Submitted to
Southwest Power Pool

Report On

GEN-2016-091
Modification Request Impact Study

Revision R1

Date of Submittal
September 10, 2021

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
09/10/2021	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-2016-091, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the G16-091-TAP 345 kV bus on the Gracemont to Lawton East Side (L.E.S.) 345 kV line.

The GEN-2016-091 project is proposed to interconnect in the American Electric Power (AEP) control area with a capacity of 303.6 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-091 to change the turbine configuration to 1 x GE 116 2.3 MW + 93 x GE 127 2.82 MW + 16 x SGRE 108 2.415 MW for a total generating capacity of 303.2 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2016-091 are shown in Table ES-2.

Table ES-1: GEN-2016-091 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-091	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	132 x Siemens VS 2.3 MW	303.6

Table ES-2: GEN-2016-091 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="4">Modification</th></tr>
<tr><td>Point of Interconnection</td><td>Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)</td><td colspan="4">Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)</td></tr>
<tr><td>Configuration/ Capacity</td><td>132 x Siemens VS 2.3 MW = 303.6 MW</td><td colspan="4">1 x GE 116 2.3 MW + 93 x GE 127 2.82 MW + 16 x SGRE 108 2.415 MW = 303.2 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 9 miles
R = 0.000499 pu
X = 0.001509 pu
B = 0.076903 pu</td><td colspan="4">Length = 10.6 miles
R = 0.000589 pu
X = 0.005168 pu
B = 0.049909 pu</td></tr>
<tr><td>Main Substation Transformer[1]</td><td>X = 11.989% R = 0.499%, Winding MVA = 200 MVA, Rating MVA = 334 MVA</td><td colspan="2">X = 9.968% R = 0.21%, Winding MVA = 100 MVA, Rating MVA = 167 MVA</td><td colspan="2">X = 9.922% R = 0.21%, Winding MVA = 100 MVA, Rating MVA = 167 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 132:
X = 5.967%, R = 0.633%, Rating 363 MVA</td><td>Gen 1 Equivalent Qty: 16:
X = 6.986%, R = 0.691%, Winding MVA = 50.4 MVA, Rating MVA = 50.4 MVA</td><td>Gen 2 Equivalent Qty: 40:
X = 6.986%, R = 0.691%, Winding MVA = 126 MVA, Rating MVA = 126 MVA</td><td>Gen 3 Equivalent Qty: 53:
X = 6.986%, R = 0.691%, Winding MVA = 166.95 MVA, Rating MVA[2] = 166.9 MVA</td><td>Gen 4 Equivalent Qty: 1:
X = 6.986%, R = 0.691%, Winding MVA = 3.15 MVA, Rating MVA[2] = 3.2 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.004620 pu
X = 0.005990 pu
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X = 0.012186 pu
B = 0.103547 pu</td><td colspan="2">R = 0.006373 pu
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<tr><td>Reactive Power Devices</td><td>N/A</td><td colspan="2">1 x 11 MVAR 34.5 kV Capacitor Bank</td><td colspan="2">1 x 11 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

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 0.41% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to a combination of SGRE and GE turbines 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 Group 7 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 33.10 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-2016-091 project needed 22.95 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 23.86 MVAr found for the existing GEN-2016-091 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-2016-091 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-091 was not greater than 1.04 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-091 generators online were below 46 kA for the 2021SP and 2028SP models.

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 44 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breakers faults.

The results of the dynamic stability analysis showed that there were some existing voltage recovery violations under two simulated Planning P6 events consisting of prior outage faults followed by a three phase fault. In addition, the Dempsey Unit at bus 511969 was poorly damped following the prior outage on the G16-091-TAP to L.E.S 345 kV line followed by a three phase fault on the Gracemont to Minco 345 kV line. This was observed in both the pre and post modification cases so it was not attributed to this modification request.

There were no damping or voltage recovery violations attributed to the GEN-2016-091 project 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.

