SPP
Southwest
Power Pool

Impact Re-Study
For
Generation Interconnection
Request
GEN-2006-046

SPP Generation
Interconnection Studies

(#GEN-2006-046)

October 2010

Summary

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), AMEC Earth and Environmental (AMEC) performed the following Impact restudy to satisfy the Impact Study Agreement executed by the requesting Customer and SPP for SPP Generation Interconnection request #GEN-2006-046. This generation interconnection request was last studied with Mitsubishi 2.3 MW wind turbines. The Customer has subsequently asked for a restudy assuming the facility will contain GE 1.6 MW wind turbines.

The purpose of this restudy is to evaluate the Customer's request to use the GE 1.6 MW wind turbines for the proposed generation. This study addressed the stability and reactive compensation required for the GE wind turbines. The stability study shows that the interconnection of the proposed project does not have any adverse impact on the system stability in the SPP area.

GEN-2006-046 Restudy

October 8, 2010

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EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) has a requested a restudy of a generator interconnection request for a 138 kV interconnection of a 130 MW wind farm in Dewey County, Oklahoma. This wind farm will be interconnected into the existing Dewey 138kV substation. The interconnection customer has asked for a study case of 100% MW output (with dynamic reactive compensation if required). This substation is owned by Oklahoma Gas & Electric (OKGE). The request was previously studied for Mitsubishi 2.3 MW turbines but is now being studied for GE 1.6 MW turbines.

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2006-046	130	GE 1.6 MW	Dewey 138kV (514787)

The case will contain the following previous queued and later queued requests. These projects should be monitored and their generating status shall be reported for each contingency. The projects are as follows:

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2001-014	94	Suzlon 2.1MW	Fort Supply 138kV (520920)
GEN-2001-037	102	GE 1.5MW	Woodward-Mooreland 138kV (515785)
GEN-2002-005	120	Acciona 1.5MW	Moorewood – Elk City 138kV (521116)
GEN-2005-008	120	GE 1.5MW	Woodward 138kV (514785)
GEN-2006-024S	18.9	Suzlon 2.1MW	Buffalo Bear 69kV (521120)
GEN-2007-006	160	Suzlon 2.1MW	Roman Nose 138kV (514823)

SPP requested a stability analysis and a power factor analysis as part of the restudy of GEN-2006-046. 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. GEN-2001-014 trips offline due to high voltage at the generator bus for faults FLT21-3PH and FLT22-1PH (Mooreland-Iodine 138 kV near Iodine). However, this occurs even with GEN-2006-046 offline. Proper coordination of capacitors and LTCs at Fort Supply may alleviate this high voltage concern.

All generators in the monitored area remain stable during disturbances.

GEN-2006-046 has the capability of pre-contingency voltage recovery, except that a dynamic simulation of the worst-case fault from a voltage standpoint, FLT25/FLT26 (El Reno-Roman

Nose 138 kV) caused the post-contingency voltage at the GEN-2006-046 POI to recover to 0.996-0.998 pu without reactive compensation.

Low Voltage Ride Through (LVRT) analysis shows no generators tripping due to low voltage. The previous voltage-related tripping of GEN-2001-014 in the winter case was due to high voltage (1.2 PU for 0.08 seconds.)

The power factor analysis indicated that supplemental reactive capability would be necessary in accordance with the study requirements: all queued generation at the POI will be represented as equivalent generators modeled at the POI transmission bus. These generators were modeled at rated MW output and unity power factor. Supplemental reactive capability was then added as needed to maintain post-contingency bus voltages at the POI of 1.0 PU.

The results of the power factor study indicate that roughly 24 Mvar of equivalent capacitive reactive compensation is required at the Dewey 138kV bus to maintain post contingency bus voltages at 1.0 PU. It will be left to the customer to determine if this reactive capability shall be provided utilizing turbine capacity and/or with supplemental reactive compensation.

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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 restudy the impact of generator GEN-2006-046 in the SPP interconnection queue. The site studied is in Dewey County in central Oklahoma. This restudy is at the customer's request based on the replacement of Mitsubishi 2.3 MW turbines with GE 1.6 MW turbines.

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

SPP requested a power factor analysis and stability analysis based on a list of faults provided by SPP. The results of this study

a. Determined the equivalent amount of reactive compensation required at the 138kV POI to maintain adequate post contingency voltage with GEN-2006-046 modeled at the 138kV POI bus with 0 Var output.

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.

