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SPP Southwest Power Pool

Report On

GEN-2008-086N02 and GEN-2014-032 Modification Request Impact Study

Revision R1

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anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
12/02/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2008-086N02 and GEN-2014-032, two active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Meadow Grove 230 kV Substation.

The GEN-2008-086N02 and GEN-2014-032 projects interconnect in the Nebraska Public Power District (NPPD) control area with a combined capacity of 211.22 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2008-086N02 and GEN-2014-032 to change the turbine configuration to 118 x GE 1.85 MW for a total capacity of 218.3 MW. The combined generating capacity for GEN-2008-086N02 and GEN-2014-032 (218.3) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 211.22 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. The existing and modified configurations for GEN-2008-086N02 and GEN-2014-032 are shown in Table ES-2.

Table ES-1: GEN-2008-086N02 & GEN-2014-032 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2008-086N02	Meadow Grove 230 kV (640540)	118 x GE 1.79 MW	201
GEN-2014-032	Meadow Grove 230 kV (640540)		10.22
		Total Combined Capacity	211.22

Table ES-2: GEN-2008-086N02 & GEN-2014-032 Modification Request

Facility	Existing		Modification	
Point of Interconnection	Meadow Grove 230 kV (640540)		Meadow Grove 230 kV (640540)	
Configuration/Capacity	118 x GE 1.79 MW = 211.22 MW		118 x GE 1.85 MW = 218.3 MW PPC to limit POI to 211.22 MW	
Generation Interconnection Line	Shared with GEN-2014-013 & GEN-2014-031: Length = 24.4 miles R = 0.004480 pu X = 0.035770 pu B = 0.071480 pu Rating MVA = 420 MVA		Shared with GEN-2014-013 & GEN-2014-031: Length = 22.45 miles R = 0.004120 pu X = 0.032910 pu B = 0.065740 pu Rating MVA = 420 MVA	
Main Substation Transformer[1]	X12 = 8.916% R12 = 0.237%, X23 = 8.916% R23 = 0.237%, X13 = 8.916% R13 = 0.237%, Winding MVA = 66 MVA, Winding 1 & 2 Rating MVA = 110 MVA, Winding 3 Rating MVA = 40 MVA	X12 = 8.774% R12 = 0.238%, X23 = 8.774% R23 = 0.238%, X13 = 8.774% R13 = 0.238%, Winding MVA = 66 MVA, Winding 1 & 2 Rating MVA = 110 MVA, Winding 3 Rating MVA = 40 MVA	X12 = 8.696% R12 = 0.233%, X23 = 3.343% R23 = 0.475%, X13 = 10.448% R13 = 0.134%, Winding MVA = 66 MVA, Rating MVA = 113 MVA	X12 = 8.735% R12 = 0.236%, X23 = 3.361% R23 = 0.473%, X13 = 10.535% R13 = 0.79%, Winding MVA = 66 MVA, Rating MVA = 113 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 59 (GEWTG2)	Gen 2 Equivalent Qty: 59 (GEWTG2)	Gen 1 Equivalent Qty: 59 (REGCAU1)	Gen 2 Equivalent Qty: 59 (REGCAU1)
	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA[2] = 103.3 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA[2] = 103.3 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA = 121.5 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA = 121.5 MVA
Equivalent Collector Line[3]	R = 0.000000 pu X = 0.000010 pu B = 0.000000 pu	R = 0.000000 pu X = 0.000010 pu B = 0.000000 pu	R = 0.019880 pu X = 0.021943 pu B = 0.076448 pu	R = 0.018050 pu X = 0.017917 pu B = 0.070350 pu

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.77% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, project capacity increase, and the use of a PPC required short circuit and dynamic stability analyses.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2017-001 study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL),
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2008-086N02 and GEN-2014-032 projects needed 22.2 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 7.2 MVAr found for the existing GEN-2008-086N02 and GEN-2014-032 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2008-086N02 and GEN-2014-032 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2008-086N02 and GEN-2014-032 POI was no greater than 0.96 kA[1] for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2008-086N02 and GEN-2014-032 generators online were below 27 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that EFD oscillations were found for several faults studied in the 21LL case from the Jeffrey Unit (640013) and John Units 1 & 2 (640014 & 640015). This issue was observed in the DISIS and modification cases so it was not attributed to the GEN-2008-086N02 and GEN-2014-032 modification.

There were no damping or voltage recovery violations attributed to the GEN-2008-086N02 and GEN-2014-032 projects observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other

[1] For buses not on the generation interconnection line

Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2008-086N02 and GEN-2014-032. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33 software. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-001 power flow configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of the DISIS study.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the turbine parameters and, if needed, the collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors are offline.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

The GEN-2008-086N02 and GEN-2014-032 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Meadow Grove 230 kV Substation. At the time of the posting of this report, GEN-2008-086N02 and GEN-2014-032 are active Interconnection Requests with queue statuses of “IA FULLY EXECUTED/COMMERCIAL OPERATION.” GEN-2008-086N02 and GEN-2014-032 are wind farms and have maximum summer and winter queue capacities of 201 MW and 10.22 MW respectively with Energy Resource Interconnection Service (ERIS).

