P: Stability Study for Group 8

R1-2010

Generator Interconnection Impact Study for DISIS-2009-001 - Group 8

Prepared for

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Section

1

Introduction

1.1 Background

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Siemens PTI performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customers and SPP for SPP Generation Interconnection request. The requests for interconnection were placed with SPP in accordance to SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

The purpose of this report is to present the results of the stability and power factor analysis performed to evaluate the impact of the proposed DISIS-2009-001 cluster of interconnections with regard to Group 8 projects on the Southwest Power Pool system. Eventual indicative solutions to the identified issues are proposed based on the impact of each generation interconnection on the Southwest Power Pool system.

Four projects in this cluster are connected to four different points of interconnection at different voltage levels, ranging from 69 kV to 345 kV. Section 2 describes all proposed wind farms projects in detail.

Transient stability analysis was performed using the package provide by SPP. It contains the latest stability database in PSS®E version 30.3.3. The stability package also includes the dynamic data for the previously queued projects.

1.2 Purpose

The steady state and stability study was carried out to:

(a) Determine the ability of the proposed generation facilities to remain in synchronism and within applicable planning standards following system faults with unsuccessful reclosing.

(b) Determine the amount of transient support required from the costumer to meet the power factor requirement at the POI.

(c) Determine the ability of the wind farm to meet FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage) with and without additional reactive support.

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Section

2

Model Development

The study has considered the 2010 Summer Peak and Winter Peak load flow models provided by SPP with the required interconnection generations modeled. The base cases also contain all the significant previous queued generation interconnection projects in the interconnection queue.

2.1 Power Flow Data

The Group 8 of DISIS-2009-001 contains three proposed wind generation projects and one nuclear power generation project. Table 2-1 presents the size of the nuclear and wind generation projects, the Wind Turbine Generator (WTGs) manufacturers, the reactive capability of the nuclear generator and wind farm as well as the point of interconnection and the PSS®E bus numbers in the load flow models.

Table 2-1 – Details of the Interconnection Requests

Request	Size (MW)	Model	Reactive capability of Wind Farm		Point of Interconnection	Bus Number
			Max (MVAr)	Min (MVAr)		
GEN-2008-021	1250	Nuclear Steam Turbine	600.0	-425.0	Wolf Creek 345kV	532797
GEN-2008-38	150	G.E. 1.5MW	49.3	-49.3	Tap Shidler – Pawhuska 138kV	570838
GEN-2008-127	200	Siemens 2.3MW	65.25	-73.95	Tap Sooner – Rose Hill 345kV	573039
GEN-2009-025	60	GE 1.5MW	19.6	-29.2	Tap Deerck – Sincblk2 69KV	573049

The analysis was carried out using the database package provided by SPP which also includes the modeling data for the previously queued projects, as shown in Table 2-2:

Table 2-2 – Details of the Prior Queued Interconnection Requests

Request	Size	Wind Turbine Model	Point of Interconnection	Bus Number
GEN-2002-004	200	GE.1.5MW	Latham 345kV	532800
GEN-2004-010	300	Clipper 2.5MW	Latham 345kV	532800
GEN-2005-013	201	G.E. 1.5MW	Latham – Neosho 345kV	574000
GEN-2005-016	150	Gamesa 2MW	Latham – Neosho 345kV	574000
GEN-2007-025	300	Clipper 2.5MW	Wichita-Woodring 345kV	532781

GEN-2008-013	300	G.E. 1.5MW	Wichita – Woodring 345kV	210130

Figures 2-1 to 2-6 present the surrounding area of the Group 8 points of interconnection, showing the line flows and voltage profile for the load flow models considered in the study for summer and winter peak scenarios, respectively.

Figure 2-1 - Group 8 Points of Interconnection Surrounding Area – *Diagram1* Summer Peak

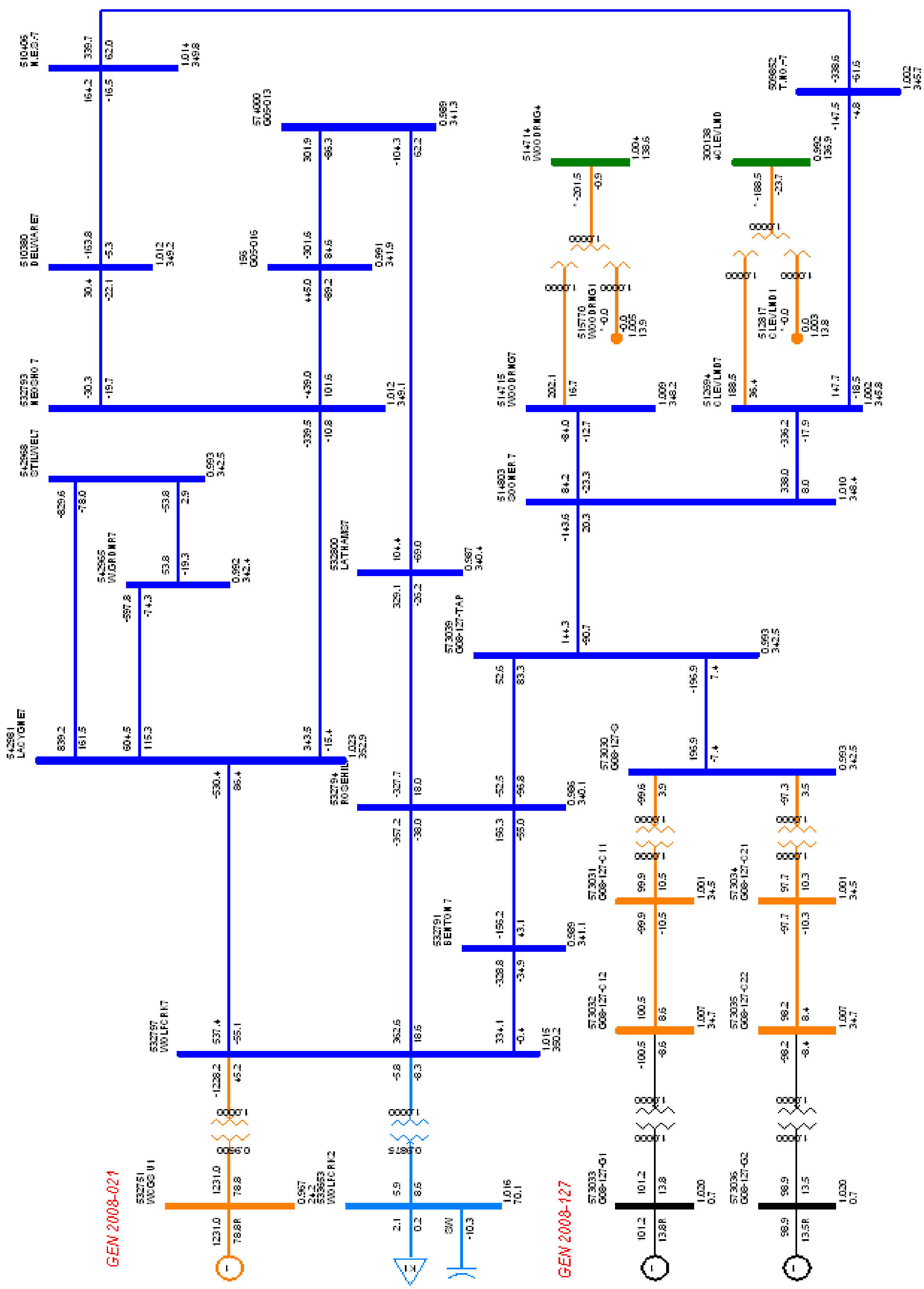


Figure 2-2 - Group 8 Points of Interconnection Surrounding Area – *Diagram2* Summer Peak

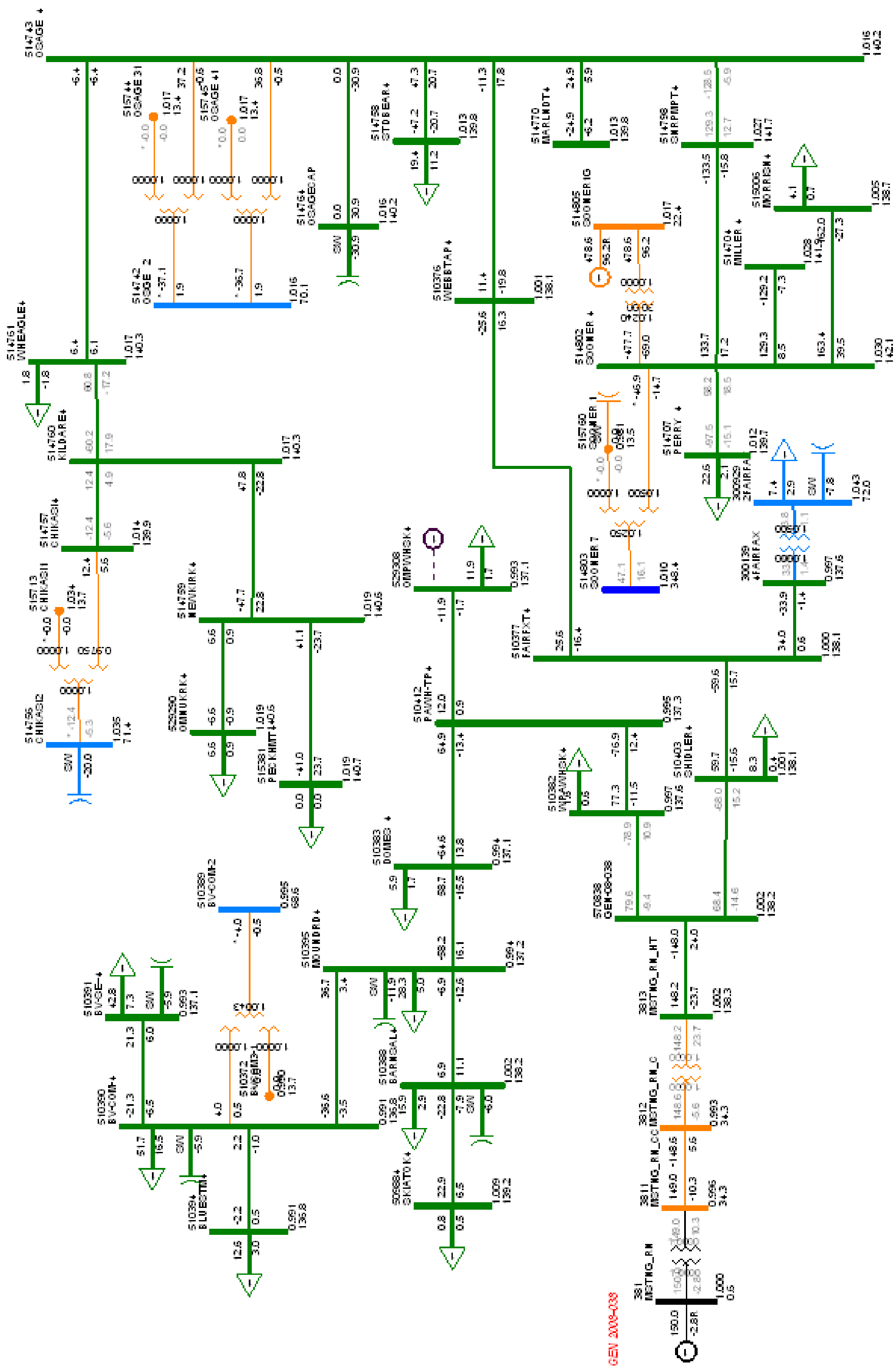


Figure 2-3 - Group 8 Points of Interconnection Surrounding Area – *Diagram3* Summer Peak

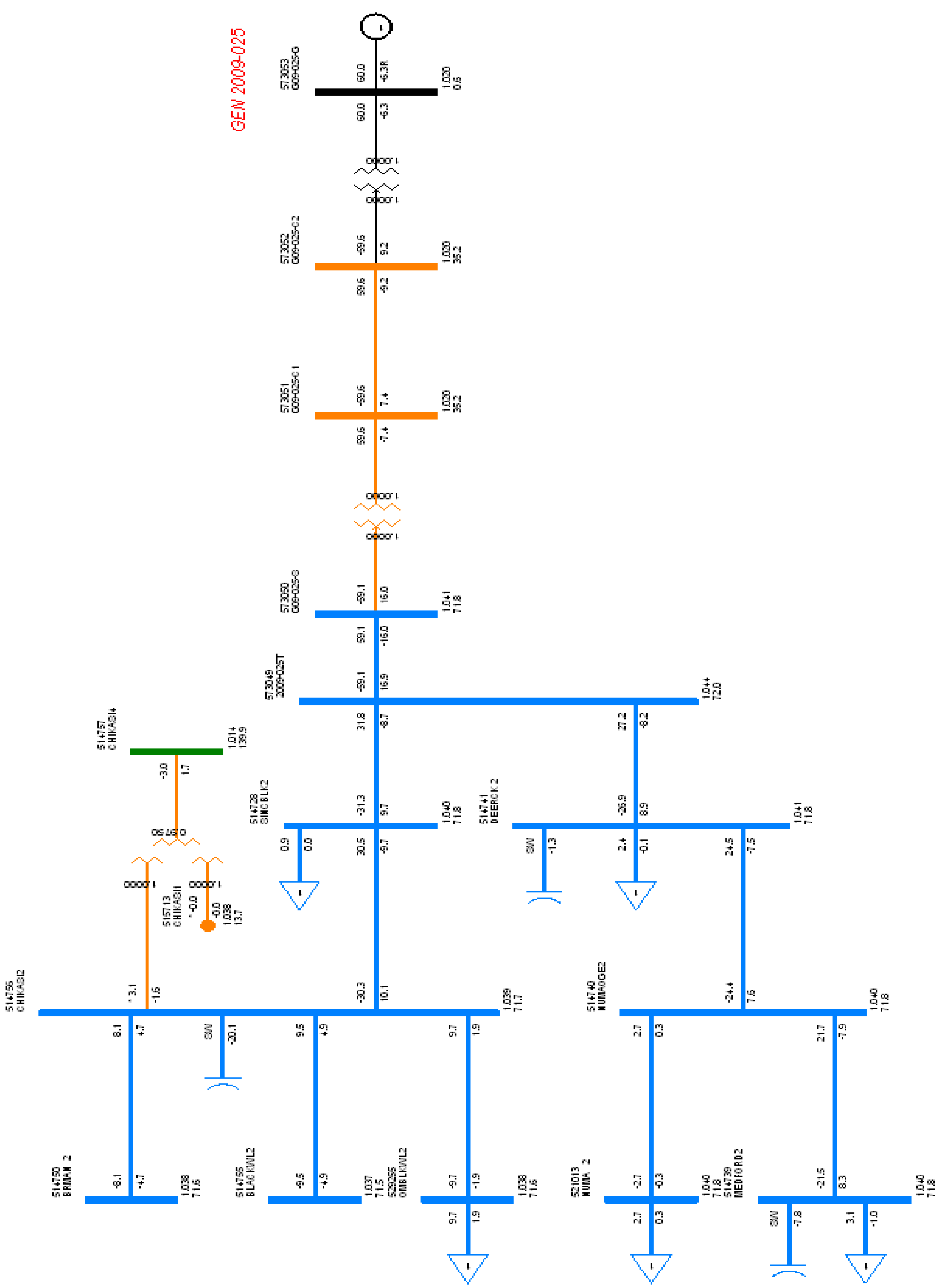


Figure 2-4 - Group 8 Points of Interconnection Surrounding Area – *Diagram1*
Winter Peak

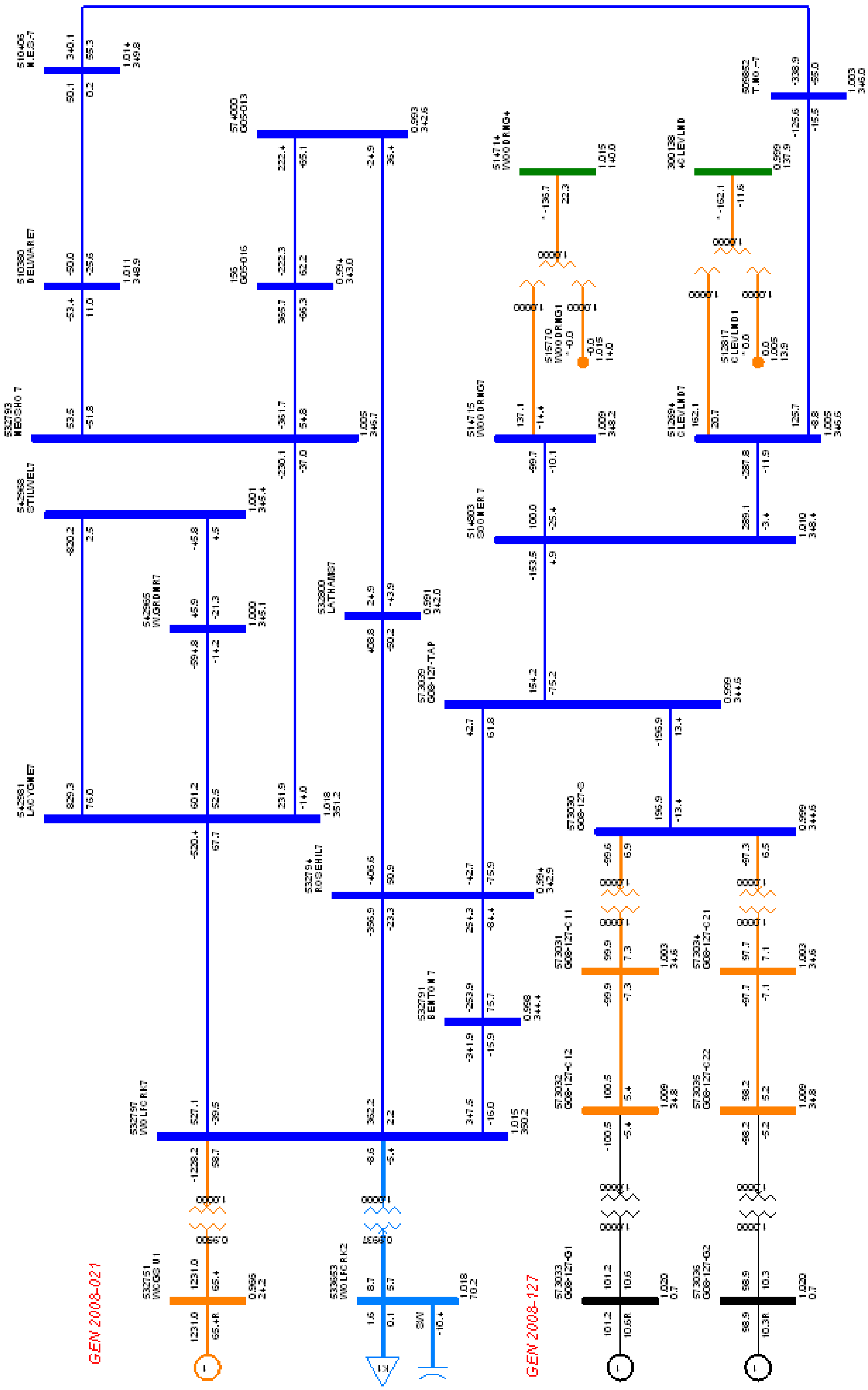


Figure 2-5 - Group 8 Points of Interconnection Surrounding Area – *Diagram2*
Winter Peak

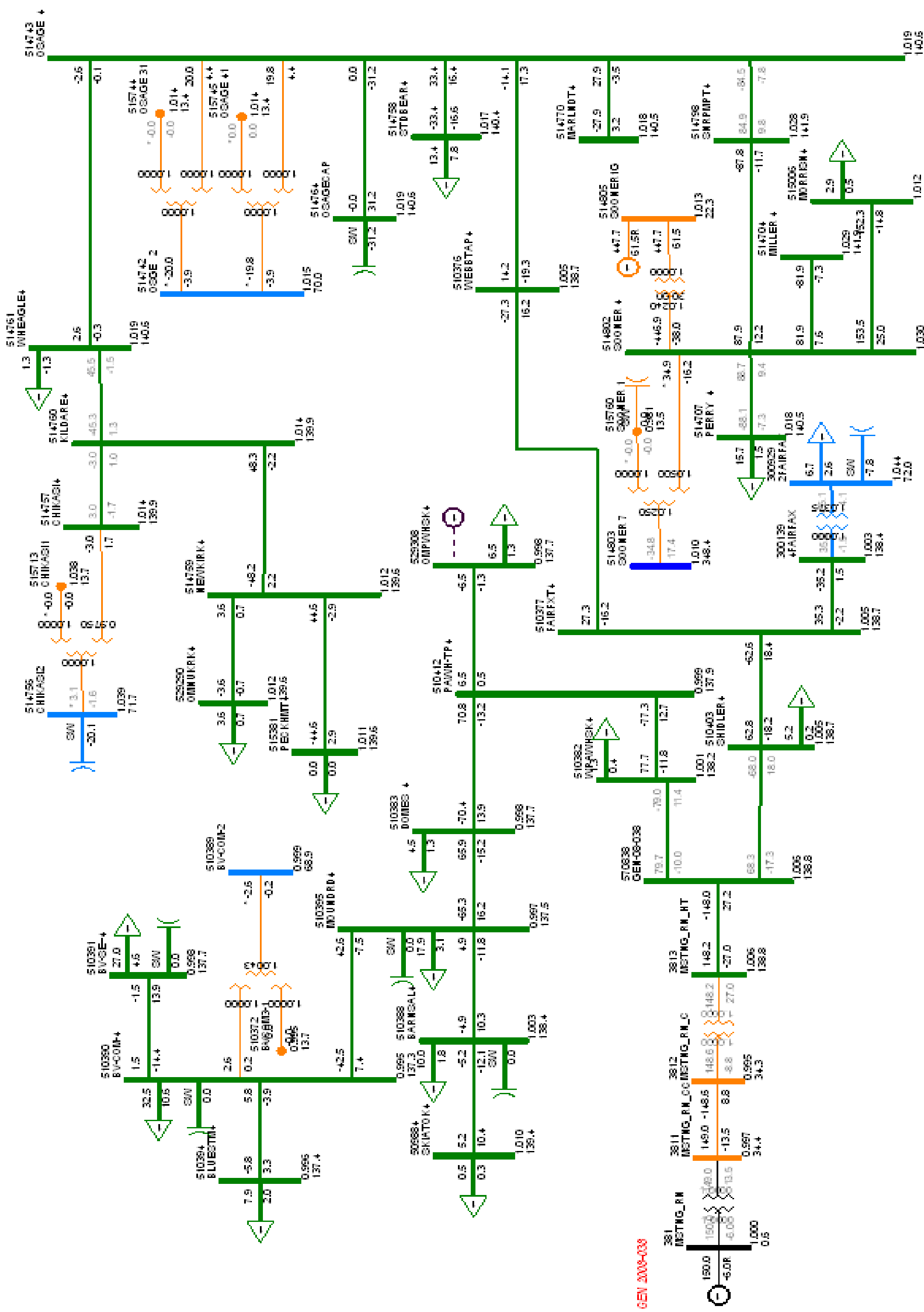
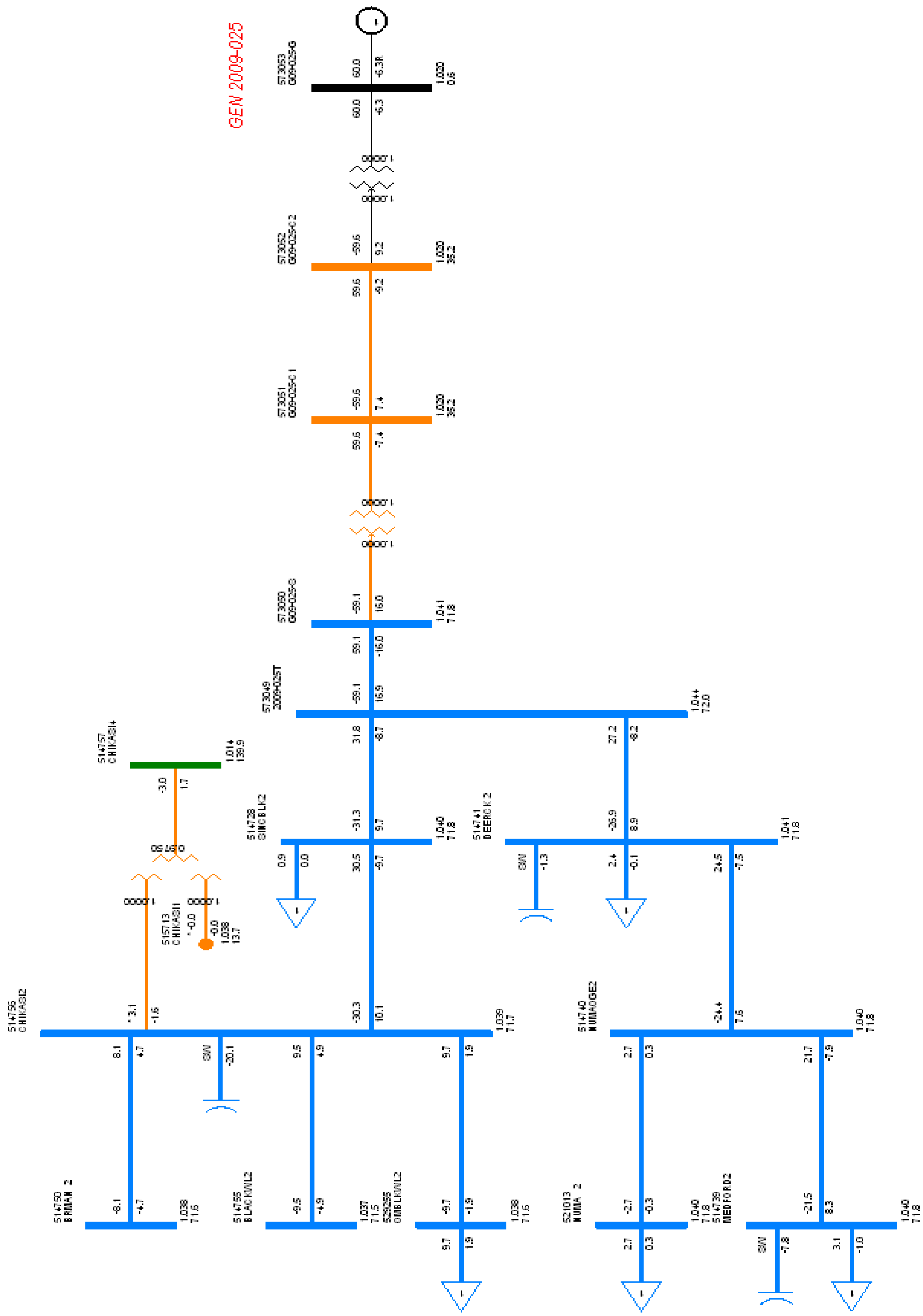


Figure 2-6 - Group 8 Points of Interconnection Surrounding Area – *Diagram3*
Winter Peak



Figures A-1 to A-4 in Appendix A present the single line diagrams, showing the modeling details of each Group 8 interconnection requests.

2.2 Stability Database

The transient stability analysis was performed using the data provided by SPP. Stability models for the Group 8 interconnection requests were already added to the dynamic database. All turbine parameters used in the simulation models are the default parameters in the wind turbine package. It is assumed that each wind turbine generators (WTGs) would be controlling the voltage of its own bus.

The default voltage protection model set points recommended by the manufacturer were used. The wind units were modeled with their built-in voltage ride through capability. Also, the default frequency protection model set points recommended by the manufacturer were used.

The PSS®E dynamic models output list is shown in Appendix B, documenting the model parameters of each one of the Group 8 nuclear steam turbine and wind turbines modeled in the stability study.

Section

3

Methodology and Assumptions

The study considered the 2010 power flow cases with the required interconnection generation requests modeled as described in Section 2. The base case also contains all the significant previous queued projects in the interconnection queue.

The monitored areas in this study are shown in Table 3-1.

Table 3-1 – Areas of Interest

Area Number	Area Name
520	AEPW
523	GRDA
524	OKGE
525	WFEC
536	WERE
540	MIPU
541	KACP

3.1 Methodology

3.1.1 Stability Simulations

The dynamic simulations were performed using the PSS®E version 30.3.3 with the latest stability database provided by SPP. Three-phase faults and single-phase faults in the neighborhood of DISIS-2008-009 – Group 8 Points of interconnection were simulated. Any adverse impact on the system stability was documented and further investigated with appropriate solutions to determine whether a static or dynamic VAR device is required or not.

3.1.2 Steady State Simulations

3.1.2.1 N-1 Contingency Analysis

An N-1 contingency analysis was performed to evaluate voltage violations, if any, caused by disturbances (tripping of the faulted line). The voltages at each POI were monitored for deviations from the base case voltage and the percentage deviations were documented.

The summer peak and winter peak load flow cases were adjusted to ensure there are no relevant pre contingency voltage criteria violations. During contingency analysis it was reported voltages of any monitored bus found to be outside the range of the post-contingency criteria and having more than 1% of project impact.

3.1.2.2 Power Factor Analysis

A QV analysis was performed to determine the reactive support requirement at each project's POI. QV curves, plotted for base case and contingency conditions, are used to determine the reactive power support required at each POI, in order to maintain the bus scheduled pre contingency voltages.

These curves are obtained through a series of AC load flow calculations. Starting with no reactive support at a bus, the voltage is computed for a series of power flows as the reactive support is increased in steps, until the power flow experiences convergence difficulties as the system approaches the voltage collapse point.

3.2 Disturbances for Stability Analysis

The stability simulations considered three-phase (3PH) faults and single line-to-ground (SLG) faults.

The disturbances evaluated are listed in the following Table 3-2:

Table 3-2: Disturbances for Stability Analysis

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Wolf Creek (532797) – Benton (532791) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
2	FLT02-1PH	Single-phase fault on the Wolf Creek (532797) – Benton (532791) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 300 cycles and reclose Benton 345 kV end back into the fault. d. Leave fault on for 3.6 cycles, then trip the line and remove the fault.
3	FLT03-3PH	3 phase fault on the Wolf Creek (532797) – Rose Hill (532794) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
4	FLT04-1PH	Single-phase fault on the Wolf Creek (532797) – Rose Hill (532794) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 300 cycles and reclose Rose Hill 345 kV end back into the fault. d. Leave fault on for 3.6 cycles, then trip the line and remove the

		fault.
5	FLT05-3PH	3 phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
6	FLT06-1PH	Single-phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near Wolf Creek. a. Apply fault at the Wolf Creek 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
7	FLT07-3PH	3 phase fault on the Stilwell (542968) – LaCygne (542981) 345kV line near Stilwell. a. Apply fault at the Stilwell 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 1200 cycles, and then re-close the Stilwell end of the line back into the fault. d. Leave fault on for 3.6 cycles, then trip the line and remove fault.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho. a. Apply fault at the Neosho 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
10	FLT10-1PH	Single-phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho. a. Apply fault at the Neosho 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 300 cycles, and then re-close Neosho 345 kV end back into the fault.. d. Leave the fault on for 3.6 cycles, then trip the line and remove the fault.
11	FLT11-3PH	3 phase fault on the West Gardner (542965) – LaCygne (542981) 345kV line near LaCygne. a. Apply fault at the LaCygne 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 1200 cycles, and then re-close the West Gardner end of the line back into the fault. d. Leave fault on for 3.6 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Sooner (514803) to GEN-2008-127 (573039) 345kV line, near GEN-2008-127. a. Apply fault at the GEN-2008-127 345kV bus. b. Clear fault after 3 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the Sooner end of the line in (b) back into the fault. d. Leave fault on for 3 cycles, then trip the line in (b) and remove

		fault.
14	FLT14-1PH	Single-phase fault on the Sooner (514803) to GEN-2008-127 (573039) 345kV line, near GEN-2008-127. a. Apply fault at the GEN-2008-127 345kV bus. b. Clear fault after 3 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the Sooner end of the line in (b) back into the fault. d. Leave fault on for 3 cycles, then trip the line in (b) and remove fault.
15	FLT15-3PH	3 phase fault on the Rose Hill (532794) to GEN-2008-127 (573039) 345kV line, near GEN-2008-127. a. Apply fault at the GEN-2008-127 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line.
16	FLT16-1PH	Single-phase fault on the Rose Hill (532794) to GEN-2008-127 (573039) 345kV line, near GEN-2008-127. a. Apply fault at the GEN-2008-127 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 300 cycles, and then re-close the Rose Hill end of the line in (b) back into the fault. d. Leave fault on for 3.6 cycles, then trip the line in (b) and remove fault.
17	FLT17-3PH	3 phase fault on the Sooner (514803) to Woodring (514715) 345kV line, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 3 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 3 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Sooner (514803) to Cleveland (512694) 345kV line, near Cleveland. a. Apply fault at the Cleveland 345kV bus. b. Clear fault after 3 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 3 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Rose Hill (532794) to Latham (532800) 345kV line, near Rose Hill. a. Apply fault at the Rose Hill 345V bus. b. Clear fault after 4 cycles by tripping the faulted line and remove the fault.
22	FLT22-1PH	Single-phase fault on the Rose Hill (532794) to Latham (532800) 345kV line, near Rose Hill. a. Apply fault at the Rose Hill 345V bus.

		b. Clear fault after 4 cycles by tripping the faulted line. c. Wait 30 cycles, and then re-close the Rose Hill end of the line in (b) back into the fault. d. Leave fault on for 4 cycles, then trip the line in (b) and remove fault.
23	FLT23-3PH	3 phase fault on the GEN-2008-038 (570838) to Shidler (510403) 138kV line, near GEN-2008-038. a. Apply fault at the GEN-2008-038 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the GEN-2008-038 (570838) to W Pawhuska (510382) 138kV line, near GEN-2008-038. a. Apply fault at the GEN-2008-038 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Mound Road (510395) to Barnsdall (510388) 138kV line, near Mound Road. a. Apply fault at the Mound Road 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Mound Road (510395) to BV-Comanche (510390) 138kV line, near Mound Road. a. Apply fault at the Mound Road 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the Northeastern (510406) to Delaware (510380) 345kV line, near Delaware. a. Apply fault at the Delaware 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove

		fault.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the GEN-2009-025 (573049) to Sinclair Blackwell (514728) 69kV line, near GEN-2009-025. a. Apply fault at the GEN-2009-025 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the GEN-2009-025 (573049) to Deer Creek (514741) 69kV line, near GEN-2009-025. a. Apply fault at the GEN-2009-025 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Chikasia 138/69kV autotransformer near the 138kV bus (514757). a. Apply fault at the Chikasia 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Kildare (514760) to Newkirk (514759) 138kV line, near Kildare. a. Apply fault at the Kildare 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Osage (514743) to Webb City Tap (510376) 138kV line, near Osage. a. Apply fault at the Osage 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-1PH	*Single phase fault and sequence like previous*

43	FLT43-3PH	3 phase fault on the Sooner (514802) to Sooner Pump Tap (514798) 138kV line, near Sooner. a. Apply fault at the Sooner 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Sooner (514802) to Miller (514704) 138kV line, near Sooner. a. Apply fault at the Sooner 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the Osage (514743) to Marland Tap (514770) 138kV line, near Osage. a. Apply fault at the Osage 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-1PH	*Single phase fault and sequence like previous*

In order to simulate single line to ground faults, equivalent reactances were determined to be applied at the buses. Table 3-3 presents the equivalent reactances obtained for the summer peak case and Table 3-4 presents the equivalent reactance for the winter peak case.

Table 3-3: Equivalent Reactances – Line to Ground Faults

Summer Peak

BUS	Equivalent Reactance (MVAr)
532797	-5100
542968	-8300
532793	-5600
542981	-9200

BUS	Equivalent Reactance (MVAr)
573039	-4400
514715	-4800
512694	-5100
532794	-5900
570838	-825
510395	-1300
510380	-4200
573049	-325
514757	-900
514760	-1200
514743	-2200
514802	-4400

Table 3-4: Equivalent Reactances – Line to Ground Faults

Winter Peak

BUS	Equivalent Reactance (MVAr)
532797	-5000
542968	-7700
532793	-4300
542981	-8700
573039	-4000
514715	-4600
512694	-5000
532794	-5100
570838	-825

BUS	Equivalent Reactance (MVAr)
510395	-1300
510380	-4000
573049	-325
514757	-800
514760	-1100
514743	-2000
514802	-4200

The following Figures 3-1 and 3-2 present the fault locations within the study area.