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	2011 Summer Peak		2009 Winter Peak	
		Load (MW)	Generation (MW)	Load (MW)	Generation (MW)
520	AEPW	10246.6	9441.9	7879.9	7004.7
524	OKGE	5949.6	7312.5	4190.8	4961.1
525	WFEC	1415.9	1342.5	1306.5	1175.7
526	SPS	5620.1	5438.9	4042.6	3993.9
531	MIDW	259.6	6.1	198.3	21.0
534	SUNC	547.3	578.0	448.7	569.7
536	WERE	5946.9	5851.8	3947.6	4133.0

- **POWER FACTOR ANALYSIS**

A power factor analysis was performed to determine if additional reactive compensation was required to hold the voltage at the point of interconnection consistent with the voltage schedule in the base case or 1.0 PU, whichever is higher. The equivalent wind farm model of GEN-2006-046 was disconnected from the point of interconnection as were any previously queued generation interconnection requests at the point of interconnection. A generator with the equivalent real power MW and no reactive capability was modeled for each interconnection request at the POI. A var generator was modeled at each queued wind farm's substation high voltage bus POI. These var generators were set to hold a voltage schedule at the POI consistent with the voltage schedule provided in the base case or 1.0 PU voltage (whichever is higher).

A list of contingencies shown in Table 2 was simulated. Additional reactive compensation was modeled at the 138kV side of the POI of the wind farm collector substation to maintain 1.00 PU post contingency bus voltage.

Table 2: Steady-State Contingency Descriptions

Cont No.	Description
FLT01	Dewey (514787) to Iodine (514796) 138kV line
FLT03	Dewey (514787) to Taloga (521065) 138 kV line
FLT05	Dewey (514787) to Southard (514822) 138 kV line
FLT07	Elk City (511458) to Red Hills Wind (xx) 138 kV line
FLT09	Mooreland (520999) – Cedardale (520848) 138 kV
FLT11	Mooreland (520999) – Glass Mtn. (514788) 138 kV line
FLT13	Woodward (514376) – Iodine (OG&E) (514796) 138kV line
FLT15	Cimarron autotransformer (514898-514901-515715)
FLT17	Woodring autotransformer (514715-514714-515770)
FLT19	Mooreland (520999) – GEN-2001-037 (515785) 138 kV line
FLT21	Mooreland (520999) – Iodine (520957) 138kV line
FLT23	Woodward (515375) to Tatonga (515407) 345kV line
FLT25	El Reno (514823) to Roman Nose (514819) 138kV line

Tables 3 contains the results of the powerflow analysis for each of the fault conditions specified in Table 2 for the summer and winter conditions. The table contains bus voltage at the POI and the supplemental reactive support from the equivalent var generator modeled at the POI 138kV substation bus.

Table 3: Voltage at POI and Supplemental Reactive

Cont. No.	GEN-2006-046					
	Summer			Winter		
	Voltage (PU)	P	Q	Voltage (PU)	P	Q
Base Case	1.023	130	0	1.031	130	0
FLT01	1.032	130	0	1.043	130	0
FLT03	1.028	130	0	1.037	130	0
FLT05	1.024	130	0	1.027	130	0
FLT07	1.014	130	0	1.024	130	0
FLT09	1.016	130	0	1.026	130	0
FLT11	1.017	130	0	1.027	130	0
FLT13	1.028	130	0	1.040	130	0
FLT15	1.022	130	0	1.034	130	0
FLT17	1.022	130	0	1.031	130	0
FLT19	1.021	130	0	1.030	130	0
FLT21	1.023	130	0	1.031	130	0
FLT23	1.014	130	0	1.026	130	0
FLT25	1.000	130	23.7	1.000	130	20.4

- **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.

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

Table 4: Fault Descriptions

Cont. No.	*Cont. Name*	*Description*
1	FLT01-3PH	3 phase fault on the Dewey (514787) to Iodine (514796) 138kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey to Iodine. 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 Cont. No. 1*
3	FLT03-3PH	3 phase fault on the Dewey (514787) to Taloga (521065) 138 kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey to Taloga. 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 Cont. No. 3*
5	FLT05-3PH	3 phase fault on the Dewey (514787) to Southard (514822) 138 kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey to Southard. 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 Cont. No. 5*
7	FLT07-3PH	3 phase fault on the Elk City (511458) to Red Hills Wind (xx) 138 kV line, near Elk City. a. Apply fault at the Elk City 138kV bus. b. Clear fault after 5 cycles by tripping the line from Elk City – GEN-2002-005T. 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.
8	FLT08-1PH	*Single phase fault and sequence like Cont. No. 7*
9	FLT09-3PH	3 phase fault on the Mooreland (520999) – Cedardale (520848) 138 kV line, near Cedardale. a. Apply fault at the Cedardale 138kV bus. b. Clear fault after 5 cycles by tripping the line from Mooreland - Cedardale. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single phase fault and sequence like Cont. No. 9*
11	FLT11-3PH	3 phase fault on the Mooreland (520999) – Glass Mtn. (514788) 138 kV line, near Mooreland. a. Apply fault at the Mooreland 138kV bus. b. Clear fault after 5 cycles by tripping the line from Mooreland – Glass Mtn. c. Wait 20 cycles, and then re-close the line in (b) back into the fault.

