Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2015-082
Modification Request Impact Study

Revision R1

Date of Submittal
September 28, 2020

anedenconsulting.com

TABLE OF CONTENTS

Revision History R-1
Executive Summary ES-1
1.0 Scope of Study 1
1.1 Power Flow 1
1.2 Stability Analysis, Short Circuit Analysis 1
1.3 Charging Current Compensation Analysis 1
1.4 Study Limitations 1
2.0 Project and Modification Request 2
3.0 Existing vs Modification Comparison 4
3.1 POI Injection Comparison 4
3.2 Turbine Parameters Comparison 4
3.3 Equivalent Impedance Comparison Calculation 5
4.0 Charging Current Compensation Analysis 6
4.1 Methodology and Criteria 6
4.2 Results 6
5.0 Short Circuit Analysis 8
5.1 Methodology 8
5.2 Results 8
6.0 Dynamic Stability Analysis 9
6.1 Methodology and Criteria 9
6.2 Fault Definitions 10
6.3 Results 16
7.0 Material Modification Determination 23
7.1 Results 23
8.0 Conclusions 24

LIST OF TABLES

Table ES-1: GEN-2015-082 Existing Configuration ES-1
Table ES-2: GEN-2015-082 Modification Request ES-1
Table 2-1: GEN-2015-082 Existing Configuration 2
Table 2-2: GEN-2015-082 Modification Request 3
Table 3-1: GEN-2015-082 POI Injection Comparison 4
Table 3-2: Turbine Parameter Differences 5
Table 3-3: GEN-2015-082 Impedance Comparisons 5
Table 3-4: GEN-2015-082 Combined Impedance Comparison 5
Table 4-1: Shunt Reactor Size for Low Wind Study 6
Table 5-1: POI Short Circuit Results 8
Table 5-2: 2018SP Short Circuit Results 8
Table 5-3: 2026SP Short Circuit Results 8
Table 6-1: Fault Definitions 10
Table 6-2: GEN-2015-082 Dynamic Stability Results 16
Table 6-3: PO1 Project Curtailment Levels 20
Table 6-4: PO3 Project Curtailment Levels 20

LIST OF FIGURES

Figure 2-1: GEN-2015-082 Single Line Diagram (Existing Configuration) 2
Figure 2-2: GEN-2015-082 Single Line Diagram (New Configuration) 3
Figure 4-1: GEN-2015-082 Single Line Diagram (MRIS Shunt Reactor) 7
Figure 6-1: FLT08-3PH GEN-2006-044 (579380) Response (18SP MRIS Case) 18
Figure 6-2: FLT08-3PH GEN-2006-044 (579380) Response (18SP Base Case) 18
Figure 6-3: FLT08-3PH GEN-2006-044 (579380) Response After Relays Disabled (18SP MRIS Case) 19
Figure 6-4: FLT39-PO1 GEN-2015-082 Response (17WP MRIS Case) 21
Figure 6-5: FLT39-PO1 GEN-2015-082 Response After Generation Curtailed to 950 MW (17WP MRIS Case) 21
Figure 6-6: FLT04-PO3 GEN-2015-082 Response (17WP MRIS Case) 22
Figure 6-7: FLT04-PO3 GEN-2015-082 Response After Generation Curtailed to 1000 MW (17WP MRIS Case) 22

APPENDICES

APPENDIX A: GEN-2015-082 Generator Dynamic Model
APPENDIX B: Detailed Turbine Parameters Comparison
APPENDIX C: Short Circuit Results
APPENDIX D: SPP Disturbance Performance Requirements
APPENDIX E: Dynamic Stability Simulation Plots

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
09/28/2020	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-2015-082, an active generation interconnection request with a point of interconnection (POI) at the Badger 345 kV Substation.

The GEN-2015-082 project is proposed to interconnect in the Oklahoma Gas and Electric Company (OKGE) control area with a capacity of 200 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2015-082 from the previously studied 100 x GE 2.0MW to a turbine configuration of 48 x GE 1.715 MW + 11 x GE 1.79 MW + 8 x GE 2.3 MW + 21 x GE 2.35 MW + 12 x GE 2.52 MW wind turbines for total capacity of 200 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line. The modification request changes are shown in Table ES-2 below.

Table ES-1: GEN-2015-082 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-082	200	100 x GE 2.0MW = 200 MW	Badger 345 kV (515677)

Table ES-2: GEN-2015-082 Modification Request

Facility	Existing	Modification				
Point of Interconnection	Badger 345 kV (515677)	Badger 345 kV (515677)				
Configuration/Capacity	100 x GE 2.0MW = 200 MW	48 x GE 1.715 MW + 11 x GE 1.79 MW + 8 x GE 2.3 MW + 21 x GE 2.35 MW + 12 x GE 2.52 MW = 200 MW				
Generation Interconnection Line	Length = 25 miles R = 0.001225 pu X = 0.012480 pu B = 0.210000 pu	Length = 8.52 miles R = 0.000433 pu X = 0.003986 pu B = 0.077790 pu				
Main Substation Transformer	X = 8.5%, R = 0.21%, Winding 138 MVA, Rate A 184 MVA, Rate B 230 MVA	X12 = 8.5%, R12 = 0.131%, X23 = 11.98%, R23 = 0.631%, X13 = 3.97%, R13 = 0.496% Winding 135 MVA, Rating 225 MVA				
GSU Transformer	Gen 1 Equivalent Qty: 100: X = 5.8%, R = 0.767%, Rating 225 MVA	Gen 1 Equivalent Qty: 48: X = 5.7%, R = 0.76%, Rating 86.4 MVA	Gen 2 Equivalent Qty: 11: X = 5.71%, R = 0.64%, Rating 19.8 MVA	Gen 3 Equivalent Qty: 8: X = 5.7%, R = 0.76%, Rating 18.4 MVA	Gen 4 Equivalent Qty: 21: X = 5.7%, R = 0.76%, Rating 48.3 MVA	Gen 5 Equivalent Qty: 12: X = 5.7%, R = 0.76%, Rating 33.6 MVA
Equivalent Collector Line	R = 0.002858 pu X = 0.002575 pu B = 0.029450 pu	R = 0.006957 pu X = 0.009357 pu B = 0.103401 pu				

SPP determined that power flow should not be performed based on the POI injection decrease of 0.62%. However, SPP determined that a turbine parameter comparison and an impedance comparison should be performed to evaluate whether dynamic stability analysis and short-circuit analysis are appropriate.

The turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models changed significantly. The modification request resulted in a change in the equivalent impedances from the point of interconnection to the generator step up transformers of approximately 1.72%. Due to the change in modeling parameters, a dynamic stability analysis was deemed necessary and the scope of this modification request study was expanded from a charging current compensation analysis to include both short-circuit analysis and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2016-002 Group 2 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP), and
3. 2026 Summer Peak (2026SP).

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2015-082 project needed 18.16 MVAr of reactor shunts on the 34.5 kV bus of the project substation, a decrease from the 24 MVAr found in the DISIS-2016-001-1 Report[1]. 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 customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2015-082 contribution to three-phase fault currents in the immediate systems at or near GEN-2015-082 was not greater than 0.76 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2015-082 generators online were below 34 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 51 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that the loss of the Hitchland to G14-037-TAP 345 kV line caused the GEN-2006-044 Generating Facilities at buses 579380 and 523107,

[1] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

comprised of DeWind D9.2 Wind Turbine Generators represented with the DWD8G1 model, to trip in response to a fault event on this circuit. This problem also occurs for both generators in the existing base case. As the tripping response is present in both the DISIS and modified cases, it is not caused by the GEN-2015-082 modification. The RELUNS and G59REL relays were disabled which mitigated this existing issue.

The loss of the Badger to Beaver double circuit 345 kV lines caused a post-fault steady state low voltage violation at the Walkenmeyer 345 kV bus in the existing DISIS cases (FLT1008-SB and FLT40-PO2) which persisted in the MRIS cases as well. This existing steady state issue can be mitigated if the projects interconnected at Beaver and Hitchland 345 kV substations provide their Generation Interconnection Agreement (GIA) required point-of-interconnection 0.95 power factor.