Figure 3-1 – Fault Locations in the Study Area – *Diagram1*

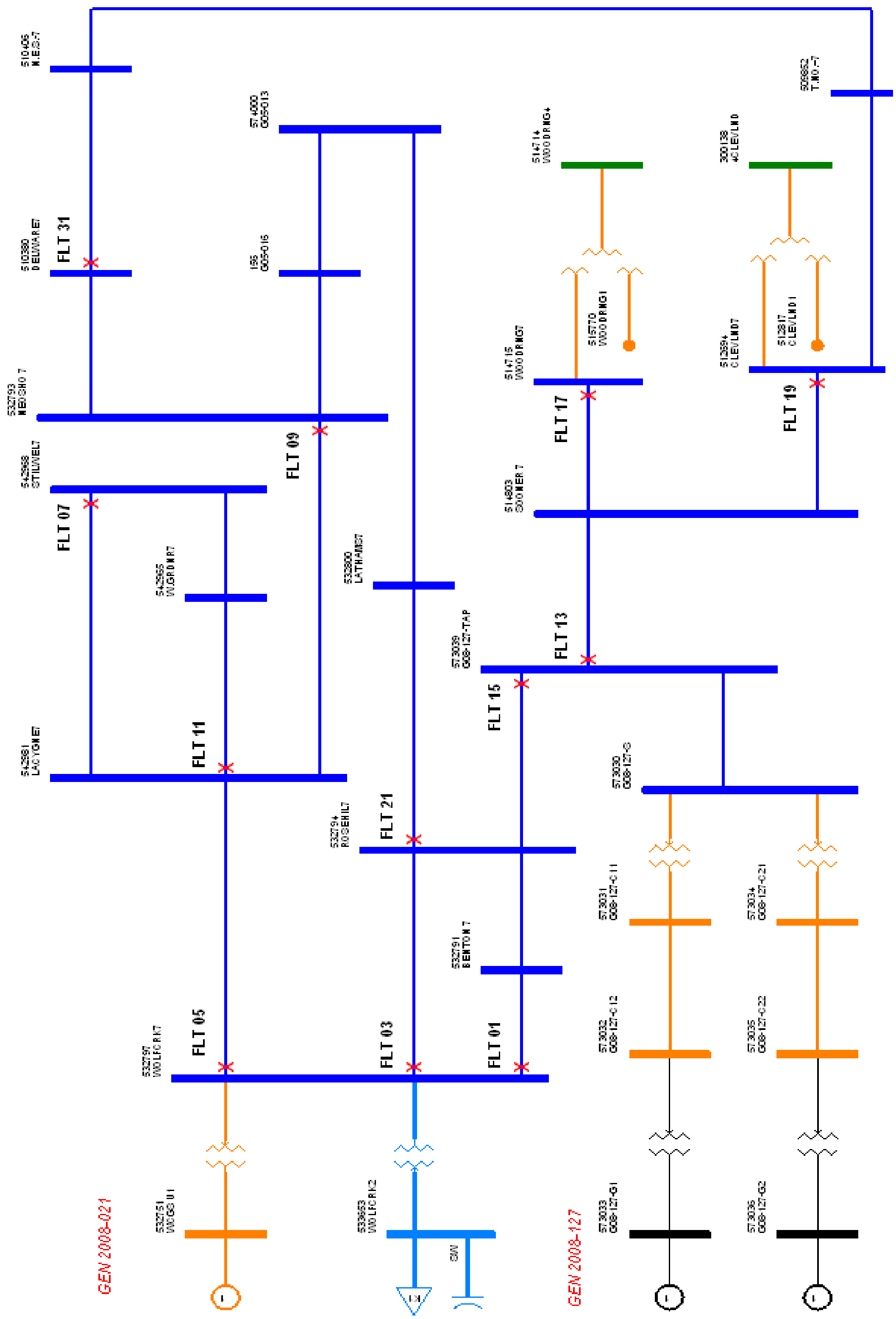


Figure 3-2 – Fault Locations in the Study Area – *Diagram2*

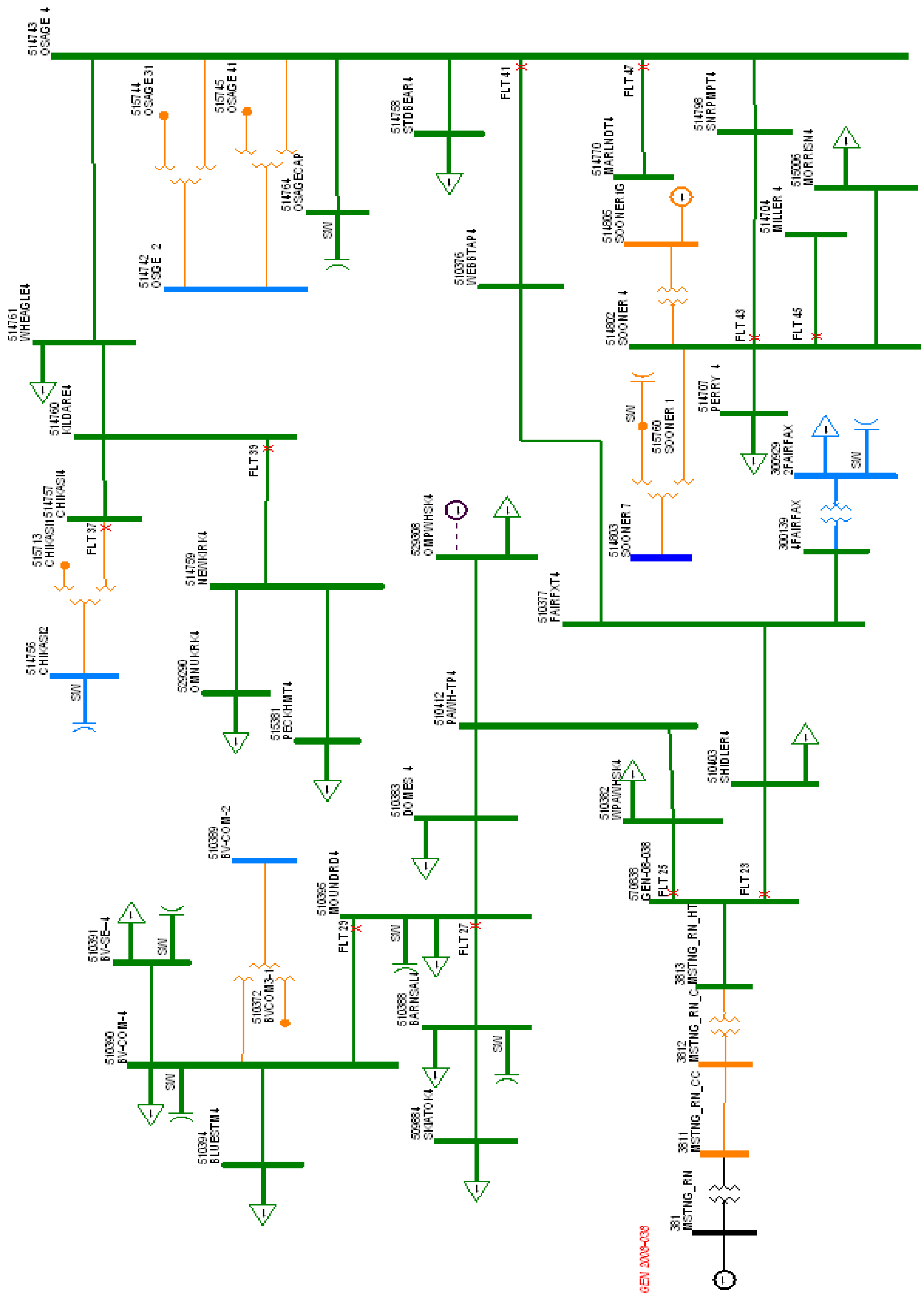
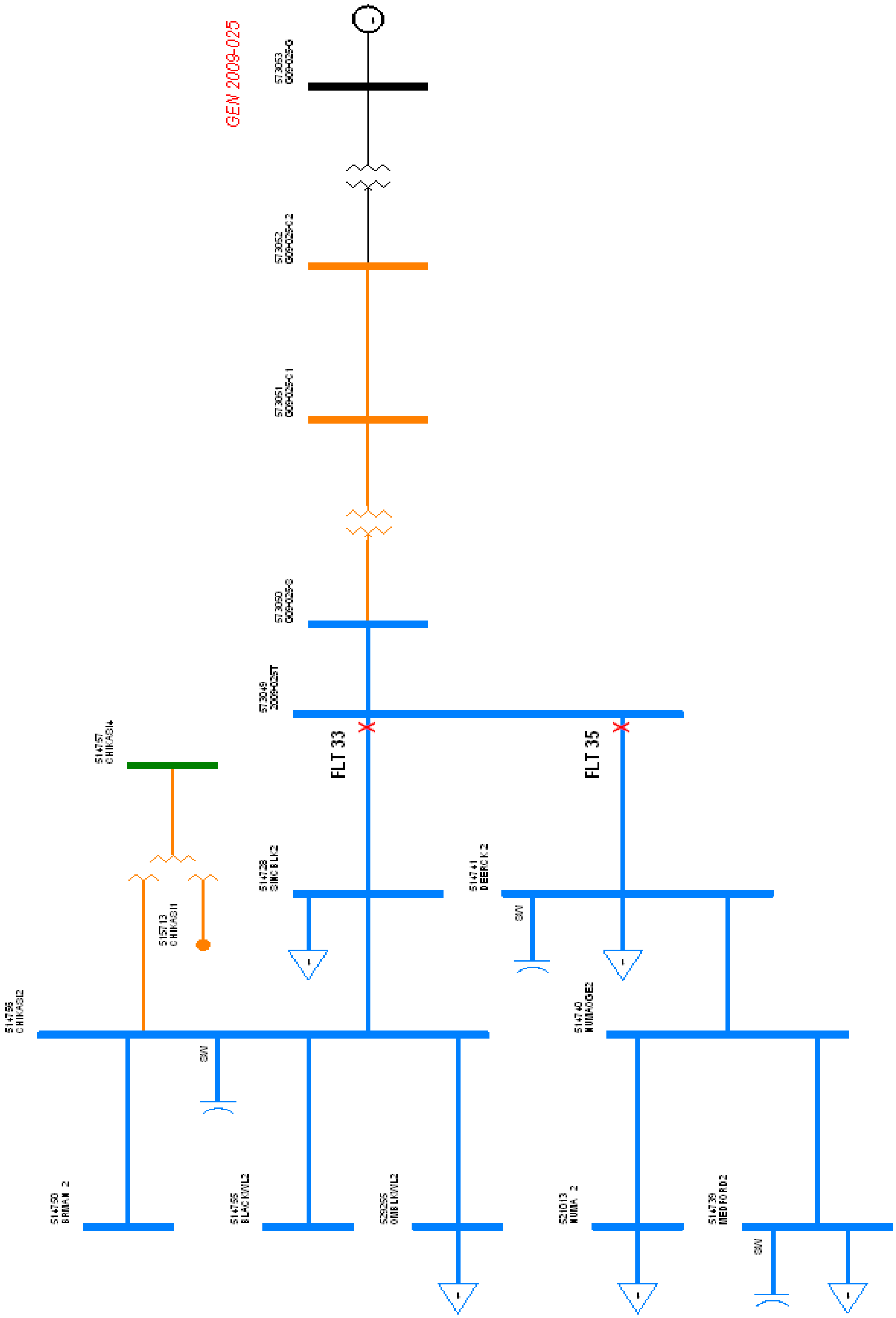


Figure 3-3 – Fault Locations in the Study Area – *Diagram3*



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Section

4

Analysis Performed

4.1 Steady State Performance

Table 4-1 and Table 4-2 summarize the results obtained from the steady state analysis for Summer Peak and Winter Peak base cases, respectively. The tables list the voltage deviations at the Points of Interconnection of the proposed study projects of Group 8, as well as the prior queued projects. Note that only the contingencies that cause a voltage criterion violation or have an impact of at least 1% in the POI's voltages are listed.

The complete set of results for both summer peak and winter peak scenarios are presented in Appendix C.

Table 4-1: Results Obtained – Steady State Analysis – Summer Peak Base Case

Bus #	Bus Name	KV	Contingency Voltage	Base Voltage	% Deviation
Base Case					
210130	G08-13T	345.0	-	1.0100	-
532781	G07-25T	345.0	-	1.0079	-
532797	WOLFCRK7	345.0	-	1.0150	-
532800	LATHAMS7	345.0	-	0.9870	-
570838	GEN-08-038	138.0	-	1.0017	-
573039	G08-127-TAP	345.0	-	0.9927	-
573049	2009-025T	69.0	-	1.0375	-
574000	G05-013	345.0	-	0.9897	-
FLT 13					
573039	G08-127-TAP	345.0	0.9811	0.9927	-1.17%
FLT 15					
573039	G08-127-TAP	345.0	1.0165	0.9927	2.40%
FLT 21					
532800	LATHAMS7	345.0	0.9442	0.9870	-4.34%
574000	G05-013	345.0	0.9477	0.9897	-4.24%
FLT 33					
573049	2009-025T	69.0	1.0233	1.0375	-1.37%

FLT 41					
570838	GEN-08-038	138.0	0.9901	1.0017	-1.16%

Table 4-2: Results Obtained – Steady State Analysis – Winter Peak Base Case

Bus #	Bus Name	KV	Contingency Voltage	Base Voltage	% Deviation
Base Case					
210130	G08-13T	345.0	-	1.0100	-
532781	G07-25T	345.0	-	1.0116	-
532797	WOLFCRK7	345.0	-	1.0150	-
532800	LATHAMS7	345.0	-	0.9915	-
570838	GEN-08-038	138.0	-	1.0055	-
573039	G08-127-TAP	345.0	-	0.9990	-
573049	2009-025T	69.0	-	1.0437	-
574000	G05-013	345.0	-	0.9933	-
FLT 05					
532800	LATHAMS7	345.0	0.9806	0.9915	-1.10%
573039	G08-127-TAP	345.0	0.9885	0.9990	-1.05%
574000	G05-013	345.0	0.9827	0.9933	-1.07%
FLT 13					
573039	G08-127-TAP	345.0	0.9884	0.9990	-1.06%
FLT 15					
573039	G08-127-TAP	345.0	1.0165	0.9990	1.75%
FLT 21					
532800	LATHAMS7	345.0	0.9000	0.9915	-9.23%
574000	G05-013	345.0	0.9044	0.9933	-8.95%
FLT 23					
570838	GEN-08-038	138.0	0.9948	1.0055	-1.06%
FLT 33					
573049	2009-025T	69.0	1.0289	1.0437	-1.42%
FLT 41					
570838	GEN-08-038	138.0	0.9945	1.0055	-1.09%

The winter peak scenario is more stressed leading to a greater number of critical contingencies, compared to the summer peak scenario. In spite of that, in both scenarios some contingencies cause voltage rise or drop equal to or greater than 0.01 p.u. However, the voltage profile of the POI's surrounding area remains within the limits. The exceptions are:

- The outage of the 345 kV line between Rose Hill and Latham substations (FLT 21) results in voltage below 0.95 pu at Latham and G05-013 345 kV substations, during both the scenarios.

The Group 8 projects have significant impact on the voltages of the buses monitored in the study system, either in base case conditions or under contingencies.

4.2 Power Factor Analysis

A QV analysis was performed to determine the amount of reactive support required to maintain the scheduled voltages at the points of interconnection of each one of the proposed wind facilities. The contingencies described in Table 3-2 were evaluated in steady state conditions for summer and winter peak base cases, with variable MVAr injection at the POIs.

Table 4-3 presents for each one of the proposed wind facilities in Group 8, the MVAr requirements and the associated power factor that the projects must be able to provide under contingencies.

Table 4-3: MVAr Requirements and Power Factor at the POI for the Proposed Projects Interconnection

Project	Point of Interconnection	V Scheduled (p.u)	MVAr Requirements at POI	Contingency	Power Factor at POI (lagging – supplying vars)
GEN-2008-038	Shilder – Pawhuska 138 kV	1.002	17.5 MVAr	FLT 41 (SP)	0.993
GEN-2008-127	Sooner – Rose Hill 345 kV	0.999	96 MVAr	FLT 5 (WP)	0.902
GEN-2009-025	Deer Creek – Sinclair Blackwell 345 kV	1.038	6.5 MVAr	FLT 33 (SP)	0.994

4.3 Dynamic Results

The stability analysis was carried out using both Summer Peak and Winter Peak load flow models.

In order to determine the impact of the project on the overall system dynamics as well as to determine the requirements to meet the FERC Order 661-A Guidelines, 48 contingencies listed by Table 3-2 were simulated. The results obtained are described in this sub-section.

The results obtained from the stability simulations for Summer Peak and Winter Peak base cases show that none of the contingency leads to trip or loss of synchronism.

The results indicate that, for both scenarios, no dynamic reactive support is required.

The results obtained show:

- The new proposed projects, did not trip during any of the contingencies tested. That is, no trips occurred due to LVRT.
- All other generators in the monitored areas were stable and remained in synchronism during all contingencies and the system conditions considered.

- Acceptable damping and voltage recovery was observed, within applicable standards.

Additional plots of selected system variables documenting the stability simulations are included in Appendix C.

Section

5

Conclusions

The four projects of DISIS-2009-001 Group 8 have been evaluated to determine the system requirements to meet the requirements associated with FERC Order 661-A Guidelines for Low Voltage Ride Through (LVRT) and therefore, for them to interconnect to the SPP transmission system.

Steady state and stability analysis were carried out to evaluate the system performance under contingencies

In general the Group 8 interconnection requests have significant impact on the voltage profile of the monitored system, either in base case conditions or under contingencies. The outage of 345 kV line between Rose Hill to Latham substations results in significant voltage criteria violations during the winter scenario.

The power factor analysis determined the amount of reactive support required to maintain the scheduled voltages at each one of the points of interconnection.

None of the Group 8 projects have an adverse impact on the stability of the SPP system, for the contingencies and system conditions tested.

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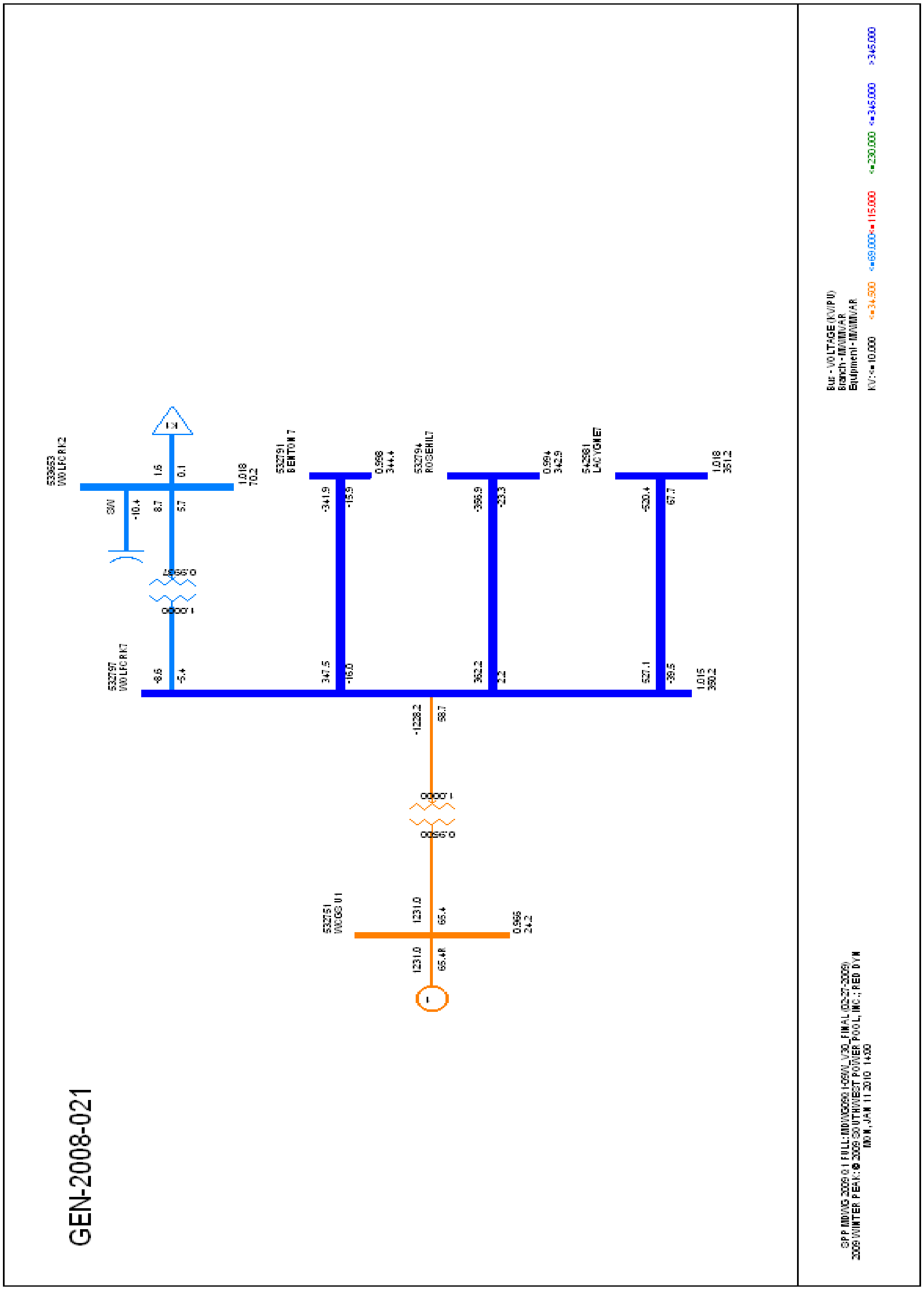
Appendix

A

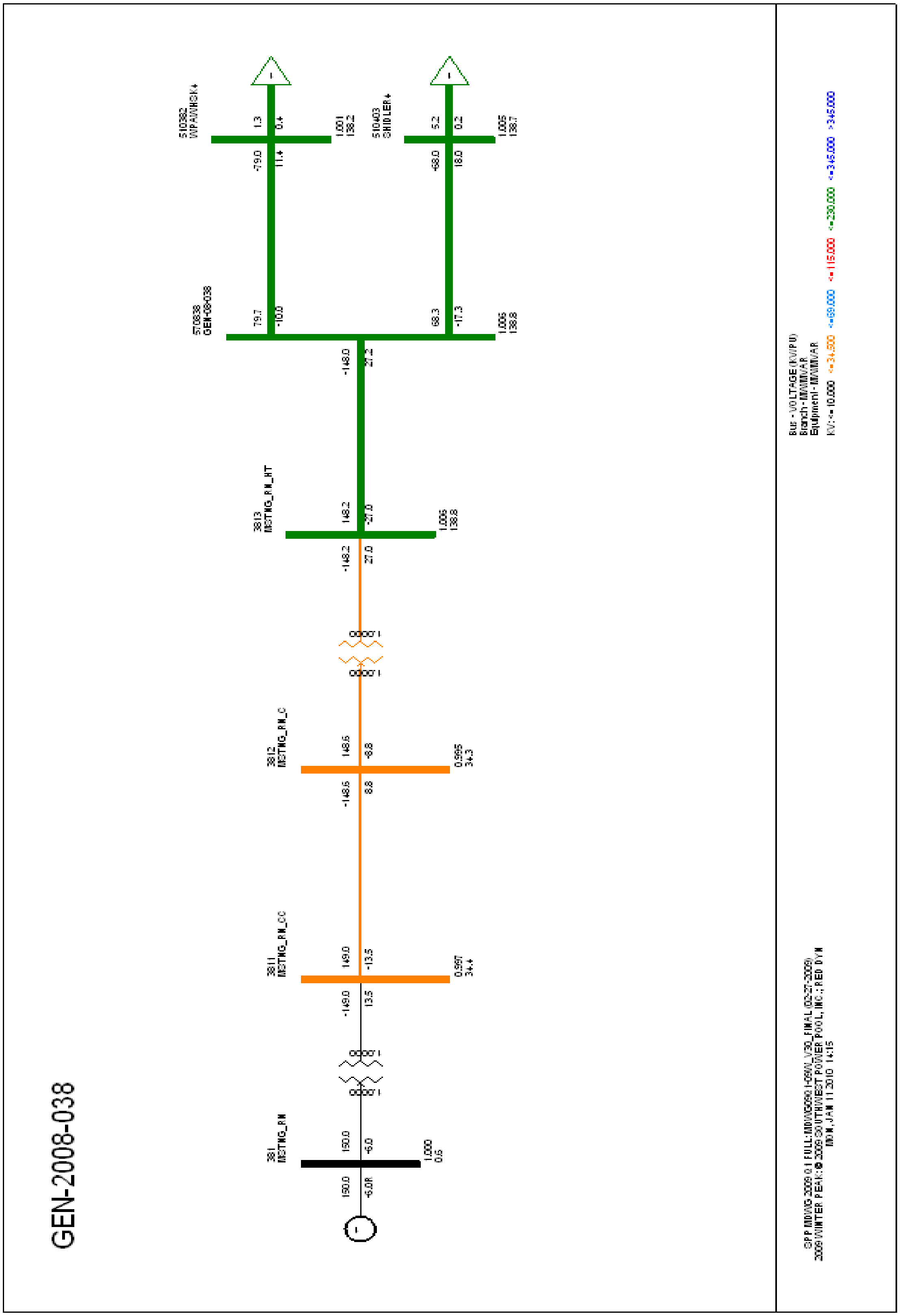
Nuclear STG and WTG Single Line Diagrams

This appendix contains the single line diagrams, showing the modeling details of each Group 8 project.

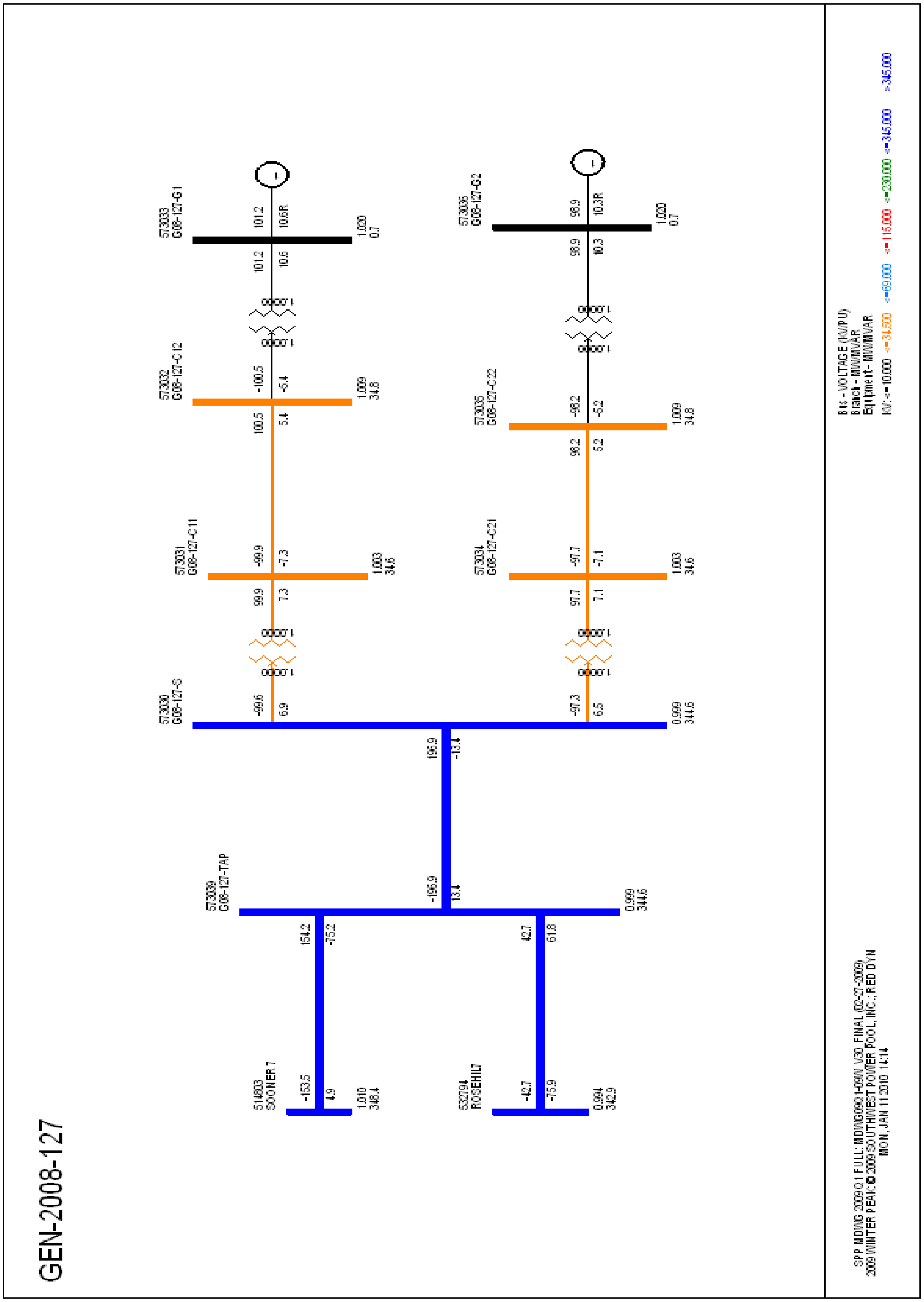
A.1 Gen-2008-021



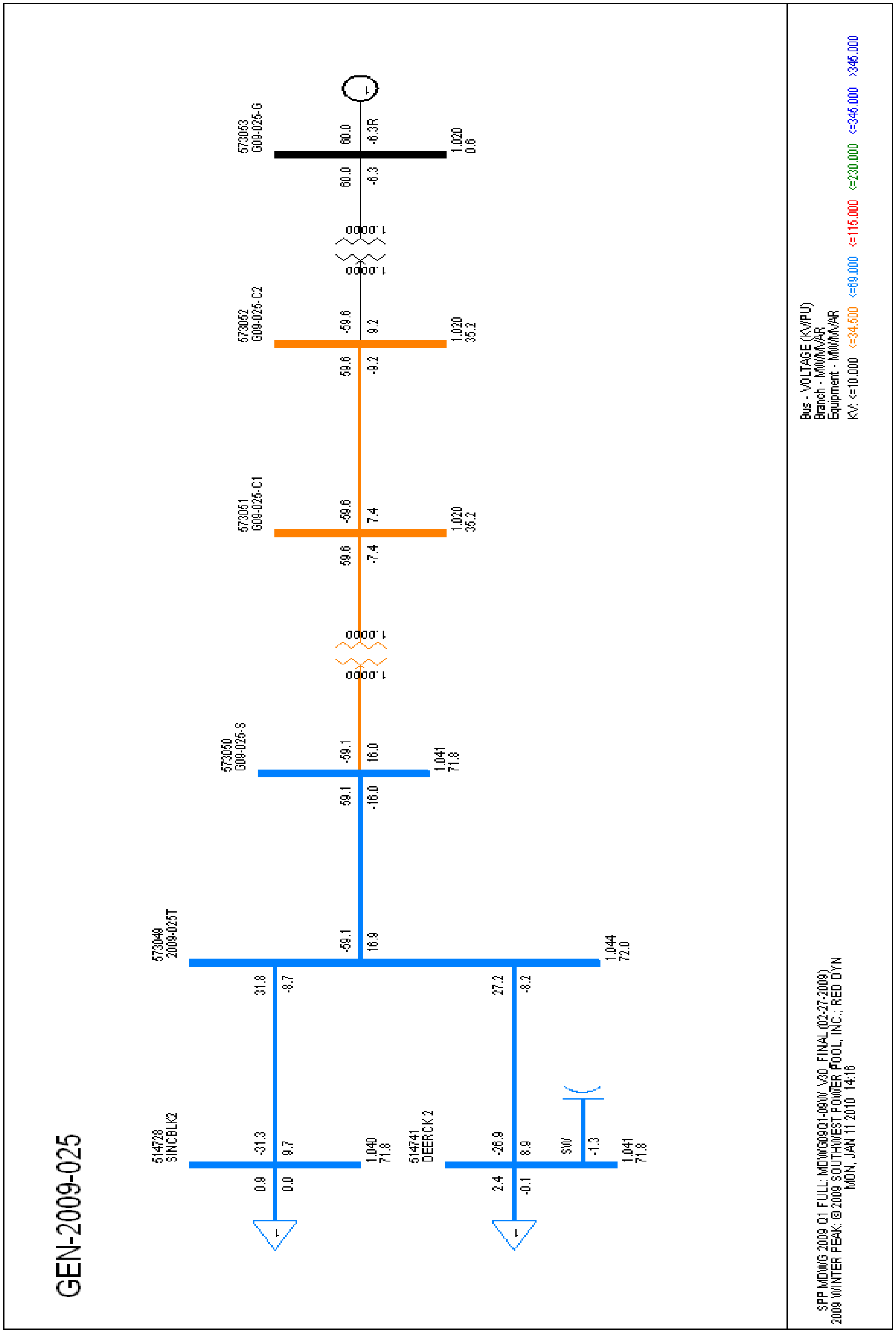
A.2 Gen-2008-038



A.3 Gen-2008-127



A.4 Gen-2009-025



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Appendix

B

Nuclear STG and WTG Dynamic Models Documentation

This appendix shows the model data used to represent the turbines in the simulations.

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Appendix

C

Steady State Results

This Appendix shows the voltage analysis results. The voltages at each he POI were monitored for any deviations from the base case voltage and the percentage voltage deviations were documented.

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Appendix

D

Stability Results

The plots of the evaluated contingencies are shown in this appendix. There are 4 plots for each contingency, which include the following channels:

- Bus Voltages.
- Speed Deviation.
- Active and Reactive Power Injection at the POI
- Electrical and mechanical power of the proposed Nuclear Steam Turbine and WTGs

D.1 Summer Peak Stability Results

D.2 Winter Peak Stability Results

Q: Stability Study for Group 9

DEFINITIVE IMPACT STUDY
DISIS-2009-001 (Group 9)

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EXECUTIVE SUMMARY

The following interconnection impact study for the Definitive Interconnection System Impact Study DISIS-2009-001 (Group 9) is in response to a request through the Southwest Power Pool (SPP) OATT. Group 9 consists of GEN-2006-044N (40.5 MW), GEN 2007-011N06 (75 MW), GEN 2007-011N09 (75 MW), and GEN 2008-086N02 (199.5 MW), which will respectively interconnect into Nebraska Public Power District (NPPD) at the Neligh to Petersburg 115 kV line switching station, Petersburg 115 kV substation, Bloomfield 115 kV substation, and Columbus to Ft. Randall 230 kV switching station. Studies were performed for summer 2010 and winter 2009 peak loading with Group 9 wind farms and prior queued projects operating at rated output power (100% output power) and remaining wind farms at 20% output power. Group 9 wind farms consist of GE 1.5 MW wind turbine generators.

Group 9 can successfully interconnect into the transmission system at the desired locations provided that the wind farms can supply the reactive power needed to meet a voltage schedule equal to the base case voltage or nominal voltage, whichever is higher at the Point of Interconnection (POI) for transmission facility outage contingencies specified by SPP. The GE wind turbine generators' dynamic VAR capabilities through WindCONTROL should be used fully to provide the steady-state leading (inductive) and lagging (capacitive) reactive power to meet the voltage schedule at the POI. No additional capacitor banks are required. Power factor requirements for the worst single transmission facility outage contingencies consist of the following:

- 99.55% leading to 95.0 % lagging power factor from GEN-2006-044N at the Tap of Neligh to Petersburg 115 kV switching station
- 94.8 % leading to 98.1% lagging power factor from GEN 2007-011N06 at the Petersburg 115 kV substation
- 98.5 % leading to 98.1% lagging power factor from GEN 2007-011N09 at the Bloomfield 115 kV substation
- 98.1 % leading to 98.5% lagging power factor from GEN 2008-086N02 at the Columbus to Ft. Randall 230 kV switching station

Transient stability analysis performed for 3-phase and single-line-to-ground fault contingencies at locations specified by SPP indicate that before the Group 9 generation interconnection projects can successfully interconnect into the transmission system at their desired locations, upgrades are necessary to maintain voltage stability for fault disturbance #3, #31, #38, #39, and #40. These upgrades were proposed by SPP and consist of:

- New Bloomfield - Belden 115 kV transmission line
- New Petersburg - Madison 115kV-transmission line

1. INTRODUCTION

The following interconnection impact study for the Definitive Impact Study DISIS-2009-001 (Group 9) has been performed in response to a request through the Southwest Power Pool OATT. Studies were performed for summer 2010 and winter 2009 peak loading with Group 9 wind farms and prior queued projects operating at rated output power (100% output power).

Definitive Interconnection System Impact Study DISIS-2009-001 (Group 9) consists of the following wind generation projects:

- **GEN-2006-044N** – GE 1.5 MW – 40.5 MW – Interconnection at Neligh to Petersburg 115 kV line switching station
- **GEN-2007-011N06** – GE 1.5 MW – 75 MW – Interconnection at Petersburg 115 kV substation
- **GEN-2007-011N09** – GE 1.5 MW – 75 MW – Interconnection at Bloomfield 115 kV substation
- **GEN-2008-086N02** – GE 1.5 MW – 199.5 MW – Interconnection at Columbus to Ft. Randall 230 kV switching station

2. TRANSMISSION SYSTEM AND STUDY AREA

The study area involves transmission facilities at 230 and 115 kV. The wind generation projects in Group 9 will interconnect into Nebraska Public Power District (NPPD). In addition to NPPD, the following areas were monitored for power flow and dynamic stability analysis:

Midwest Energy, Inc. (MIDW)

Missouri Public Service (MIPU)

Kansas City Power & Light (KACP)

Omaha Public Power District (OPPD)

Lincoln Electric System (LES)

Western Area Power Administration (WAPA)

Sunflower Electric Power Company (SUNC)

Westar Energy, Inc (WERE)

3. POWER FLOW BASE CASES

The following power flow base cases scenarios were analyzed:

Summer peak 2010, which includes aggregate representation of wind turbine generators for Definitive Impact Study DISIS-2009-001 (Group 9) wind farms and prior queued projects at 100% output power. DISIS-2009-001 (Group 10 projects were also dispatched at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

Winter Peak 2009, which includes aggregate representation of wind turbine generators for Definitive Impact Study DISIS-2009-001 (Group 9) wind farms and prior queued projects at 100% output power. DISIS-2009-001 (Group 10 projects were also dispatched at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

4 WIND FARM MODELS

Definitive Impact Study DISIS-2009-001 (Group 9) wind farms and prior queued projects were modeled as aggregates of wind turbine generators. The aggregate models were part of the base case.

4.1 General Electric GE – 1.5 MW/60 Hz Wind Turbine Generator

The GE 1.5 MW wind turbine generator is a variable-speed doubly-fed induction generator with power converter and electrical pitch control. The standard GE turbine can operate continuously between 95% leading (inductive) to 95% lagging (capacitive). With an optional upgrade, the turbines can continuously operate between 90% leading to 90% lagging power factor. GEN 2007-011N06 and GEN 2007-011N09 were modeled as standard GE turbines. GEN-2006-044N and GEN 2008-086N02 were modeled with optional extended power factor range.

5. POWER FLOW ANALYSIS

Transmission voltages should not exceed 105% of nominal system voltage during normal and emergency operating conditions. The above is true in general; however, voltage deviations of up to 110% may be allowed depending on equipment ratings and specific location requirements. Operating voltage should be at or above 95% of nominal although depending on equipment ratings, it is possible to operate below this limit, but above 90% voltage.

5.1 Facility Outage Contingencies

Single transmission facility outage contingencies specified by SPP are listed in Table 5.1.

Table 5.1: List of Power Flow Contingencies

Cont. No.	N-1 Contingency	N-1-1 Contingency
1	GEN-2006-044N to Neligh 115 kV line	
2	GEN-2006-044N to Petersburg 115 kV line	
3	Albion to Petersburg 115 kV line	
4	Albion to Fullerton 115 kV line	
5	Albion to Genoa 115 kV line	
6	Albion to Spalding 115 kV line	
7	Neligh-Clearwater-O'Neill 115 kV lines	
8	Neligh-County Line-BattleCreek-NorthNorfolk 115 kV lines	
9	Creighton to Neligh 115 kV line	
10	O'Neill-Spencer-Ft.Randall 115 kV lines	
11	O'Neill-Emmet-Atkinson-Stuart-Ainsworth 115 kV lines	
12	Ainsworth to Valentine 115 kV line	
13	Ainsworth Wind to Ainsworth 115 kV line	
14	AinsworthWind-Calamus-Thedford 115 kV lines	
15	Bloomfield to Creighton 115 kV line	
16	Bloomfield to Gavins 115 kV line	
17	Hartington to Gavins 115 kV line	
18	Yankton to Gavins 115 kV line	
19	Yankton Jct to Gavins 115 kV line	
20	Shell Creek to Kelly 230 kV line	
21	Columbus West to Kelly 230 kV line	
22	East Columbus to Kelly 230 kV line	
23	GEN-2008-086N02 to Kelly 230 kV line	
24	GEN-2008-086N02 to Fort Randall 230 kV line	
25	Fort Randall to Fort Thompson 230 kV line	
26	Fort Randall to Utica Jct 230 kV line	

Cont. No.	N-1 Contingency	N-1-1 Contingency
27	Fort Randall to Lake Platt 230 kV line	
28	Fort Randall to Sioux City 230 kV line	
29	Kelly 230/115 kV auto at the 115 kV	
30	Spirit Mound to Manning 115 kV line	
31	Gavins – Yankton Junction 115 kV	Manning - Spirit Mound 115 kV line **(results in islanding of the Spirit Mount 100 MW generation)**
32	Petersburg – Neligh 115 kV	Albion – Genoa 115 kV line
33	Neligh – County Line 115 kV	Bloomfield - Gavins Point 115 kV line
34	Neligh – County Line 115 kV	Petersburg 115 kV line

Voltage levels within the study area were monitored for each contingency in Table 5.1. Result summarized in Table 5.2 and 5.3 indicate that there are locations where the voltages are outside of the 90% to 110% wide voltage range. Adjustments to GEN 2007-011N06 and G06-32 transformers' no-load tap settings from flat to 105% (on the high voltage winding) can correct a number of voltage excursions as indicated in Table 5.4 and 5.5.

