Southwest Power Pool

Interim Operational Impact Study

For Generation Interconnection Request

GEN-2010-006

SPP Generation Interconnection Studies

(#GEN-2010-006)

December *2010*

Executive Summary

<OMITTED TEXT> (Customer) has requested an Interim Operational Impact Study (IOIS) under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of 205 MW winter, 180 MW summer of generation within the balancing authority of Southwestern Public Service Company (SPS) in Lubbock County, Texas. SPP expects to complete the Impact Study as part of the cluster study DISIS-2010-001. SPP may not be able to complete all interconnection studies required under the OATT in time for the Customer's requested in-service date of June 1, 2011. Therefore, Customer has requested this IOIS to determine the impacts of interconnecting its generating facility to the transmission system before all required studies can be completed and all required Network Upgrades identified in the DISIS-2010-001 posted on July 30, 2010 can be placed into service. IOIS are conducted under GIP Section 11A of the SPP OATT.

This study is intended only as an Interim Operation Study that will be used in order to tender an Interim Interconnection Agreement to the Customer for Interim Interconnection Service. If an Interim Interconnection Agreement is not executed with the Customer, this study will be inapplicable. If an Interim Interconnection Agreement is executed with the Customer, this study will be considered inapplicable upon termination of such Interim Interconnection Agreement.

This study assumed that only the higher queued projects identified in Table 3 of this study might go into service before the completion of all Network Upgrades identified in DISIS-2010-001. If any additional generation projects not identified in Table 3 but with queue priority over GEN-2010-006 request to go into commercial operation before all Network Upgrades identified through the DISIS-2010-001 study process as required, then this study must be conducted again to determine whether sufficient interim interconnection capacity exists to interconnect the GEN-2010-006 interconnection request in addition to all higher priority requests in operation or pending operation.

A power flow analysis showed no thermal overloads for the cases studied. Powerflow analysis was based on both summer and winter peak conditions and light loading cases.

The power factor requirements for GEN-2010-006 are +/-95% at the point of interconnection (POI) per the SPP Tariff.

The stability study results show that with the Customer facility the transmission system remains stable for all simulated contingencies and conditions studied. If the Customer changes generation technology, this IOIS will be considered invalid and the Customer will not be allowed to interconnect on an interim basis.

The generation facility was studied with one Siemens combustion turbine. This stability analysis addresses the dynamic stability effects of interconnecting the plant to the rest of the SPS transmission system for the system condition as it will be on June 1, 2011. Two seasonal base cases were used in the study to analyze the stability impacts of the proposed generation facility. The cases studied were modified 2011 summer peak and 2011 winter peak cases that were adjusted to reflect system conditions at the requested in-service date. Each case was modified to include prior queued projects that are listed in the body of the report. Thirty-nine (39) contingencies were identified for use in this study. The combustion generator was modeled using information provided by the Customer.

The latest cost estimate for network upgrades and the interconnection facilities for interim operation is $1,408,514. These costs are detailed in this report in Table 1.

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.

1.0 Introduction

<OMITTED TEXT> (Customer) has requested an Interim Operational Impact Study (IOIS) under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of 205 MW winter, 180 MW summer of generation within the balancing authority of Southwestern Public Service Company (SPS) in Lubbock County, Texas. SPP expects to complete the Impact Study as part of the cluster study DISIS-2010-001. SPP may not be able to complete all interconnection studies required under the OATT in time for the Customer's requested in-service date of June 1, 2011. Therefore, Customer has requested this IOIS to determine the impacts of interconnecting its generating facility to the transmission system before all required studies can be completed and all required Network Upgrades identified in the DISIS-2010-001 posted on July 30, 2010 can be placed into service. IOIS are conducted under GIP Section 11A of the SPP OATT.

This Impact study addresses the thermal loading and dynamic stability effects of interconnecting the generation to the rest of the SPS transmission system for the system condition as it will be on June 1, 2011. The generation facility was studied with a single gas turbine. Two seasonal base cases were used in the study to analyze the stability impacts of the proposed generation facility. The cases studied were modified versions of the 2011 summer peak and 2011 winter peak to reflect the system conditions at the requested in-service date. Each case was modified to include prior queued projects that are listed in the body of the report. Thirty-nine (39) contingencies were identified for this study.

2.0 Purpose

The purpose of this IOIS is to evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The IOIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the IOIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in **Error! Reference source not found.**3; or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued projects not included in this study signing an interconnection agreement, may require a re-study of this request at the expense of the customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

3.0 Facilities

3.1 Generating Facility

The project was modeled as a single gas combustion turbine generator of 205 MW winter, 180 MW summer of generation output. The gas combustion turbine is connected to a 230/16.5KV substation autotransformer at the point of interconnection (POI).

3.2 <u>Interconnection Facility</u>

The Point of Interconnection of GEN-2010-006 will be at the Jones 2 Substation. Figure 1 shows the proposed POI with proposed upgrades. Figure 2 shows the summer Facility One-Line Diagram.

