GEN-2011-025 Impact Restudy for Generator Modification (Turbine Change)

April 2014
Generator Interconnection

Southwest Power Pool

Executive Summary

The GEN-2011-025 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied GE 1.6MW wind turbine generators to combination of Alstom ECO 110 3.0MW and the Alstom ECO 122 2.7MW wind turbine generators.

In this restudy the project uses four (4) Alstom ECO 110 3.0MW and twenty-five (25) Alstom ECO 122 2.7MW wind turbine generators for an aggregate power of 79.5MW. The point of interconnection (POI) for GEN-2011-025 is at the new Southwestern Public Service Company (SPS) 115kV switching station on the Crosby to Floyd County 115kV transmission line. The interconnection customer has provided documentation that shows the Alstom ECO 110 3.0MW wind turbine generator has a reactive capability of 0.90 lagging (providing VARS) and 0.90 leading (absorbing VARS) power factor, and the ECO 122 2.7MW wind turbine generator has a reactive capability of 0.83 lagging (providing VARS) and 0.83 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 2014 winter, 2015 summer, and 2024 summer seasons.

The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the Alstom ECO 110 3.0MW and the Alstom ECO 122 2.7MW 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 was 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.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2011-025 GIA in place, GEN-2011-025 with the Alstom ECO 110 3.0MW and the Alstom ECO 122 2.7MW 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-2011-025 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 November 30, 2015. This restudy is for a change from GE to Alstom ECO wind turbine generators.

Table I-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2011-025	79.5	Alstom ECO 110 3.0MW (4 machines for 12MW) Alstom ECO 122 2.7MW (25 machines for 67.5MW)	Tap on Floyd County - Crosby County 115kV line (G11-025-POI, 562004)

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-2001-033	180	Mitsubishi 1000	San Juan Mesa 230kV (524885)
GEN-2001-036	80	Mitsubishi 1000	Norton 115kV (524502)
GEN-2006-018	170	GENSAL	Tuco 230kV (525830)
GEN-2006-026	502	GENROU (527901, 527902, 527903)	Hobbs 115kV(527891) Hobbs 230kV (527894)
GEN-2008-022	300	GE 2.5MW	Tap on Eddy County – Tolk 345kV line (G08-022-POI, 560007)
GEN-2010-006	180 Summer 205 Winter	GENROU	Jones_bus2 230kV(526337)
ASGI-2010-010	42	GENSAL	Lovington 115kV (528334)
ASGI-2010-020	30	Nordex 2.5MW	Tap LE-Tatum to LE-Crsroads 69kV (AS10-020-POI, 560360)
ASGI-2010-021	15	Mitsubishi MPS-1000A 1.0MW	Tap LE-Saundrtp to LE-Anderson 69kV (ASGI-021-POI, 560364)
GEN-2010-046	56	GENSAL	Tuco 230kV (525830)
ASGI-2011-003	10	Sany 2.0MW	Hendricks 69kV (525943)

Table I-2: Prior Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
ASGI-2011-001	27.3	Suzlon 2.1MW	Lovington 115kV (528334)
GEN-2011-045	180 Summer 205 Winter	GENROU	Jones_bus2 230kV (526337)
GEN-2011-046	23 Summer 27 Winter	GENROU	Quay County 115kV (524472)
GEN-2011-048	165 Summer 175 Winter	GENROU	Mustang 230kV (527151)
ASGI-2011-004	19.8	Sany 1.8MW	Crosby 69kV (525915)
GEN-2012-001	61.2	CCWE 3.6MW (WT4)	Tap Grassland to Borden 230kV (526679)
GEN-2012-009	15 MW increase (Pgen=165MW)	GENROU	Mustang 230kV (527151)
GEN-2012-010	15 MW increase (Pgen=165MW)	GENROU	Mustang 230kV (527151)
GEN-2012-020	478	GE 1.68MW	Tuco 230kV (525830)
GEN-2012-034	7 MW increase (Pgen=172MW)	GENROU	Mustang 230kV (527151)
GEN-2012-035	7 MW increase (Pgen=172MW)	GENROU	Mustang 230kV (527151)
GEN-2012-036	7 MW increase (Pgen=172MW Summer/185MW Winter)	GENROU	Mustang 230kV (527151)
GEN-2012-037	196 Summer 203 Winter	GENROU	Tuco 345kV (525832)
ASGI-2012-002	18	Vestas 1.65MW V82	Clovis 115kV (524808)
GEN-2013-013	248.4	Siemens 2.3MW (583633, 583636)	Tap Tolk (525549) – Eddy County (527802) 345kV (560007)
GEN-2013-016	191 Summer 203 Winter	GENROU (583456)	Tuco 345kV (525832)
GEN-2013-022	25.0	Solaron 500kW (583313)	Caprock 115kV (524486)
ASGI-2013-002	18.4	Siemens 2.3MW VS (583613)	Tucumcari 115kV (524509)
ASGI-2013-003	18.4	Siemens 2.3MW VS (583623)	Clovis 115kV (524808)
ASGI-2013-005	19.8	Vestas V82 1.65MW (583283)	FE-Clovis 115kV (524808)
ASGI-2013-006	2.0	Gamesa G114 2MW (583813)	Erskine 115kV (526109)

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 2014 winter peak, the 2015 summer peak, and the 2024 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 POI for the wind interconnection project for pre-contingency and post-contingency conditions. The contingencies used in the power factor analysis are 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-2011-025 generation interconnection request is shown in Figure II-1. The POI is the new SPS 345kV switching station on the Floyd County to Crosby County 115kV transmission line.

