GEN-2012-028 Impact Restudy for Generator Modification (Turbine Change)

February 2015 Generator Interconnection

Executive Summary

The GEN-2012-028 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied GE 1.7MW wind turbine generators (44 machines total) to Vestas V110 VCSS 2.0MW wind turbine generators.

In this restudy the project uses thirty-seven (37) Vestas V110 VCSS 2.0MW wind turbine generators for an aggregate power of 74.0MW. The point of interconnection (POI) for GEN-2012-028 is at the Western Farmers Electric Cooperative (WFEC) Gotebo 69kV Substation. The interconnection customer has provided documentation that shows the Vestas V110 VCSS 2.0MW wind turbine generators have a reactive capability of 0.98 lagging (providing VARS) and 0.96 leading (absorbing VARS) power factor.

This study was performed to determine whether the request for modification is considered Material. To determine this, study models that included Interconnection Requests through DISIS-2013-002 were used that analyzed the timeframes of 2015 summer, 2015 winter, and 2025 summer models.

The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the Vestas V110 VCSS 2.0MW wind turbine generators. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

A power factor analysis and a low-wind/no-wind condition analysis were performed for this modification request. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the POI. Since the Vestas V110 VCSS 2.0MW wind turbines have limited reactive capability, the generation facility will need external capacitor banks or other reactive equipment to meet the power factor requirement at the POI. Additionally, the project will be required to install approximately 3.5 Mvar of reactor shunts on its substation 34.5kV bus(es). This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind/no-wind conditions.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2012-028 GIA in place, GEN-2012-028 with the Vestas V110 VCSS 2.0MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid.

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the customer may be required to reduce its generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

I. Introduction

GEN-2012-028 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. The in-service date assumed for the generation addition was October 1, 2015. This restudy is for a change from GE 1.7 MW to Vestas V110 2.0MW wind turbines.

Table I-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2012-028	74	Vestas V110 VCSS 2.0MW (37 generators)	Gotebo 69kV (520925)

The prior-queued and equally-queued requests shown in Table I-2 were included in this study and the wind farms were dispatched to 100% of rated capacity.

Table I-2: Prior Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2001-026	74.3	WT1G1	Washita 138kV (521089)
GEN-2002-005	120.0	Acciona AW1500	Red Hills Wind 138kV (521116)
GEN-2003-004 GEN-2004-023 GEN-2005-003	151.2	WT2G1	Washita 138kV (521089)
GEN-2003-005 GEN-2011-037	105.6	GE 1.6 MW	Blue Canyon V 138kV (521129)
GEN-2003-022 GEN-2004-020	147.0	GE 1.5 MW	Weatherford Wind Farm 115kV (511506)
GEN-2006-002	101.0	GE 1.5 MW (506784) GE 1.6 MW (506786)	Sweetwater 230kV (511541)
GEN-2006-035	225.0	Gamesa G90 2.0 MW	Sweetwater 230kV (511541)
GEN-2006-043	99.0	Siemens 2.3MW	Sweetwater 230kV (511541)
GEN-2007-032	150.0	Acciona AW1500	Tap Clinton-Clinton Jct. 138kV (560652) (511485-520856)
GEN-2007-052	150.0	Gas Turbine	Anadarko 138kV (520814)
GEN-2008-023	150.0	GE 1.6 MW	Hobart Junction 138kV (511463)
GEN-2008-037	101.0	Vestas V90	Tap Washita-Blue Canyon I 138kV (520395)
GEN-2011-049	250.7	Siemens 2.3MW	Border 345kV (515458)

The study included a stability analysis of the 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 relays disabled. Also, a power factor analysis was performed on this project since it is a wind farm. The analyses were performed on three seasonal models, the modified versions of the 2015 summer peak, the 2015 winter peak, and the 2025 summer peak cases.

The stability analysis determines the impacts of the new interconnecting project on the stability and voltage recovery of the nearby systems and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades is investigated. The three-phase faults and the single line-to-ground faults listed in Table III-1 were used in the stability analysis.

The power factor analysis determines the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. The contingencies used in the power factor analysis were a subset of the stability analysis contingencies shown in Table III-1.

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the customer may be required to reduce its generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

II. Facilities

A one-line drawing for the GEN-2012-028 generation interconnection request is shown in Figure II-1. The POI is the WFEC Gotebo 69kV substation.

