GEN-2014-001
Impact Restudy for Generator Modification (Turbine Change)

April 2015
Generator Interconnection

Southwest Power Pool

Executive Summary

The GEN-2014-001 interconnection customer has requested a modification to its Interconnection Request to change wind generator manufacturer from GE to Gamesa. SPP has performed this system impact restudy to determine the effects of changing wind turbine generators from the previously studied[1] GE 1.7MW wind turbine generators (118 machines total for aggregate power of 200.6MW) to Gamesa 2.1 MW wind turbine generators (95 machines total for aggregate power of 199.5MW). The point of interconnection (POI) remains at a new substation on the Westar Energy (WERE) Wichita to Emporia Energy Center 345kV line.

The study models used were the 2015 summer, the 2015 winter, and the 2025 summer cases and included Interconnection Requests through DISIS-2014-001. The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the Gamesa 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 low-wind/no-wind condition analysis was performed for this modification request. The project will be required to install approximately 23.5 Mvar of shunt reactors 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.

The power factor analysis was not performed again for this study. The results from DISIS 2014-001 are still valid. GEN-2014-001 will be required to meet 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI.

With the assumptions outlined in this report and with all the required network upgrades from the DISIS-2014-001 in place, GEN-2014-001 with the Gamesa 2.0MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. 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.

[1] DISIS-2014-001 posted July 2014, see Appendix L: Group 8 Dynamic Stability Analysis Report performed by S&C Electric Company.

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-2014-001 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. This restudy is for a change from one hundred eighteen (118) GE 1.7MW to ninety-five (95) Gamesa 2.0MW wind turbines.

Table I-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2014-001	199.5	Gamesa 2.0MW	Tap on the Wichita to Emporia Energy Center 345kV line

The prior-queued, equally-queued and lower 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 and Later Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2002-004	199.5	GE.1.5MW	Latham 345kV (532800)
GEN-2005-013	199.8	Vestas V90 1.8MW	Caney River 345kV (532780)
GEN-2007-025	299.2	GE 1.6MW	Viola 345kV (532798)
GEN-2008-013	299.04	GE 1.68MW	Hunter 345kV (515476)
GEN-2008-021	1283	GENROU	Wolf Creek 345kV (532797)
GEN-2008-098	100.0	Gamesa G114 2.0MW	Tap on the Wolf Creek – LaCygne 345kV line (Waverly 345kV, 532799)
GEN-2009-025	59.8	Siemens 2.3MW	Tap on the Deerck – Sincblk 69KV line (515528)
GEN-2010-003	100.0	Gamesa G114 2.0MW	Tap on the Wolf Creek – LaCygne 345kV line (Waverly 345kV, 532799)
GEN-2010-005	299.2	GE 1.6MW	Viola 345kV (532798)
ASGI-2010-006	150	GE1.5MW	Remington 138kV (301369)
GEN-2010-055	4.8	GENROU	Wekiwa 138kV (509757)
GEN-2011-057	150.0	Vestas V110 2.0MW	Creswell 138kV (532981)
GEN-2012-027	150.7	GE 1.62MW	Shidler 138kV (510403)
GEN-2012-032	299	Siemens 2.3MW	Tap Rose Hill-Sooner 345kV (562318)
GEN-2012-033	98.8	GE 1.62MW	Tap Bunch Creek-South 4th 138kV(562303)
GEN-2012-040	76.5	GE 1.7MW	Chilocco 138kV (521198)
GEN-2012-041	85 Summer 121.5 Winter	GENROU	Tap Rose Hill-Sooner 345kV (562318)

Table I-2: Prior and Later Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2013-012	4 x 168.0MW Summer 4 x 215MW Winter	GENROU (514910) (514911) (514912) (514942)	Redbud 345kV (514909)
GEN-2013-028	516.4 Summer 559.5 Winter	GENROU (583743, 583746)	Tap on Tulsa N to GRDA1 345kV (562423)
GEN-2013-029	299.8	GE 2.3MW and Vestas V100 VCSS 2.0MW	Renfrow 345kV(515543)

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 low-wind/no-wind 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 models included Interconnection Requests through DISIS-2014-001.

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 was not re-run as the results from the DISIS 2014-001 study are still valid. GEN-2014-001 will be required to meet 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI.