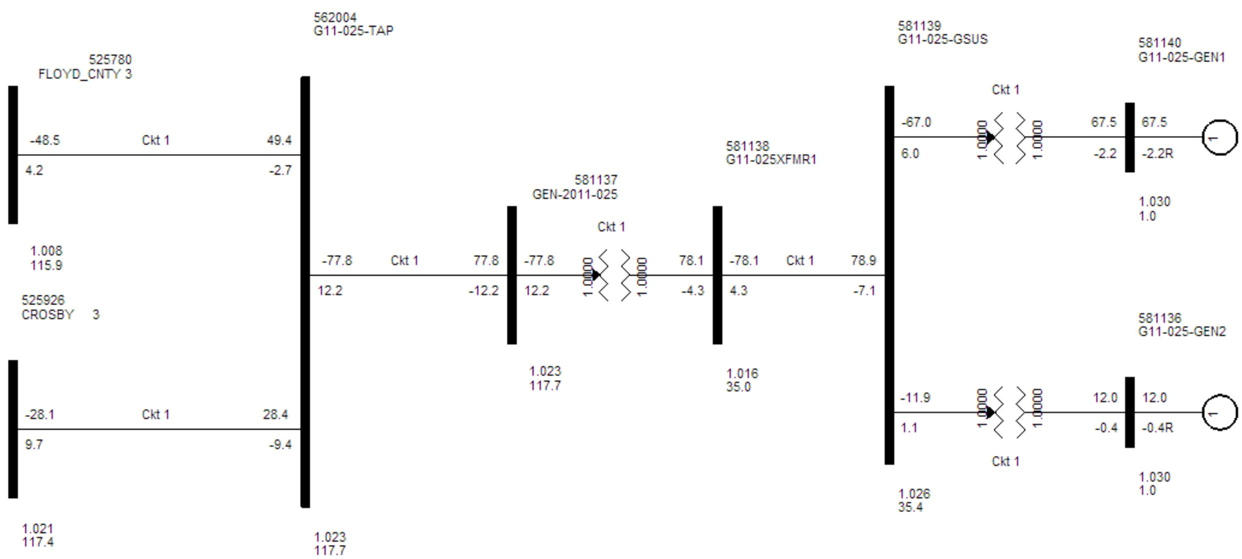

Figure II-1: GEN-2011-025 One-line Diagram

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 2013 series of Model Development Working Group (MDWG) dynamic study models including the 2014 winter peak, the 2015 summer peak, and the 2024 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

Fifty-six (56) 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)

The control areas monitored are 524, 525, 526, 531, 534, and 536.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
1	FLT_01_G11025TAP_CROSBY_115kV_3PH	3 phase fault on the G11-025 Tap (562004) to Crosby (525926) 115kV line, near G11-025 Tap. a. Apply fault at the G11-025 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.
2	FLT_02_G11025TAP_CROSBY_115kV_1PH	*Single phase fault and sequence like previous*
3	FLT_03_G11025TAP_FLOYDCOUNTY_115kV_3PH	3 phase fault on the G11-025 Tap (562004) to Eddy County (525780) 115kV line, near G11-025 Tap. a. Apply fault at the G11-025 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.
4	FLT_04_G11025TAP_FLOYDCOUNTY_115kV_1PH	*Single phase fault and sequence like previous*
5	FLT_05_FLOYDCOUNTY_COX_115kV_3PH	3 phase fault on the Floyd County (525780) to Cox (525326) 115kV line, near Floyd County. a. Apply fault at the Floyd County 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.
6	FLT_06_FLOYDCOUNTY_COX_115kV_1PH	*Single phase fault and sequence like previous*
7	FLT_07_FLOYDCOUNTY_TUCOINT_115kV_3PH	3 phase fault on the Floyd County (525780) to Tuco (525828) 115kV line, near Floyd County. a. Apply fault at the Floyd County 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	FLT_08_FLOYDCOUNTY_TUCOINT_115kV_1PH	*Single phase fault and sequence like previous*
9	FLT_09_COX_KISER_115kV_3PH	3 phase fault on the Cox (525326) to Kiser (525272) 115kV line, near Cox. a. Apply fault at the Cox 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.
10	FLT_10_COX_KISER_115kV_1PH	*Single phase fault and sequence like previous*

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
11	FLT_11_COX_HALECOUNTY_115kV_3PH	3 phase fault on the Cox (525326) to Hale County (525454) 115kV line, near Cox. a. Apply fault at the Cox 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.
12	FLT_12_COX_HALECOUNTY_115kV_1PH	*Single phase fault and sequence like previous*
13	FLT_13_TUCOINT_HALECOUNTY_115kV_3PH	3 phase fault on the Tuco (525828) to Hale County (525454) 115kV line, near Tuco. a. Apply fault at the Tuco 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.
14	FLT_14_TUCOINT_HALECOUNTY_115kV_1PH	*Single phase fault and sequence like previous*
15	FLT_15_TUCOINT_STANTONWEST_115kV_3PH	3 phase fault on the Tuco (525828) to Stanton West (526076) 115kV line, near Tuco. a. Apply fault at the Tuco 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.
16	FLT_16_TUCOINT_STANTONWEST_115kV_1PH	*Single phase fault and sequence like previous*
17	FLT_17_TUCOINT_LUBBOCKEAST_115kV_3PH	3 phase fault on the Tuco (525828) to Lubbock East (526298) 115kV line, near Tuco. a. Apply fault at the Tuco 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	FLT_18_TUCOINT_LUBBOCKEAST_115kV_1PH	*Single phase fault and sequence like previous*
19	FLT_19_CROSBY_LUBBOCKEAST_115kV_3PH	3 phase fault on the Crosby (525926) to Lubbock East (526298) 115kV line, near Crosby. a. Apply fault at the Crosby 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	FLT_20_CROSBY_LUBBOCKEAST_115kV_1PH	*Single phase fault and sequence like previous*