Table 5.2: Voltage excursions for Summer 2010

Cont. No.	> 110%					< 90%
	560897 CLR_1	**560896 G06-32**	**211 LRDORDG_1G**	**659170 STEGALDC**	**659171 MBPP-1**	**652267 NUNDRWD9**
FLAT, 1, 2, and 4 thru 34				✓	✓	✓
3			✓	✓	✓	✓

Table 5.3: Voltage excursions for Winter 2009

Cont. No.	> 110%					< 90%
	560897 CLR_1	**560896 G06-32**	**211 LRDORDG_1G**	**659170 STEGALDC**	**659171 MBPP-1**	**652267 NUNDRWD9**
FLAT, 1, 2, 4 thru 32, and 34	✓	✓		✓	✓	
3 and 33	✓	✓	✓	✓	✓	

Table 5.4: Voltage excursions for Summer 2010 with XFMR tap changes at GEN 2007-011N06 and G06-32

Cont. No.	> 110%					< 90%
	560897 CLR_1	**560896 G06-32**	**211 LRDORDG_1G**	**659170 STEGALDC**	**659171 MBPP-1**	**652267 NUNDRWD9**
FLAT, and 1 thru 34				✓	✓	✓

Table 5.5: Voltage excursions for Winter 2009 with XFMR tap changes at GEN 2007-011N06 and G06-32

Cont. No.	> 110%					< 90%
	560897 CLR_1	**560896 G06-32**	**211 LRDORDG_1G**	**659170 STEGALDC**	**659171 MBPP-1**	**652267 NUNDRWD9**
FLAT, and 1 thru 34				✓	✓	

5.2 Power Factor Requirements at the Point of Interconnection

SPP has specific voltage requirements for interconnecting wind farm projects. Wind generation projects are required to meet a voltage schedule at the POI consistent with the voltage in the SPP base case or nominal voltage, whichever is higher, for single transmission facility outage contingencies specified by SPP.

Voltage schedules at the point of interconnect locations from the original Definitive Impact Study DISIS-2009-001 (Group 9) base cases are listed in Table 5.6.

Table 5.6: Base Case Voltage of Point of Interconnection Locations

Point of Interconnection	Summer Peak 2010 (pu)	Winter Peak 2009 (pu)
Tap of Neligh to Petersburg 115 kV switching station	1.044	1.043
Petersburg 115 kV substation	1.045	1.045
Bloomfield 115 kV substation	1.035	1.035
Tap of Columbus to Ft. Randall 230 kV switching station	1.030	1.030

The power factor needs to maintain a voltage schedule at the POI consistent with SPP requirements for the worst case contingencies is summarized in Table 5.7.

Table 5.7: Power factor needs at POI

Point of Interconnection	Interconnection Request	Leading Power Factor Requirements	Lagging Power Factor Requirements
		Power Factor	Power Factor
Tap of Neligh to Petersburg 115 kV switching station	GEN-2006-044N	-99%	95.0%
Petersburg 115 kV substation	GEN-2007-011N06	-94.8%	98.1%
Bloomfield 115 kV substation	GEN-2007-011N09	-98.5%	98.1%
Tap of Columbus to Ft. Randall 230 kV switching station	GEN-2008-086N02	-98.13%	98.5%

GE wind turbine generators can be set up to control the terminal voltage at the POI through the GE WindCONTROL system. Table 5.8 summarizes the control scheme for each interconnect request project as well as transformer no-load tap settings. Figures 5.1 to 5.4 show the power flow diagrams corresponding to each point of interconnection and wind farm projects for the worst contingencies.

Table 5.8: Summary of wind farm control, capacitor bank sizes and transformer tap settngs assumptions for transient stability analysis

Project Name	Wind Turbine Generator			Voltage Schedule at POI to be Met by Project Request		Cap Bank Requirement	XFMR No-Load Tap Setting (% of High Side Winding)	
	Make	PF Range (%)	Control Scheme	Summer (pu)	Winter (pu)		230/34.5 kV or 138/34.5 kV	WTG GSU
GEN-2006-044N	GE 1.5 MW	+/- 90	Meet voltage schedule at POI	1.044	1.043	none	100	100
GEN-2007-011N06	GE 1.5 MW	+/- 95	Meet voltage schedule at POI	1.045	1.045	none	105	100
GEN-2007-011N09	GE 1.5 MW	+/- 95	Meet voltage schedule at POI	1.010	1.010	none	100	100
GEN-2008-086N02	GE 1.5 MW	+/- 90	Meet voltage schedule at POI	1.030	1.030	none	100	100

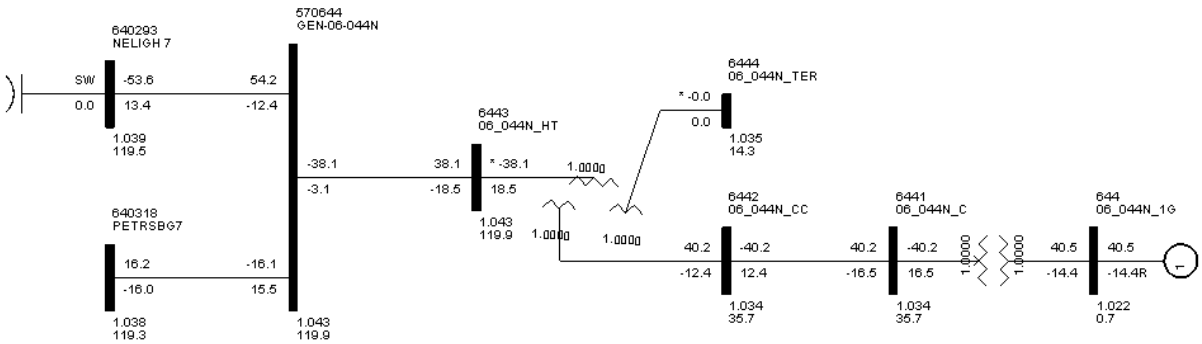

Figure 5.1: Power flow diagram of GEN-2006-044N for contingency No. 34, winter

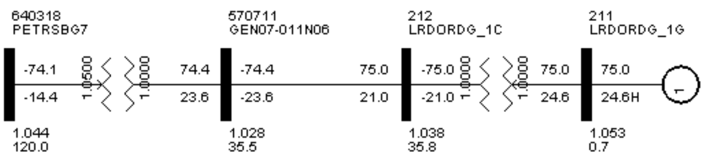

Figure 5.2: Power flow diagram of GEN 2007-011N06 for contingency No. 3, summer

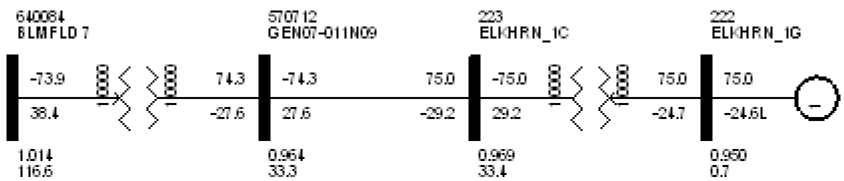

Figure 5.3: Power flow diagram of GEN 2007-011N09 for contingency No. 34, winter

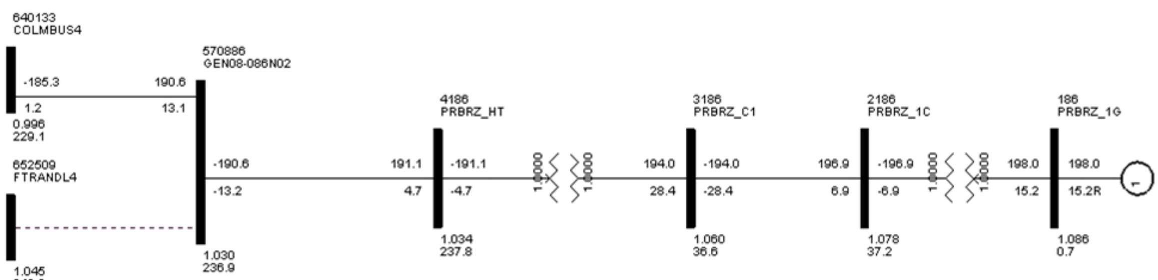

Figure 5.4: Power flow diagram of GEN 2008-086N02 for contingency No. 24, winter

6. TRANSIENT STABILITY ANALYSIS AND RESULTS

Transient stability analysis was performed for fault contingencies in Table 6.1.

Table 6.1: SPP fault contingencies

Cont. Name	Description
FLT01-3PH	3 phase fault on the GEN-2006-044N to Neligh 115 kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT02-3PH	3 phase fault on the GEN-2006-044N to Petersburg 115 kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT03-3PH	3 phase fault on the Albion to Petersburg 115 kV line, near Petersburg. a. Apply fault at the Petersburg 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT04-3PH	3 phase fault on the Albion to Fullerton 115 kV line, near Albion. a. Apply fault at the Albion 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT05-3PH	3 phase fault on the Albion to Genoa 115 kV line, near Albion. a. Apply fault at the Albion 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT6-3PH	3 phase fault on the Albion to Spalding 115 kV line, near Albion. a. Apply fault at the Albion 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT7-3PH	3 phase fault on the Clearwater to Neligh 115 kV line, near Neligh. a. Apply fault at the Neligh 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines.
FLT8-3PH	3 phase fault on the County Line to Neligh 115 kV line, near Neligh. a. Apply fault at the Neligh 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines.
FLT9-3PH	3 phase fault on the Creighton to Neligh 115 kV line, near Neligh. a. Apply fault at the Neligh 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.

Cont. Name	Description
FLT10-3PH	3 phase fault on the O'Neill to Spencer 115 kV line, near O'Neill. a. Apply fault at the O'Neill 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines.
FLT11-3PH	3 phase fault on the O'Neill to Emmett 115 kV line, near O'Neill. a. Apply fault at the O'Neill 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines.
FLT12-3PH	3 phase fault on the Ainsworth to Valentine 115 kV line, near Ainsworth. a. Apply fault at the Ainsworth 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT13-3PH	3 phase fault on the Ainsworth Wind to Ainsworth 115 kV line, near Ainsworth. a. Apply fault at the Ainsworth 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT14-3PH	3 phase fault on the Ainsworth Wind to Calamus 115 kV line, near Ainsworth Wind. a. Apply fault at the Ainsworth Wind 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines.
FLT15-3PH	3 phase fault on the Bloomfield to Creighton 115 kV line, near Bloomfield. a. Apply fault at the Bloomfield 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT15-3PH	3 phase fault on the Bloomfield to Gavins 115 kV line, near Bloomfield. a. Apply fault at the Bloomfield 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT16-3PH	3 phase fault on the Hartington to Gavins 115 kV line, near Hartington. a. Apply fault at the Gavins Point 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT17-3PH	3 phase fault on the Yankton to Gavins 115 kV line, near Yankton. a. Apply fault at the Gavins Point 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT19-3PH	3 phase fault on the Yankton Jct to Gavins 115 kV line, near Yankton Jct a. Apply fault at the Yankton Jct 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT20-3PH	3 phase fault on the Shell Creek to Kelly 230 kV line, near Columbus a. Apply fault at the Kelly 230 kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.

Cont. Name	Description
FLT21-3PH	3 phase fault on the Columbus West to Kelly 230 kV line, near Columbus a. Apply fault at the Kelly 230 kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT22-3PH	3 phase fault on the East Columbus to Kelly 230 kV line, near Columbus a. Apply fault at the Kelly 230 kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT23-3PH	3 phase fault on the GEN-2008-086N02 to Kelly 230 kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT24-3PH	3 phase fault on the GEN-2008-086N02 to Fort Randall 230 kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT25-3PH	3 phase fault on the Fort Randall to Fort Thompson 230 kV line, near GEN-Fort Randall a. Apply fault at the Ft. Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT26-3PH	3 phase fault on the Fort Randall to Utica Jct 230 kV line, near Fort Randall a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT27-3PH	3 phase fault on the Fort Randall to Lake Platt 230 kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT28-3PH	3 phase fault on the Fort Randall to Sioux City 230 kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
FLT29-3PH	3 phase fault on the Kelly 230/115 kV auto at the 115 kV a. Apply fault at the Columbus 115 kV bus. b. Clear fault after 5.5 cycles by tripping autotransformer.
FLT30-3PH	3 phase fault on the Spirit Mound to Manning 115 kV line, near Spirit Mound. a. Apply fault at the Manning 115 kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.

Cont. Name	**Description**
FLT31-1PH	SLG fault on Bloomfield – Gavins Point 115 kV line, near Bloomfield. Stuck breaker at Gavins. a. Apply fault at Bloomfield 115 kV bus. b. Clear Bloomfield end of line at 5.5 cycles. Leave fault on end of open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.
FLT32-1PH	SLG fault on Creighton – Neligh 115 kV line, near Creighton. Stuck breaker at Creighton. a. Apply fault at Creighton 115 kV bus. b. Clear Neligh end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. c. Clear Creighton 115 kV bus and fault at 18.0 cycles.
FLT33-1PH	SLG fault on Gavins Point – Hartington 115 kV line, near Gavins Point. Stuck breaker at Gavins Point. a. Apply fault at Gavins Point 115 kV bus. b. Clear Hartington end of line at 6.5 cycles. Leave fault on open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.
FLT34-1PH	SLG fault on Neligh-County Line, near Neligh. Stuck PCB at Neligh. a. Apply fault at Neligh 115 kV bus. b. Clear North Norfolk end of Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Neligh 115 kV bus and fault at 18.0 cycles.
FLT35-1PH	SLG fault on Albion-Genoa 115 kV line near Albion. Stuck PCB at Albion. a. Apply fault on Albion 115 kV bus. b. Clear Genoa end of Albion-Genoa 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Albion 115 kV bus and fault at 18.0 cycles.
FLT36-1PH	SLG fault on Kelly – Columbus West 230 kV line. Stuck PCB at Kelly. a. Apply fault on Kelly 230 kV bus. b. Clear Columbus West end of line at 6.0 cycles. Leave fault on open-ended line. c. Clear Kelly 230 kV bus and fault at 14.5 cycles.
FLT37-3PH	3PH fault on Manning - Spirit Mound 115 kV line with prior outage of Gavins – Yankton Junction 115 kV. a. Prior Outage: Gavins Point – Yankton Junction 115 kV line b. Apply 3PH fault on Manning115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Spirit Mound– Manning 115 kV line **(results in islanding of Spirit Mount 100 MW generation)**

Cont. Name	Description
FLT38-3PH	3PH fault on Albion – Genoa 115 kV line with prior outage of Petersburg – Neligh 115 kV. a. Prior Outage: Petersburg – Neligh 115 kV line Petersburg to 570644 to Neligh b. Apply 3PH fault on Albion 115 kV bus. c. Clear Albion end of Albion – Genoa 115 kV line in 5.5 cycles. Leave fault on end of line out of Genoa. d. Clear fault after 6.5 cycles and trip faulted Albion – Genoa 115 kV line.
FLT39-3PH	3PH fault on Bloomfield - Gavins Point 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Bloomfield 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Gavins Point – Bloomfield 115 kV line.
FLT40-3PH	3PH fault on Petersburg-Albion 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Petersburg 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Albion – Petersburg 115 kV line.

The prior queued projects monitored are listed in Table 6.2.

Table 6.2: Prior queued wind farm projects monitored

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2006-020N	42	Vestas 3.0 MW	Bloomfield 115kV (640084)
GEN-2006-038N019	80	GE 1.5 MW	Petersburg 115kV (640318)
GEN-2007-011N08	81	Vestas 3.0 MW	Bloomfield 115kV (640084)
GEN-2006-037N	100	GE 1.5 MW	Valentine 115kV (640392)
GEN-2006-037N1	75	GE 1.5 MW	Broken Bow 115kV (640089)
GEN-2003-021N	75	CIMTR	Ainsworth 115kV (640050)
GEN-2004-005N	30	GE 1.5 MW	St Francis 115kV (640351)
GEN-2006-038N005	80	CIMTR	Broken Bow (640089)

The case shall also include several adjacent generating units in the WAPA system at 100% of PMAX. These generating units are listed below:

Bus #	Bus Name	kV	Unit ID
652546	FTRDL12G	13.800	1
652546	FTRDL12G	13.800	2
652547	FTRDL34G	13.800	3
652547	FTRDL34G	13.800	4
652548	FTRDL56G	13.800	5
652548	FTRDL56G	13.800	6
652549	FTRDL78G	13.800	7
652549	FTRDL78G	13.800	8
652575	GAVINS1G	13.800	1
652576	GAVINS2G	13.800	2
652577	GAVINS3G	13.800	3
659116	SPIRI71G	13.800	1 (Spirit Mount 50 MW generation)
659117	SPIRI72G	13.800	2 (Spirit Mount 50 MW generation)

6.1 Stability Criteria

Disturbances including three-phase and single-phase to ground faults should not cause synchronous and asynchronous plants to become unstable or disconnect from the transmission grid.

The criterion for synchronous generator stability as defined by NERC is:

"Power system stability is defined as that condition in which the difference of the angular positions of synchronous machine rotor becomes constant following an aperiodic system disturbance."

Voltage magnitudes and frequencies at terminals of asynchronous generators should not exceed magnitudes and durations that will cause protection elements to operate. Furthermore, the response after the disturbance needs to be studied at the terminals of the machine to insure that there are no sustained oscillations in power output, speed, frequency, etc.

Voltage magnitudes and angles after the disturbance should settle to a constant and reasonable operating level. Frequencies should settle to the nominal 60 Hz power frequency.

6.2 Modeling of Wind Turbine Generators

PSS®E Wind Modeling Package for GE 1.5/3.6/2.5 MW Wind Turbines Issue 5.1.0 was used for transient stability analysis.

The voltage and frequency relay settings used with the GE 1.5 MW model for the Definitive Impact Study DISIS-2009-001 (Group 9) projects are listed in Table 6.3.

Table 6.3: GE 1.5 MW relay settings of
Definitive Impact Study DISIS-2009-001 (Group 9) projects

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|< for t =	0.90 10.0	Pu S
Undervoltage (27-2)	Relay trips if |Vbus|< for t =	0.75 1.9	Pu S
Undervoltage (27-3)	Relay trips if |Vbus|< for t =	0.50 1.2	Pu S
Undervoltage (27-4)	Relay trips if |Vbus|< for t =	0.30 0.7	Pu S
Undervoltage (27-5)	Relay trips if |Vbus|< for t =	0.15 0.2	Pu S
Overvoltage (59-1)	Relay trips if |Vbus|> for t =	1.1 1.0	Pu S
Overvoltage (59-2)	Relay trips if |Vbus|> for t =	1.15 0.1	Pu S
Overvoltage (59-3)	Relay trips if |Vbus|> for t =	1.3 0.02	Pu S
Underfrequency (81U-1)	Relay trips if Fbus < for t =	57.5 10.0	Hz S
Underfrequency (81U-2)	Relay trips if Fbus < for t =	56.5 0.02	Hz S
Overfrequency (81O-1)	Relay trips if Fbus > for t =	61.5 30.0	Hz S
Overfrequency (81U-2)	Relay trips if Fbus > for t =	62.5 0.02	Hz S

6.3 Transient Stability Results: Summer Peak 2010

An undisturbed run of 30 seconds was performed on the Summer Peak 2010 power flow case to verify proper initialization of dynamic models. GEN-2006-046, which is being dispatched at 20% of rated output power, fails to initialize correctly at reduced output and causes the turbines to trip off during initialization. This is likely an issue with the Mitsubishi MWT-92/95 model. This problem has been brought up and discussed with SPP and there is a general consensus that the presence or absence of GEN-2006-046 will have little impact on the results due its low wind penetration into the area of interest.

The areas being monitored remain stable and Definitive Impact Study DISIS-2009-001 (Group 9) and prior queued project will survive each fault contingency for the fault contingencies in Table 6.1 provided that GEN-2006-038N019 is studied with GE 1.5 MW turbines (instead of CIMTR) and the new Bloomfield - Belden 115 kV and Petersburg - Madison 115kV-transmission lines are included in the base case. Without these upgrades, fault disturbance #3, #31, #38, #39, and #40 cause PSS/E to crash early in the dynamic simulation as a result of voltage instability and inability of the PSS/E solution to converge.

6.4 Transient Stability Results: Winter Peak 2009

An undisturbed run of 30 seconds was performed on the Winter Peak 2009 power flow case to verify proper initialization of dynamic models. Similarly to the Summer Peak 2010 case, GEN-2006-046 trips off during initialization.

Also similarly to the Summer Peak 2010 case, the areas being monitored remain stable and Definitive Impact Study DISIS-2009-001 (Group 9) and prior queued project will survive each fault contingency for the fault contingencies in Table 6.1 provided that GEN-2006-038N019 is studied with GE 1.5 MW turbines (instead of CIMTR) and the new Bloomfield - Belden 115 kV and Petersburg - Madison 115kV-transmission lines are included in the base case. Without these upgrades, fault disturbance #3, #31, #38, #39, and #40 cause PSS/E to crash early in the dynamic simulation as a result of voltage instability and inability of the PSS/E solution to converge.

Table 6.8: Transient Stability Results Summary (with upgrades)

Contingency Name	Summer Peak 2010	Winter Peak 2009
FLT01-3PH	STABLE	STABLE
FLT02-3PH	STABLE	STABLE
FLT03-3PH	STABLE	STABLE
FLT04-3PH	STABLE	STABLE
FLT05-3PH	STABLE	STABLE
FLT06-3PH	STABLE	STABLE
FLT07-3PH	STABLE	STABLE
FLT08-3PH	STABLE	STABLE
FLT09-3PH	STABLE	STABLE
FLT10-3PH	STABLE	STABLE
FLT11-3PH	STABLE	STABLE
FLT12-3PH	STABLE	STABLE
FLT13-3PH	STABLE	STABLE
FLT14-3PH	STABLE	STABLE
FLT15-3PH	STABLE	STABLE
FLT16-3PH	STABLE	STABLE
FLT17-3PH	STABLE	STABLE
FLT18-3PH	STABLE	STABLE
FLT19-3PH	STABLE	STABLE
FLT20-3PH	STABLE	STABLE
FLT21-3PH	STABLE	STABLE
FLT22-3PH	STABLE	STABLE
FLT23-3PH	STABLE	STABLE
FLT24-3PH	STABLE	STABLE
FLT25-3PH	STABLE	STABLE
FLT26-3PH	STABLE	STABLE
FLT27-3PH	STABLE	STABLE
FLT28-3PH	STABLE	STABLE
FLT29-3PH	STABLE	STABLE
FLT30-3PH	STABLE	STABLE
FLT31-1PH	STABLE	STABLE
FLT32-1PH	STABLE	STABLE
FLT33-1PH	STABLE	STABLE
FLT34-1PH	STABLE	STABLE
FLT35-1PH	STABLE	STABLE

Contingency Name	Summer Peak 2010	Winter Peak 2009
FLT36-1PH	STABLE	STABLE
FLT37-3PH	STABLE (Spirit Mount 100 MW generation islanded)	STABLE
FLT38-3PH	STABLE	STABLE
FLT39-3PH	STABLE	STABLE
FLT40-3PH	STABLE	STABLE

7. CONCLUSIONS AND RECOMMENDATIONS

1 Definitive Impact Study DISIS-2009-001 (Group 9) wind farms are required to demonstrate that they can operate at the following power factors for the worst single transmission facility outage contingency in each case.

- 99% leading to 95 % lagging power factor from GEN-2006-044N at the Tap of Neligh to Petersburg 115 kV switching station
- 94.8 % leading to 98.1% lagging power factor from GEN 2007-011N06 at the Petersburg 115 kV substation
- 98.5 % leading to 98.1% lagging power factor from GEN 2007-011N09 at the Bloomfield 115 kV substation
- 98.1 % leading to 98.5% lagging power factor from GEN 2008-086N02 at the Columbus to Ft. Randall 230 kV switching station

2 It is recommended that wind farm developers take advantage of the reactive output power capability of GE wind turbine generators to meet the voltage schedule at the POI. This does away with any capacitor bank requirement.

3 The system will remain stable and Definitive Impact Study DISIS-2009-001 (Group 9) and prior queued project will survive for 3-phase and single-line-to-ground fault contingencies at locations specified by SPP provided that the following upgrades are in place:

- New Bloomfield - Belden 115 kV transmission line
- New Petersburg - Madison 115kV-transmission line
- GE 1.5 MW wind turbine generators used at GEN-2006-038N019

R: Stability Study for Group 10

POWER SYSTEMS DIVISION
GRID SYSTEMS CONSULTING

System Impact Study for DISIS-2009-001 Group 10

DRAFT REPORT

REPORT NO.: 2010-E4032-R0
Issued On: Feb 02, 2010

Prepared for:
Southwest Power Pool, Inc.

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ABB Inc – Grid Systems Consulting **Technical Report**

Southwest Power Pool, Inc.	**No.** 2010-E4032-R0	
System Impact Study for DISIS-2009-001 Group 10	Date: 02/02/2010	# Pages 50

Author(s):	**Reviewed by:**	**Approved by:**
B Kondala Rao	Amit Kekare	Willie Wong

Executive Summary

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a system impact study for approximately 175 MW of wind-based generation (collectively known as DISIS-2009-001 Group 10 Projects) on the SPP system. The proposed windfarms are located in Southwest Nebraska. Below are the details of the Group 10 wind farm projects:

Project No	Project Size	Wind Turbine Model	Point of Interconnection	County
GEN-2006-037N	100	GE 1.5MW	Valentine 115 kV (#640392)	Cherry county, NE
GEN-2006-037N1	75	GE 1.5MW	Broken Bow 115 kV (#640089)	Custer County, NE

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed DISIS-2009-001 Group 10 (175 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement for wind farms.

To achieve these objectives the following analyses were performed on the 2010 Summer Peak and 2009 Winter Peak system conditions with Group 10 projects in-service

- Power factor analysis for the selected contingencies.
- Transient stability analysis under various local and regional contingencies.
- LVRT performance under selected contingencies near POI.

Following is the summary of study findings:

Power factor analysis

The power factor analysis was performed to determine the need of additional reactive power compensation, if any, for the DISIS-2009-001 Group10 wind farm projects. The results of power factor analysis indicated that all the Group 10 projects have the adequate reactive power capability to meet the power factor requirement at the POI.

Stability Analysis

The stability analysis was performed to determine the impact, if any, of the proposed DISIS-2009-001 Group 10 projects on the stability of the SPP system. The significant results of stability analysis are as follows:

- The system was found to be STABLE following all the simulated faults with the DISIS-2009-001 Group 10 projects.

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed DISIS-2009-001 Group 10 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

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.

Rev No.	Revision Description	Date	Authored by	Reviewed by	Approved by
0	Draft Report	02/02/2010	Kondala Rao	A. Kekare	W. Wong
DISTRIBUTION: Charles Hendrix – Southwest Power Pool, Inc. Ray Offenbacker – Southwest Power Pool, Inc.					

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1 INTRODUCTION

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a system impact study for approximately 175 MW of wind-based generation (collectively known as DISIS-2009-001 Group 10 Projects) on the SPP system. There are total two (2) generation projects (see Table 1-1). The proposed projects are located in Southwest Nebraska. Figure 1-1 shows the locations of Group 10 projects with proposed 175 MW generation.

The study evaluated the "collective impact" of the Group 10 generation projects on the stability of the SPP system. The scope of this study was limited to the transient stability analysis.

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed Group 10 (175 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement for wind farms.

To achieve these objectives the following analyses were performed on the 2010 Summer Peak and 2009 Winter Peak system conditions with Group 10 projects in-service

- Power factor analysis for the selected contingencies.
- Transient stability analysis under various local and regional contingencies.
- LVRT performance under selected contingencies near POI.

The study was performed on 2010 Summer Peak and 2009 Winter Peak cases, provided by SPP. This report documents the methods, analysis and results of the system impact study.

Table 1-1: List of Group 10 Projects

Project No	Project Size	Wind Turbine Model	Point of Interconnection	County
GEN-2006-037N	100	GE 1.5MW	Valentine 115 kV (#640392)	Cherry county, NE
GEN-2006-037N1	75	GE 1.5MW	Broken Bow 115 kV (#640089)	Custer County, NE

1.1 REPORT ORGANIZATION

This report is organized as follows:

Section 2: Description of proposed Group 10 Projects
Section 3: Study methodology
Section 4: Model Development
Section 5: Power Factor Analysis Results

Section 6: Stability Analysis Results
Section 7: Conclusions

The detailed study results are compiled in separate Appendices.

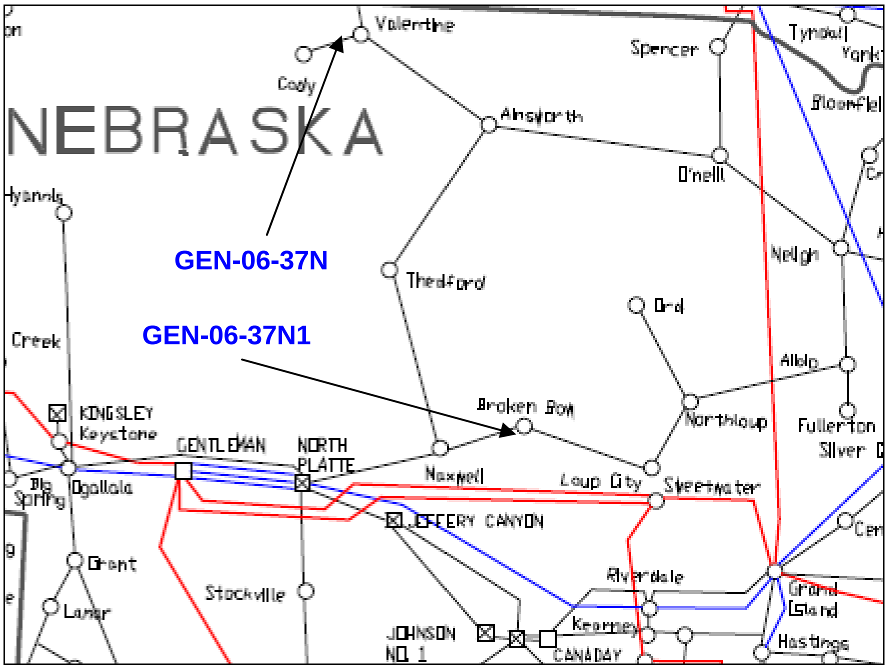

Figure 1-1 DISIS-2009-001 Group 10 Projects

2 DESCRIPTION OF GROUP 10 PROJECTS

The details of load flow and dynamic data for the DISIS-2009-001 Group 10 wind farm projects are included in the Appendix A.

2.1 GEN-2006-37N

- Wind farm rating: 100 MW
- Interconnection:

  Voltage: 115 kV

  Location: Nebraska Public Power District (NPPD) Valentine 115 kV substation.

  Transformer: One (1) step-up transformers connecting to the 115 kV

  MVA: 69/115 MVA

  Voltage: 115/34.5 kV

  Z: 10.5 % on 69 MVA

- Wind Turbines:

  Number: Sixty seven (67)

  Manufacturer: GE

  Type: Doubly-fed induction generator (DFIG)

  Machine Terminal voltage: 0.575 kV

  Rated Power: 1.5 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 117.3
  High voltage: 34.5 kV,
  Low voltage: 0.575 kV
  Z: 5.841% on 117.25 MVA

- Reactive Power Capability: 0.95 lagging/ 0.9 leading
- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage

  Undervoltage

  Overfrequency

  Underfrequency

No additional reactive power compensation (e.g. shunt capacitor bank) was modeled for the proposed GEN-2006-37N Windfarm.

Figure 2-1 shows the one-line diagram of the GEN-2006-37N windfarm.

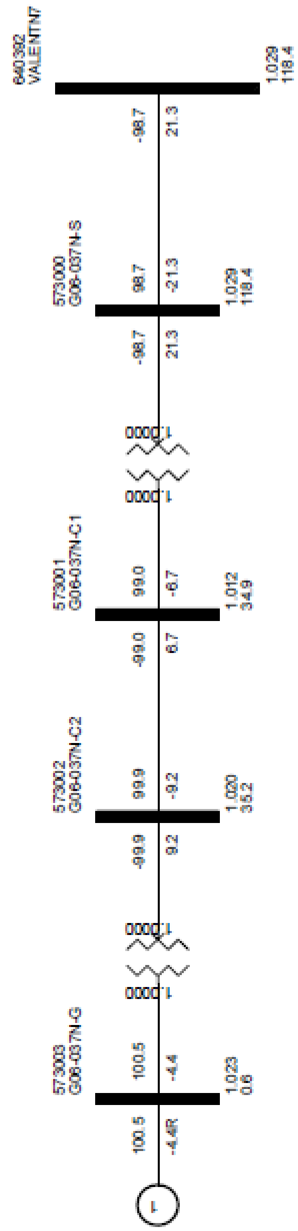

Figure 2-1 One-line diagram for GEN-2006-37N Project

2.2 GEN-2006-37N1

- Wind farm rating: 75 MW
- Interconnection:
  - Voltage: 115 kV
  - Location: Nebraska Public Power District (NPPD) Broken Bow 115 kV substation.
  - Transformer: One (1) step-up transformers connecting to the 115 kV
  - MVA: 53105 MVA
  - Voltage: 115/34.5 kV
  - Z: 9.00 % on 53 MVA
- Wind Turbines:
  - Number: Fifty (50)
  - Manufacturer: GE
  - Type: Doubly-fed induction generator (DFIG)

Machine Terminal voltage: 0.575 kV

  - Rated Power: 1.5 MW
  - Frequency: 60 Hz
  - Generator Step-up Transformer
    - MVA: 87.5
    - High voltage: 34.5 kV,
    - Low voltage: 0.575 kV
    - Z: 5.84% on 87.5 MVA
- Reactive Power Capability: 0.95 lagging/ 0.90 leading
- Fault Ride-through: Manufacturer’s default ride-through capability was modeled
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage
  Undervoltage
  Overfrequency
  Underfrequency

No additional reactive power compensation (e.g. shunt capacitor bank) was modeled for the proposed GEN-2006-37N1 windfarm.

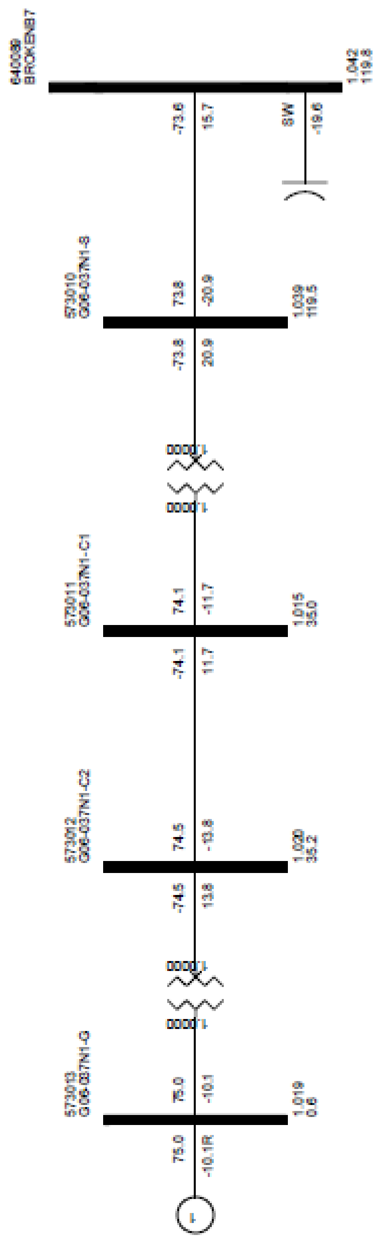

Figure 2-2: one-line diagram for GEN-2006-37N1 Project

3 STUDY METHODOLOGY

3.1 POWER FACTOR ANALYSIS

SPP transmission planning criteria[1] requires the generation interconnection projects to maintain the power factor at the Point of Interconnection (POI) to near-unity for system intact conditions and within lag/lead 0.95 p.f. range for post-contingency conditions

If the reactive power capability of the proposed project is not adequate to meet the above-mentioned requirements then additional reactive power compensation (e.g. shunt capacitors) may need to be added.

The purpose of the power factor analysis was to determine whether the proposed wind farm projects will meet the power factor requirement at the Point of Interconnection (POI) in system intact and contingency conditions.

This analysis was performed for each wind farm project at a time, considering the other wind farms to be on-line at maximum output and without additional reactive power compensation. Following steps were taken to perform the power factor analysis:

- A VAR generator with large capacity (+/- 9999 Mvar) was modeled at the POI of the subject wind farm. The VAR generator was set to hold the POI voltage consistent with the voltage schedule in the provided base case or 1.00 p.u. (whichever was higher). The reactive power capability of the wind farm was set to zero.
- A list of selected contingencies in the vicinity of the subject windfarm project was simulated. The results were used to identify the most-limiting contingency from steady state voltage and power factor perspective.
- If the required reactive power support, to maintain an acceptable power factor at the POI, was found to be beyond the capability of proposed windfarm then the additional reactive power compensation (e.g. shunt capacitor banks) was considered.

It is important to note that the reactive power compensation identified in this analysis was primarily to meet steady state criteria. The need for dynamic reactive power support, if any, will be determined during transient stability analysis.

3.2 TRANSIENT STABILITY ANALYSIS

The purpose of the transient stability analysis was to determine the “collective impact”, if any, of the DISIS-2009-001 Group 10 wind farm projects on the system stability and the nearby transmission system and generating stations.

Using Planning Standards approved by NERC, the following stability definition was applied in the Transient Stability Analysis:

“Power system stability is defined as that condition in which the differences of the angular positions of synchronous machine rotors become constant following an aperiodic system disturbance.”

[1] The SPP transmission planning criteria was provided for the purpose of this study.

Stability analysis was performed using Siemens-PTI's PSS/E™ dynamics program V30.3.3. Three-phase and single-line-to-ground (SLG) faults were simulated for the specified duration and synchronous machine rotor angles and wind turbine generator speeds were monitored to check whether synchronism is maintained following fault removal.