The low-wind/no-wind analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line capacitance. A shunt reactor size was determined to offset the capacitive effect and to maintain zero Mvar flow at the POI when the plant generators and capacitors are off-line such as might be seen in low-wind or no-wind conditions.

II. Facilities

A one-line drawing for the GEN-2014-001 generation interconnection request is shown in Figure II-1. The POI is a new substation on the Wichita to Emporia Energy Center 345kV line.

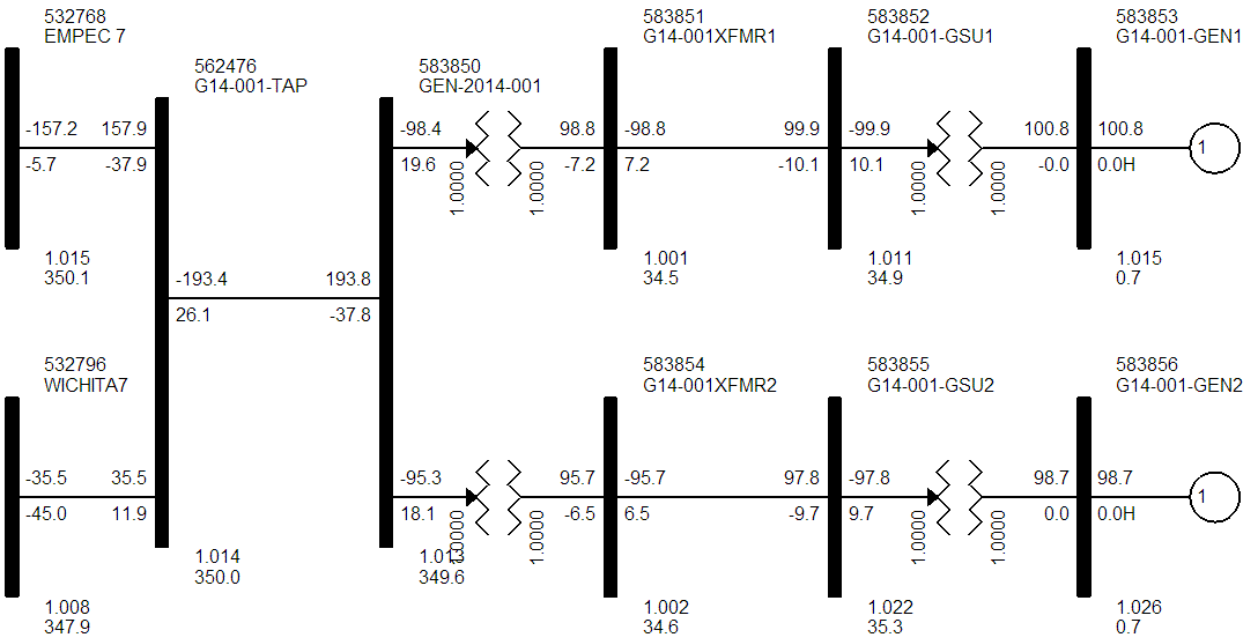

Figure II-1: GEN-2014-001 One-line Diagram

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

Fifty-three (53) 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	FLT01-3PH	3 phase fault on the GEN-2014-001 (562476) to Wichita (532796) 345kV line ckt 1, near GEN-2014-001. a. Apply fault at the GEN-2014-001 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.
2	FLT02-3PH	3 phase fault on the GEN-2014-001 (562476) to EMPEC (532768) 345kV line ckt 1, near GEN-2014-001. a. Apply fault at the GEN-2014-001 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	FLT03-3PH	3 phase fault on the Wichita (532796) to Reno (532771) 345kV line ckt 1, near Wichita. a. Apply fault at the Wichita 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.
4	FLT04-3PH	3 phase fault on the Wichita (532796) to Benton (532791) 345kV line ckt 1, near Wichita. a. Apply fault at the Wichita 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.
5	FLT05-3PH	3 phase fault on the Wichita (532796) to Viola (532798) 345kV line ckt 1, near Wichita. a. Apply fault at the Wichita 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
6	FLT06-3PH	3 phase fault on the Wichita (532796) to Thistle (539801) 345kV line ckt 1, near Wichita. a. Apply fault at the Wichita 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.
7	FLT07-3PH	3 phase fault on the Lang (532769) to EMPEC (532768) 345kV line ckt 1, near Lang. a. Apply fault at the Lang 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.
8	FLT08-3PH	3 phase fault on the Morris (532770) to EMPEC (532768) 345kV line ckt 1, near Morris. a. Apply fault at the Morris 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.
9	FLT09-3PH	3 phase fault on the Swissvale (532774) to EMPEC (532768) 345kV line ckt 1, near Swissvale. a. Apply fault at the Swissvale 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.
10	FLT10-3PH	3 phase fault on the Wichita (532796) to GEN-2014-001 (562476)345kV line ckt 1, near Wichita. a. Apply fault at the Wichita 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
11	FLT11-3PH	3 phase fault on the Lang (533304) to East St (533301) 115kV line ckt 1, near Lang. a. Apply fault at the Lang 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	FLT12-3PH	3 phase fault on the Lang (533304) to Reading (533306) 115kV line ckt 1, near Lang. a. Apply fault at the Lang 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.
13	FLT13-3PH	3 phase fault on the Lang (533304) to Prairie (533307) 115kV line ckt 1, near Lang. a. Apply fault at the Lang 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	FLT14-3PH	3 phase fault on the Morris (532770) to JEC (532766) 345kV line ckt 1, near Morris. a. Apply fault at the Morris 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.
15	FLT15-3PH	3 phase fault on the Morris (532863) to Swissvale (532856) 230kV line ckt 1, near Morris. a. Apply fault at the Morris 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
16	FLT16-3PH	3 phase fault on the Morris (532863) to McDowell (532862) 230kV line ckt 1, near Morris. a. Apply fault at the Morris 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.
17	FLT17-3PH	3 phase fault on the Morris (532863) to Union Ridge (532874) 230kV line ckt 1, near Morris. a. Apply fault at the Morris 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	FLT18-3PH	3 phase fault on the Swissvale (532774) to W. Gardner (542965) 345kV line ckt 1, near Swissvale. a. Apply fault at the Swissvale 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.
19	FLT19-3PH	3 phase fault on the Swissvale (532856) to Auburn (532851) 230kV line ckt 1, near Swissvale. a. Apply fault at the Swissvale 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.