After the prior outage of the Badger to G16-003-TAP 345 kV Circuit 1 line, nearby generation was required to be curtailed to 950 MW in the 17WP, 1100 MW in the 18SP case, and 1200 MW in the 26SP case to have GEN-2015-082 remain stable following the fault Circuit 2 of the double circuit.

After the prior outage of the G16-003-TAP to Woodward 345 kV Circuit 2 line, nearby generation was required to be curtailed to 1000MW in the 17WP, 1150MW in the 18SP, and 1250 MW in the 26SP case to have GEN-2015-082 remain stable following the fault on Circuit 1 of the double circuit.

There were no other damping or voltage recovery violations 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 impact on the cost or timing of any Interconnection Request with a later Queue priority date.

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-2015-082. 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 33.7 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 existing configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of 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 collection parameters and collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short-circuit analysis would be required if either of 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 plant'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-2015-082 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Badger 345 kV Substation. At the time of the posting of this report, GEN-2015-082 is an active IR with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2015-082 is a wind farm, has a maximum summer and winter queue capacity of 200 MW, and has Energy Resource Interconnection Service (ERIS).

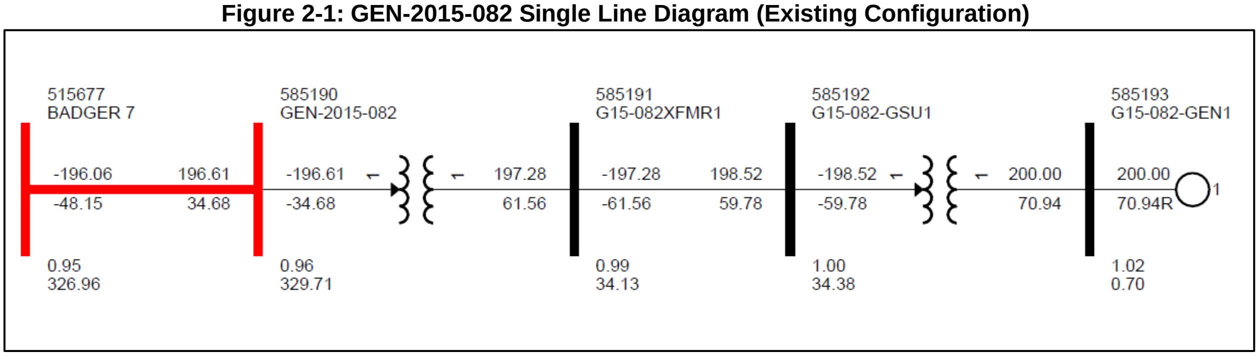
GEN-2015-082 was originally studied as part of Group 2 in the DISIS-2016-001 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-082 configuration.

The GEN-2015-082 project is proposed to interconnect in the Oklahoma Gas and Electric Company (OKGE) control area with a combined nameplate capacity of 200 MW as shown in Table 2-1 below.

Table 2-1: GEN-2015-082 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-082	200	100 x GE 2.0MW = 200 MW	Badger 345 kV (515677)

Figure 2-1: GEN-2015-082 Single Line Diagram (Existing Configuration)



The GEN-2015-082 Modification Request included a turbine configuration change to a total of 48 x GE 1.715 MW + 11 x GE 1.79 MW + 8 x GE 2.3 MW + 21 x GE 2.35 MW + 12 x GE 2.52 MW wind turbines for total capacity of 200 MW. In addition, the modification request included changes to the collection system, generation step-up transformers, main substation transformer, and the generation interconnection line. The major modification request changes are shown in Figure 2-2 and Table 2-2 below.

Figure 2-2: GEN-2015-082 Single Line Diagram (New Configuration)

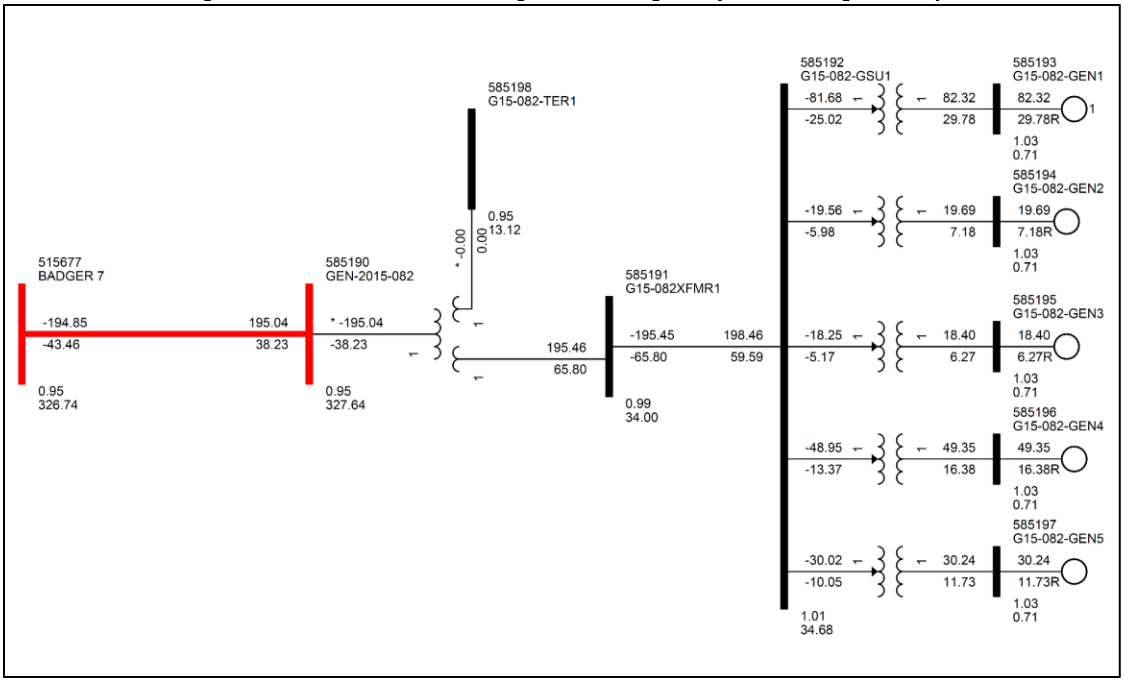


Table 2-2: GEN-2015-082 Modification Request

Facility	Existing	Modification				
Point of Interconnection	Badger 345 kV (515677)	Badger 345 kV (515677)				
Configuration/Capacity	100 x GE 2.0MW = 200 MW	48 x GE 1.715 MW + 11 x GE 1.79 MW + 8 x GE 2.3 MW + 21 x GE 2.35 MW + 12 x GE 2.52 MW = 200 MW				
Generation Interconnection Line	Length = 25 miles R = 0.001225 pu X = 0.012480 pu B = 0.210000 pu	Length = 8.52 miles R = 0.000433 pu X = 0.003986 pu B = 0.077790 pu				
Main Substation Transformer	X = 8.5%, R = 0.21%, Winding 138 MVA, Rate A 184 MVA, Rate B 230 MVA	X12 = 8.5%, R12 = 0.131%, X23 = 11.98%, R23 = 0.631%, X13 = 3.97%, R13 = 0.496% Winding 135 MVA, Rating 225 MVA				
GSU Transformer	Gen 1 Equivalent Qty: 100: X = 5.8%, R = 0.767%, Rating 225 MVA	Gen 1 Equivalent Qty: 48: X = 5.7%, R = 0.76%, Rating 86.4 MVA	Gen 2 Equivalent Qty: 11: X = 5.71%, R = 0.64%, Rating 19.8 MVA	Gen 3 Equivalent Qty: 8: X = 5.7%, R = 0.76%, Rating 18.4 MVA	Gen 4 Equivalent Qty: 21: X = 5.7%, R = 0.76%, Rating 48.3 MVA	Gen 5 Equivalent Qty: 12: X = 5.7%, R = 0.76%, Rating 33.6 MVA
Equivalent Collector Line	R = 0.002858 pu X = 0.002575 pu B = 0.029450 pu	R = 0.006957 pu X = 0.009357 pu B = 0.103401 pu				

3.0 Existing vs Modification Comparison

To determine whether stability analysis is required, 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 using the modification request data and the three DISIS-2016-002 Group 2 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP), and
3. 2026 Summer Peak (2026SP).

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.7 software.