For three-phase faults, a fault admittance of –j2E9 was used (essentially infinite admittance or zero impedance). The PSS/E dynamics program only simulates the positive sequence network. Unbalanced faults (like single-phase line faults) involve the positive, negative, and zero sequence networks. For unbalanced faults, the equivalent fault admittance was inserted in the PSS/E positive sequence model between the faulted bus and ground to simulate the effect of the negative and zero sequence networks. For a single-line-to-ground (SLG) fault, the fault admittance equals the inverse of the sum of the positive, negative and zero sequence Thevenin impedances at the faulted bus. Since PSS/E inherently models the positive sequence fault impedance, the sum of the negative and zero sequence Thevenin impedances needs to be added and entered as the fault impedance at the faulted bus. The fault impedance was estimated to give a positive sequence voltage at the fault location of approximately 60% of pre-fault voltage, which is a typical value.

Another important aspect of the stability analysis was to determine the ability of the wind generators to stay connected to the grid during disturbances. This is primarily determined by their low-voltage ride-through capabilities – or lack thereof – as represented in the models by low-voltage trip settings. The Federal Energy Regulatory Commission (FERC) Post-transition period LVRT standard for Interconnection of Wind generating plants includes a Low Voltage Ride Through (LVRT) requirement. The key features of LVRT requirements are:

- A wind generating plant must remain in-service during three-phase faults with normal clearing (maximum 9 cycles) and single-line-to-ground faults with delayed clearing, and have subsequent post-fault recovery to pre-fault voltage unless the clearing of the fault effectively disconnects the generator from the system.
- The maximum clearing time the wind generating plant shall be required to withstand a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the GSU connected at POI.

These criteria were used to evaluate the LVRT capabilities of the Group 10 Projects.

4 MODEL DEVELOPMENT

Two power flow cases – “DISIS_10SP-G10.sav” and “DISIS_09WP-G10.sav” – representing the 2010 Summer Peak and 2009 Winter Peak conditions were provided by SPP. The base cases included all the DISIS-2009-001 Group 10 projects.

4.1 MODEL DEVELOPMENT FOR GEN-2006-37N AND GEN-2006-37N1

The details of the GEN-2006-37N and GEN-2006-37N1 wind farm project are provided in section 2.1 and section 2.2 respectively.

The proposed wind farm projects were already included in the customer provided power flow cases – “DISIS_10SP-G10.sav” and “DISIS_09WP-G10.sav” for 2010 Summer Peak and 2009 Winter Peak conditions. Figure 2-1 and Figure 2-2 shows the one-line diagram for the GEN-2006-37N and GEN-2006-37N1 wind farm project respectively.

Figure 4-1 and Figure 4-2 show the one-line diagram in the local area of Group 10 projects for 2010 Summer Peak and 2009 Winter Peak system conditions respectively.

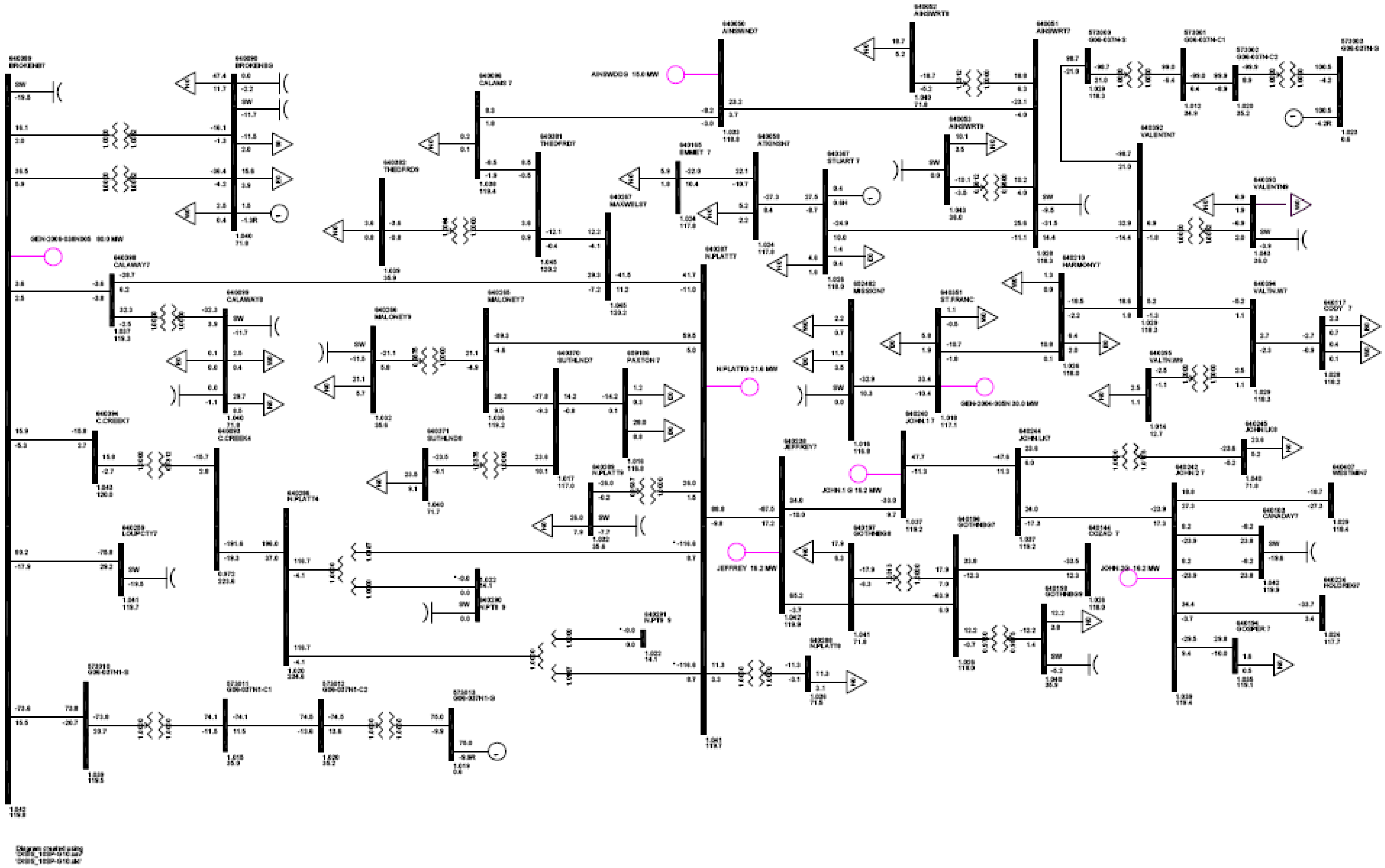

Figure 4-1 One-line Diagram of the local area with Group 10 Projects (2010 Summer Peak)

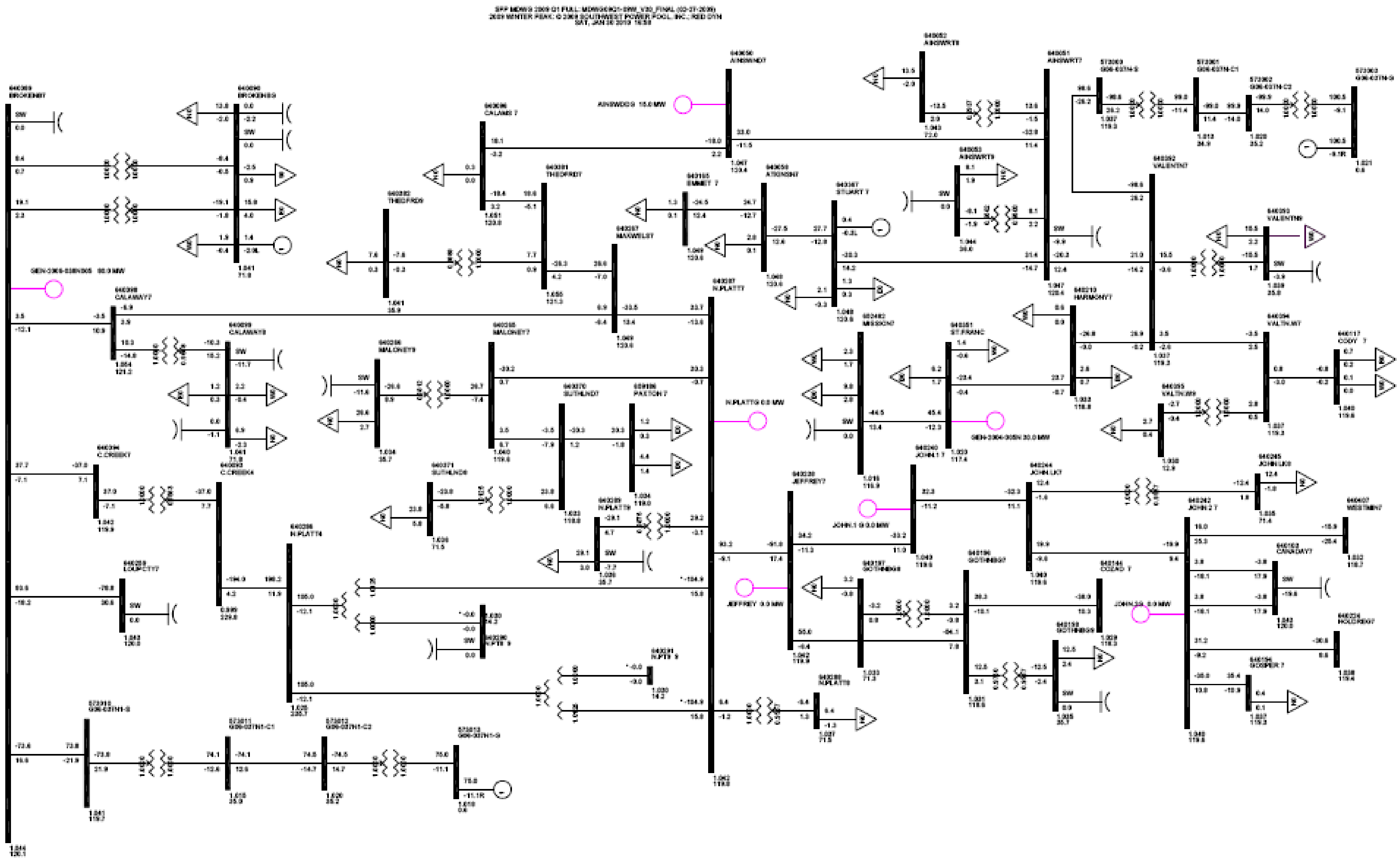

Figure 4-2 One-line Diagram of the local area with Group 10 Projects (2009 Winter Peak)

5 POWER FACTOR ANALYSIS RESULTS

Table 5-1 lists the contingencies simulated for Power Factor analysis.

Table 5-1: List of contingencies simulated for Power Factor Analysis

Contingency Name	Contingency Description
CONT_01	Broken Bow (640089) to Crooked Creek (640094) 115kV line
CONT_02	Broken Bow (640089) to Callaway (640098) 115kV line
	Callaway (640098) 115kV BUS
CONT_03	Broken Bow (640089) to Loup City (640259) 115kV line
CONT_04	North Loup (640284) to Loup City (640259) 115kV line
CONT_05	St Libory Jct (640353) to Loup City (640259) 115kV line
	St Libory Jct (640353) 115kV BUS
	St. Paul (640355) 115 kV BUS
CONT_06	Maxwell (640267) to Thedford (640381) 115kV line
CONT_07	Crooked Creek (640093) to North Platte (640286) 230kV line
CONT_08	Crooked Creek (640093) to Riverdale (640330) 230kV line
CONT_09	St. Francis (640351) to Mission (652482) 115kV line
CONT_10	Harmony (640210) to Valentine (640392) 115kV line
	Harmony (640210) to St. Francis (640351) 115kV line
CONT_11	Ainsworth (640051) to Valentine (640392) 115kV line
CONT_12	Ainsworth Wind (640050) to Ainsworth (640051) 115kV line
CONT_13	Ainsworth Wind (640050) to Calamus (640096) 115kV line
CONT_14	Ainsworth (640051) to Stuart (640367)
	Stuart (640367) to Atkinson (640058)
	Atkinson (640058) to Emmett (640165) 115kV line
	O’Neill (640305) to Emmett (640165) 115kV line
CONT_15	O’Neill (640305) to Spencer (640349) 115kV line
CONT_16	Hartington (640212) to Gavins (652511) 115kV line
CONT_17	Shell Creek (640343) to Columbus (640133) 230kV line
CONT_18	Columbus West (640131) to Columbus (640133) 230kV line
CONT_19	East Columbus (640126) to Columbus (640133) 230kV line
CONT_20	GEN-2008-086N02 (570886) to Columbus (640133) 230kV line
CONT_21	GEN-2008-086N02 (570886) to Fort Randall (652509) 230kV line
CONT_22	Fort Randall (652509) to Fort Thompson (652507) 230kV line
CONT_23	Fort Randall (652509) to Utica Jct (652526) 230kV line
CONT_24	Fort Randall (652509) to Lake Platt (652516) 230kV line
CONT_25	Fort Randall (652509) to Sioux City (652565) 230kV line
CONT_26	Columbus 230/115 kV auto at the 230kV (640133)
CONT_27	Clearwater (640113) to Neligh (640293) 115kV line

Contingency Name	Contingency Description
CONT_28	County Line (640115) to Neligh (640293) 115kV line
CONT_29	Creighton (640149) to Neligh (640293) 115kV line
CONT_30	Maxwell (640267) to North Platte (640287) 115kV line
CONT_31	North Platte (640287) 230/115kV auto 1 & 2
CONT_32	North Platte (640286) to GGS (640184) 230kV line
CONT_33	GGS (640183) to Sweetwater (640374) 345kV line
CONT_34	GGS (640183) to Red Willow (640325) 345kV line
CONT_35	Bloomfield (640084) to Creighton (640149)
CONT_36	Bloomfield (640084) to Gavins Point (652511)
CONT_37	Yankton (652532) to Gavins (652511) 115kV line
CONT_38	Yankton Jct (660006) to Gavins (652511)
CONT_39	Spirit Mound (659121) to Manning (652517) 115 kV line
CONT_40	Neligh (640293) TO County Line (640115) 115 kV line
	County Line (640115) TO BattleCreek (640072) 115 kV line
	BattleCreek (640072) TO NorthNorfolk (640296) 115 kV line
CONT_41	Albion (640054)-Genoa(640181) 115 kV line

Power factor analysis was performed for each of the windfarm project in DISIS-2009-001 Group 10.

5.1 POWER FACTOR ANALYSIS RESULTS FOR GEN-2006-37N

The proposed GEN-2006-37N windfarm (100 MW) will be comprised of GE 1.5 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +0.95/-0.9p.f. The wind turbine generators were modeled in voltage control mode.

Next, as described in section 3.1, the VAR generator was modeled at POI. The VAR generator was set to hold the 115 kV POI (Valentine 115kV) voltage consistent with the pre-contingency voltage schedule in the provided base cases. The reactive power capability of the wind farm was set to zero.

The contingencies from Table 5-1 were simulated on 2010 Summer Peak and 2009 Winter Peak system conditions. Table 5-2 lists the VARs provided by the VAR generator at POI following the simulated contingencies.

Table 5-2 VAR generator output at the GEN-06-37N POI

Contingency	2010 Summer Peak	2009 Winter Peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	4.9**	8.6**
CONT_01	4.8	8.1
CONT_02	4.7	8.1
CONT_03	4.5	7.7
CONT_04	4.8	8.3
CONT_05	4.8	8.2
CONT_06	3.6	8.3
CONT_07	4.8	8.1
CONT_08	4.8	8
CONT_09	7.3	2.5
CONT_10	6.5	10.9
CONT_11	10	8.9
CONT_12	7.1	6.3
CONT_13	3.2	7.9
CONT_14	3.2	3.8
CONT_15	2.6	8.3
CONT_16	4.9	8.4
CONT_17	4.8	8.4
CONT_18	4.8	8.3
CONT_19	4.8	8.4
CONT_20	4.8	8.7
CONT_21	4.8	8.4
CONT_22	4.7	8.4

Contingency	2010 Summer Peak	2009 Winter Peak
CONT_23	4.9	8.6
CONT_24	4.8	8.4
CONT_25	4.8	8.6
CONT_26	4.8	8.4
CONT_27	3.1	8.4
CONT_28	5.2	8.2
CONT_29	4.8	8.5
CONT_30	4.7	9.3
CONT_31	3.4	8.3
CONT_32	4.7	8.4
CONT_33	4.3	7.4
CONT_34	4.5	8
CONT_35	4.7	8.7
CONT_36	4.3	7.1
CONT_37	4.8	8.4
CONT_38	4.4	8.2
CONT_39	4.8	8.4
CONT_40	5.2	8.2
CONT_41	4.8	8

**The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).

The results indicated that the *CONT_11*: loss of Ainsworth - Valentine 115kV line and *CONT_10*: loss of Valentine - Harmony - St. Francis 115kV line will yield the maximum reactive power output for GEN-2006-37N in 2010 Summer Peak and 2009 Winter Peak respectively. Therefore, the wind farm is required to be able to provide 10.9 Mvars at the point of interconnection for a composite power factor range of 98.5% lagging assuming voltage control with the GE turbines.

5.2 Power Factor Analysis results for GEN-2006-37N1

The proposed GEN-2006-37N1 windfarm (75 MW) will be comprised of GE 1.5 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +0.95/-0.90 p.f. The wind turbine generators were modeled in voltage control mode.

Next, as described in section 3.1, a VAR generator was modeled at the POI (Broken Bow 115 kV). The VAR generator was set to hold the POI voltage consistent with the pre-contingency voltage schedule in the provided base cases. The reactive power capability of the wind farm was set to zero.

The contingencies from Table 5-1 were simulated on 2010 Summer Peak and 2009 Winter Peak system conditions. Table 5-3 lists the VARs provided by the VAR generator at POI following the simulated contingencies.

Table 5-3 VAR generator output at the GEN-06-37N1 POI

Contingency	2010 Summer Peak	2009 Winter Peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	11.3**	13.1**
CONT_01	9.7	10.9
CONT_02	13.5	0.7
CONT_03	3.5	0.6
CONT_04	16.8	10.4
CONT_05	12.9	11.6
CONT_06	10.5	10.9
CONT_07	1.3	2.8
CONT_08	9.6	12.4
CONT_09	9.2	10.7
CONT_10	10	11.7
CONT_11	12.2	13.8
CONT_12	10.6	11.1
CONT_13	12.5	13.1
CONT_14	9.2	11
CONT_15	11.2	13.2
CONT_16	11.2	12.9
CONT_17	10.9	12.8
CONT_18	11.2	12.7
CONT_19	11.2	12.8
CONT_20	9.6	11.2
CONT_21	11.2	13.2
CONT_22	11.1	13

Contingency	2010 Summer Peak	2009 Winter Peak
CONT_23	10.8	12.8
CONT_24	11.2	13
CONT_25	10.8	12.8
CONT_26	11	12.8
CONT_27	11	13.2
CONT_28	11.6	12.8
CONT_29	11.1	13.1
CONT_30	15.7	20.2
CONT_31	6	11.3
CONT_32	10.1	12.4
CONT_33	1.8	3.8
CONT_34	6.7	9.7
CONT_35	10.6	13
CONT_36	11.7	12.8
CONT_37	11.2	13.2
CONT_38	11.6	13.3
CONT_39	11.4	13.2
CONT_40	11.9	12.9
CONT_41	13	14.8

**The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).

The results indicated that the *CONT_04*: loss of North Loup - Loup City 115kV line and *CONT_30*: loss of Maxwell - North Platte 115kV line will yield the maximum reactive power output for GEN-2006-37N1 in 2010 Summer Peak and 2009 Winter Peak respectively. Therefore, GEN-2006-037N1 is required to be able to provide up to 20.2 Mvars at the point of interconnection for a composite power factor range of 97.5% leading/lagging assuming voltage control of the GE turbines.

6 STABILITY ANALYSIS RESULTS

Stability simulations were performed to examine the transient behavior of the Group 10 projects and impact of the proposed addition of generation on the SPP system. A number of three-phase and single phase faults without re-closing were simulated. The fault clearing times for the simulations are given inTable 6-1.

Table 6-1: Fault Clearing Times

Faulted bus kV level	Normal Clearing
345	4.5 cycles
230	6 cycles
230/115 Auto	5.5 cycles
115	6.5 cycles

Table 6-2 lists all the faults simulated for transient stability analysis.

Forty six (46) three phase and six (6) single-line-to-ground faults with Stuck breaker without re-closing were simulated. For all cases analyzed, the initial disturbance was applied at t = 0.1 seconds. The breaker clearing was applied at the appropriate time following this fault inception.

Table 6-2 List of Simulated Faults for Group 10 SIS

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Broken Bow (640089) to Crooked Creek (640094) 115kV line, near BrokenBow. a. Apply fault at the Broken Bow 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
2	FLT02-3PH	3 phase fault on the Broken Bow (640089) to Callaway (640098) 115kV line, near Broken Bow. a. Apply fault at the Broken Bow 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line and the Callaway 115 kV bus.
3	FLT03-3PH	3 phase fault on the Broken Bow (640089) to Loup City (640259) 115kV line, near Broken Bow. a. Apply fault at the Broken Bow 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
4	FLT04-3PH	3 phase fault on the North Loup (640284) to Loup City (640259) 115kV line, near Loup City a. Apply fault at the Loup City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
5	FLT05-3PH	3 phase fault on the St Libory Jct (640353) to Loup City (640259) 115kV line, near Loup City a. Apply fault at the Loup City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line and the St. Libory and St. Paul 115 kV buses.
6	FLT06-3PH	3 phase fault on the Maxwell (640267) to Thedford (640381) 115kV line, near Maxwell. a. Apply fault at the Maxwell 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
7	FLT07-3PH	3 phase fault on the Crooked Creek (640093) to North Platte (640286) 230kV line, near Crooked Creek. a. Apply fault at the Crooked Creek 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
8	FLT08-3PH	3 phase fault on the Crooked Creek (640093) to Riverdale (640330) 230kV line, near Crooked Creek. a. Apply fault at the Crooked Creek 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
9	FLT09-3PH	3 phase fault on the St. Francis (640351) to Mission (652482) 115kV line, near Mission. a. Apply fault at the Mission 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
10	FLT10-3PH	3 phase fault on the Harmony (640210) to St. Francis (640351) 115kV line, near St. Francis. a. Apply fault at the St. Francis115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted Valentine – Harmony – St. Francis 115 kV line.
11	FLT11-3PH	3 phase fault on the Harmony (640210) to Valentine (640392) 115kV line, near Valentine. a. Apply fault at the Harmony 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted Valentine – Harmony – St. Francis 115 kV line.
12	FLT12-3PH	3 phase fault on the Ainsworth (640051) to Valentine (640392) 115kV line, near Valentine. a. Apply fault at the Valentine 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
13	FLT13-3PH	3 phase fault on the Ainsworth Wind (640050) to Ainsworth (640051) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
14	FLT14-3PH	3 phase fault on the Ainsworth Wind (640050) to Calamus (640096) 115kV line, near Ainsworth Wind. a. Apply fault at the Ainsworth Wind 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
15	FLT15-3PH	3 phase fault on the Ainsworth (640051) to Stuart (640367) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted Ainsworth-Stuart-Atkinson-Emmet-O'Neill 115 kV line.
16	FLT16-3PH	3 phase fault on the O'Neill (640305) to Spencer (640349) 115kV line, near O'Neill. a. Apply fault at the O'Neill 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.
17	FLT17-3PH	3 phase fault on the Hartington (640212) to Gavins (652511) 115kV line, near Hartington. a. Apply fault at the Hartington 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
18	FLT18-3PH	3 phase fault on the Shell Creek (640343) to Kelly (640133) 230kV line, near Kelly a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
19	FLT19-3PH	3 phase fault on the Columbus West (640131) to Kelly (640133) 230kV line, near Kelly a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
20	FLT20-3PH	3 phase fault on the East Columbus (640126) to Kelly (640133) 230kV line, near Kelly a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
21	FLT21-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Kelly (640133) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
22	FLT22-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Fort Randall (652509) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
23	FLT23-3PH	3 phase fault on the Fort Randall (652509) to Fort Thompson (652507) 230kV line, near GEN-Fort Randall a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
24	FLT24-3PH	3 phase fault on the Fort Randall (652509) to Utica Jct (652526) 230kV line, near Fort Randall a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
25	FLT25-3PH	3 phase fault on the Fort Randall (652509) to Lake Platt (652516) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
26	FLT26-3PH	3 phase fault on the Fort Randall (652509) to Sioux City (652565) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
27	FLT27-3PH	3 phase fault on the Kelly 230/115 kV auto at the 115kV (640134) a. Apply fault at the Kelly 115kV bus. b. Clear fault after 5.5 cycles by tripping autotransformer.
28	FLT28-3PH	3 phase fault on the Clearwater (640113) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted Neligh-Clearwater-O'Neill 115 kV line.
29	FLT29-3PH	3 phase fault on the County Line (640115) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV line.
30	FLT30-3PH	3 phase fault on the Creighton (640149) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.
31	FLT31-3PH	3 phase fault on the Maxwell (640267) to North Platte (640287) 115kV line, near Maxwell. a. Apply fault at the Maxwell 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
32	FLT32-3PH	3 phase fault on the North Platte (640287) 23/115kV auto. a. Apply fault at the North Platte 115kV bus. b. Clear fault after 5.5 cycles by tripping the faulted line..
33	FLT33-3PH	3 phase fault on the North Platte (640286) to GGS (640184) 230kV line ckt 1, near North Platte. a. Apply fault at the North Platte 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
34	FLT34-3PH	3 phase fault on the GGS (640183) to Sweetwater (640374) 345kV line ckt 1, near GGS. a. Apply fault at the GGS 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.
35	FLT35-3PH	3 phase fault on the GGS (640183) to Red Willow (640325) 345kV line, near GGS. a. Apply fault at the GGS 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.
36	FLT36-3PH	3 phase fault on the Bloomfield (640084) to Creighton (640149) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
37	FLT37-1PH	SLG fault on Bloomfield – Gavins Point 115 kV line, near Bloomfield. Stuck breaker at Gavins. a. Apply fault at Bloomfield 115 kV bus. b. Clear Bloomfield end of line at 5.5 cycles. Leave fault on end of open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.

Cont. No.	Cont. Name	Description
38	FLT38-1PH	SLG fault on Creighton – Neligh 115 kV line, near Creighton. Stuck breaker at Creighton. a. Apply fault at Creighton 115 kV bus. b. Clear Neligh end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. c. Clear Creighton 115 kV bus and fault at 18.0 cycles.
39	FLT39-1PH	SLG fault on Gavins Point – Hartington 115 kV line, near Gavins Point. Stuck breaker at Gavins Point. a. Apply fault at Gavins Point 115 kV bus. b. Clear Hartington end of line at 6.5 cycles. Leave fault on open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.
40	FLT40-1PH	SLG fault on Neligh-County Line, near Neligh. Stuck PCB at Neligh. a. Apply fault at Neligh 115 kV bus. b. Clear North Norfolk end of Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Neligh 115 kV bus and fault at 18.0 cycles.
41	FLT41-1PH	SLG fault on Albion-Genoa 115 kV line near Albion. Stuck PCB at Albion. a. Apply fault on Albion 115 kV bus. b. Clear Genoa end of Albion-Genoa 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Albion 115 kV bus and fault at 18.0 cycles.
42	FLT42-1PH	SLG fault on Kelly – Columbus West 230 kV line. Stuck PCB at Kelly. a. Apply fault on Kelly 230 kV bus. b. Clear Columbus West end of line at 6.0 cycles. Leave fault on open-ended line. c. Clear Kelly 230 kV bus and fault at 14.5 cycles.
43	FLT43-3PH	3PH fault on Spirit Mound – Manning 115 kV line with prior outage of Gavins Point – Yankton Junction 115 kV. a. Prior Outage: Gavins Point – Yankton Junction 115 kV line b. Apply 3PH fault on Manning115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Spirit Mound – Manning 115 kV line.
44	FLT44-3PH	3PH fault on Albion – Genoa 115 kV line with prior outage of Petersburg – Neligh 115 kV. a. Prior Outage: 115 kV line b. Apply 3PH fault on Albion 115 kV bus. c. Clear Albion end of Albion – Genoa 115 kV line in 5.5 cycles. Leave fault on end of line out of Genoa. d. Clear fault after 6.5 cycles and trip faulted Albion – Genoa 115 kV line.
45	FLT45-3PH	3 phase fault on the Bloomfield (640084) to Gavins (652511) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
46	FLT46-3PH	3 phase fault on the Hartington (640212) to Gavins (652511) 115kV line, near Hartington. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
47	FLT47-3PH	3 phase fault on the Yankton (652532) to Gavins (652511) 115kV line, near Yankton. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
48	FLT48-3PH	3 phase fault on the Yankton Jct (660006) to Gavins (652511) 115kV line, near Yankton Jct a. Apply fault at the Yankton Jct 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
49	FLT49-3PH	3 phase fault on the Spirit Mound (659121) to Manning (652517) 115 kV line, near Spirit Mound. a. Apply fault at the Manning 115 kV bus (652517). b. Clear fault after 6.5 cycles by tripping the faulted line.
50	FLT50-3PH	3PH fault on Broken Bow – Loup City 115 kV line with prior outage of Broken Bow – Callaway 115 kV. a. Prior Outage: Broken Bow – Callaway 115 kV line b. Apply 3PH fault on Broken Bow 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Broken Bow – Loup City 115 kV line.
51	FLT51-3PH	3PH fault on Gavins Point – Bloomfield 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Bloomfield 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Gavins Point – Bloomfield 115 kV line.
52	FLT52-3PH	3PH fault on Albion - Petersburg 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Petersburg 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Albion – Petersburg 115 kV line.

Table 6-3 and Table 6-4 summarize the stability analysis results for 2010 Summer Peak and 2009 Winter Peak system conditions.

Table 6-3 Results of stability analysis – Summer Peak 2010

FAULT	2010 Summer Peak	
	Without Group 10 Projects	With Group 10 Projects
FLT01-3PH	---	STABLE
FLT02-3PH	---	STABLE
FLT03-3PH	---	STABLE
FLT04-3PH	---	STABLE
FLT05-3PH	---	STABLE
FLT06-3PH	---	STABLE
FLT07-3PH	---	STABLE
FLT08-3PH	---	STABLE
FLT09-3PH	---	STABLE
FLT10-3PH	---	STABLE
FLT11-3PH	---	STABLE
FLT12-3PH	---	STABLE
FLT13-3PH	---	STABLE
FLT14-3PH	---	STABLE
FLT15-3PH	---	STABLE
FLT16-3PH	---	STABLE
FLT17-3PH	---	STABLE
FLT18-3PH	---	STABLE
FLT19-3PH	---	STABLE
FLT20-3PH	---	STABLE
FLT21-3PH	---	STABLE
FLT22-3PH	---	STABLE
FLT23-3PH	---	STABLE
FLT24-3PH	---	STABLE
FLT25-3PH	---	STABLE
FLT26-3PH	---	STABLE
FLT27-3PH	---	STABLE
FLT28-3PH	---	STABLE
FLT29-3PH	---	STABLE
FLT30-3PH	---	STABLE
FLT31-3PH	---	STABLE
FLT32-3PH	---	STABLE

FAULT	2010 Summer Peak	
	Without Group 10 Projects	**With Group 10 Projects**
FLT33-3PH	---	STABLE
FLT34-3PH	---	STABLE
FLT35-3PH	---	STABLE
FLT36-3PH	---	STABLE
FLT37-1PH	---	STABLE
FLT38-1PH	---	STABLE
FLT39-1PH	---	STABLE
FLT40-1PH	---	STABLE
FLT41-1PH	---	STABLE
FLT42-1PH	---	STABLE
FLT43-3PH	---	STABLE
FLT44-3PH	---	STABLE
FLT45-3PH	---	STABLE
FLT46-3PH	---	STABLE
FLT47-3PH	---	STABLE
FLT48-3PH	---	STABLE
FLT49-3PH	---	STABLE
FLT50-3PH	---	STABLE
FLT51-3PH	---	STABLE
FLT52-3PH	---	STABLE

Table 6-4 Results of stability analysis – Winter Peak 2009

FAULT	2009 Winter Peak	
	Without Group 10 Projects	With Group 10 Projects
FLT01-3PH	---	STABLE
FLT02-3PH	---	STABLE
FLT03-3PH	---	STABLE
FLT04-3PH	---	STABLE
FLT05-3PH	---	STABLE
FLT06-3PH	---	STABLE
FLT07-3PH	---	STABLE
FLT08-3PH	---	STABLE
FLT09-3PH	---	STABLE
FLT10-3PH	---	STABLE
FLT11-3PH	---	STABLE
FLT12-3PH	---	STABLE
FLT13-3PH	---	STABLE
FLT14-3PH	---	STABLE
FLT15-3PH	---	STABLE
FLT16-3PH	---	STABLE
FLT17-3PH	---	STABLE
FLT18-3PH	---	STABLE
FLT19-3PH	---	STABLE
FLT20-3PH	---	STABLE
FLT21-3PH	---	STABLE
FLT22-3PH	---	STABLE
FLT23-3PH	---	STABLE
FLT24-3PH	---	STABLE
FLT25-3PH	---	STABLE
FLT26-3PH	---	STABLE
FLT27-3PH	---	STABLE
FLT28-3PH	---	STABLE
FLT29-3PH	---	STABLE
FLT30-3PH	---	STABLE
FLT31-3PH	---	STABLE
FLT32-3PH	---	STABLE
FLT33-3PH	---	STABLE
FLT34-3PH	---	STABLE

FAULT	2009 Winter Peak	
	Without Group 10 Projects	With Group 10 Projects
FLT35-3PH	---	STABLE
FLT36-3PH	---	STABLE
FLT37-1PH	---	STABLE
FLT38-1PH	---	STABLE
FLT39-1PH	---	STABLE
FLT40-1PH	---	STABLE
FLT41-1PH	---	STABLE
FLT42-1PH	---	STABLE
FLT43-3PH	---	STABLE
FLT44-3PH	---	STABLE
FLT45-3PH	---	STABLE
FLT46-3PH	---	STABLE
FLT47-3PH	---	STABLE
FLT48-3PH	---	STABLE
FLT49-3PH	---	STABLE
FLT50-3PH	---	STABLE
FLT51-3PH	---	STABLE
FLT52-3PH	---	STABLE

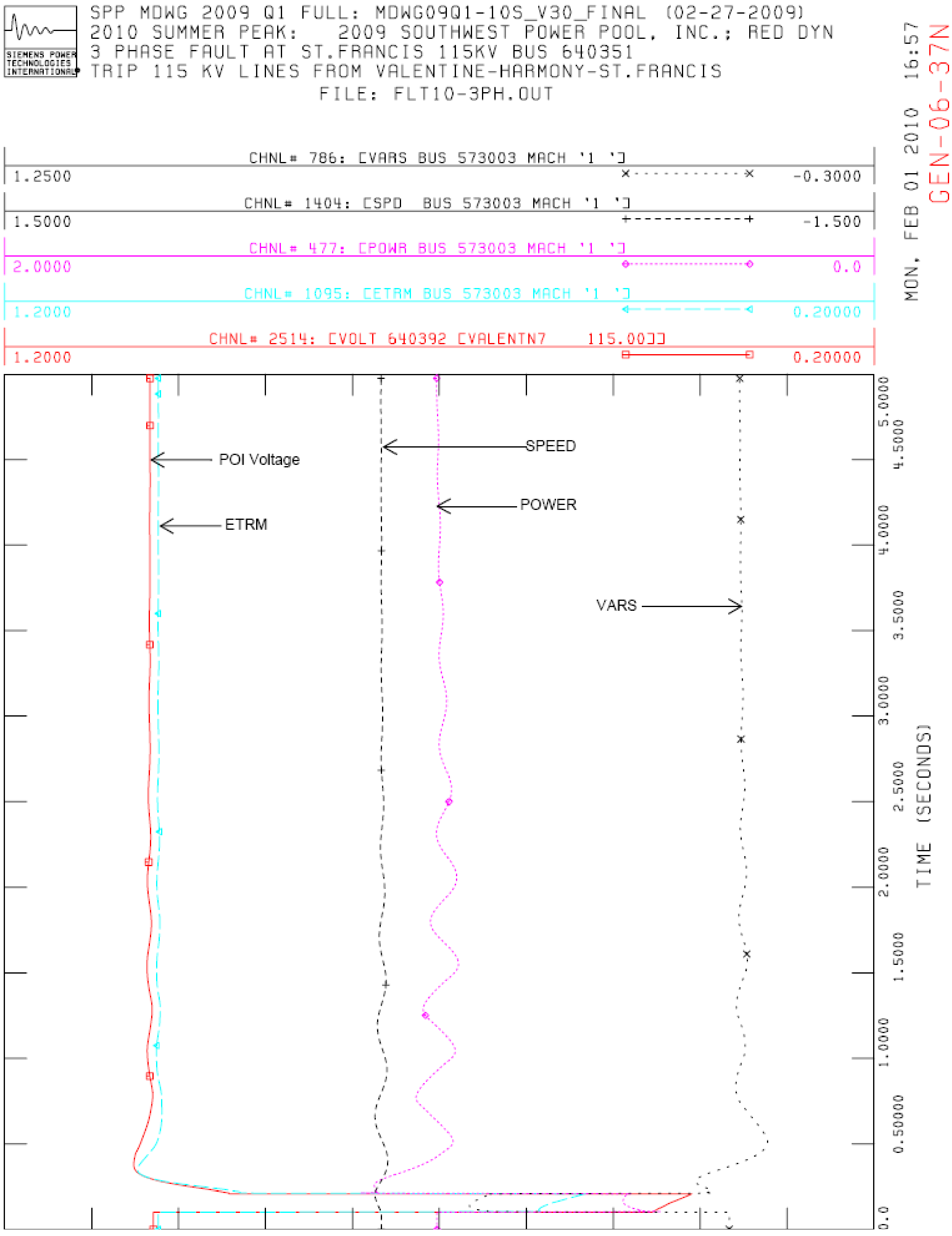

Figure 6-1: Gen-06-37N FLT10-3PH (Summer Peak)

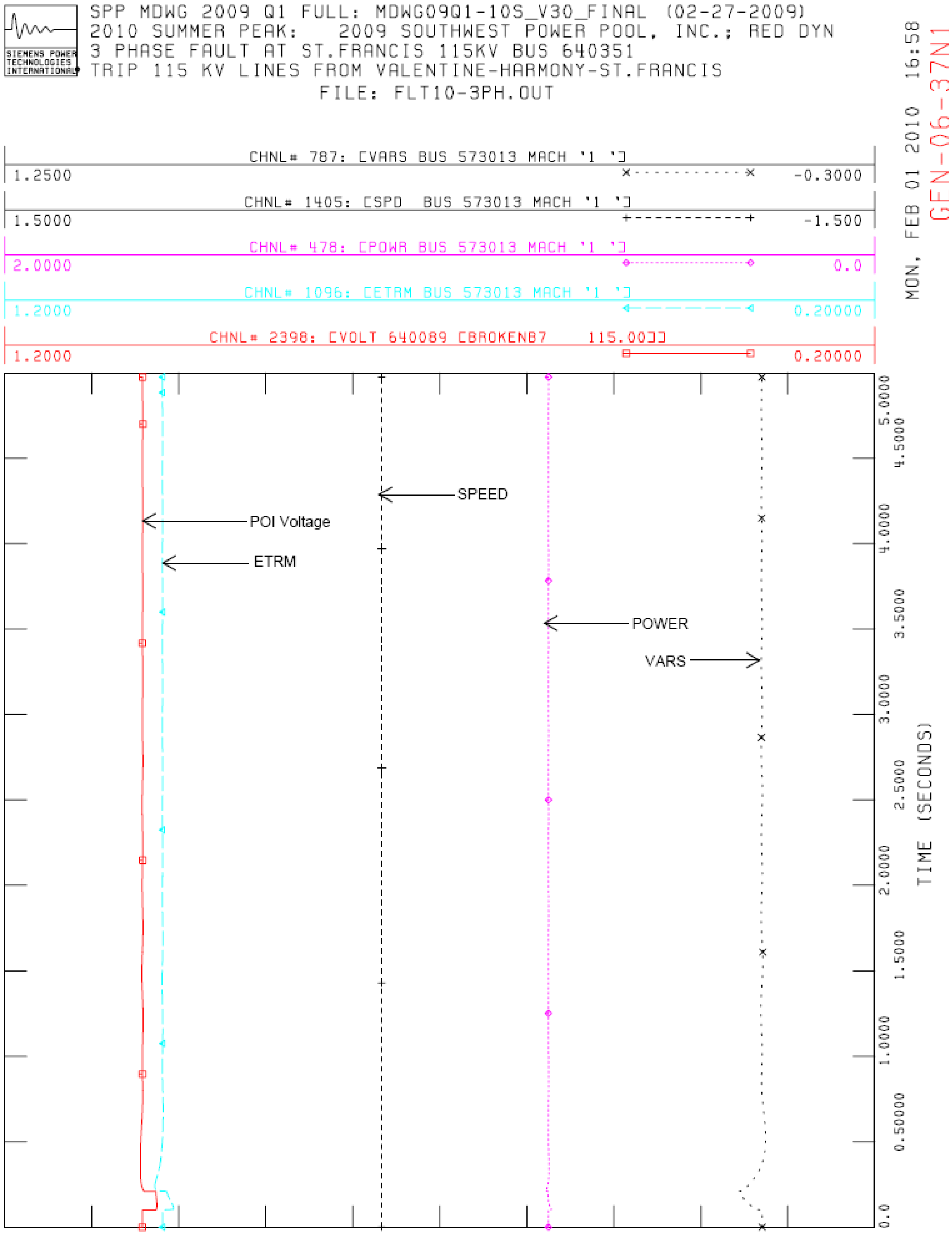

Figure 6-2: Gen-06-37N1 FLT10-3PH (Summer Peak)

6.1 FERC LVRT Compliance

As explained in section 2, the proposed Group 10 windfarm projects were modeled with the low voltage ride through capacity. To determine the compliance of the Group 10 wind farm projects total of Five (10) faults were simulated. Faults were simulated at the POI of Group 10 wind farm project and normally cleared by tripping one transmission element at a time. Table 6-5 lists the faults simulated for LVRT analysis.