20	FLT20-3PH	3 phase fault on the Swissvale (532856) to Lawhill (532853) 230kV line ckt 1, near Swissvale. a. Apply fault at the Swissvale 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
21	FLT21-3PH	3 phase fault on the Swissvale (532856) to Techill (532857) 230kV line ckt 1, near Swissvale. a. Apply fault at the Swissvale 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-3PH	3 phase fault on the Benton (532791) to Rosehill (532794) 345kV line ckt 1, near Benton. a. Apply fault at the Benton 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.
23	FLT23-3PH	3 phase fault on the Benton (532791) to Wolfcreek (532797) 345kV line ckt 1, near Benton. a. Apply fault at the Benton 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-3PH	3 phase fault on the Benton (532986) to Midian (532990) 138kV line ckt 1, near Benton. a. Apply fault at the Benton 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.
25	FLT25-3PH	3 phase fault on the Benton (532986) to 29th (533024) 138kV line ckt 1, near Benton. a. Apply fault at the Benton 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
26	FLT26-3PH	3 phase fault on the Benton (532986) to Chisholm (533035) 138kV line ckt 1, near Benton. a. Apply fault at the Benton 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.
27	FLT27-3PH (2015SP/WP only)	3 phase fault on the Benton (532986) to Comotar (533037) 138kV line ckt 1, near Benton. a. Apply fault at the Benton 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.
28	FLT28-3PH	3 phase fault on the Renfrow (515543) to Hunters (515476) 138kV line ckt 1, near Renfrow. a. Apply fault at the Renfrow 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.
29	FLT29-3PH	3 phase fault on the Thistle (539801) to Clark County (539800) 345kV line ckt 1, near Thistle. a. Apply fault at the Thistle 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.
30	FLT30-3PH	3 phase fault on the Thistle (539801) to Woodward (515375) 345kV line ckt 1, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line, Thistle (539801) to G12-016-TAP (562286) to Woodward (515375). 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.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
31	FLT31-3PH	3 phase fault on the Reno (532771) to Summit (532773) 345kV line ckt 1, near Reno. a. Apply fault at the Reno 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	FLT32-3PH	3 phase fault on the Renfro (515543) 345kV to Renfro (515544) 138kV/(515545) 13.8kV transformer at the 345kV bus. a. Apply fault at the Renfro 345kV bus. b. Clear fault after 5 cycles by tripping the transformer
33	FLT33-3PH	3 phase fault on the Lang (533304) 115kV to Lang (532769) 345kV/(532808) 14.4kV transformer at the 115kV bus. a. Apply fault at the Lang 115kV bus. b. Clear fault after 5 cycles by tripping the transformer
34	FLT34-3PH	3 phase fault on the Wichita (532796) 345kV to Evans (533040) 138kV/(532830) 13.8kV transformer at the 345kV bus. a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the transformer
35	FLT35-3PH	3 phase fault on the Morris (532770) 345kV to Morris (532863) 230kV/(532809) 14.4kV transformer at the 345kV bus. a. Apply fault at the Morris 345kV bus. b. Clear fault after 5 cycles by tripping the transformer
36	FLT36-3PH	3 phase fault on the Morris (532863) 230kV to Morris (533305) 115kV/(532890) 13.8kV transformer at the 230kV bus. a. Apply fault at the Morris 230kV bus. b. Clear fault after 5 cycles by tripping the transformer
37	FLT37-3PH	3 phase fault on the Swissvale (532856) 230kV to Swissvale (532774) 345kV/(532815) 14.4kV transformer at the 230kV bus. a. Apply fault at the Swissvale 230kV bus. b. Clear fault after 5 cycles by tripping the transformer
38	FLT38-3PH	3 phase fault on the Benton (532791) 345kV to Benton (532986) 138kV/(532821) 13.8kV transformer at the Benton 345kV bus. a. Apply fault at the Benton 345kV bus. b. Clear fault after 5 cycles by tripping the transformer
39	FLT39-3PH	3 phase fault on the Thistle (539801) 345kV to Thistle (539804) 138kV/(539802) 13.8kV transformer at the Thistle 345kV bus. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles by tripping the transformer