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-2016-091. 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 33.10 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 most recently studied 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 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-2016-091 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G16-091-TAP 345 kV bus on the Gracemont to Lawton East Side (L.E.S.) 345 kV line. At the time of the posting of this report, GEN-2016-091 is an active Interconnection Request with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2016-091 is a wind farm and has a maximum summer and winter queue capacity of 303.6 MW with Energy Resource Interconnection Service (ERIS).

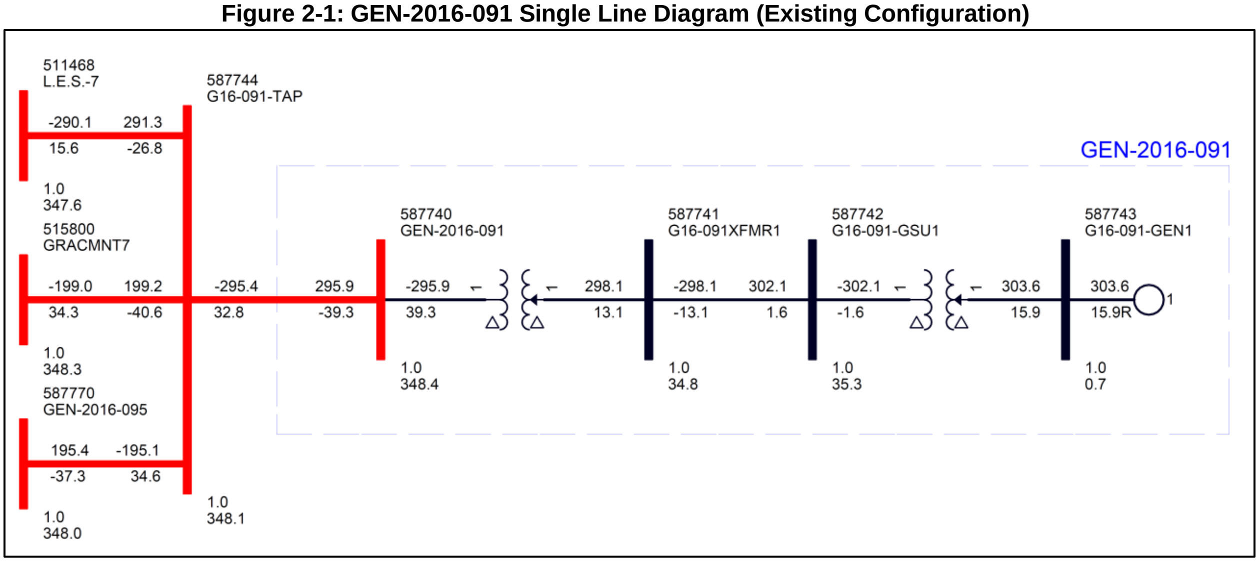
The GEN-2016-091 project was originally studied as part of Group 7 in the DISIS-2016-002 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-091 configuration.

The GEN-2016-091 project is proposed to interconnect in the American Electric Power (AEP) control area with a capacity of 303.6 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-091 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-091	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	132 x Siemens VS 2.3 MW	303.6

Figure 2-1: GEN-2016-091 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-091 to change the turbine configuration to 1 x GE 116 2.3 MW + 93 x GE 127 2.82 MW + 16 x SGRE 108 2.415 MW for a total generating capacity of 303.2 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, main substation transformer, and reactive power devices. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-091 modification. The existing and modified configurations for GEN-2016-091 are shown in Table 2-2.