Table 6-5: List of faults for FERC LVRT compliance

Fault Name	Description
FLT01-3PH_LVRT	3 phase fault on the Broken Bow (640089) to Crooked Creek (640094) 115kV line, near Broken Bow.
	a. Apply fault at the Broken Bow 115kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
FLT01-1PH_LVRT	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
FLT02-3PH_LVRT	3 phase fault on the Broken Bow (640089) to Callaway (640098) 115kV line, near Broken Bow.
	a. Apply fault at the Broken Bow 115kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line and the Callaway 115 kV bus
FLT02-1PH_LVRT	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
FLT03-3PH_LVRT	3 phase fault on the Broken Bow (640089) to Loup City (640259) 115kV line, near Broken Bow.
	a. Apply fault at the Broken Bow 115kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line
FLT03-1PH_LVRT	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
FLT11-3PH_LVRT	3 phase fault on the Harmony (640210) to Valentine (640392) 115kV line, near Valentine.
	a. Apply fault at the Harmony 115kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted Valentine – Harmony – St. Francis 115 kV line.
FLT11-1PH_LVRT	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles)and sequence like previous*
FLT12-3PH_LVRT	3 phase fault on the Ainsworth (640051) to Valentine (640392) 115kV line, near Valentine.
	a. Apply fault at the Valentine 115kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
FLT12-1PH_LVRT	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles)and sequence like previous*

The results of the simulations indicated that all the two (2) wind farm projects in the DISIS-2009-001 Group 10 meet the FERC LVRT criteria for the interconnection of the wind farm generation (FERC Order 661 – A).

The results of the FERC LVRT compliance are included in Appendix D for reference.

7 CONCLUSIONS

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed Group 10 (175 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement.

The study was performed on 2010 Summer Peak and 2009 Winter Peak cases, provided by SPP.

To achieve these objective the following analyses were performed on the 2010 Summer Peak and 2009 Winter Peak system conditions with Group 10 projects in-service

- Power factor Analysis for the selected contingencies.
- Transient Stability analysis under various local and regional contingencies.
- LVRT performance under selected contingencies near POI.

Following is the summary of study findings:

Power factor analysis

The power factor analysis was performed to determine the need of additional reactive power compensation, if any, for the DISIS-2009-001 Group10 wind farm projects. The results of power factor analysis indicated that all the Group 10 projects, will have the power factor requirements listed in section 5.

Stability Analysis

The stability analysis was performed to determine the impact, if any, of the proposed DISIS-2009-001 Group 10 projects on the stability of the SPP system. The significant results of stability analysis are as follows:

- The system was found to be STABLE following all the simulated faults with the DISIS-2009-001 Group 10 projects.

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed Group 10 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

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.

S: Stability Study for Group 11

Pterra Consulting

Technical Report R105-10

Impact Study for Generation Interconnection Request DISIS-2009-001 (Group 11)

Submitted to

Southwest Power Pool

January 2010

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Executive Summary

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnectionwind farm projects DISIS-2009-001 (Group 11). The group 11 contains study projects: Gen-2008-092 and Gen-2009-011, which are described in Section 1.

The analysis was conducted through the Southwest Power Pool ("SPP") Tariff. Power factor analysis and transient stability simulations were conducted with all two projects in service at their full output.

Two base cases for 2010 summer peak and 2009 winter peak conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP. The two projects are already modeled in the base cases.

The results of the Power Factor analysis showed that the study projects must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

Seventy-eight (78) faults were considered for the transient stability simulations which included 3-phase faults as well as 1-phase to ground faults at the locations defined by SPP. The results of the simulations showed no angular or voltage instability problems for the faults. The study finds that the interconnection of the two proposed projects does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

Section 1. Introduction

1.1. Project Overview

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under DISIS-2009-001 (Group 11) as described in Table 1-1:

Table 1-1 Projects Included Under DISIS-2009-001 (Group 11)

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2008-092	200	GE 1.5MW	Knoll 230kV (530558)
GEN-2009-011	50	Gamesa 2.0MW	Tap Plainville (539686) – Phillipsburg (539685) 115kV. Bus # 570911

Figures 1-1, and 1-2 show the interconnection diagrams of the Project to SPP's system as modeled in the power flow cases.

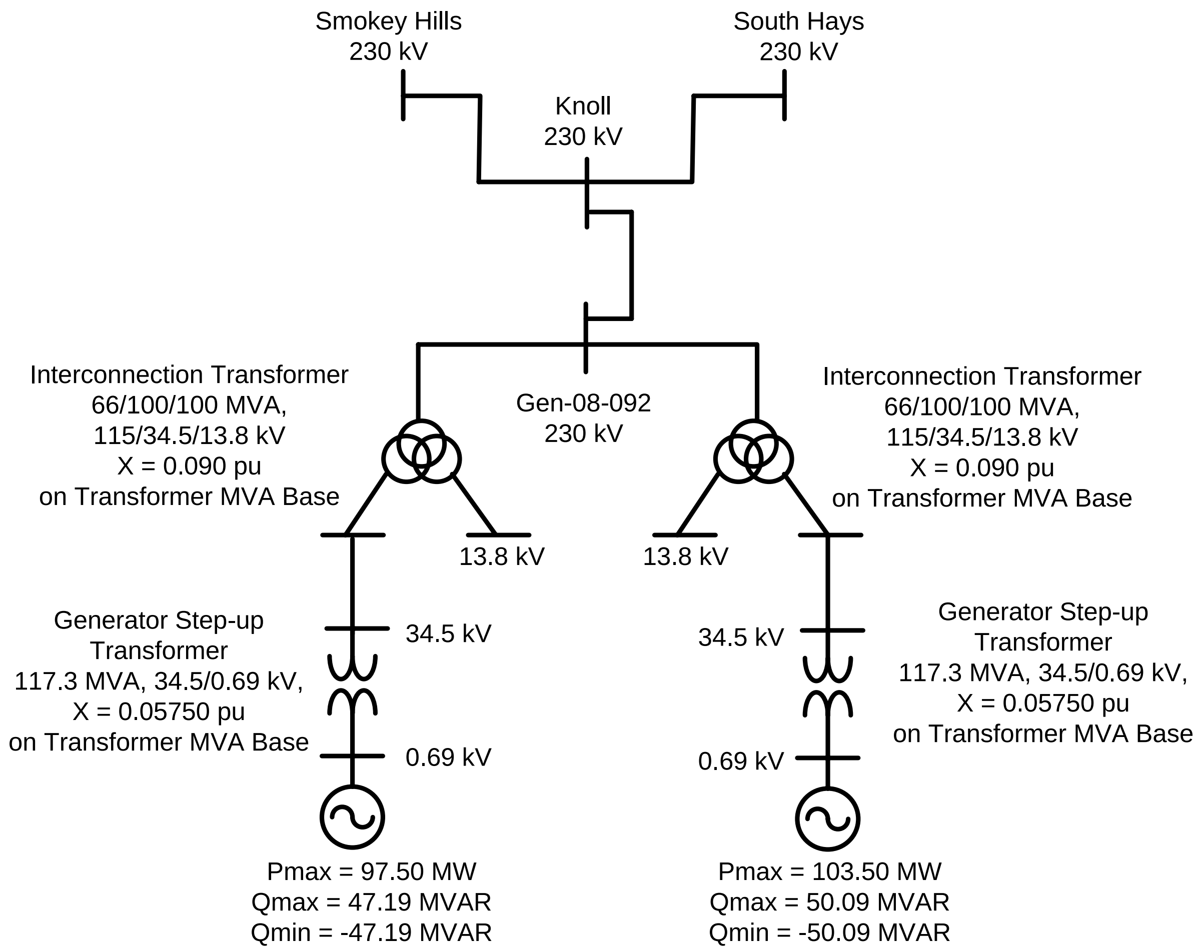

Figure 1-1 Power Flow Model for GEN-2008-092

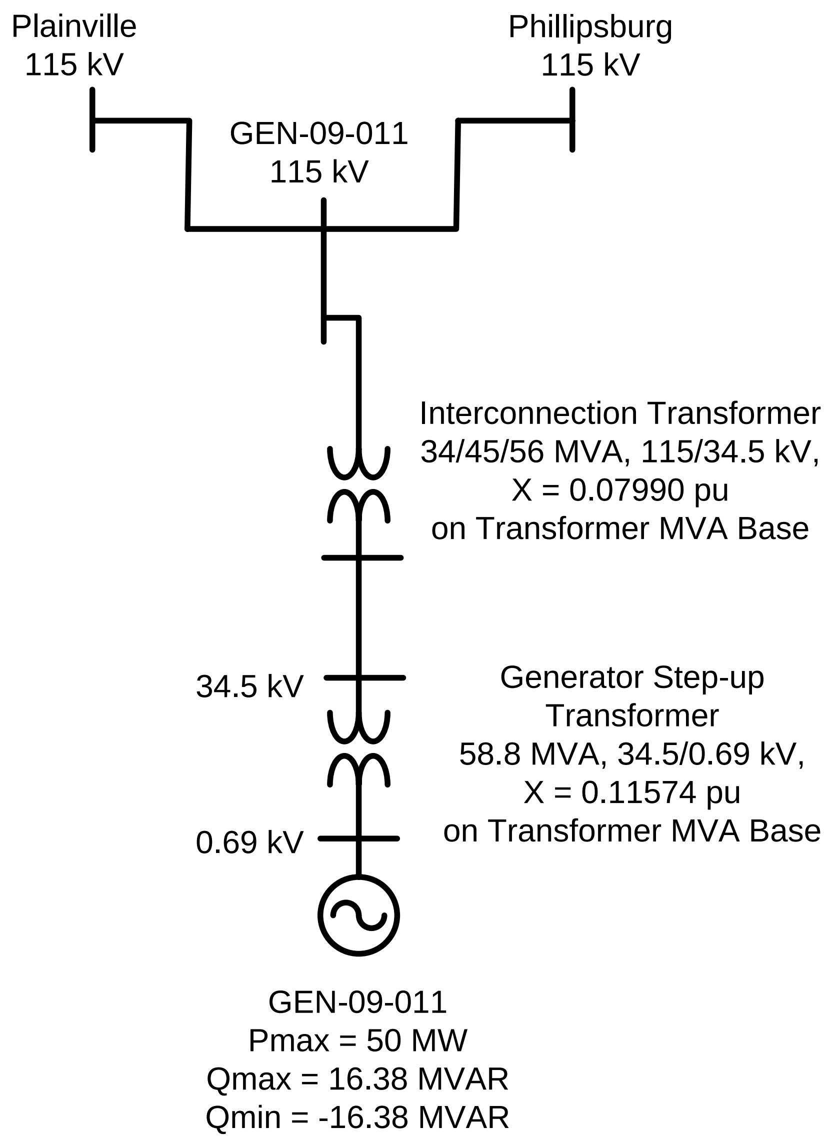

Figure 1-2 Power Flow Model for GEN-2009-011

Table 1-2 shows the list of prior queued projects modeled in the base case.

Table 1-2 List of Prior Queued Projects

Request	Size MW	Wind Turbine Model	Point of Interconnection
GEN-2003-006A	200	Vestas V90 3.0MW	Elm Creek 230kV (539639)
GEN-2003-019	250	GE 1.5MW	Smoky Hills 230kV (530592)
GEN-2006-031	75	Gas	Knoll 115kV (530561)
GEN-2006-032	200	Gamesa 2.0MW	South Hays 230kV (530582)

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting the proposed wind farms to SPP's transmission system.

Section 2. Power Factor Analysis

2.1. Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

1. Model a VAR generator at the Project's 230 or 115 kV bus, whichever is applicable. The VAR generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage, whichever is higher.

2. Steady state contingency analysis is conducted to determine the power factor necessary at the POI for each contingency.

3. According to the contingency analysis results, determine whether capacitors are required for the Project or not.

4. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks are considered. The preference is to locate the capacitance banks is on the 34.5 kV Customer side. Factors to sizing capacitor banks include:

    4.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.

    4.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).

    4.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

Analysis was performed for each proposed project with all two projects in service. A VAR generator was modeled at each point of interconnection and was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases. These voltages are summarized in the Table 2-1.

No changes were made in the base cases provided other than the addition of the VAR generators. Contingency analysis was run for 39 contingencies.

Table 2-1 Pre-contingency Voltages at POI

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)	
			Summer Peak	Winter Peak
GEN-2008-092	Knoll 230kV (530558)	200	1.024	1.030
GEN-2009-011	Tap Plainville (539686) – Phillipsburg (539685) 115kV. Bus # 570911	50	1.005	1.005

2.2.1. GEN-2008-092

The VAR generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2-1. The highest values (marked in yellow in the table) obtained are as follows:

1. For the summer case, the VAR generator supplies 31.8 MVar for the outage of Spearville (531469) to Knoll (560004) 345kV line and absorbs 14.9 MVar for the loss of Knoll (530558) to South Hays (530582) 230kV line.
2. For the winter case, the VAR generator supplies 31.5 MVar for the outage of Spearville (531469) to Knoll (560004) 345kV line and absorbs 7.3 MVar for the loss of Knoll (530561) to Saline (530551) 115kV line.

Table 2-2 VAR Generator Output in Summer and Winter Peak Cases for GEN-2008-092

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Summer Peak Case Gen-2008-092					
FLT00	Base Case	1.0000	lag	-195.2	0
FLT01-3PH	Setab (531465) to Holcomb (531449) 345kV line	1.0000	lag	-195.2	-0.7
FLT03-3PH	Setab (531465) to Mingo (531451) 345kV line	1.0000	lag	-195.2	-1.6
FLT05-3PH	Setab 345kV (531465) to 115kV (531464) transformer	1.0000	lead	-195.2	0.1
FLT07-3PH	Mingo (531451) to Red Willow (640325) 345kV line	0.9998	lag	-195.2	-3.4
FLT09-3PH	Mingo 345kV (531451) to 115kV (531429) transformer	1.0000	lead	-195.2	0.1
FLT11-3PH	Gentleman (640183) to Sweetwater (640374) 345kV line	0.9994	lag	-195.2	-6.9
FLT13-3PH	Holcomb (531449) to GEN-2007-040 (531000) 345kV line	0.9999	lead	-195.2	3.3
FLT15-3PH	Holcomb 345kV (531449) to 115kV (531448) transformer	1.0000	lead	-195.2	0.1
FLT17-3PH	Finney (523853) to GEN-2003-013 (560029) 345kV line	0.9999	lag	-195.2	-2.3
FLT19-3PH	Spearville (531469) to Knoll (560004) 345kV line	0.9870	lag	-195.2	-31.8
FLT21-3PH	Spearville (531469) to Comanche (765341) 345kV line	0.9981	lag	-195.2	-12.1
FLT23-3PH	Sweetwater (640374) to Axtell (640065) 345kV line	0.9999	lag	-195.2	-2

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Summer Peak Case Gen-2008-092					
FLT25-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9998	lag	-195.2	-4
FLT27-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9971	lead	-195.2	14.9
FLT29-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	1.0000	lead	-195.2	0.1
FLT31-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	1.0000	lead	-195.2	0.1
FLT33-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9993	lead	-195.2	7.1
FLT35-3PH	Knoll (530561) to Redline (530605) 115kV line	1.0000	lag	-195.2	-0.4
FLT37-3PH	South Hays (530582) to Mullergren (539679) 230kV line	0.9944	lag	-195.2	-20.7
FLT39-3PH	Mullergren (539679) to Circle (532871) 230kV line	1.0000	lag	-195.2	-1.5
FLT41-3PH	Summit (532873) to Hope (532874) 230kV line	1.0000	lag	-195.2	-1.2
FLT43-3PH	Summit (532873) to E. McPherson (532872) 230kV line	1.0000	lag	-195.2	-1.7
FLT45-3PH	Summit 230kV (532873) to 345kV (532773) transformer	1.0000	lead	-195.2	0.1
FLT47-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9998	lag	-195.2	-4
FLT49-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9971	lead	-195.2	14.9
FLT51-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	1.0000	lead	-195.2	0.1
FLT53-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	1.0000	lead	-195.2	0.1
FLT55-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9993	lead	-195.2	7.1
FLT57-3PH	Knoll (530561) to Redline (530605) 115kV line	1.0000	lag	-195.2	-0.4
FLT59-3PH	Knoll (530561) to N Hays (530581) 115kV line	1.0000	lag	-195.2	-0.3
FLT61-3PH	GEN-2009-011 (570911) to Philipsburg (539685) 115kV line	0.9994	lag	-195.2	-6.7
FLT63-3PH	GEN-2009-011 (570911) to Plainview (539686) 115kV line	1.0000	lag	-195.2	-1
FLT65-3PH	Smith Center (539693) to Philipsburg (539685) 115kV line	1.0000	lag	-195.2	-1.8
FLT67-3PH	Rhoades (531373) to Philipsburg (539685) 115kV line	1.0000	lag	-195.2	-0.2
FLT69-3PH	Rhoades (531373) to Graham (531386) 115kV line	1.0000	lag	-195.2	-0.9
FLT71-3PH	Smith Center (539693) to Ionia (539647) 115kV line	1.0000	lead	-195.2	0.4
FLT73-3PH	Smith Center (539693) to Glen Elder (539663) 115kV line	1.0000	lag	-195.2	-0.1
FLT75-3PH	Pioneer Tap (539642) to Rolling Hills (539643) 115kV line	1.0000	lag	-195.2	0
FLT77-3PH	Pioneer Tap (539642) to Mullergren (539678) 115kV line	1.0000	lead	-195.2	1.8

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Winter Peak Case Gen-2008-092					
FLT00	Base Case	1.0000	lag	-195.2	0
FLT01-3PH	Setab (531465) to Holcomb (531449) 345kV line	1.0000	lag	-195.2	-1.4
FLT03-3PH	Setab (531465) to Mingo (531451) 345kV line	1.0000	lag	-195.2	-1.5
FLT05-3PH	Setab 345kV (531465) to 115kV (531464) transformer	1.0000	lag	-195.2	0
FLT07-3PH	Mingo (531451) to Red Willow (640325) 345kV line	0.9999	lag	-195.2	-2.2
FLT09-3PH	Mingo 345kV (531451) to 115kV (531429) transformer	1.0000	lag	-195.2	0
FLT11-3PH	Gentleman (640183) to Sweetwater (640374) 345kV line	0.9994	lag	-195.2	-6.7
FLT13-3PH	Holcomb (531449) to GEN-2007-040 (531000) 345kV line	0.9994	lead	-195.2	6.5
FLT15-3PH	Holcomb 345kV (531449) to 115kV (531448) transformer	1.0000	lag	-195.2	0
FLT17-3PH	Finney (523853) to GEN-2003-013 (560029) 345kV line	1.0000	lag	-195.2	-0.7
FLT19-3PH	Spearville (531469) to Knoll (560004) 345kV line	0.9872	lag	-195.2	-31.5
FLT21-3PH	Spearville (531469) to Comanche (765341) 345kV line	0.9976	lag	-195.2	-13.6
FLT23-3PH	Sweetwater (640374) to Axtell (640065) 345kV line	1.0000	lead	-195.2	0.1
FLT25-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	1.0000	lag	-195.2	-1.7
FLT27-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9994	lag	-195.2	-6.8
FLT29-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	1.0000	lag	-195.2	0
FLT31-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	1.0000	lag	-195.2	0
FLT33-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9993	lead	-195.2	7.3
FLT35-3PH	Knoll (530561) to Redline (530605) 115kV line	1.0000	lag	-195.2	-0.5
FLT37-3PH	South Hays (530582) to Mullergren (539679) 230kV line	0.9980	lag	-195.2	-12.4
FLT39-3PH	Mullergren (539679) to Circle (532871) 230kV line	1.0000	lead	-195.2	0.4
FLT41-3PH	Summit (532873) to Hope (532874) 230kV line	1.0000	lag	-195.2	-1.4
FLT43-3PH	Summit (532873) to E. McPherson (532872) 230kV line	0.9999	lag	-195.2	-2.3
FLT45-3PH	Summit 230kV (532873) to 345kV (532773) transformer	1.0000	lag	-195.2	0
FLT47-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	1.0000	lag	-195.2	-1.7
FLT49-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9994	lag	-195.2	-6.8
FLT51-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	1.0000	lag	-195.2	0
FLT53-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	1.0000	lag	-195.2	0
FLT55-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9993	lead	-195.2	7.3
FLT57-3PH	Knoll (530561) to Redline (530605) 115kV line	1.0000	lag	-195.2	-0.5
FLT59-3PH	Knoll (530561) to N Hays (530581) 115kV line	1.0000	lag	-195.2	-0.3
FLT61-3PH	GEN-2009-011 (570911) to Philipsburg (539685) 115kV line	0.9997	lag	-195.2	-4.7

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Winter Peak Case Gen-2008-092					
FLT63-3PH	GEN-2009-011 (570911) to Plainview (539686) 115kV line	1.0000	lead	-195.2	0.7
FLT65-3PH	Smith Center (539693) to Philipsburg (539685) 115kV line	0.9999	lag	-195.2	-2.2
FLT67-3PH	Rhoades (531373) to Philipsburg (539685) 115kV line	1.0000	lead	-195.2	0.5
FLT69-3PH	Rhoades (531373) to Graham (531386) 115kV line	1.0000	lag	-195.2	-0.9
FLT71-3PH	Smith Center (539693) to Ionia (539647) 115kV line	1.0000	lead	-195.2	0.3
FLT73-3PH	Smith Center (539693) to Glen Elder (539663) 115kV line	1.0000	lag	-195.2	-0.1
FLT75-3PH	Pioneer Tap (539642) to Rolling Hills (539643) 115kV line	1.0000	lag	-195.2	0
FLT77-3PH	Pioneer Tap (539642) to Mullergren (539678) 115kV line	1.0000	lead	-195.2	1.8

2.2.2. Gen-2009-011

The VAR generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2-2. The highest values obtained are as follows:

1. For the summer case, the VAR generator supplies 3.9 MVar for the outage of Knoll (530561) to Saline (530551) 115kV line
2. For the winter case, the VAR generator supplies 0.9 MVar for the outage of Knoll (530561) to Saline (530551) 115kV line and absorbs 3.6 MVar for the loss of Holcomb (531449) to GEN-2007-040 (531000) 345kV line

Table 2-3 VAR Generator Output in Summer and Winter Peak Cases for Gen-2009-011

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Summer Peak Case for Gen-2009-011					
FLT00	Base Case	0.9999	lag	-50	-0.7
FLT01-3PH	Setab (531465) to Holcomb (531449) 345kV line	0.9998	lag	-50	-1
FLT03-3PH	Setab (531465) to Mingo (531451) 345kV line	0.9998	lag	-50	-0.9
FLT05-3PH	Setab 345kV (531465) to 115kV (531464) transformer	0.9999	lag	-50	-0.8
FLT07-3PH	Mingo (531451) to Red Willow (640325) 345kV line	0.9996	lag	-50	-1.4
FLT09-3PH	Mingo 345kV (531451) to 115kV (531429) transformer	0.9999	lag	-50	-0.8
FLT11-3PH	Gentleman (640183) to Sweetwater (640374) 345kV line	0.9997	lag	-50	-1.3
FLT13-3PH	Holcomb (531449) to GEN-2007-040 (531000) 345kV line	0.9999	lag	-50	-0.7
FLT15-3PH	Holcomb 345kV (531449) to 115kV (531448)	0.9999	lag	-50	-0.8

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Summer Peak Case for Gen-2009-011					
	transformer				
FLT17-3PH	Finney (523853) to GEN-2003-013 (560029) 345kV line	0.9998	lag	-50	-1.1
FLT19-3PH	Spearville (531469) to Knoll (560004) 345kV line	0.9978	lag	-50	-3.3
FLT21-3PH	Spearville (531469) to Comanche (765341) 345kV line	0.9992	lag	-50	-2
FLT23-3PH	Sweetwater (640374) to Axtell (640065) 345kV line	0.9998	lag	-50	-0.9
FLT25-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9997	lag	-50	-1.2
FLT27-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9999	lag	-50	-0.8
FLT29-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	0.9999	lag	-50	-0.8
FLT31-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	0.9999	lag	-50	-0.8
FLT33-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9969	lag	-50	-3.9
FLT35-3PH	Knoll (530561) to Redline (530605) 115kV line	0.9983	lag	-50	-2.9
FLT37-3PH	South Hays (530582) to Mullergren (539679) 230kV line	0.9980	lag	-50	-3.1
FLT39-3PH	Mullergren (539679) to Circle (532871) 230kV line	0.9998	lag	-50	-1.1
FLT41-3PH	Summit (532873) to Hope (532874) 230kV line	0.9998	lag	-50	-0.9
FLT43-3PH	Summit (532873) to E. McPherson (532872) 230kV line	0.9998	lag	-50	-1
FLT45-3PH	Summit 230kV (532873) to 345kV (532773) transformer	0.9999	lag	-50	-0.8
FLT47-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9997	lag	-50	-1.2
FLT49-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9999	lag	-50	-0.8
FLT51-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	0.9999	lag	-50	-0.8
FLT53-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	0.9999	lag	-50	-0.8
FLT55-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9969	lag	-50	-3.9
FLT57-3PH	Knoll (530561) to Redline (530605) 115kV line	0.9983	lag	-50	-2.9
FLT59-3PH	Knoll (530561) to N Hays (530581) 115kV line	0.9998	lag	-50	-0.9
FLT61-3PH	GEN-2009-011 (570911) to Philipsburg (539685) 115kV line	0.9998	lag	-50	-0.9
FLT63-3PH	GEN-2009-011 (570911) to Plainview (539686) 115kV line	1.0000	lag	-50	-0.4
FLT65-3PH	Smith Center (539693) to Philipsburg (539685) 115kV line	0.9996	lag	-50	-1.4
FLT67-3PH	Rhoades (531373) to Philipsburg (539685) 115kV line	0.9995	lag	-50	-1.5
FLT69-3PH	Rhoades (531373) to Graham (531386) 115kV line	0.9997	lag	-50	-1.2
FLT71-3PH	Smith Center (539693) to Ionia (539647) 115kV line	0.9998	lag	-50	-1
FLT73-3PH	Smith Center (539693) to Glen Elder (539663) 115kV line	0.9997	lag	-50	-1.2
FLT75-3PH	Pioneer Tap (539642) to Rolling Hills (539643) 115kV line	0.9999	lag	-50	-0.7
FLT77-3PH	Pioneer Tap (539642) to Mullergren (539678) 115kV line	0.9974	lag	-50	-3.6

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Winter Peak Case for Gen 20090-011					
FLT00	Base Case	0.9980	lead	-50	3.1
FLT01-3PH	Setab (531465) to Holcomb (531449) 345kV line	0.9983	lead	-50	2.9
FLT03-3PH	Setab (531465) to Mingo (531451) 345kV line	0.9984	lead	-50	2.8
FLT05-3PH	Setab 345kV (531465) to 115kV (531464) transformer	0.9980	lead	-50	3.1
FLT07-3PH	Mingo (531451) to Red Willow (640325) 345kV line	0.9985	lead	-50	2.7
FLT09-3PH	Mingo 345kV (531451) to 115kV (531429) transformer	0.9980	lead	-50	3.1
FLT11-3PH	Gentleman (640183) to Sweetwater (640374) 345kV line	0.9987	lead	-50	2.5
FLT13-3PH	Holcomb (531449) to GEN-2007-040 (531000) 345kV line	0.9974	lead	-50	3.6
FLT15-3PH	Holcomb 345kV (531449) to 115kV (531448) transformer	0.9980	lead	-50	3.1
FLT17-3PH	Finney (523853) to GEN-2003-013 (560029) 345kV line	0.9983	lead	-50	2.9
FLT19-3PH	Spearville (531469) to Knoll (560004) 345kV line	0.9998	lead	-50	0.9
FLT21-3PH	Spearville (531469) to Comanche (765341) 345kV line	0.9994	lead	-50	1.7
FLT23-3PH	Sweetwater (640374) to Axtell (640065) 345kV line	0.9980	lead	-50	3.1
FLT25-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9983	lead	-50	2.9
FLT27-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9982	lead	-50	3
FLT29-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	0.9980	lead	-50	3.1
FLT31-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	0.9980	lead	-50	3.1
FLT33-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9998	lag	-50	-0.9
FLT35-3PH	Knoll (530561) to Redline (530605) 115kV line	0.9992	lead	-50	2
FLT37-3PH	South Hays (530582) to Mullergren (539679) 230kV line	0.9995	lead	-50	1.5
FLT39-3PH	Mullergren (539679) to Circle (532871) 230kV line	0.9979	lead	-50	3.2
FLT41-3PH	Summit (532873) to Hope (532874) 230kV line	0.9983	lead	-50	2.9
FLT43-3PH	Summit (532873) to E. McPherson (532872) 230kV line	0.9984	lead	-50	2.8
FLT45-3PH	Summit 230kV (532873) to 345kV (532773) transformer	0.9980	lead	-50	3.1
FLT47-3PH	Knoll (530558) to Smoky Hill (530592) 230kV line	0.9983	lead	-50	2.9
FLT49-3PH	Knoll (530558) to South Hays (530582) 230kV line	0.9982	lead	-50	3
FLT51-3PH	Knoll 230kV (530558) to 345kV (560004) transformer	0.9980	lead	-50	3.1
FLT53-3PH	Knoll 230kV (530558) to 115kV (530561) transformer	0.9980	lead	-50	3.1
FLT55-3PH	Knoll (530561) to Saline (530551) 115kV line	0.9998	lag	-50	-0.9
FLT57-3PH	Knoll (530561) to Redline (530605) 115kV line	0.9992	lead	-50	2
FLT59-3PH	Knoll (530561) to N Hays (530581) 115kV line	0.9979	lead	-50	3.2
FLT61-3PH	GEN-2009-011 (570911) to Philipsburg (539685) 115kV line	1.0000	lead	-50	0.3
FLT63-3PH	GEN-2009-011 (570911) to Plainview (539686) 115kV line	0.9992	lead	-50	2
FLT65-3PH	Smith Center (539693) to Philipsburg (539685) 115kV line	0.9985	lead	-50	2.7

Cont._ Name	Cont-Description	PF @ POI	PF	MW @ POI	MVAR @ POI
Winter Peak Case for Gen 20090-011					
FLT67-3PH	Rhoades (531373) to Philipsburg (539685) 115kV line	0.9997	lead	-50	1.3
FLT69-3PH	Rhoades (531373) to Graham (531386) 115kV line	0.9984	lead	-50	2.8
FLT71-3PH	Smith Center (539693) to Ionia (539647) 115kV line	0.9982	lead	-50	3
FLT73-3PH	Smith Center (539693) to Glen Elder (539663) 115kV line	0.9984	lead	-50	2.8
FLT75-3PH	Pioneer Tap (539642) to Rolling Hills (539643) 115kV line	0.9980	lead	-50	3.1
FLT77-3PH	Pioneer Tap (539642) to Mullergren (539678) 115kV line	0.9993	lead	-50	1.9

2.3. Conclusions

The results of the Power Factor analysis showed that the study projects must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

3.1. Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

3.2. Faults Simulated

Seventy-eight (78) faults were considered for the transient stability simulations which included three phase faults as well as single phase line faults at the locations defined by SPP. Single-phase line faults were simulated by applying a fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice. Prior queued projects shown in Table 1-2 and units in areas 520, 524, 525, 526, 531, 534, 536, 640, 645, 650 were monitored in the simulations.

Table 3-1 shows the list of simulated faults. It also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-1 List of Simulated Faults

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Setab (531465) to Mingo (531451) 345kV line, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
5	FLT05-3PH	3 phase fault on the Setab 345kV (531465) to 115kV (531464) to (531259) 3 winding transformer, near the 345 kV bus. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Mingo 345kV (531451) to 115kV (531429)) to (531452) 3 winding transformer, near the 345 kV bus. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Gentleman (640183) to Sweetwater (640374) 345kV line, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (210400) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448)) to (531450) 3 winding transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (560029) 345kV line, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Spearville (531469) to Knoll (530700) 345kV line, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Spearville (531469) to Comanche (765341) 345kV line, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Sweetwater (640374) to Axtell (640065) 345kV line, near Sweetwater. a. Apply fault at the Sweetwater 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the Knoll (530558) to Smoky Hill (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Knoll 230kV (530558) to 345kV (530700) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Knoll (530561) to Saline (530551) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Knoll (530561) to Redline (530605) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the South Hays (530582) to Mullergren (539679) 230kV line, near South Hays. a. Apply fault at the South Hays 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Summit (532873) to Hope (532874) 230kV line, near Summit. a. Apply fault at the Summit 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Summit (532873) to E. McPherson (532872) 230kV line, near Summit. a. Apply fault at the Summit 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Summit 230kV (532873) to 345kV (532773)) to (532813) 3 winding transformer, near the 230kV bus. a. Apply fault at the Summit 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
46	FLT46-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
47	FLT47-3PH	Same as Cont.No 25 3 phase fault on the Knoll (530558) to Smoky Hill (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-1PH	*Single phase fault and sequence like previous*
49	FLT49-3PH	Same as Cont.No 27 3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT50-1PH	*Single phase fault and sequence like previous*
51	FLT51-3PH	Same as Cont.No 29 3 phase fault on the Knoll 230kV (530558) to 345kV (530700) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
52	FLT52-1PH	*Single phase fault and sequence like previous*
53	FLT53-3PH	Same as Cont.No 31 3 phase fault on the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
54	FLT54-1PH	*Single phase fault and sequence like previous*
55	FLT55-3PH	Same as Cont.No 33 3 phase fault on the Knoll (530561) to Saline (530551) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
56	FLT56-1PH	*Single phase fault and sequence like previous*
57	FLT57-3PH	Same as Cont.No 35 3 phase fault on the Knoll (530561) to Redline (530605) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
58	FLT58-1PH	*Single phase fault and sequence like previous*
59	FLT59-3PH	3 phase fault on the Knoll (530561) to N Hays (530581) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
60	FLT60-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
61	FLT61-3PH	3 phase fault on the GEN-2009-011 (570911) to Philipsburg (539685) 115kV line, near GEN-2009-011. a. Apply fault at the GEN-2009-011 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
62	FLT62-1PH	*Single phase fault and sequence like previous*
63	FLT63-3PH	3 phase fault on the GEN-2009-011 (570911) to Plainview (539686) 115kV line, near GEN-2009-011. a. Apply fault at the GEN-2009-011 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
64	FLT64-1PH	*Single phase fault and sequence like previous*
65	FLT65-3PH	3 phase fault on the Smith Center (539693) to Philipsburg (539685) 115kV line, near Philipsburg. a. Apply fault at the Philipsburg 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
66	FLT66-1PH	*Single phase fault and sequence like previous*
67	FLT67-3PH	3 phase fault on the Rhoades (531373) to Philipsburg (539685) 115kV line, near Philipsburg. a. Apply fault at the Philipsburg 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
68	FLT68-1PH	*Single phase fault and sequence like previous*
69	FLT69-3PH	3 phase fault on the Rhoades (531373) to Graham (531386) 115kV line, near Rhoades. a. Apply fault at the Rhoades 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
70	FLT70-1PH	*Single phase fault and sequence like previous*
71	FLT71-3PH	3 phase fault on the Smith Center (539693) to Ionia (539647) 115kV line, near Ionia. a. Apply fault at the Ionia 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
72	FLT72-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
73	FLT73-3PH	3 phase fault on the Smith Center (539693) to Glen Elder (539663) 115kV line, near Ionia. a. Apply fault at the Rhoades 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
74	FLT74-1PH	*Single phase fault and sequence like previous*
75	FLT75-3PH	3 phase fault on the Pioneer Tap (539642) to Rolling Hills (539643) 115kV line, near Rolling Hills. a. Apply fault at the Rolling Hills 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
76	FLT76-1PH	*Single phase fault and sequence like previous*
77	FLT77-3PH	3 phase fault on the Pioneer Tap (539642) to Mullergren (539678) 115kV line, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
78	FLT78-1PH	*Single phase fault and sequence like previous*

Simulations were performed with a 0.5-second steady-state run followed by the appropriate disturbance as described in Table 3-1. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.3. Simulation Results

The simulations conducted in the study did not find any angular or voltage instability problems for the 78 faults. The study finds that the interconnection of the two proposed projects does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

Section 4. Conclusions

The findings of the impact study for the proposed interconnection projects under projects DISIS-2009-001 (Group 11) containing Gen-2008-092 and Gen-2009-011, considered at 100% of their proposed installed capacities are as follows:

1. The results of the Power Factor analysis showed that the study projects must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

2. For the two proposed projects, the stability simulations with 78 specified faults did not show any angular or voltage instability problems in the SPP system. The study finds that these interconnections do not impact stability performance of the SPP system for the contingencies tested on the base cases provided.

