GEN-2013-030 Impact Restudy for Generator Modification (Turbine Change)

November 2016
Generator Interconnection

Southwest Power Pool

Revision History

Date	Author	Change Description
9/16/2016	SPP	Restudy for Generator Modification issued.
11/4/2016	SPP	Modify executive summary to show that study results are also applicable to the Siemens SWT-2.3-108 (2.3076MW rated power) wind turbine generator

Executive Summary

The GEN-2013-030 Interconnection Customer has requested a modification to its Generator Interconnection Request to change from one hundred fifty (150) Vestas V100 VCSS 2.0MW (aggregate power is 300.0MW) wind turbine generators to one hundred thirty (130) Siemens SWT-2.3-108 (Uprated to 2.3076MW) (aggregate power is 300.0MW) wind turbine generators.

The point of interconnection (POI) is the Oklahoma Gas and Electric (OKGE) Beaver 345kV Substation. The study was conducted using the Siemens SWT-2.3-108 2.3MW proprietary wind turbine model provided by the interconnection customer. The dynamic characteristics of the uprated 2.3076MW wind turbine generator are the same as the 2.3MW wind turbine generator. ABB Inc. (ABB) performed the study for this modification request, and ABB's report on the study follows this summary.

The study models used were the 2016 winter, the 2017 summer, and the 2025 summer cases and included Interconnection Requests through DISIS-2015-002. The study showed that no stability problems were found with the contingencies studied during the summer and the winter peak conditions as a result of changing to the Siemens SWT-2.3-108 (Uprated to 2.3076MW) wind turbines. Additionally, GEN-2013-030 was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements.

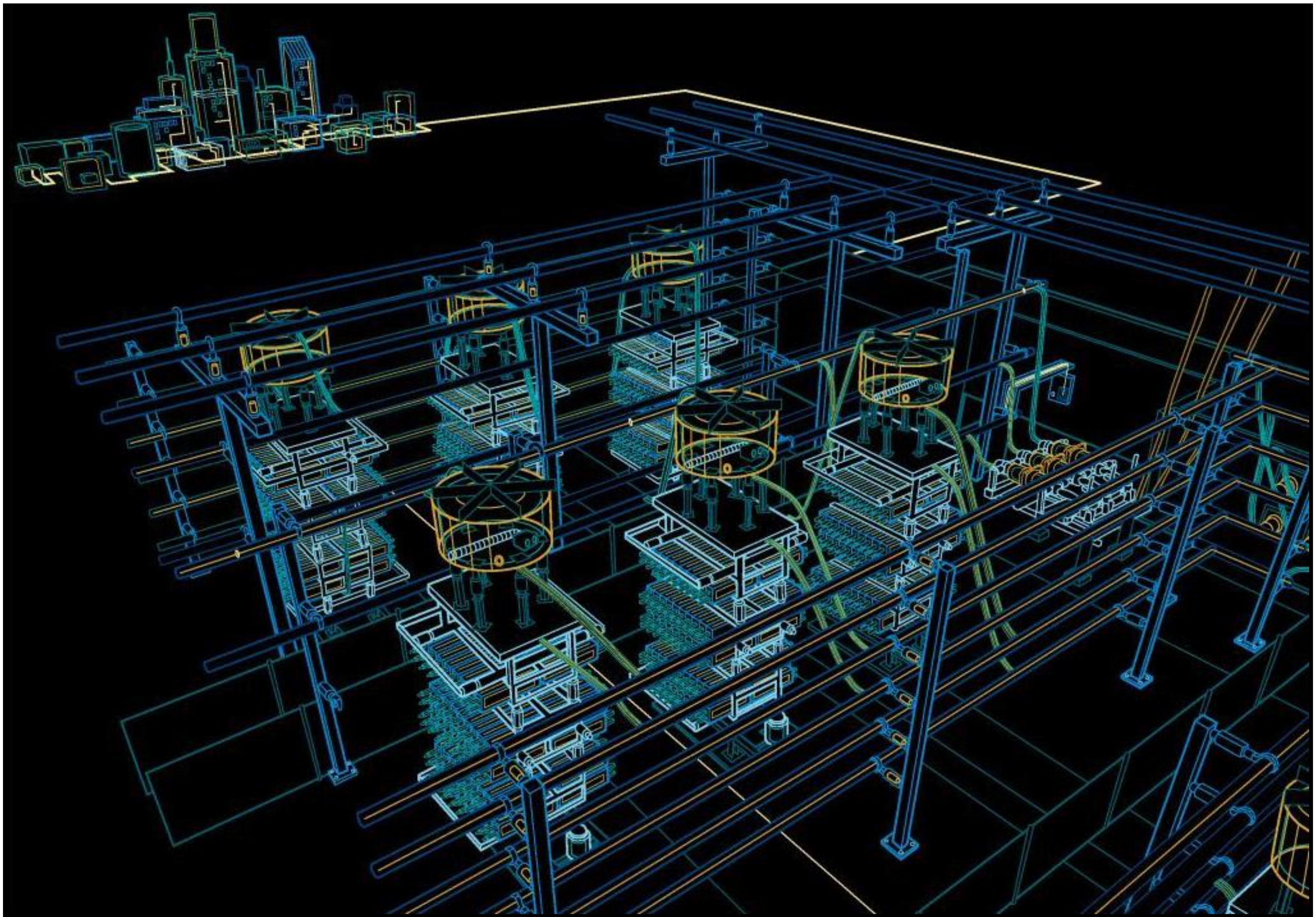
A power factor analysis was performed for the study and it was found that the GEN-2013-030 will be required to meet the 0.95 power factor lagging (providing vars) and 0.95 power factor leading (absorbing vars) at the POI. A short circuit analysis was performed and is detailed in the ABB report.

A low wind/no wind condition analysis was performed for this modification request. The analysis showed that the project will inject approximately 18.6Mvars into the POI during periods of low wind/no wind. GEN-2013-030 will be required to have approximately 18MVars of shunt reactors to offset the capacitive injection.

With the assumptions outlined in this report and with all required network upgrades in place, GEN-2013-030 will be able to reliably interconnect to the SPP transmission grid with the Siemens SWT-2.3-108 (Uprated to 2.3076MW) wind turbine generator.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, 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. If the Customer wishes to obtain deliverability to a specific customer, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS.



Southwest Power Pool

GEN-2013-030 SYSTEM IMPACT RESTUDY

Final Report

Report No. r00

2 September 2016

Power and productivity
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LEGAL NOTICE

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Revised:

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Rev No.	*Revision Description*	*Date*	*Authored by*	*Reviewed by*	*Approved by*

SUMMARY

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for generator modification for generation interconnection request GEN-2013-030 (299 MW wind farm connected at Beaver County 345kV bus).

Request	Size (MW)	Generator Model	POI
GEN-2013-030	299.0	Siemens SWT 2.3 MW	Beaver County 345kV bus (515554)

The objective of this study is to re-evaluate the impact of project GEN-2013-030 on the existing and future systems based on change of wind turbines. While the previous study model was based on Vestas V110 2.0 MW wind turbine-generators, the present one is based on Siemens SWT 2.3 MW wind-turbine generators.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis. The following is a summary of study results.

For FLT04-3PH and FLT06-3PH, the studied generators and some pre-queued projects showed undamped oscillations. And voltages of some buses and machine responses also showed wiggling response following these two faults for all three seasons except for FLT04-3PH in 2025 Summer Peak Case. Pre-project cases were created for all three study seasons to simulate the above two faults. No oscillations were observed in pre-project cases. In discussions with SPP since FLT04-3PH and FLT06-3PH are double circuit faults, the mitigation will be the curtailment of generation in the area.

For the rest of the studied faults, the simulation results showed no stability problems and no voltage violations for all three seasons. All the simulation results were summarized in Table 2-2. Also, for the contingencies simulated GEN-2013-030 remained on line and, therefore, will comply with FERC Order 661A low voltage ride-through.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The results show need for reactive power from the study project following the critical contingencies. The proposed GEN-2013-030 need to

design their facility to meet the SPP pro-forma 95% lagging (providing vars) and 95% leading (absorbing vars) power factor requirements at the Point of Interconnection.

The Low/No Wind analysis shows that an 18.61 MVAr shunt reactor is required to bring the MVAr flow in the POI down to approximate zero under low/no wind conditions. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

Contents

1 INTRODUCTION

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for generator modification for generation interconnection request GEN-2013-030 (299 MW wind farm connected at Beaver County 345kV bus) as shown in Table 1-1.

Table 1-1: GEN-2013-030 Generation Interconnection Request

Request	Size (MW)	Generator Model	POI
GEN-2013-030	299.0	Siemens SWT 2.3MW	Beaver County 345kV bus

The objective of this study is to re-evaluate the impact of project GEN-2013-030 on the existing and future systems - based on change of wind turbines. While the previous study model was based on Vestas V110 2.0 MW wind turbine-generators, the present one is based on Siemens SWT 2.3 MW wind-turbine generators.

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

SPP provided the study cases for all three system scenarios which include GEN-2013-030 modeled with Siemens SWT 2.3 MW wind turbine-generators. The following changes were made by ABB to update the three cases, as requested by SPP.

- The dispatch of two prior-queued projects (GEN-2002-022, GEN-2008-051) were reduced from 100% of nameplate as in the provided cases to 20%. Generators in SPP footprint, defined by the automation file (“2015_MDWG_DIS1502_Scale_Subsystem_G02.idv”) provided by SPP, are re-dispatched up by the decremental dispatch amounts of the two prior-queued projects.