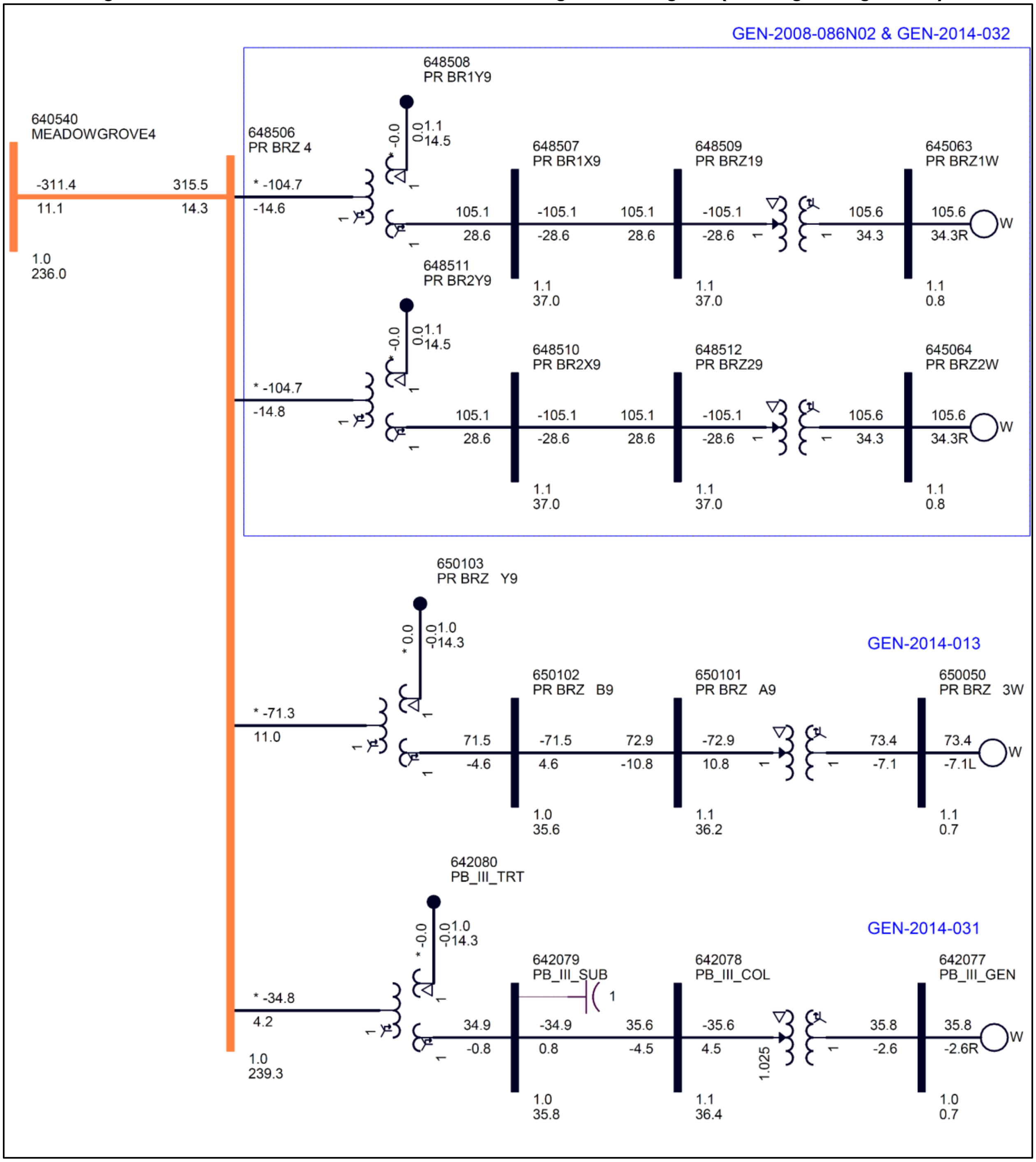
The GEN-2008-086N02 and GEN-2014-032 projects were originally studied in the DISIS-2009-001 and DISIS-2014-002 studies respectively. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2008-086N02 and GEN-2014-032 configuration.

The GEN-2008-086N02 and GEN-2014-032 projects interconnect in the Nebraska Public Power District (NPPD) control area with a combined capacity of 211.22 MW as shown in Table 2-1 below.

Table 2-1: GEN-2008-086N02 & GEN-2014-032 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2008-086N02	Meadow Grove 230 kV (640540)	118 x GE 1.79 MW	201
GEN-2014-032	Meadow Grove 230 kV (640540)		10.22
		Total Combined Capacity	211.22

Figure 2-1: GEN-2008-086N02 & GEN-2014-032 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2008-086N02 and GEN-2014-032 to a turbine configuration of 118 x GE 1.85 MW for a total capacity of 218.3 MW. The combined generating capacity for GEN-2008-086N02 and GEN-2014-032 (218.3 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, (211.22 MW), as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the

Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2008-086N02 and GEN-2014-032 modification. The existing and modified configurations for GEN-2008-086N02 and GEN-2014-032 are shown in Table 2-2.

Figure 2-2: GEN-2008-086N02 & GEN-2014-032 Single Line Diagram (Modification Configuration)

