant number of governors from the benchmark event case in order to match the measured frequency response to recorded events, the recommendations from the 2018 study will need to continue to be addressed by industry. Additional outreach to industry groups such as the NERC System Analysis and Modeling Subcommittee (SAMS), the North American Transmission Forum (NATF), and the North American Generation Forum (NAGF) with a focus on improving governor modeling should continue.

As part of the investigation into modeling the frequency responsiveness of load, the EIPC FRWG should look into the development of dynamic load models, specifically composite load models, to determine if this would be an appropriate way to capture this behavior. The next frequency response study should include such considerations in the findings.

In addition to these recommendations, as the 10,000 MW benchmark test simulation demonstrated, there is a need for future studies to begin to investigate mitigation options to a decline in frequency response. One such option explored in this study included increasing the number of responsive governors, but in practice this would require model validation for individual generators which demonstrates governor responsiveness to frequency events. Another potential future mitigation option may be fast frequency response from non-synchronous resources. The FRWG should include such considerations in the next frequency response study.

Recommendation #1: Gross PMax Values

The MMWG should emphasize to model data submitters the importance of using Gross MW capability for PMAX and inclusion of generator auxiliary load in the case models.

The MMWG Procedural Manual[5] in Section 8.2-D-4 states "Generator MW Limits - The generation capability limits specified for generators (PMIN and PMAX) should represent realistic continuous seasonal unit output capability for the generator in that given base case. PMAX should always be greater than or equal to PMIN. *Gross maximum and minimum unit output capabilities should be used along with the unit auxiliary load modeled at the bus or buses from which it is supplied* (emphasis added)."

It is recognized that for power flow studies the emphasis tends to be more towards a generators ***<u>Net</u>*** MW output. This is generally appropriate for power flow purposes since it is only the Net MW that leaves a plant switchyard and affects general area flows. Additionally, Economic Dispatch is often based on Net generation. However, for frequency studies accurate representation the generator ***<u>Gross</u>*** MW output is necessary. Using Gross MW will more correctly represent the range of turbine-generator capability upon which a number of dynamics modeling parameters are based, as discussed in Recommendation #2.

[6] Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 25, dated March 12, 2020.

Additionally, generator auxiliary load represents several percent of the total EI load being served and netting it out may result in some level of inaccuracy for frequency response study results. It is anticipated that additional discussions to determine how to best meet both the power flow and dynamics needs will be necessary.

Recommendation #2: Governor Modeling

The MMWG should emphasize the importance of appropriate selection and coordination of the frequency and turbine-governor related model parameters such as Governor Droop, Governor Dead Band, and Maximum Turbine Power for generator model data submissions. This will likely need to be a longer term effort as data to populate the newer PSSE models which better represent these quantities become available.

The MMWG Procedural Manual[6] in Section 9.2-G states "Turbine governor models which represent dead band are recommended to be used. Starting with PSSE v33.10 dead band modeling is part of the suite of available models." However, while these improved dynamic models are now available in the current versions of PSSE being used for the MMWG annual update process, it will take some time before the data necessary to populate these models is available. Generator Owners are currently in various stages of completing the requirements of NERC Standard MOD-27.[7] In general, the validated models resulting from the MOD-027 effort would be expected to include dead band.

In dynamics simulations, which are typically used for frequency related studies, Maximum Power is represented by quantities in the dynamics models for the turbine-governor, either directly or indirectly, and not by PMAX in the power flow. A "direct" example is the parameter T_{rate} (e.g. in the GGOV1, GAST2A, HYGOVDU and other models), where maximum power is entered directly as a turbine MW value. Some "indirect" examples are parameters like Pmax (e.g. in the HYGOV2, IEEEG1 and other models) or Vmax (e.g. in the TGOV1, TGOV2 and other models), which reflect maximum power as a per unit quantity based on MBASE in the power flow. Whichever models are used, care must be taken to ensure that the turbine maximum power is correctly represented in the dynamics models in order to accurately reflect the amount of "headroom" available for frequency support.

Governor Droop (or the gain 1/Droop in some models) should reflect the droop based on the appropriate actual "zero-to-maximum turbine capability" range, not the "zero to MBASE" range. Depending on the model used and the data provided, it may be necessary to adjust the droop value to achieve reflect the actual droop based on the range of turbine capability.

Again, as discussed in Recommendation #1, Maximum Power related parameters should be based on ***Gross*** MW, not Net.

[7] NERC Reliability Standard MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

Recommendation #3: Frequency Responsive Dynamics Files

The MMWG should consider the benefits of including Load-Frequency Response Characteristic Models as part of the annual MMWG Dynamics Update process. If adopted, these should be provided as a separate dyr file and not incorporated into the case year files themselves.