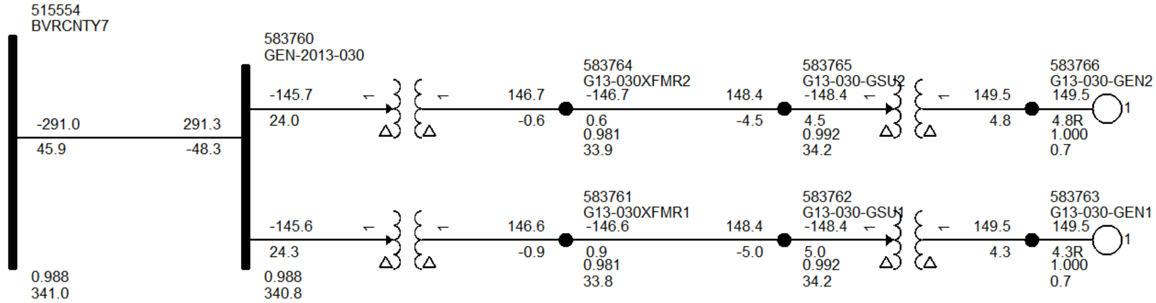
The three system scenarios supplied by SPP included the following prior queued projects:

Table 1-2: Prior Queued Projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
Llano Estacado (White Deer)	80.0	CIMTR1	Tap on Kingsmill (523712) to MIDSTRM Tap (523817) (523815)
GEN-2002-008	240	GE 1.5MW	Hitchland 345kV (523097)
GEN-2002-009	79.8	Suzlon 2.1MW	Hansford 115kV (523195)
GEN-2003-020	159.1	GE 1.5/1.6 MW	Carson Co. 115kV (523928)
GEN-2006-020S	20	D8.2 2.0MW	Frisco Wind 115kV (523160)
GEN-2006-044	370	DeWind D9.2 2.0MW	Hitchland 345kV (523097)
GEN-2007-046	200.0	Vestas V100/V110 2.0MW	Hitchland 115kV (523093)
GEN-2008-047	300	GE 1.7MW	Beaver County 345kV (515554)
GEN-2010-001	300	GE 1.85MW	Beaver County 345kV (515554)
GEN-2010-014	358.8	Siemens SWT 2.3MW	Hitchland 345kV (523097)
ASGI-2011-002	20	DeWind D8.2 2.0MW	Herring 115kV (523359)
GEN-2011-014	198	Vestas V117 3.3MW	Beaver County 345kV (515554)
GEN-2011-022	299	Siemens 2.3MW	Hitchland 345kV (523097)
ASGI-2013-001	11.5	Siemens 2.3	PanTex South 115kV(523945)
GEN-2014-037	200	Vestas V110 2.0 MW (wind)	Tap on Hitchland to Beaver County 345kV (Optima 345kV - 560010)

The one line diagram of the project is shown in Figure 1-1.

Figure 1-1: One Line Diagram of GEN-2013-030



2 STABILITY ANALYSIS

In this study, ABB investigated the stability of the system for faults in the vicinity of the proposed plant as defined by SPP. The studied faults involve three-phase transformer faults with normal clearing, three-phase line faults with normal clearing and re-closing test, and single-line-to-ground (SLG) faults with stuck breaker.

2.1 Stability Analysis Methodology

Stability analysis is performed to determine whether the electric system would meet stability criteria following the addition of the GEN-2013-030 project.

According to the latest version of Disturbance Performance Requirements, the electric system shall meet the following voltage criteria:
After a disturbance is cleared; bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.

Stability analysis was performed using Siemens-PTI's PSS/E dynamics program V32.2.2.

All the faults listed in Table 2-1 were simulated for 20 seconds.

Table 2-1: List of Faults for Stability Analysis

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on Optima 345kV (560010) to Beaver County 345kV (515554) CKT 1, near Optima. a. Apply fault at the Optima 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.
2	FLT02-3PH	3 phase fault on Optima 345kV (560010) to Hitchland 345kV (523097) CKT 1, near G14-037 Tap. a. Apply fault at the Optima 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.
3	FLT03-3PH	3 phase fault on the Beaver County 345kV (515554) to G11-14-Tap 345kV (560000) CKT 1, near Beaver County. a. Apply fault at the Beaver County 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.
4	FLT04-3PH	3 phase fault on the Beaver County 345kV (515554) to G11-014-Tap 345kV (560000) CKT 1 & 2, near Beaver County.

Cont. No.	Cont. Name	Description
		a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
5	FLT05-3PH	3 phase fault on the G11-014-Tap 345kV (560000) to Woodward 345kV (515375) CKT 1, near G11-014-Tap. a. Apply fault at the G11-014-Tap 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.
6	FLT06-3PH	3 phase fault on the G11-014-Tap 345kV (560000) to Woodward 345kV (515375) CKT 1 & 2, near G11-014-Tap. a. Apply fault at the G11-014-Tap 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
7	FLT07-3PH	3 phase fault on the Optima 345kV (560010) to Beaver County 345kV (515554) CKT 1 and 2, near Optima. a. Apply fault at the Optima 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
8	FLT08-3PH	3 phase fault on the Optima 345kV (560010) to Hitchland 345kV (523097) CKT 1 and 2, near Optima. a. Apply fault at the Optima 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
9	FLT09-3PH	3 phase fault on the Thistle 345kV (539801) to Woodward 345kV (515375) CKT 1, near Thistle. a. Apply fault at the Thistle 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.
10	FLT10-3PH	3 phase fault on the Thistle 345kV (539801) to Woodward 345kV (515375) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
11	FLT11-3PH	3 phase fault on the Woodward 345kV (515375) to Border 345kV (515458) 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.
12	FLT12-3PH	3 phase fault on the Woodward 345kV (515375) to G11-051 Tap 345kV (562075) 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.

Cont. No.	Cont. Name	Description
13	FLT13-3PH (25SP Only)	3 phase fault on the Woodward 345kV (515375) to G11-051-Tap 345kV (562075) CKT 1 and 2, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
14	FLT14-3PH	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.
15	FLT15-3PH	3 phase fault on the Border 345kV (515458) to Tuco 345kV (525832) CKT 1, near Border. a. Apply fault at the Border 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.
16	FLT16-3PH	3 phase fault on the Tuco 345kV (525832) to G14-074-Tap 345kV (560027) CKT 1, near Tuco. a. Apply fault at the Tuco 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.
17	FLT17-3PH	3 phase fault on the G14-074-Tap 345kV (560027) to OKU 345kV (511456) CKT 1, near G14-074-Tap. a. Apply fault at the G14-074-Tap 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.
18		DELETED
19	FLT19-3PH	3 phase fault on the Thistle 345kV (539801) to G1524&G1525T 345kV (560033) CKT 1, near Thistle. a. Apply fault at the Thistle 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.
20	FLT20-3PH	3 phase fault on the Thistle 345kV (539801) to G1524&G1525T 345kV (560033) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
21	FLT21-3PH	3 phase fault on the Thistle 345kV (539801) to Clark County 345kV (539800) CKT 1, near Thistle. a. Apply fault at the Thistle 345kV bus.

Cont. No.	Cont. Name	Description
		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.
22	FLT22-3PH	3 phase fault on the Thistle 345kV (539801) to Clark County 345kV (539800) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
23	FLT23-3PH	3 phase fault on the Thistle 345kV (539801) to Thistle 138kV (539804) Thistle 13.8kV (539802) XFMR CKT 1, near Thistle 345kV. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
24	FLT24-3PH (16WP Only)	3 phase fault on the Hitchland 345kV (523097) to Finney 345kV (523853) CKT 1, near Hitchland. a. Apply fault at the Hitchland 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.
25	FLT25-3PH	3 phase fault on the Hitchland 345kV (523097) to Hitchland 230kV (523095) Hitchland 13.2kV (523091) XFMR CKT 1, near Hitchland 345kV. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
26	FLT26-3PH	3 phase fault on the Potter County 345kV (523961) to Potter County 230kV (523959) Potter County 13.2kV (523957) XFMR CKT 1, near Potter County 345kV. a. Apply fault at the Potter County 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
27	FLT27-3PH	3 phase fault on the Hitchland 230kV (523095) to Ochiltree 230kV (523155) CKT 1, near Hitchland. a. Apply fault at the Hitchland 230kV 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.
28	FLT28-3PH	3 phase fault on the Hitchland 230kV (523095) to Moore County 230kV (523309) CKT 1, near Hitchland. a. Apply fault at the Hitchland 230kV 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.
29	FLT29-3PH	3 phase fault on the Finney 345kV (523853) to Holcomb 345kV (531449) CKT 1, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.

Cont. No.	Cont. Name	Description
		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.
30	FLT30-3PH	3 phase fault on the Holcomb 345kV (531449) to Buckner 345kV (531501) CKT 1, near Holcomb. a. Apply fault at the Holcomb 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.
31	FLT31-3PH	3 phase fault on Hitchland 345kV (523097) to Potter 345kV (523961) CKT 1, near Hitchland. a. Apply fault at the Hitchland 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.
32		DELETED
33	FLT33-3PH	3 phase fault on Potter County 230kV (523959) to Moore County 230kV (523309) CKT 1, near Potter County. a. Apply fault at the Potter County 230kV 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.
34	FLT34-3PH	3 phase fault on Potter County 230kV (523959) to Harrington East 230kV (523979) CKT 1, near Potter County. a. Apply fault at the Potter County 230kV 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.
35	FLT35-3PH	3 phase fault on Potter County 230kV (523959) to Rolling Hills 230kV (524010) CKT 1, near Potter County. a. Apply fault at the Potter County 230kV 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.
36	FLT36-3PH	3 phase fault on Potter County 230kV (523959) to Bushland 230kV (524267) CKT 1, near Potter County. a. Apply fault at the Potter County 230kV 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.
37	FLT37-3PH	3 phase fault on Potter County 230kV (523959) to Newhart 230kV (525461) CKT 1, near Potter County. a. Apply fault at the Potter County 230kV bus.