Figure 2-2: GEN-2016-091 Single Line Diagram (Modification Configuration)

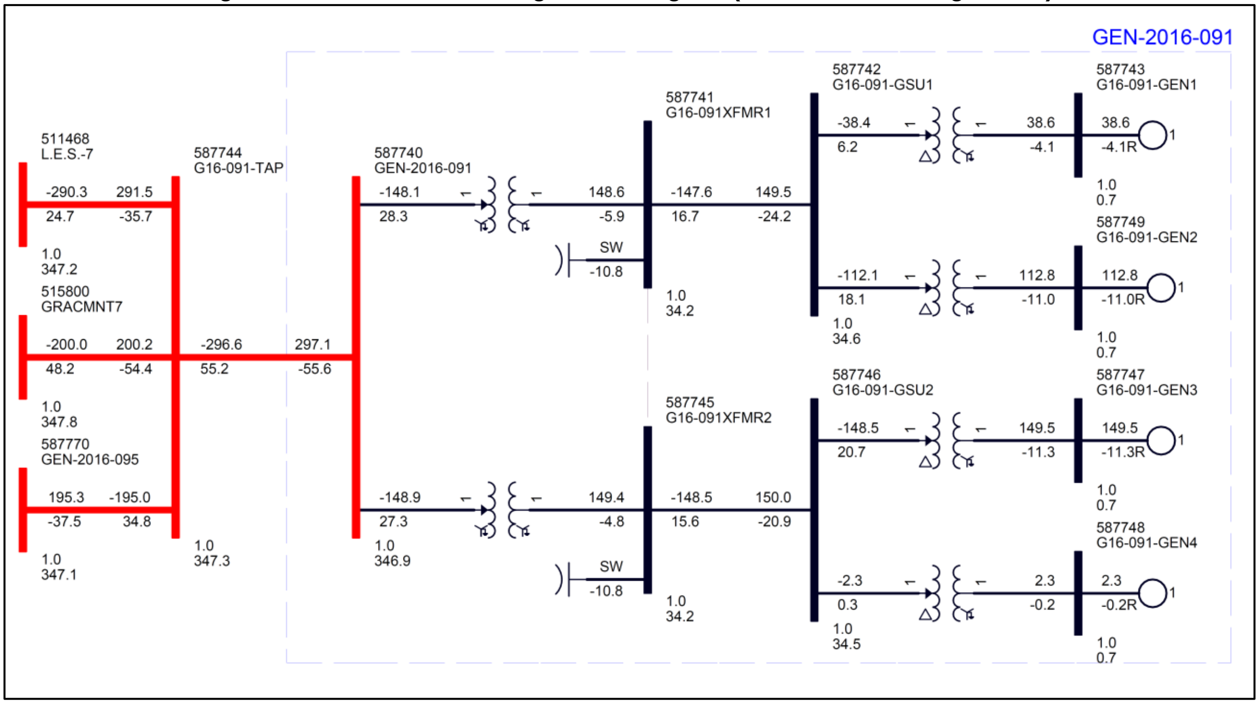


Table 2-2: GEN-2016-091 Modification Request

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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 Group 7 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.10 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 for GEN-2016-091. 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 0.41%) 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.

Table 3-1: GEN-2016-091 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2016-091	295.4	296.6	0.41%

3.2 Turbine Parameters Comparison

SPP determined that the turbine change from Siemens to a combination of SGRE and GE turbines required short circuit and dynamic stability analyses as 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 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-2016-091 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

The GEN-2016-091 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-2016-091 project needed approximately 22.95 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is a decrease from the 23.86 MVAr found for the existing GEN-2016-091 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-2016-091 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-2016-091	587744	G16-091-TAP	22.95	22.95	22.95	22.95

Figure 4-1: GEN-2016-091 Single Line Diagram (Existing Shunt Reactor)