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
40	FLT40-3PH	3 phase fault on the Reno (532771) 345kV to Reno (533416) 115kV/(532810) 13.8kV transformer at the Reno 345kV bus. a. Apply fault at the Reno 345kV bus. b. Clear fault after 5 cycles by tripping the transformer
41	FLT41-3PH	**Prior Outage Wolf Creek to Benton 345kV line** Trip Wolf Creek (532797) to Benton (532791) 345kV line, reduce Wolf Creek (532751) output to 800MW, and solve for steady state. Then -- a. Apply 3 phase fault at Wolf Creek 345kV. b. After 3.6 cycles remove fault. c. Trip Wolf Creek - Waverly (532799) 345kV line.
42	FLT42-3PH	**Prior Outage Wolf Creek to Waverly 345kV line** Trip Wolf Creek (532797) to Waverly (532799) 345kV line, reduce Wolf Creek (532751) output to 800MW, and solve for steady state. Then -- a. Apply 3 phase fault at Wolf Creek 345kV. b. After 3.6 cycles remove fault. c. Trip Wolf Creek - Benton (532791) 345kV line.
43	FLT43-3PH	**Prior Outage Wolf Creek to Rose Hill 345kV line** Trip Wolf Creek (532797) to Rose Hill (532794) 345kV line, reduce Wolf Creek (532751) output to 800MW, and solve for steady state. Then -- a. Apply 3 phase fault at Wolf Creek 345kV. b. After 3.6 cycles remove fault. c. Trip Wolf Creek - Waverly (532799) 345kV line.
44	FLT44-1PH	**Wichita (532796) 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Wichita (532796) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop Wichita (532796)-Reno (532771) 345kV, ckt 1 line. d. Drop Wichita –Evans Transformer (532796,533040, 532830,"1").
45	FLT45-1PH	**Wichita (532796) 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Wichita (532796) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop Wichita (532796)-Benton (532791) 345kV, ckt 1 line. d. Drop Wichita –Evans Transformer (532796,533040,532830,"1").
46	FLT46-1PH	**Wichita (532796) 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Wichita (532796) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop Wichita (532796)-Viola (532798) 345kV, ckt 1 line. d. Drop Wichita –Evans Transformer (532796,533040,532830,"1").