3.1 POI Injection Comparison

The real power output at the POI was determined using PSS/E for both the existing configuration and the requested modification. The percentage change in the POI injection before and after the modification request was then compared. 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 (decrease of 0.62%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2015-082 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2015-082	196.06	194.85	-0.62%

3.2 Turbine Parameters Comparison

The turbine dynamic stability models from the existing configuration and the requested modification were compared to determine if the change in modeling parameters was significant.

For the turbine collection, the turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models did change significantly. The parameter differences are shown in Table 3-2. SPP determined that dynamic stability analysis and short-circuit analysis were required due to the change in turbines as the stability responses of the existing GE turbine and the requested modification’s GE turbine may differ. The generator dynamic model for the modification can be found in Appendix A. The full parameter comparison can be found in Appendix B.

Table 3-2: Turbine Parameter Differences

Model Parameter (GEWTE2)	Existing	Modification			
	2.0MW	1.715MW	1.79MW	2.3MW	2.35/2.52MW
Tfv - V-regulator filter	0.15	0.5	0.50	0.50	0.50
KQi - MVAR/Volt gain	0.10	0.41	0.41	0.41	0.41
Kqd - Reactive droop gain	0.0000	0.0420	0.0100	0.0094	0.0420
Qmax limit in WindFREE Mode	0.1200	0.1050	0.1006	0.1565	0.0714
Qmin limit in WindFREE Mode	-0.1200	-0.1050	-0.1006	-0.1565	-0.0714

3.3 Equivalent Impedance Comparison Calculation

The impedances from all the components of the transmission lines, substation and step-up transformers, and equivalent collector line impedances were added in series for GEN-2015-082 before and after the modification request. The percentage increase in the impedances before and after the modification request were then compared. If the percentage increase was greater than 10%, additional dynamic stability analysis and short-circuit analysis would be performed to determine the impact of the requested modification. Table 3-3 shows the impedance differences before and after the modification request. Table 3-4 shows the increases in impedances from the original impedances to the modification request impedances.

Table 3-3: GEN-2015-082 Impedance Comparisons

System Component	Existing Model Impedances (p.u.)			Modification Request Impedances (p.u.)		
	R	*X*		*R*	*X*	
Gen Tie Line from POI to GEN-2015-082	0.00123	0.01248		0.00043	0.00399	
GEN-2015-082 collector system equivalent	0.00286	0.00258		0.00696	0.00936	
	R	*X*	*MVA Base*	*R*	*X*	*MVA Base*
GEN-2015-082 Main Transformer @ 100 MVA	0.00154	0.06159	100	0.00097	0.06296	100
GEN-2015-082 Unit GSU @ 100 MVA Base	0.0034	0.0258	100	0.00366	0.02760	100
	R	*X*	*Z*	*R*	*X*	*Z*
Total Impedance from POI to Collector System	0.009035	0.102427	0.102825	0.012017	0.103902	0.104595

Table 3-4: GEN-2015-082 Combined Impedance Comparison

Interconnection Request	Existing Impedance Z (p.u.)	MRIS Impedance Z (p.u.)	Impedance Change Z (p.u.)
GEN-2015-082 Impedance Increase	10.28%	10.46%	1.72%

SPP determined that although the change in impedance was below 10%, the change in modeling parameters has the potential to alter the project impact and would require dynamic stability analysis and short-circuit analysis to be performed to determine the impact of the requested modification.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2015-082 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 the GEN-2015-082 project, the generators and capacitors (if any) were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the 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-2015-082 project needed an approximately 18.16 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero. This is a decrease from the 24 MVAr found in the DISIS-2016-001-1 Report[2]. The final shunt reactor requirement for GEN-2015-082 is shown in Table 4-1.

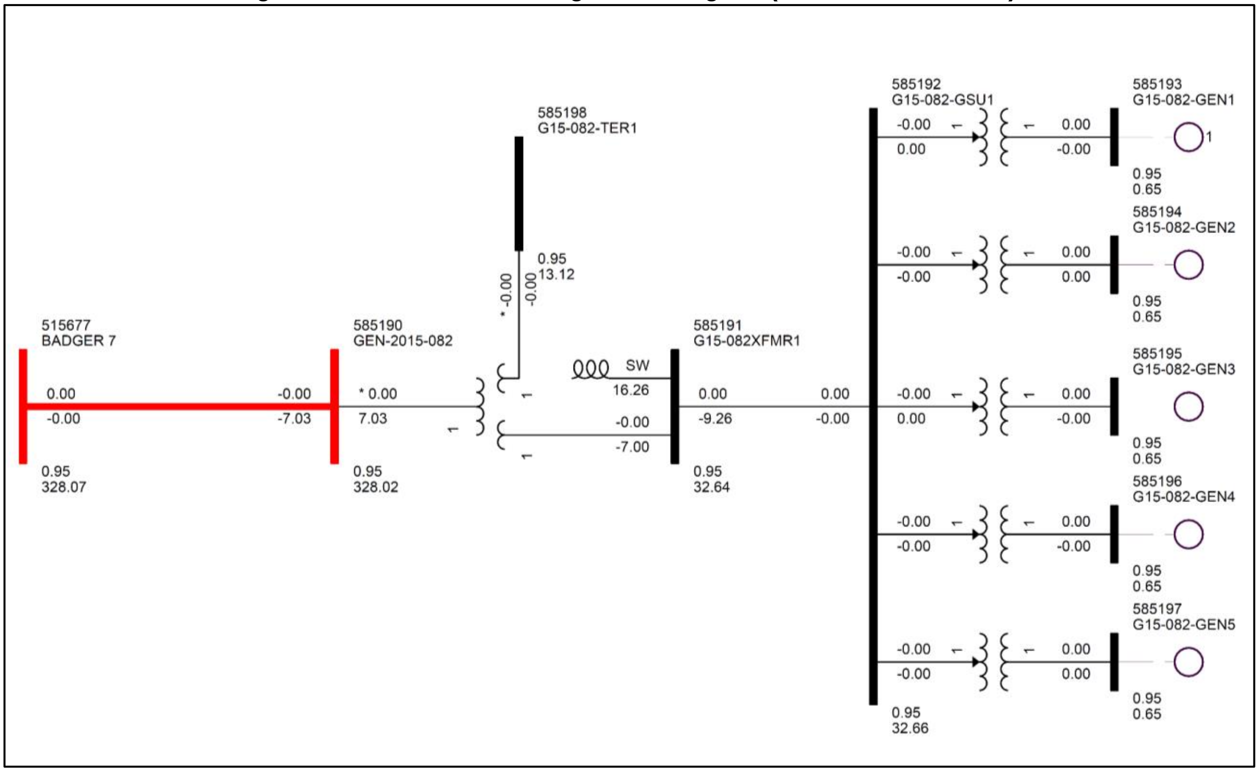
The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2015-082	515677	Badger 345 kV	18.16	18.16	18.16

[2] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

Figure 4-1: GEN-2015-082 Single Line Diagram (MRIS Shunt Reactor)



5.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for GEN-2015-082. The detail results of the short-circuit analysis are provided in Appendix C.

5.1 Methodology

The short-circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2015-082 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2015-082 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 13.27 kA.