Cont. No.	Cont. Name	Description
		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.
38	FLT38-3PH	3 phase fault on the Finney 345kV (523853) to Lamar 345kV (599950) CKT 1, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.
39	FLT39-PO (16WP Only)	**Prior outage on the Hitchland (523097) - Finney (523853)** 3 phase fault on Potter County 345kV (523961) to Hitchland 345kV (523097) CKT 1, near Potter County. a. Apply fault at the Potter County 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.
40	FLT40-PO (17SP and 25SP Only)	**Prior outage on the Hitchland (523097) – Walk Tap (531512)** 3 phase fault on Potter County 345kV (523961) to Hitchland 345kV (523097) CKT 1, near Potter County. a. Apply fault at the Potter County 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.
41	FLT41-PO (17SP and 25SP Only)	**Prior outage on the Hitchland (523097) - Walk Tap (531512)** 3 phase fault on Hitchland 345kV (523097) to G14-037-Tap 345kV (560010) CKT 1, near G14-037 Tap. a. Apply fault at the G14-037-Tap 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.
42		DELETED
43	FLT43-PO (17SP and 25SP Only)	**Prior outage on the Hitchland 345kV (523097) to Potter 345kV (523961)** 3 phase fault on Hitchland (523097) – Walk Tap (531512) CKT 1, near Hitchland. a. Apply fault at the Hitchland 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.
44	FLT44-PO	**Prior outage on the Woodward 345kV (515375) to Thistle (539801) 345kV line** 3 phase fault on Tatonga (515407) to G11-051-Tap (562075) a. Apply fault on the Tatonga (515407) 345kV to G11-051-Tap (562075) near Tatonga b. Clear fault after 5 cycles and trip the faulted line.

Cont. No.	Cont. Name	Description
		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.
45	FLT45-SB	**Woodward 345kV Stuck Breaker** a. Apply single phase fault at the Woodward (515375) 345kV bus on the Woodward – G11-051-Tap (562075) 345kV line b. Wait 16 cycles, and then drop Woodward (515375) 345kV to Thistle (539801) 345kV ckt 1 c. Trip Woodward to G11-051-Tap 345kV and remove the fault
46	FLT46-SB	**Hitchland 345kV Stuck Breaker** a. Apply single phase fault at the Hitchland (523097) 345kV bus b. Wait 16 cycles, and then drop Hitchland – Optima (560010) 345kV circuit 1 and remove fault
47	FLT47-SB (16WP Only)	**Hitchland 345kV Stuck Breaker** a. Apply single phase fault at the Hitchland (523097) 345kV bus b. Wait 16 cycles, and then drop Hitchland – Finney (523853) 345kV circuit 1 and remove fault
48	FLT48-PO	**Prior outage on the Woodward 345kV (515375) to Thistle (539801) 345kV line** 3 phase fault on Tatonga (515407) to Mathewson (515497) a. Apply 3 phase fault on the Tatonga (515407) 345kV to Mathewson (515497) line near Tatonga 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.
49	FLT49-SB	**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 – G11-14-Tap (560000) 345kV circuit 1 and remove fault
50	FLT50-SB	**G11-14-Tap 345kV Stuck Breaker** a. Apply single phase fault at the G11-14-Tap (560000) 345kV bus b. Wait 16 cycles, and then drop G11-14-Tap (560000) – Woodward (515375) 345kV circuit 1 and remove fault
51	FLT51-SB	**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

Single- line-to-ground faults were simulated with the standard method of applying fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network. The SLG fault impedance was computed by using PSS/E function “SCMU” as suggested by SPP.

The Southwest Power Pool Disturbance Performance Criteria Requirements in Appendix A were used to evaluate the system response during the initial transient period following a disturbance on the system. Generator response and bus voltages (115 kV and above) in Areas 520, 524, 525, 526, 531, 534, and 536 were monitored to ensure the system performance meets criteria requirements. Rotor angles of the nearby synchronous machines were investigated to make sure they maintained synchronism and had adequate damping following system faults.

Any wind generator must comply with FERC Order 661A on low voltage ride through requirements for wind farms. Therefore, the wind generators should not be tripped off line for faults by under voltage relay actuation. Generator speed of pre-queued projects was also monitored to ensure they stay online under system contingencies. For contingencies that result in a prior queued project tripping off-line; the contingency shall be re-run with the prior queued project's voltage and frequency tripping disabled.

2.2 STUDY RESULTS

All fault results are summarized in Table 2-2. The "Low Voltage Violation" in the table refers to bus voltages are lower than 0.7 pu. 2.5 second after the fault clearing and the "High Voltage" refers to bus voltage are higher than 1.2 pu. right after fault clearing. All violations are highlighted with **red**.

Table 2-2 Study Results Summary

Fault File Name	16WP Case			Fault File Name	17SP Case			Fault File Name	25SP Case		
	Stable?	Low Voltage Violation	High Voltage Violation		Stable?	Low Voltage Violation	High Voltage Violation		Stable?	Low Voltage Violation	High Voltage Violation
FLT01-3PH	Stable	No	No	FLT01-3PH	Stable	No	No	FLT01-3PH	Stable	No	No
FLT02-3PH	Stable	No	No	FLT02-3PH	Stable	No	No	FLT02-3PH	Stable	No	No
FLT03-3PH	Stable	No	No	FLT03-3PH	Stable	No	No	FLT03-3PH	Stable	No	No
FLT04-3PH	Undamped Oscillation	No	No	FLT04-3PH	Undamped Oscillation	No	No	FLT04-3PH	Stable	No	No
FLT05-3PH	Stable	No	No	FLT05-3PH	Stable	No	No	FLT05-3PH	Stable	No	No
FLT06-3PH	Undamped Oscillation	No	No	FLT06-3PH	Undamped Oscillation	No	No	FLT06-3PH	Undamped Oscillation	No	No
FLT07-3PH	Stable	No	No	FLT07-3PH	Stable	No	No	FLT07-3PH	Stable	No	No
FLT08-3PH	Stable	No	No	FLT08-3PH	Stable	No	No	FLT08-3PH	Stable	No	No
FLT09-3PH	Stable	No	No	FLT09-3PH	Stable	No	No	FLT09-3PH	Stable	No	No
FLT10-3PH	Stable	No	No	FLT10-3PH	Stable	No	No	FLT10-3PH	Stable	No	No
FLT11-3PH	Stable	No	No	FLT11-3PH	Stable	No	No	FLT11-3PH	Stable	No	No
FLT12-3PH	Stable	No	No	FLT12-3PH	Stable	No	No	FLT12-3PH	Stable	No	No
FLT14-3PH	Stable	No	No	FLT14-3PH	Stable	No	No	FLT13-3PH	Stable	No	No
FLT15-3PH	Stable	No	No	FLT15-3PH	Stable	No	No	FLT14-3PH	Stable	No	No
FLT16-3PH	Stable	No	No	FLT16-3PH	Stable	No	No	FLT15-3PH	Stable	No	No
FLT17-3PH	Stable	No	No	FLT17-3PH	Stable	No	No	FLT16-3PH	Stable	No	No
FLT19-3PH	Stable	No	No	FLT19-3PH	Stable	No	No	FLT17-3PH	Stable	No	No
FLT20-3PH	Stable	No	No	FLT20-3PH	Stable	No	No	FLT19-3PH	Stable	No	No
FLT21-3PH	Stable	No	No	FLT21-3PH	Stable	No	No	FLT20-3PH	Stable	No	No
FLT22-3PH	Stable	No	No	FLT22-3PH	Stable	No	No	FLT21-3PH	Stable	No	No
FLT23-3PH	Stable	No	No	FLT23-3PH	Stable	No	No	FLT22-3PH	Stable	No	No
FLT24-3PH	Stable	No	No	FLT25-3PH	Stable	No	No	FLT23-3PH	Stable	No	No
FLT25-3PH	Stable	No	No	FLT26-3PH	Stable	No	No	FLT25-3PH	Stable	No	No
FLT26-3PH	Stable	No	No	FLT27-3PH	Stable	No	No	FLT26-3PH	Stable	No	No
FLT27-3PH	Stable	No	No	FLT28-3PH	Stable	No	No	FLT27-3PH	Stable	No	No
FLT28-3PH	Stable	No	No	FLT29-3PH	Stable	No	No	FLT28-3PH	Stable	No	No
FLT29-3PH	Stable	No	No	FLT30-3PH	Stable	No	No	FLT29-3PH	Stable	No	No
FLT30-3PH	Stable	No	No	FLT31-3PH	Stable	No	No	FLT30-3PH	Stable	No	No