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
47	FLT47-1PH	**Wichita (532796) 345kV Stuck Breaker Scenario 4** a. Apply single phase fault at the Wichita (532796) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop Wichita (532796)-Thistle (539801) 345kV, ckt 1 line. d. Drop Wichita –Evans Transformer (532796,533040,532830,"1").
48	FLT48-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Lang (532769) 345kV, ckt 1 line. d. Drop EMPEC121 generation (532740).
49	FLT49-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Morris (532770) 345kV, ckt 1 line. d. Drop EMPEC121 generation (532740).
50	FLT50-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Swissvale (532774) 345kV, ckt 1 line. d. Drop EMPEC121 generation (532740).
51	FLT51-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Lang (532769) 345kV, ckt 1 line. d. Drop EMPEC51 generation (532742).
52	FLT52-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Morris (532770) 345kV, ckt 1 line. d. Drop EMPEC51 generation (532742).
53	FLT53-1PH	**EMPEC (532768) 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the EMPEC (532768) 345kV bus. b. Wait 16 cycles and remove fault. c. Drop EMPEC (532768)-Swissvale (532774) 345kV, ckt 1 line. d. Drop EMPEC51 generation (532742).

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
54	FLT55-3PH (2024SP Only)	3 phase fault on the Benton (532986) to Belaire (532988) 138kV line ckt 1, near Benton. a. Apply fault at the Benton 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-2014-001 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.

Complete sets of plots for the stability analysis are available on request.

Table III-2: Stability Analysis Results

Contingency Number and Name		2015SP	2015WP	2025SP
1	FLT01-3PH	Stable	Stable	Stable
2	FLT02-3PH	Stable	Stable	Stable
3	FLT03-3PH	Stable	Stable	Stable
4	FLT04-3PH	Stable	Stable	Stable
5	FLT05-3PH	Stable	Stable	Stable
6	FLT06-3PH	Stable	Stable	Stable
7	FLT07-3PH	Stable	Stable	Stable
8	FLT08-3PH	Stable	Stable	Stable
9	FLT09-3PH	Stable	Stable	Stable
10	FLT10-3PH	Stable	Stable	Stable
11	FLT11-3PH	Stable	Stable	Stable
12	FLT12-3PH	Stable	Stable	Stable
13	FLT13-3PH	Stable	Stable	Stable
14	FLT14-3PH	Stable	Stable	Stable
15	FLT15-3PH	Stable	Stable	Stable
16	FLT16-3PH	Stable	Stable	Stable
17	FLT17-3PH	Stable	Stable	Stable
18	FLT18-3PH	Stable	Stable	Stable
19	FLT19-3PH	Stable	Stable	Stable
20	FLT20-3PH	Stable	Stable	Stable
21	FLT21-3PH	Stable	Stable	Stable
22	FLT22-3PH	Stable	Stable	Stable
23	FLT23-3PH	Stable	Stable	Stable
24	FLT24-3PH	Stable	Stable	Stable
25	FLT25-3PH	Stable	Stable	Stable
26	FLT26-3PH	Stable	Stable	Stable
27	FLT27-3PH (2015SP/WP only)	Stable	Stable	NA
28	FLT28-3PH	Stable	Stable	Stable
29	FLT29-3PH	Stable	Stable	Stable
30	FLT30-3PH	Stable	Stable	Stable
31	FLT31-3PH	Stable	Stable	Stable
32	FLT32-3PH	Stable	Stable	Stable
33	FLT33-3PH	Stable	Stable	Stable
34	FLT34-3PH	Stable	Stable	Stable
35	FLT35-3PH	Stable	Stable	Stable
36	FLT36-3PH	Stable	Stable	Stable
37	FLT37-3PH	Stable	Stable	Stable
38	FLT38-3PH	Stable	Stable	Stable