The maximum fault current calculated within 5 buses with GEN-2015-082 was less than 34 kA for the 2018SP and 2026SP models. The maximum increase in fault current was about 6.1% and 0.76 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	12.40	13.16	0.76	6.1%
2026SP	12.51	13.27	0.76	6.1%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	11.0	-0.02	-0.2%
115	18.9	0.05	0.3%
138	22.4	0.00	-0.1%
230	20.5	0.11	0.8%
345	33.0	0.76	6.1%
Max	**33.0**	**0.76**	**6.1%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	11.0	-0.03	-0.2%
115	18.8	0.06	0.3%
138	22.7	0.00	-0.1%
230	20.5	0.11	0.8%
345	33.0	0.76	6.1%
Max	**33.0**	**0.76**	**6.1%**

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 GEN-2015-082 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix D. 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 E.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 48 x GE 1.715 MW (GEWTG2) + 11 x GE 1.79 MW (GEWTG2) + 8 x GE 2.3 MW (GEWTG2) + 21 x GE 2.35 MW (GEWTG2) + 12 x GE 2.52 MW (GEWTG2) turbine configuration for the GEN-2015-082 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 2. The modifications requested to project GEN-2015-082 were used to create modified stability models for this impact study. In addition, the following system adjustments were made to address existing base case issues:

1. Removed the withdrawn project GEN-2014-037
2. GEN-2008-047: adjusted the voltage schedule to 1.048 regulating the generator terminal
3. GEN-2011-014: locked the Qgen to 50MVAR for each generator
4. GEN-2011-022: removed the 2nd MPT and adjusted the voltage schedule to 1.048 regulating the generator terminal
5. GEN-2013-030: adjusted the voltage schedule to 1.048 regulating the generator terminal
6. Switched off the Badger-Beaver County in-line reactors
7. Switched off the Badger-Woodward in-line reactors
8. Switched off the Thistle-Woodward in-line reactors
9. Switched off the Lamar 345 kV shunt reactor
10. Adjusted all G06-044 and Novus wind generator voltage schedules to 1.03 regulating the generator terminal
11. Switched on the TX county capbank
12. Switched off the Clark County shunt reactor
13. Adjusted the Goodwell MPT tap ratio and switched on the 34.5 kV capbanks
14. Adjusted the Buff Dunes wind farm MPT tap ratio and switched on the 34.5 kV capbanks
15. Adjusted the Nobel Wind farm MPT tap ratio and switched on the 34.5 kV capbanks

The modified dynamics model data for the DISIS-2016-001 Group 2 request, GEN-2015-082, 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-2015-082 and other equally and prior queued projects in Group 2. In addition, voltages of five (5) buses away from the POI of GEN-2015-

082 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 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-2015-082 and selected additional fault events for GEN-2015-082 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 faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 1, near BADGER. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT02-3PH	P1	3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 1, near BADGER. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on the G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 1, near G16-003-Tap. a. Apply fault at the G16-003-Tap 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT05-3PH	P1	3 phase fault on the Woodward (515375) to Border (515458) 345 kV line circuit 1, near Woodward. a. Apply fault at the Woodward 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT06-3PH	P1	3 phase fault on the Woodward (515375) to Tatonga (515407) 345 kV line circuit 1, near Woodward. a. Apply fault at the Woodward 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT08-3PH	P1	3 phase fault on the Hitchland (523097) to G14-037-TAP (560010) 345 kV line circuit 1, near Hitchland. a. Apply fault at the Hitchland 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT09-3PH	P1	3 phase fault on the Woodward 345kV (515375) to Woodward 138kV (515376) Woodward 13.8kV (515799) XFMR CKT 2, near Woodward 345kV. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT39-3PH	P1	3 phase fault on the BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 2, near BADGER. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT40-3PH	P1	3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 2, near BADGER. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT46-3PH	P1	3 phase fault on the Woodward (515375) to Thistle (539801) CKT 1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT30-1PH	P4	G11-14-Tap 345kV Stuck Breaker a. Apply single phase fault at the BADGER (515677) 345kV bus. b. Wait 16 cycles, and then drop BADGER (515677) – G16-003-TAP (560071) 345kV circuit 1 and remove fault.
FLT32-1PH	P4	Woodward 345kV Stuck Breaker a. Apply single phase fault at the Woodward (515375) 345kV bus on the Woodward – Tatonga (515407) 345kV circuit 1. b. Wait 16 cycles, and then drop Woodward (515375) 345kV to Thistle (539801) 345kV CKT 1. c. Trip Woodward to Tatonga 345kV CKT 1 and remove the fault.
FLT33-1PH	P4	Hitchland 345kV Stuck Breaker a. Apply single phase fault at the Hitchland (523097) 345kV bus. b. Wait 16 cycles, and then drop Hitchland – G14-037-TAP (560010) 345kV circuit 1 and remove fault.
FLT35-1PH	P4	Beaver 345kV Stuck Breaker a. Apply single phase fault at the Beaver County (515554) 345kV bus. b. Wait 16 cycles, and then drop Beaver County – BADGER (515677) 345kV circuit 1 and remove fault.
FLT36-1PH	P4	Woodward 345kV Stuck Breaker a. Apply single phase fault at the Woodward (515375) 345kV bus. b. Wait 16 cycles, and then drop Woodward (515375) – Border (515458) 345kV circuit 1 and remove fault.
FLT39-PO1	P6	**PRIOR OUTAGE: BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 1** 3 phase fault on the BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 2, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT40-PO2	P6	**PRIOR OUTAGE: BADGER (515677) to Beaver County (515554) 345 kV line circuit 1** 3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 2, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO3	P6	**PRIOR OUTAGE: G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 2** 3 phase fault on the G16-001-Tap (560071) to Woodward (515375) 345 kV line circuit 1, near G16-001- Tap. a. Apply fault at the G16-001-Tap 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT06-PO4	P6	**PRIOR OUTAGE: Woodward (515375) to Tatonga (515407) 345 kV line circuit 2** 3 phase fault on the Woodward (515375) to Tatonga (515407) 345 kV line circuit 1, near Woodward. a. Apply fault at the Woodward 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT07-PO5	P6	**PRIOR OUTAGE: Beaver County (515554) to G14-037-TAP (560010) kV line circuit 2** 3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT08-PO6	P6	**PRIOR OUTAGE: Hitchland (523097) to G14-037-TAP (560010) 345 kV line circuit 2** 3 phase fault on the Hitchland (523097) to G14-037-TAP (560010) 345 kV line circuit 1, near Hitchland. a. Apply fault at the Hitchland 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT46-PO7	P6	**PRIOR OUTAGE: Thistle (539801) to Woodward (515375) 345kV line circuit 2** 3 phase fault on the Thistle (539801) to Woodward (515375) CKT 1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the Beaver County (515554) to GEN-2013-030 (583760) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G13-030-GEN1 (583763)** **Trip generator G13-030-GEN2 (583766)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the Beaver County (515554) to PALDR2W7 (515590) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G08-047-GEN1 (573506)** **Trip generator G08-047-GEN2 (573510)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the Beaver County (515554) to BALKOW (515618) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the G14-037-TAP (560010) to GEN-2014-037 (584210) 345 kV line circuit 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G14-037-GEN1 (584213)** **Trip generator G14-037-GEN2 (584216)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the G14-037-TAP (560010) to Hitchland (523097) 345 kV line circuit 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9006-3PH	P1	3 phase fault on the Woodward (515375) to G07621119-20 (515599) 345 kV line circuit 1, near Woodward. a. Apply fault at the Woodward 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator GW WTG11 (585413)** **Trip generator GW WTG12 (585414)** **Trip generator GW WTG21 (585417)** **Trip generator GW WTG22 (585418)** **Trip generator CB WTG1 (585423)** **Trip generator CB WTG2 (585426)** **Trip generator PC1 WTG1 (585433)** **Trip generator PC1 WTG2 (585436)** **Trip generator PC2 WTG1 (585443)** **Trip generator PC2 WTG2 (585446)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the BADGER (515677) to GEN-2011-014 (515686) 345 kV line circuit 1, near GEN-2011-014. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G11-014-GEN2 (515682)** **Trip generator G11-014-GEN1 (515678)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the G16-003-Tap (560071) to GEN-2016-003 (587020) 345 kV line circuit 1, near G16-003-Tap. a. Apply fault at the G16-003-Tap 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G16-003-GEN1 (587023)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO1	P6	**PRIOR OUTAGE of BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 1** 3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 1, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO1	P6	**PRIOR OUTAGE of BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 1** 3 phase fault on the G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 1, near G16-003-Tap. a. Apply fault at the G16-003-Tap 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT07-PO1	P6	**PRIOR OUTAGE of BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 1** 3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO2	P6	**PRIOR OUTAGE of BADGER (515677) to Beaver County (515554) 345 kV line circuit 1** 3 phase fault on the G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 1, near G16-003-Tap. a. Apply fault at the G16-003-Tap 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT07-PO2	P6	**PRIOR OUTAGE of BADGER (515677) to Beaver County (515554) 345 kV line circuit 1** 3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT39-PO2	P6	**PRIOR OUTAGE of BADGER (515677) to Beaver County (515554) 345 kV line circuit 1** 3 phase fault on the BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 2, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO3	P6	**PRIOR OUTAGE of G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 2** 3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 1, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT07-PO3	P6	**PRIOR OUTAGE of G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 2** 3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, near Beaver County. a. Apply fault at the Beaver County 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT39-PO3	P6	**PRIOR OUTAGE of G16-003-Tap (560071) to Woodward (515375) 345 kV line circuit 2** 3 phase fault on the BADGER (515677) to G16-003-Tap (560071) 345 kV line circuit 2, near Badger. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT40-PO5	P6	**PRIOR OUTAGE: Beaver County (515554) to G14-037-TAP (560010) kV line circuit 2** 3 phase fault on the BADGER (515677) to Beaver County (515554) 345 kV line circuit 2, near BADGER. a. Apply fault at the BADGER 345 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at BADGER (515677)** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to Beaver County (515554) 345 kV line circuit 2. c. Trip the BADGER (515677) to GEN-2011-014 (515686) line circuit 1 and remove the fault. Trip generator G11-014-GEN2 (515682) Trip generator G11-014-GEN1 (515678)
FLT1002-SB	P4	**Stuck Breaker on at Woodward (515375)** a. Apply single-phase fault at Woodward (515375) on the 345kV bus. b. After 16 cycles, trip the Woodward (515375) 345kV bus on the Woodward – Tatonga (515407) 345kV circuit 1 c. Trip the Woodward 345kV (515375) to Woodward 138kV (515376) Woodward 13.8kV (515799) XFMR circuit 2, and remove the fault.
FLT1003-SB	P4	**Stuck Breaker on at Woodward (515375)** a. Apply single-phase fault at Woodward (515375) on the 345kV bus. b. After 16 cycles, trip the Woodward (515375) 345kV bus on the Woodward – Tatonga (515407) 345kV circuit 2. c. Trip the Woodward 345kV (515375) to Woodward 138kV (515376) Woodward 13.8kV (515795) XFMR circuit 1, and remove the fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1004-SB	P4	**Stuck Breaker on at Woodward (515375)** a. Apply single-phase fault at Woodward (515375) on the 345kV bus. b. After 16 cycles, trip the Woodward (515375) to G16-003-Tap (560071)345 kV line circuit 2. c. Trip the Woodward (515375) to G07621119-20 (515599) 345 kV line circuit 1, and remove the fault. **Trip generators connected to Bus 515599**
FLT1005-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to BADGER (515677) 345 kV line circuit 2. c. Trip the Beaver County (515554) to BALKOW (515618) 345 kV line circuit 1, trip the plant and remove the fault. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)**
FLT1006-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to PALDR2W7 (515590) 345 kV line circuit 1. c. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1, and remove the fault. **Trip generator G08-047-GEN1 (573506)** **Trip generator G08-047-GEN2 (573510)**
FLT1007-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 1 c. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 2, and remove the fault
FLT1008-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to BADGER (515677) 345 kV line circuit 2. c. Trip the Beaver County (515554) to BADGER (515677) 345 kV line circuit 1, and remove the fault.
FLT1009-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line circuit 2. c. Trip the Beaver County (515554) to BALKOW (515618) 345 kV line circuit 1, and remove the fault. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)**
FLT1010-SB	P4	**Stuck Breaker on at Beaver County (515554)** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the Beaver County (515554) to PALDR2W7 (515590) 345 kV line circuit 1. c. Trip the Beaver County (515554) to BADGER (515677) 345 kV line circuit 1, and remove the fault. **Trip generator G08-047-GEN1 (573506)** **Trip generator G08-047-GEN2 (573510)**