Fault File Name	16WP Case			Fault File Name	17SP Case			Fault File Name	25SP Case		
	Stable?	Low Voltage Violation	High Voltage Violation		Stable?	Low Voltage Violation	High Voltage Violation		Stable?	Low Voltage Violation	High Voltage Violation
FLT31-3PH	Stable	No	No	FLT33-3PH	Stable	No	No	FLT31-3PH	Stable	No	No
FLT33-3PH	Stable	No	No	FLT34-3PH	Stable	No	No	FLT33-3PH	Stable	No	No
FLT34-3PH	Stable	No	No	FLT35-3PH	Stable	No	No	FLT34-3PH	Stable	No	No
FLT35-3PH	Stable	No	No	FLT36-3PH	Stable	No	No	FLT35-3PH	Stable	No	No
FLT36-3PH	Stable	No	No	FLT37-3PH	Stable	No	No	FLT36-3PH	Stable	No	No
FLT37-3PH	Stable	No	No	FLT38-3PH	Stable	No	No	FLT37-3PH	Stable	No	No
FLT38-3PH	Stable	No	No	FLT40-PO	Stable	No	No	FLT38-3PH	Stable	No	No
FLT39-PO	Stable	No	No	FLT41-PO	Stable	No	No	FLT40-PO	Stable	No	No
FLT44-PO	Stable	No	No	FLT43-PO	Stable	No	No	FLT41-PO	Stable	No	No
FLT45-SB	Stable	No	No	FLT44-PO	Stable	No	No	FLT43-PO	Stable	No	No
FLT46-SB	Stable	No	No	FLT45-SB	Stable	No	No	FLT44-PO	Stable	No	No
FLT47-SB	Stable	No	No	FLT46-SB	Stable	No	No	FLT45-SB	Stable	No	No
FLT48-PO	Stable	No	No	FLT48-PO	Stable	No	No	FLT46-SB	Stable	No	No
FLT49-SB	Stable	No	No	FLT49-SB	Stable	No	No	FLT48-PO	Stable	No	No
FLT50-SB	Stable	No	No	FLT50-SB	Stable	No	No	FLT49-SB	Stable	No	No
FLT51-SB	Stable	No	No	FLT51-SB	Stable	No	No	FLT50-SB	Stable	No	No
								FLT51-SB	Stable	No	No

Figure 2-1 shows an example for the response of one studied generator following fault FLT01-3PH for 2016 Winter Peak case. The machine speed, active and reactive power output and terminal voltage are plotted to show the generator response.

All the simulation plots are included in Appendix B.

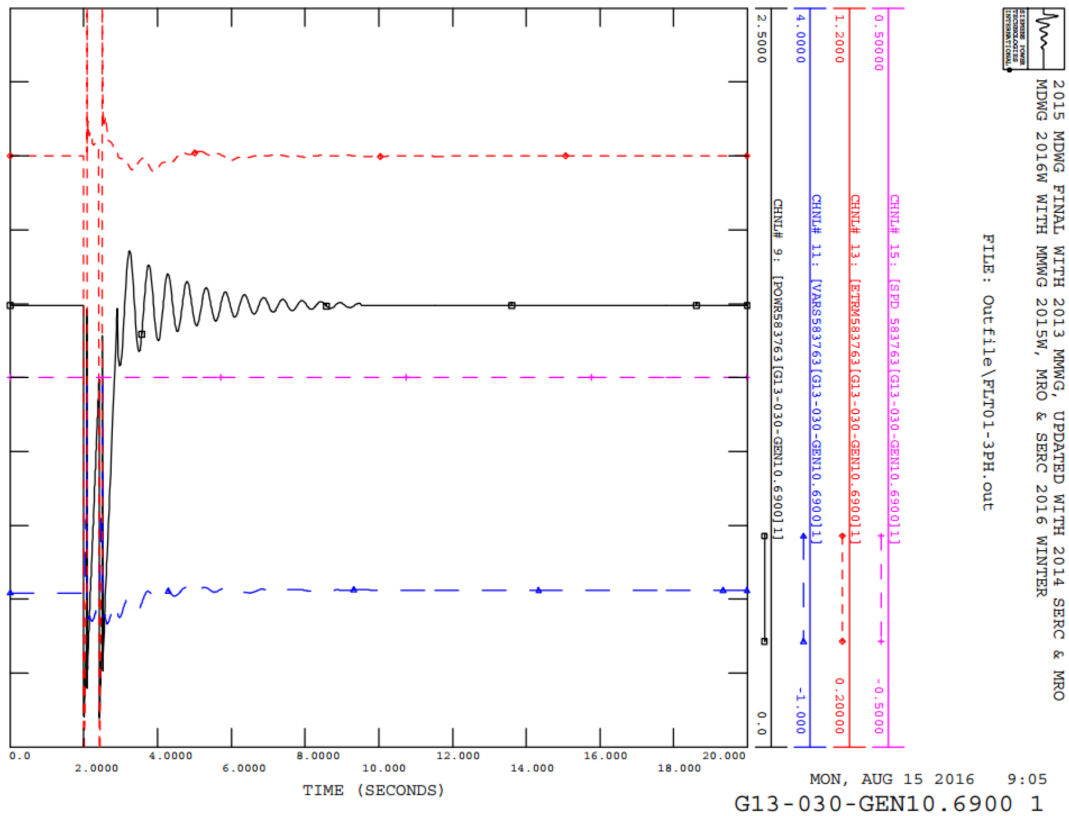


Figure 2-1: GEN-2013-030 Response Following Fault FLT01-3PH for 2016 Winter Peak Case

For FLT04-3PH and FLT06-3PH, some generators in the vicinity of the project and prior-queued generators showed undamped oscillations. One example of generator with undamped oscillations is plotted in Figure 2-2. Voltages of some buses and machine responses also showed wiggling response following these two faults for all three seasons except FLT04-3PH for 2025 Summer Peak Case. Figure 2-3 presents an example for bus voltage.

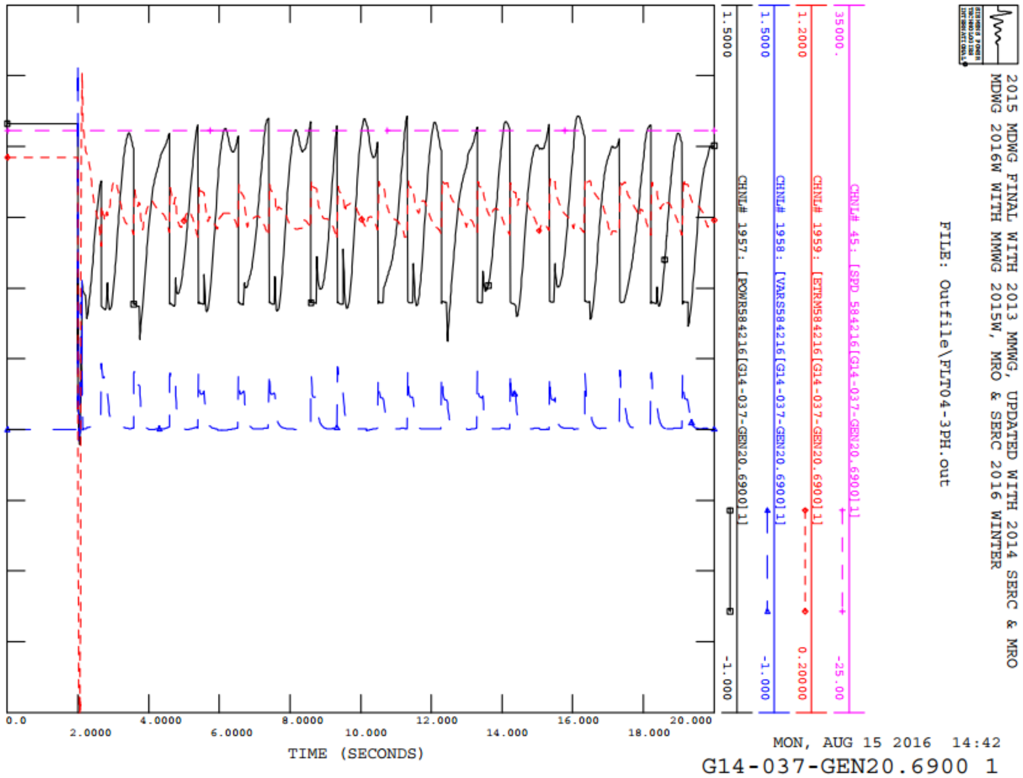


Figure 2-2 One Example of Generator with Undamped Oscillation for FLT04-3PH 2016 Winter Peak