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
21	FLT_21_LUBBOCKEAST_LUBBOCKSOUTH_115kV_3PH	3 phase fault on the Lubbock East (526298) to Lubbock South (526268) 115kV line, near Lubbock East. a. Apply fault at the Lubbock East 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.
22	FLT_22_LUBBOCKEAST_LUBBOCKSOUTH_115kV_1PH	*Single phase fault and sequence like previous*
23	FLT_23_TUCOINT_SWISHER_230kV_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.
24	FLT_24_TUCOINT_SWISHER_230kV_1PH	*Single phase fault and sequence like previous*
25	FLT_25_TUCOINT_TOLKEAST_230kV_3PH	3 phase fault on the Tuco (525830) to Tolk East (525524) 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.
26	FLT_26_TUCOINT_TOLKEAST_230kV_1PH	*Single phase fault and sequence like previous*
27	FLT_27_TUCOINT_CARLISLE_230kV_3PH	3 phase fault on the Tuco (525830) to Carlisle (526161) 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.
28	FLT_28_TUCOINT_CARLISLE_230kV_1PH	*Single phase fault and sequence like previous*
29	FLT_29_TUCOINT_JONES_230kV_3PH	3 phase fault on the Tuco (525830) to Jones (526337) 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.
30	FLT_30_TUCOINT_JONES_230kV_1PH	*Single phase fault and sequence like previous*

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
31	FLT_31_TUCOINT_OKLAUNION_345kV_3PH	3 phase fault on the Tuco (525832) to Oklaunion (511456) 345kV line, near Tuco. a. Apply fault at the Tuco 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT_32_TUCOINT_OKLAUNION_345kV_1PH	*Single phase fault and sequence like previous*
33	FLT_33_TUCOINT_SWEETWATER_345kV_3PH	3 phase fault on the Tuco (525832) to Sweetwater (562335) 345kV line, near Tuco. a. Apply fault at the Tuco 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT_34_TUCOINT_SWEETWATER_345kV_1PH	*Single phase fault and sequence like previous*
35	FLT_35_LUBBOCKEAST_JONES_230kV_3PH	3 phase fault on the Lubbock East (526299) to Jones (526337) 230kV line, near Lubbock East. a. Apply fault at the Lubbock East 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.
36	FLT_36_LUBBOCKEAST_JONES_230kV_1PH	*Single phase fault and sequence like previous*
37	FLT_37_JONES_LPHOLLY_230kV_3PH	3 phase fault on the Jones (526337) to LP Holly (522870) 230kV line, near Jones. a. Apply fault at the near 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.
38	FLT_38_JONES_LPHOLLY_230kV_1PH	*Single phase fault and sequence like previous*
39	FLT_39_JONES_LUBBOCKSOUTH_230kV_3PH	3 phase fault on the Jones (526337) to Lubbock South (526269) 230kV line, near Jones. a. Apply fault at the near 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.
40	FLT_40_JONES_LUBBOCKSOUTH_230kV_1PH	*Single phase fault and sequence like previous*

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
41	FLT_41_JONES_GRASSLAND_230kV_3PH	3 phase fault on the Jones (526337) to Grassland (526677) 230kV line, near Jones. a. Apply fault at the near 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.
42	FLT_42_JONES_GRASSLAND_230kV_1PH	*Single phase fault and sequence like previous*
43	FLT_43_LUBBOCKSOUTH_ALLEN_115kV_3PH	3 phase fault on the Lubbock South (526935) to Allen (523213) 115kV line, near Lubbock South. a. Apply fault at the near Lubbock South 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.
44	FLT_44_LUBBOCKSOUTH_ALLEN_115kV_1PH	*Single phase fault and sequence like previous*
45	FLT_45_LUBBOCKSOUTH_SPWOODROW_115kV_3PH	3 phase fault on the Lubbock South (526935) to SP Woodrow (526602) 115kV line, near Lubbock South. a. Apply fault at the near Lubbock South 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.
46	FLT_46_LUBBOCKSOUTH_SPWOODROW_115kV_1PH	*Single phase fault and sequence like previous*
47	FLT_47_FLOYDCOUNTY_FLOYDCOUNTY_115_69kV_3PH	3 phase fault on the Floyd County (525780) 115kV to Floyd County (525779) 69kV/(525777) 13.2kV transformer, near Floyd County 115kV. a. Apply fault at the Floyd County 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
48	FLT_48_COX_COX_115_69kV_3PH	3 phase fault on the Cox (525326) 115kV to Cox (535325) 69kV/(525324) 13.2kV transformer ckt 2, near Cox 115kV. a. Apply fault at the Cox 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
49	FLT_49_TUCOINT_TUCOINT_115_69kV_3PH	3 phase fault on the Tuco (525828) 115kV to Tuco (525826) 69kV/(525823) 13.2kV transformer, near Tuco 115kV. a. Apply fault at the Tuco 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
50	FLT_50_TUCOINT_TUCOINT_115_230kV_3PH	3 phase fault on the Tuco (525828) 115kV to Tuco (525830) 230kV/(525821) 13.2kV transformer, near Tuco 115kV. a. Apply fault at the Tuco 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
51	FLT_51_CROSBYCOUNTY_CROSBYCOUNTY_115_69kV_3PH	3 phase fault on the Crosby County (525926) 115kV to Crosby County (525925) 69kV/(525924) 13.2kV transformer, near Crosby County 115kV. a. Apply fault at the Crosby County 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
52	FLT_52_LUBBOCKEAST_LUBOCKEAST_115_69kV_3PH	3 phase fault on the Lubbock East (526298) 115kV to Lubbock East (526297) 69kV/(526295) 13.2kV transformer, near Lubbock East 115kV. a. Apply fault at the Lubbock East 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
53	FLT_53_LUBBOCKEAST_LUBOCKEAST_115_230kV_3PH	3 phase fault on the Lubbock East (526298) 115kV to Lubbock East (526299) 230kV/(526294) 13.2kV transformer, near Lubbock East 115kV. a. Apply fault at the Lubbock East 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
54	FLT_54_TUCOINT_TUCOINT_230_345kV_3PH	3 phase fault on the Tuco (525830) 230kV to Tuco (525832) 345kV/(525824) 13.2kV transformer, near Tuco 230kV. a. Apply fault at the Tuco 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
55	FLT_55_GRASSLAND_GRASSLAND_230_115kV_3PH	3 phase fault on the Grassland (526677) 230kV to Grassland (526676) 115kV/(526674) 13.2kV transformer, near Grassland 230kV. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
56	FLT_56_LUBBOCKSOUTH_LUBBOCKSOUTH_230_115kV_3PH	3 phase fault on the Lubbock South (526269) 230kV to Lubbock South (526268) 115kV/(526265) 13.2kV transformer, near Lubbock South 230kV. a. Apply fault at the Lubbock East 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