6.3 Results

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

Table 6-2: GEN-2015-082 Dynamic Stability Results

Fault ID	2017WP			2018SP			2026SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Unit Trip*	Pass	Pass	Unit Trip*
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT40-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT30-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT35-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT36-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Fail**	Stable	Pass	Fail**	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT04-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO1	Simulation Crashed		Unit Trip***	Fail	Fail	Unit Trip***	Fail	Fail	Unit Trip***
FLT40-PO2	Pass	Pass	Stable	Pass	Fail**	Stable	Pass	Fail**	Stable
FLT04-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO3	Simulation Crashed		Unit Trip****	Fail	Fail	Unit Trip****	Fail	Fail	Unit Trip****
FLT07-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT40-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO6	Pass	Pass	Unit Trip*	Pass	Pass	Unit Trip*	Pass	Pass	Unit Trip*
FLT46-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

*Generator 579380 Unit 1 tripped after fault in 18SP and 26SP, generator 523107 Unit 1 tripped after fault in 26SP. Existing base case issue.

**FLT1008-SB is equivalent to FLT40-PO2 (loss of Badger - Beaver County 345kV double circuit line). Low voltage violation at Walkemeyer 345 kV. Discussed further below.

***Generators contributing to the instability to be curtailed TO 950 MW in 17WP, 1100 MW in 18SP, and 1200 MW in 26SP.

****Generators contributing to the instability to be curtailed TO 1000 MW in 17WP, 1150 MW in 18SP, and 1250 MW in 26SP.

The results of the dynamic stability analysis showed that the loss of the Hitchland to G14-037-TAP 345 kV line caused the GEN-2006-044 Generating Facilities at buses 579380 and 523107, comprised of DeWind D9.2 Wind Turbine Generators represented with the DWD8G1 model, to trip in response to a fault event on this circuit.

Figure **6-1** shows that GEN-2006-044 unit 1 at bus 579380 tripped after the fault in the 18SP model. This problem also occurs for the generator in the existing base case model as shown in Figure 6-2. As the tripping response is present in both the DISIS and modified cases, it is not caused by the GEN-2015-082 modification. The RELUNS and G59REL relays were disabled which mitigated this existing issue as shown in Figure **6-3**.

Figure 6-1: FLT08-3PH GEN-2006-044 (579380) Response (18SP MRIS Case)

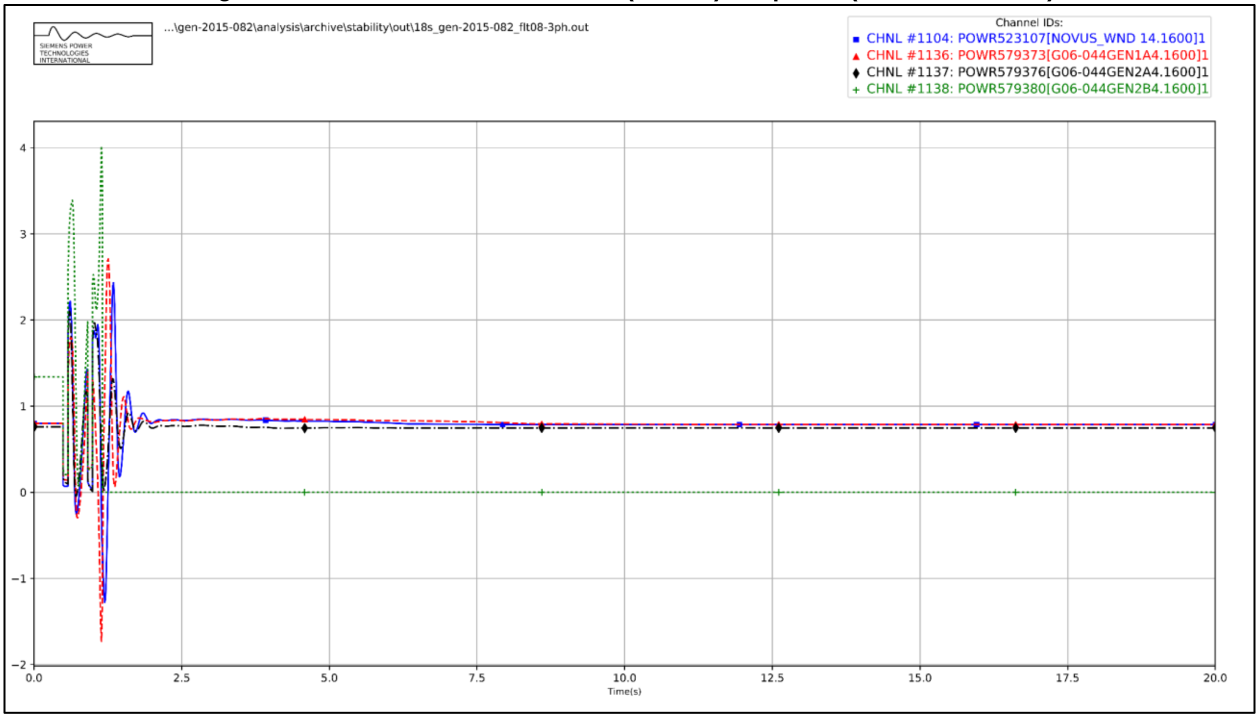


Figure 6-2: FLT08-3PH GEN-2006-044 (579380) Response (18SP Base Case)