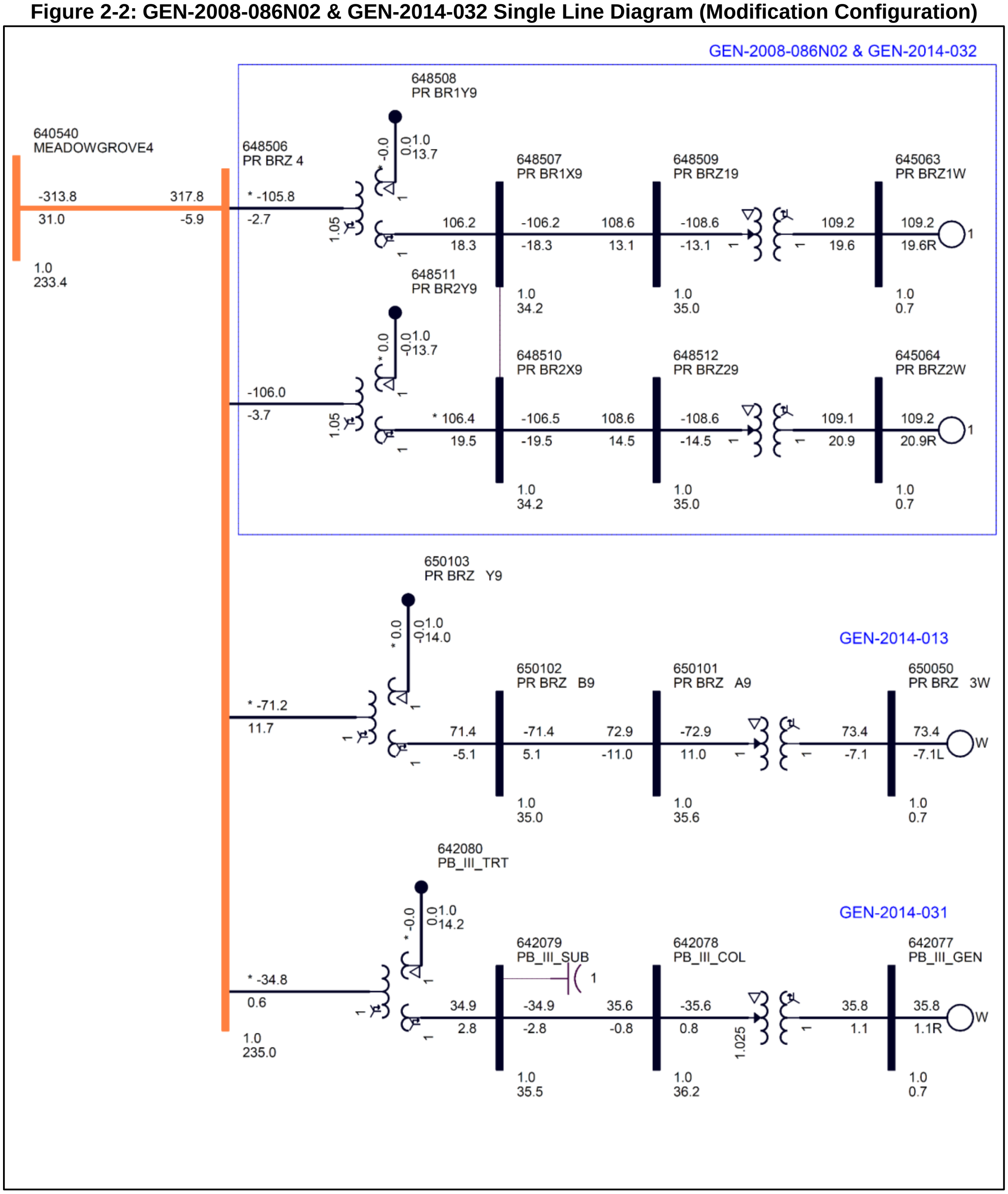


Table 2-2: GEN-2008-086N02 & GEN-2014-032 Modification Request

Facility	Existing		Modification	
Point of Interconnection	Meadow Grove 230 kV (640540)		Meadow Grove 230 kV (640540)	
Configuration/Capacity	118 x GE 1.79 MW = 211.22 MW		118 x GE 1.85 MW = 218.3 MW PPC to limit POI to 211.22 MW	
Generation Interconnection Line	Shared with GEN-2014-013 & GEN-2014-031: Length = 24.4 miles R = 0.004480 pu X = 0.035770 pu B = 0.071480 pu Rating MVA = 420 MVA		Shared with GEN-2014-013 & GEN-2014-031: Length = 22.45 miles R = 0.004120 pu X = 0.032910 pu B = 0.065740 pu Rating MVA = 420 MVA	
Main Substation Transformer[1]	X12 = 8.916% R12 = 0.237%, X23 = 8.916% R23 = 0.237%, X13 = 8.916% R13 = 0.237%, Winding MVA = 66 MVA, Winding 1 & 2 Rating MVA = 110 MVA, Winding 3 Rating MVA = 40 MVA	X12 = 8.774% R12 = 0.238%, X23 = 8.774% R23 = 0.238%, X13 = 8.774% R13 = 0.238%, Winding MVA = 66 MVA, Winding 1 & 2 Rating MVA = 110 MVA, Winding 3 Rating MVA = 40 MVA	X12 = 8.696% R12 = 0.233%, X23 = 3.343% R23 = 0.475%, X13 = 10.448% R13 = 0.134%, Winding MVA = 66 MVA, Rating MVA = 113 MVA	X12 = 8.735% R12 = 0.236%, X23 = 3.361% R23 = 0.473%, X13 = 10.535% R13 = 0.79%, Winding MVA = 66 MVA, Rating MVA = 113 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 59 (GEWTG2)	Gen 2 Equivalent Qty: 59 (GEWTG2)	Gen 1 Equivalent Qty: 59 (REGCAU1)	Gen 2 Equivalent Qty: 59 (REGCAU1)
	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA[2] = 103.3 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA[2] = 103.3 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA = 121.5 MVA	X = 5.726%, R = 0.527%, Winding MVA = 103.25 MVA, Rating MVA = 121.5 MVA
Equivalent Collector Line[3]	R = 0.000000 pu X = 0.000010 pu B = 0.000000 pu	R = 0.000000 pu X = 0.000010 pu B = 0.000000 pu	R = 0.019880 pu X = 0.021943 pu B = 0.076448 pu	R = 0.018050 pu X = 0.017917 pu B = 0.070350 pu

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-001 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modifications with the PPC in place for GEN-2008-086N02 and GEN-2014-032. The percentage change in the POI injection was then evaluated. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.77%) in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1. The MW shown includes injections from both the GEN-2008-086N02 and GEN-2014-032 projects and nearby projects GEN-2014-013 and GEN-2014-031 which share the gen-tie line with GEN-2008-086N02 and GEN-2014-032.

