Southwest Power Pool

GEN-2009-011
Impact Restudy

SPP Generation
Interconnection Studies

GEN-2009-011

February 2011

Executive Summary

This report contains the findings of a restudy of GEN-2009-011. The GEN-2009-011 interconnection request was studied as part of the DISIS-2009-001 Definitive Impact Study, Cluster Group #11, which was originally posted in January 2010. The original report showed that GEN-2009-011 did not require dynamic reactive compensation The final PF requirements of the original report at the point of interconnection were 0.99 (Lagging) and 1.0 (Leading).

This restudy was performed solely to evaluate the effects of a turbine manufacturer change of switching wind turbine manufacturers from Gamesa (2.0MW) for 50MW to Siemens (20 x 2.3MW and 1 x 3.0MW) for 49MW. The requested In-Service Date is 7/31/2011. This in service date cannot be accommodated. This study looked at interconnection at Plainville – Phillipsburg 115kV with and interconnection injection of 49MW. The restudy results for the final PF requirements at the point of interconnection are 1.0 (Lagging) and 0.953 (Leading) with no need for dynamic reactive compensation in addition to the wind turbine capability.

The findings of the restudy show that for no stability problems were found during summer or winter peak conditions due to the addition of these generators.

Power factor requirements were determined as shown in 5-3 of the report below. However, any change in wind turbine model or controls could change the results.

With the assumptions outlined in this report, GEN-2009-011 should be able to reliably connect to the SPP transmission grid once all required network upgrades are completed as required in the DISIS-2009-001 Impact Study. These requirements include the Priority Projects which are slated for an in service date of 12/31/2014.

Nothing in this study should be construed as a guarantee of transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS by the Customer.

Final Report

For

Southwest Power Pool

From

S&C Electric Company

INTERCONNECTION IMPACT STUDY (RESTUDY)

OF

GEN-2009-011

S&C Project No. 5160

February 18, 2011

S&C Electric Company

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Report Revision History:

Date of Report	Issue	Comments
February 14, 2011	Rev. A	Draft report for review and comments
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EXECUTIVE SUMMARY

S&C Electric Company performed an interconnection impact study for GEN-2009-011 in response to a request for a re-study through the Southwest Power Pool (SPP) Tariff studies. GEN-2009-011 is a proposed 50 MW wind farm project in Kansas, which would tap the existing Plainville to Phillipsburg 115 kV line. GEN-2009-011 and prior queued projects were studied at 100% of rated power output using 2010/2011 summer and winter peak loading cases provided by SPP. Wind farms at remote locations with low wind penetration were studied at 20% of rated power output. GEN-2009-011 was studied with twenty (20) Siemens SWT 2.3 VS (2.3 MW) wind turbine generators and a single Siemens SWT 3.0 VS (3 MW) wind turbine generator.

Power factor analysis results for SPP outage contingencies indicate that, in order to maintain the voltage at the Plainville to Phillipsburg 115 kV tap to pre-outage voltage levels, GEN-2009-011 must be capable of operating within the following power factor limits:

- 99.88% leading (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the Concordia 230/115 kV transformer in the 2010/2011 summer peak case.
- 95.30% leading (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the GEN-2009-011 to Plainville 115 kV line in the 2010/2011 winter peak case.

Transient stability analysis results for three-phase and single-line-to-ground fault disturbances specified by SPP show that nearby areas will retain angular, frequency and voltage stability post fault for both summer and winter cases. GEN-2009-011 and prior queued wind farm projects will ride through each fault contingency.

There is no need for a STATCOM or SVC for dynamic reactive power support.

GEN-2009-011 can successfully interconnect into the transmission system at the desired location without reduction in output power for the SPP fault disturbance contingencies.

1. INTRODUCTION

S&C Electric Company performed an interconnection impact study for GEN-2009-011 in response to a request for a re-study through the Southwest Power Pool (SPP) Tariff studies. GEN-2009-011 is a proposed 50 MW wind farm project in Kansas, which would tap the existing Plainville to Phillipsburg 115 kV line. GEN-2009-011 and prior queued projects in the SPS area were studied at 100% of rated power output using 2010/2011 summer and winter peak loading cases provided by SPP. Wind farms at remote locations with low wind penetration were studied at 20% of rated power output. GEN-2009-011 was studied with twenty (20) Siemens SWT 2.3 VS wind turbine generators and a single Siemens SWT 3.0 VS wind turbine generator (WTG).