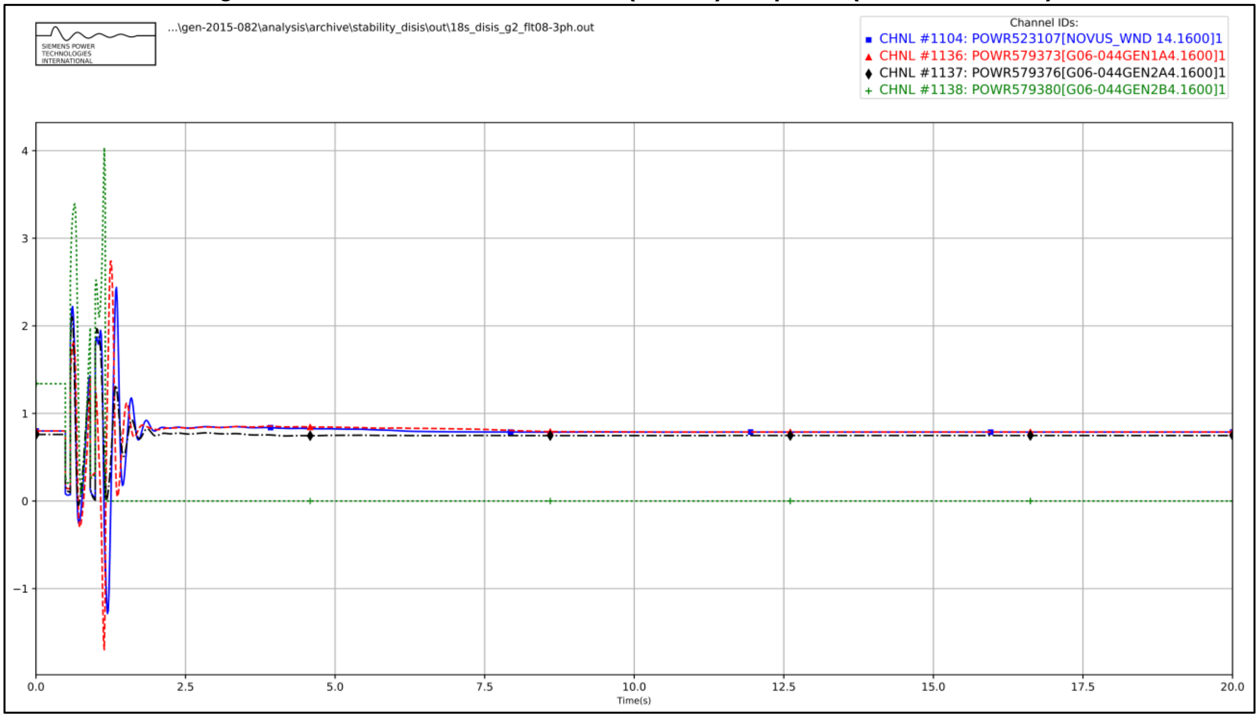
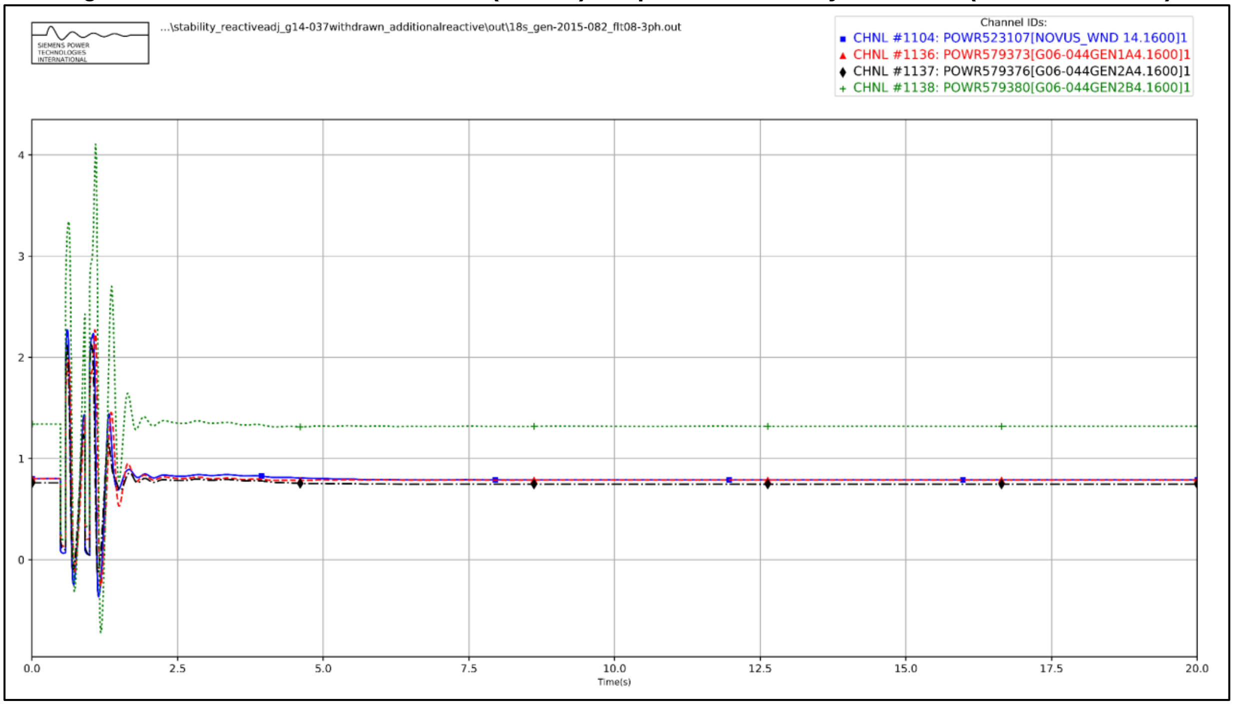


Figure 6-3: FLT08-3PH GEN-2006-044 (579380) Response After Relays Disabled (18SP MRIS Case)



The loss of the Badger to Beaver double circuit 345 kV lines caused a post-fault steady state low voltage violation at the Walkenmeyer 345 kV bus in the existing DISIS cases (FLT1008-SB and FLT40-PO2) which persisted in the MRIS cases as well. This existing steady state issue can be mitigated if the projects interconnected at Beaver and Hitchland 345 kV substations provide their Generation Interconnection Agreement (GIA) required point-of-interconnection 0.95 power factor.

In addition, the loss of either the full 345 kV double circuit between Badger and G16-003-TAP or the full 345 kV double circuit between G16-003-TAP and Woodward (FLT39-PO1 and FLT04-PO3) caused GEN-2015-082 to become unstable and required curtailment after the prior outage of either Badger to G16-003-TAP 345 kV Circuit 1 line or G16-003-TAP to Woodward 345 kV Circuit 2 line in all three cases.

The nearby generation shown in Table 6-3 was required to be curtailed to 950 MW in the 17WP, 1100 MW in the 18SP case, and 1200 MW in the 26SP case after the prior outage of the Badger to G16-003-TAP 345 kV Circuit 1 line to have GEN-2015-082 remain stable following the fault Circuit 2 of the double circuit.

Table 6-3: PO1 Project Curtailment Levels

Project Name	Capacity (MW)	17WP Pgen (MW)	18SP Pgen (MW)	26SP Pgen (MW)
GEN-2008-047	299.2	219.34	253.97	277.06
GEN-2010-001	299.7	219.70	254.39	277.52
GEN-2011-014	198.0	145.15	168.07	183.35
GEN-2013-030	299.0	219.19	253.80	276.87
GEN-2015-082	200.0	146.62	169.77	185.20
Total	1295.9	950.0	1100.0	1200.0

The nearby generation shown in Table 6-4 was required to be curtailed to 1000MW in the 17WP, 1150MW in the 18SP, and 1250 MW in the 26SP case after the prior outage of the G16-003-TAP to Woodward 345 kV Circuit 2 line to have GEN-2015-082 remain stable following the fault on Circuit 1 of the double circuit.