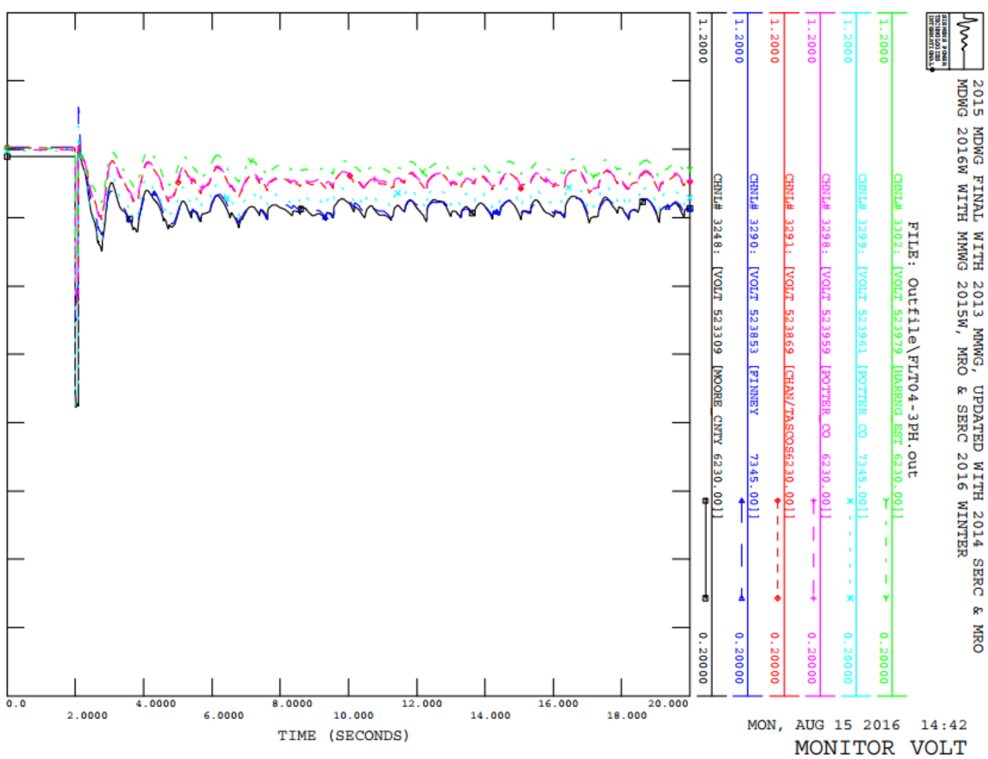


Figure 2-3 Bus Voltage Wiggling Example

Pre-project cases were created for all three study seasons to simulate the above two faults. No undamped oscillations were observed for either faults and for all three pre-project cases. In discussions with SPP since FLT04-3PH and FLT06-3PH are double circuit faults, the mitigation will be the curtailment of generation in the area.

For the rest of the studied faults, the simulation results showed no instability problems and no voltage violations for all three seasons. Also, for the contingencies simulated GEN-2013-030 remained on line and, therefore will comply with FERC Order 661A low voltage ride-through.

3 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on the 2017 Summer Peak and 2025 Summer Peak power flow cases using the PSS/E program. Only three-phase symmetrical fault current levels were calculated at up to five buses away from the point of interconnection.

Table 3-1 tabulates all the three-phase fault current levels, and the calculated values were listed here for SPP's reference.

Table 3-1: Three-Phase Fault Currents

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
599041	DEWIND-HV 115.00	6952.7	599041	DEWIND-HV 115.00	6920.4
524290	WILDOR2_JUS6230.00	6545.7	524290	WILDOR2_JUS6230.00	6519.6
523267	PRINGLE 6230.00	4301.7	523267	PRINGLE 6230.00	4309.6
515590	PALDR2W7 345.00	11380.9	515590	PALDR2W7 345.00	11632.2
524295	SPNSPUR_WND134.500	14590.2	524295	SPNSPUR_WND134.500	14411.1
515592	PALDRW21 34.500	8069.1	515592	PALDRW21 34.500	8091.0
515593	PALDRWT1 13.200	62048.1	515593	PALDRWT1 13.200	62307.3
515594	PALDRWT2 13.800	13901.1	515594	PALDRWT2 13.800	13931.7
523277	VALERO 3115.00	9704.4	523277	VALERO 3115.00	9733.7
515599	NBUFFRG7 345.00	8146.6	515599	NBUFFRG7 345.00	8612.4
584210	GEN-2013-030345.00	10512.1	584210	GEN-2013-030345.00	10642.4
584211	G14-037XFMR134.500	15969.4	584211	G14-037XFMR134.500	16012.0
584212	G14-037-GSU134.500	15232.8	584212	G14-037-GSU134.500	15270.4
584213	G14-037-GEN10.6900	718090.5	584213	G14-037-GEN10.6900	719610.2
584214	G14-037XFMR234.500	17073.4	584214	G14-037XFMR234.500	17118.5
584215	G14-037-GSU234.500	16917.9	584215	G14-037-GSU234.500	16961.5
584216	G14-037-GEN20.6900	814156.6	584216	G14-037-GEN20.6900	815947.7
531481	HUGOTON3 115.00	5943.2	531481	HUGOTON3 115.00	5955.6
581148	GEN-2011-022345.00	9008.3	581148	GEN-2011-022345.00	9093.9
581149	G11-022XFMR134.500	18222.1	581149	G11-022XFMR134.500	18251.0
581150	G11-022XFMR234.500	18115.3	581150	G11-022XFMR234.500	18144.4
581151	G11-022-GSU134.500	17429.4	581151	G11-022-GSU134.500	17453.8
581152	G11-022-GSU234.500	17013.5	581152	G11-022-GSU234.500	17036.4
581153	G11-022-GEN10.6900	753108.2	581153	G11-022-GEN10.6900	753754.4
581154	G11-022-GEN20.6900	739386.4	581154	G11-022-GEN20.6900	740002.2
523301	MOORE_E 113.200	12880.0	523301	MOORE_E 113.200	12671.6
523302	MOORE_TR1 113.200	20049.3	523302	MOORE_TR1 113.200	20261.4
523304	MOORE_W 3115.00	10663.5	523304	MOORE_W 3115.00	10710.6
515591	PALDRW11 34.500	32019.9	515591	PALDRW11 34.500	32194.3
523308	MOORE_E 3115.00	10663.5	523308	MOORE_E 3115.00	10710.6
523309	MOORE_CNTY 6230.00	6667.4	523309	MOORE_CNTY 6230.00	6632.9
524296	SPNSPUR_WND7345.00	4423.4	524296	SPNSPUR_WND7345.00	4384.8
515634	PALDR1W7 345.00	9851.4	515634	PALDR1W7 345.00	10041.3

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
531510	WALKTAP3 115.00	10289.8	531510	WALKTAP3 115.00	10352.1
531511	WALKETP-T 13.800	26710.1	531511	WALKETP-T 13.800	26723.3
531512	WALKTAP7 345.00	7698.1	531512	WALKTAP7 345.00	7791.6
599105	SPNSPUR-CB1 34.500	13396.9	599105	SPNSPUR-CB1 34.500	13231.3
573509	G08-047-GSU234.500	6831.3	573509	G08-047-GSU234.500	6844.4
573510	G08-047-GEN20.6900	270801.5	573510	G08-047-GEN20.6900	270968.5
523853	FINNEY 7345.00	10400.1	523853	FINNEY 7345.00	10512.3
583760	GEN-2013-030345.00	10749.7	583760	GEN-2013-030345.00	10974.8
583761	G13-030XFMR134.500	16904.9	583761	G13-030XFMR134.500	16959.9
583762	G13-030-GSU134.500	15999.5	583762	G13-030-GSU134.500	16043.5
583763	G13-030-GEN10.6900	671561.9	583763	G13-030-GEN10.6900	672378.8
583764	G13-030XFMR234.500	16916.5	583764	G13-030XFMR234.500	16971.4
583765	G13-030-GSU234.500	16027.3	583765	G13-030-GSU234.500	16071.6
583766	G13-030-GEN20.6900	672490.7	583766	G13-030-GEN20.6900	673310.2
523866	CHANNING 134.500	6179.1	523866	CHANNING 134.500	6107.2
523869	CHAN/TASCOS6230.00	3843.7	523869	CHAN/TASCOS6230.00	3814.3
523115	BUFF_DN_TR2113.200	513006.7	523115	BUFF_DN_TR2113.200	519402.7
525458	NEWHART_TR2113.200	16868.5	525458	NEWHART_TR2113.200	16710.0
525459	NEWHART_TR1113.200	16868.5	525459	NEWHART_TR1113.200	16710.0
525460	NEWHART 3115.00	14722.7	525460	NEWHART 3115.00	14707.0
525461	NEWHART 6230.00	10814.3	525461	NEWHART 6230.00	10865.2
539800	CLARKCOUNTY7345.00	11512.2	539800	CLARKCOUNTY7345.00	11663.2
539801	THISTLE7 345.00	14939.3	539801	THISTLE7 345.00	15463.7
539802	THISTLE T1 13.800	7899.2	539802	THISTLE T1 13.800	7948.1
539804	THISTLE4 138.00	16225.8	539804	THISTLE4 138.00	16621.8
599068	NTHBUF_XFMR134.500	20323.0	599068	NTHBUF_XFMR134.500	20673.7
523957	POTTER_TR 113.200	6632.6	523957	POTTER_TR 113.200	6652.5
523959	POTTER_CO 6230.00	20124.8	523959	POTTER_CO 6230.00	20149.7
523961	POTTER_CO 7345.00	7347.7	523961	POTTER_CO 7345.00	7316.0
599071	NTHBUF_XFMR234.500	20283.8	599071	NTHBUF_XFMR234.500	20632.4
523186	SPEARMAN 3115.00	8928.6	523186	SPEARMAN 3115.00	8952.5
523973	HARRNGTON3 124.000	112654.2	523973	HARRNGTON3 124.000	113779.9
523977	HARRNG_WST 6230.00	26062.2	523977	HARRNG_WST 6230.00	26282.5
523978	HARRNG_MID 6230.00	26062.2	523978	HARRNG_MID 6230.00	26282.5
523979	HARRNG_EST 6230.00	26062.2	523979	HARRNG_EST 6230.00	26282.5
599074	NTHBUF_EHV2 345.00	6322.7	599074	NTHBUF_EHV2 345.00	6595.7
515795	WWDEHV31 13.800	61104.4	515795	WWDEHV31 13.800	61877.9
515799	WWDEHV21 13.800	60734.4	515799	WWDEHV21 13.800	61524.8
579296	G07-046-XF-134.500	13879.0	579296	G07-046-XF-134.500	13950.2
514785	WOODWRD4 138.00	20085.1	514785	WOODWRD4 138.00	20767.4
579299	G07-046-XF-234.500	11219.5	579299	G07-046-XF-234.500	11275.5
524007	ROLLHILLS 3115.00	19009.9	524007	ROLLHILLS 3115.00	19061.0
524008	ROLHILLS_TR113.200	17095.8	524008	ROLHILLS_TR113.200	17047.8