2 TRANSMISSION SYSTEM AND STUDY AREA

The wind generation projects in GEN-2009-011 will interconnect into the Mid Kansas Electric Company, LLC (MKEC) transmission system. The following areas were also monitored:

Midwest Energy, Inc. (MIDW)

AEP West (AEPW)

Oklahoma Gas and Electric (OKGE)

Western Farmers Electric Cooperative (WFEC)

Sunflower Electric Power Company (SUNC)

Westar Energy, Inc (WERE)

Southwestern Public Service (SPS)

Nebraska Public Power District (NPPD)

Lincoln Electric System (LES)

3. POWER FLOW BASE CASES

The following power flow base cases were provided by SPP:

MDWG_2010_2011SP_DISIS-2010-001-G11.sav – 2010/2011 summer peak, which includes aggregate representation of prior queued projects at 100% of rated output power and wind turbine generators (WTGs) for GEN-2009-011 from a previous study. Other cluster projects were also included with wind farms at 20% of rated output power.

MDWG_2010_2011WP_DISIS-2010-001-G11.sav – 2010/2011 winter peak, which includes aggregate representation of prior queued projects at 100% of rated output power and WTGs for GEN-2009-011 from a previous study. Other cluster projects were also included with wind farms at 20% of rated output power.

4 POWER FLOW MODEL

GEN-2009-011 and prior queued projects were modeled as aggregates of wind turbine generators. The aggregate models were part of the base case supplied by SPP. However, the GEN-2009-011 model that was included in the base case was represented differently in the previous study. The 34.5 kV collector cable system was left unmodified, but the equivalent wind turbine generator was replaced by one conventional generator representing the Siemens SWT 3.0 MW WTG and another generator representing the twenty (20) Siemens SWT 2.3 MW WTGs. The equivalent GSU transformer was also replaced with a 3.4 MVA transformer for the single SWT 3.0 MW turbine and a 52 MVA transformer equivalent for the twenty (20) 2.6 MVA GSU transformers associated with the SWT 2.3 MW WTGs.

4.1 Siemens SWT Wind Turbine Generators

The SWT WTG consists of a rotor, gearbox, induction generator, machine bridge, DC link, and network bridge. The machine bridge and network bridge decouple the generator from the power system and allows the WTG to operate at a definite power factor setpoint. The power factor range of operation in steady-state and dynamically is variable and is a function of the voltage at the generator terminals and the active power output of the generator. At rated output power and at nominal terminal voltage, the output power factor range varies from 90% leading (inductive) to 90% lagging (capacitive) power factor. The lagging power factor range is reduced if the terminal voltage is higher than nominal. The leading power factor range is reduced if the terminal voltage is less than nominal and increased if the terminal voltage is greater than nominal.

For the power factor analysis, the generators were set to control their terminal voltage to nominal (i.e. 0.69 kV).

5. POWER FACTOR REQUIREMENTS AT THE POINT OF INTERCONNECTION (POI)

SPP has specific voltage requirements for interconnecting wind farms. The project is required to maintain the voltage at the POI to nominal or base case voltage level, whichever is higher, for single transmission facility outage contingencies. The contingencies were specified by SPP. The POI for GEN-2009-011 is tap on the Plainville to Phillipsburg 115 kV line.