Cont. No.	*Cont. Name*	*Description*
		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 Cont. No.11*
13	FLT13-3PH	3 phase fault on the Woodward (514785) – Iodine (OG&E) (514796) 138kV line near Woodward. a. Apply fault at the Woodward bus. b. Clear fault after 5 cycles by tripping the line from Woodward-Iodine. 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 Cont. No.13*
15	FLT15-3PH	3 phase fault on the Cimarron autotransformer (514898-514901-515715) a. Apply fault at the Cimaron 138kV bus. b. Clear fault after 5 cycles by taking the auto out of service
16	FLT16-1PH	*Single phase fault and sequence like Cont. No.15*
17	FLT17-3PH	3 phase fault on the Woodring autotransformer (514715-514714-515770) a. Apply fault at the Woodring 138kV bus. b. Clear fault after 5 cycles by taking the auto out of service
18	FLT18-1PH	*Single phase fault and sequence like Cont. No.17*
19	FLT19-3PH	3 phase fault on the Mooreland (520999) – GEN-2001-037 (514785) 138 kV line, near Mooreland. a. Apply fault at the Mooreland 138kV bus. b. Clear fault after 5 cycles by tripping the line from Mooreland – GEN-2001-037. 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 Cont. No.19*
21	FLT21-3PH	3 phase fault on the Mooreland (520999) – Iodine (520957) 138kV line near Iodine. a. Apply fault at the Iodine bus. b. Clear fault after 5 cycles by tripping the line from Mooreland-Iodine. 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 Cont. No.21*
23	FLT23-3PH	3 phase fault on one of the Woodward (515375) to Tatonga (515378) 345kV lines, near Tatonga. a. Apply fault at the Woodward 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 Cont. No. 23*
25	FLT25-3PH	3 phase fault on one of the El Reno (514823) to Roman Nose () 138kV line, near El Reno. a. Apply fault at the El Reno 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.

Cont. No.	*Cont. Name*	*Description*
26	FLT26-1PH	*Single phase fault and sequence like Cont No. 25*

In order to simulate 1PH faults, equivalent shunt Mvar[1] were determined to be applied at the faulted buses. Table 5 presents equivalent reactors used in the transient stability study.

Table 5: Equivalent Shunt Mvar at Faulted Bus for Single-Line-to-Ground Faults

Fault No.	Faulted Bus No.	2011 Summer Peak (Mvar)	2011 Winter Peak (Mvar)
FLT02-1PH	514787	-1059.5	-1053.0
FLT04-1PH	514787	-1059.5	-1053.0
FLT06-1PH	514787	-1059.5	-1053.0
FLT08-1PH	511458	-1240.0	-1269.2
FLT10-1PH	520848	-817.6	-820.5
FLT12-1PH	520999	-2578.2	-2420.7
FLT14-1PH	515376	-1666.8	-1626.6
FLT16-1PH	514898	-6267.6	-5838.6
FLT18-1PH	514714	-2468.6	-2478.7
FLT20-1PH	520999	-2578.2	-2420.7
FLT22-1PH	520999	-2578.2	-2420.7
FLT24-1PH	515407	-2047.3	-1983.5
FLT26-1PH	514819	-2495.3	-2465.2

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 5. The wind farm capability of post-fault voltage recovery at the POI was also checked.

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

3. PROJECT DESCRIPTION

Following is a table of the proposed wind farms in Group 1.

Table 6: Points of Interconnection for Group 1

Request	Size (MW)	Turbine Model	Point Of Interconnection	
			Bus No.	Bus Name in model
GEN-2006-046	130	GE 1.6MW	514787	Dewey 138

The one-line diagram of GEN-2006-046 in Figure 1 uses the following color codes for nominal voltages:

Red	**34.5 kV**
Blue	**138 kV**

All voltages and line flows are from the 2011 summer peak base case. The out of service generator at bus 515903 represents the equivalent generator used in the power factor analysis.