Table 3-1: GEN-2008-086N02 & GEN-2014-032 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2008-086N02 & GEN-2014-032	311.4*	313.8*	0.77%

*The total MW amount includes the GEN-2014-013 & GEN-2014-031 projects which share the gen-tie line

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, the project capacity increase, and the use of a PPC required short circuit and dynamic stability analysis. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

As short circuit and dynamic stability analyses were required, a turbine parameters comparison was not needed for the determination of the scope of the study.

3.3 Equivalent Impedance Comparison Calculation

As the turbine stability model change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2008-086N02 and GEN-2014-032 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

For this analysis the GEN-2014-013 and GEN-2014-031 projects that share the gen-tie line were disconnected. The GEN-2008-086N02 and GEN-2014-032 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2008-086N02 and GEN-2014-032 projects needed approximately 22.2 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is an increase from the 7.2 MVAr found for the existing GEN-2008-086N02 and GEN-2014-032 configuration calculated using the DISIS-2017-001 models. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing configuration. Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2008-086N02 and GEN-2014-032 are shown in Table 4-1.

The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

Table 4-1: Shunt Reactor Size for Low Wind Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2008-086N02 & GEN-2014-032	640540	Meadow Grove 230 kV	22.2	22.2	22.2	22.2

Figure 4-1: GEN-2008-086N02 & GEN-2014-032 Single Line Diagram (Existing Shunt Reactor)

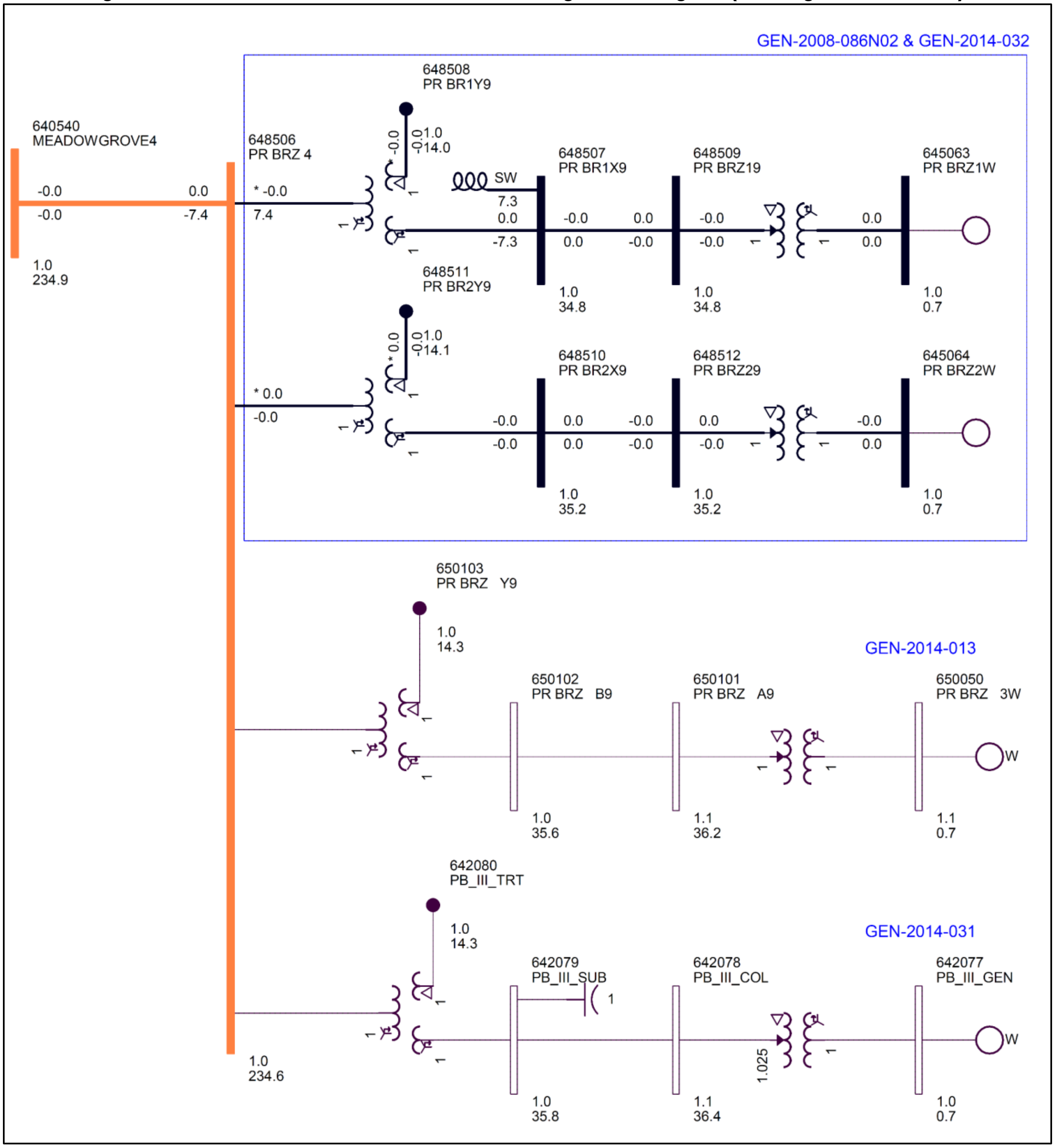
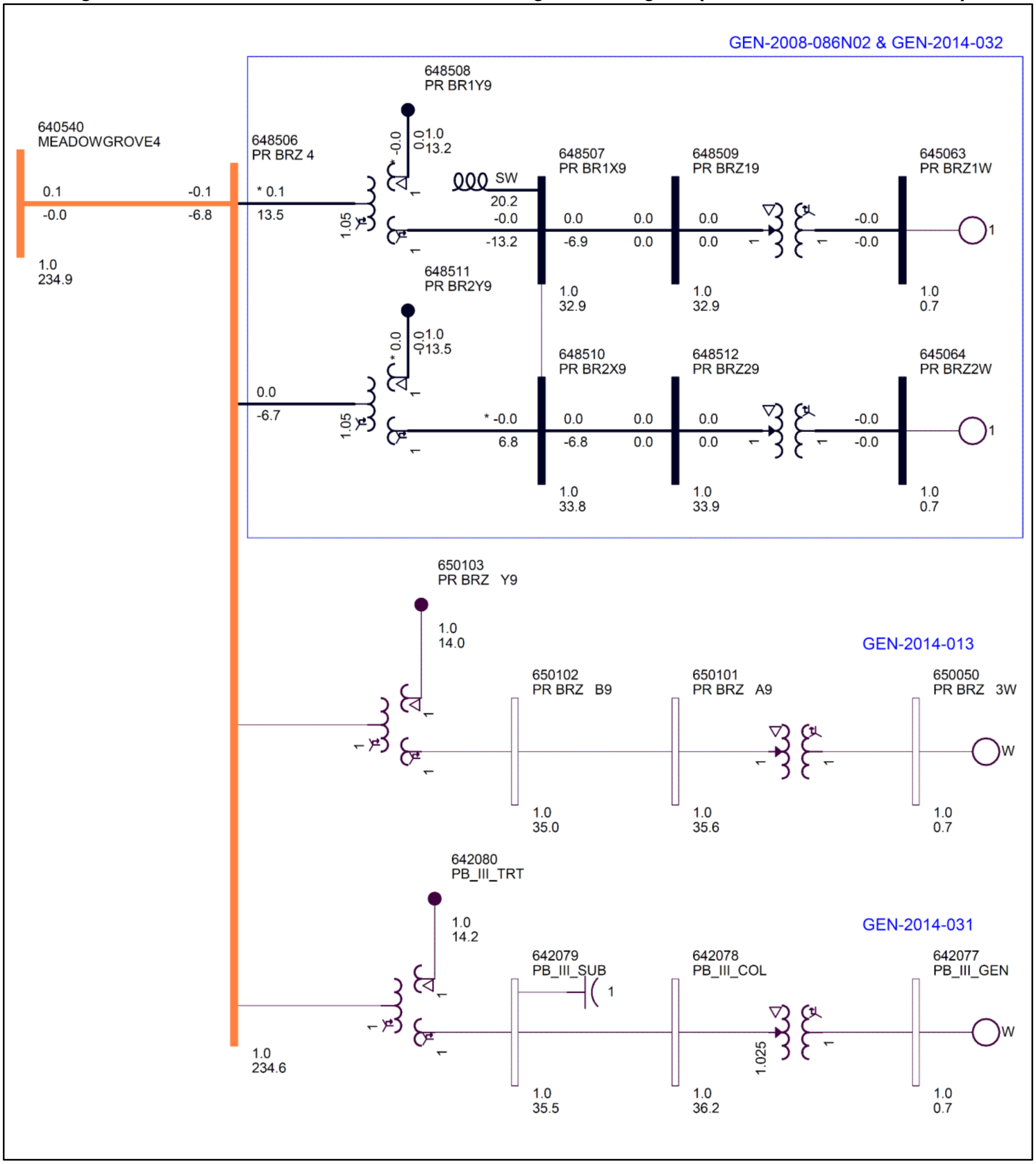