Load frequency response is a significant contributor to slowing the decay of frequency, particularly in the initial seconds of a large generation loss (i.e. early in the primary frequency response part of the event). Having some modeling of this effect readily as part of the MMWG series of case files might be beneficial for frequency related studies by the EIPC or other users of these cases. It is anticipated that the data provided would consist of a simple dyr file on an Area basis using a PSSE dynamic load characteristic model such as LDFRAR or similar. The MMWG could collect the input from individual submitters into a single dyr file applicable to all case years. Such data should generally be from the dynamic simulations performed at least every five years per NERC Standard PRC-006[8] (Automatic Under Frequency Load Shedding). UFLS settings, at least on an Area-wide basis, do not change frequently. Therefore, the data collection burden on MMWG members would be minimal.

Providing this data as a separate dyr file that would not be incorporated into the dynamics data files for each individual case year is desirable to avoid unnecessarily increasing the size and complexity of the individual case files with data that would not be used in the majority of studies/simulations performed. This separate dyr file concept is already being used for the complex load models provided for the MMWG annual updates.

[8] NERC Reliability Standard PRC-006-3, Automatic Under Frequency Load Shedding.

8. Conclusion

The analysis and simulation of this study demonstrated that the EI would have sufficient system inertia over the next 5 years with the generation resource mix, load, and interchange levels and governor participation modeled. However, with the addition of non-synchronous generation and planned resource retirements, maintaining frequency in the EI is a concern which warrants continued study. The EIPC TC has been tasked with identifying and understanding how future generation contingencies could lead to UFLS events due to the reduction of frequency support from the changing generation resource mix. In order to study and plan for possible increased non-synchronous generation with reduced inertia, there is a need for improved frequency responsive simulation power flow models. With assistance from all FRWG members, monthly meetings and collaborative efforts have allowed the FRWG to develop, assign, and complete many tasks in support of this effort. In 2018, a similar effort was undertaken by the EIPC FRWG to study and analyze events during low inertia conditions. This report details information on the updated technical analysis, model modifications, and simulations performed by members of the EIPC FRWG, with the assistance of S&C Electric, to assess the NERC ERSWG forward looking frequency Measures 1, 2, and 4 for the EI for inclusion in the 2020 NERC LTRA.

In total, 12 tasks were completed. Through completion of the tasks, the EIPC FRWG was able to benchmark historical low inertia and frequency events and visually compare the results to the actual measurements. . Simulation of Event 2 concluded that approximately 30% of governors provided frequency response which was determined to provide a closer match to the actual event. This compares to approximately 45% of governors that provided frequency response in the study performed by the FRWG in 2018. The three frequency events that were benchmarked include generation losses of 2,299 MW (MSSC), 3,853 MW (Largest Generator 10-Year Trip), and 4,500 MW. Results of the simulations are shown in Figure 6-16, Figure 6-17, and Figure 6-18. The amount of non-responsive governors for each simulation is shown in Table 6-13. Comparison of the Measure 1, 2, and 4 calculations between the 2018 and 2020 studies in Tables 6-14 and 6-15 show a decrease in total load and an increase in non-synchronous generation. The change in total load was driven by an increased focus on modeling minimum system load in the 2020 study along with decreasing forecasted minimum load levels. With governors turned off or disabled based on the benchmarking analysis, generation dispatch changes similar to the lowest observed EI inertia, and future changes to synchronous generation expected in the next 5 years, all three frequency events exhibited satisfactory frequency response with a minimum nadir of 59.80 Hz and are significantly far away from the initial UFLS set point of 59.6 Hz. Coupled with an increase in planned non-synchronous generation, this resulted in a decrease in total system inertia for this study. The changes have resulted in a lower frequency nadir for all simulations. Continued focus on this minimum load/low inertia condition will be necessary to forecast the earliest possible onset of UFLS triggered for the future planned system based on historical events.

While improvements to future modeling of governors is expected to supersede the need for limiting generator governor responses, this study has shown that continued improvement is still needed in this area. The benchmarking analysis performed for this study demonstrated the frequency response sensitivity to changes in governor modeling is greater than changes in total system inertia at the current resource mix levels. The FRWG will continue to follow the improvement in accuracy of governor models as described in recommendation 2 and the implementation of the NERC standard MOD-027.

The results of the analysis were submitted for inclusion in the 2021 NERC LTRA. While the MMWG is planning to include a minimum load case for the 2021 model build process, three recommendations for improvements to the MMWG case building process have been maintained and the FRWG will work with the MMWG and other industry groups to implement those recommendations.