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
524010	ROLLHILLS 6230.00	19252.4	524010	ROLLHILLS 6230.00	19330.5
514796	IODINE-4 138.00	7312.1	514796	IODINE-4 138.00	7404.1
576398	G10-014XFMR134.500	16586.4	576398	G10-014XFMR134.500	16604.3
531465	SETAB 7 345.00	7184.2	531465	SETAB 7 345.00	7259.0
531501	BUCKNER7 345.00	9673.4	531501	BUCKNER7 345.00	9757.1
539654	CIM-PLT3 115.00	7270.0	539654	CIM-PLT3 115.00	7268.6
584980	GEN-2015-060138.00	5764.6	584980	GEN-2015-060138.00	5816.0
523140	TXFARMS 3115.00	5108.3	523140	TXFARMS 3115.00	5101.0
579375	G06-044GSU2A34.500	17163.0	579375	G06-044GSU2A34.500	17210.0
523087	TC-TXCOUNTY134.500	4632.4	523087	TC-TXCOUNTY134.500	4629.2
525832	TUCO_INT 7345.00	10159.7	525832	TUCO_INT 7345.00	12468.8
579369	G06-044GSU1B34.500	17977.4	579369	G06-044GSU1B34.500	17986.2
579370	G06-044-MV1A115.00	8299.2	579370	G06-044-MV1A115.00	8313.6
579371	G06-044-XF1A34.500	14229.1	579371	G06-044-XF1A34.500	14235.7
579374	G06-044-XF2A34.500	17370.5	579374	G06-044-XF2A34.500	17398.8
515375	WWRDEHV7 345.00	17451.4	515375	WWRDEHV7 345.00	19954.5
515376	WWRDEHV4 138.00	24219.4	515376	WWRDEHV4 138.00	25398.6
579377	G06-044-MV2B115.00	10331.3	579377	G06-044-MV2B115.00	10352.0
579378	G06-044-XF2B34.500	22765.7	579378	G06-044-XF2B34.500	22778.4
531252	WALKMYR1 13.800	16046.3	531252	WALKMYR1 13.800	16025.5
515394	KEENAN 4 138.00	8275.2	515394	KEENAN 4 138.00	8421.0
523147	WADE 3115.00	3570.4	523147	WADE 3115.00	3565.3
515398	OUSPRT 4 138.00	9102.2	515398	OUSPRT 4 138.00	9278.6
523085	TC-TXCN_TR1113.200	5760.3	523085	TC-TXCN_TR1113.200	5759.9
523086	TC-TXCN_TR2113.200	5761.3	523086	TC-TXCN_TR2113.200	5761.0
515407	TATONGA7 345.00	10650.3	515407	TATONGA7 345.00	16311.4
523089	TC-TXCOUNTY269.000	8202.6	523089	TC-TXCOUNTY269.000	8320.6
523090	TEXAS_CNTY 3115.00	8729.3	523090	TEXAS_CNTY 3115.00	8702.0
523091	HITCHLD_TR0113.200	32978.4	523091	HITCHLD_TR0113.200	32980.9
523092	HITCHLD_TR1113.200	20475.3	523092	HITCHLD_TR1113.200	21285.7
523093	HITCHLAND 3115.00	17381.0	523093	HITCHLAND 3115.00	17326.4
523094	HITCHLD_TR2113.200	22557.5	523094	HITCHLD_TR2113.200	22553.9
523095	HITCHLAND 6230.00	14533.5	523095	HITCHLAND 6230.00	14652.9
523097	HITCHLAND 7345.00	14687.6	523097	HITCHLAND 7345.00	14919.9
523098	HITCHLD_TR4113.200	22122.3	523098	HITCHLD_TR4113.200	21285.7
523099	TC-WHITING 3115.00	2204.3	523099	TC-WHITING 3115.00	2208.4
523101	NOBLE_WND 7345.00	14628.6	523101	NOBLE_WND 7345.00	14859.1
523102	NOBLE_TR 113.800	32298.2	523102	NOBLE_TR 113.800	32361.0
523103	NOBLE_WND 3115.00	10486.3	523103	NOBLE_WND 3115.00	10526.2
523106	TXPHSF 3115.00	4080.7	523106	TXPHSF 3115.00	3977.4
523107	NOVUS_WND 14.1600	171675.3	523107	NOVUS_WND 14.1600	171722.4
523109	NOVUS1 134.500	17977.4	523109	NOVUS1 134.500	17986.2
523110	NOVUS1_TR1 113.800	521771.6	523110	NOVUS1_TR1 113.800	531150.8

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
523111	NOVUS1 3115.00	19302.4	523111	NOVUS1 3115.00	19394.4
523112	NOVUS1 7345.00	14434.3	523112	NOVUS1 7345.00	14657.9
523113	TC-MCMURRY 3115.00	6633.1	523113	TC-MCMURRY 3115.00	6623.6
523114	BUFF_DN_TR1113.200	517552.2	523114	BUFF_DN_TR1113.200	524048.6
524263	BSHLND_TR1 113.200	20293.5	524263	BSHLND_TR1 113.200	20310.3
523116	BUFF_DUNES1134.500	26489.1	523116	BUFF_DUNES1134.500	26545.0
523118	BUFF_DUNES 7345.00	6296.7	523118	BUFF_DUNES 7345.00	6341.7
523120	COLE 3115.00	4105.7	523120	COLE 3115.00	4106.1
523125	NBLWND-CB2 134.500	8112.2	523125	NBLWND-CB2 134.500	8118.5
523127	NBLWND-LV1 134.500	8351.2	523127	NBLWND-LV1 134.500	8358.6
523128	NBLWND-LV2 134.500	9999.7	523128	NBLWND-LV2 134.500	10011.4
523129	NBLWND-LV3 134.500	9494.0	523129	NBLWND-LV3 134.500	9503.9
523130	NBLWND-HV2 3115.00	5138.2	523130	NBLWND-HV2 3115.00	5148.6
523131	NBLWND-HV3 3115.00	7922.8	523131	NBLWND-HV3 3115.00	7946.3
560000	G11-14-TAP 345.00	12302.1	560000	G11-14-TAP 345.00	12742.6
515458	BORDER 7345.00	5037.3	515458	BORDER 7345.00	5164.6
582019	GEN-2011-019345.00	17451.4	582019	GEN-2011-019345.00	19954.5
582020	GEN-2011-020345.00	17451.4	582020	GEN-2011-020345.00	19954.5
573505	G08-047-GSU134.500	29399.1	573505	G08-047-GSU134.500	29530.7
560010	G14-037-TAP 345.00	14374.4	560010	G14-037-TAP 345.00	14621.4
576395	GEN-2010-014345.00	10928.2	576395	GEN-2010-014345.00	11053.8
576396	G10-014-XFMR115.00	13088.5	576396	G10-014-XFMR115.00	13142.6
576397	G10-014-XF-1115.00	9156.8	576397	G10-014-XF-1115.00	9182.6
599950	LAMAR7 345.00	2445.3	599950	LAMAR7 345.00	2458.4
523151	OCHLTRE_TR1113.200	10328.1	523151	OCHLTRE_TR1113.200	10267.5
576408	G10-014XFMR234.500	18423.3	576408	G10-014XFMR234.500	18446.2
523154	OCHILTREE 3115.00	5858.2	523154	OCHILTREE 3115.00	5848.2
523155	OCHILTREE 6230.00	4190.0	523155	OCHILTREE 6230.00	4191.2
523158	PERRYTON 3115.00	5589.1	523158	PERRYTON 3115.00	5579.2
576407	G10-014-XF-2115.00	12339.4	576407	G10-014-XF-2115.00	12387.3
523160	FRISCO_WND 3115.00	6952.7	523160	FRISCO_WND 3115.00	6920.4
562075	G11-051-TAP 345.00	11925.1	562075	G11-051-TAP 345.00	16991.5
525213	SWISHER 6230.00	10315.4	525213	SWISHER 6230.00	10418.4
560033	G1524&G1525T345.00	19090.6	560033	G1524&G1525T345.00	19754.8
523174	GOODWELLWND3115.00	6572.3	523174	GOODWELLWND3115.00	6596.4
523175	LASLEY 3115.00	5644.9	523175	LASLEY 3115.00	5590.8
523177	RB-SPURLOCK3115.00	5643.5	523177	RB-SPURLOCK3115.00	5609.2
583090	G1149&G1504 345.00	4617.2	583090	G1149&G1504 345.00	4721.2
578547	G10-001-GSU234.500	16730.2	578547	G10-001-GSU234.500	16782.6
523195	HANSFORD 3115.00	10207.2	523195	HANSFORD 3115.00	10213.0
523197	EXCELN4-HV23115.00	4724.7	523197	EXCELN4-HV23115.00	4731.7
583110	GEN-2011-051345.00	11925.1	583110	GEN-2011-051345.00	16991.5
531404	WALKMYR2 69.000	8232.0	531404	WALKMYR2 69.000	8320.0