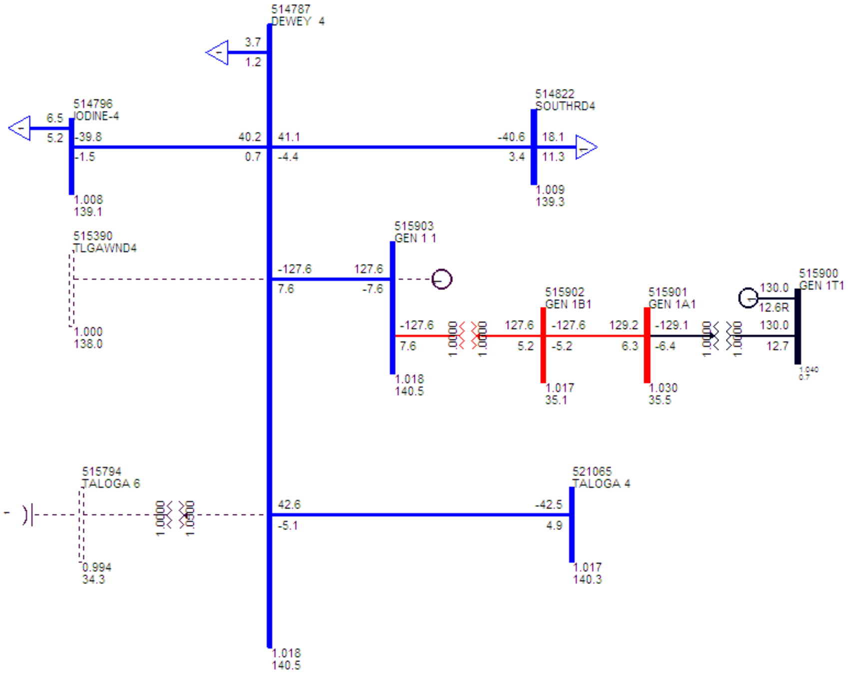

Figure 1: GEN-2006-046 Interconnection One-Line Diagram

As illustrated below, GEN-2006-046 is located in north-central Oklahoma northwest of Oklahoma City.

Figure 2: Geographical Location of GEN-2006-046 Project

The following is the detailed description of the wind project in GEN-2006-046.

GEN-2006-046

- Wind farm rating
    - Active power capability:129.6 MW
    - Reactive power capability: 42.7 MVAR (0.95 pf option)
    - 63.0 MVAR (0.90 pf option)
- Interconnection:
    - Voltage: 138 kV
    - Location: Existing OKGE Dewey 138 kV substation
    - Transformer: One step-up transformer connecting to the 138 kV
        - MVA: Rate A - 90, Rate B - 120, Rate C - 150
        - Voltage: 138/34.5 kV
        - X: 9.67% on a 90 MVA base
- Wind turbine:
    - Number: 81
    - Manufacturer: GE
    - Type: Induction generator (DFIG)
    - Machine terminal voltage: 690 V
    - Rated power: 1.6 MW
    - Frequency: 60Hz
    - Generator step-up transformer
        - MVA: 1.75
        - Voltage: 34.5/0.690 kV
        - R: 0.767% on a 1.75 MVA base
        - X: 5.75% on a 1.75 MVA base
- Generator protection (with LVRT II option. ZVRT also available.)
    - Undervoltage
        - Relay trips when $V_{bus} < 0.15$ pu for $t = 0.02$ s
        - $V_{bus} < 0.30$ pu for $t = 0.7$ s
        - $V_{bus} < 0.50$ pu for $t = 1.1$ s
        - $V_{bus} < 0.75$ pu for $t = 1.7$ 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-2006-046 wind farm (130 MW) will be comprised of 81 GE 1.6 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with no reactive power capability. GEN-2006-046 was modeled as an equivalent 130 MW generator with 0 Var capability at the 138kV POI at Dewey substation. A continuously variable Var generator was modeled at the 138kV POI and scheduled to maintain 1.00 PU post contingency voltages at the Dewey 138kV bus.

A contingency analysis was run for 2011 summer and winter peak conditions considering all of the faults described in Table 2.

The results listed in Tables 3 indicate that approximately 24 Mvar of reactive compensation at the 138kV POI is required to maintain 1.00 PU post contingency voltages. It will be left to the customer to determine if this reactive capability shall be provided utilizing turbine capacity and/or with supplemental reactive compensation.