Figure 4-2: GEN-2008-086N02 & GEN-2014-032 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2008-086N02 and GEN-2014-032. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 230 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2008-086N02 and GEN-2014-032 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2008-086N02 and GEN-2014-032 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 5.5 kA with the GEN-2008-086N02 and GEN-2014-032 projects online.

The maximum fault current calculated within 5 buses of the GEN-2008-086N02 and GEN-2014-032 POI was less than 27 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2008-086N02 and GEN-2014-032 contribution to three-phase fault current was about 21.3% and 0.96 kA[2].

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	4.54	5.50	0.96	21.2%
2028SP	4.52	5.48	0.96	21.3%

Table 5-2: 2021SP Short Circuit Results[2]

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	21.1	0.00	0.0%
115	26.1	0.18	0.9%
161	20.7	0.00	0.0%
230	20.0	0.96	21.2%
345	25.1	0.09	1.0%
Max	**26.1**	**0.96**	**21.2%**

Table 5-3: 2028SP Short Circuit Results[2]

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	20.9	0.00	0.0%
115	26.1	0.19	0.9%
161	20.7	0.00	0.0%
230	20.2	0.96	21.3%
345	25.2	0.10	1.0%
Max	**26.1**	**0.96**	**21.3%**

[2] For buses not on the generation interconnection line

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the combined GEN-2008-086N02 and GEN-2014-032 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2008-086N02 and GEN-2014-032 configuration of 118 x GE 1.85 MW (REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 models. The modifications requested for the GEN-2008-086N02 and GEN-2014-032 projects were used to create modified stability models for this impact study.

