Southwest Power Pool

GEN-2012-002
Impact Restudy for Generator Modification (Turbine Change)

SPP Generation Interconnection Studies

GEN-2012-002

September 2013

Executive Summary

The GEN-2012-002 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied Siemens 2.3MW wind turbine generators to the GE1.7MW wind turbine generators. Mistubishi Electric Power Products, Inc. (MEPPI) was commissioned to perform this restudy, and its report of the results is attached.

In this restudy the project uses fifty-nine (59) GE 1.7MW wind turbine generators for an aggregate power of 100.3MW and is located near Scott City, KS. The interconnection restudy request shows that the GE 1.7MW wind turbine generators will have the optional +/-0.90 power factor capabilities installed.

The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the GE 1.7MW wind turbine generators. Additionally, the project wind farm 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.

A power factor analysis was performed in this study. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the point of interconnection.

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator[s] may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the **Customer may be required to reduce their generation output to 0 MW under certain system conditions** to allow system operators to maintain the reliability of the transmission network.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2012-002 GIA in place, GEN-2012-002 should be able to reliably interconnect to the SPP transmission grid.

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 by the Customer.

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Southwest Power Pool, Inc. (SPP)

GEN-2012-002 System Impact Restudy (GE 1.7 MW)

Final Report

PXE-0732
Revision #01

September 2013

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Services Department
Warrendale, PA

Title: **GEN-2012-002 System Impact Restudy (GE 1.7 MW): Final Report PXE-0732**
Date: September 2013
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EXECUTIVE SUMMARY

SPP requested a system impact restudy of its generation interconnection request. The interconnection request required a Power Factor Analysis and a Stability Analysis detailing the impacts of the interconnecting project as shown in Table ES-1.

Table ES-1
Interconnection Project Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection (POI)
GEN-2012-002	100.3 (59 turbines)	GE 1.7 MW	Tap on Pile-Scott City 115 kV (562110)

SUMMARY OF STABILITY ANALYSIS

For 2014 summer and 2014 winter peak conditions, the Stability Analysis determined that there were no voltage violations or wind turbine tripping that occurred from interconnecting GEN-2012-002 at 100% output.

SUMMARY OF POWER FACTOR ANALYSIS

The Power Factor Analysis shows that GEN-2012-002 has a power factor range of 0.9924 leading (absorbing) to 0.9843 lagging (supplying) for 2014 summer peak conditions and a power factor range of 0.9626 leading (absorbing) to 0.9940 lagging (supplying) for 2014 winter peak conditions.

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SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "GEN-2012-002 System Impact Restudy." SPP requested an Interconnection System Impact Study for one generation interconnection, which requires a Power Factor Analysis, Stability Analysis, and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 32.2.0 was used for this study. SPP provided the stability database cases for 2014 summer peak and 2014 winter peak seasons and a list of contingencies to be examined. The model includes the study project and the previously queued projects as listed in Table 2-1 and Table 2-2, respectively. Refer to Appendix A for the steady-state and dynamic model data for the study projects. A power flow one-line diagram for the generation interconnection project is shown in Figure 2-1.

The Power Factor analysis will determine the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. Table 2-3 lists the contingencies developed from the three-phase fault definitions provided in the Group's interconnection impact study request.

The Stability Analysis will determine the impacts of the new interconnecting project on the stability and voltage recovery of the nearby systems and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades will be investigated. Three-phase faults and single line-to-ground faults will be examined as listed in Table 2-3.

Table 2-1
Interconnection Project Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection (POI)
GEN-2012-002	100.3 (59 turbines)	GE 1.7 MW	Tap on Pile-Scott City 115 kV (562110)

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2001-039M	99	Vestas V90VCRS 3.0MW	Central Plains 115kV (531485)
GEN-2003-006A	201	Vestas V90VCRS 3.0MW	Elm Creek 230kV (539639)
GEN-2003-019	249.3	GE 1.5MW & Vestas 3.0MW	Smoky Hills 230kV (530592)
GEN-2006-031	75	Gas	Knoll 115kV (530561)
GEN-2006-040	108	Acciona AW1500 1.5MW	Mingo 115kV (531429)
GEN-2007-011	135	Acciona AW1500 1.5MW	Syracuse 115kV (531437)
GEN-2008-017	300	GE 1.5MW	Setab 345kV (531465)
GEN-2008-092	201	GE 1.5MW	Knoll 230kV (530558)
GEN-2009-008	198.9	GE 1.7MW	South Hays 230kV (530582)
GEN-2009-020	48.3	Siemens 2.3MW	Tap on the Bazine to Nekoma 69kV line (560306)
GEN-2010-048	70	Nordex 2.5MW	Tap on the Ross Beach to Redline 115kV line (560366)
GEN-2010-057	201	GE 1.5MW	Rice County 230kV (530686)