5. VOLTAGE RECOVERY RESULTS

Dynamic simulations were performed using each fault Included in Table 5. Voltage recovery as determined via dynamic simulation was checked against all contingencies. If the post-fault voltage recovers 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 that GEN-2006-046 generators did not trip during any of the contingencies tested. That is, the wind farm GEN-2006-046 meets FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage). Table 8 lists the post-fault voltages at POI calculated with no reactive compensation on either side of the POI.

Table 7: Post-Fault Voltage Recovery by Dynamic Simulation

Fault Name	Voltage @ GEN-2006-046 POI (Tatonga 345 kV bus) (pu)	
	Summer Peak	Winter Peak
FLT01 & FLT02	1.0219	1.0276
FLT03 & FLT04	1.0197	1.0239
FLT05 & FLT06	1.0187	1.0204
FLT07 & FLT08	1.0145	1.0191
FLT09 & FLT10	1.0149	1.0202
FLT11 & FLT12	1.0156	1.0206
FLT13 & FLT14	1.0201	1.0260
FLT15 & FLT16	1.0183	1.0237
FLT17 & FLT18	1.0178	1.0236
FLT19 & FLT20	1.0180	1.0229
FLT21 & FLT22	1.0200	1.0276
FLT23 & FLT24	1.0136	1.0203
FLT25 & FLT26	0.99609	0.99794

Figure 3 below shows the highest and lowest post-fault voltage at the POI resulting from FLT01-3PH/FLT02-1PH (highest) and FLT25-3PH/FLT26-1PH (lowest) for the summer case.