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-2011-025 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.

Figures III-1, III-2, and III-3 show sample plots of the network response to a three phase fault at the POI and subsequent clearing action (tripping of the GEN-2011-025 Tap to Crosby County 115kV line). Complete sets of plots for the stability analysis are available on request.

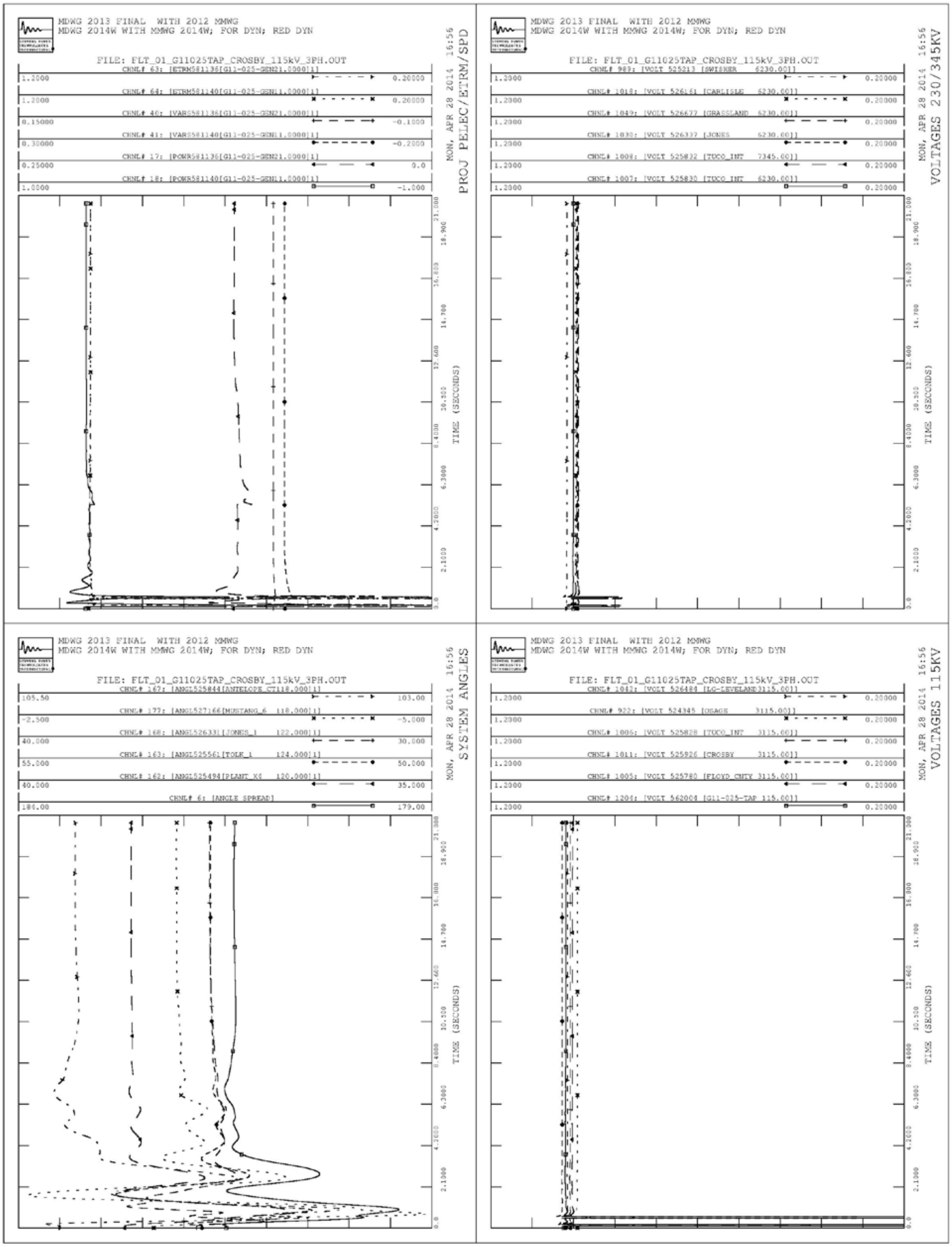

Figure III-1: Plot for GEN-2011-025 Tap to Crosby County 115kV Contingency (fault near GEN-2011-025 Tap) – 2014 Winter Peak