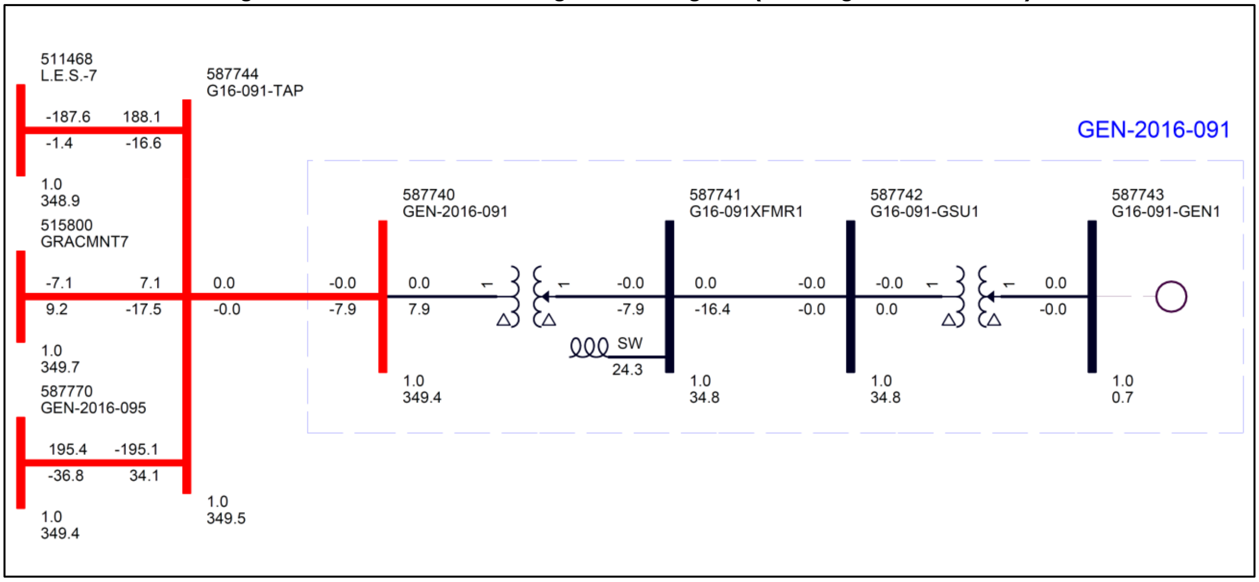
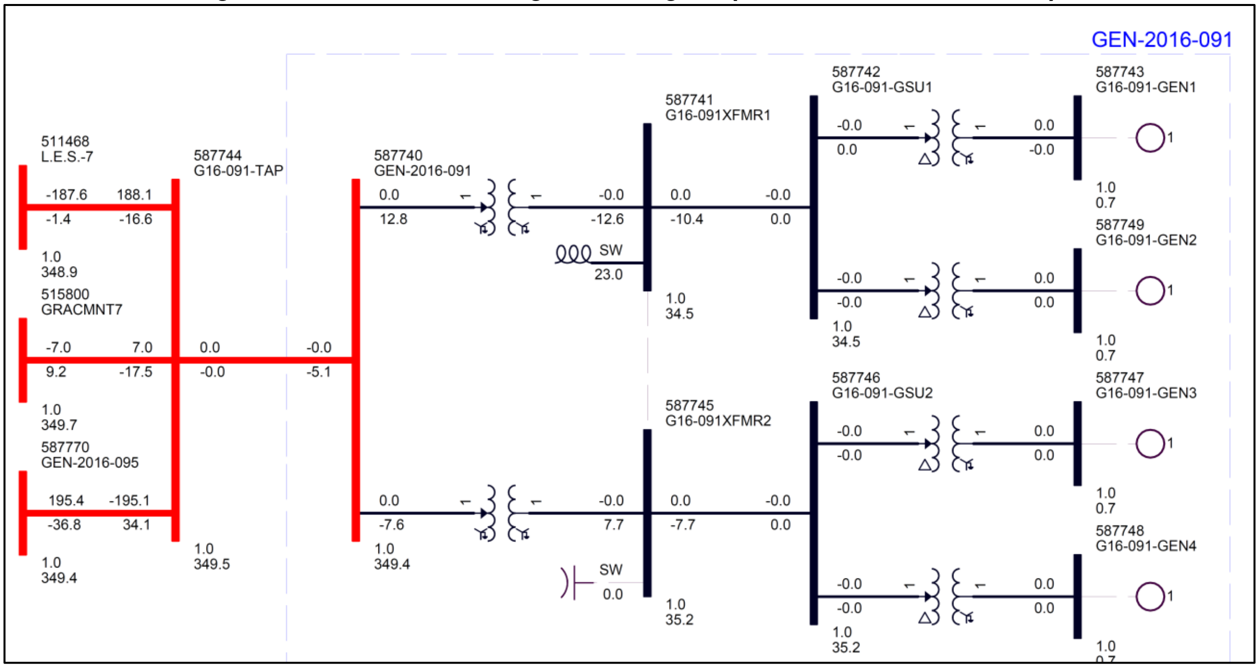