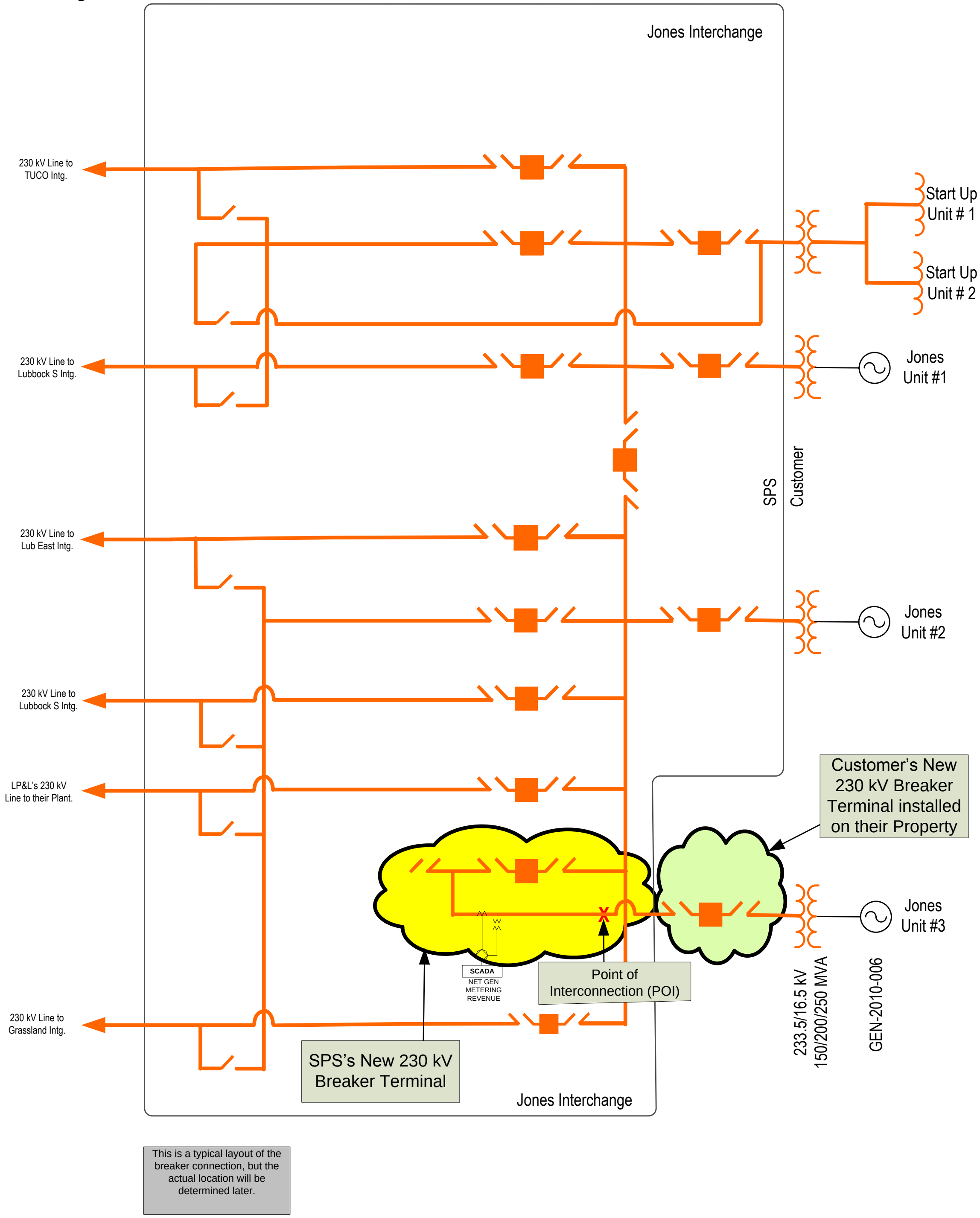

Figure 1: GEN-2010-006 Facility and Proposed Interconnection Configuration

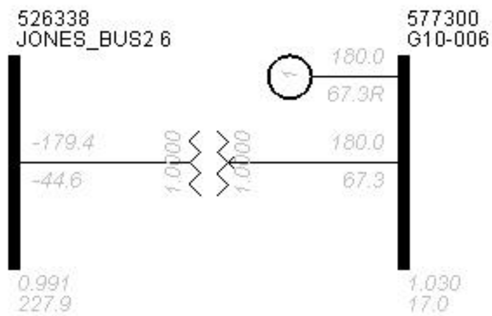

Figure 2: GEN-2010-006 Facility One-Line Diagram

Estimated costs to interconnect on an Interim basis are shown in Table 1.

Table 1: Required Interconnection Projects[1]

Project	Description	Estimated Cost
	Network Upgrades	
1	Disturbance Monitoring Device	$ 0
2	Transmission Line Work	$ 0
3	Right-Of-Way	$ 0
4	230 kV Breaker Line Terminal	$ 1,124,014
5	Remote Terminal Unit (RTU) and DFR	$ 54,500
	Subtotal:	**$ 1,178,514**
	Transmission Owner Interconnection Facilities (at the Interconnection Customer's expense)	
6	Communications [2]	*$ See footnote*
7	Revenue metering	$ 200,000
8	230 kV Line arrestors	$ 30,000
	Subtotal:	**$ 230,000**
	Total Cost	**$ 1,408,514**

[1] The cost estimates are 2010 dollars with an accuracy level of ±20%.

[2] It is the Requester's responsibility to provide both the data circuit and both dial-up telephone circuits.

4.0 Power Flow Analysis

A powerflow analysis was conducted for the Interconnection Customer's facility using a modified version of the 2011 spring, 2011 summer, and 2011 winter seasonal models. The output of the Interconnection Customer's facility was offset in the model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ERIS) Interconnection Request. This analysis was conducted assuming that previous queued requests in the immediate area of this interconnect request were in-service.