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.	Description
0	System Intact
1	Outage of the Setab 345kV (531465) to 115kV (531464) transformer
2	Outage of the Mingo (531451) to Red Willow (640325) 345kV line
3	Outage of the Mingo 345kV (531451) to 115kV (531429) transformer
4	Outage of the Post Rock (530583) to Gen-2010-016 (576704) 345kV line
5	Outage of the Post Rock (530583) to Axtell (640065) 345kV line
6	Outage of the Knoll (530558) to Smoky Hills (530592) 230kV line
7	Outage of the Post Rock (530584) to South Hays (530582) 230kV line
8	Outage of the Post Rock (530584) to Knoll (530558) 230kV line
9	Outage of the POSTROCK6 (530584) to 345kV POSTROCK7 (530583) transformer
10	Outage of one circuit of the Knoll 230kV (530558) to 115kV (530561) transformer
11	Outage of the Knoll (530561) to Saline (530551) 115kV line
12	Outage of the Knoll (530561) to Redline (530605) 115kV line
13	Outage of the South Hays (530582) to Mullergren (539679) 230kV line
14	Outage of the Knoll (530561) to N Hays (530581) 115kV line
15	Outage of the Pioneer Tap (539642) to Mullergren (539678) 115kV line
16	Outage of the Heizer (530563) 69kV – Heizer (530601) 115kV transformer
17	Outage of one circuit of the Heizer (530601) 115kV – Mullergren (539679) 230kV transformer
18	Outage of the Mullergren (539679) 230kV – GRTBEND3 (539678) 115kV transformer
19	Outage of the S. Hays (530582) 230kV – S. Hays (530553) 115kV transformer
20	Outage of the Concordia (539657) 115kV – Concordia (532658) 230kV transformer
21	Outage of the Mullergren (539679) – Circle (532871) 230kV line
22	Outage of the Mullergren (539679) – Spearville (539695) 230kV line
23	Outage of the Graham (531386) – Beach Station (530557) 115kV line
24	Outage of the Hoxie (530556) – Beach Station (530557) 115kV line
25	Outage of the GEN-2009-011 (570911) – Phillipsburg (539685) 115kV line
26	Outage of the GEN-2009-011 (570911) – Plainville (539686) 115kV line

The base case voltages at the point of interconnection for summer and winter are listed in Table 5.2.

Table 5.2: Base Case Voltage at the Point of Interconnection

Point of Interconnection	Summer Peak 2010/2011 (pu)	Winter Peak 2010/2011 (pu)
Plainville (539686) to Phillipsburg (539685) 115kV tap (570911)	1.00	1.01

The power factor required to maintain the voltage schedule of Table 5.2 at the POI for the contingencies listed in Table 5.1 is summarized in Table 5.3.

Table 5.3: Power Factor Requirements at the POI for Outage Contingencies in Table 5.1

	Summer				Winter			
Cont. No.	P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor	
0	48.2	-9.0	98.30%	leading	48.1	-11.9	97.07%	leading
1	48.2	-9.0	98.30%	leading	48.1	-11.8	97.12%	leading
2	48.2	-8.7	98.41%	leading	48.1	-11.1	97.44%	leading
3	48.1	-5.8	99.28%	leading	48.1	-11.4	97.30%	leading
4	48.1	-5.1	99.44%	leading	48.1	-6.6	99.07%	leading
5	48.2	-7.7	98.75%	leading	48.1	-10.3	97.78%	leading
6	48.2	-7.6	98.78%	leading	48.1	-10.7	97.61%	leading
7	48.1	-6.5	99.10%	leading	48.1	-8.6	98.44%	leading
8	48.1	-4.2	99.62%	leading	48.1	-6.7	99.04%	leading
9	48.2	-8.0	98.65%	leading	48.1	-10.9	97.53%	leading
10	48.1	-5.3	99.40%	leading	48.1	-6.8	99.02%	leading
11	48.2	-6.9	98.99%	leading	48.1	-3.2	99.78%	leading
12	48.2	-4.4	99.59%	leading	48.1	-9.4	98.14%	leading
13	48.2	-4.0	99.66%	leading	48.1	-7.1	98.93%	leading
14	48.2	-9.7	98.03%	leading	48.1	-12.6	96.74%	leading
15	48.2	-4.9	99.49%	leading	48.1	-8.9	98.33%	leading
16	48.2	-9.0	98.30%	leading	48.1	-11.8	97.12%	leading
17	48.2	-9.0	98.30%	leading	48.1	-11.9	97.07%	leading
18	48.2	-7.4	98.84%	leading	48.1	-11.2	97.39%	leading
19	48.2	-7.5	98.81%	leading	48.1	-11.2	97.39%	leading
20	48.2	-2.4	99.88%	leading	48.1	-4.8	99.51%	leading
21	48.2	-8.3	98.55%	leading	48.1	-11.2	97.39%	leading
22	48.2	-7.7	98.75%	leading	48.1	-10.6	97.66%	leading
23	48.2	-7.0	98.96%	leading	48.1	-12.0	97.03%	leading
24	48.2	-7.8	98.72%	leading	48.1	-11.0	97.48%	leading
25	48.2	-7.3	98.87%	leading	48.1	-4.9	99.49%	leading
26	48.2	-10.9	97.54%	leading	48.1	-15.3	95.30%	leading

The results above indicate that the project must be able to operate at the following extreme power factors cases:

- 99.88% leading (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the Concordia 230/115 kV transformer (contingency #20) in the 2010/2011 summer peak case.
- 95.30% leading (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the GEN-2009-011 to Plainville 115 kV line (contingency #26) in the 2010/2011 winter peak case.