Figure 4-2: GEN-2016-091 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2016-091. 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 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-2016-091 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-2016-091 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 15.48 kA with the GEN-2016-091 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-091 POI was less than 46 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2016-091 contribution to three-phase fault current was about 7.3% and 1.04 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	14.25	15.29	1.04	7.3%
2026SP	14.44	15.48	1.04	7.2%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.04	0.2%
115	19.8	0.00	0.0%
138	45.4	0.27	1.1%
230	28.9	0.01	0.2%
345	35.0	1.04	7.3%
Max	**45.4**	**1.04**	**7.3%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	20.1	0.04	0.2%
115	19.5	0.00	0.0%
138	45.3	0.26	1.0%
230	27.5	0.02	0.2%
345	35.1	1.04	7.2%
Max	**45.3**	**1.04**	**7.2%**

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-2016-091 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-2016-091 configuration of 1 x GE 116 2.3 MW (GEWTG2) + 93 x GE 127 2.82 MW (GEWTG2) + 16 x SGRE 108 2.415 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 Group 7 models. The modifications requested for the GEN-2016-091 projects were used to create modified stability models for this impact study.

The following system adjustments were made to address existing base case issues that are not attributed to the modification request:

1. The generators on buses 520519, 520520, and 520522 were GNET
2. The frequency protection relays at buses 589037 and 589037 were disabled