Table 6-4: PO3 Project Curtailment Levels

Project Name	Capacity (MW)	17WP Pgen (MW)	18SP Pgen (MW)	26SP Pgen (MW)
GEN-2008-047	299.2	222.36	255.71	277.95
GEN-2010-001	299.7	222.73	256.14	278.41
GEN-2011-014	198.0	147.15	169.22	183.94
GEN-2013-030	299.0	222.21	255.54	277.76
GEN-2015-082	200.0	148.63	170.93	185.79
GEN-2016-003	248.4 (49.7 Online)	36.92	42.46	46.15
Total	1544.3	1000.0	1150.0	1250.0

Figure 6-4 and Figure 6-5 show the updated GEN-2015-082 response to FLT39-PO1 before and after curtailment respectively. Figure 6-6 and Figure 6-7 show the updated GEN-2015-082 response to FLT04-PO3 before and after curtailment respectively.

Figure 6-4: FLT39-PO1 GEN-2015-082 Response (17WP MRIS Case)

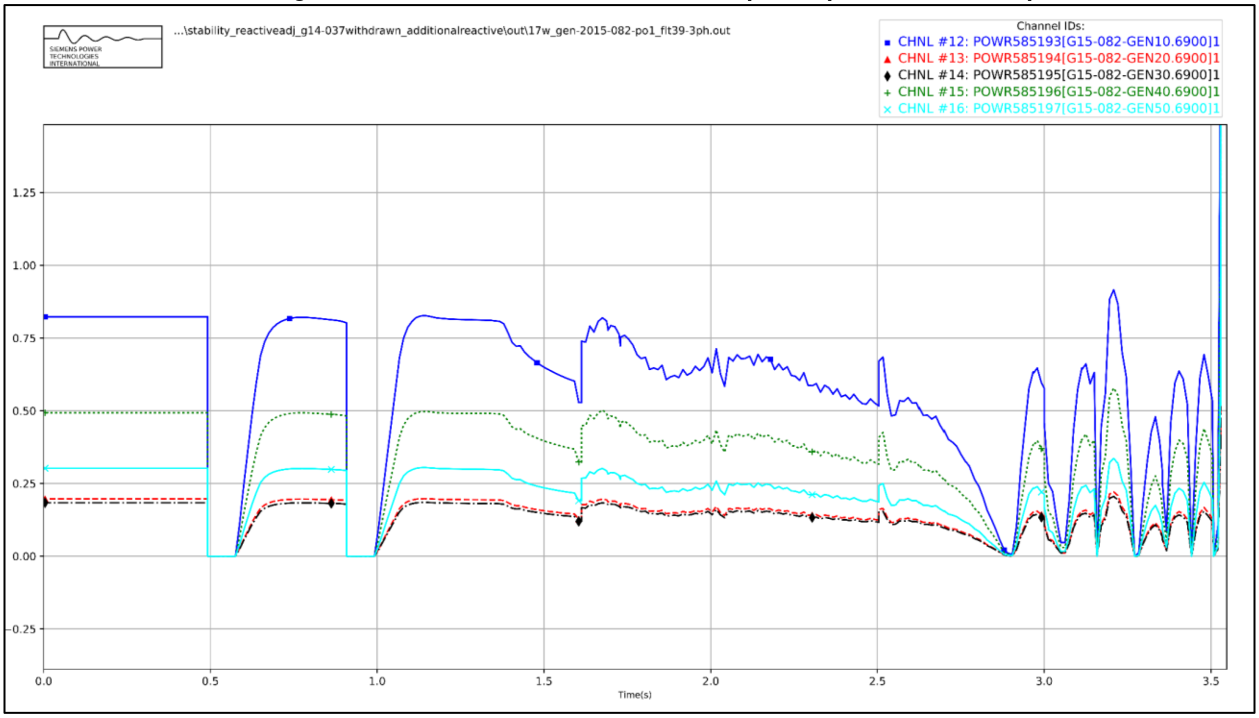


Figure 6-5: FLT39-PO1 GEN-2015-082 Response After Generation Curtailed to 950 MW (17WP MRIS Case)

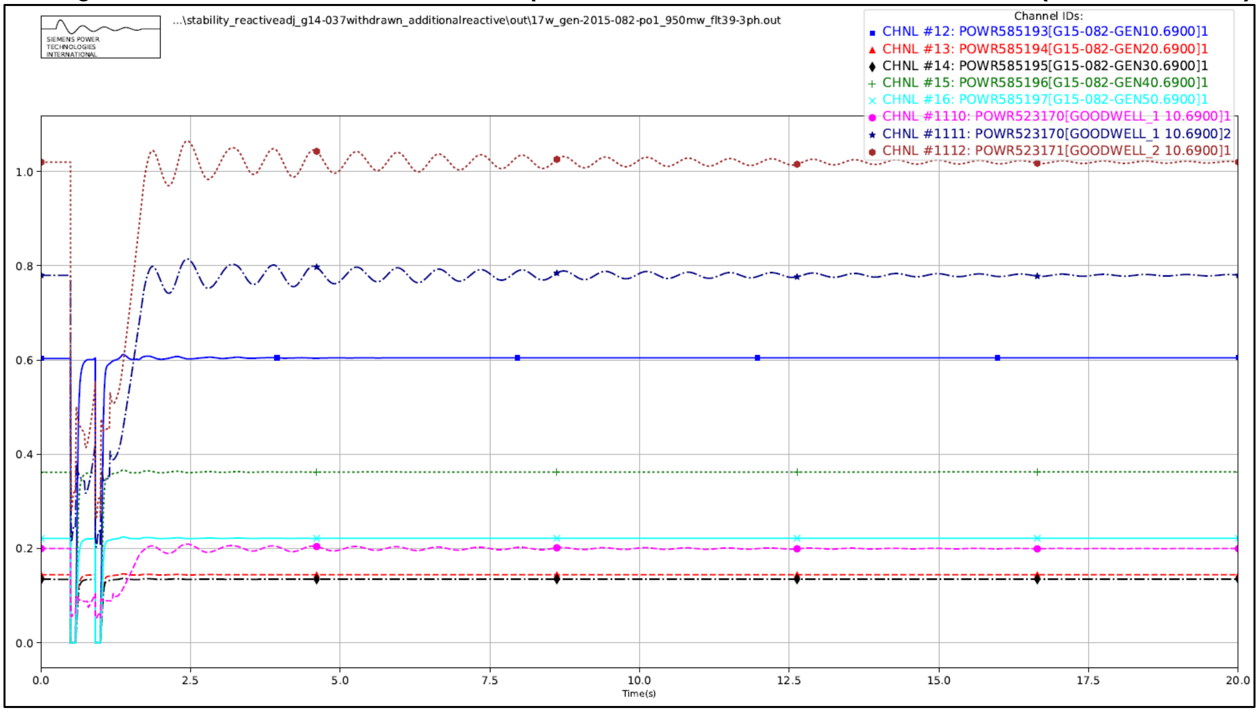


Figure 6-6: FLT04-PO3 GEN-2015-082 Response (17WP MRIS Case)