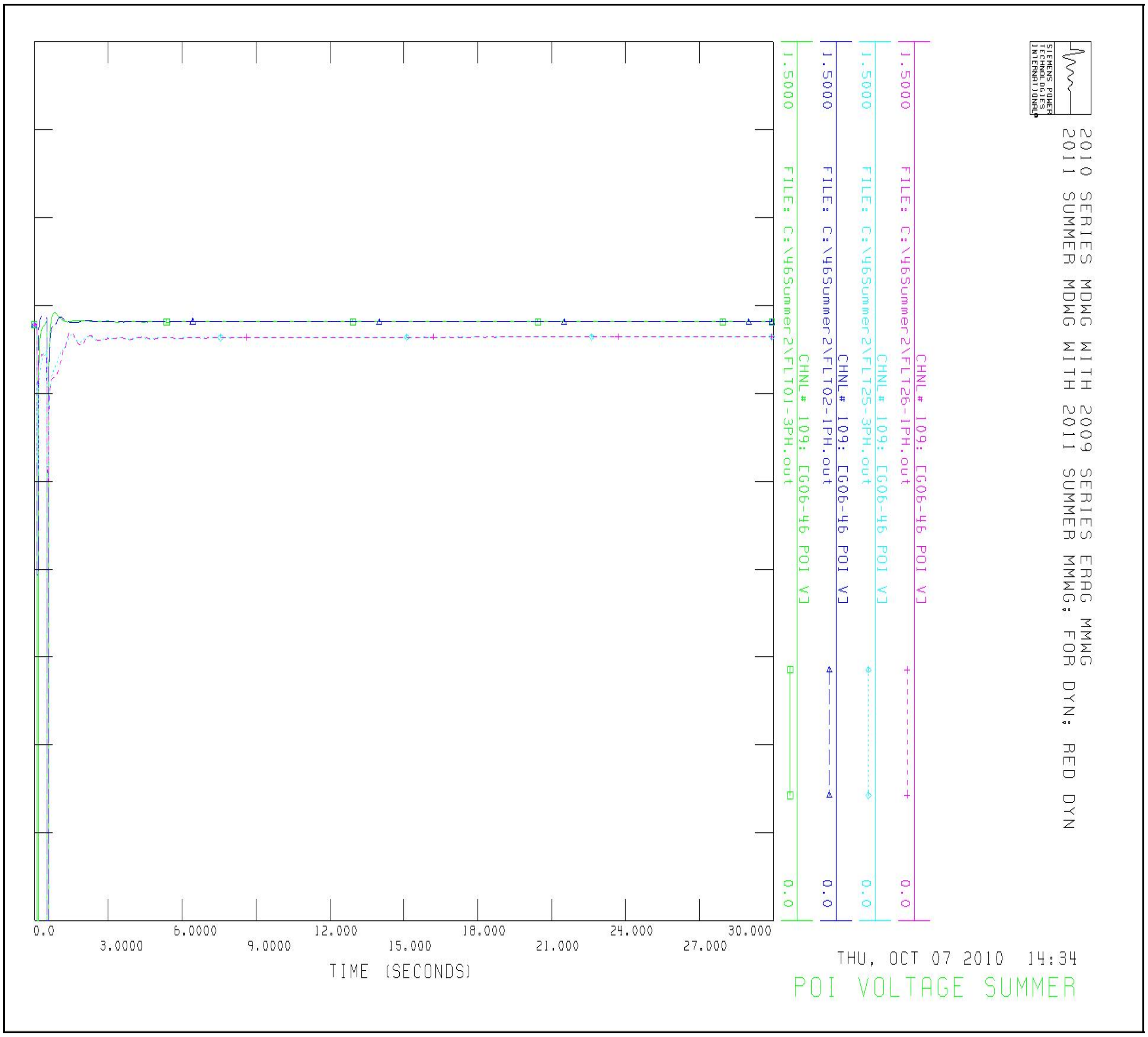

Figure 3: POI Voltage Recovery for FLT01/FLT02 and FLT25/FLT26, Summer Peak

Figure 4 below shows the highest and lowest post-fault voltage at the POI resulting from FLT01-3PH/FLT02-1PH (highest) and FLT25-3PH/FLT26-1PH (lowest) for the summer case.