The modified dynamics model data for the GEN-2016-091 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-2016-091 and other equally and prior queued projects in Group 7. In addition, voltages of five (5) buses away from the POI of GEN-2016-091 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-2016-091 and selected additional fault events for GEN-2016-091 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.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT09-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to TUCO_INT (525832) 345 kV line circuit 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 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.
FLT14-3PH	P1	3 phase fault on the L.E.S.-4 138 kV (511467) / 345 kV (511468)/ 13.8 kV (511411) XFMR CKT 2, near L.E.S. -4 138 kV. a. Apply fault at the L.E.S. -4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT15-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line circuit 1, near L.E.S.-7. a. Apply fault at the L.E.S.-7 345 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.
FLT16-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line circuit 1, near L.E.S.-7. a. Apply fault at the L.E.S.-7 345 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.
FLT26-3PH	P1	3 phase fault on the TERRYRD7 (511568) to SUNNYSD7 (515136) 345 kV line circuit 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 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.
FLT27-3PH	P1	3 phase fault on the MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 7 345 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.
FLT32-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 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.
FLT33-3PH	P1	3 phase fault on the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT34-3PH	P1	3 phase fault on the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 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.
FLT56-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 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.
FLT57-3PH	P1	3 phase fault on the G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 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
FLT61-3PH	P1	3 phase fault on the TUCO_INT (525832) to O.K.U.-7 (511456) 345 kV line circuit 1, near TUCO_INT. a. Apply fault at the TUCO_INT 345 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.
FLT73-3PH	P1	3 phase fault on the TERRYRD7 (511568) to L.E.S.-7 (511468) 345 kV line circuit 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 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.
FLT74-3PH	P1	3 phase fault on the CIMARON7 (514901) to MINCO 7 (514801) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 345 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.
FLT33-PO1	P6	**PRIOR OUTAGE of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1** 3 phase fault on the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT33-PO2	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1** 3 phase fault on the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT33-PO3	P6	**PRIOR OUTAGE of GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line circuit 1** 3 phase fault on the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT34-PO2	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1** 3 phase fault on the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 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.
FLT57-PO1	P6	**PRIOR OUTAGE of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1** 3 phase fault on the G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 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.
FLT9001-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 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 GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN1 (563273) 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
FLT9003-3PH	P1	3 phase fault on the MINCO 7 (514801) to MCNOWND7 (515444) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator MNCOWNG1 (515907) 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 MINCO 7 (514801) to MNCWND37 (515549) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator MNCOWNG1 (515921) Trip generator G15-057-GEN1 (584953) Trip generator G15-057-GEN2 (584954) Trip generator G15-057-GEN3 (584955) Trip generator MNCO4G11 (515943) Trip generator G14-056-GEN2 (584064) Trip generator G14-056-GEN3 (584067) 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.
FLT9005-3PH	P1	3 phase fault on the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line circuit 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 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 G16-037-TAP (560078) to GEN-2016-037 (587230) 345 kV line circuit 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G16-037-GEN1 (587233) 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 L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1, near L.E.S. -4 345 kV. a. Apply fault at the L.E.S. -4 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the TERRYRD7 (511568) to RUSHSPR7 (511571) 345 kV line circuit 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G14-057-GEN1 (584073) Trip generator G15-092-GEN1 (563262) Trip generator G15-092-GEN2 (563263) Trip generator G15-045-GEN1 (584862) 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 O.K.U.-7 (511456) to GEN-2017-065 (589030) 345 kV line circuit 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G17-065-GEN1 (589033) Trip generator G17-065-GEN2 (589037) 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 O.K.U.-7 (511456) to OKLAUN 7 (599891) 345 kV line circuit 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 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
FLT9011-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to GEN-2017-033 (588760) 345 kV line circuit 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G17-033-GEN1 (588763) Trip generator G17-033-GEN2 (588767) 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.
FLT9012-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to OKLAUN HVDC7 (511565) 345 kV line circuit 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 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.
FLT9013-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-095 (587770) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G16-095-GEN1 (587773) 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.
FLT56-PO2	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1** 3 phase fault on the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 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-PO2	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line circuit 1** 3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN1 (563273) 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.
FLT15-PO4	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line circuit 1** 3 phase fault on the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line circuit 1, near L.E.S.-7. a. Apply fault at the L.E.S.-7 345 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.
FLT16-PO4	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line circuit 1** 3 phase fault on the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line circuit 1, near L.E.S.-7. a. Apply fault at the L.E.S.-7 345 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-PO4	P6	**PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line circuit 1** 3 phase fault on the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511411) XFMR CKT 1, near L.E.S. -4 345 kV. a. Apply fault at the L.E.S. -4 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1001-SB	P4	**Stuck Breaker on GRACMNT7 (515800) 345kV bus.** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line circuit 1.
FLT1002-SB	P4	**Stuck Breaker on GRACMNT7 (515800) 345kV bus.** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line circuit 1. d. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line circuit 1.
FLT1003-SB	P4	**Stuck Breaker on GRACMNT7 (515800) 345kV bus.** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line circuit 1. d. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line circuit 1.
FLT1004-SB	P4	**Stuck Breaker on GRACMNT7 (515800) 345kV bus.** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line circuit 1. d. Trip the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1.
FLT1005-SB	P4	**Stuck Breaker on L.E.S.-7 (511468) 345kV bus.** a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to G16-091-TAP (587744) 345 kV line circuit 1. d. Trip the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.
FLT1006-SB	P4	**Stuck Breaker on L.E.S.-7 (511468) 345kV bus.** a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line circuit 1. d. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line circuit 1.
FLT1007-SB	P4	**Stuck Breaker on L.E.S.-7 (511468) 345kV bus.** a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line circuit 1. d. Trip the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.