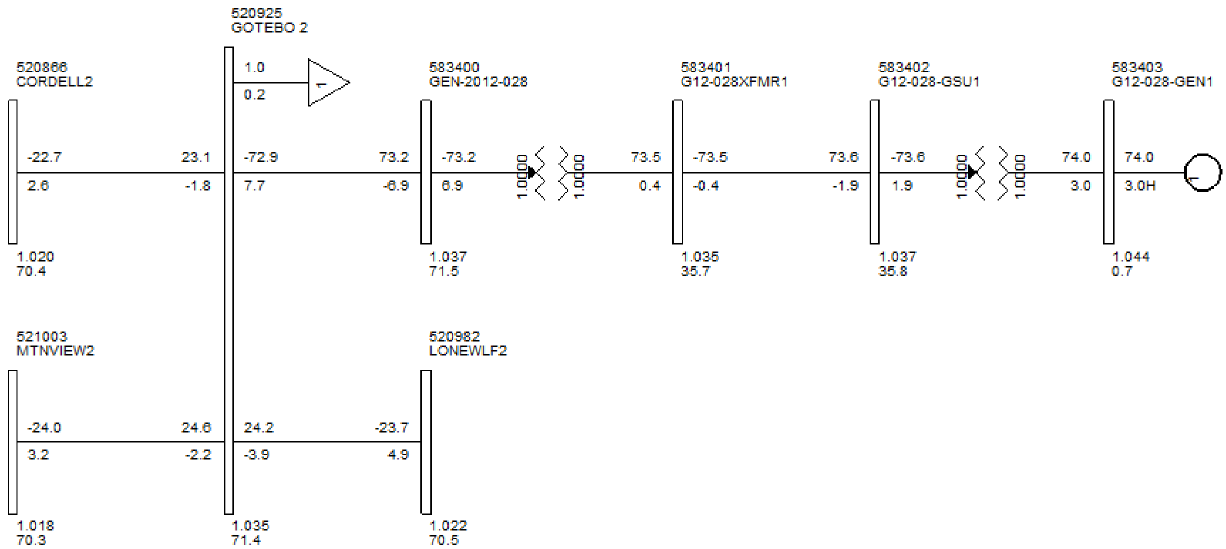

Figure II-1: GEN-2012-028 One-line Diagram

III. Stability Analysis

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria bandwidth during and after a disturbance while considering the addition of a generator interconnection request.

Model Preparation

Transient stability analysis was performed using modified versions of the 2014 series of Model Development Working Group (MDWG) dynamic study models including the 2015 summer peak, the 2015 winter peak, and the 2025 summer peak seasonal models. The cases are then loaded with prior queued interconnection requests and network upgrades assigned to those interconnection requests. Finally the prior queued and study generation are dispatched into the SPP footprint. Initial simulations are then carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

Disturbances

Twelve (12) contingencies were identified for use in this study and are listed in Table III-1. These contingencies included three-phase faults and single-phase line faults at locations defined by SPP. Single-phase line faults were simulated by applying 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.

Except for transformer faults, the typical sequence of events for a three-phase and a single-phase fault is as follows:

1. apply fault at particular location
2. continue fault for five (5) cycles, clear the fault by tripping the faulted facility
3. after an additional twenty (20) cycles, re-close the previous facility back into the fault
4. continue fault for five (5) additional cycles
5. trip the faulted facility and remove the fault

Transformer faults are typically modeled as three-phase faults, unless otherwise noted. The sequence of events for a transformer fault is as follows:

1. apply fault for five (5) cycles
2. clear the fault by tripping the affected transformer facility (unless otherwise noted there will be no re-closing into a transformer fault)