The Southwest Power Pool (SPP) Criteria states that:

> "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable NERC Reliability Standards for transmission planning. All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category A."

The ACCC function of PSS/E was used to simulate single contingencies in portions of or all of the control area of SPS and other control areas within SPP and the resulting data analyzed. This satisfies the "more probable" contingency testing criteria mandated by NERC and the SPP criteria.

The ACCC analysis indicates that as a result of the Customer's project at full nameplate power the SPS transmission system will experience no thermal overloads.

Table 2: Thermal Overloads

Season	Overloaded Elements
11G	None
11SP	None
11WP	None

5.0 Power Factor Analysis

The power factor requirements for GEN-2010-006 are +/-95% at the POI per FERC and SPP Tariff requirements.

6.0 Stability Analysis

The Stability Analysis was performed by American Earth and Environmental (AMEC). The entire analysis is attached in Appendix A.

6.1 Contingencies Simulated

Thirty-nine (39) contingencies were considered for the transient stability simulations. These contingencies included three phase and single phase transmission line faults and transformer faults at 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.

The faults that were defined and simulated are in Appendix A – Interim Impact Study.

6.2 Further Model Preparation

The base cases contain prior queued projects as shown in Table 3.

The generation from the study customer and the previously queued customers were dispatched into the SPP footprint.

Initial simulations were carried out on both base cases and cases with the added generation for a no-disturbance run of 20 seconds to verify the numerical stability of the model. All cases were confirmed to be stable.

Table 3: Prior Queued Projects

Project	MW
GEN-2006-018	168
ASGI-2010-010	42
GEN-2002-022	240

6.3 Results

Results of the stability analysis are in Appendix A – Interim Impact Study. The results indicate that for all contingencies studied the transmission system remains stable.

7.0 Conclusion

<OMITTED TEXT> (Customer) has requested an Interim Operation Impact Study for interim interconnection service of 205 MW winter, 180 MW summer of generation within the balancing authority of Southwestern Public Service Company (SPS) in Lubbock County, Texas, in accordance with the OASIS posting made by SPP on March 6, 2009.

Powerflow analysis based on both summer and winter peak conditions and light loading cases showed no thermal overloads for the cases studied.

The results of this study show that the generation facility and the transmission system remain stable for all contingencies studied.

The power factor requirements for GEN-2010-006 are +/-95% at the POI per FERC and SPP Tariff requirements.

The Customer will be responsible for an estimated $1,408,514 in interconnection substation costs in order to move forward into an Interim Interconnection Agreement.

The estimates do not include any costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer requests transmission service through Southwest Power Pool's OASIS. It should be noted that the models used for simulation do not contain all SPP transmission service.

APPENDIX A.

GEN-2010-006 Interim Impact Study

November 1, 2010





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EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) has a requested an Interim Impact Study of a generator interconnection request for a 230 kV interconnection of a 205 MW (winter) gas fired plant near Lubbock, Texas. This plant will be interconnected into the existing Jones 230 kV 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 SPS.

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2010-006	205 Winter / 180 Summer	GENROU	Jones Bus 2 230kV

The case will contain the following previous queued and later queued requests. Other previous queued requests were not included as they were not considered to be in service for the purposes of this study. These projects should be monitored and their generating status shall be reported for each contingency. The projects are as follows:

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2006-018	168	GENSAL	Tuco 230kV
ASGI-2010-010	42	GENSAL	Lovington 115kV
GEN-2002-022	240	Siemens SMK 203	Bushland 230kV

SPP requested a stability analysis as part of the Interim Impact Study of GEN-2010-006. SPP did not request an Available Transfer Capability (ATC) study or a power factor study as part of this assessment.

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

All generators in the monitored area remain stable during disturbances.

Without reactive compensation, GEN-2010-006 voltage recovers to within approximately 0.005 pu of its pre-contingency value for the worst-case fault (Jones-Tuco 230 kV near Jones, summer case.)

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

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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 generator GEN-2010-006 in the SPP interconnection queue. The site studied is for a 205 MW (winter), 180 MW (summer) gas fired plant near Lubbock, Texas.

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

SPP requested a stability analysis based on a list of faults provided by SPP. The results of this study determine the ability of the generators to remain in synchronism following three-phase and single-line-to-ground faults.

2. STUDY METHODOLOGY

SPP provided 2011 summer peak and 2010-11 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		2010-11 Winter Peak	
		Load (MW)	Generation (MW)	Load (MW)	Generation (MW)
520	AEPW	10246.3	9341.2	7878.3	6946.2
524	OKGE	5956.5	6861.9	4194.5	4631.8
525	WFEC	1418.5	1231.5	1306.7	1071.6
526	SPS	5621.5	5911	4039.9	4581.3
531	MIDW	258.7	6.1	197.6	21
534	SUNC	546.5	589.1	447.7	557.5
536	WERE	5946.9	5853.1	3946.8	4137.5

3. 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 any generators trip offline during the disturbance.