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-2016-091 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
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT26-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT27-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT61-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT73-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	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
FLT1001-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
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
FLT33-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO1	Fail*	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-PO2	Fail**	Pass	Stable	Fail**	Pass	Stable**	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

***Steady state voltage violations were found in the 19WP case.**
****Steady state low voltage violation was found in the 19WP and 21LL case. Poorly damped oscillations on the Dempsey Unit (511969) were also found in the 21LL case.**

During the prior outage of the Minco to Cimaron 345 kV line, a fault on the G16-091-TAP to L.E.S. 345 kV line caused low voltage steady state violations in the 19WP case. This was observed in both the pre and post modification cases for FLT57-PO1, so it was not attributed to this modification request.

During the prior outage of the G16-091-TAP to L.E.S. 345 kV line, a fault on the Gracemont to Minco 345 kV line caused a low voltage steady state violation in the 19WP and 21LL cases. This was observed in both the pre and post modification cases for FLT34-PO2, so it was not attributed to this modification request. During this fault there were also oscillations present for the Dempsey Unit at bus 511969 in the 21 LL case.

Figure 6-1 shows the Dempsey Unit oscillations in the 21LL modification case. This problem was also present in the existing DISIS-2017-001 21LL case as shown in Figure 6-2, so it was not attributed to this modification request.

Figure 6-1: FLT34-PO2 Dempsey Unit (511969) Oscillations (21LL Modification Case)