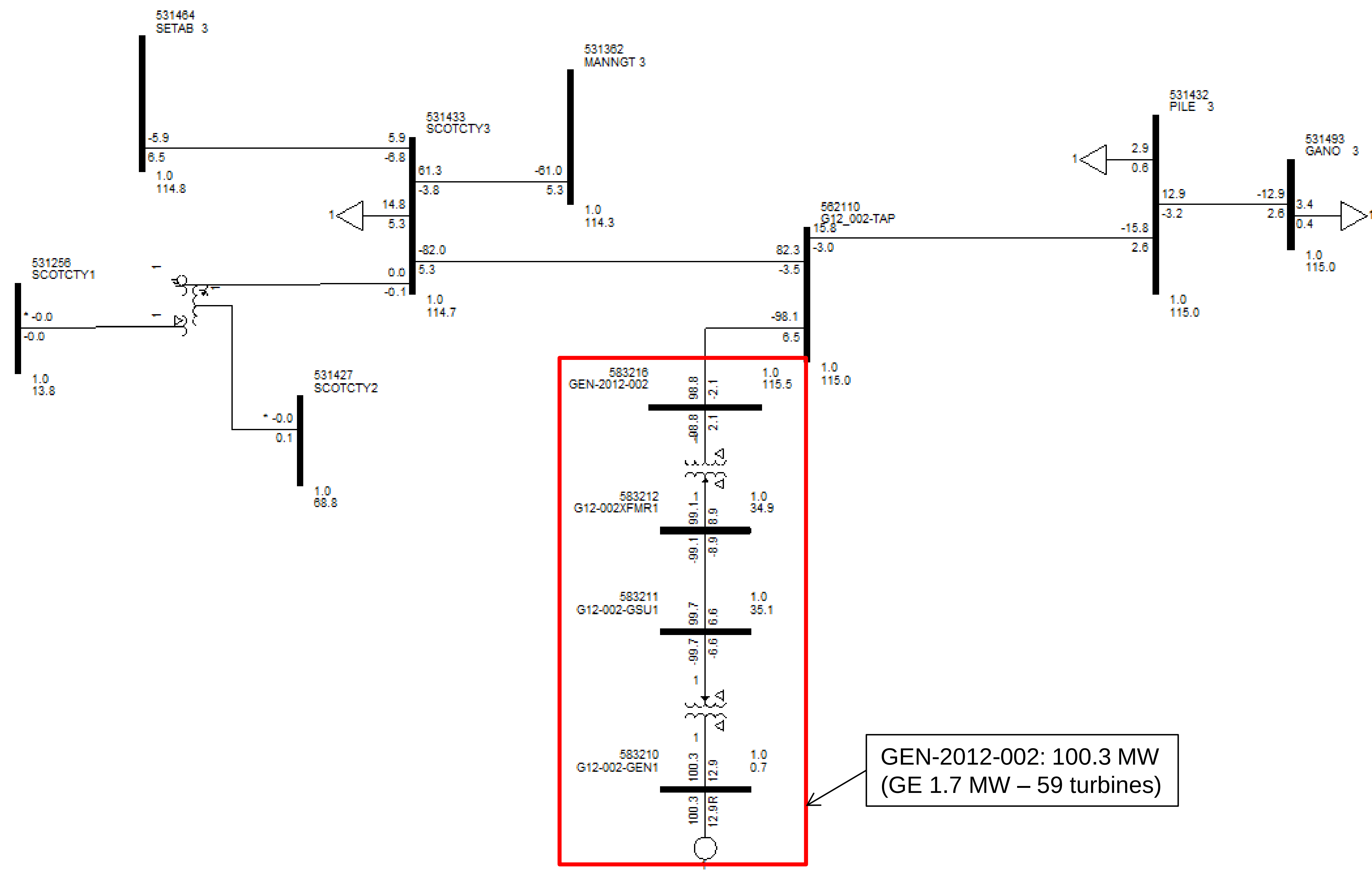

Figure 2-1. Power flow one-line diagram for interconnection project GEN-2012-002.

Table 2-3
Case List with Contingency Description

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the G12_002-TAP (562110) to Pile (531432) 115kV line, near G12_002-TAP. a. Apply fault at the G12_002-TAP 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single-phase fault similar to previous fault.*
3	FLT03-3PH	3 phase fault on the G12_002-TAP (562110) to Scott City (531433) 115kV line, near G12_002-TAP. a. Apply fault at the G12_002-TAP 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single-phase fault similar to previous fault.*
5	FLT05-3PH	3 phase fault on Dobson (531419) to Gano (531493) 115kV line, near Dobson. a. Apply fault at the Dobson 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single-phase fault similar to previous fault.*
7	FLT07-3PH	3 phase fault on the Dobson (531419) to Morris (531430) 115kV line, near Dobson. a. Apply fault at the Dobson 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-1PH	*Single-phase fault similar to previous fault.*
9	FLT09-3PH	3 phase fault on the Dobson (531419) to KSAVWTP (531480) 115kV line, near Dobson. a. Apply fault at the Dobson 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single-phase fault similar to previous fault.*
11	FLT11-3PH	3 phase fault on the Dobson (531419) to Lowe Tap (531425) 115kV line, near Dobson. a. Apply fault at the Dobson 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single-phase fault similar to previous fault.*
13	FLT13-3PH	3-Phase fault on the Scott City 115kV (531433)/Scott City 69kV (531427) transformer near the Scott City 115kV bus. a. Apply fault at the Scott City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
14	FLT14-3PH	3 phase fault on the Scott City (531433) to Setab (531464) 115kV line, near Scott City. a. Apply fault at the Scott City 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT15-1PH	*Single-phase fault similar to previous fault.*
16	FLT16-3PH	3 phase fault on the Scott City (531433) - Manning Tap (531362) 115kV line, near Scott City. a. Apply fault at the Scott City 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
17	FLT17-1PH	*Single-phase fault similar to previous fault.*