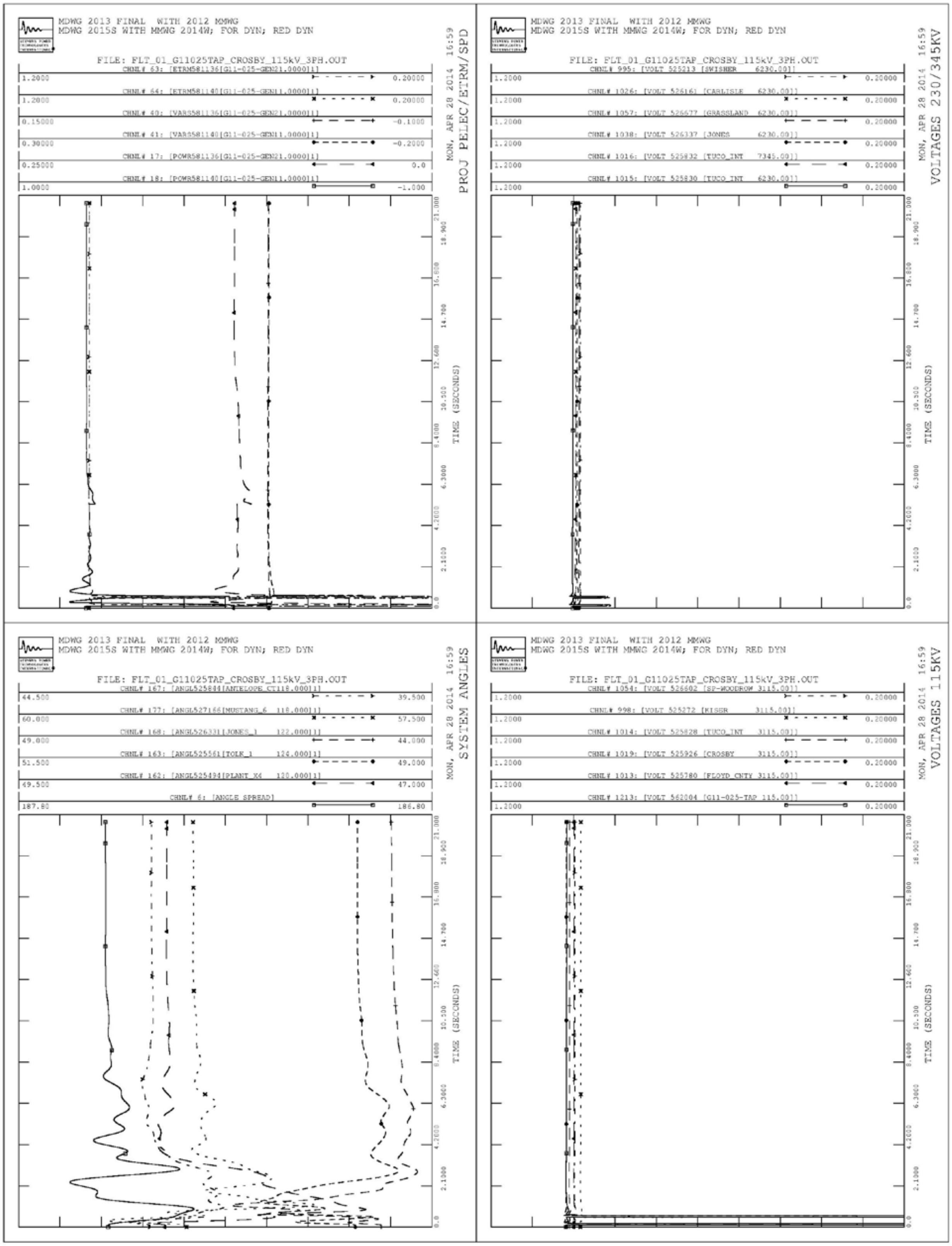

Figure III-2: Plot for GEN-2011-025 Tap to Crosby County 115kV Contingency (fault near GEN-2011-025 Tap) – 2015 Summer Peak