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

Table 2: Fault Descriptions

Cont. No.	*Cont. Name*	*Description*
1	FLT01-3PH	3 phase fault on the Eddy Co. 230kV (527800) to 345kV (527802) transformer, near the 230kV bus. a. Apply fault at the Eddy Co. 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
2	FLT02-3PH	3 phase fault on the Eddy Co. (527082) to Tolk (525549) 345kV line, near Eddy Co. a. Apply fault at the Eddy Co. 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.
3	FLT03-1PH	*Single phase fault and sequence like previous*
4	FLT04-3PH	3 phase fault on the Tolk 230kV (525543) to 345kV (525549) transformer, near the 230kV bus. a. Apply fault at the Tolk 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
5	FLT05-3PH	3 phase fault on the Tolk E (525524) to Tuco (525830) 230kV line, near Tolk E. a. Apply fault at the Tolk E 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.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Grassland (526676) to Lynn Co. (526656) 115kV line, near Grassland. a. Apply fault at the Grassland 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.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Grassland 230kV (526677) to 115kV (526676)

Cont. No.	*Cont. Name*	*Description*
		transformer, near the 230kV bus. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-3PH	3 phase fault on the Grassland (526677) to Borden (526830) 230kV line, near Grassland. a. Apply fault at the Grassland 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.
11	FLT11-1PH	*Single phase fault and sequence like previous*
12	FLT12-3PH	3 phase fault on the Grassland (526677) to Jones (526338) 230kV line, near Grassland. a. Apply fault at the Grassland 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.
13	FLT13-1PH	*Single phase fault and sequence like previous*
14	FLT14-3PH	3 phase fault on the Jones (526338) to Lubbock E (526299) 230kV line, near Jones Bus2. a. Apply fault at the Jones 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.
15	FLT15-3PH	3 phase fault on the Jones (526337) to Tuco (525830) 230kV line, near Jones Bus1. a. Apply fault at the Jones 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.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Tuco (525830) to Swisher (525213) 230kV line, near Tuco. a. Apply fault at the Tuco 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.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Tuco 230kV (525830) to 345kV (525832) transformer, near the 230kV bus. a. Apply fault at the Tuco 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
20	FLT20-3PH	3 phase fault on the OKV (511465) to Tuco (525832) 345kV line, near

Cont. No.	*Cont. Name*	*Description*
		OKV. a. Apply fault at the OKV 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.
21	FLT21-1PH	*Single phase fault and sequence like previous*
22	FLT22-3PH	3 phase fault on the Roosevelt S (524911) to Tolk (525524) 230kV line, near Roosevelt S. a. Apply fault at the Roosevelt S 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.
23	FLT23-1PH	*Single phase fault and sequence like previous*
24	FLT24-3PH	3 phase fault on the San Juan (524885) to Oasis (524875) 230kV line, near Oasis. a. Apply fault at the Oasis 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.
25	FLT25-1PH	*Single phase fault and sequence like previous*
26	FLT26-3PH	3 phase fault on the Seven Rivers (528094) 115kv to Severn Rivers (528093) 69kV transformer, near Seven Rivers 115kV a. Apply fault at the Seven Rivers 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
27	FLT27-3PH	3 phase fault on the Seven Rivers (528094) 115kv to Severn Rivers (528095) 230kV transformer, near Seven Rivers 230kV a. Apply fault at the Seven Rivers 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
28	FLT28-3PH	3 phase fault on the Lovington (527848) 115kV to Lea County (527849) 230kV transformer, near Lea County 230kV a. Apply fault at the Lea County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
29	FLT29-3PH	3 phase fault on the Lovington (528334) to Lea County (527848) 115kV line, near Lea County a. Apply fault at the Lea county 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
30	FLT30-3PH	3 phase fault on the Eddy Co. (527800) to Chaves Co (527483) 230kV line, near Eddy Co. a. Apply fault at the Eddy Co. 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.
31	FLT31-1PH	*Single phase fault and sequence like previous*
32	FLT32-3PH	3 phase fault on the Eddy Co. (527800) to Cunningham (527866) 230kV

Cont. No.	*Cont. Name*	*Description*
		line, near Eddy Co. a. Apply fault at the Eddy Co. 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.
33	FLT33-1PH	*Single phase fault and sequence like previous*
34	FLT34-3PH	3 phase fault on the Eddy Co. (527800) to Seven Rivers (528095) 230kV line, near Eddy Co. a. Apply fault at the Eddy Co. 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 Jones (526338) to LP Holly (522870) 230kV line, near Jones Bus2. a. Apply fault at the Jones 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*
38	FLT38-3PH	3 phase fault on the Jones (526338) to Lubbock (526269) 230kV line, near Jones Bus2. a. Apply fault at the Jones 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.
39	FLT39-1PH	*Single phase fault and sequence like previous*

In order to simulate 1PH faults, equivalent shunt Mvar[1] were determined to be applied at the faulted buses. Table 3 presents equivalent reactors used in the transient stability study.

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

Table 3: Equivalent Shunt Mvar at Faulted Bus for Single-Line-to-Ground Faults

Fault No.	Faulted Bus No.	2011 Summer Peak (Mvar)	2010-11 Winter Peak (Mvar)
FLT03-1PH	527802	-1422.9	-1509.9
FLT06-1PH	525524	-5946.5	-4372.4
FLT08-1PH	526676	-652.6	-670.6
FLT11-1PH	526677	-1498.9	-1505.8
FLT13-1PH	526677	-1498.9	-1505.8
FLT16-1PH	526337	-3612.6	-3581.8
FLT18-1PH	525830	-3396.8	-3298.0
FLT21-1PH	511456	-1997.7	-1975.5
FLT23-1PH	524911	-2018.3	-1882.8
FLT25-1PH	524875	-1645.1	-1556.2
FLT31-1PH	527800	-1640.6	-1509.9
FLT33-1PH	527800	-1640.6	-1509.9
FLT35-1PH	527800	-1640.6	-1509.9
FLT37-1PH	526338	-3612.6	-3581.8
FLT39-1PH	526338	-3612.6	-3581.8

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 following the faults defined in Table 2. The GEN-2010-006 combustion turbine capability of post-fault voltage recovery at the POI was also checked.