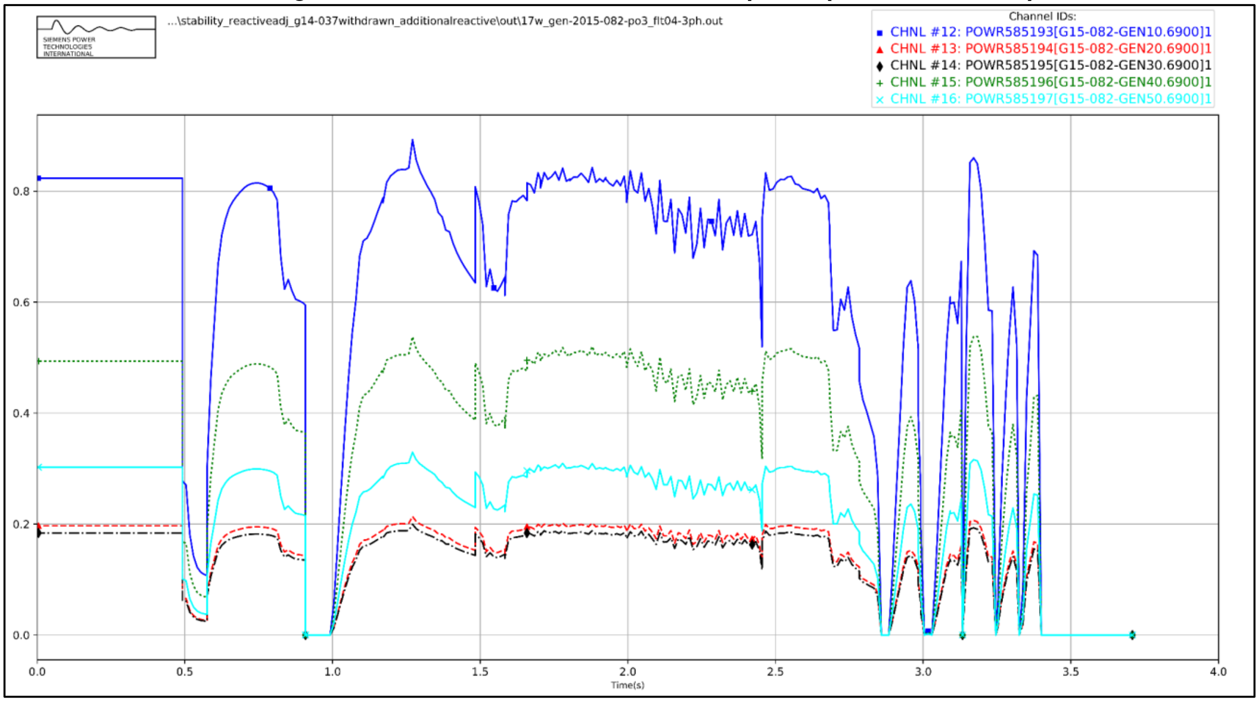
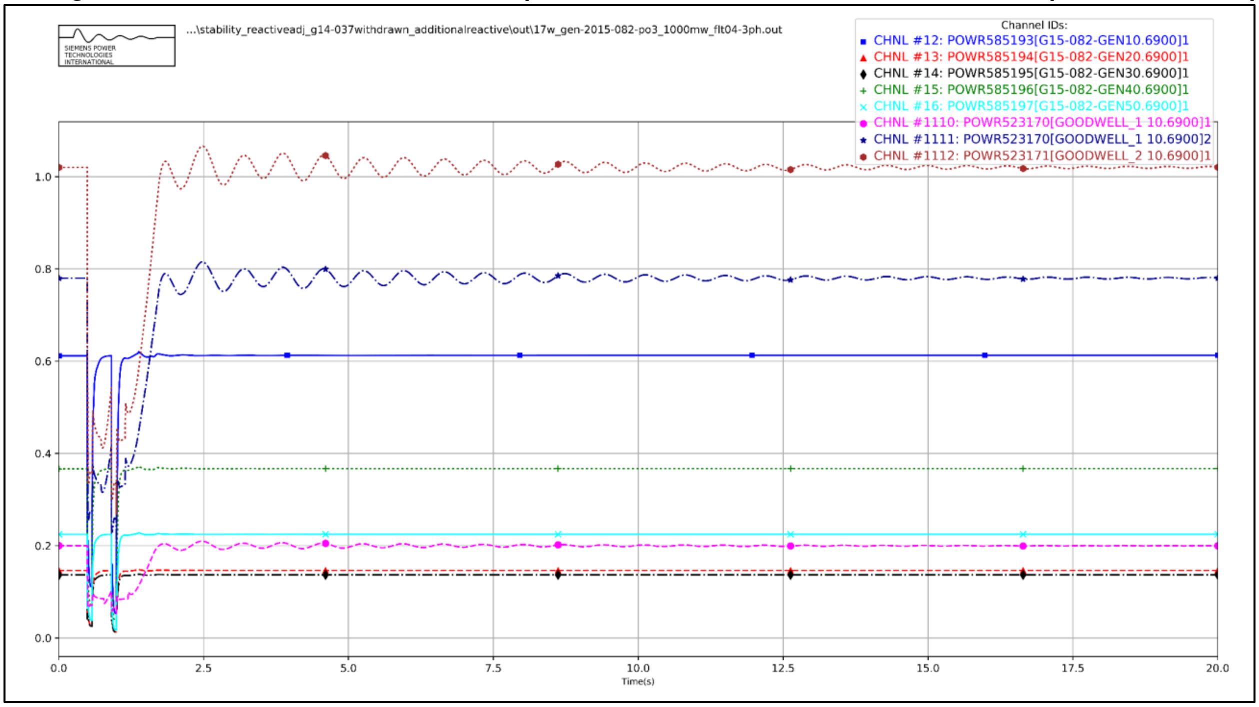


Figure 6-7: FLT04-PO3 GEN-2015-082 Response After Generation Curtailed to 1000 MW (17WP MRIS Case)



There were no other damping or voltage recovery violations 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 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. A Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

7.1 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-2015-082 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

8.0 Conclusions

The Interconnection Customer for GEN-2015-082 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 48 x GE 1.715 MW + 11 x GE 1.79 MW + 8 x GE 2.3 MW + 21 x GE 2.35 MW + 12 x GE 2.52 MW wind turbines for total capacity of 200 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line.

SPP determined that power flow should not be performed based on the POI injection decrease of 0.62%. However, SPP determined that a turbine parameter comparison and an impedance comparison should be performed to evaluate whether dynamic stability analysis and short-circuit analysis is appropriate.

The turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models changed significantly. The modification request resulted in a change in the equivalent impedances from the point of interconnection to the generator step up transformers of approximately 1.72%. Due to the change in modeling parameters, a dynamic stability analysis was deemed necessary and the scope of this modification request study was expanded from a charging current compensation analysis to include both short-circuit analysis and dynamic stability analysis.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2015-082 project needed 18.16 MVAr of reactor shunts on the 34.5 kV bus of the project substation, a decrease from the 24 MVAr found in the DISIS-2016-001-1 Report[3]. 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 customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2015-082 contribution to three-phase fault currents in the immediate systems at or near GEN-2015-082 was not greater than 0.76 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2015-082 generators online were below 34 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 51 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that the loss of the Hitchland to G14-037-TAP 345 kV line caused the GEN-2006-044 Generating Facilities at buses 579380 and 523107,

[3] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

comprised of DeWind D9.2 Wind Turbine Generators represented with the DWD8G1 model, to trip in response to a fault event on this circuit. This problem also occurs for both generators in the existing base case. As the tripping response is present in both the DISIS and modified cases, it is not caused by the GEN-2015-082 modification. The RELUNS and G59REL relays were disabled which mitigated this existing issue.

The loss of the Badger to Beaver double circuit 345 kV lines caused a post-fault steady state low voltage violation at the Walkenmeyer 345 kV bus in the existing DISIS cases (FLT1008-SB and FLT40-PO2) which persisted in the MRIS cases as well. This existing steady state issue can be mitigated if the projects interconnected at Beaver and Hitchland 345 kV substations provide their Generation Interconnection Agreement (GIA) required point-of-interconnection 0.95 power factor.

After the prior outage of the Badger to G16-003-TAP 345 kV Circuit 1 line, nearby generation was required to be curtailed to 950 MW in the 17WP, 1100 MW in the 18SP case, and 1200 MW in the 26SP case to have GEN-2015-082 remain stable following the fault Circuit 2 of the double circuit.

After the prior outage of the G16-003-TAP to Woodward 345 kV Circuit 2 line, nearby generation was required to be curtailed to 1000MW in the 17WP, 1150MW in the 18SP, and 1250 MW in the 26SP case to have GEN-2015-082 remain stable following the fault on Circuit 1 of the double circuit.

There were no other damping or voltage recovery violations 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 impact on the cost or timing of any Interconnection Request with a later Queue priority date.

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.