The modified dynamics model data for the GEN-2008-086N02 and GEN-2014-032 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2008-086N02 and GEN-2014-032 and other equally and prior queued projects in their cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2008-086N02 and GEN-2014-032 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 534 (SUNC), 536 (WERE), 540 (GMO), 541 (KCPL), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), and 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2008-086N02 and GEN-2014-032 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

[3] Based on the DISIS-2017-001 Cluster Groups

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line circuit 1, near MEADOWGROVE4. a. Apply fault at the MEADOWGROVE4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the MEADOWGROVE4 (640540) to COLUMBUS4 (640133) 230 kV line circuit 1, near MEADOWGROVE4. a. Apply fault at the MEADOWGROVE4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the COLUMBUS4 (640133) to COLMB.W4 (640131) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the KELLY T1 230 kV (640133) /115 kV (640134) /13.2 kV (640135) transformer circuit 1, near COLUMBUS4 230kV. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9005-3PH	P1	3 phase fault on the COLUMBUS4 (640133) to E.COL.4 (640126) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the COLUMBUS4 (640133) to SHELCRK4 (640343) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the FTRANDL4 (652509) to LAKPLAT-ER4 (655475) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the FTRANDL4 (652509) to FTTHOMP4 (652507) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the FTRANDL4 (652509) to UTICAJC4 (652526) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the FTRANDL4 (652509) to SIOUXCY4 (652565) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the FT KV1B 230 kV (652507) /69 kV (652276) transformer circuit 2, near FTTHOMP4 230kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9012-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to BIGBND24 (652541) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator BGBND56G (652544).** **Trip generator BGBND78G (652545).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to BIGBND14 (652540) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator BGBND12G (652542).** **Trip generator BGBND34G (652543).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the FT2 KU1B 230 kV (652507) /345 kV (652506) /13.8 kV (652274) transformer circuit 1, near FTTHOMP4 230kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9015-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to LETCHER4 (652606) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to G17-094-TAP (589324) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to WESSINGTON 4 (652607) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line circuit 2, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to G16-094-TAP (587764) 230 kV line circuit 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the UTICAJC4 (652526) to VFODNES4 (652398) 230 kV line circuit 1, near UTICAJC4. a. Apply fault at the UTICAJC4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the UJ KV3A 230 kV (652526) /115 kV (652626) /13.2 kV (652627) transformer circuit 1, near UTICAJC4 230kV. a. Apply fault at the UTICAJC4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9022-3PH	P1	3 phase fault on the UTICAJC4 (652526) to GEN-2015-089 (563230) 230 kV line circuit 1, near UTICAJC4. a. Apply fault at the UTICAJC4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-089-GEN1 (563232).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the SIOUXCY4 (652565) to RASMUSN-ER4 (655484) 230 kV line circuit 1, near SIOUXCY4. a. Apply fault at the SIOUXCY4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the RASMUSN-ER4 (655484) to UTICAJC4 (652526) 230 kV line circuit 1, near RASMUSN-ER4. a. Apply fault at the RASMUSN-ER4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the SIOUXCY4 (652565) to TWIN CH4 (640386) 230 kV line circuit 1, near SIOUXCY4. a. Apply fault at the SIOUXCY4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the SIOUXCY4 (652565) to DENISON4 (652567) 230 kV line circuit 1, near SIOUXCY4. a. Apply fault at the SIOUXCY4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on the SIOUXCY4 (652565) to SIOUXCY2 (652552) 230 kV line circuit 1, near SIOUXCY4. a. Apply fault at the SIOUXCY4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the SC KV1A 230 kV (652565) /161 kV (652566) /13.8 kV (652308) transformer circuit 1, near SIOUXCY4 230kV. a. Apply fault at the SIOUXCY4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9029-3PH	P1	3 phase fault on the COLMB.W4 (640131) to GR ISLD4 (640200) 230 kV line circuit 1, near COLMB.W4. a. Apply fault at the COLMB.W4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the COLMB.WST T1 230 kV (640131) /34.5 kV (640132) /13.8 kV (643039) transformer circuit 1, near COLMB.W4 230kV. a. Apply fault at the COLMB.W4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9031-3PH	P1	3 phase fault on the COL.EAST T3 230 kV (640126) /115 kV (640127) /13.8 kV (643036) transformer circuit 1, near E.COL.4 230kV. a. Apply fault at the E.COL.4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9032-3PH	P1	3 phase fault on the SHELLCREEKT1 230 kV (640343) /345 kV (640342) /13.8 kV (643136) transformer circuit 1, near SHELCRK4 230kV. a. Apply fault at the SHELCRK4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9033-3PH	P1	3 phase fault on the SHELCRK3 (640342) to HOSKINS3 (640226) 345 kV line circuit 1, near SHELCRK3. a. Apply fault at the SHELCRK3 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	P1	3 phase fault on the SHELCRK3 (640342) to COLMB.E3 (640125) 345 kV line circuit 1, near SHELCRK3. a. Apply fault at the SHELCRK3 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1	3 phase fault on the FR E 230 kV (652509) /115 kV (652510) transformer circuit 1, near FTRANDL4 230kV. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9003-PO1	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line circuit 1;** 3 phase fault on the COLUMBUS4 (640133) to COLMB.W4 (640131) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-PO1	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line circuit 1;** 3 phase fault on the KELLY T1 230 kV (640133) /115 kV (640134) /13.2 kV (640135) transformer circuit 1, near COLUMBUS4 230kV. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9005-PO1	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line circuit 1;** 3 phase fault on the COLUMBUS4 (640133) to E.COL.4 (640126) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-PO1	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line circuit 1;** 3 phase fault on the COLUMBUS4 (640133) to SHELCRK4 (640343) 230 kV line circuit 1, near COLUMBUS4. a. Apply fault at the COLUMBUS4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9007-PO2	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to COLUMBUS4 (640133) 230 kV line circuit 1;** 3 phase fault on the FTRANDL4 (652509) to LAKPLAT-ER4 (655475) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-PO2	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to COLUMBUS4 (640133) 230 kV line circuit 1;** 3 phase fault on the FTRANDL4 (652509) to FTTHOMP4 (652507) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-PO2	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to COLUMBUS4 (640133) 230 kV line circuit 1;** 3 phase fault on the FTRANDL4 (652509) to UTICAJC4 (652526) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-PO2	P6	**PRIOR OUTAGE of the MEADOWGROVE4 (640540) to COLUMBUS4 (640133) 230 kV line circuit 1;** 3 phase fault on the FTRANDL4 (652509) to SIOUXCY4 (652565) 230 kV line circuit 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to LAKPLAT-ER4 (655475) 230 kV line circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2.
FLT1002-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to FTTHOMP4 (652507) 230 kV line circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2.
FLT1003-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to UTICAJC4 (652526) 230 kV line circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2.
FLT1004-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to SIOUXCY4 (652565) 230 kV line circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2.
FLT1005-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to MEADOWGROVE4 (640540) 230 kV line circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2.
FLT1006-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR B 230kV (652509) / 13.8kV (652547) transformer circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2. **Trip generator FTRDL34G (652547)**
FLT1007-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR C 230kV (652509) / 13.8kV (652548) transformer circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2. **Trip generator FTRDL56G (652548)**
FLT1008-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR D 230kV (652509) / 13.8kV (652549) transformer circuit 1. d. Trip the FR F 230kV (652509) / 115kV (652510) transformer circuit 2. **Trip generator FTRDL78G (652549)**
FLT1009-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to LAKPLAT-ER4 (655475) 230 kV line circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1010-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to FTTHOMP4 (652507) 230 kV line circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1.
FLT1011-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to UTICAJC4 (652526) 230 kV line circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1.
FLT1012-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to SIOUXCY4 (652565) 230 kV line circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1.
FLT1013-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FTRANDL4 (652509) to MEADOWGROVE4 (640540) 230 kV line circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1.
FLT1014-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR B 230kV (652509) / 13.8kV (652547) transformer circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1. **Trip generator FTRDL34G (652547)**
FLT1015-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR C 230kV (652509) / 13.8kV (652548) transformer circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1. **Trip generator FTRDL56G (652548)**
FLT1016-SB	P4	**Stuck Breaker on at FTRANDL4 (652509) at 230kV bus** a. Apply single-phase fault at FTRANDL4 (652509) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the FR D 230kV (652509) / 13.8kV (652549) transformer circuit 1. d. Trip the FR E 230kV (652509) / 115kV (652510) transformer circuit 1. **Trip generator FTRDL78G (652549)**
FLT1017-SB	P4	**Stuck Breaker on at COLMBUS4 (640133) at 230kV bus** a. Apply single-phase fault at COLMBUS4 (640133) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus COLMBUS4 (640133).