4. PROJECT DESCRIPTION

Following tables contain the Points of Interconnection for the Interconnection Customers requesting restudy and of higher queued projects.

Table 4: Points of Interconnection for Restudy

Request	Size (MW)	Generator Model	Point Of Interconnection	
			Bus No.	Bus Name in model
GEN-2010-006	205 Winter / 180 Summer	GENROU	526338	Jones Bus 2 230kV

Table 5: Points of Interconnection of Higher Queued Projects

Request	Size (MW)	Generator Model	Point Of Interconnection	
			Bus No.	Bus Name in model
GEN-2006-018	168	GENSAL	525830	Tuco 230kV
ASGI-2010-010	42	GENSAL	528334	Lovington 115kV
GEN-2002-022	240	Siemens SMK 203	524267	Bushland 230kV

The one-line diagram of GEN-2010-006 in Figure 1 uses the following color codes for nominal voltages and all voltages and line flows are from the 2011 summer peak base case:

Red **220 kV**
Blue **less than 25 kV**

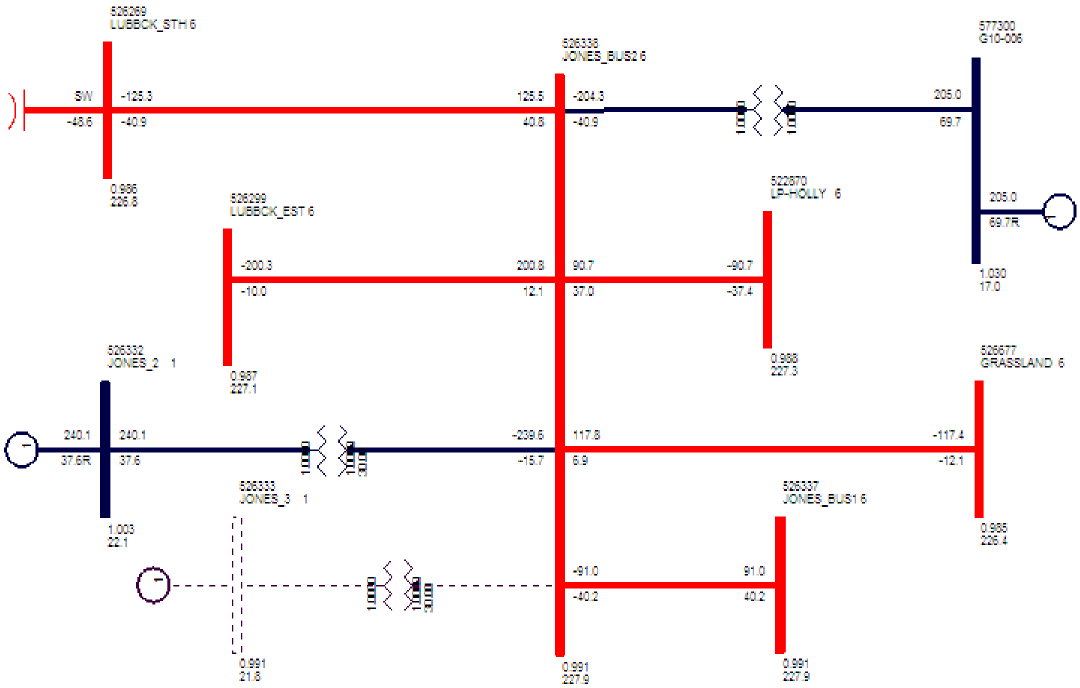

Figure 1: GEN-2010-006 Interconnection One-Line Diagram

As illustrated below, GEN-2010-006 is located in northwest Texas near Lubbock.

Figure 2: Geographical Location of GEN-2010-006 Project

The following is the detailed description of project GEN-2010-006.

GEN-2010-006

- Interconnection:
  Voltage: 230 kV
  Location: Existing SPS Jones Bus 2 220kV substation
- Generator Type: Combustion Turbine
- System Models: GENROU (round rotor generator)
  EXST1 (exciter)
  PSS2A (power system stabilizer)
  WESGOV (governor)

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 its pre-contingency value, the generator interconnection is considered acceptable from a voltage recovery standpoint.

The dynamic simulation showed that the GEN-2010-006 generator did not trip during any of the contingencies tested. Table 6 lists the post-fault voltages at POI calculated with no reactive compensation on either side of the POI. Yellow highlighting indicates the highest voltage, and blue highlighting indicates the lowest voltage.