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description
18	FLT18-3PH	3 phase fault on the City Services Tap (531416) - City Services (531418) 115kV line, near City Services Tap. a. Apply fault at the City Services Tap 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
19	FLT19-1PH	*Single-phase fault similar to previous fault.*
20	FLT20-3PH	3 phase fault on the City Services Tap (531416) - Central Plains Tap (531485) 115kV line, near City Services Tap. a. Apply fault at the City Services Tap 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
21	FLT21-1PH	*Single-phase fault similar to previous fault.*
22	FLT22-3PH	3-Phase fault on the Setab 345kV (531465)/Setab 115kV (531464) transformer near the Setab 345 kV bus. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
23	FLT23-3PH	3 phase fault on the Setab (531465) to Mingo (531451) 345kV line, near Setab. a. Apply fault at the Setab 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single-phase fault similar to previous fault.*
25	FLT25-3PH	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab. a. Apply fault at the Setab 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single-phase fault similar to previous fault.*
27	FLT27-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single-phase fault similar to previous fault.*
29	FLT29-3PH	3 phase fault on the Holcomb (531449) to Finney (523853) 345kV line, ckt 1, near Holcomb. a. Apply fault at the Holcomb 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single-phase fault similar to previous fault.*
31	FLT31-3PH	3 phase fault on the Holcomb (531449) to Buckner (531501) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT32-1PH	*Single-phase fault similar to previous fault.*
33	FLT33-3PH	3-Phase fault on the Holcomb 345kV (531449)/Holcomb 115kV (531448)/Holcomb 13.8kV (531450) transformer near the Holcomb 345kV bus. A. Apply fault at the Holcomb 345kV bus. B. Clear fault after 5 cycles by tripping the faulted transformer.

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description
34	FLT34-3PH	3 phase fault on the Holcomb (531449) to Plymell (531393) 115kV line, near Holcomb. a. Apply fault at the Holcomb 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
35	FLT35-1PH	*Single-phase fault similar to previous fault.*
36	FLT36-3PH	3 phase fault on the Finney (523853) - Hitchland (523097) 345kV line, near the Finney bus. a. Apply fault at the Finney 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
37	FLT37-1PH	*Single-phase fault similar to previous fault.*
38	FLT38-3PH	3 phase fault on the Spearville (531469) - Buckner (531501) 345kV line, near the Spearville bus. a. Apply fault at the Spearville 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
39	FLT39-1PH	*Single-phase fault similar to previous fault.*
40	FLT40-3PH	3 phase fault on the Spearville (531469) - GEN-2011-017 POI (560242) 345kV line, near the Spearville bus. a. Apply fault at the Spearville 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
41	FLT41-1PH	*Single-phase fault similar to previous fault.*
42	FLT42-3PH	3-Phase fault on the Spearville 345kV (531469)/Spearville 230kV (539695)/Spearville 13.8kV (531468) transformer near the Spearville 345kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
43	FLT43-3PH	3-Phase fault on the Post Rock 345kV (530583)/Post Rock 230kV (530584)/Post Rock 13.8kV (530673) transformer near the Post Rock 345kV bus. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
44	FLT44-3PH	3 phase fault on the Post Rock (530583) - Axtell (640065) 345kV line, near the Post Rock bus. a. Apply fault at the Post Rock 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave the fault on for 5 cycles, then trip the line in (b) and remove fault.
45	FLT45-1PH	*Single-phase fault similar to previous fault.*

SECTION 3: STABILITY ANALYSIS

The objective of the stability analysis was to determine the impacts of the new wind farm on the stability and voltage recovery on the SPP transmission system. If problems with stability or voltage recovery were identified the need for reactive compensation or system upgrades were investigated.

Approach

The 2014 winter peak and 2014 summer peak power flows provided by SPP were examined prior to the Stability Analysis to ensure they contained the proposed study project (GEN-2012-002) modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., "flat lines") were achieved. Three-phase and single line-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 3-1 for a list of the calculated single-phase fault impedances used for this analysis.