T: Stability Study for Group 12

Group 12
Definitive Interconnection System Impact Study

January 18, 2010

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EXECUTIVE SUMMARY

The Southwest Power Pool (SPP), on behalf of generation interconnection customers, desires a definitive interconnection system impact study for a generator grouping in northwest Arkansas collectively referred to as Group 12. Group 12 consists of only one generator:

- GEN-2009-006. 60 MW wind farm (40 General Electric 1.5 MW turbines) connected to the AEPW Southeast Fayetteville 161 kV bus.

There are no previously queued generators in Group 12.

SPP requested a stability analysis and a power factor analysis for the queued generator projects in Group 12. SPP did not request an Available Transfer Capability (ATC) study as part of this study.

Transient stability analysis shows no new problems with the dynamic response of study generation in the region of interest.

All generators in the monitored area remain stable during disturbances.

All wind turbine generators have the capability of pre-contingency voltage recovery.

Low Voltage Ride Through (LVRT) analysis shows no generators tripping offline due to low voltage.

Power factor analysis also shows no generators tripping offline due to voltage collapse and no reactive compensation needed. It also gives the following power factor requirement at the Point of Interconnection (POI) within Group 12:

- GEN-2009-006: 0.954 leading ~ 0.979 lagging

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1. INTRODUCTION

The Southwest Power Pool (hereafter referred to as SPP) commissioned AMEC Earth and Environmental (hereafter referred to as AMEC) to study the impact of a group of generators in the SPP interconnection queue referred to as Group 12. The site studied is in northwest Arkansas, within approximately 160 miles of Little Rock.

The site studied was:

1. GEN-2009-006. 60 MW wind generation (40 x 1.5 MW GE wind turbines) connected to the AEPW Southeast Fayetteville 161 kV bus.

SPP did not request an Available Transfer Capability (ATC) study. The ATC study will be required when the generation companies request transmission service.

SPP requested a stability analysis and a power factor analysis. Given SPP's list of faults, AMEC performed a dynamics study and a power factor study to:

a. Determine the amount of reactive compensation required at the wind farm facility on the customer side following transmission line and transformer outages to meet the power factor requirement at the point of interconnection (POI).

b. Determine the ability of the wind farm to meet FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage) with and without additional reactive power support.

c. Determine the ability of the generators to remain in synchronism following three-phase and single-line-to-ground faults.

The results of the study are given in the following sections.

2. STUDY METHODOLOGY

SPP provided 2010 summer peak and 2009 winter peak load flow cases in PSS/E format. Table 1 below shows the total demand and generation in the monitored areas.

Table 1: Description of Study Areas

Area No.	Area Name	2010 Summer Peak		2009 Winter Peak	
		Load (MW)	Generation (MW)	Load (MW)	Generation (MW)
520	AEPW	10137.7	8537.3	7800.1	6102.1
524	OKGE	6256.1	7184.9	4358.6	4879.1
525	WFEC	1352.4	1313.3	1217.9	1154.5
526	SPS	5719.3	6773.0	3983.9	5089.0
531	MIDW	278.8	270.3	204.1	269.8
534	SUNC	531.8	749.7	440.0	698.9
536	WERE	6066.8	5880.9	3999.8	4291.4

- **POWER FACTOR ANALYSIS**

A var generator with large capacity was placed at the wind farm POI. The var generator was set to hold a voltage schedule at the POI consistent with the voltage schedule in the base case or 1.0 pu, whichever is higher. A list of contingencies shown in Table 2 was simulated. If the required reactive support to maintain an acceptable power factor (+/-0.95) at the POI is beyond the capability of the wind farm, the additional reactive compensation at the wind farm customer side was considered.

Table 2: Steady-State Contingency Descriptions

Cont No.	Description
FLT01/02	Outage of SE Fayetteville (506943) to Hyland (506937) 161 kV line
FLT03/04	Outage of Fayetteville (506933) to S Fayetteville (506947) 161 kV line
FLT05/06	Outage of Dyess (506927) to Elm Springs (504010) 161 kV line
FLT07/08	Outage of Dyess (506927) to Tontitown (506957) 161 kV line
FLT09/10	Outage of S Fayetteville (506947) to Farmington (506956) 161 kV line
FLT11/12	Outage of Clarksville (509745) to Chambers Spring (506945) 345 kV line
FLT13/14	Outage of Chambers Spring (506945) to Tontitown (506959) 345 kV line
FLT15/16	Outage of Chambers Spring 345/161 kV auto transformer

Cont No.	Description
FLT17/18	Outage of Tontitown 345/161kV auto transformer
FLT19/20	Outage of Flint Creek (506935) to GRDA-1 (512650) 345 kV line
FLT21/22	Outage of Flint Creek (506935) to Monette (547481) 345 kV line
FLT23/24	Outage of Flint Creek (506934) to Tontitown (506957) 161 kV line
FLT25/26	Outage of Beaver(505480) to Eureka Springs (506932) 161 kV line
FLT27/28	Outage of S Fayetteville(506947) to SE Fayetteville (506943) 161 kV line
FLT29/30	Outage of S Springdale(506949) to Dyess (506927) 161 kV line
FLT31/32	Outage of E Rogers(506931) to Dyess (506927) 161 kV line
FLT33/34	Outage of Flint Creek (506934) to Gentry(504201) 161 kV line

- **DYNAMIC ANALYSIS**

The study areas are shown in Table 1. These areas are monitored in the dynamic analysis.

The transmission line and transformer faults were simulated and synchronous machine rotor angles and wind turbine generator speeds were monitored to check whether synchronism of the synchronous machines is maintained and whether the wind turbine generators trip offline during the disturbance.

All line faults were simulated in the following fashion:

a. Apply fault to a line near one of its buses.

b. Clear fault after five (5) cycles by tripping the faulted line.

c. Wait 20 cycles and reclose the tripped line into the fault.

d. Leave fault on for five (5) cycles, then trip the line and remove the fault.

All transformer faults were simulated in the following fashion:

a. Apply fault at one of the transformer buses. In this analysis, the only transformer faults involve the Chambers Spring 345/161/13.8 kV and the Tontitown 345/161/13.8 kV three-winding auto transformers. All transformer faults are simulated at the 345 kV bus.

b. Clear fault after five (5) cycles by tripping the faulted transformer. (No reclosing occurs for transformer faults in this study.)

All faults were simulated in three-phase (3Φ) and single-line-to-ground (1Φ) versions. Odd numbered faults are 3Φ, and even numbered faults are 1Φ.

Following is a summary of the faults simulated in this analysis.

Table 3: Fault Descriptions

Fault No.	Description
01 & 02	SE Fayetteville (506943) to Hyland (506937) 161 kV line, near SE Fayetteville
03 & 04	Fayetteville (506933) to S Fayetteville (506947) 161 kV line, near Fayetteville
05 & 06	Dyess (506927) to Elm Springs (504010) 161 kV line, near Dyess
07 & 08	Dyess (506927) to Tontitown (506957) 161 kV line, near Tontitown
09 & 10	S Fayetteville (506947) to Farmington (506956) 161 kV line, near S Fayetteville
11 & 12	Clarksville (509745) to Chambers Spring (506945) 345 kV line, near Chambers Spring
13 & 14	Chambers Spring (506945) to Tontitown (506959) 345 kV line, near Chambers Spring
15 & 16	Chambers Spring 345/161 kV auto transformer on the 345 kV bus (506945)
17 & 18	Tontitown 345/161 kV auto transformer on the 345 kV bus (506959)
19 & 20	Flint Creek (506935) to GRDA-1 (512650) 345 kV line, near Flint Creek
21 & 22	Flint Creek (506935) to Monette (547481) 345 kV line, near Flint Creek
23 & 24	Flint Creek (506934) to Tontitown (506957) 161 kV line, near Tontitown
25 & 26	Beaver(505480) to Eureka Springs (506932) 161 kV line, near Eureka Springs
27 & 28	S Fayetteville(506947) to SE Fayetteville (506943) 161 kV line, near SE Fayetteville
29 & 30	S Springdale(506949) to Dyess (506927) 161 kV line, near Dyess
31 & 32	E Rogers(506931) to Dyess (506927) 16 1kV line, near Dyess
33 & 34	Flint Creek (506934) to Gentry(504201) 161 kV line, near Flint Creek

In order to simulate 1Φ faults, equivalent shunt Mvar[1] were determined to be applied at the faulted buses. Table 4 presents equivalent reactors used in the transient stability study.

Table 4: Equivalent Shunt Mvar at Faulted Bus for Single-Line-to-Ground Faults

Fault No.	Faulted Bus No.	2010 Summer Peak (Mvar)	2009 Winter Peak (Mvar)
FLT02	506943	-2290.6	-2055.6
FLT04	506933	-2406.3	-2150.1
FLT06	506927	-3330.5	-2849.4

[1] The equivalent shunt Mvar causes the voltage at the faulted bus dropped to 0.60 pu.

Fault No.	Faulted Bus No.	2010 Summer Peak (Mvar)	2009 Winter Peak (Mvar)
FLT08	506957	-4297.0	-3431.0
FLT10	506947	-2526.6	-2257.8
FLT12	506945	-3991.9	-3576.5
FLT14	506945	-3991.9	-3576.5
FLT16	506945	-3991.9	-3576.5
FLT18	506959	-3615.3	-3189.5
FLT20	506935	-5428.5	-5158.7
FLT22	506935	5428.5	-5158.7
FLT24	506957	4297.0	-3431.0
FLT26	506932	1621.8	-1632.9
FLT28	506943	2290.6	-2055.6
FLT30	506927	-3300.5	-2849.4
FLT32	506927	-3300.5	-2849.4
FLT34	506934	-6100.5	-5664.8

Another important aspect of the dynamic analysis was to check FERC Order 661A compliance. The turbine generators were monitored to determine whether they stayed connected to the grid (Low Voltage Ride Through - LVRT) following the faults defined in Table 3. The wind farm capability of post-fault voltage recovery at the POI was also checked.

3. PROJECT DESCRIPTION

Following is a table of the proposed wind farm in Group 12.

Table 5: Points of Interconnection for Group 12

Request	Size (MW)	Turbine Model	Point Of Interconnection		
			Common Name	Bus No.	Bus Name in Model
GEN-2009-006	60	GE 1.5 MW	Southeast Fayetteville 161 kV	506943	SEFAYTV5

All of the following one-line diagrams use this color code for nominal voltages:

Blue **161 kV**
Black **lower voltage levels**

Following is the one-line diagram of the interconnections of GEN-2009-006. All voltages and line flows are from the 2010 summer peak base case.

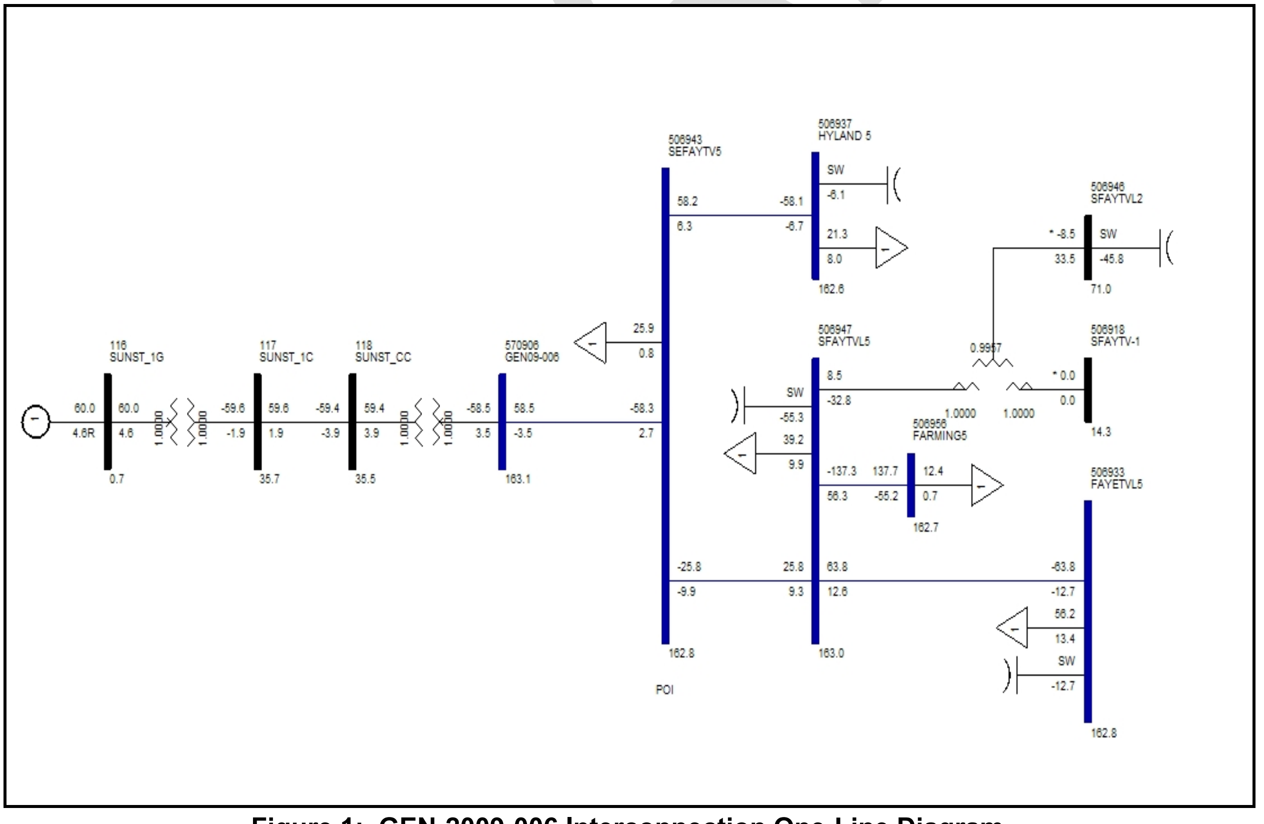

Figure 1: GEN-2009-006 Interconnection One-Line Diagram

As illustrated below, the site in Group 12 is within approximately 160 miles to the northwest of Little Rock.

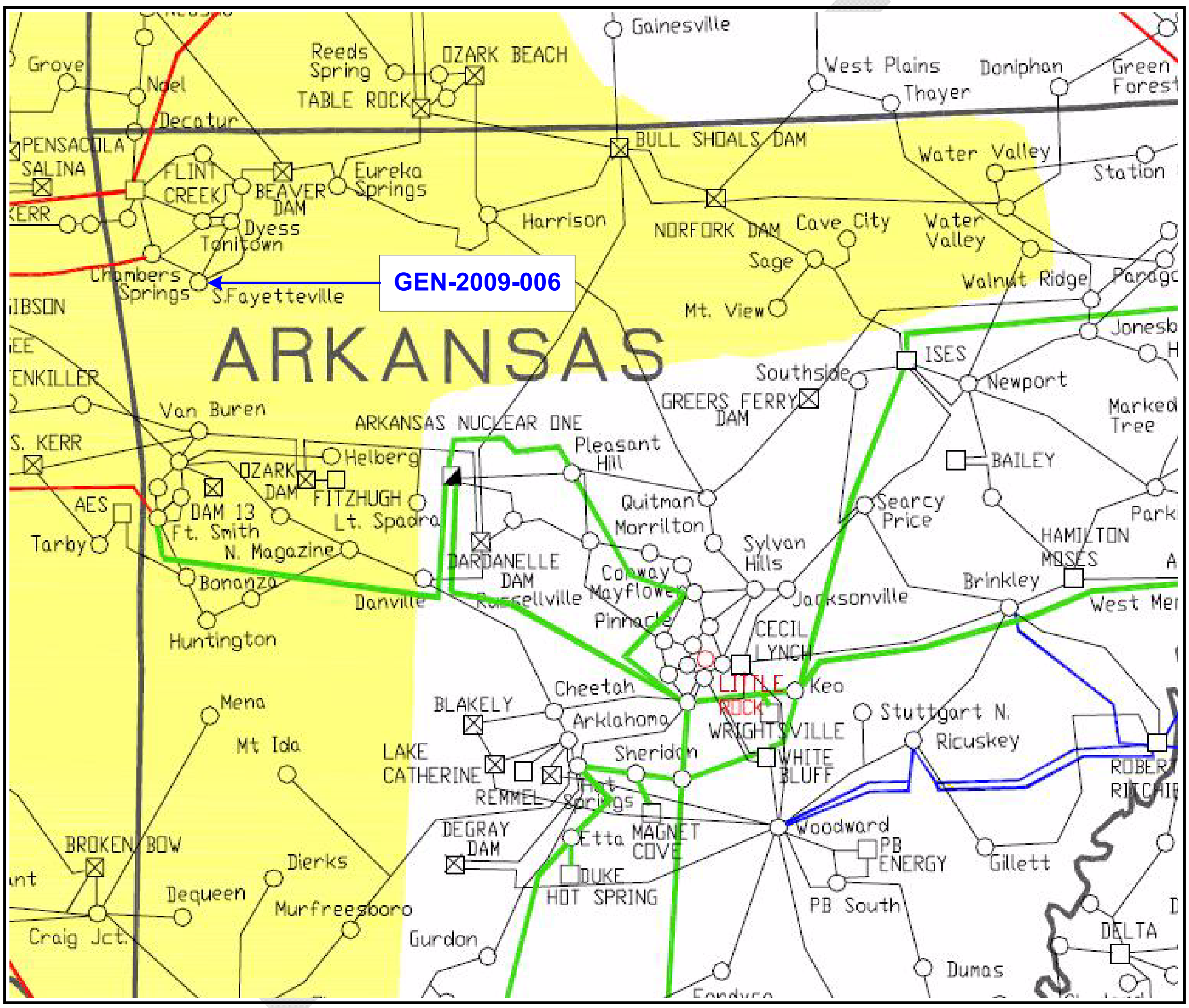

Figure 2: Geographical Location of Group 12 Project

The following is the detailed description of the wind projects in Group 12.

GEN-2009-006

- Wind farm rating
  - Active power capability: 60 MW
  - Reactive power capability: 29 MVAR

- Interconnection:
  - Voltage: 161 kV
  - Location: Existing AEPW Southeast Fayetteville 161 kV substation
  - Transformer: One step-up transformer connecting to the 161 kV
    - MVA: Rate A - 41, Rate B - 55, Rate C - 68
    - Voltage: 161/34.5 kV
    - X: 9.0% on 41 MVA

- Wind turbine:
  - Number: Forty (40)
  - Manufacturer: GE
  - Type: Doubly-fed induction generator (DFIG)

  - Machine terminal voltage: 690 V
  - Rated power: 1.5 MW
  - Frequency: 60Hz
  - Generator step-up transformer
    - MVA: 1.75
    - Voltage: 34.5/0.6kV
    - X: 5.75% on 1.7 MVA

- Generator protection
  - Undervoltage
    - Relay trips when $V_{bus} < 0.15$ pu for t = 0.2 s
      $V_{bus} < 0.30$ pu for t = 0.7 s
      $V_{bus} < 0.50$ pu for t = 1.2 s
      $V_{bus} < 0.75$ pu for t = 1.9 s
      $V_{bus} < 0.90$ pu for t = 10.0 s
  - Overvoltage
    - Relay trips when $V_{bus} > 1.10$ pu for t = 1.0 s
      $V_{bus} > 1.15$ pu for t = 0.1 s
      $V_{bus} > 1.30$ pu for t = 0.02 s
  - Underfrequency
    - Relay trips when $F_{bus} < 56.5$ Hz for t = 0.2 s
      $F_{bus} < 57.5$ Hz for t = 10.0 s
  - Overfrequency
    - Relay trips when $F_{bus} > 61.5$ Hz for t = 30.0 s
      $F_{bus} > 62.5$ Hz for t = 0.02 s

4. POWER FACTOR RESULTS

The proposed GEN-2009-006 wind farm (60 MW) will be comprised of 40 GE 1.5 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.90 p.f. The wind turbine generators were modeled in voltage control mode. They were set to regulate the voltage at the POI in summer peak case and to regulate its terminal bus voltage in winter peak case.

Table 6 lists the voltages of GEN-2009-006 POI in the base and all contingency cases. In all scenarios the POI voltage deviations from the base case value are quite small (below 0.8%) except FLT33/34 (the outage of Flint Creek - Centry 161 kV line) in winter peak case with the voltage deviation at about 1.028%. However, this voltage drop is not due to the GEN-2009-006 generation interconnection. With GEN-2009-006 offline, the post-contingency voltage at the GEN-2009-006 POI for the worst-case contingency (FLT33/34) in the winter case is somewhat worse (0.9790 pu with GEN-2009-006 offline vs. 0.9816 pu with GEN-2009-006 generation online).

Table 6: Steady-State Results: Voltage at GEN-2009-006 POI

Cont. No.	Voltage at POI (Southeast Fayetteville 161 kV Bus 506943) (pu)			
	Summer Peak		Winter Peak	
	GEN-2009-006 Online	GEN-2009-006 Offline	GEN-2009-006 Online	GEN-2009-006 Offline
Base Case	1.0113	1.0101	0.9918	0.9902
FLT01 & FLT02	1.0113	1.0135	0.9932	0.9917
FLT03 & FLT04	1.0113	1.0139	0.9945	0.9928
FLT05 & FLT06	1.0113	1.0092	0.9909	0.9891
FLT07 & FLT08	1.0113	1.0085	0.9896	0.9876
FLT09 & FLT10	1.0113	1.0178	0.9897	0.9873
FLT11 & FLT12	1.0113	1.0088	0.9871	0.9848
FLT13 & FLT14	1.0113	1.0087	0.9878	0.9858
FLT15 & FLT16	1.0113	1.0105	0.9921	0.9906
FLT17 & FLT18	1.0113	1.0089	0.9883	0.9862
FLT19 & FLT20	1.0113	1.0096	0.9905	0.9886
FLT21 & FLT22	1.0113	1.0100	0.9912	0.9897
FLT23 & FLT24	1.0113	1.0090	0.9872	0.9848
FLT25 & FLT26	1.0113	1.0106	0.9924	0.9908
FLT27 & FLT28	1.0113	1.0027	0.9894	0.9863
FLT29 & FLT30	1.0113	1.0031	0.9865	0.9836

FLT31 & FLT32	1.0113	1.0113	0.9935	0.9919
FLT33 & FLT34	1.0113	1.0026	0.9816	0.9790

At the Point of Interconnection (POI), a continuously variable shunt var generator was placed into the model for the power factor analysis. Then, a contingency analysis was run using all faults described above. The shunt was set to regulate the post-contingency voltage to the pre-contingency value or 1.pu, whichever was greater. Table 7 lists the reactive injection required at POI to hold the POI voltage firmly at 1.0113 pu in summer peak scenarios and 1.0 pu in winter peak scenarios.

A significant portion of the var injection in the winter peak case is due to the pre-existing voltage of less than unity at the POI. This low voltage is due primarily to the switched shunt at bus 506947 (SFAYTVL5 161 kV) being online in the summer case and offline in the winter case, and the MATISN generators 1-3 (buses 509410, 509411, and 509412) being online in the summer case and offline in the winter case. The shunt provides 54 Mvar, and the MATISN generators provide up to 118 Mvar after GSU var losses are taken into account, to the 161 kV transmission system in the Fayetteville area.

Table 7: Var Generator Output at GEN-2009-006 POI

Cont. No.	Mvar Injection at POI (Southeast Fayetteville 161 kV Bus 506943)	
	Summer Peak	Winter Peak
Base Case	2.4	34.8
FLT01 & FLT02	-4.4	23.2
FLT03 & FLT04	-6.4	20.8
FLT05 & FLT06	3.6	36.8
FLT07 & FLT08	5.4	42.4
FLT09 & FLT10	-11.5	31.4
FLT11 & FLT12	5.4	52.5
FLT13 & FLT14	5.6	50.6
FLT15 & FLT16	1.4	33.5
FLT17 & FLT18	5.0	48.8
FLT19 & FLT20	3.3	40.6
FLT21 & FLT22	2.5	37.4
FLT23 & FLT24	4.9	49.0
FLT25 & FLT26	1.1	32.1
FLT27 & FLT28	8.8	22.0
FLT29 & FLT30	13.4	46.8
FLT31 & FLT32	-0.8	26.5

FLT33 & FLT34	14.1	79.3

In most summer peak scenarios reactive power injection is needed. FLT33/34 (the outage of Flint Creek - Centry 161 kV line) requires the most Mvar injection and FLT09/10 (the outage of S Fayetteville - Farmington 161 kV line) requires the most Mvar absorption. In all winter peak scenarios Mvar injection is needed with the largest amount in contingency FLT33/34. In all summer peak scenarios the wind turbine generator reactive power capability is able to meet the var requirement at the POI. In certain winter peak scenarios the var injection at POI is beyond the wind turbine generator reactive power capability. However, that violation can be removed if the voltage schedule at the POI drops slightly.

Next, the power factor analysis was repeated for all contingencies without the var generator at POI. Table 8 and Table 9 summarize the pre-contingency and post-contingency voltages at POI and power factors at both POI and the wind farm.

Table 8: Voltage at POI and P.F. at POI and Wind Farm without VAR Generator, Summer Peak

Cont. No.	Voltage @ POI (pu)	Power Factor of Wind Generator GEN-2009-006					Power Factor @ POI				
		P	Q	MVA	PF	Lead/Lag	P	Q	MVA	PF	Lead/Lag
Base Case	1.0113	60.0	4.6	60.18	0.997	Lag	58.3	-2.7	58.36	0.999	Lead
FLT01&02	1.0113	60.0	-8.3	60.67	0.991	Lead	58.1	-16.9	60.51	0.960	Lead
FLT03&04	1.0150	60.0	1.8	60.03	1.000	Lag	58.3	5.6	58.57	0.995	Lag
FLT05&06	1.0113	60.0	7.1	60.42	0.993	Lag	58.3	-0.1	58.30	1.000	Lead
FLT07&08	1.0113	60.0	10.7	60.95	0.984	Lag	58.3	-3.6	58.41	0.998	Lag
FLT09&10	1.0150	60.0	-9.6	60.76	0.987	Lead	58.1	-18.3	60.91	0.954	Lead
FLT11&12	1.0113	60.0	10.7	60.95	0.984	Lag	58.3	3.6	58.41	0.998	Lag
FLT13&14	1.0113	60.0	11.2	61.04	0.983	Lag	58.3	4.0	58.44	0.998	Lag
FLT15&16	1.0113	60.0	2.6	60.06	0.999	Lag	58.3	-4.8	58.50	0.997	Lead
FLT17&18	1.0113	60.0	10.0	60.83	0.986	Lag	58.3	2.8	58.37	0.999	Lag
FLT19&20	1.0113	60.0	6.6	60.36	0.994	Lag	58.3	-0.7	58.30	1.000	Lead
FLT21&22	1.0113	60.0	4.9	60.20	0.997	Lag	58.3	-2.4	58.35	0.999	Lead
FLT23&24	1.0113	60.0	9.7	60.78	0.987	Lag	58.3	2.6	58.36	0.999	Lag
FLT25&26	1.0113	60.0	2.2	60.04	0.999	Lag	58.3	-5.3	58.54	0.996	Lead
FLT27&28	1.0113	60.0	17.8	62.58	0.959	Lag	58.3	10.5	59.24	0.984	Lag
FLT29&30	1.0090	60.0	18.3	62.73	0.956	Lag	58.3	10.9	59.31	0.983	Lag
FLT31&32	1.0113	60.0	-1.6	60.02	1.000	Lead	58.2	-9.3	58.94	0.987	Lead

Cont. No.	Voltage @ POI (pu)	Power Factor of Wind Generator GEN-2009-006					Power Factor @ POI				
		P	Q	MVA	PF	Lead/Lag	P	Q	MVA	PF	Lead/Lag
FLT33&34	1.0090	60.0	19.5	63.09	0.951	Lag	58.3	12.1	59.54	0.979	Lag

Table 9: Voltage at POI and P.F. at POI and Wind Farm without VAR Generator, Winter Peak

Cont. No.	Voltage @ POI (pu)	Power Factor of Wind Generator GEN-2009-006					Power Factor @ POI				
		P	Q	MVA	PF	Lead/Lag	P	Q	MVA	PF	Lead/Lag
Base Case	0.9918	60.0	3.6	60.11	0.998	Lag	58.2	-4.3	58.36	0.997	Lead
FLT01&02	0.9932	60.0	3.2	60.09	0.999	Lag	58.2	-4.7	58.39	0.997	Lead
FLT03&04	0.9945	60.0	2.9	60.07	0.999	Lag	58.2	-5.1	58.42	0.996	Lead
FLT05&06	0.9909	60.0	3.9	60.13	0.998	Lag	58.2	-4.1	58.34	0.998	Lead
FLT07&08	0.9896	60.0	4.3	60.15	0.997	Lag	58.2	-3.7	58.32	0.998	Lead
FLT09&10	0.9897	60.0	4.3	60.15	0.997	Lag	58.2	-3.7	58.32	0.998	Lead
FLT11&12	0.9871	60.0	5.1	60.22	0.996	Lag	58.2	-3.0	58.28	0.999	Lead
FLT13&14	0.9878	60.0	4.8	60.19	0.997	Lag	58.2	-3.2	58.29	0.998	Lead
FLT15&16	0.9921	60.0	3.6	60.11	0.998	Lag	58.2	-4.4	58.37	0.997	Lead
FLT17&18	0.9883	60.0	4.7	60.18	0.997	Lag	58.2	-3.3	58.29	0.998	Lead
FLT19&20	0.9905	60.0	4.1	60.14	0.998	Lag	58.2	-3.9	58.33	0.998	Lead
FLT21&22	0.9912	60.0	3.8	60.12	0.998	Lag	58.2	-4.1	58.34	0.998	Lead
FLT23&24	0.9872	60.0	5.0	60.21	0.997	Lag	58.2	-3.0	58.28	0.999	Lead
FLT25&26	0.9924	60.0	3.5	60.10	0.998	Lag	58.2	-4.5	58.37	0.997	Lead
FLT27&28	0.9894	60.0	4.4	60.16	0.997	Lag	58.2	-3.6	58.31	0.998	Lead
FLT29&30	0.9865	60.0	5.2	60.22	0.996	Lag	58.2	-2.8	58.27	0.999	Lead
FLT31&32	0.9935	60.0	3.2	60.09	0.999	Lag	58.2	-4.8	58.40	0.997	Lead
FLT33&34	0.9816	60.0	6.7	60.37	0.994	Lag	58.2	-1.5	58.22	1.000	Lead

For the base case and all contingencies, the voltages at the POI are all above 0.98 pu, and the power factors at POI and wind farm are all above 0.95. Therefore, no additional reactive compensation is required. The voltage at POI in winter peak is slightly lower than unity. If higher voltage needed, the shunt at the bus 506947 (SFAYTVL5) can be simply switched back online.

5. VOLTAGE RECOVERY RESULTS

Dynamic simulations were performed using each fault noted in Section 2. All faults were cleared after five (5) cycles. Faulted transmission lines were reclosed into the fault 20 cycles after the initial clearing, then cleared and locked out after five (5) more cycles. Faulted transformers were not reclosed.

Voltage recovery as determined via dynamic simulation was checked against all contingencies. If the voltage recovers post-fault to a steady-state level consistent with the steady-state simulation, the generator interconnection is considered acceptable from a voltage recovery standpoint.

In these dynamic simulations, real loads are modeled as constant current and reactive loads are modeled as constant admittance; i.e. MW loads are proportional to voltage and Mvar loads are proportional to voltage squared. In contrast, loads are modeled as constant MW and constant Mvar in steady-state simulations. Therefore, due to differences in load modeling, minor differences in voltages are to be expected between dynamic and steady-state simulations.

The dynamic simulation showed all generators did not trip during any of the contingencies tested. That is, the wind farm GEN-2009-006 meets FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage). Table 10 lists the post-fault voltages at POI[2].

Table 10: Post-Fault Voltage Recovery by Dynamic Simulation

Fault No.	Voltage @ GEN-2009-006 POI (Southeast Fayetteville 161 kV bus) (pu)	
	Summer Peak	Winter Peak
FLT01	1.0144	0.9930
FLT02	1.0144	0.9930
FLT03	1.0148	0.9942
FLT04	1.0148	0.9943
FLT05	1.0102	0.9906
FLT06	1.0102	0.9906
FLT07	1.0093	0.9893
FLT08	1.0093	0.9893
FLT09	1.0179	0.9894
FLT10	1.0179	0.9894

[2] The PTI utility tool PSSECHOP was used to retrieve the post-fault voltage at the PO from the dynamic simulation channel output files.

Fault No.	Voltage @ GEN-2009-006 POI (Southeast Fayetteville 161 kV bus) (pu)	
	Summer Peak	Winter Peak
FLT11	1.0073	0.9834
FLT12	1.0074	0.9834
FLT13	1.0086	0.9866
FLT14	1.0086	0.9866
FLT15	1.0116	0.9921
FLT16	1.0116	0.9921
FLT17	1.0092	0.9874
FLT18	1.0092	0.9874
FLT19	1.0091	0.9883
FLT20	1.0091	0.9883
FLT21	1.0104	0.9897
FLT22	1.0105	0.9897
FLT23	1.0103	0.9871
FLT24	1.0104	0.9872
FLT25	1.0129	0.9928
FLT26	1.0129	0,9928
FLT27	1.0059	0.9894
FLT28	1.0060	0.9894
FLT29	1.0055	0.9864
FLT30	1.0055	0.9864
FLT31	1.0128	0.9932
FLT32	1.0129	0.9932
FLT33	1.0025	0.9801
FLT34	1.0026	0.9801

The two (2) plots below show the highest post-fault voltage at the POI following the faults FLT09-3Φ and FLT10-1Φ in summer peak case and the lowest post-fault voltage at the POI following the faults in FLT33-3Φ and FLT34-1Φ in winter peak case.