Table 6: Post-Fault Voltage Recovery by Dynamic Simulation

Fault Name	Voltage @ GEN-2010-006 POI (Jones 230 kV bus) (pu)	
	Summer Peak	Winter Peak
Base Case	0.99100	0.99080
FLT01-3PH	0.99103	0.99096
FLT02-3PH	0.99039	0.98986
FLT03-1PH	0.99039	0.98986
FLT04-3PH	0.99083	0.99084
FLT05-3PH	0.99042	0.98986
FLT06-1PH	0.99041	0.98986
FLT07-3PH	0.99087	0.99076
FLT08-1PH	0.99087	0.99076
FLT09-3PH	0.99005	0.99031

Fault Name	Voltage @ GEN-2010-006 POI (Jones 230 kV bus) (pu)	
	Summer Peak	Winter Peak
FLT10-3PH	0.99234	0.99089
FLT11-1PH	0.99234	0.99089
FLT12-3PH	0.98954	0.98877
FLT13-1PH	0.98954	0.98876
FLT14-3PH	0.98927	0.99019
FLT15-3PH	0.98580	0.98784
FLT16-1PH	0.98578	0.98782
FLT17-3PH	0.99196	0.99056
FLT18-1PH	0.99196	0.99055
FLT19-3PH	0.98752	0.98965
FLT20-3PH	0.98751	0.98749
FLT21-1PH	0.98751	0.98749
FLT22-3PH	0.99082	0.99063
FLT23-1PH	0.99081	0.99063
FLT24-3PH	0.99092	0.99070
FLT25-1PH	0.99092	0.99070
FLT26-3PH	0.99099	0.99080
FLT27-3PH	0.99097	0.99078
FLT28-3PH	0.99106	0.99091
FLT29-3PH	0.99096	0.99081
FLT30-3PH	0.99085	0.99064
FLT31-1PH	0.99085	0.99064
FLT32-3PH	0.99082	0.99064
FLT33-1PH	0.99082	0.99064
FLT34-3PH	0.99082	0.99064
FLT35-1PH	0.99082	0.99064
FLT36-3PH	0.99092	0.99141
FLT37-1PH	0.99091	0.99141
FLT38-3PH	0.99132	0.99079
FLT39-1PH	0.99131	0.99078

Figure 3 below shows the highest and lowest post-fault voltage at the POI resulting from FLT10-3PH/FLT11-1PH (highest) and FLT16-1PH (lowest) for the summer case.

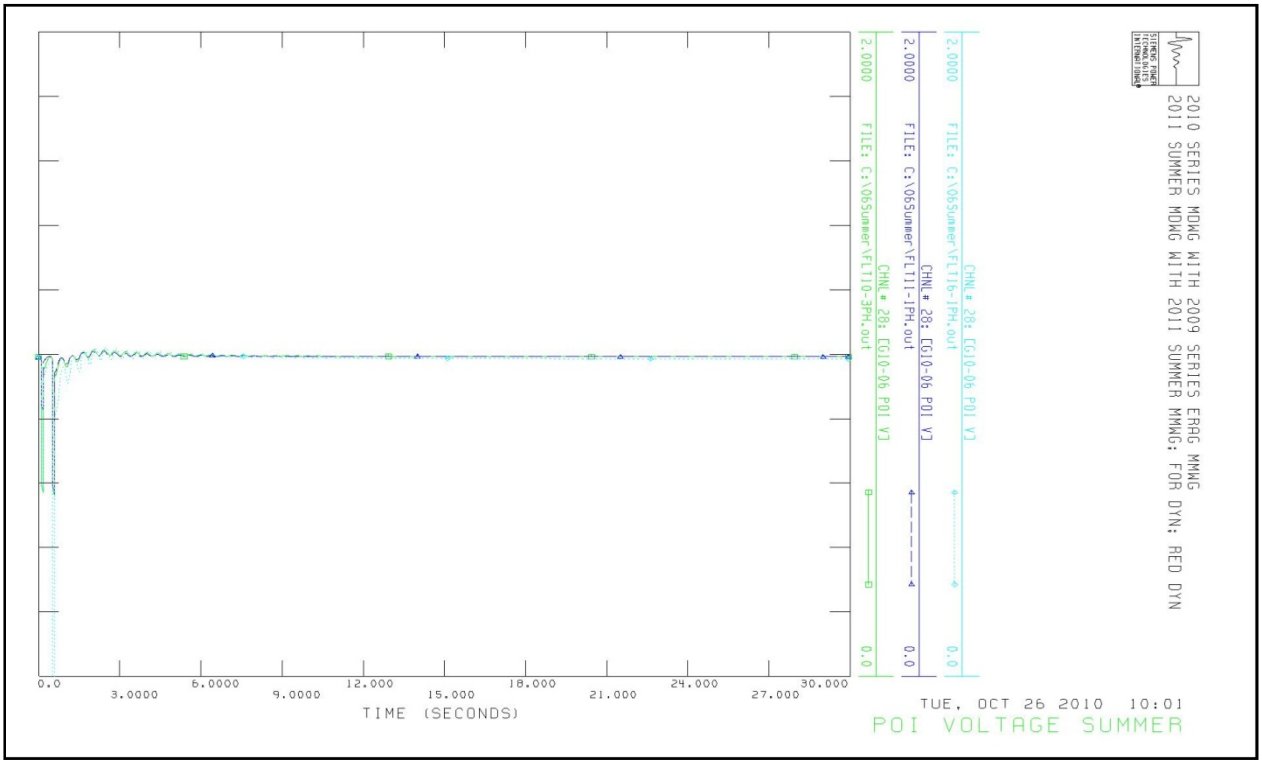

Figure 3: POI Voltage Recovery for FLT10/FLT11 and FLT16, Summer Peak

Figure 4 below shows the highest and lowest post-fault voltage at the POI resulting from FLT36-3PH/FLT37-1PH (highest) and FLT20-3PH/FLT21-1PH (lowest) for the winter case.