Table 3-1
Calculated Single-Phase Fault Impedances

Contingency Number	Contingency Name	Single Phase Fault Impedance (MVA)	
		2014 Summer Peak	2014 Winter Peak
2	FLT02-1PH	-1000.0	-1000.0
4	FLT04-1PH	-1000.0	-1000.0
6	FLT06-1PH	-1625.0	-1375.0
8	FLT08-1PH	-1625.0	-1375.0
10	FLT10-1PH	-1625.0	-1375.0
12	FLT12-1PH	-1625.0	-1375.0
15	FLT15-1PH	-1250.0	-1250.0
17	FLT17-1PH	-1250.0	-1250.0
19	FLT19-1PH	-1375.0	-1375.0
21	FLT21-1PH	-1375.0	-1375.0
24	FLT24-1PH	-3218.8	-3218.8
26	FLT26-1PH	-3218.8	-3218.8
28	FLT28-1PH	-2406.3	-2406.3
30	FLT30-1PH	-4843.8	-4843.8
32	FLT32-1PH	-4843.8	-4843.8
35	FLT35-1PH	-3625.0	-3218.8
37	FLT37-1PH	-4843.8	-4843.8
39	FLT39-1PH	-6468.8	-6468.8
41	FLT41-1PH	-6468.8	-6468.8
45	FLT45-1PH	-3421.9	-3421.9

Bus voltages and previously queued generation in the study area were monitored in addition to the bus voltages in the following areas:

- 525 WFEC
- 526 SPS
- 531 MIDW
- 534 SUNC
- 536 WERE
- 640 NPPD

The results of the analysis determined if reactive compensation or system upgrades were required to obtain acceptable system performance. If additional reactive compensation was required, the size, type, and location were determined. The proposed reactive reinforcements would ensure the wind farm meets FERC Order 661A low voltage requirements and return the wind farm to its pre-disturbance operating voltage. If the results indicated the need for fast responding reactive support, dynamic support such as an SVC or STATCOM was investigated. If tripping of the prior queued projects was observed during the stability analysis (for under/over voltage or under/over frequency) the simulations were re-ran with the prior queued project's voltage and frequency tripping disabled.

Results

Refer to Table 3-2 for a summary of the Stability Analysis results for the cases listed in Table 2-3.

Table 3-2
Stability Analysis Results Summary

Contingency Number	Contingency Name	2014 Summer Peak		2014 Winter Peak	
		Stable?	Acceptable?	Stable?	Acceptable?
1	FLT01-3PH	Yes	Yes	Yes	Yes
2	FLT02-1PH	Yes	Yes	Yes	Yes
3	FLT03-3PH	Yes	Yes	Yes	Yes
4	FLT04-1PH	Yes	Yes	Yes	Yes
5	FLT05-3PH	Yes	Yes	Yes	Yes
6	FLT06-1PH	Yes	Yes	Yes	Yes
7	FLT07-3PH	Yes	Yes	Yes	Yes
8	FLT08-1PH	Yes	Yes	Yes	Yes
9	FLT09-3PH	Yes	Yes	Yes	Yes
10	FLT10-1PH	Yes	Yes	Yes	Yes
11	FLT11-3PH	Yes	Yes	Yes	Yes
12	FLT12-1PH	Yes	Yes	Yes	Yes
13	FLT13-3PH	Yes	Yes	Yes	Yes
14	FLT14-3PH	Yes	Yes	Yes	Yes
15	FLT15-1PH	Yes	Yes	Yes	Yes
16	FLT16-3PH	Yes	Yes	Yes	Yes
17	FLT17-1PH	Yes	Yes	Yes	Yes
18	FLT18-3PH	Yes	Yes	Yes	Yes
19	FLT19-1PH	Yes	Yes	Yes	Yes
20	FLT20-3PH	Yes	Yes	Yes	Yes
21	FLT21-1PH	Yes	Yes	Yes	Yes
22	FLT22-3PH	Yes	Yes	Yes	Yes
23	FLT23-3PH	Yes	Yes	Yes	Yes
24	FLT24-1PH	Yes	Yes	Yes	Yes
25	FLT25-3PH	Yes	Yes	Yes	Yes
26	FLT26-1PH	Yes	Yes	Yes	Yes
27	FLT27-3PH	Yes	Yes	Yes	Yes
28	FLT28-1PH	Yes	Yes	Yes	Yes
29	FLT29-3PH	Yes	Yes	Yes	Yes
30	FLT30-1PH	Yes	Yes	Yes	Yes
31	FLT31-3PH	Yes	Yes	Yes	Yes
32	FLT32-1PH	Yes	Yes	Yes	Yes
33	FLT33-3PH	Yes	Yes	Yes	Yes
34	FLT34-3PH	Yes	Yes	Yes	Yes
35	FLT35-1PH	Yes	Yes	Yes	Yes
36	FLT36-3PH	Yes	Yes	Yes	Yes