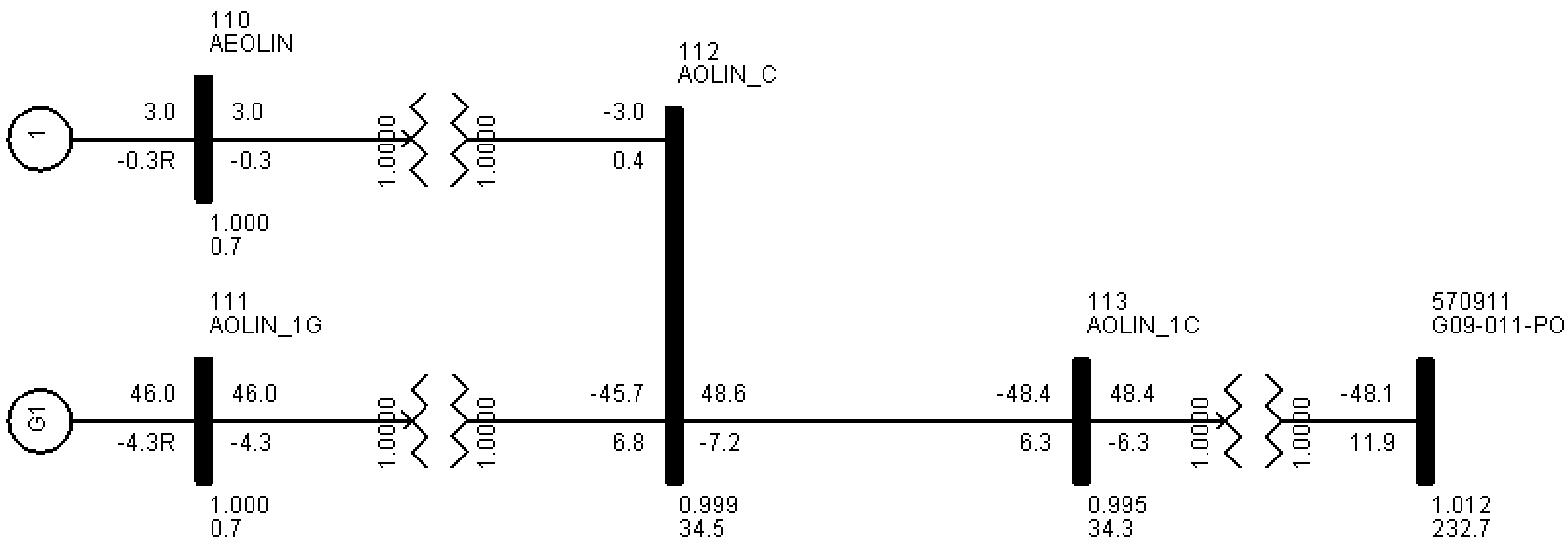

Figure 5.1: Power Flow Diagram of GEN-2009-011 for Normal System Condition (Winter Peak)

6. Transient Stability Analysis

Transient stability analysis was performed for the fault contingencies listed in Table 6.1, which were specified by SPP.

Table 6.1: SPP fault contingencies

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3-phase fault on the Setab 345kV (531465) to 115kV (531464) 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.
2	FLT02-3PH	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.
3	FLT03-1PH	Single phase fault on the line in previous fault. a. Apply fault. 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	FLT04-3PH	3-phase fault on the Mingo 345kV (531451) to 115kV (531429) 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.
5	FLT05-3PH	3-phase fault on the Post Rock (530583) to Gen-2010-016 (576704) 345kV line, near Post Rock. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
6	FLT06-1PH	Single phase fault on the line in previous fault. a. Apply fault. 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.
7	FLT07-3PH	3-phase fault on the Post Rock (530583) to Axtell (640065) 345kV line, near Post Rock. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
8	FLT08-1PH	Single phase fault on the line in previous fault. a. Apply fault. 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.
9	FLT09-3PH	3-phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Smoky Hills.. a. Apply fault at the Smoky Hills 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.