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
1	FLT_01_Gotebo_Cordell_69kV_3PH	3 phase fault on the Gotebo (520925) to Cordell (520866) 69kV line, at Gotebo. a. Apply fault at the Gotebo 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.
2	FLT_02_Gotebo_Lonewolf_69kV_3PH	3 phase fault on the Gotebo (520925) to Lonewolf (520982) 69kV line, at Gotebo. a. Apply fault at the Gotebo 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.
3	FLT_03_Gotebo_MountainView_69kV_3PH	3 phase fault on the Gotebo (520925) to Mountain View (521003) 69kV line, at Gotebo. a. Apply fault at the Gotebo 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.
4	FLT_04_Taloga_Canton_69kV_3PH	3 phase fault on the Taloga (521064) to Canton (520843) 69kV line, at Taloga. a. Apply fault at the Taloga 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.
5	FLT_05_Taloga_Vici_69kV_3PH	3 phase fault on the Taloga (521064) to Vici (521082) 69kV line, at Taloga. a. Apply fault at the Taloga 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.
6	FLT_06_Taloga_Taloga_69_138kV_3PH	3 phase fault on the Taloga (521065) 138 / (521064) 69 / (521178) 13.8kV transformer, at Taloga 69kV bus. a. Apply fault at the Taloga 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
7	FLT_07_Washita2_Caddo_69kV_3PH	3 phase fault on the Washita (520838) to Caddo (520838) 69kV line, at Washita. a. Apply fault at the Washita 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.
8	FLT_08_Washita2_Washita4_69_138kV_3P	3 phase fault on the Washita (521089) 138 / (521088) 69 / (521179) 13.8kV transformer, at Washita 69kV bus. a. Apply fault at the Washita 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line
9	FLT_09_Lkcreek_CarterJ_69kV_3PH	3 phase fault on the Lake Creek (520978) to Carter Junction (520846) 69kV line, at Lake Creek. a. Apply fault at the Lake Creek 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.
10	FLT_10_Lkcreek_Granite_69kV_3PH	3 phase fault on the Lake Creek (520978) to Granite (520927) 69kV line, at Lake Creek. a. Apply fault at the Lake Creek 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.
11	FLT_11_Gracemont_LES_345kV_3PH	3 phase fault on Gracemont (515800) to Lawton Eastside (511468) 345kV line, at Gracemont. a. Apply fault at the Gracemont 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.
12	FLT_12_Washita4_Gracemont_138kV_3PH	3 phase fault on Washita (521089) to Gracemont (515802) 138kV line, at Washita. a. Apply fault at the Washita 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.

Results

The stability analysis was performed and the results are summarized in Table III-2. Based on the stability results and with all network upgrades in service, GEN-2012-028 did not cause any stability problems and remained stable for all faults studied. No generators tripped or went unstable, and voltages recovered to acceptable levels.

Table III-2: Stability Analysis Results

Contingency Number and Name		2015SP	2015WP	2025SP
1	FLT_01_Gotebo_Cordell_69kV_3PH	OK	OK	OK
2	FLT_02_Gotebo_Lonewolf_69kV_3PH	OK	OK	OK
3	FLT_03_Gotebo_MountainView_69kV_3PH	OK	OK	OK
4	FLT_04_Taloga_Canton_69kV_3PH	OK	OK	OK
5	FLT_05_Taloga_Vici_69kV_3PH	OK	OK	OK
6	FLT_06_Taloga_Taloga_69_138kV_3PH	OK	OK	OK
7	FLT_07_Washita2_Caddo_69kV_3PH	OK	OK	OK
8	FLT_08_Washita2_Washita4_69_138kV_3P	OK	OK	OK
9	FLT_09_Lkcreek_CarterJ_69kV_3PH	OK	OK	OK
10	FLT_10_Lkcreek_Granite_69kV_3PH	OK	OK	OK
11	FLT_11_Gracemont_LES_345kV_3PH	OK	OK	OK
12	FLT_12_Washita4_Gracemont_138kV_3PH	OK	OK	OK

NOTE: “- NA -“means the contingency is not applicable

FERC LVRT Compliance

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu.

Contingencies 1,2, and 3 in Table III-2 simulated the LVRT contingencies. GEN-2012-028 met the LVRT requirements by staying on line and the transmission system remaining stable.

IV. Power Factor Analysis

A subset of the stability faults was used as power flow contingencies to determine the power factor requirements for the wind farm to maintain scheduled voltage at the POI. The voltage schedule was set equal to the voltages at the POI before the project is added, with a minimum of 1.0 per unit. A fictitious reactive power source replaced the study project to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study project at the POI were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study project must install before commercial operation.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage is less than 0.95 lagging, then the requirement is limited to 0.95 lagging. The lower limit for leading power factor requirement is also 0.95. If a project never operated leading under any contingency, then the leading requirement is set to 1.0. The same applies on the lagging side.

The power factor analysis showed a need for reactive capability by the study project at the POI. The final power factor requirement in the Generator Interconnection Agreement (GIA) will be the pro-forma 0.95 lagging to 0.95 leading at the POI, and this requirement is shown in Table IV-1. The detailed power factor analysis tables are in Appendix B. Since the Vestas V100 and V110 VCSS 2.0MW wind turbines have limited reactive capability (0.98 lagging and 0.96 leading), the generation facility will require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI.