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the four modified cases. The associated stability plots are provided in Appendix D.

Table 6-2: GEN-2008-086N02 & GEN-2014-032 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

***EFD oscillations found for Jeffrey Unit (640013) & John Units 1 & 2 (640014 & 640015) in 21LL case with and without the modification included**

During several faults studied in the 21LL case the Jeffrey Unit (640013) and John Units 1 & 2 (640014 & 640015) showed EFD oscillations. This was observed in both the DISIS and modification cases, so it was not attributed to the GEN-2008-086N02 and GEN-2014-032 project. Figure 6-1 shows the Jeffrey and John EFD oscillation during FLT9034-3PH in the 21LL Modification case. This problem was also present in the existing DISIS-2017-001 21LL case as shown in Figure 6-2.

Figure 6-1: FLT9034-3PH Jeffrey &John Units EFD Oscillations (21LL Modification Case)

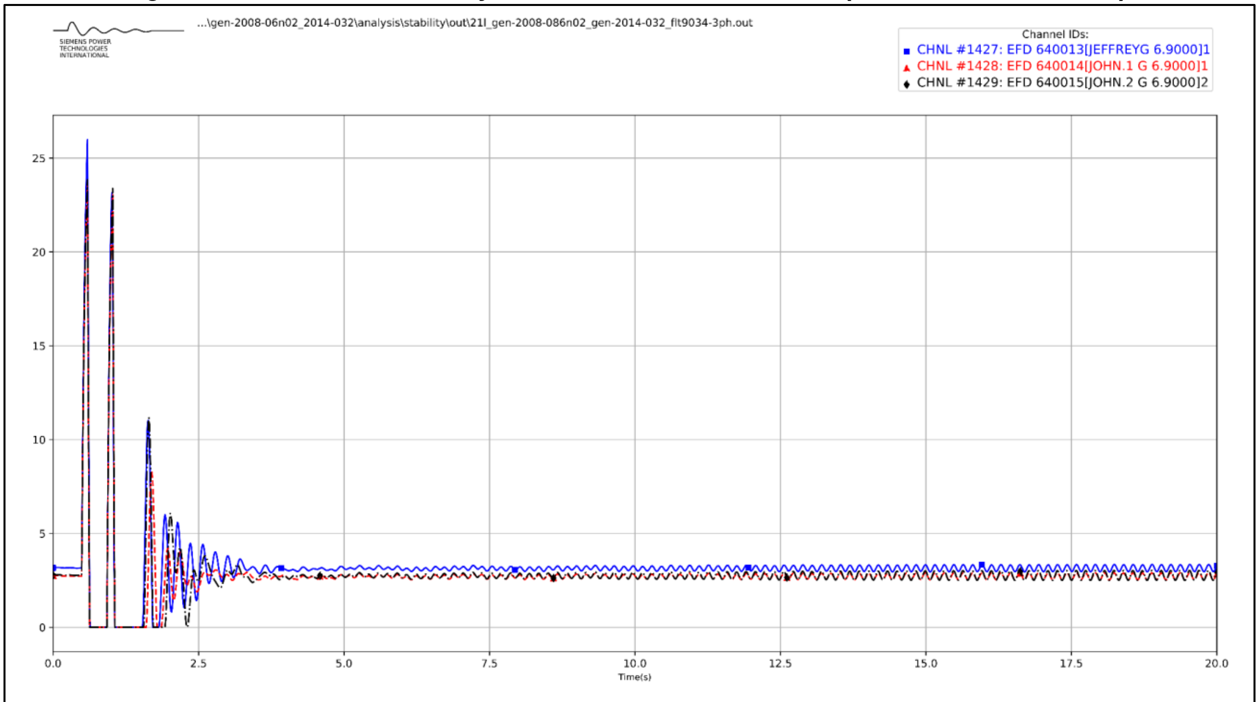
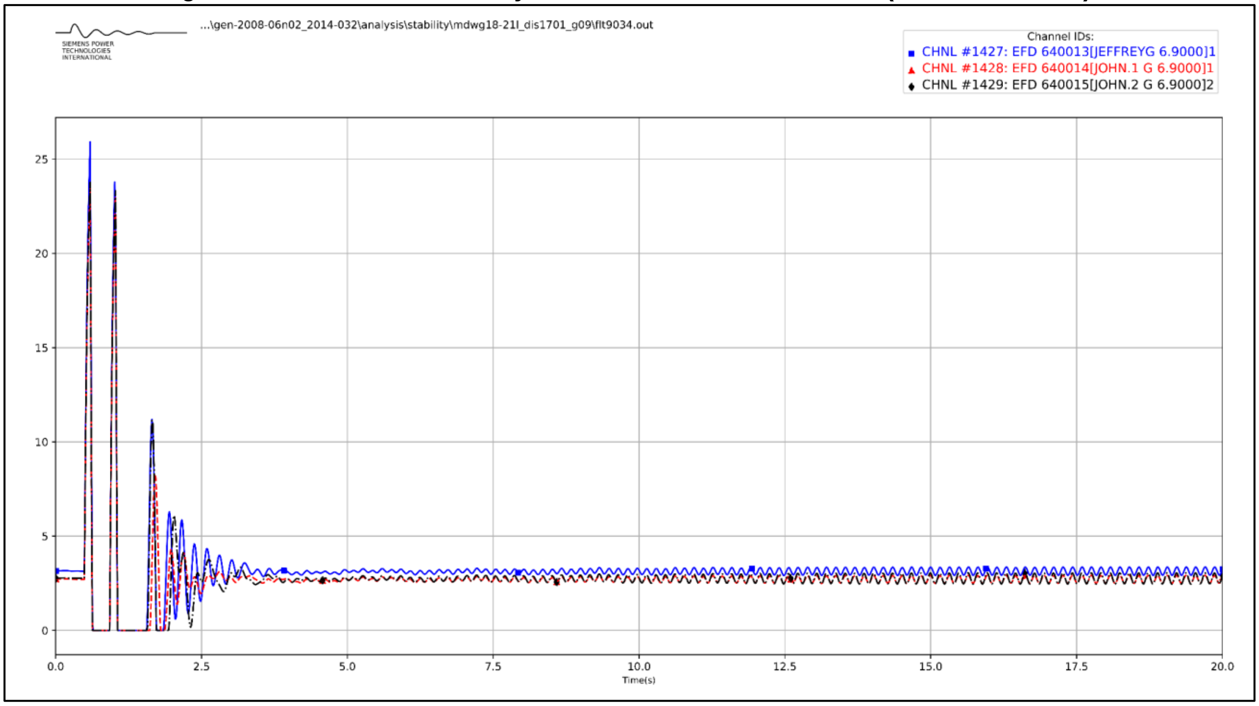


Figure 6-2: FLT9034-3PH Jeffrey & John Units EFD Oscillations (21LL DISIS Case)



There were no damping or voltage recovery violations attributed to the GEN-2008-086N02 and GEN-2014-032 projects observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount which is stated in its GIA. This is allowable as long as they install the proper control and protection devices, and the requested modification is not determined to be a Material Modification.

7.1 Results

The modified generating capacity of GEN-2008-086N02 and GEN-2014-032 (218.3 MW) exceeds the GIA Interconnection Service amount, (211.22 MW), as listed in Appendix A of the GIA.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

8.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2008-086N02 and GEN-2014-032 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2008-086N02 and GEN-2014-032 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 118 x GE 1.85 MW consistent for a total combined capacity of 218.3 MW. The combined generating capacity of GEN-2008-086N02 and GEN-2014-032 (218.3 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 211.22 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.77% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, project capacity increase, and the use of a PPC required short circuit and dynamic stability analyses.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2008-086N02 and GEN-2014-032 projects needed 22.2 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 7.2 MVAr found for the existing GEN-2008-086N02 and GEN-2014-032 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project’s transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2008-086N02 and GEN-2014-032 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2008-086N02 and GEN-2014-032 POI was not greater than 0.96 kA[4] for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2008-086N02 and GEN-2014-032 generators online were below 27 kA for the 2021SP and 2028SP models.

[4] For buses not on the generation interconnection line

The dynamic stability analysis was performed using the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that EFD oscillations were found for several faults studied in the 21LL case from the Jeffrey Unit (640013) and John Units 1 & 2 (640014 & 640015). This issue was observed in the DISIS and modification cases so it was not attributed to the GEN-2008-086N02 and GEN-2014-032 modification.

There were no damping or voltage recovery violations attributed to the GEN-2008-086N02 and GEN-2014-032 projects observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool’s OASIS by the customer.