Cont. No.	Cont. Name	Description
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3-phase fault on the Post Rock (530584) to South Hays (530582) 230kV line, near Post Rock. a. Apply fault at the Post Rock 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.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3-phase fault on the Post Rock (530584) to Knoll (530558) 230kV line, near Post Rock. a. Apply fault at the Post Rock 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.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3-phase fault on the POSTROCK6 (530584) to 345kV POSTROCK7 (530583) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
16	FLT16-3PH	3-phase fault on one circuit of 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.
17	FLT17-3PH	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.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	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.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	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.
22	FLT22-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
23	FLT23-3PH	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.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	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.
26	FLT26-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3-phase fault on the Heizer (530563) 69kV – Heizer (530601) 115kV transformer on the 115kV bus a. Apply fault at the Heizer 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
30	FLT30-3PH	3-phase fault on one circuit of the Heizer (530601) 115kV – Mullergren (539679) 230kV transformer on the 115kV bus a. Apply fault at the Heizer 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
31	FLT31-3PH	3-phase fault on the Mullergren (539679) 230kV – GRTBEND3 (539678) 115kV transformer on the 230kV bus a. Apply fault at the Mullergren 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
32	FLT32-3PH	3-phase fault on the S. Hays (530582) 230kV – S. Hays (530553) 115kV transformer on the 115kV bus a. Apply fault at the S. Hays 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
33	FLT33-3PH	3-phase fault on the Concordia (539657) 115kV – Concordia (532658) 230kV transformer on the 230kV bus a. Apply fault at the Concordia 230kV bus b. Clear fault after 5 cycles by tripping the faulted line.
34	FLT34-3PH	3-phase fault on the Mullergren (539679) – 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.
35	FLT35-1PH	*Single phase fault and sequence like previous*
36	FLT36-3PH	3-phase fault on the Mullergren (539679) – Spearville (539695) 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.
37	FLT37-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
38	FLT38-3PH	3-phase fault on the Graham (531386) – Beach Station (530557) 115kV line, near Graham. a. Apply fault at the Graham 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.
39	FLT39-1PH	*Single phase fault and sequence like previous*
40	FLT40-3PH	3-phase fault on the Hoxie (530556) – Beach Station (530557) 115kV line, near Hoxie. a. Apply fault at the Hoxie 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.
41	FLT41-1PH	*Single phase fault and sequence like previous*
42	FLT42-3PH	3-phase fault on the GEN-2009-011 (570911) – Phillisburg (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.
43	FLT43-1PH	*Single phase fault and sequence like previous*
44	FLT44-3PH	3-phase fault on the GEN-2009-011 (570911) – Plainville (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.
45	FLT45-1PH	*Single phase fault and sequence like previous*

Single line to ground faults were simulated in a manner consistent with currently-accepted practices, which is to assume that a single line to ground will cause a voltage drop at the fault location of 60% of nominal.

The prior-queued projects monitored are listed in Table 6.2.

Table 6.2: Prior Queued Projects Monitored

Request	Size (MW)	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)
GEN-2008-092	200	GE 1.5MW	Knoll 230kV (530558)

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 generators 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 Siemens SWT Wind Turbine Generators

Dynamic simulations used Version 1 of the generic WT4 user model available in PSS/E 30.3.3. Default voltage and frequency relay settings were used to evaluate low voltage ride through (LVRT) capabilities of GEN-2009-011.

Table 6.3: Siemens SWT Voltage and Frequency Protection Settings

Protection Element	Descrition	Setting
Undervoltage Level 1	VL, lower voltage threshold (pu)	0.85
	TP, relay pickup time (sec)	3
Undervoltage Level 2	VL, lower voltage threshold (pu)	0.7
	TP, relay pickup time (sec)	2.6
Undervoltage Level 3	VL, lower voltage threshold (pu)	0.4
	TP, relay pickup time (sec)	1.6
Undervoltage Level 3	VL, lower voltage threshold (pu)	0.15
	TP, relay pickup time (sec)	0.85
Overvoltage Level 1	VU, upper voltage threshold (pu)	1.1
	TP, relay pickup time (sec)	1
Overvoltage Level 2	VU, upper voltage threshold (pu)	1.2
	TP, relay pickup time (sec)	0.15
Underfrequency Level 1	FL, lower frequency threshold	57
	TP, relay pickup time (sec)	10
Underfrequency Level 2	FL, lower frequency threshold	56.4
	TP, relay pickup time (sec)	0.1
Overfrequency Level 1	FU, upper frequency threshold	62.4
	TP, relay pickup time (sec)	0.1

6.3 Transient Stability Results

Undisturbed runs of 10 seconds were performed for the summer and winter peak cases to verify proper initialization of dynamic models. GEN-2006-046, which is dispatched in the summer and winter power flow cases at 20% of rated output power, failed to initialize properly and disconnected during initialization. At reduced generator output, the Mitsubishi MWT-92/95 model identifies the initial condition as suspect. This problem has been discussed with SPP previously. The presence or absence of GEN-2006-046 has little impact on the results due to its low penetration into the MKEC area.