Table IV-1: Power Factor Requirements [a]

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement at POI	
				Lagging [b]	Leading [c]
GEN-2012-028	74	Vestas V110 VCSS 2.0MW	Gotebo 69kV (520925)	0.95[d]	0.95[e]

Notes:

a. 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, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.

b. Lagging is when the generating plant is supplying reactive power to the transmission grid, like a shunt capacitor. In this situation, the alternating current sinusoid “lags” behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.

c. Leading is when the generating plant is taking reactive power from the transmission grid, like a shunt reactor. In this situation, the alternating current sinusoid “leads” the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

d. Electrical need is lower, but PF requirement limited to 0.95 by FERC order.

e. The most leading power factor determined through analysis was 1.00.

In a separate test, the effect of low-wind/no-wind conditions at the wind farm is analyzed. The project generators and capacitors (if any) were turned off in the base case (Figure IV-1). The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables.

Shunt reactors were added at the study project substation 34.5 kV buses to bring the Mvar flow into the Gotebo 69kV substation down to approximately zero (Gotebo 69kV in Figure IV-2). Final shunt reactor requirement for this project is approximately 3.5 Mvars. The one-line diagram in Figure IV-2 shows actual Mvar output at the specific voltages in the base case. The results shown are for the 2015SP case. The other two cases (2015WP and 2025SP) were almost identical since the plant design is the same in all cases.

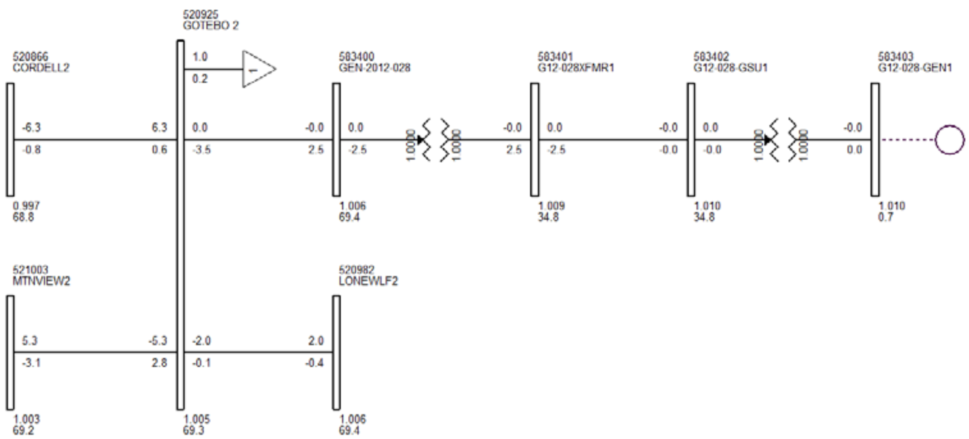

Figure IV-1: GEN-2012-028 with generators off and no shunt reactors

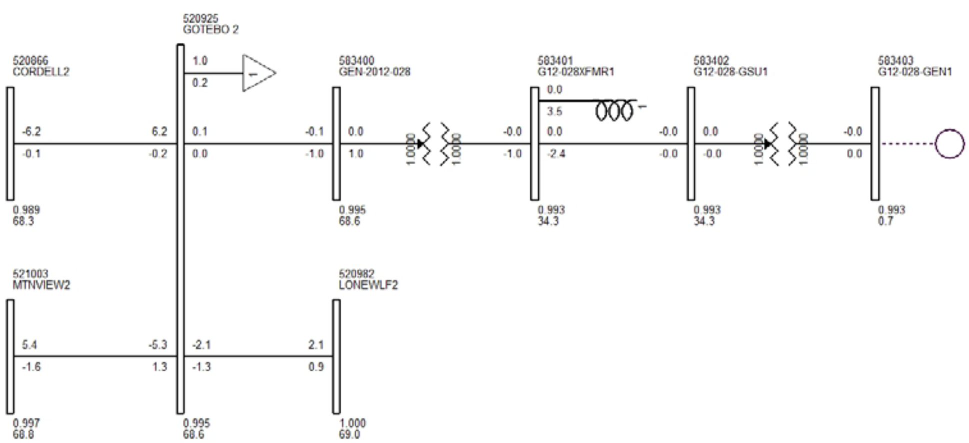

Figure IV-2: GEN-2012-028 with generators turned off and shunt reactors added to the low side of the substation 69/34.5kV transformers

V. Conclusion

The SPP GEN-2012-028 Impact Restudy evaluated the impact of interconnecting the project shown below.