2017 SP			2025 SP		
Number	**Name**	**3PH(Amp)**	**Number**	**Name**	**3PH(Amp)**
531405	WALKMYR3 115.00	9890.1	531405	WALKMYR3 115.00	9947.4
523216	RB-HOGUE 3115.00	3637.3	523216	RB-HOGUE 3115.00	3578.5
523256	ETTER 3115.00	5245.9	523256	ETTER 3115.00	5206.3
523221	XIT_INTG 6230.00	2608.3	523221	XIT_INTG 6230.00	2573.9
581113	G11-014XFMR134.500	13781.7	581113	G11-014XFMR134.500	13909.9
579412	G08-051-GSU234.500	16070.7	579412	G08-051-GSU234.500	15864.8
524623	DEAFSMITH 6230.00	7732.0	524623	DEAFSMITH 6230.00	7853.9
585180	GEN-2015-081345.00	10442.3	585180	GEN-2015-081345.00	14053.4
531450	HOLCTER1 13.800	18143.1	531450	HOLCTER1 13.800	18291.9
515554	BVRCNTY7 345.00	13227.8	515554	BVRCNTY7 345.00	13565.5
582119	G11-019XFMR134.500	37523.6	582119	G11-019XFMR134.500	38267.0
582120	G11-020XFMR134.500	37542.0	582120	G11-020XFMR134.500	38285.3
524266	BUSHLAND 3115.00	9119.7	524266	BUSHLAND 3115.00	9152.7
524267	BUSHLAND 6230.00	9505.8	524267	BUSHLAND 6230.00	9484.5
578542	GEN-2010-001345.00	11004.0	578542	GEN-2010-001345.00	11239.4
578543	G10-001XFMR134.500	16999.4	578543	G10-001XFMR134.500	17054.4
578544	G10-001-GSU134.500	16878.4	578544	G10-001-GSU134.500	16931.8
578545	G10-001-GEN10.6900	670947.4	578545	G10-001-GEN10.6900	671813.1
578546	G10-001XFMR234.500	16956.1	578546	G10-001XFMR234.500	17011.4
579411	G08-051XFMR234.500	16641.2	579411	G08-051XFMR234.500	16428.9
578548	G10-001-GEN20.6900	666641.8	578548	G10-001-GEN20.6900	667496.2
531448	HOLCOMB3 115.00	22230.4	531448	HOLCOMB3 115.00	22407.2
525481	PLANT_X 6230.00	22367.3	525481	PLANT_X 6230.00	23629.9
581112	GEN-2011-014345.00	11118.5	581112	GEN-2011-014345.00	11482.7
531449	HOLCOMB7 345.00	10490.8	531449	HOLCOMB7 345.00	10604.3
581114	G11-014-GSU134.500	13179.8	581114	G11-014-GSU134.500	13298.7
581117	G11-014XFMR234.500	12824.3	581117	G11-014XFMR234.500	12945.4
581118	G11-014-GSU234.500	12093.9	581118	G11-014-GSU234.500	12204.5

4 POWER FACTOR ANALYSIS

Since the studied project is a renewable energy project, power factor analysis was performed on three provided cluster scenarios upon SPP's request.

4.1 POWER FACTOR ANALYSIS METHODOLOGY

Power Factor Analysis was performed for the studied wind farm under system intact and contingency conditions. All N-1, three phase stability faults shown in Table 2-1 were analyzed as power flow contingencies. The power factor requirements for the wind farm were determined to maintain the voltage at the POI to the schedule voltage which is the higher of the POI voltage in the provided base case or 1.0 per unit. Fictitious var generator was added to the studied wind farm to maintain the scheduled voltage following all studied contingencies. The MW and Mvar injections from the studied wind farm at the POI were recorded and the power factors were calculated for all contingencies. The most lagging and most leading power factors determine the minimum power factor range capability required for the studied wind farm.

If more than one studied project share the same POI, the projects were grouped together and common power factor requirements were determined for this group of studied projects. With this method, none of the studied projects is required to provide more or less than its fair share of the reactive power requirements at the same POI. If a prior-queued project is connected at the same POI as the studied project, the prior-queued project was not grouped with the studied project since its reactive power requirements was determined in previous studies. However, the voltage schedules of the prior-queued project and the studied project at the same POI were coordinated and the local existing capacitor banks were set to their maximum capability, if necessary.

Per FERC and SPP requirements, if the power factor needed to maintain the scheduled voltage is less than 0.95 lagging or leading, the requirements is limited to 0.95 lagging or leading.

If the required power factor at the POI is beyond the capability of the studied wind turbine, the approximate size of the additional capacitors were determined.

4.2 STUDY RESULTS

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections.

Table 4-1 summarizes the power factor analysis results. The detailed power factor analysis results for each studied contingency are provided in Appendix C.

There are several cases which the wind project was observed to require less than 95% power factor (providing vars) at the Point of Interconnection. Per SPP and FERC requirements, the generating facility shall be designed to meet the requirement of 95% lagging (providing vars) and 95% leading (absorbing vars) to the Point of Interconnection.

These capacitor bank sizes are only estimates based on the information provided by the Interconnection Customer for its collector system design. Final needs will be based on final designs of the collector system determined by the Interconnection Customer to meet the power factor requirement.

Table 4-1 Power Factor Analysis Results

Request	Size (MW)	Generator Model	POI	Scenario	PF Analysis Worst Scenario		Final PF Requirement	
					Leading[1]	Lagging[2]	Leading[1]	Lagging[2]
GEN-2013-030	299	Siemens SWT 2.3MW	Beaver County 345kV Bus	16WP	N/A	0.672	1.0	0.95
				17SP	N/A	0.918	1.0	0.95
				25SP	1.0	0.964	1.0	0.95

Notes:

1. Leading is when the generator is absorbing reactive power from the transmission grid.
2. Lagging is when the generator is providing reactive power to the transmission grid.

5 LOW WIND/NO WIND ANALYSIS

In this study, ABB investigated the GEN-2013-030 project for low wind/no wind conditions, since the interconnected wind farm is connected at a 345kV bus.

5.1 LOW/NO WIND ANALYSIS METHODOLOGY

Low wind/No wind analysis is performed to determine the required shunt reactor size at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

For each studied scenario, the studied wind generator and capacitor bank (none in this case) was switched out of service with the collector system as modeled remaining in service. The resulting reactive power injection into the transmission network coming from the capacitance of the project's transmission lines and collector cables was measured. Then, the required shunt reactor size was calculated to bring the MVAr flow into the POI down to approximately zero.

5.2 STUDY RESULTS

Table 5-1 summaries the Low/No Wind analysis results. It is shown that 18.61 MVAr shunt reactor at the substation high side bus (515554) is required to bring the MVAr flow in the POI down to approximately zero under low/no wind conditions for all three studied seasons. This reactor bank size is approximate to be finalized during final facility and collector system design.

Table 5-1 Low/No Wind Analysis Results

Scenario	Reactive Power Injection at POI (MVAr)	Bus 560010 Volt (pu)	Required Shunt Reactor (MVAr)
16WP	18.78	1.0044	**18.61**
17SP	18.93	1.0085	**18.61**
25SP	19.05	1.0117	**18.61**

6 CONCLUSIONS

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for generator modification for generation interconnection request GEN-2013-030 (299 MW wind farm connected at Beaver County 345kV bus).

Request	Size (MW)	Generator Model	POI
GEN-2013-030	299.0	Siemens SWT 2.3 MW	Beaver County 345kV bus (515554)

The objective of this study is to re-evaluate the impact of project GEN-2013-030 on the existing and future systems based on change of wind turbines. While the previous study model was based on Vestas V110 2.0 MW wind turbine-generators, the present one is based on Siemens SWT 2.3 MW wind-turbine generators.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis. The following is a summary of study results.

For FLT04-3PH and FLT06-3PH, the studied generators and some pre-queued projects showed undamped oscillations. And voltages of some buses and machine responses also showed wiggling response following these two faults for all three seasons except for FLT04-3PH in 2025 Summer Peak Case. Pre-project cases were created for all three study seasons to simulate the above two faults. No oscillations were observed in pre-project cases. In discussions with SPP since FLT04-3PH and FLT06-3PH are double circuit faults, the mitigation will be the curtailment of generation in the area.

For the rest of the studied faults, the simulation results showed no stability problems and no voltage violations for all three seasons. All the simulation results were summarized in Table 2-2. Also, for the contingencies simulated GEN-2013-030 remained on line and, therefore will comply with FERC Order 661A low voltage ride-through.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP’s reference.

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The results show need for reactive power from the study project following the critical contingencies. The proposed GEN-2013-030 need to design their facility to meet the SPP pro-forma 95% lagging (providing vars) and 95% leading (absorbing vars) power factor requirements at the Point of Interconnection.

The Low/No Wind analysis shows that an 18.61 MVAr shunt reactor is required to bring the MVAr flow in the POI down to approximate zero under low/no wind conditions. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

APPENDIX A SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE CRITERIA REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements (“Requirements”) shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$\text{SPPR} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% ≥ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio ≥ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of } 5^{th} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR5) x 100% ≥ 22.6%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.