Results show that GEN-2009-011 and prior-queued projects will ride through each fault disturbance listed in Table 6.1 for both the summer and winter peak case.

Voltage, frequency and angular stability will be retained post-fault. Transient stability plots of the undisturbed run and fault contingencies #1 through #45 for summer and winter can be found in Appendices A and B. The complete set of stability plots can be found in Appendices C and D. The channel data is based on the bus numbers listed in Table 6.1 and Table 6.4. Transient stability results are summarized in Table 6.5.

Table 6.4: Bus Numbers for Transient Stability Plots

Interconnection Request Projects	Bus numbers		
	POI	WTG	
GEN-2009-011	570911	111	110
GEN-2003-006A	539639	574013	574015
GEN-2003-019	530592	579094	579095
GEN-2006-031	530561	56626	
GEN-2006-032	530582	560897	
GEN-2008-092	530558	922	923

Table 6.5: Transient Stability Results Summary

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
0	UNFAULTED	STABLE	STABLE
1	FLT01-3PH	STABLE	STABLE
2	FLT02-3PH	STABLE	STABLE
3	FLT03-1PH	STABLE	STABLE
4	FLT04-3PH	STABLE	STABLE
5	FLT05-3PH	STABLE	STABLE
6	FLT06-1PH	STABLE	STABLE
7	FLT07-3PH	STABLE	STABLE
8	FLT08-1PH	STABLE	STABLE
9	FLT09-3PH	STABLE	STABLE
10	FLT10-1PH	STABLE	STABLE
11	FLT11-3PH	STABLE	STABLE
12	FLT12-1PH	STABLE	STABLE
13	FLT13-3PH	STABLE	STABLE
14	FLT14-1PH	STABLE	STABLE
15	FLT15-3PH	STABLE	STABLE
16	FLT16-3PH	STABLE	STABLE
17	FLT17-3PH	STABLE	STABLE
18	FLT18-1PH	STABLE	STABLE
19	FLT19-3PH	STABLE	STABLE
20	FLT20-1PH	STABLE	STABLE
21	FLT21-3PH	STABLE	STABLE
22	FLT22-1PH	STABLE	STABLE
23	FLT23-3PH	STABLE	STABLE
24	FLT24-1PH	STABLE	STABLE
25	FLT25-3PH	STABLE	STABLE
26	FLT26-1PH	STABLE	STABLE
29	FLT29-3PH	STABLE	STABLE
30	FLT30-3PH	STABLE	STABLE
31	FLT31-3PH	STABLE	STABLE
32	FLT32-3PH	STABLE	STABLE
33	FLT33-3PH	STABLE	STABLE
34	FLT34-3PH	STABLE	STABLE
35	FLT35-1PH	STABLE	STABLE
36	FLT36-3PH	STABLE	STABLE
37	FLT37-1PH	STABLE	STABLE
38	FLT38-3PH	STABLE	STABLE
39	FLT39-1PH	STABLE	STABLE
40	FLT40-3PH	STABLE	STABLE
41	FLT41-1PH	STABLE	STABLE
42	FLT42-3PH	STABLE	STABLE
43	FLT43-1PH	STABLE	STABLE
44	FLT44-3PH	STABLE	STABLE
45	FLT45-1PH	STABLE	STABLE

7. Conclusions and Recommendations

Transient analysis results indicate that GEN-2009-011 can successfully interconnect into the transmission system at 100% output power and at the desired location.

GEN-2009-011 must meet the following power factor requirements at the POI:

- 99.88% lagging (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the Concordia 230/115 kV transformer (contingency #20) in the summer 2010/2011 peak case.
- 95.30% lagging (inductive) power factor at the Plainville to Phillipsburg 115 kV tap for an outage of the GEN-2009-011 – Plainville 115kV line (contingency #26) in the winter 2010/2011 peak case.