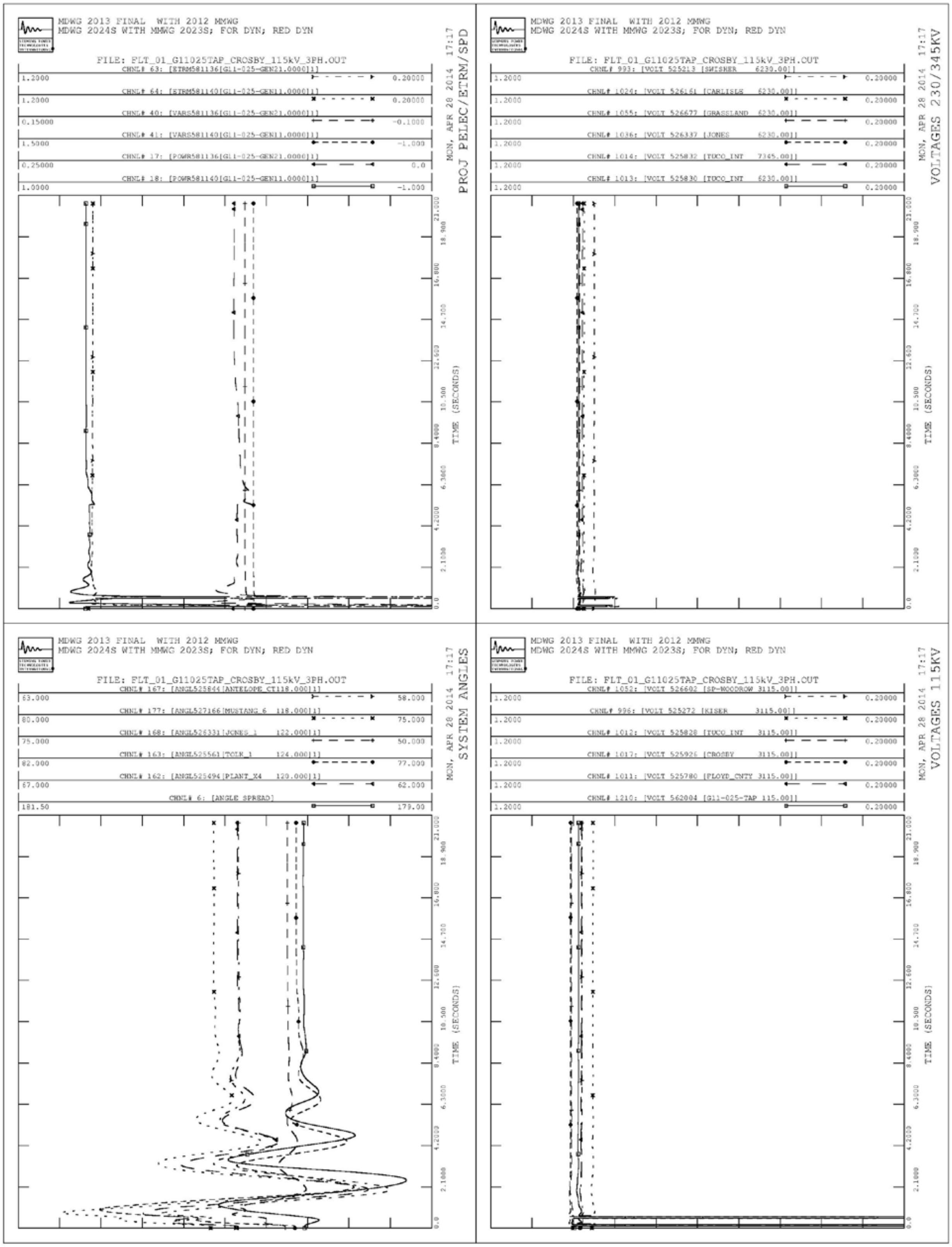

Figure III-3: Plot for GEN-2011-025 Tap to Crosby County 115kV Contingency (fault near GEN-2011-025 Tap) – 2024 Summer Peak

Table III-2: Stability Analysis Results

	Contingency Number and Name	2014WP	2015SP	2024SP
1	FLT_01_G11025TAP_CROSBY_115kV_3PH	Stable	Stable	Stable
2	FLT_02_G11025TAP_CROSBY_115kV_1PH	Stable	Stable	Stable
3	FLT_03_G11025TAP_FLOYDCOUNTY_115kV_3PH	Stable	Stable	Stable
4	FLT_04_G11025TAP_FLOYDCOUNTY_115kV_1PH	Stable	Stable	Stable
5	FLT_05_FLOYDCOUNTY_COX_115kV_3PH	Stable	Stable	Stable
6	FLT_06_FLOYDCOUNTY_COX_115kV_1PH	Stable	Stable	Stable
7	FLT_07_FLOYDCOUNTY_TUCOINT_115kV_3PH	Stable	Stable	Stable
8	FLT_08_FLOYDCOUNTY_TUCOINT_115kV_1PH	Stable	Stable	Stable
9	FLT_09_COX_KISER_115kV_3PH	Stable	Stable	Stable
10	FLT_10_COX_KISER_115kV_1PH	Stable	Stable	Stable
11	FLT_11_COX_HALECOUNTY_115kV_3PH	Stable	Stable	Stable
12	FLT_12_COX_HALECOUNTY_115kV_1PH	Stable	Stable	Stable
13	FLT_13_TUCOINT_HALECOUNTY_115kV_3PH	Stable	Stable	Stable
14	FLT_14_TUCOINT_HALECOUNTY_115kV_1PH	Stable	Stable	Stable
15	FLT_15_TUCOINT_STANTONWEST_115kV_3PH	Stable	Stable	Stable
16	FLT_16_TUCOINT_STANTONWEST_115kV_1PH	Stable	Stable	Stable
17	FLT_17_TUCOINT_LUBBOCKEAST_115kV_3PH	Stable	Stable	Stable
18	FLT_18_TUCOINT_LUBBOCKEAST_115kV_1PH	Stable	Stable	Stable
19	FLT_19_CROSBY_LUBBOCKEAST_115kV_3PH	Stable	Stable	Stable
20	FLT_20_CROSBY_LUBBOCKEAST_115kV_1PH	Stable	Stable	Stable
21	FLT_21_LUBBOCKEAST_LUBBOCKSOUTH_115kV_3PH	Stable	Stable	Stable
22	FLT_22_LUBBOCKEAST_LUBBOCKSOUTH_115kV_1PH	Stable	Stable	Stable
23	FLT_23_TUCOINT_SWISHER_230kV_3PH	Stable	Stable	Stable
24	FLT_24_TUCOINT_SWISHER_230kV_1PH	Stable	Stable	Stable
25	FLT_25_TUCOINT_TOLKEAST_230kV_3PH	Stable	Stable	Stable
26	FLT_26_TUCOINT_TOLKEAST_230kV_1PH	Stable	Stable	Stable
27	FLT_27_TUCOINT_CARLISLE_230kV_3PH	Stable	Stable	Stable
28	FLT_28_TUCOINT_CARLISLE_230kV_1PH	Stable	Stable	Stable
29	FLT_29_TUCOINT_JONES_230kV_3PH	Stable	Stable	Stable
30	FLT_30_TUCOINT_JONES_230kV_1PH	Stable	Stable	Stable
31	FLT_31_TUCOINT_OKLAUNION_345kV_3PH	Stable	Stable	Stable