Table 3-2 (Continued)
Stability Analysis Summary of Results

Contingency Number	Contingency Name	2014 Summer Peak		2014 Winter Peak	
		Stable?	Acceptable?	Stable?	Acceptable?
37	FLT37-1PH	Yes	Yes	Yes	Yes
38	FLT38-3PH	Yes	Yes	Yes	Yes
39	FLT39-1PH	Yes	Yes	Yes	Yes
40	FLT40-3PH	Yes	Yes	Yes	Yes
41	FLT41-1PH	Yes	Yes	Yes	Yes
42	FLT42-3PH	Yes	Yes	Yes	Yes
43	FLT43-3PH	Yes	Yes	Yes	Yes
44	FLT44-3PH	Yes	Yes	Yes	Yes
45	FLT45-1PH	Yes	Yes	Yes	Yes

The Stability Analysis determined that there was no wind turbine tripping that occurred from interconnecting GEN-2012-002 at 100% output.

Note for Fault #20, a three-phase fault on the City Services Tap (531416) to Central Plains Tap (531485) 115 kV line, due to a modeling issue for the Central Plains WTG (GEN-2001-039M, Vestas 3.0 MW model), the reactive support of this WTG was set to 0.98 lagging power factor (supplying 20 Mvar) for summer and winter peak conditions.

<u>2014 Summer Peak Summary</u>

For 2014 summer peak conditions, the Stability Analysis determined that there were no wind turbine tripping that occurred from interconnecting GEN-2012-002 at 100% output. No voltages were observed to exceed 1.20 p.u. or fall below 0.7 p.u. at any time after the fault was cleared.

Refer to Figure 3-1 for a plot of bus voltages during the representative limiting contingency, Contingency #16 (FLT16-3PH), a 3 phase fault on the Scott City (531433) to Manning Tap (531362) 115 kV line. There was no load or generator tripping observed for this contingency. Refer to Figure 3-2 and Figure 3-3 for plots of the response of GEN-2012-002 during this fault.

<u>2014 Winter Peak Summary</u>

For 2014 winter peak conditions, the Stability Analysis determined that there were no wind turbine tripping that occurred from interconnecting GEN-2012-002 at 100% output. No voltages were observed to exceed 1.20 p.u. or fall below 0.7 p.u. at any time after the fault was cleared.

Refer to Appendix B and Appendix C for a complete set of plots for all contingencies for 2014 summer and 2014 winter, respectively.