- Recommendation #1: Gross PMax Values
- Recommendation #2: Governor Modeling
- Recommendation #3: Frequency Responsive Dynamics Files

The FRWG would like to thank all members from the Planning Coordinators for their effort and participation to successfully complete the assigned tasks. The FRWG would also like to thank S&C Electric Company for their exemplary work in compiling necessary data and completing the simulations used in the completion of this study. Following review of the study results with NERC, the next steps for the FRWG will be to work with the TC and determine the next scope of work for the FRWG going forward.

Appendix A: Frequency Response Components

1. **A to B frequency response** captures the effectiveness of primary frequency response in stabilizing frequency following a large frequency excursion. This Measure is the conventional means of calculating frequency response as the ratio of net MW lost to the difference between Point A and Point B.

$$\textit{Frequency Response (Current)} = \frac{Generation\ Lost\ (MW)}{Frequency\ (A) - Frequency\ (B)}$$

Trending ALR1-12 in MW/0.1 Hz year to year versus trending only system conditions will provide additional insights concerning primary frequency response levels and characteristics. ALR1-12 metric is already being used. However, trending it versus time does not provide information on how at similar system conditions the response is changing year to year.

2. **A to C frequency response** captures the impacts of inertial response, load response (load damping) and initial governor response (governor response is triggered immediately after frequency falls outside of a pre-set dead band; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed). This Measure is calculated as the ratio of net megawatt lost to difference between Point A and Point C frequency.

$$\textit{Frequency Response (Nadir)} = \frac{Generation\ Lost\ (MW)}{Frequency\ (A) - Frequency\ (C)}$$

Trending this Measure year to year will capture effects of changes in generation mix and load characteristics and help identify needs for synchronous inertia and/or some forms of fast frequency response (e.g., from battery storage or load resources with under-frequency relays).

3. **C to B ratio** captures the difference between maximum frequency deviation and settling frequency. The C to B ratio is related to governor responsiveness with respect to frequency deviation reading, and their capability to arrest and stabilize system frequency.

$$\textit{C:B Ratio} = \frac{Frequency\ (C) - Frequency\ (A)}{Frequency\ (B) - Frequency\ (A)}$$

This Measure should also be trended year to year versus trending only system conditions to provide insight into the amount of generation providing primary frequency response compared with the total committed generation on-line.

4. **C' to C ratio** is the ratio between the absolute frequency minimum (Point C') caused by governor withdrawal and the initial frequency nadir (Point C).

$$\textit{C':C Ratio} = \frac{Frequency\ (C') - Frequency\ (A)}{Frequency\ (C) - Frequency\ (A)}$$

In the EI, the difference between Point C and Point C' is of concern due to governor response withdrawal. While ALR1-12 data does not contain C', original frequency data with 1-second resolution (which captures 300 seconds of an event) can be used. In the EI, trending the difference between Point C and Point C' for similar-sized events will capture whether Generator Owners are working with vendors to adjust plant Distributed Control Systems load controllers to mitigate the impact of governor response withdrawals.

5. <u>Time-based Measures</u> are used to capture the speed in which inertial and primary frequency response as well as governor withdrawal are occurring. These Measures can be trended year to year to identify trends in the rate of change of frequency decline and whether the governor withdrawal phenomena are trending toward improvement or further degradation. These Measures include:

a. **<u>tC-t0 Measure</u>** is the difference in time between the frequency nadir and initial event. It captures the time in which system inertia and governor response arrest declining frequency to its minimum level. Trending this time difference can be useful for ensuring that the defined times for BAL-003-1 fit the actual event data. In addition, trending this with respect to event size and initial frequency can help identify how dead band settings play a role in frequency arrest.

b. **<u>tC'-tC Measure</u>** is the difference in time between the governor withdrawal minimum and the initial frequency nadir. This Measure captures the time in which governor stabilization and withdrawal occur prior to secondary controls and load responsiveness beginning to return frequency to its initial value.

c. **<u>tC'-t0 Measure</u>** is the difference in time between the governor withdrawal minimum and the initial event. This provides a comprehensive picture of the overall time in which frequency declines and continues to fall due to the initiating event. While C' should be mitigated and eliminated entirely, the time between the initial event and absolute minimum should also be minimized. In the EI, it is observed that the minimum frequency level (C' value) due to governor response withdrawal generally occurs 59–78 seconds after an event.

Examples of the proposed frequency response Measures are provided in Appendix A. It should be noted that historical trending of frequency response does not show aggressively degrading frequency response in any of the four interconnections. Efforts related to BAL-003-1 and surveying the Generator Owners regarding governor set point controls have proved effective in communicating the need for primary frequency response. The Measures outlined herein should be tracked for each interconnection such that frequency response can continue to be metricized year to year. If concerns arise and a notable decline in frequency response is observed, then NERC will explore root causes of the declining trends and appropriate action can be taken.