Table III-2: Stability Analysis Results

Contingency Number and Name		2014WP	2015SP	2024SP
32	FLT_32_TUCOINT_OKLAUNION_345kV_1PH	Stable	Stable	Stable
33	FLT_33_TUCOINT_SWEETWATER_345kV_3PH	Stable	Stable	Stable
34	FLT_34_TUCOINT_SWEETWATER_345kV_1PH	Stable	Stable	Stable
35	FLT_35_LUBBOCKEAST_JONES_230kV_3PH	Stable	Stable	Stable
36	FLT_36_LUBBOCKEAST_JONES_230kV_1PH	Stable	Stable	Stable
37	FLT_37_JONES_LPHOLLY_230kV_3PH	Stable	Stable	Stable
38	FLT_38_JONES_LPHOLLY_230kV_1PH	Stable	Stable	Stable
39	FLT_39_JONES_LUBBOCKSOUTH_230kV_3PH	Stable	Stable	Stable
40	FLT_40_JONES_LUBBOCKSOUTH_230kV_1PH	Stable	Stable	Stable
41	FLT_41_JONES_GRASSLAND_230kV_3PH	Stable	Stable	Stable
42	FLT_42_JONES_GRASSLAND_230kV_1PH	Stable	Stable	Stable
43	FLT_43_LUBBOCKSOUTH_ALLEN_115kV_3PH	Stable	Stable	Stable
44	FLT_44_LUBBOCKSOUTH_ALLEN_115kV_1PH	Stable	Stable	Stable
45	FLT_45_LUBBOCKSOUTH_SPWOODROW_115kV_3PH	Stable	Stable	Stable
46	FLT_46_LUBBOCKSOUTH_SPWOODROW_115kV_1PH	Stable	Stable	Stable
47	FLT_47_FLOYDCOUNTY_FLOYDCOUNTY_115_69kV_3PH	Stable	Stable	Stable
48	FLT_48_COX_COX_115_69kV_3PH	Stable	Stable	Stable
49	FLT_49_TUCOINT_TUCOINT_115_69kV_3PH	Stable	Stable	Stable
50	FLT_50_TUCOINT_TUCOINT_115_230kV_3PH	Stable	Stable	Stable
51	FLT_51_CROSBYCOUNTY_CROSBYCOUNTY_115_69kV_3PH	Stable	Stable	Stable
52	FLT_52_LUBBOCKEAST_LUBOCKEAST_115_69kV_3PH	Stable	Stable	Stable
53	FLT_53_LUBBOCKEAST_LUBOCKEAST_115_230kV_3PH	Stable	Stable	Stable
54	FLT_54_TUCOINT_TUCOINT_230_345kV_3PH	Stable	Stable	Stable
55	FLT_55_GRASSLAND_GRASSLAND_230_115kV_3PH	Stable	Stable	Stable
56	FLT_56_LUBBOCKSOUTH_LUBBOCKSOUTH_230_115kV_3PH	Stable	Stable	Stable

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 and 3 in Table III-2 simulated the LVRT contingencies. GEN-2011-025 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.

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-2011-025	300	Vestas V100 VCSS 2.0MW	Tap Tolk (525549) – Eddy County (527802) 345kV (560007)	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. The most lagging power factor determined through analysis was 0.98.

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

V. Conclusion

The SPP GEN-2011-025 Impact Restudy evaluated the impact of interconnecting the project shown below.

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2011-025	79.5	Alstom ECO 110 3.0MW (4 machines for 12MW) Alstom ECO 122 2.7MW (25 machines for 67.5MW)	Tap on Floyd County - Crosby County 115kV line (G11-025-POI, 562004)

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and any required capacitor banks in service, the GEN-2011-025 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied. All generators in the monitored areas remained stable for all of the modeled disturbances.

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.

A power factor analysis was 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.

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

(Plots available on request)