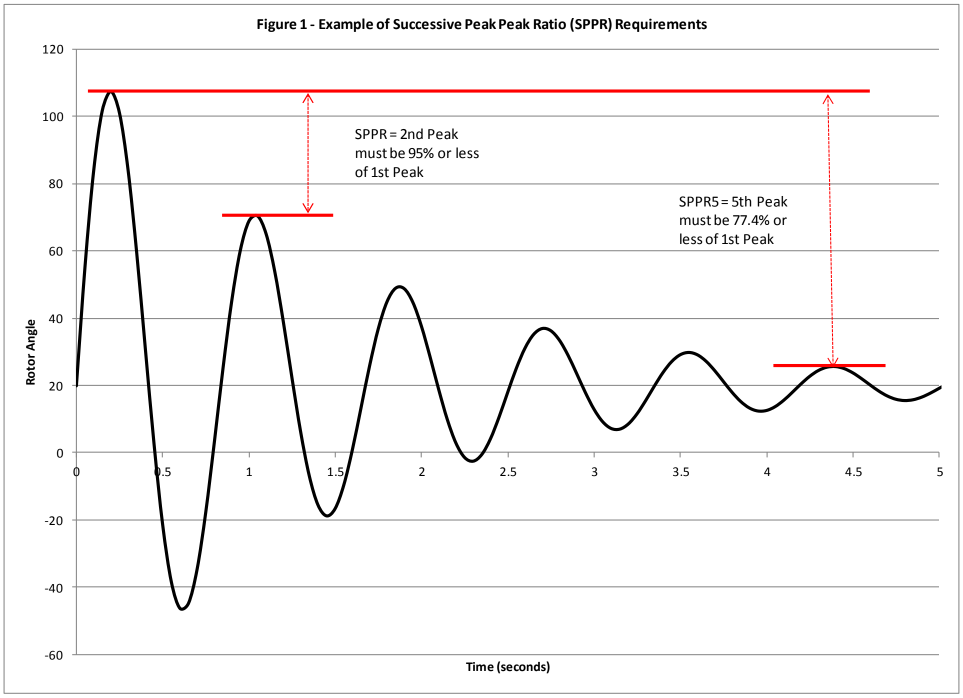


Figure 1 - Example of Successive Peak Peak Ratio (SPPR) Requirements

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

After a disturbance is cleared; bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.

Qualitatively, this Requirement is shown in Figure 2 below.

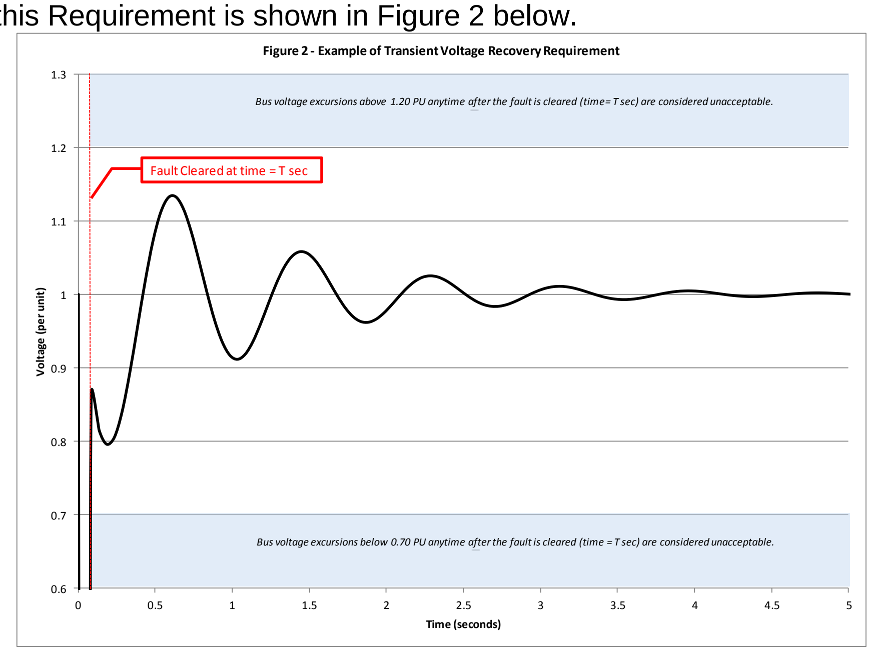


Figure 2 - Example of Transient Voltage Recovery Requirement

APPENDIX B SIMULATION PLOTS FOR STABILITY ANALYSIS

APPENDIX C POWER FACTOR ANALYSIS RESULTS

All the contingency numbers shown in this appendix match with the fault numbers shown in Table 2-1.

C.1 GEN-2013-030 2016 Winter Peak Case

The GEN-2013-030 POI voltage is 0.9883 pu in the provided 2016 winter peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-291.6	-30.6	0.995	lagging
Contingency	1	-291.7	-41.0	0.990	lagging
Contingency	2	-291.6	-32.4	0.994	lagging
Contingency	3	-291.7	-63.1	0.977	lagging
Contingency	4	-291.5	-193.5	0.833	lagging
Contingency	5	-291.6	-31.0	0.994	lagging
Contingency	6	-291.7	-38.7	0.991	lagging
Contingency	7	-291.6	-38.4	0.991	lagging
Contingency	8	-291.6	-34.7	0.993	lagging
Contingency	9	-291.6	-28.0	0.995	lagging
Contingency	10	-291.7	-58.9	0.980	lagging
Contingency	11	-291.7	-66.0	0.975	lagging
Contingency	12	-291.6	-31.9	0.994	lagging
Contingency	13	-291.6	-33.8	0.993	lagging
Contingency	14	-291.6	-31.9	0.994	lagging
Contingency	15	-290.4	-319.9	**0.672**	lagging
Contingency	16	-291.6	-32.5	0.994	lagging
Contingency	17	-291.8	-65.4	0.976	lagging
Contingency	18	-291.6	-36.9	0.992	lagging
Contingency	19	-291.7	-40.8	0.990	lagging
Contingency	20	-290.9	-274.9	0.727	lagging
Contingency	21	-291.7	-79.1	0.965	lagging
Contingency	22	-291.7	-89.0	0.956	lagging
Contingency	23	-291.6	-36.4	0.992	lagging
Contingency	24	-291.6	-30.4	0.995	lagging
Contingency	25	-291.6	-29.0	0.995	lagging
Contingency	26	-291.6	-34.7	0.993	lagging
Contingency	27	-291.7	-38.3	0.991	lagging
Contingency	28	-291.6	-35.0	0.993	lagging

C.2 GEN-2013-030 2017 Summer Peak Case

The GEN-2013-030 POI voltage is 0.9933 pu in the provided 2017 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-291.5	-4.2	1.000	lagging
Contingency	1	-291.5	-14.5	0.999	lagging
Contingency	2	-291.5	-6.1	1.000	lagging
Contingency	3	-291.6	-28.7	0.995	lagging
Contingency	4	-291.7	-126.3	**0.918**	lagging
Contingency	5	-291.5	-1.5	1.000	lagging
Contingency	6	-291.5	-10.8	0.999	lagging
Contingency	7	-291.5	-10.1	0.999	lagging
Contingency	8	-291.5	-7.6	1.000	lagging
Contingency	9	-291.5	-2.4	1.000	lagging
Contingency	10	-291.5	-15.8	0.999	lagging
Contingency	11	-291.6	-18.1	0.998	lagging
Contingency	12	-291.5	-5.4	1.000	lagging
Contingency	13	-291.5	-7.6	1.000	lagging
Contingency	14	-291.5	-4.4	1.000	lagging
Contingency	15	-291.5	-6.9	1.000	lagging
Contingency	16	-291.6	-37.5	0.992	lagging
Contingency	17	-291.5	-10.7	0.999	lagging
Contingency	18	-291.5	-12.9	0.999	lagging
Contingency	19	-291.8	-102.2	0.944	lagging
Contingency	20	-291.6	-37.9	0.992	lagging
Contingency	21	-291.7	-48.4	0.987	lagging
Contingency	22	-291.5	-13.1	0.999	lagging
Contingency	23	-291.5	-5.3	1.000	lagging
Contingency	24	-291.5	-3.6	1.000	lagging
Contingency	25	-291.5	-8.5	1.000	lagging
Contingency	26	-291.5	-9.8	0.999	lagging
Contingency	27	-291.5	-5.0	1.000	lagging

C.3 GEN-2013-030 2025 Summer Peak Case

The GEN-2013-030 POI voltage is 0.9973 pu in the provided 2025 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-291.3	17.7	0.998	leading
Contingency	1	-291.4	9.8	0.999	leading
Contingency	2	-291.3	16.4	0.998	leading
Contingency	3	-291.5	-7.5	1.000	lagging
Contingency	4	-291.7	-80.2	**0.964**	lagging
Contingency	5	-291.3	19.9	0.998	leading
Contingency	6	-291.4	15.8	0.999	leading
Contingency	7	-291.4	13.6	0.999	leading
Contingency	8	-291.4	15.9	0.999	leading
Contingency	9	-291.3	20.8	0.997	leading
Contingency	10	-291.3	19.3	0.998	leading
Contingency	11	-291.3	18.6	0.998	leading
Contingency	12	-291.3	16.3	0.998	leading
Contingency	13	-291.4	14.9	0.999	leading
Contingency	14	-291.3	17.8	0.998	leading
Contingency	15	-291.4	12.8	0.999	leading
Contingency	16	-291.6	-18.5	0.998	lagging
Contingency	17	-291.4	10.2	0.999	leading
Contingency	18	-291.5	3.5	1.000	leading
Contingency	19	-291.6	-37.1	0.992	lagging
Contingency	20	-291.5	-9.6	0.999	lagging
Contingency	21	-291.6	-28.3	0.995	lagging
Contingency	22	-291.4	10.5	0.999	leading
Contingency	23	-291.4	15.0	0.999	leading
Contingency	24	-291.3	17.0	0.998	leading
Contingency	25	-291.4	14.3	0.999	leading
Contingency	26	-291.4	13.4	0.999	leading
Contingency	27	-291.3	17.2	0.998	leading