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2012-028	74	Vestas V110 VCSS 2.0MW	Gotebo 69kV (520925)

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2012-028 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied.

A power factor analysis and a low-wind/no-wind condition analysis were performed for this modification request. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the POI. Since the Vestas V110 VCSS 2.0MW wind turbines have limited reactive capability, the generation facility will require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI. Additionally, the project will be required to install a total of approximately 3.5 Mvar of reactor shunts on its substation 34.5kV buses. This is necessary to offset the capacitive effect on the transmission network cause by the project's transmission line and collector system during low-wind or no-wind conditions.

Low Voltage Ride Through (LVRT) analysis showed the study generators did not trip offline due to low voltage when all Network Upgrades are in service.

All generators in the monitored areas remained stable for all of the modeled disturbances.

Any changes to the assumptions made in this study, for example, one or more of the previously queued requests withdraw, may require a re-study 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.

APPENDIX A

PLOTS

Available upon request

APPENDIX B

POWER FACTOR ANALYSIS

GEN-2012-028	**2015 Summer Peak**				**2015 Winter Peak**				**2025 Summer Peak**			
POI: Gotebo 69kV (520925)	**MW**	**Mvar**	**PF**		**MW**	**Mvar**	**PF**		**MW**	**Mvar**	**PF**	
POI voltage for all seasons is 1.0PU												
FLT_00_NoFault	74	-19.8506	0.965853	LEAD	74	-20.7388	0.9629	LEAD	74	-20.5803	0.963435	LEAD
FLT_01_Gotebo_Cordell_69kV	74	-18.5335	0.970039	LEAD	74	-17.6366	0.972754	LEAD	74	-20.9123	0.962312	LEAD
FLT_02_Gotebo_Lonewolf_69kV	74	-14.7337	0.980749	LEAD	74	-17.1169	0.974276	LEAD	74	-13.5652	0.98361	LEAD
FLT_03_Gotebo_MountainView_69kV	74	-15.0094	0.980044	LEAD	74	-14.8553	0.98044	LEAD	74	-17.1504	0.974179	LEAD
FLT_04_Taloga_Canton_69kV	74	-19.7642	0.966135	LEAD	74	-20.742	0.96289	LEAD	74	-20.6279	0.963275	LEAD
FLT_05_Taloga_Vici_69kV	74	-19.9054	0.965674	LEAD	74	-20.8821	0.962415	LEAD	74	-20.7671	0.962805	LEAD
FLT_06_Taloga_Taloga_69_138kV	74	-17.7778	0.972334	LEAD	74	-18.4125	0.970412	LEAD	74	-17.8491	0.972121	LEAD
FLT_07_Washita2_Caddo_69kV	74	-17.4988	0.973161	LEAD	74	-17.648	0.97272	LEAD	74	-18.6765	0.969596	LEAD
FLT_08_Washita2_Washita4_69_138kV	74	-19.5119	0.966951	LEAD	74	-21.3698	0.960742	LEAD	74	-20.0396	0.965233	LEAD
FLT_09_Lkcreek_CarterJ_69kV	74	-13.4665	0.983842	LEAD	74	-18.9142	0.968853	LEAD	74	-15.4618	0.978861	LEAD
FLT_10_Lkcreek_Granite_69kV	74	-23.1335	0.954449[b]	LEAD	74	-21.0199	0.961945	LEAD	74	-22.39	0.957147	LEAD
FLT_11_LES_Gracemont_345kV	74	-19.6237	0.966591	LEAD	74	-20.5767	0.963447	LEAD	74	-20.6269	0.963278	LEAD
FLT_12_Gracemont_Washita4_138kV	74	-19.7895	0.966052	LEAD	74	-20.6953	0.963047	LEAD	74	-20.6148	0.963319	LEAD

NOTE:

a. Lowest lagging (supplying vars) power factor requirement for all three seasons
b. Lowest leading (absorbing vars) power factor requirement for all three seasons

APPENDIX C

PROJECT MODELS

Available on request