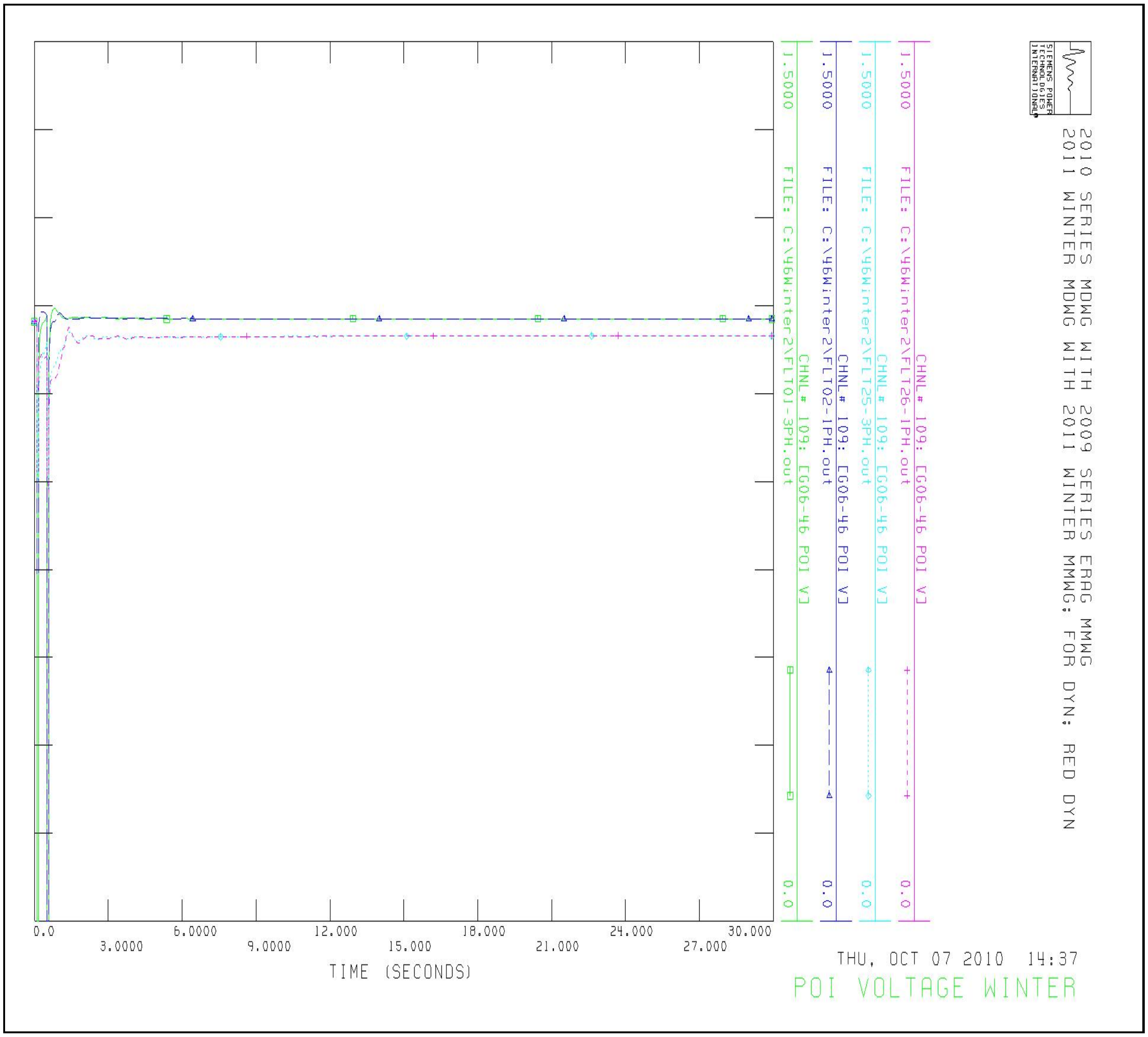

Figure 4: POI Voltage Recovery for FLT01/FLT02 and FLT25/FLT26, Winter Peak

6. TRANSIENT STABILITY RESULTS

Based on the dynamics results, GEN-2006-046 did not cause any new stability problems. For the faults studied, the three-phase faults are relatively more severe than the corresponding single-line- to-ground faults. No synchronous generators pulled out of synchronism with the grid. However, GEN-2001-014 tripped on overvoltage for FLT01-3PH and FLT02-1PH in the winter case, because the generator bus voltage at bus 99953 exceeded 1.2 pu for 0.08 seconds. Proper coordination of capacitors and LTCs at Fort Supply may alleviate this high voltage concern. This overvoltage tripping occurs with or without the GEN-2006-046 wind farm.

Following are plots of the generator MW output in pu for GEN-2006-046 for the most severe faults: FLT03-3PH, and FLT04-1PH. FLT03 and FLT04 are faults on the Dewey-Taloga 138 kV line near Dewey. Note that the GE DFIG wind turbine model was not intended to model post-fault rotor speed. Speed ramps up post-fault from about 0.2 pu to 0.5 pu over 10 seconds for all faults even after the electrical power, POI voltage, etc. settles to pre-fault equilibrium. Even a test fault 700 miles away caused this speed ramp-up. Therefore, the electrical power at GEN-2006-046 is plotted in the following instead of rotor speed.