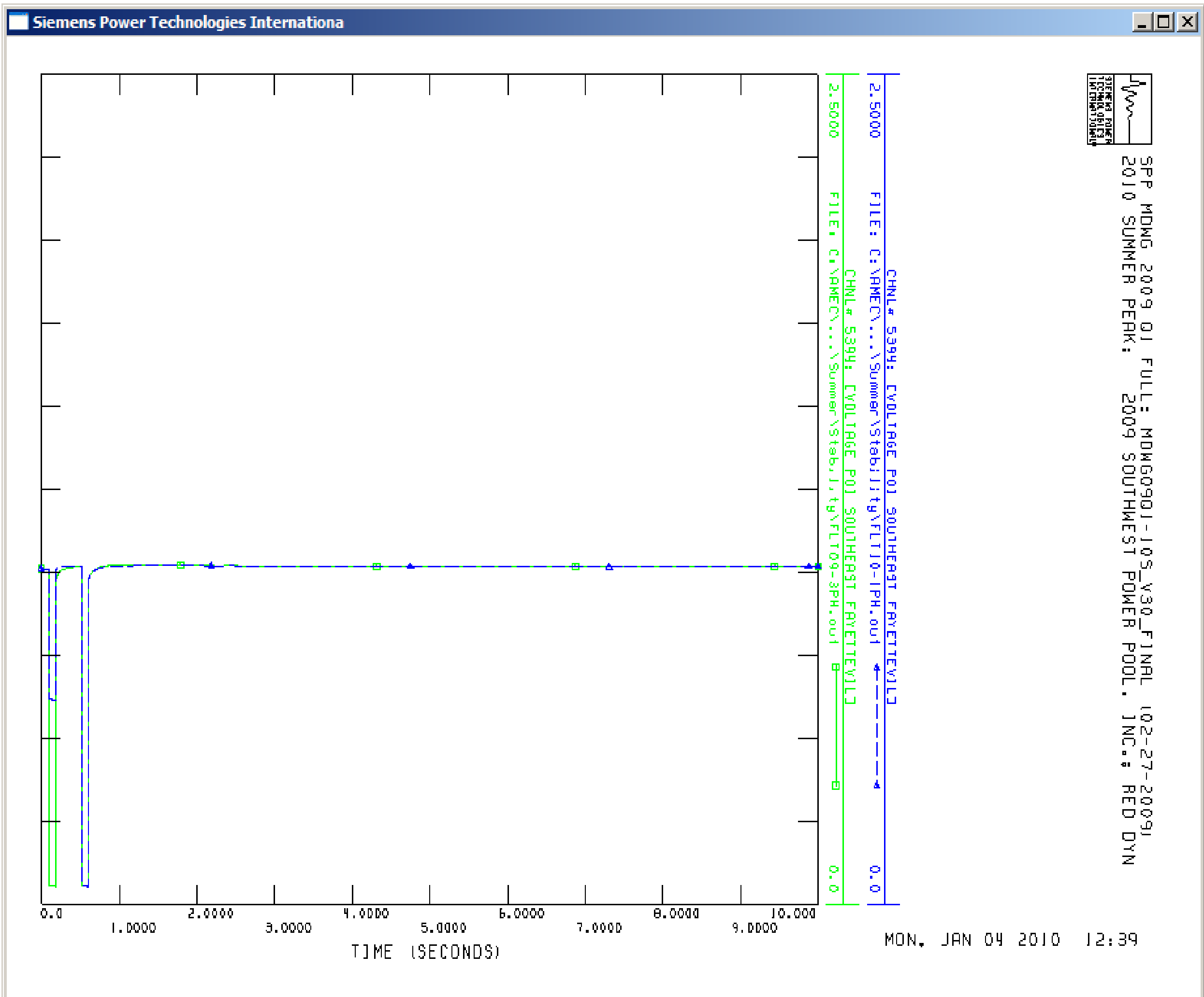

Figure 3: POI Voltage Recovery for FLT09-3Φ & FLT10-1Φ, Summer Peak

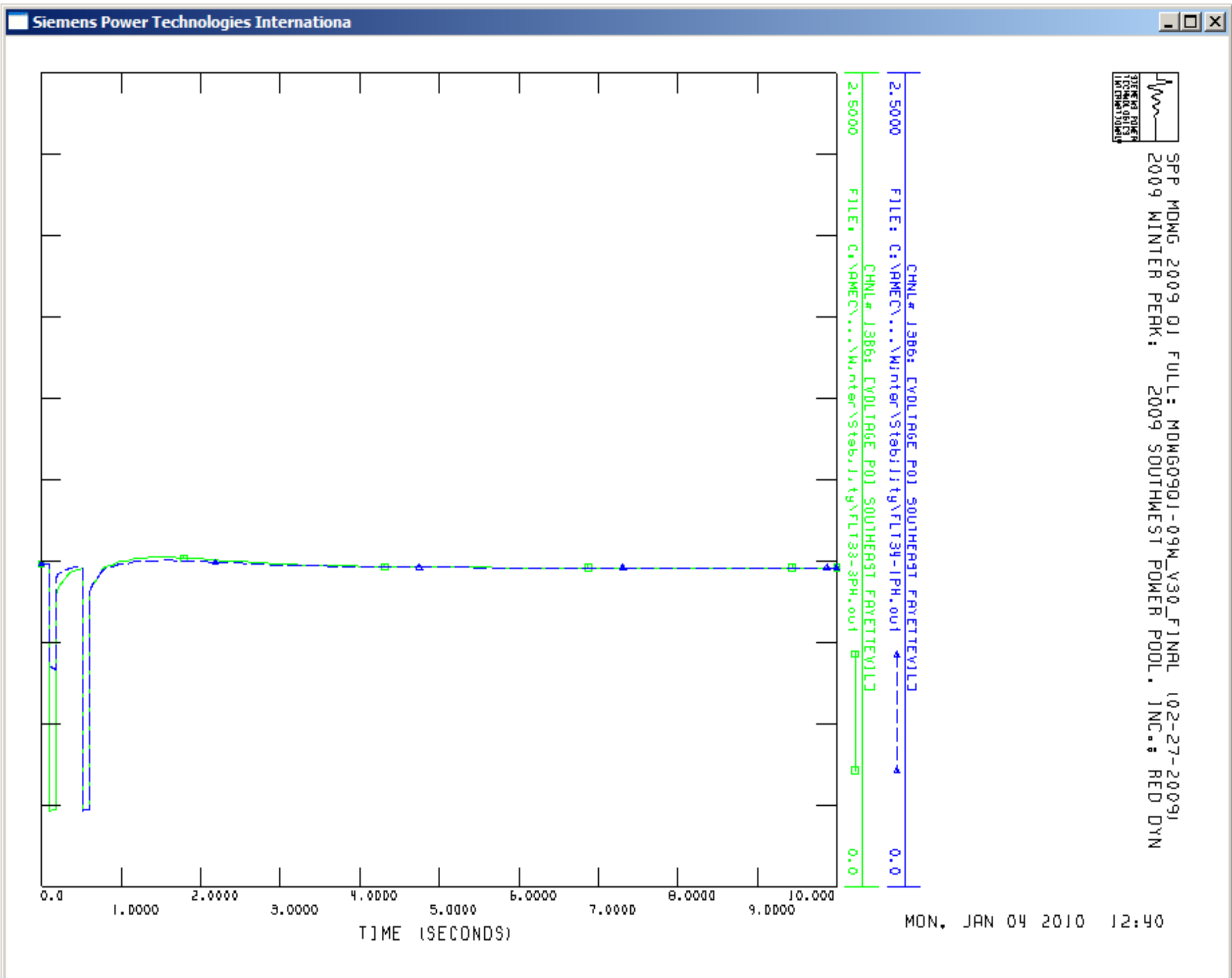

Figure 4: POI Voltage Recovery for FLT33-3Φ & FLT34-1Φ, Winter Peak

6. TRANSIENT STABILITY RESULTS

Based on the dynamics results, GEN-2009-006 did not cause any new stability problems. For the faults studied, the three-phase faults are relatively severe than the corresponding single-line- to-ground faults. No synchronous generators pulled out of synchronism with the grid and no generators tripped.

Below are the worst-case faults[3] for the generator to be studied in Group 12, as determined by visual inspection of the rotor speed graphs from PSS/E dynamic analysis.

Table 10: Worst Faults for Dynamic Behavior within Group 12 (Summer Peak)

Generator	Worst Fault	Worst Fault Description
GEN-2009-006	FLT01-3Φ	SE Fayetteville to Hyland 161 kV, near SE Fayetteville
GEN-2009-006	FLT03-3Φ	Fayetteville to S Fayetteville 161 kV, near Fayetteville

Following are graphs of the rotor speeds for GEN-2009-006 after applying the respective 3Φ faults to the summer peak case.

[3] Here the severity of the faults is measured by the oscillation amplitude of the wind turbine generator speed.

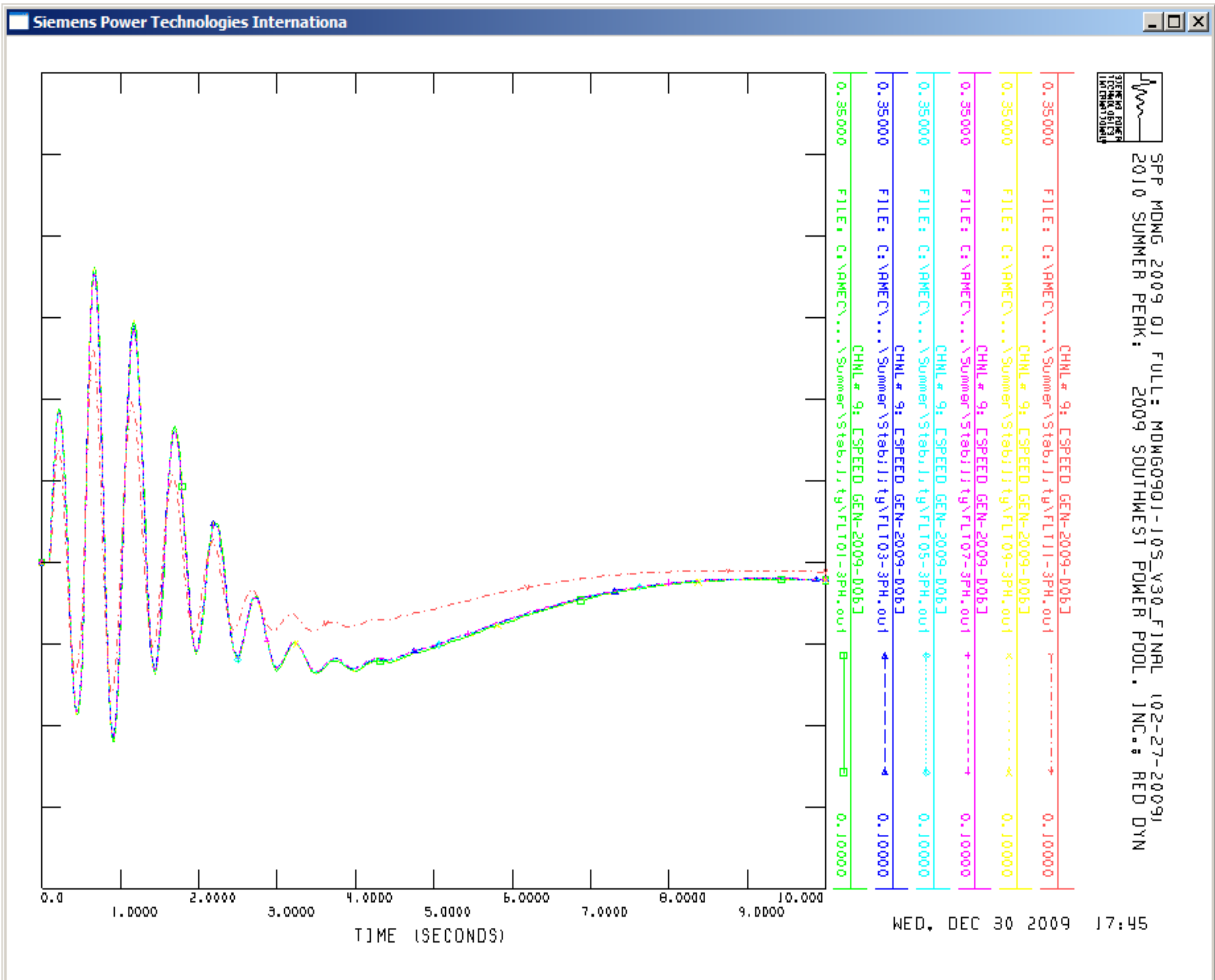

Figure 5: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT01-3Φ ~ FLT11-3Φ, Summer Peak

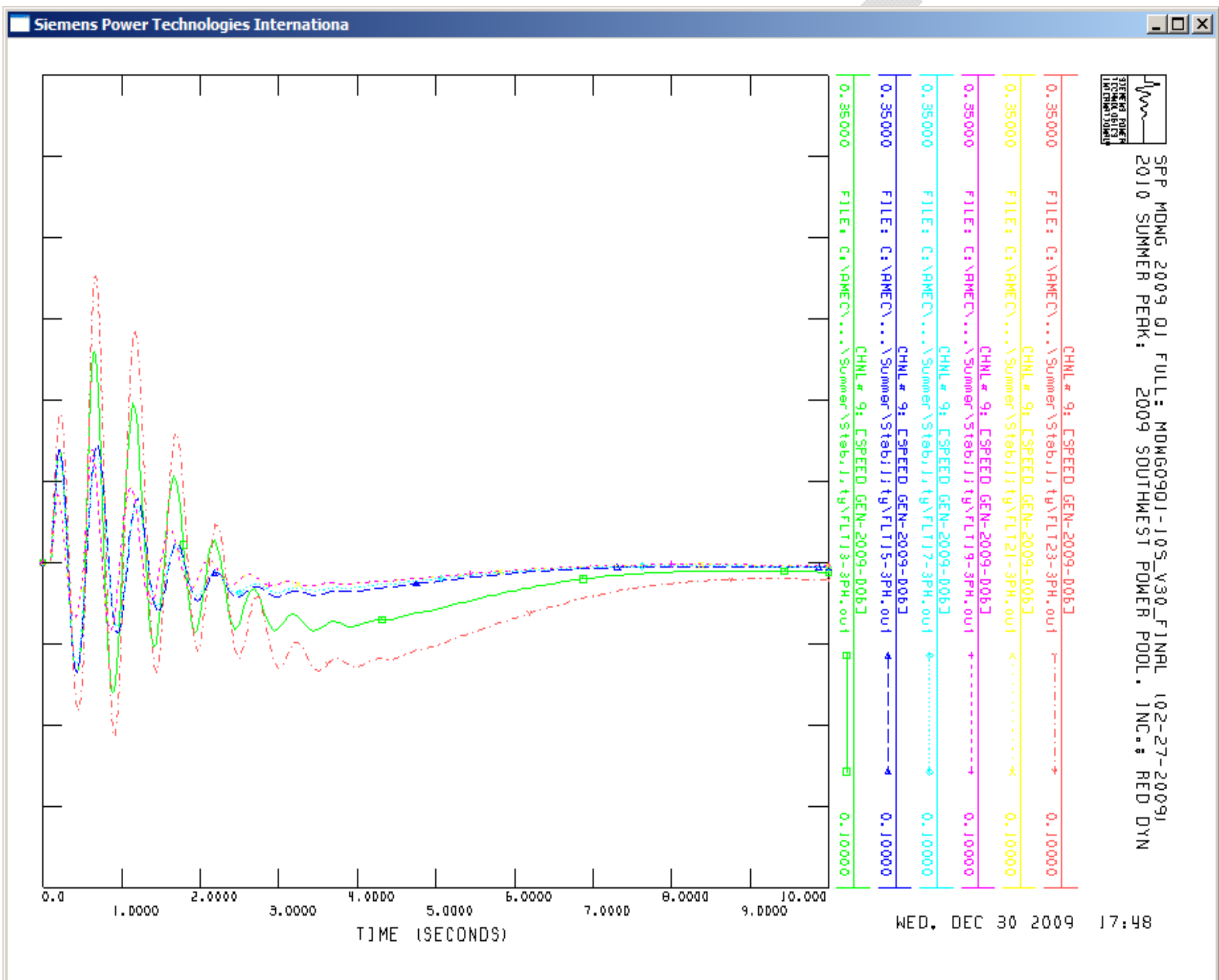

Figure 6: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT13-3Φ ~ FLT23-3Φ, Summer Peak

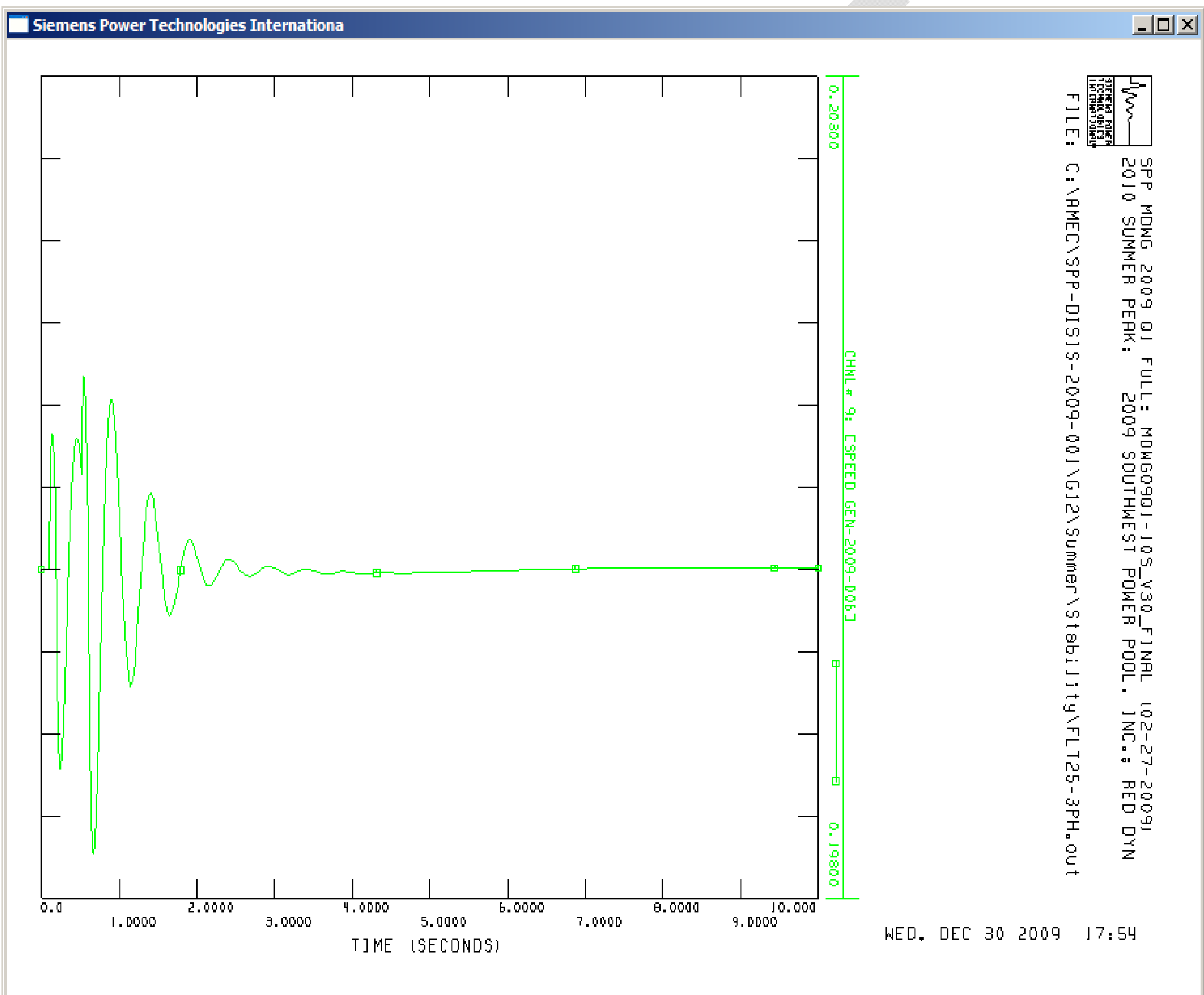

Figure 7: **Response of GEN-2009-006 Wind Turbine Generator Speed to FLT25-3Φ, Summer Peak**

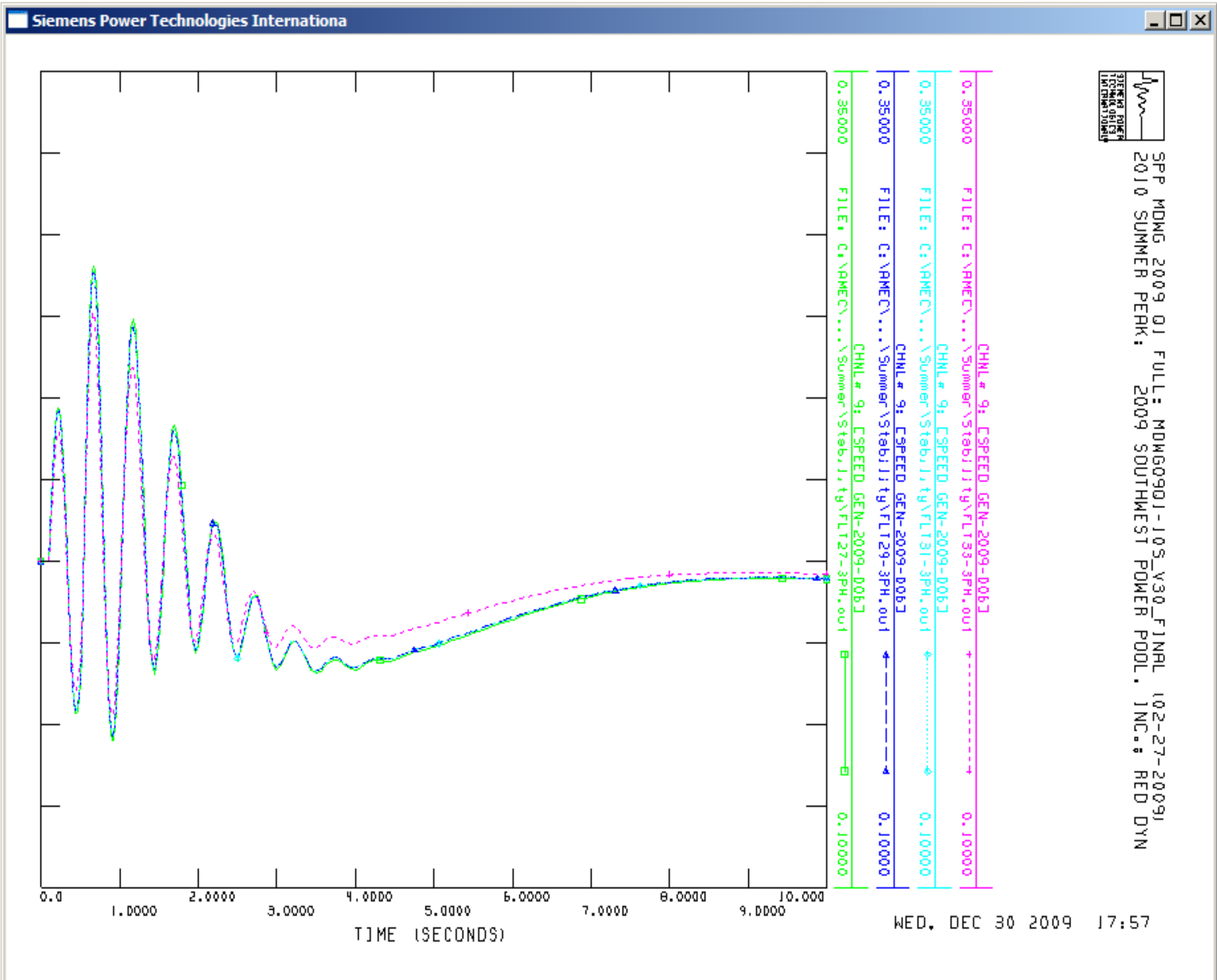

Figure 8: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT27-3Φ ~ FLT33-3Φ, Summer Peak

Similar results were obtained in dynamic analysis of the winter peak case. The worst-case faults for the winter peak case are shown below. The worst-case faults are the same for the winter and summer peak cases for Group 12.

Table 11: Worst Faults for Dynamic Behavior within Group 12 (Winter Peak)

Generator	Worst Fault	Worst Fault Description
GEN-2009-006	FLT01-3Φ	SE Fayetteville to Hyland 161 kV, near SE Fayetteville
GEN-2009-006	FLT03-3Φ	Fayetteville to S Fayetteville 161 kV, near Fayetteville

Following are graphs of the rotor speeds for GEN-2009-006 after applying the respective 3Φ faults to the winter peak case.

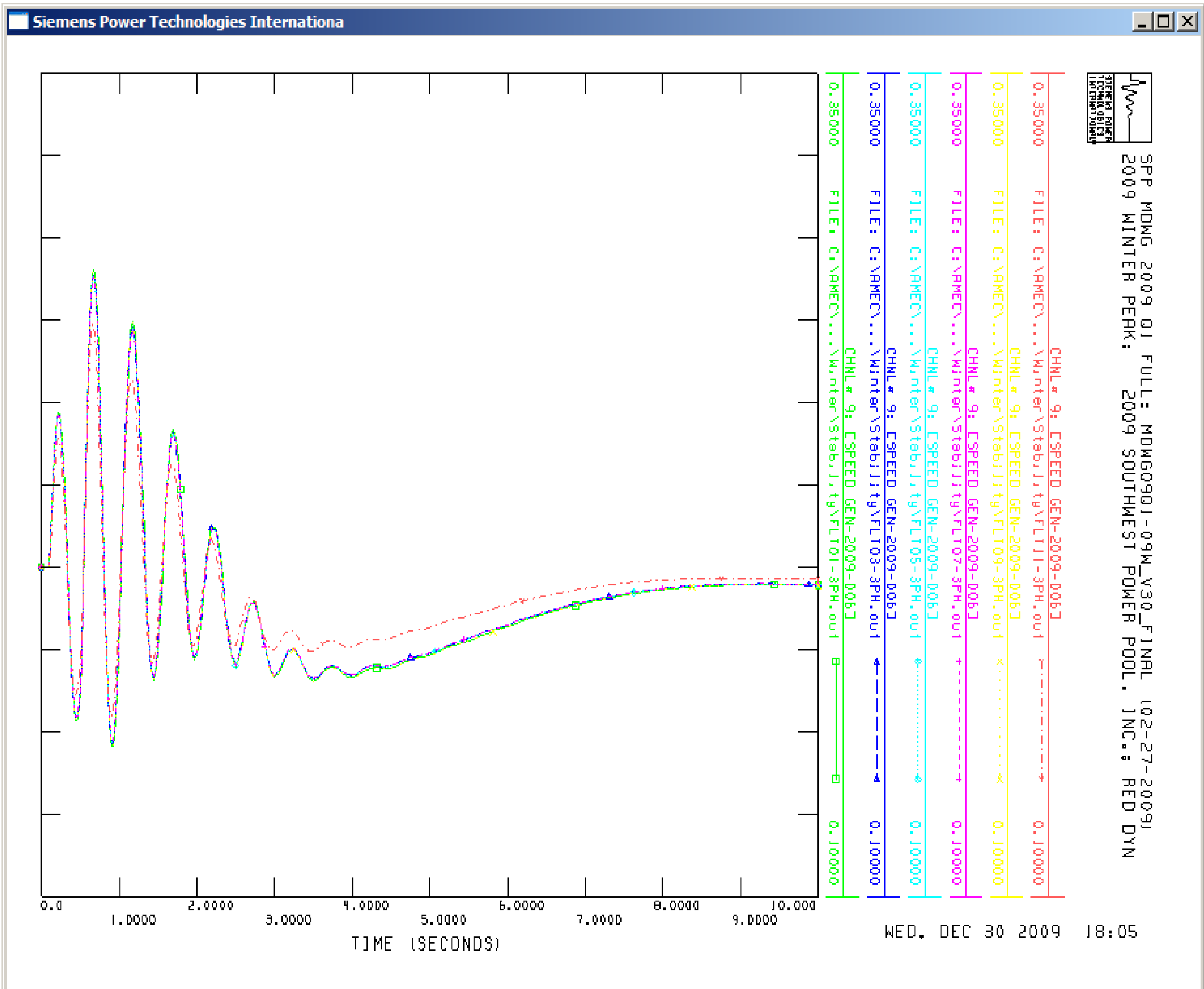

Figure 9: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT01-3Φ ~ FLT11-3Φ, Winter Peak

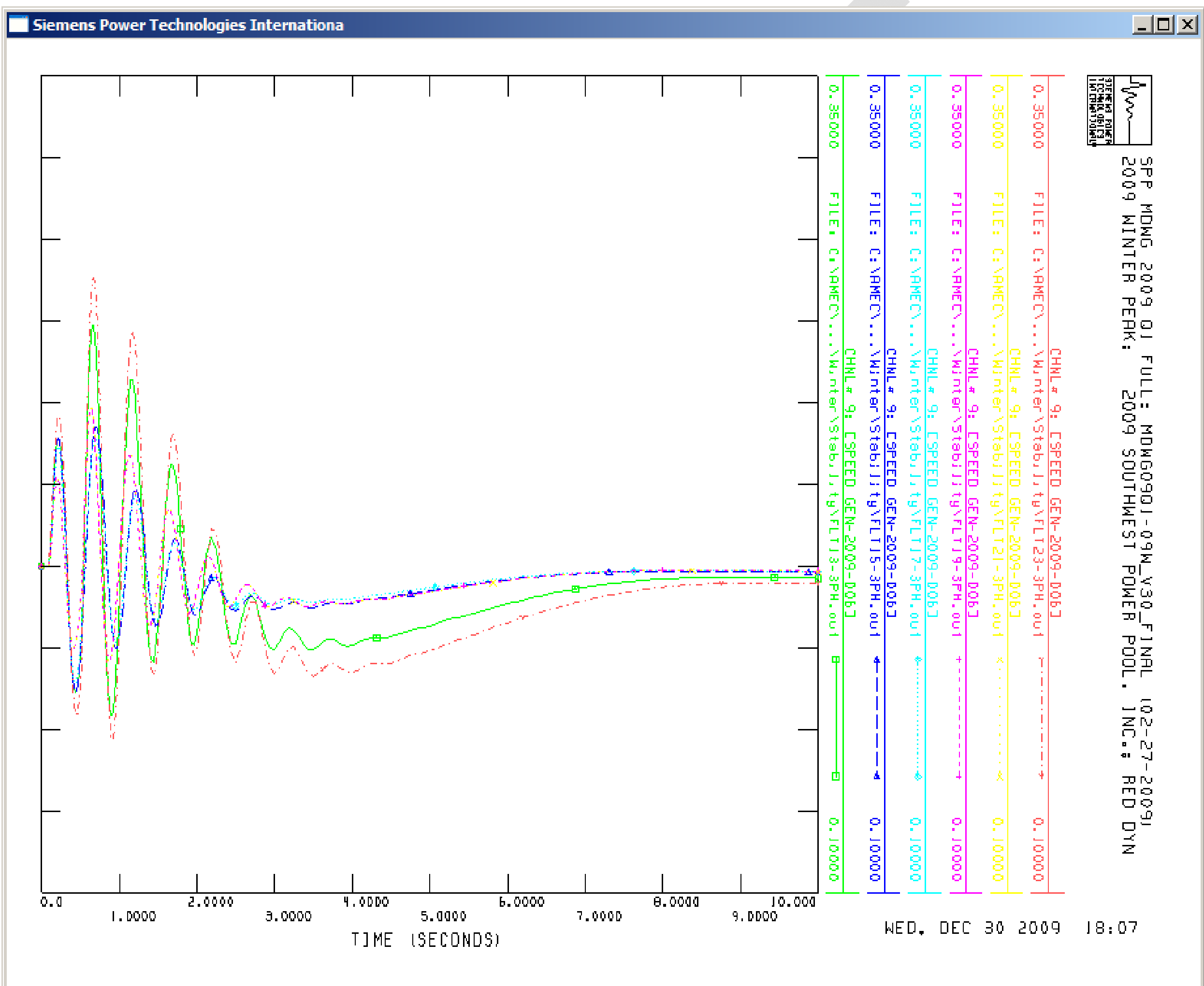

Figure 10: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT13-3Φ ~ FLT23-3Φ, Winter Peak

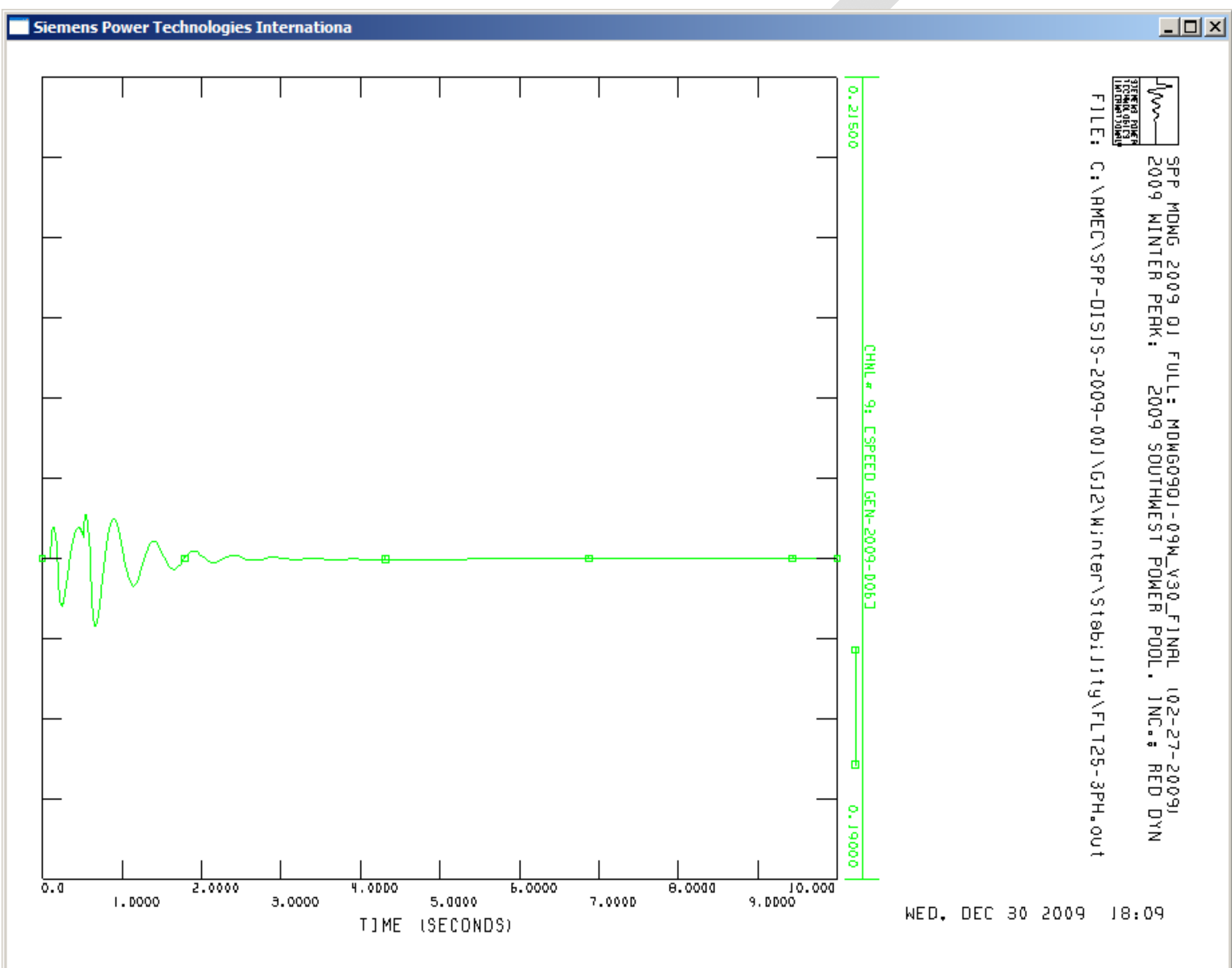

Figure 11: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT25-3Φ, Winter Peak

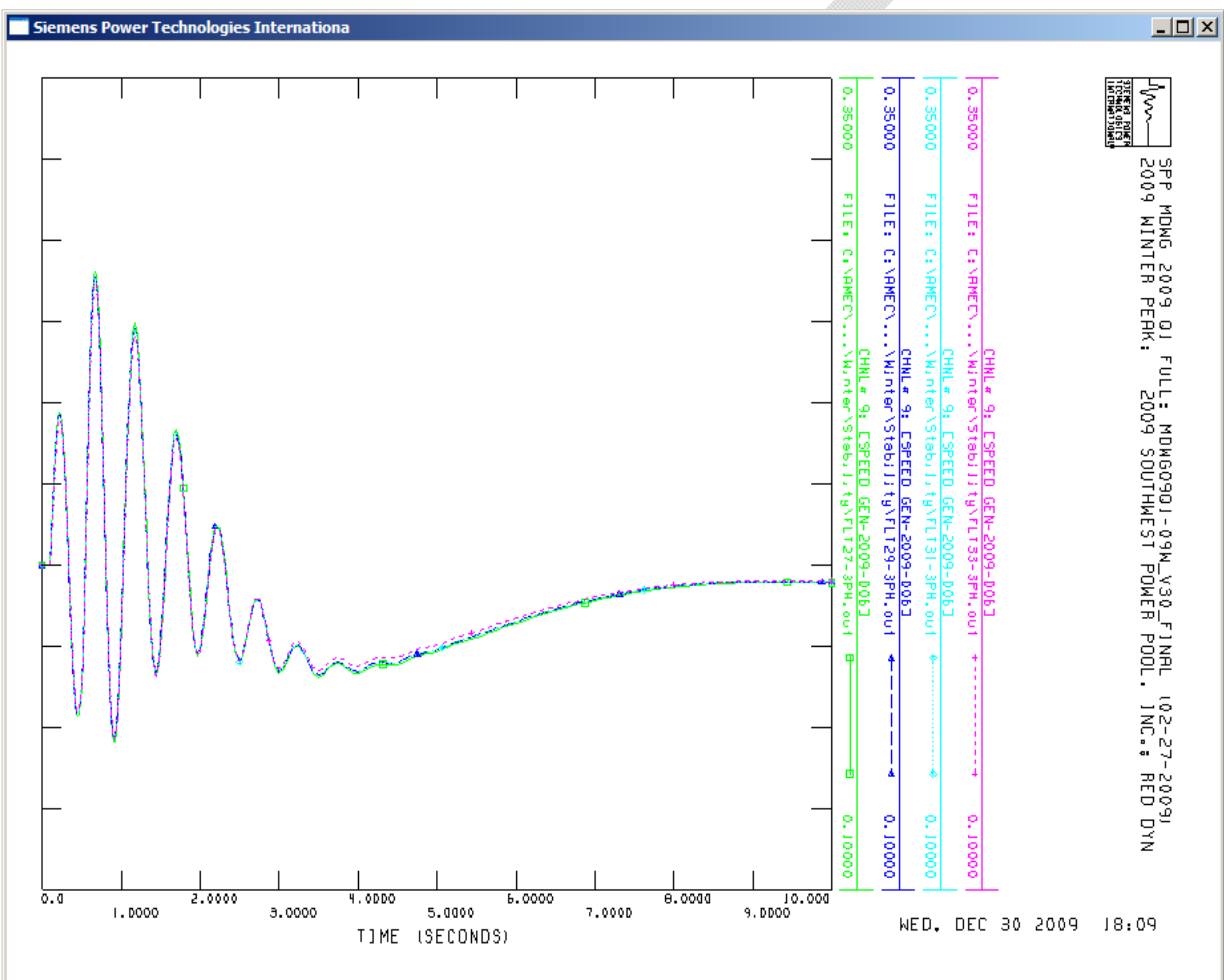

Figure 12: Response of GEN-2009-006 Wind Turbine Generator Speed to FLT27-3Φ ~ FLT33-3Φ, Winter Peak

7. CONCLUSIONS

Based on the results of Group 12 studies, the following findings had been observed:

- Both the voltage and power factor at the POI met the requirement without the additional reactive power support.
- All generators appeared capable of meeting LVRT requirements. No generators tripped off line under the fault conditions.
- All wind farms had the capability of recovering to the pre-contingency voltage following the fault disturbance.
- Neither the rotor angles of the synchronous machines in the studied areas suffered from instability nor the wind turbine generators in the studied areas tripped off-line under the fault disturbance.

U: Stability Study for Group 13

SPP DISIS-2009-001 Group 13
Definitive Impact Study

Final Report for

Southwest Power Pool

Prepared by:
Excel Engineering, Inc.

January 28, 2010

Principal Contributor:

William Quaintance, P.E.

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0. Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of **Arkansas**.

William Quaintance
Arkansas Registration Number 13865

1. Background and Scope

The DISIS-2009-001 Group 13 Definitive Impact Study is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose is to study the impacts of interconnecting the project shown in Table 1-1. The in-service date assumed for the generation addition was 2010.

Table 1-1. Interconnection Requests Evaluated

Request	MW Sum/Win	Turbine	Point of Interconnection
GEN-2008-129	641/675	Combined Cycle Gas	Pleasant Hill 161kV (541225)

The previously-queued requests shown in Table 1-2 were included in this study and dispatched at 100% of rated capacity.

Table 1-2. Nearby Interconnection Requests Already in the Queue

Request	MW	Turbine	Point of Interconnection
GEN-2006-014	300	G.E. 1.5MW	Wind Farms 161kV (89572)
GEN-2006-017	300	Clipper 2.5MW	Wind Farms 161kV (89572)
GEN-2007-015	135	GE 1.5MW	Humboldt-Kelley 161kV (540007)
GEN-2007-017	100	G.E. 1.5 MW	Wind Farms 161kV (89572)
GEN-2007-053	110	Gamesa 2.0MW	Wind Farms 161kV (89572)
GEN-2008-119O	60	G.E. 1.5MW	Humboldt-Kelley 161kV (640500)

The study included a stability analysis for each proposed interconnection request. Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled. Since none of the interconnection requests in this group were wind projects, a power factor analysis was NOT performed.

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on Excel's knowledge of the electric power system and on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is sensitive to the assumptions made with respect to other generation additions and transmission improvements being contemplated by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The DISIS-2009-001 Group 13 Definitive Impact Study evaluated the impacts of interconnecting project GEN-2008-129 to the SPP electric system. No stability problems were found during summer or winter peak conditions due to the addition of this plant.

The standard power factor requirement for the synchronous generators of GEN-2008-129 is 0.95 leading to 0.95 lagging at the POI.

With the assumptions described in this report, DISIS-2009-001 Group 13 should be able to connect without causing any stability problems on the SPP transmission grid.