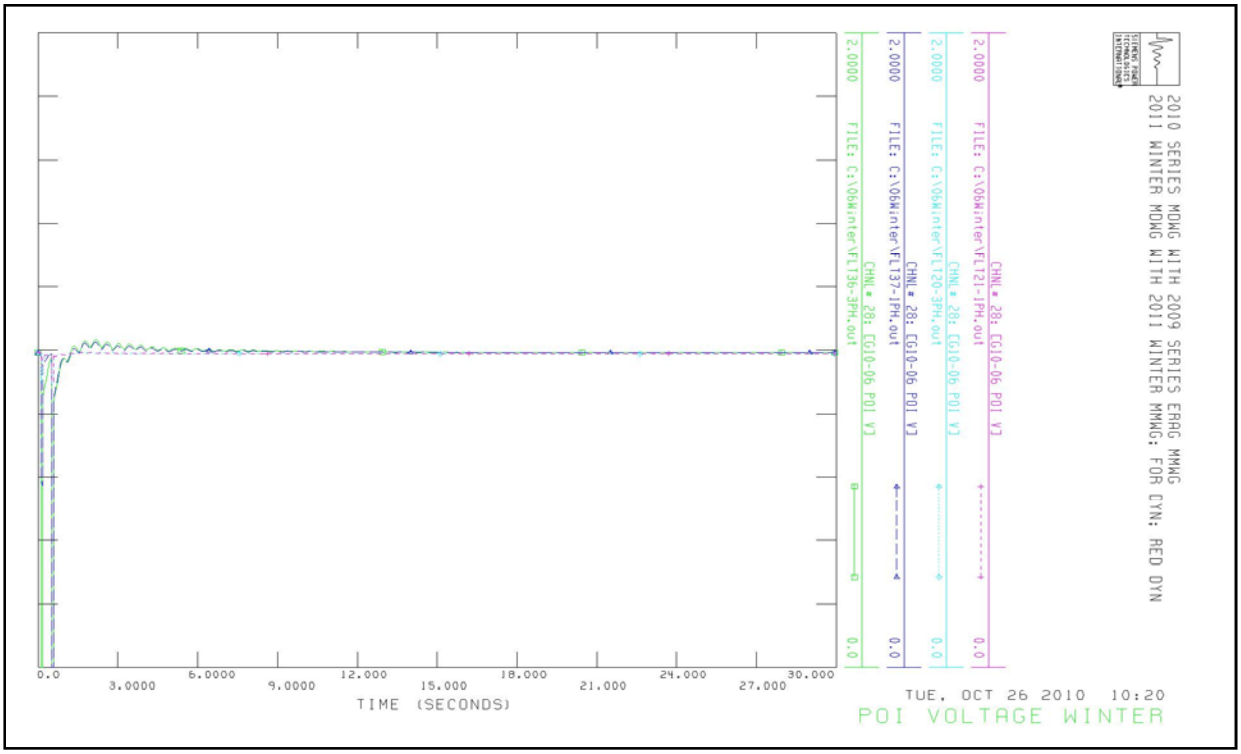

Figure 4: POI Voltage Recovery for FLT36/FLT37 and FLT20/FLT21, Winter Peak

6. TRANSIENT STABILITY RESULTS

Based on the dynamics results, GEN-2010-006 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, and no generators tripped on undervoltage or overvoltage.

Following are plots of the generator MW output in pu for GEN-2010-006 for the most severe faults: FLT15-3PH & FLT16-1PH. FLT15-3PH & FLT16-1PH are faults on the Jones-Tuco 230 kV line near Jones.