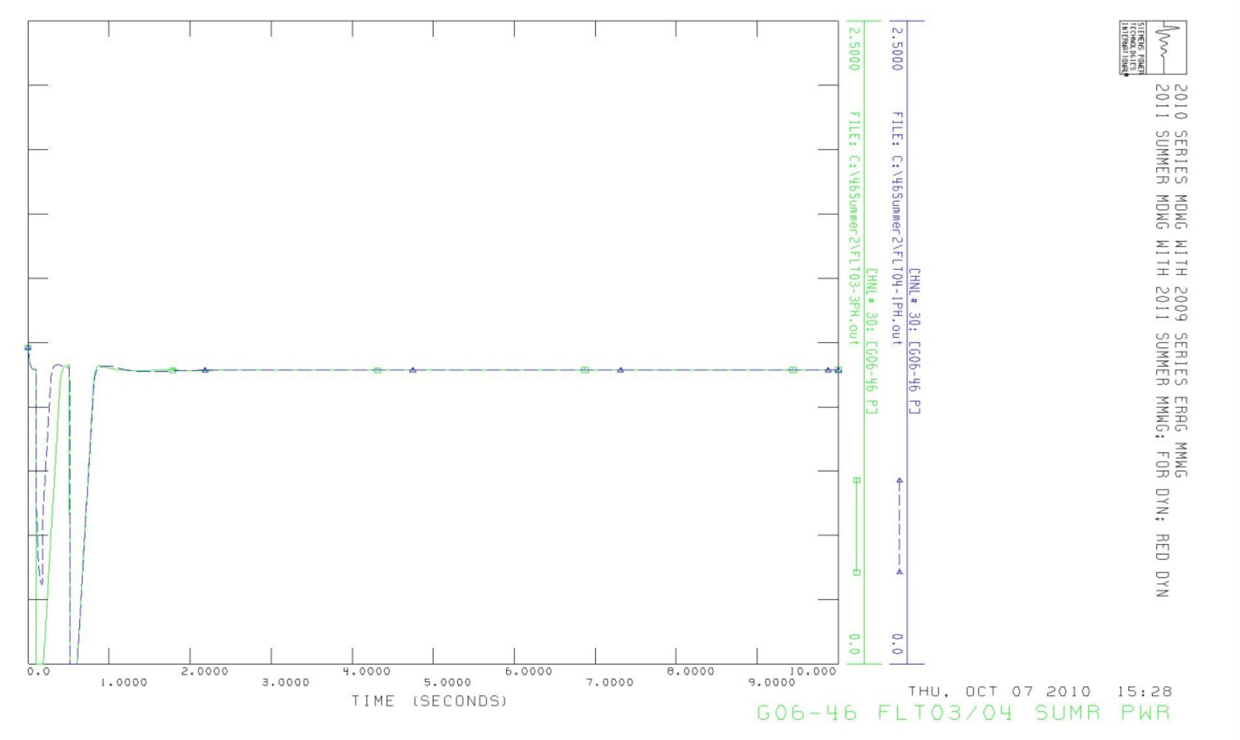

Figure 5: Response of GEN-2006-046 Wind Turbine Generator MW Output to FLT03-3PH and FLT04-1PH, Summer Peak

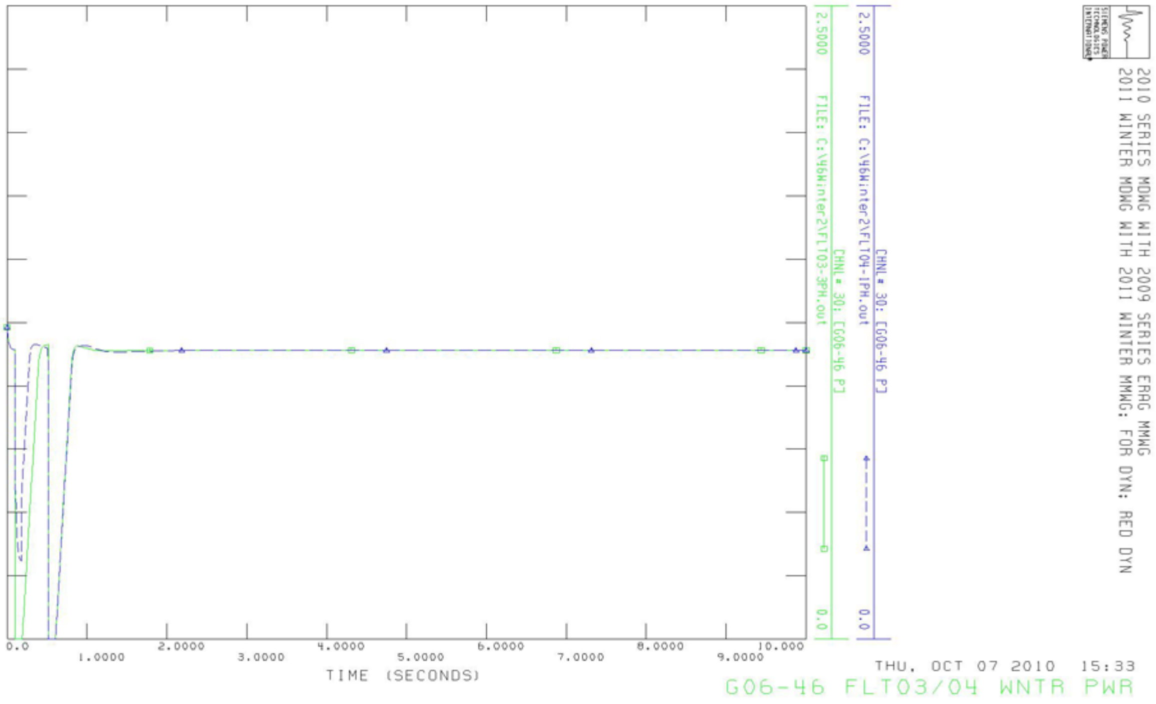

Figure 6: Response of GEN-2006-046 Wind Turbine Generator MW Output to FLT03-3PH and FLT04-1PH, Winter Peak

7. CONCLUSIONS

Based on the results of Group 1 studies, the following findings had been observed:

- The addition of the equivalent of 24 Mvar at the 138kV side of the POI is required to maintain post contingency POI bus voltage at 1.00 PU with GEN-2006-046 on line.
- GEN-2006-046 meets LVRT requirements. No wind turbine generators tripped off line under the fault conditions, except the previous queued project GEN-2001-014 which tripped for overvoltage in the winter case for FLT01 & FLT02. GEN-2001-014 tripped for overvoltage even without GEN-2006-046.
- GEN-2006-046 had the capability of recovering to the pre-contingency voltage following the fault disturbance.
- None of the synchronous machines in the studied areas suffered from instability for the faults studied.