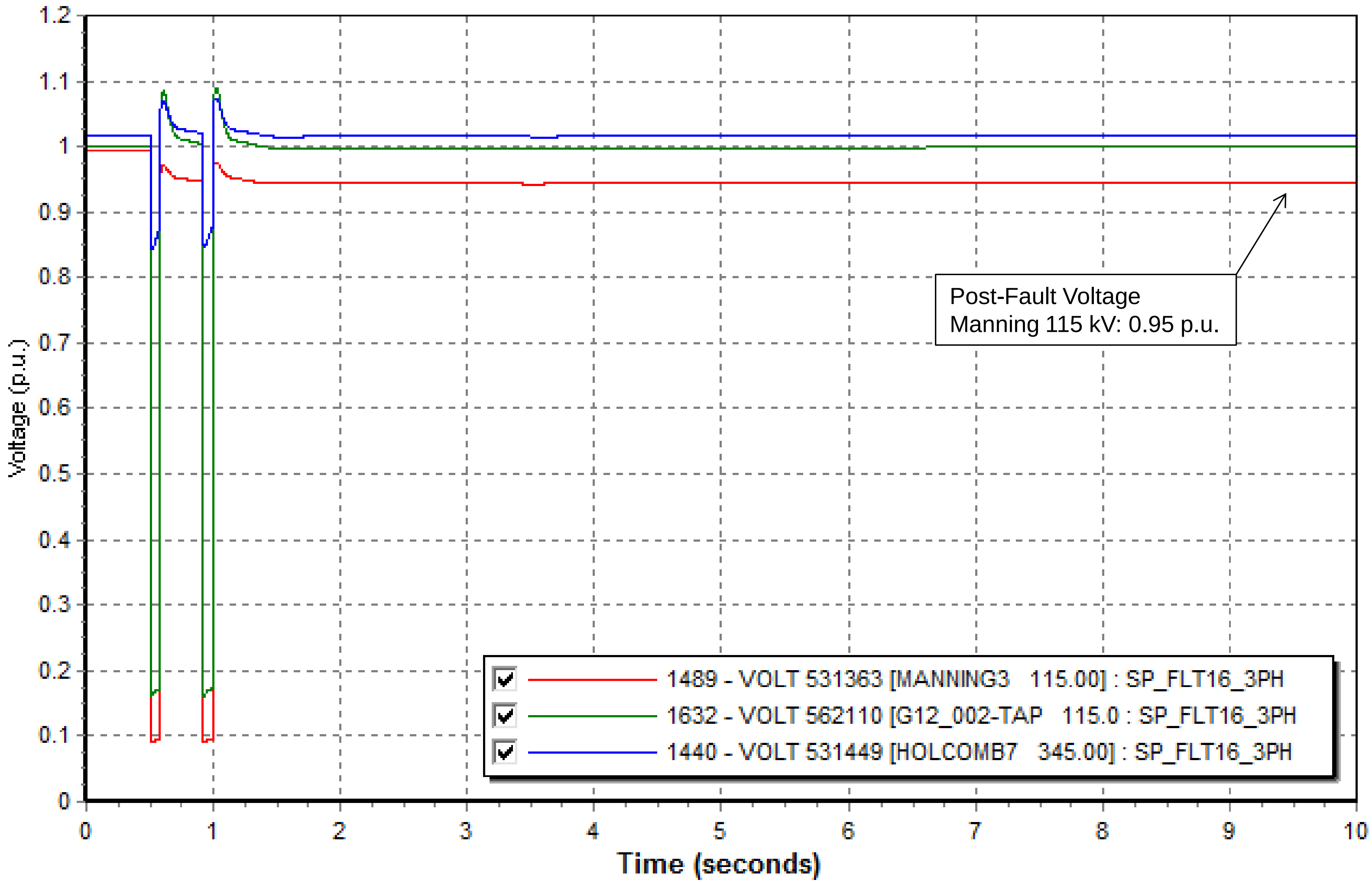

Figure 3-1. Plot of bus voltages during Contingency #16 (FLT16-3PH) for 2014 summer peak conditions.

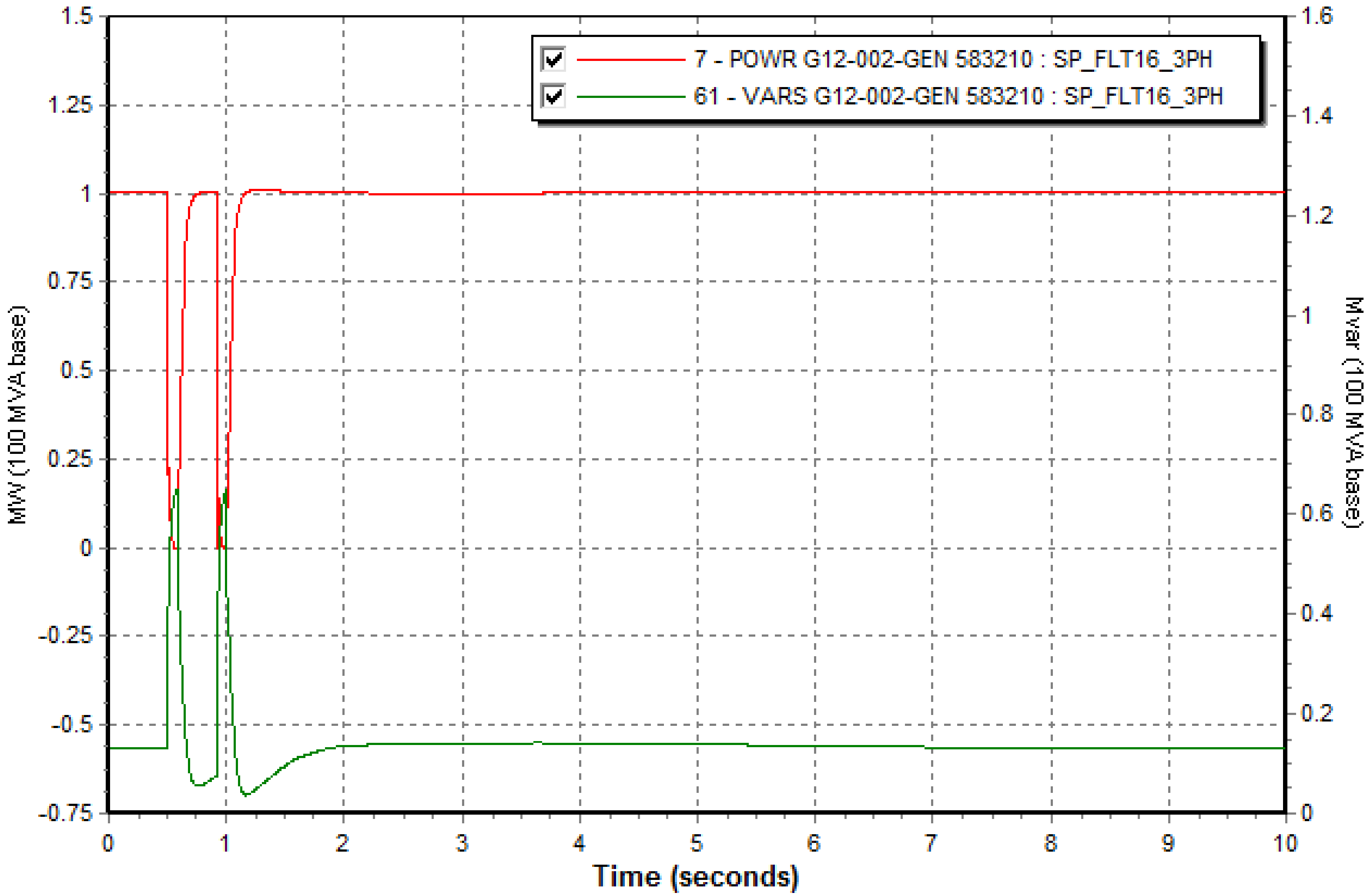

Figure 3-2. MW and Mvar plot for GEN-2012-002 during Contingency #16 for 2014 summer peak conditions.