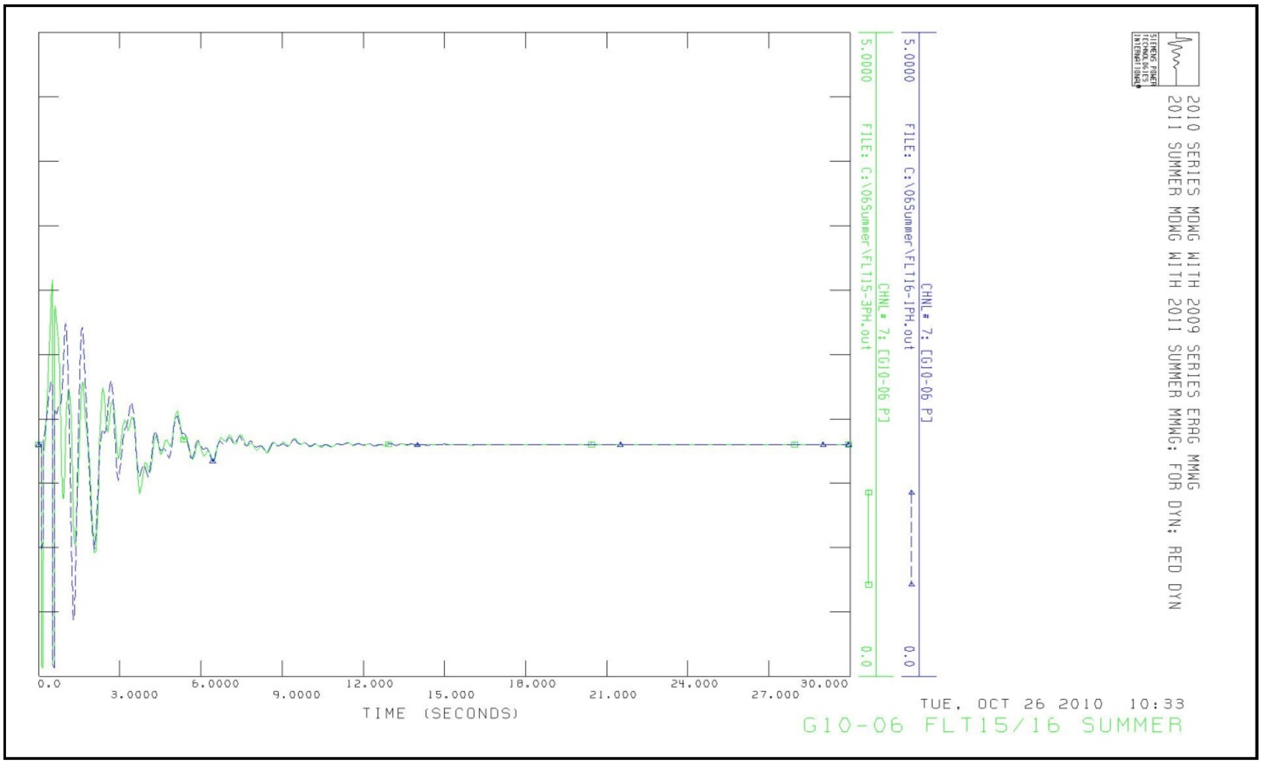

Figure 5: Response of GEN-2010-006 Combustion Turbine Generator MW Output to FLT15-3PH and FLT16-1PH, Summer Peak

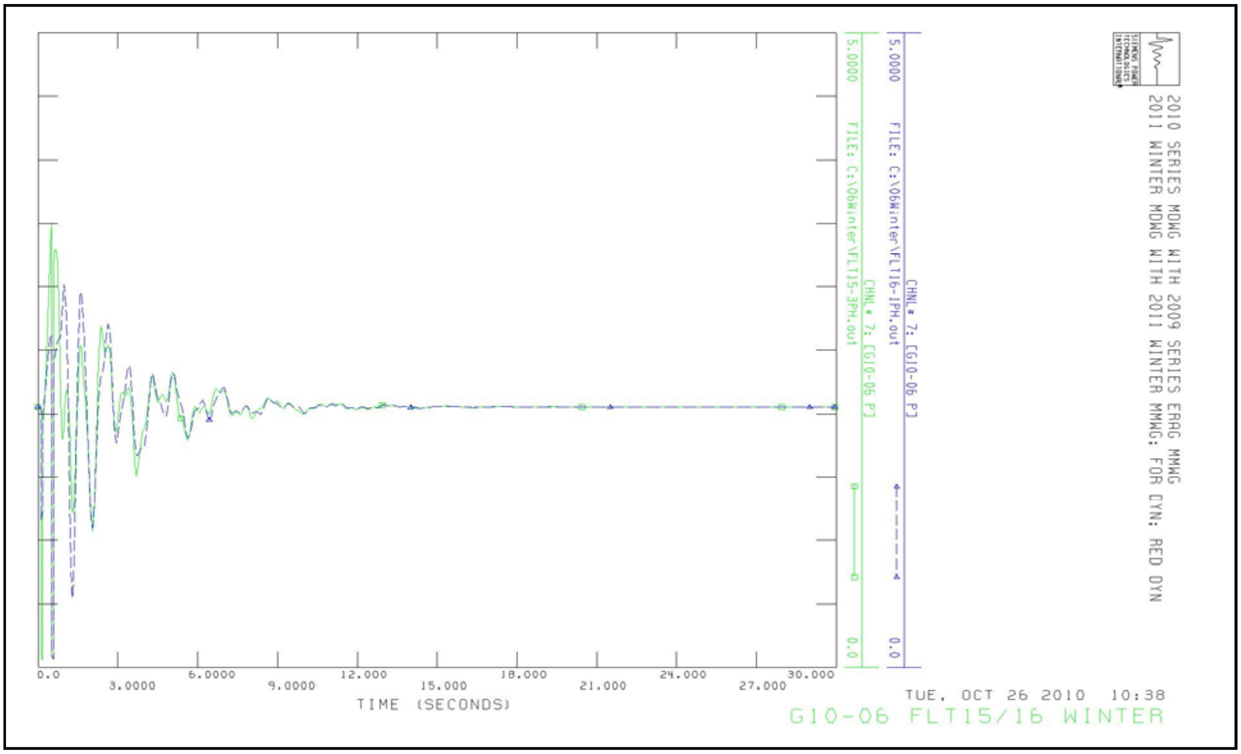

Figure 6: Response of GEN-2010-006 Combustion Turbine Generator MW Output to FLT15-3PH and FLT16-1PH, Winter Peak

7. CONCLUSIONS

Based on the results of restudy of GEN-2010-006, the following findings had been observed:

1. None of the machines in the studied areas suffered from instability for the faults studied.
2. If a post-contingency voltage drop of 0.0052 pu is tolerable for the worst single contingency (Jones-Tuco 230 kV, fault at Jones, summer), GEN-2010-006 does not require reactive compensation.