3. Study Development and Assumptions

3.1 Simulation Tools

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. Each plant's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. As a result, no additional generator modeling was required.

A power flow one-line diagram of GEN-2008-129 is shown in Figure 3-1. GEN-2008-129 is a natural gas fired combined cycle plant consisting of two 180 MW (summer rating) gas turbines and a single 281 MW (summer rating) steam turbine. This plant is connected to the Pleasant Hill 161 kV bus. An existing autotransformer connects the Pleasant Hill 161 and 345 kV buses.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

Figure 3-2 and Figure 3-3 show the location of the study project on the transmission system. Figure 3-2 shows the nearby 161 kV transmission system and Figure 3-3 shows entire 345 kV loop around Kansas City. The green ellipse indicates the study project point of interconnection (POI). The green X's indicate the fault locations examined in this study. Red transmission lines are nominally 345 kV and blue lines are 161 kV.

3.3 Monitored Facilities

All generators in Areas 531, 534, 536, 540, 541, 640, and 645 were monitored.

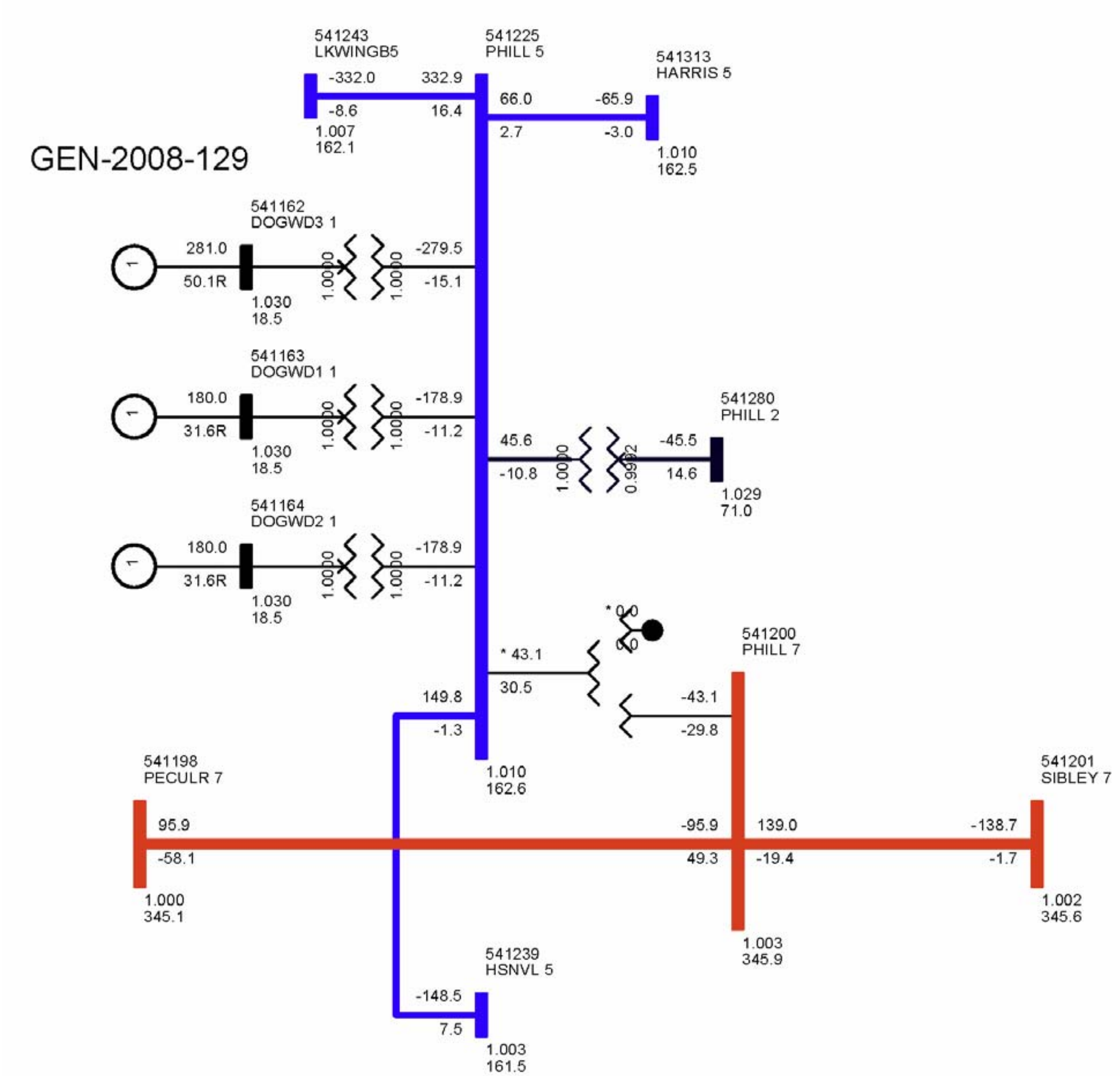

Figure 3-1. Power Flow One-line for GEN-2008-129 and adjacent equipment

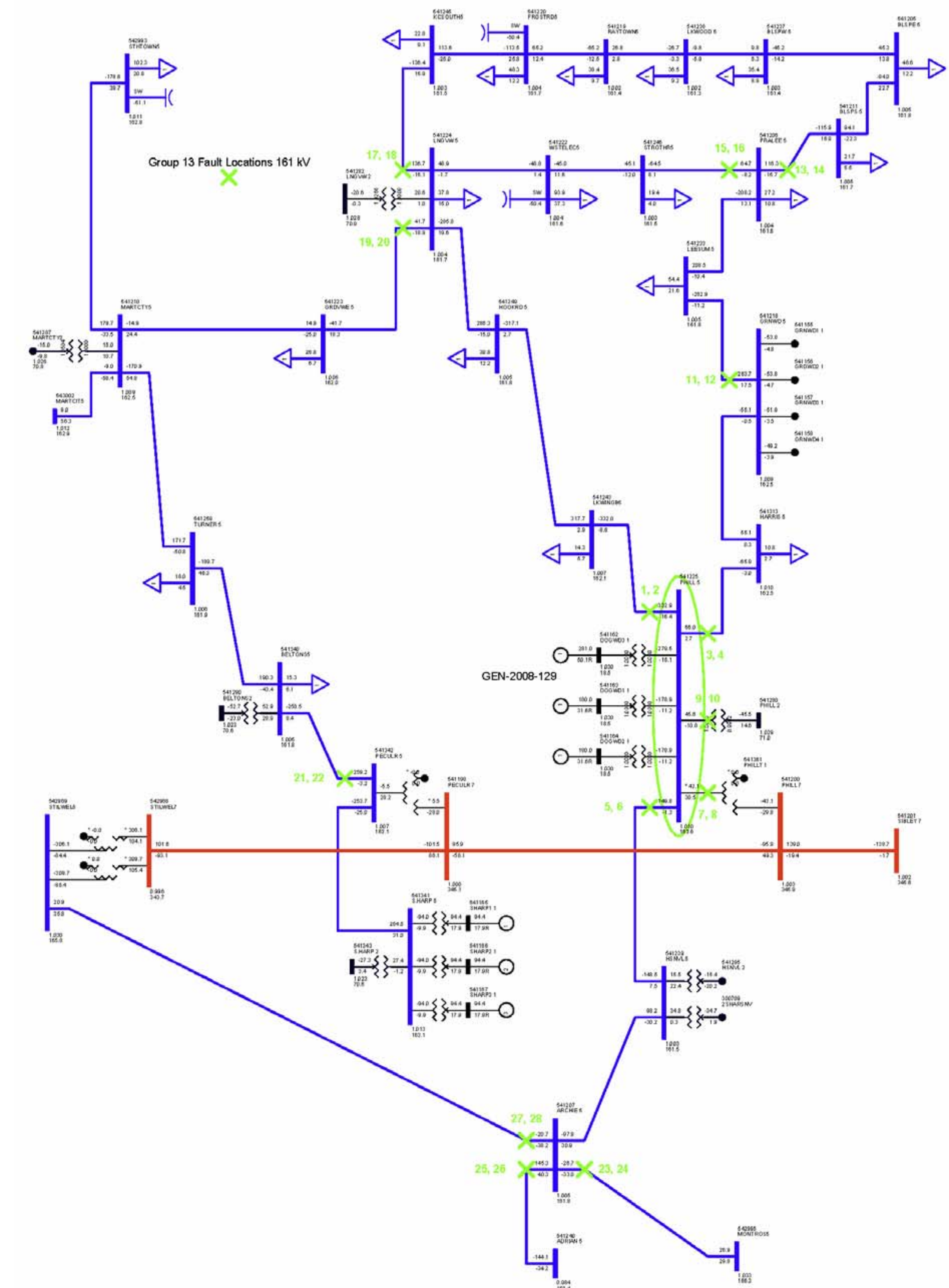

Figure 3-2. 161 kV Transmission System near GEN-2008-129

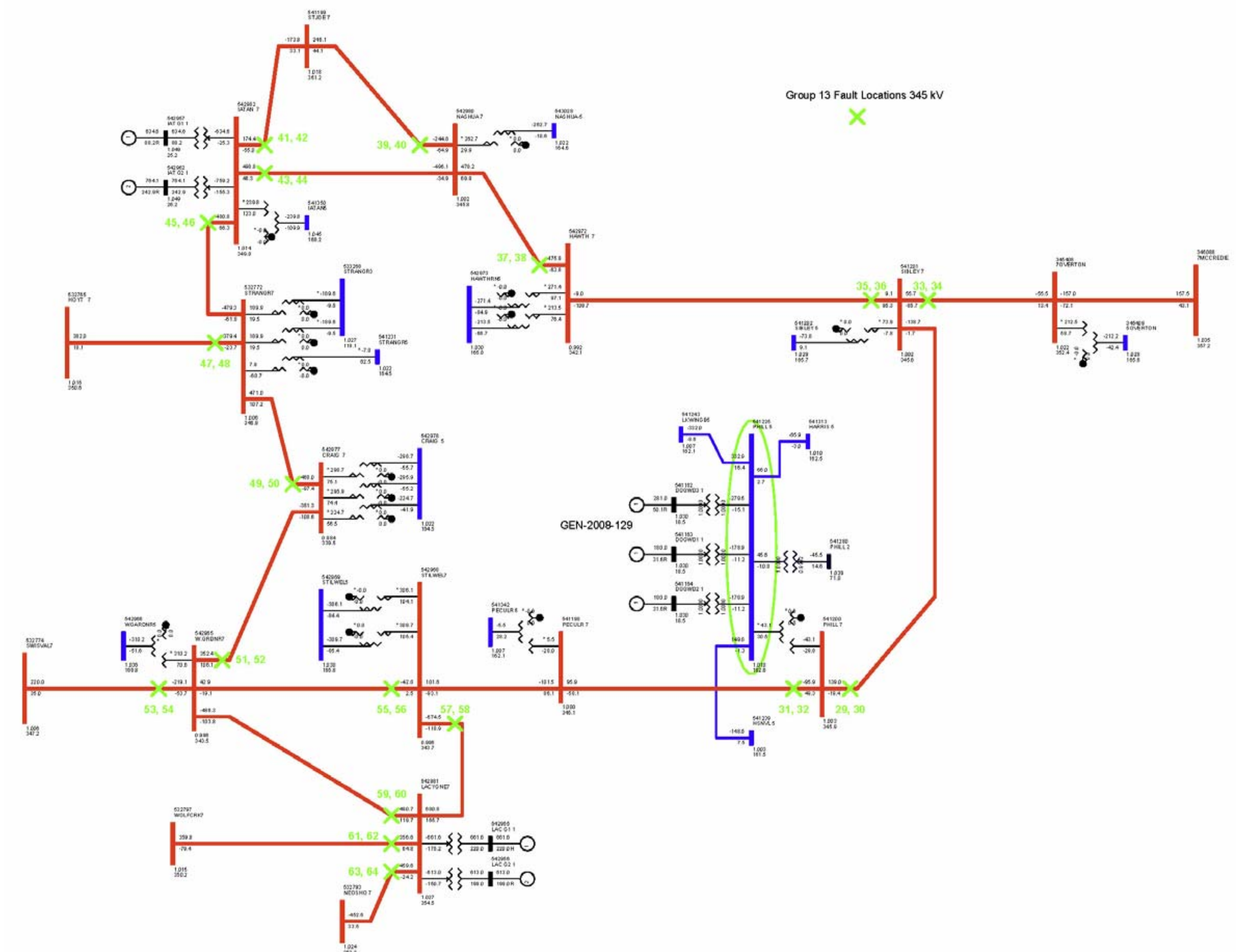

Figure 3-3. 345 kV Transmission System around Kansas City

3.4 Performance Criteria

The wind generators must comply with the FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generators should not trip off line for faults for under voltage relay actuation. If a wind generator trips off line, an appropriately sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP was consulted to determine if the addition of an SVC or STATCOM is warranted for the specific condition. None of the study requests in Group 13 is a wind farm.

Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

3.5 Performance Evaluation Methods

Since none of the interconnection requests are wind projects, a power factor analysis was NOT performed.

ATC studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission facilities may be required based on subsequent ATC analysis.

Stability analysis was performed for each proposed interconnection request. Faults were simulated on transmission lines at the POIs and on other nearby transmission equipment. The faults in Table 3-1 were run for each case (three phase and single phase as noted).

Table 3-1. Fault Definitions for DISIS-2009-001 Group 13

Cont. No.	Contingency Name	Description
1	FLT01-3PH	3 phase fault on the Pleasant Hill (541225) to Longview (541224) 161kV line, near Pleasant Hill. a. Apply fault at the Pleasant Hill 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Pleasant Hill (541225) to Greenwood (541218) 161kV line, near Pleasant Hill. a. Apply fault at the Pleasant Hill 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Pleasant Hill (541225) to Harrisonville (541239) 161kV line, near Pleasant Hill. a. Apply fault at the Pleasant Hill 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Pleasant Hill 161kV (541225) to 345kV (541200) transformer, near the 161kV bus. a. Apply fault at the Pleasant Hill 161kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Pleasant Hill 161kV (541225) to 69kV (541280) transformer, near the 161kV bus. a. Apply fault at the Pleasant Hill 161kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Greenwood (541218) to Prairie Lee (541206) 161kV line, near Greenwood. a. Apply fault at the Greenwood 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Prairie Lee (541206) to Blue Springs East (541205) 161kV line, near Prairie Lee. a. Apply fault at the Prairie Lee 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	*Single phase fault and sequence like previous*

Cont. No.	Contingency Name	Description
15	FLT15-3PH	3 phase fault on the Prairie Lee (541206) to Longview (541224) 161kV line, near Prairie Lee. a. Apply fault at the Prairie Lee 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Longview (541224) to Blue Springs East (541205) 161kV line, near Longview. a. Apply fault at the Longview 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Longview (541224) to Martin City (541210) 161kV line, near Longview. a. Apply fault at the Longview 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Peculiar (541342) to Belton South (541340) 161kV line, near Peculiar. a. Apply fault at the Peculiar 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Archie (541207) to Montrose (542995) 161kV line, near Archie. a. Apply fault at the Archie 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the Archie (541207) to Adrian (541240) 161kV line, near Archie. a. Apply fault at the Archie 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Archie (541207) to Stilwell (542969) 161kV line, near Archie. a. Apply fault at the Archie 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single phase fault and sequence like previous*

Cont. No.	Contingency Name	Description
29	FLT29-3PH	3 phase fault on the Pleasant Hill (541200) to Sibley (541201) 345kV line, near Pleasant Hill. a. Apply fault at the Pleasant Hill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the Pleasant Hill (541200) to Peculiar (541198) 345kV line, near Pleasant Hill. a. Apply fault at the Pleasant Hill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Sibley (541201) to Overton (345408) 345kV line, near Sibley. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Sibley (541201) to Hawthorn (542972) 345kV line, near Sibley. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Hawthorn (542972) to Nashua (542980) 345kV line, near Hawthorn. a. Apply fault at the Hawthorn 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Nashua (542980) to St. Joseph (541199) 345kV line, near Nashua. a. Apply fault at the Nashua 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Iatan (542982) to St. Joseph (541199) 345kV line, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Iatan (542982) to Nashua (542980) 345kV line, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Contingency Name	Description
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Iatan (542982) to Stranger Creek (532772) 345kV line, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the Stranger Creek (532772) to Hoyt (532765) 345kV line, near Stranger Creek. a. Apply fault at the Stranger Creek 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-1PH	*Single phase fault and sequence like previous*
49	FLT49-3PH	3 phase fault on the Craig (542977) to Stranger Creek (532772) 345kV line, near Craig. a. Apply fault at the Craig 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT50-1PH	*Single phase fault and sequence like previous*
51	FLT51-3PH	3 phase fault on the West Gardner (542965) to Craig (542977) 345kV line, near West Gardner. a. Apply fault at the West Gardner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
52	FLT52-1PH	*Single phase fault and sequence like previous*
53	FLT53-3PH	3 phase fault on the West Gardner (542965) to Swissvale (532774) 345kV line, near West Gardner. a. Apply fault at the West Gardner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
54	FLT54-1PH	*Single phase fault and sequence like previous*
55	FLT55-3PH	3 phase fault on the Stilwell (542968) to West Gardner (542965) 345kV line, near Stilwell. a. Apply fault at the Stilwell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
56	FLT56-1PH	*Single phase fault and sequence like previous*
57	FLT57-3PH	3 phase fault on the Stilwell (542968) to Lacygne (542981) 345kV line, near Stilwell. a. Apply fault at the Stilwell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
58	FLT58-1PH	*Single phase fault and sequence like previous*

Cont. No.	Contingency Name	Description
59	FLT59-3PH	3 phase fault on the Lacygne (542981) to West Gardner (542965) 345kV line, near Lacygne. a. Apply fault at the Lacygne 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
60	FLT60-1PH	*Single phase fault and sequence like previous*
61	FLT61-3PH	3 phase fault on the Lacygne (542981) to Wolf Creek (532797) 345kV line, near Lacygne. a. Apply fault at the Lacygne 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
62	FLT62-1PH	*Single phase fault and sequence like previous*
63	FLT63-3PH	3 phase fault on the Lacygne (542981) to Neosho (532793) 345kV line, near Lacygne. a. Apply fault at the Lacygne 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
64	FLT64-1PH	*Single phase fault and sequence like previous*

4. Results and Observations

4.1 Stability Analysis Results

All faults were run for both summer and winter peak conditions. If a previously-queued generator tripped for any of these faults, the voltage and frequency tripping was disabled, and the fault was re-run to check for system stability. No tripping occurred in this study.

Table 4-1 summarizes the overall results for all faults run. Figure 4-1 and Figure 4-2 show representative summer peak season plots for a fault at the POI of each of the study project generators (steam and gas turbines respectively). Complete sets of plots for both summer and winter peak seasons for each fault and each wind project are included in Appendices A and B.

The system remains stable for all simulated faults. All study projects stay on-line for all simulated faults.

Table 4-1. Summary of Stability Results

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
1	FLT01-3PH	3 phase fault on the Pleasant Hill (541225) to Longview (541224) 161kV line, near Pleasant Hill.	OK	OK
2	FLT02-1PH	*Single phase fault and sequence like previous*	OK	OK
3	FLT03-3PH	3 phase fault on the Pleasant Hill (541225) to Greenwood (541218) 161kV line, near Pleasant Hill.	OK	OK
4	FLT04-1PH	*Single phase fault and sequence like previous*	OK	OK
5	FLT05-3PH	3 phase fault on the Pleasant Hill (541225) to Harrisonville (541239) 161kV line, near Pleasant Hill.	OK	OK
6	FLT06-1PH	*Single phase fault and sequence like previous*	OK	OK
7	FLT07-3PH	3 phase fault on the Pleasant Hill 161kV (541225) to 345kV (541200) transformer, near the 161kV bus.	OK	OK
8	FLT08-1PH	*Single phase fault and sequence like previous*	OK	OK
9	FLT09-3PH	3 phase fault on the Pleasant Hill 161kV (541225) to 69kV (541280) transformer, near the 161kV bus.	OK	OK
10	FLT10-1PH	*Single phase fault and sequence like previous*	OK	OK
11	FLT11-3PH	3 phase fault on the Greenwood (541218) to Prairie Lee (541206) 161kV line, near Greenwood.	OK	OK
12	FLT12-1PH	*Single phase fault and sequence like previous*	OK	OK
13	FLT13-3PH	3 phase fault on the Prairie Lee (541206) to Blue Springs East (541205) 161kV line, near Prairie Lee.	OK	OK
14	FLT14-1PH	*Single phase fault and sequence like previous*	OK	OK
15	FLT15-3PH	3 phase fault on the Prairie Lee (541206) to Longview (541224) 161kV line, near Prairie Lee.	OK	OK
16	FLT16-1PH	*Single phase fault and sequence like previous*	OK	OK

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
17	FLT17-3PH	3 phase fault on the Longview (541224) to Blue Springs East (541205) 161kV line, near Longview.	OK	OK
18	FLT18-1PH	*Single phase fault and sequence like previous*	OK	OK
19	FLT19-3PH	3 phase fault on the Longview (541224) to Martin City (541210) 161kV line, near Longview.	OK	OK
20	FLT20-1PH	*Single phase fault and sequence like previous*	OK	OK
21	FLT21-3PH	3 phase fault on the Peculiar (541342) to Belton South (541340) 161kV line, near Peculiar.	OK	OK
22	FLT22-1PH	*Single phase fault and sequence like previous*	OK	OK
23	FLT23-3PH	3 phase fault on the Archie (541207) to Montrose (542995) 161kV line, near Archie.	OK	OK
24	FLT24-1PH	*Single phase fault and sequence like previous*	OK	OK
25	FLT25-3PH	3 phase fault on the Archie (541207) to Adrian (541240) 161kV line, near Archie.	OK	OK
26	FLT26-1PH	*Single phase fault and sequence like previous*	OK	OK
27	FLT27-3PH	3 phase fault on the Archie (541207) to Stilwell (542969) 161kV line, near Archie.	OK	OK
28	FLT28-1PH	*Single phase fault and sequence like previous*	OK	OK
29	FLT29-3PH	3 phase fault on the Pleasant Hill (541200) to Sibley (541201) 345kV line, near Pleasant Hill.	OK	OK
30	FLT30-1PH	*Single phase fault and sequence like previous*	OK	OK
31	FLT31-3PH	3 phase fault on the Pleasant Hill (541200) to Peculiar (541198) 345kV line, near Pleasant Hill.	OK	OK
32	FLT32-1PH	*Single phase fault and sequence like previous*	OK	OK
33	FLT33-3PH	3 phase fault on the Sibley (541201) to Overton (345408) 345kV line, near Sibley.	OK	OK
34	FLT34-1PH	*Single phase fault and sequence like previous*	OK	OK
35	FLT35-3PH	3 phase fault on the Sibley (541201) to Hawthorn (542972) 345kV line, near Sibley.	OK	OK
36	FLT36-1PH	*Single phase fault and sequence like previous*	OK	OK
37	FLT37-3PH	3 phase fault on the Hawthorn (542972) to Nashua (542980) 345kV line, near Hawthorn.	OK	OK
38	FLT38-1PH	*Single phase fault and sequence like previous*	OK	OK
39	FLT39-3PH	3 phase fault on the Nashua (542980) to St. Joseph (541199) 345kV line, near Nashua.	OK	OK
40	FLT40-1PH	*Single phase fault and sequence like previous*	OK	OK
41	FLT41-3PH	3 phase fault on the Iatan (542982) to St. Joseph (541199) 345kV line, near Iatan.	OK	OK
42	FLT42-1PH	*Single phase fault and sequence like previous*	OK	OK
43	FLT43-3PH	3 phase fault on the Iatan (542982) to Nashua (542980) 345kV line, near Iatan.	OK	OK
44	FLT44-1PH	*Single phase fault and sequence like previous*	OK	OK
45	FLT45-3PH	3 phase fault on the Iatan (542982) to Stranger Creek (532772) 345kV line, near Iatan.	OK	OK

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
46	FLT46-1PH	*Single phase fault and sequence like previous*	OK	OK
47	FLT47-3PH	3 phase fault on the Stranger Creek (532772) to Hoyt (532765) 345kV line, near Stranger Creek.	OK	OK
48	FLT48-1PH	*Single phase fault and sequence like previous*	OK	OK
49	FLT49-3PH	3 phase fault on the Craig (542977) to Stranger Creek (532772) 345kV line, near Craig.	OK	OK
50	FLT50-1PH	*Single phase fault and sequence like previous*	OK	OK
51	FLT51-3PH	3 phase fault on the West Gardner (542965) to Craig (542977) 345kV line, near West Gardner.	OK	OK
52	FLT52-1PH	*Single phase fault and sequence like previous*	OK	OK
53	FLT53-3PH	3 phase fault on the West Gardner (542965) to Swissvale (532774) 345kV line, near West Gardner.	OK	OK
54	FLT54-1PH	*Single phase fault and sequence like previous*	OK	OK
55	FLT55-3PH	3 phase fault on the Stilwell (542968) to West Gardner (542965) 345kV line, near Stilwell.	OK	OK
56	FLT56-1PH	*Single phase fault and sequence like previous*	OK	OK
57	FLT57-3PH	3 phase fault on the Stilwell (542968) to Lacygne (542981) 345kV line, near Stilwell.	OK	OK
58	FLT58-1PH	*Single phase fault and sequence like previous*	OK	OK
59	FLT59-3PH	3 phase fault on the Lacygne (542981) to West Gardner (542965) 345kV line, near Lacygne.	OK	OK
60	FLT60-1PH	*Single phase fault and sequence like previous*	OK	OK
61	FLT61-3PH	3 phase fault on the Lacygne (542981) to Wolf Creek (532797) 345kV line, near Lacygne.	OK	OK
62	FLT62-1PH	*Single phase fault and sequence like previous*	OK	OK
63	FLT63-3PH	3 phase fault on the Lacygne (542981) to Neosho (532793) 345kV line, near Lacygne.	OK	OK
64	FLT64-1PH	*Single phase fault and sequence like previous*	OK	OK

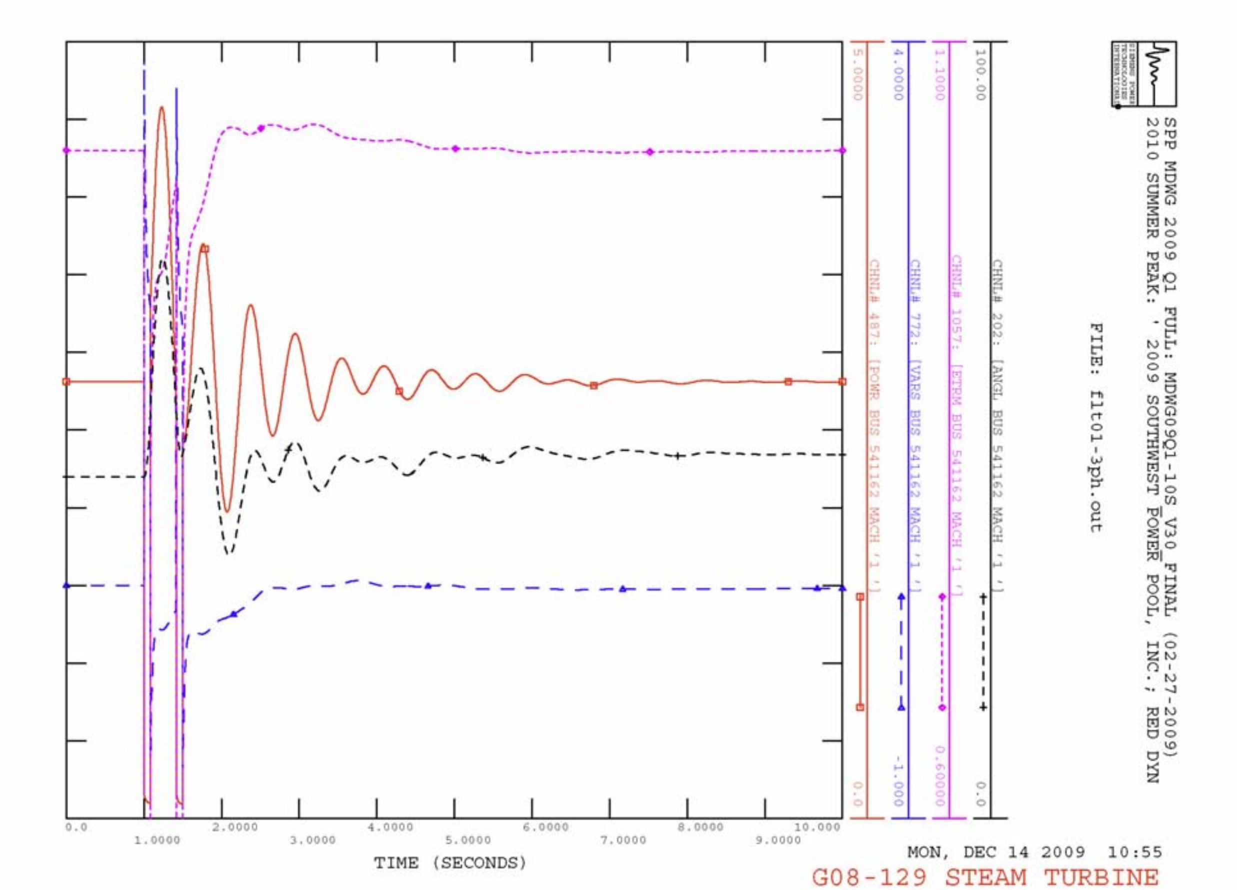

Figure 4-1. **GEN-2008-129 Steam Turbine Plot for Fault 01, a 3 phase fault on the Pleasant Hill – Longview 161 kV line, near Pleasant Hill**

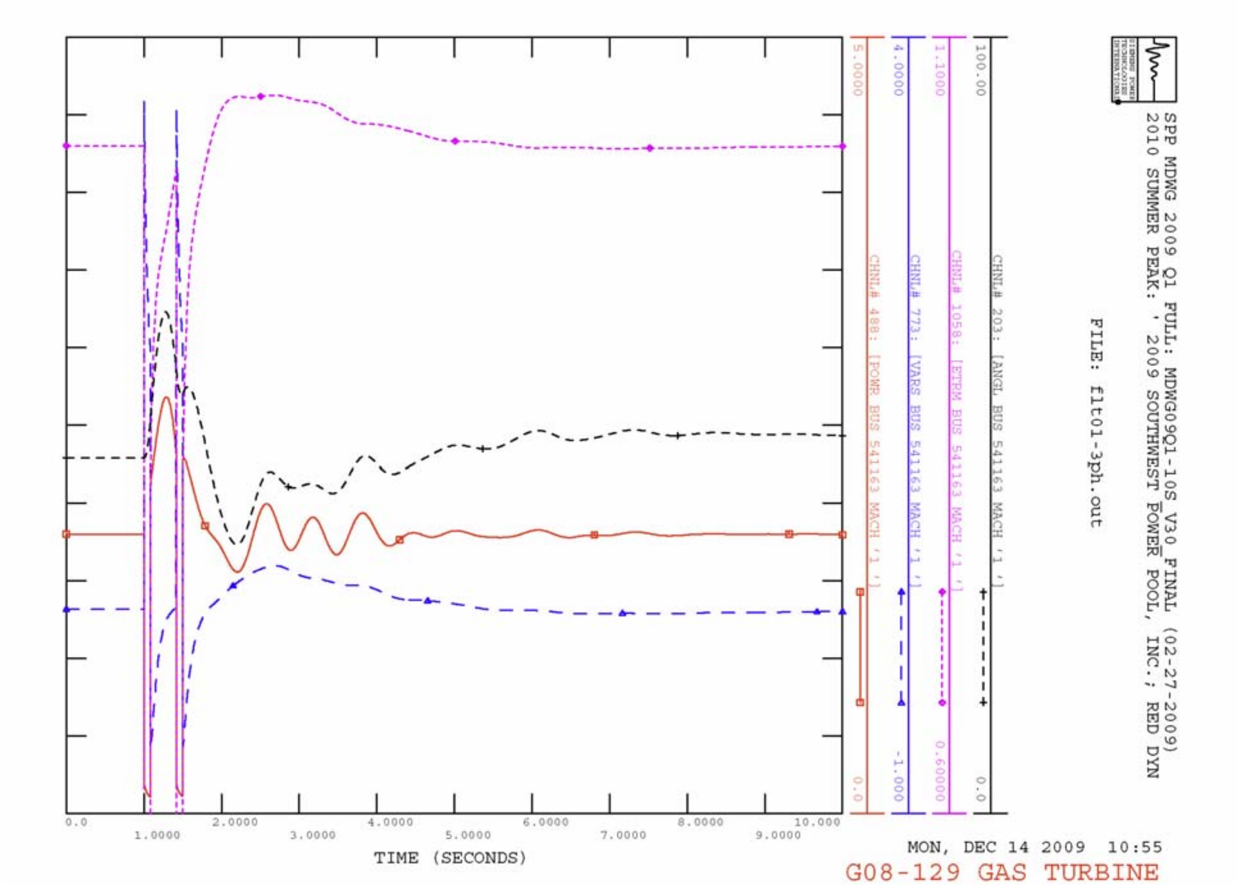

Figure 4-2. GEN-2008-129 Gas Turbine Plot for Fault 01, a 3 phase fault on the Pleasant Hill – Longview 161 kV line, near Pleasant Hill

4.2 Generator Performance

Study project GEN-2008-129 has synchronous generators for the two gas turbines and the steam turbine. While stable, the gas turbine excitation system responds rather slowly after fault clearing. The terminal voltage overshoots to more than 106% and takes approximately 3 seconds to come back to steady state. See for example Figure 4-2 above. The project developer should provide updated and accurate dynamic model parameters when the units are commissioned.

Prior-queued project GEN-2007-053 uses Gamesa 2.0 MW wind turbines. The power and speed of these generators oscillates long after a fault is cleared. See for example the plot for fault 39 in Figure 4-3 below. It is not known if these oscillations would occur in the actual wind turbine generators or if this is simply an inaccuracy of the Gamesa wind turbine dynamic model. It is not expected that these oscillations are due to the addition of the study project GEN-2008-129.

The other prior-queued projects perform well for all faults, with no tripping evident.

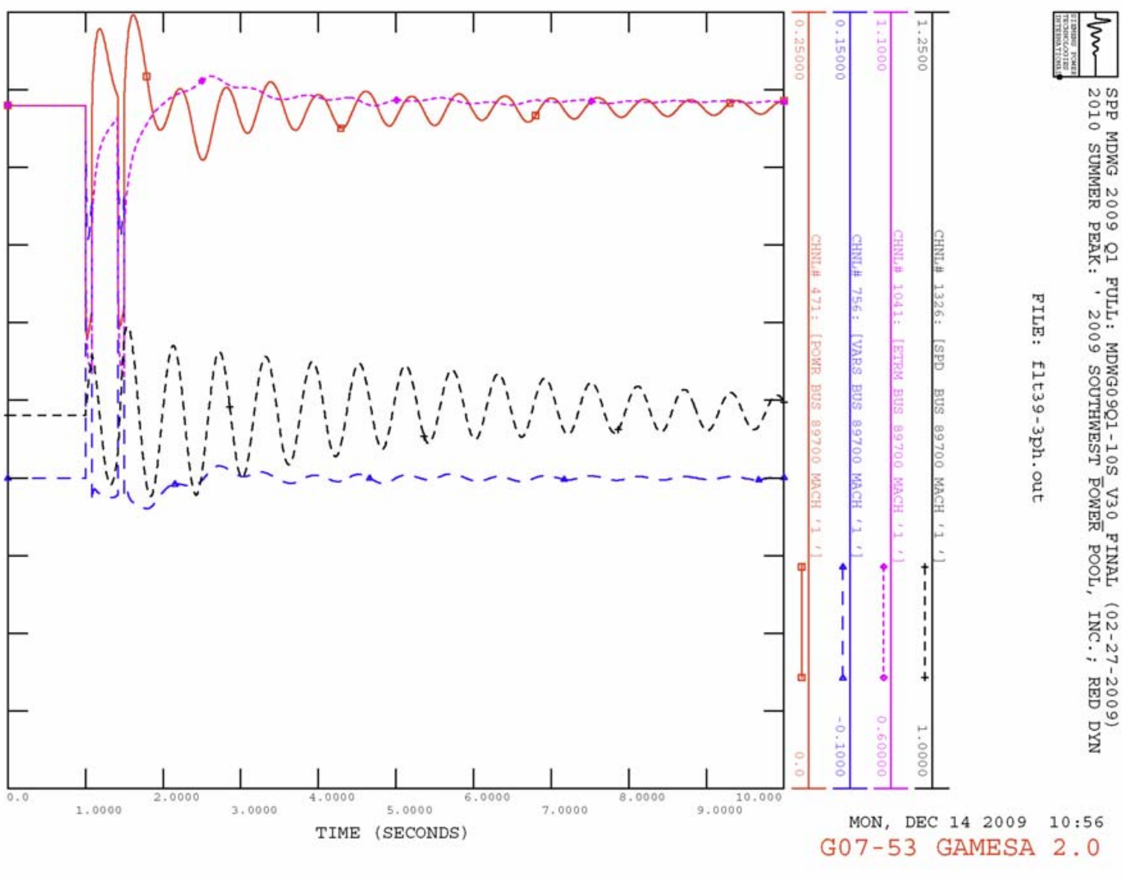

Figure 4-3. GEN-2007-053 Plot for Fault 39, a 3 phase fault on the Nashua to St. Joseph 345 kV line, near Nashua

4.3 Power Factor Requirements

There are no wind farms in Group 13, so no power factor test was performed.

The standard requirement for synchronous generators such as those in GEN-2008-129 is 0.95 lagging to 0.95 leading at the POI.

The final power factor requirements are shown in Table 4-2 below. These are only the minimum power factor ranges. A project developer may install more capability than this if desired.

Table 4-2. Power Factor Requirements [1]

Request	MW Sum/Win	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2008-129	641/675	Combined Cycle	Pleasant Hill 161kV	0.95	0.95

Notes:
1. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, and collector line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid "lags" behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
3. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid "leads" the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

5. Conclusions

The DISIS-2009-001 Group 13 Definitive Impact Study evaluated the impacts of interconnecting the project shown below.

Table 5-1. Interconnection Requests Evaluated

Request	MW Sum/Win	Turbine	Point of Interconnection
GEN-2008-129	641/675	Combined Cycle Gas	Pleasant Hill 161kV (541225)

No stability problems were found during summer or winter peak conditions due to the addition of these generators.

The standard power factor requirement for the synchronous generators of GEN-2008-129 is 0.95 leading to 0.95 lagging at the POI.

With the assumptions described in this report, DISIS-2009-001 Group 13 should be able to connect without causing any stability problems on the SPP transmission grid.

Appendix A – Summer Peak Plots

See attachment.

Appendix B – Winter Peak Plots

See attachment.

Appendix C – Power Factor Details

None required because no wind farms in study group.

Appendix D – Project Model Data

See attachment.