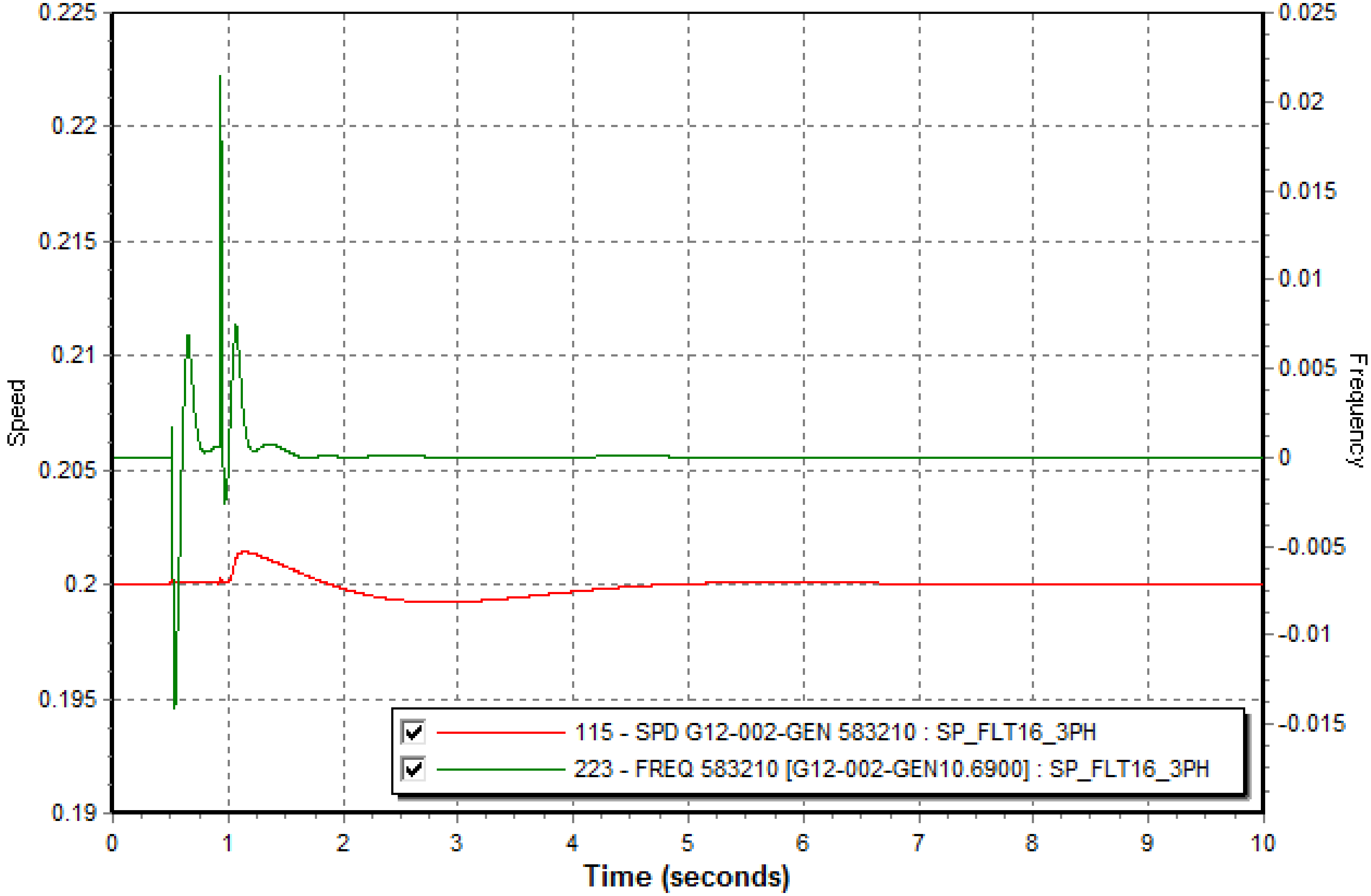

Figure 3-3. Speed and Frequency plot for GEN-2012-002 during Contingency #16 for 2014 summer peak conditions.

SECTION 4: POWER FACTOR ANALYSIS

The objective of this task is to quantify the power factor at the point of interconnection for the wind farms during base case and system contingencies. SPP transmission planning practice requires interconnecting generation projects to maintain the power factor (pf) at the Point of Interconnection (POI) near unity for system intact conditions and within +/- 0.95 pf for post-contingency conditions. This is analyzed by having the wind farm maintain a prescribed voltage schedule at the point of interconnection of 1.0 p.u. voltage, or if the pre-project voltage is higher than 1.0 p.u., to maintain the pre-project voltage schedule.