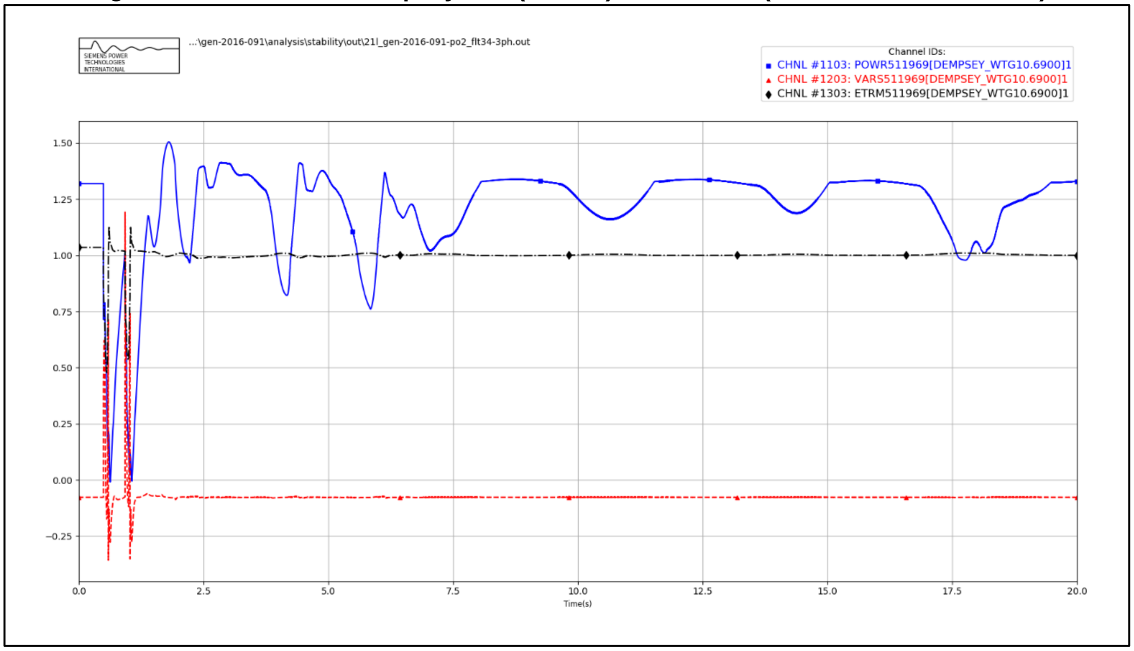
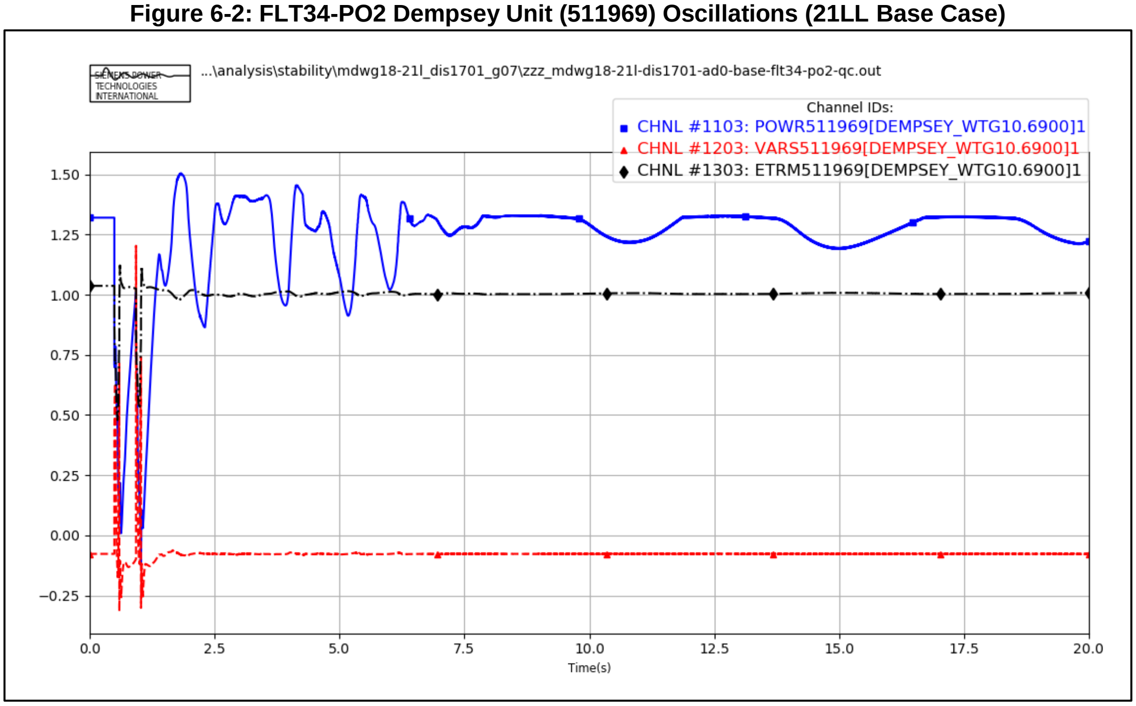


Figure 6-2: FLT34-PO2 Dempsey Unit (511969) Oscillations (21LL Base Case)



There were no damping or voltage recovery violations attributed to the GEN-2016-091 project 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. 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.

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-2016-091 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.

8.0 Conclusions

The Interconnection Customer for GEN-2016-091 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 1 x GE 116 2.3 MW + 93 x GE 127 2.82 MW + 16 x SGRE 108 2.415 MW for a total generating capacity of 303.2 MW.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.41% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to a combination of SGRE and GE turbines 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.

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-2016-091 project needed 22.95 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 23.86 MVAr found for the existing GEN-2016-091 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-2016-091 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-091 was not greater than 1.04 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-091 generators online were below 46 kA for the 2021SP and 2028SP models.

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 44 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breakers faults.

The results of the dynamic stability analysis showed that there were some existing voltage recovery violations under two simulated Planning P6 events consisting of prior outage faults followed by a three phase fault. In addition, the Dempsey Unit at bus 511969 was poorly damped following the prior outage on the G16-091-TAP to L.E.S 345 kV line followed by a three phase fault on the

Gracemont to Minco 345 kV line. This was observed in both the pre and post modification cases so it was not attributed to this modification request.

There were no damping or voltage recovery violations attributed to the GEN-2016-091 project 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.

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.