APPENDIX B

POWER FACTOR ANALYSIS

GEN-2011-025 POI: Tap on Floyd County - Crosby County 115kV line (G11-025-POI, 562004)	2014 Winter Peak POI Voltage = 1.0122 pu				2015 Summer Peak POI Voltage = 1.0024 pu				2024 Summer Peak POI Voltage = 1.0000 pu			
	MW	Mvar	PF		MW	Mvar	PF		MW	Mvar	PF	
FLT_00_NoFault	79.5	-22.69	0.96	LEAD	79.5	-25.20	0.95	LEAD	79.5	1.18	1.00	LAG
FLT_01_G11025TAP_CROSBY_115kV	79.5	-16.00	0.98	LEAD	79.5	-17.84	0.98	LEAD	79.5	5.68	1.00	LAG
FLT_03_G11025TAP_FLOYDCOUNTY_115kV	79.5	-21.83	0.96	LEAD	79.5	-24.83	0.95	LEAD	79.5	-16.50	0.98	LEAD
FLT_05_FLOYDCOUNTY_COX_115kV	79.5	-21.30	0.97	LEAD	79.5	-31.75	0.93[1]	LEAD	79.5	-16.26	0.98	LEAD
FLT_07_FLOYDCOUNTY_TUCOINT_115kV	79.5	-19.49	0.97	LEAD	79.5	-15.13	0.98	LEAD	79.5	12.53	0.99	LAG
FLT_09_COX_KISER_115kV	79.5	-21.78	0.96	LEAD	79.5	-25.13	0.95	LEAD	79.5	-0.42	1.00	LEAD
FLT_11_COX_HALECOUNTY_115kV	79.5	-22.32	0.96	LEAD	79.5	-24.20	0.96	LEAD	79.5	2.45	1.00	LAG
FLT_13_TUCOINT_HALECOUNTY_115kV	79.5	-22.49	0.96	LEAD	79.5	-24.41	0.96	LEAD	79.5	2.30	1.00	LAG
FLT_15_TUCOINT_STANTONWEST_115kV	79.5	-21.84	0.96	LEAD	79.5	-25.17	0.95	LEAD	79.5	1.46	1.00	LAG
FLT_17_TUCOINT_LUBBOCKEAST_115kV	79.5	-22.49	0.96	LEAD	79.5	-24.89	0.95	LEAD	79.5	1.34	1.00	LAG
FLT_19_CROSBY_LUBBOCKEAST_115kV	79.5	-23.69	0.96	LEAD	79.5	-22.44	0.96	LEAD	79.5	6.69	1.00	LAG
FLT_21_LUBBOCKEAST_LUBBOCKSOUTH_115kV	79.5	-26.59	0.95	LEAD	79.5	-30.85	0.93	LEAD	79.5	-8.81	0.99	LEAD
FLT_23_TUCOINT_SWISHER_230kV	79.5	-22.54	0.96	LEAD	79.5	-24.66	0.96	LEAD	79.5	4.71	1.00	LAG
FLT_25_TUCOINT_TOLKEAST_230kV	79.5	-21.62	0.96	LEAD	79.5	-24.97	0.95	LEAD	79.5	1.54	1.00	LAG
FLT_27_TUCOINT_CARLISLE_230kV	79.5	-22.08	0.96	LEAD	79.5	-24.98	0.95	LEAD	79.5	0.83	1.00	LAG
FLT_29_TUCOINT_JONES_230kV	79.5	-21.99	0.96	LEAD	79.5	-25.47	0.95	LEAD	79.5	1.62	1.00	LAG
FLT_31_TUCOINT_OKLAUNION_345kV	79.5	-22.62	0.96	LEAD	79.5	-23.98	0.96	LEAD	79.5	10.53	0.99	LAG
FLT_33_TUCOINT_SWEETWATER_345kV	79.5	-22.10	0.96	LEAD	79.5	-24.14	0.96	LEAD	79.5	9.03	0.99	LAG
FLT_35_LUBBOCKEAST_JONES_230kV	79.5	-14.57	0.98	LEAD	79.5	-12.95	0.99	LEAD	79.5	20.85	0.97[2]	LAG
FLT_37_JONES_LPHOLLY_230kV	79.5	-22.38	0.96	LEAD	79.5	-24.74	0.95	LEAD	79.5	2.02	1.00	LAG
FLT_39_JONES_LUBBOCKSOUTH_230kV	79.5	-22.78	0.96	LEAD	79.5	-25.28	0.95	LEAD	79.5	1.63	1.00	LAG
FLT_41_JONES_GRASSLAND_230kV	79.5	-22.09	0.96	LEAD	79.5	-24.47	0.96	LEAD	79.5	1.65	1.00	LAG
FLT_43_LUBBOCKSOUTH_ALLEN_115kV	79.5	-22.57	0.96	LEAD	79.5	-24.01	0.96	LEAD	79.5	1.87	1.00	LAG
FLT_45_LUBBOCKSOUTH_SPWOODROW_115kV	79.5	-22.29	0.96	LEAD	79.5	-25.01	0.95	LEAD	79.5	0.32	1.00	LAG
FLT_47_FLOYDCOUNTY_FLOYDCOUNTY_115_69kV	79.5	-22.53	0.96	LEAD	79.5	-23.43	0.96	LEAD	79.5	3.86	1.00	LAG

GEN-2011-025 **POI: Tap on Floyd County - Crosby County 115kV line (G11-025-POI, 562004)**	**2014 Winter Peak** POI Voltage = 1.0122 pu				**2015 Summer Peak** POI Voltage = 1.0024 pu				**2024 Summer Peak** POI Voltage = 1.0000 pu			
	MW	**Mvar**	**PF**		**MW**	**Mvar**	**PF**		**MW**	**Mvar**	**PF**	
FLT_48_COX_COX_115_69kV	79.5	-23.53	0.96	LEAD	79.5	-25.52	0.95	LEAD	79.5	1.09	1.00	LAG
FLT_49_TUCOINT_TUCOINT_115_69kV	79.5	-22.65	0.96	LEAD	79.5	-24.98	0.95	LEAD	79.5	1.61	1.00	LAG
FLT_50_TUCOINT_TUCOINT_115_230kV	79.5	-21.95	0.96	LEAD	79.5	-23.32	0.96	LEAD	79.5	1.59	1.00	LAG
FLT_51_CROSBYCOUNTY_CROSBYCOUNTY_115_69kV	79.5	-23.49	0.96	LEAD	79.5	-25.20	0.95	LEAD	79.5	1.18	1.00	LAG
FLT_52_LUBBOCKEAST_LUBOCKEAST_115_69kV	79.5	-22.54	0.96	LEAD	79.5	-24.76	0.95	LEAD	79.5	1.99	1.00	LAG
FLT_53_LUBBOCKEAST_LUBOCKEAST_115_230kV	79.5	-12.84	0.99	LEAD	79.5	-13.55	0.99	LEAD	79.5	19.24	0.97	LAG
FLT_54_TUCOINT_TUCOINT_230_345kV	79.5	-23.29	0.96	LEAD	79.5	-25.54	0.95	LEAD	79.5	0.57	1.00	LAG
FLT_55_GRASSLAND_GRASSLAND_230_115kV	79.5	-21.35	0.97	LEAD	79.5	-23.67	0.96	LEAD	79.5	2.66	1.00	LAG
FLT_56_LUBBOCKSOUTH_LUBBOCKSOUTH_230_115kV	79.5	-24.35	0.96	LEAD	79.5	-26.12	0.95	LEAD	79.5	0.85	1.00	LAG

NOTE:
1. Lowest leading (absorbing vars) power factor requirement for all three seasons
2. Lowest lagging (supplying vars) power factor requirement for all three seasons

APPENDIX C

PROJECT MODELS

(Power flow and dynamic models available on request)