The 2014 winter and 2014 summer peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project and any previously queued projects at the same point of interconnection were turned off during the power factor analysis. The wind farm(s) were then replaced by a generator modeled at the high side bus with the same real power (MW) capability as the wind farm(s) and open limits for the reactive power set points (Mvar). The generator was set to hold the POI scheduled bus voltage. Contingencies from the three-phase fault definitions provided in Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

4.1 Study Project – GEN-2012-002

Approach

GEN-2012-002 was disabled and a generator was placed at the study project's high side voltage bus. The generator was modeled with PGEN = 100.3 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's high side voltage bus to the GEN-2012-002 generator were disabled. The pre-project voltage at the POI (Tap on Pile to Scott City 115 kV – Bus 562110) for the 2014 summer peak conditions is 0.997 p.u. and for the 2014 winter peak conditions is 1.002 p.u. Therefore, the scheduled voltage for the POI was set to 1.00 p.u. for summer peak conditions and 1.002 p.u. for the winter peak conditions.

Results

The power factor was calculated for 2014 summer and 2014 winter peak conditions. Table 4-1 shows the power factor results for GEN-2012-002. Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 4-1
Power Factor Analysis: GEN-2012-002 (P_{GEN}=100.3 MW)*

Power Factor Analysis GEN-2012-002 (Pgen = 100.3)						
Case	2014 Summer Peak			2014 Winter Peak		
	Power Factor		Q**(MVAR)	Power Factor		Q**(MVAR)
Base	0.9998	Leading	1.94	0.9875	Leading	16.04
FLT01-3PH	1.0000	Lagging	-0.67	0.9908	Leading	13.67
FLT03-3PH	0.9993	Leading	3.88	0.9999	Leading	1.29
FLT05-3PH	1.0000	Lagging	-0.68	0.9901	Leading	14.21
FLT07-3PH	0.9997	Leading	2.33	0.9873	Leading	16.15
FLT09-3PH	1.0000	Lagging	-0.85	0.9884	Leading	15.42
FLT11-3PH	0.9998	Leading	1.90	0.9868	Leading	16.49
FLT13-3PH	0.9998	Leading	1.94	0.9875	Leading	16.04
FLT14-3PH	0.9994	Lagging	-3.53	0.9992	Leading	4.10
FLT16-3PH	0.9999	Leading	1.04	0.9932	Leading	11.77
FLT18-3PH	0.9998	Leading	1.94	0.9875	Leading	16.04
FLT20-3PH	0.9924	Leading	12.41	0.9626	Leading	28.21
FLT22-3PH	0.9843	Lagging	-18.00	0.9940	Lagging	-11.06
FLT23-3PH	0.9973	Lagging	-7.33	0.9968	Leading	8.08
FLT25-3PH	0.9965	Lagging	-8.47	0.9953	Leading	9.71
FLT27-3PH	0.9986	Lagging	-5.22	0.9959	Leading	9.12
FLT29-3PH	0.9998	Leading	1.90	0.9875	Leading	16.01
FLT31-3PH	0.9960	Lagging	-9.03	0.9961	Leading	8.90
FLT33-3PH	0.9993	Leading	3.75	0.9799	Leading	20.41
FLT34-3PH	0.9998	Leading	1.80	0.9868	Leading	16.43
FLT36-3PH	1.0000	Lagging	-0.36	0.9900	Leading	14.26
FLT38-3PH	0.9999	Lagging	-1.23	0.9891	Leading	14.95
FLT40-3PH	0.9997	Leading	2.27	0.9865	Leading	16.66
FLT42-3PH	0.9998	Leading	2.06	0.9871	Leading	16.26
FLT43-3PH	0.9998	Leading	1.93	0.9875	Leading	16.00
FLT44-3PH	1.0000	Lagging	-0.30	0.9894	Leading	14.71

*The scheduled voltage for the POI (Tap on Pile - Scott City 115 kV) was 1.00 p.u. for summer peak and 1.002 p.u. for winter peak conditions.
**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

Summary

The Power Factor Analysis shows that GEN-2012-002 has a power factor range of 0.9924 leading (absorbing) to 0.9843 lagging (supplying) for 2014 summer peak conditions and a power factor range of 0.9626 leading (absorbing) to 0.9940 lagging (supplying) for 2014 winter peak conditions.

SECTION 5: CONCLUSIONS

Stability Analysis

For 2014 summer and 2014 winter peak conditions, the Stability Analysis determined that there were no voltage violations or wind turbine tripping that occurred from interconnecting GEN-2012-002 at 100% output.

Power Factor Analysis

The Power Factor Analysis shows that GEN-2012-002 has a power factor range of 0.9924 leading (absorbing) to 0.9843 lagging (supplying) for 2014 summer peak conditions and a power factor range of 0.9626 leading (absorbing) to 0.9940 lagging (supplying) for 2014 winter peak conditions.