Table III-2: Stability Analysis Results

Contingency Number and Name		2015SP	2015WP	2025SP
39	FLT39-3PH	Stable	Stable	Stable
40	FLT40-3PH	Stable	Stable	Stable
41	FLT41-3PH	Stable	Stable	Stable
42	FLT42-3PH	Stable	Stable	Stable
43	FLT43-3PH	Stable	Stable	Stable
44	FLT44-1PH	Stable	Stable	Stable
45	FLT45-1PH	Stable	Stable	Stable
46	FLT46-1PH	Stable	Stable	Stable
47	FLT47-1PH	Stable	Stable	Stable
48	FLT48-1PH	Stable	Stable	Stable
49	FLT49-1PH	Stable	Stable	Stable
50	FLT50-1PH	Stable	Stable	Stable
51	FLT51-1PH	Stable	Stable	Stable
52	FLT52-1PH	Stable	Stable	Stable
53	FLT53-1PH	Stable	Stable	Stable
54	FLT55-3PH (2024SP Only)	NA	NA	Stable

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 and 2 in Table III-2 simulated the LVRT contingencies. GEN-2014-001 met the LVRT requirements by staying on line and the transmission system remaining stable.

IV. Power Factor Analysis

The power factor analysis was not performed since a previous analysis is still valid. Refer to DISIS-2014-001, Appendix L: Group 8 Dynamic Stability Analysis Report for the power factor analysis. GEN-2014-001 will be required to meet 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI.

V. Reduced Generation Analysis

Interconnection requests for wind generation projects that interconnect on the SPP system are analyzed for the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, curtailment, etc.) at the generation site.

Model Preparation

The project generators and capacitors (if any), and all other wind projects that share the same POI, were turned off in the base case. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables. This reactive power injection is measured at the POI. Shunt reactors were added at the study project substation low voltage bus to bring the Mvar flow into the POI down to approximately zero.

Results

A final shunt reactor requirement for each of the studied interconnection requests is shown in **Table V-1**. One line drawings used in the analysis are shown in Error! Reference source not found..

Table V-1: Summary of Shunt Reactor Requirements

Request	Capacity	POI	Approximate Shunt Reactor Required
GEN-2014-001	199.5MW	A new substation on the Wichita to Emporia Energy Center 345kV line	23.5 Mvar

The results shown are for the 2025 summer case. The other two cases (2015 summer and 2015 winter) were almost identical since the generation plant design is the same in all cases.

VI. Short Circuit Analysis

The short circuit analysis was performed on the 2025 Summer Peak power flow case using the PSS/E ASCC program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at the point of interconnection up to and including five levels away. The following pages list the results of the analysis.

Results

The results of the short circuit analysis are shown in **Table VIII-1** in **Appendix C: Short Circuit Analysis Results.**

VII. Conclusion

The SPP GEN-2014-001 Impact Restudy evaluated the impact of interconnecting the project shown below in Table VII-1.

Table VII-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2014-001	199.5	Gamesa 2.0MW	Tap on the Wichita to Emporia Energy Center 345kV line

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2014-001 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied.

A low-wind/no-wind condition analysis was performed for this modification request. The project will be required to install a total of approximately 23.5Mvar 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.

The power factor analysis was not performed for this study because the analysis performed in DISIS-2014-001 Impact Study remains valid. GEN-2014-001 will be required to meet 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI.

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 on request

APPENDIX B

POWER FACTOR ANALYSIS

Power Factor Analysis was not performed again. Results from DISIS 2014-001 remain valid. GEN-2014-001 will be required to meet 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI.

APPENDIX C

SHORT CIRCUIT ANALYSIS

Table VIII-1: Short Circuit Currents at GEN-2014-001 POI (Tap on Wichita to Emporia Energy Center) and five levels away

```
                              PSS(R)E-32.2.2 ASCC SHORT CIRCUIT CURRENTS          FRI, APR
10 2015  14:16
2014 MDWG PASS 8   WITH 2013 MMWG
MDWG 2025S WITH MMWG 2024S

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                   THREE PHASE FAULT
X---------- BUS ----------X           /I+/    AN(I+)
562476 [G14-001-TAP 345.00] AMP    10451.1   -85.18
532768 [EMPEC 7     345.00] AMP    16743.6   -86.15
532796 [WICHITA7    345.00] AMP    23690.4   -86.28
583850 [GEN-2014-001345.00] AMP     6990.9   -84.94
532740 [EMPEC121    13.800] AMP    60853.9   -89.87
532741 [EMPEC341    13.800] AMP    60853.9   -89.87
532742 [EMPEC5 1    18.000] AMP    85176.6   -89.65
532743 [EMPEC6 1    18.000] AMP    85176.6   -89.65
532744 [EMPEC7 1    18.000] AMP    85176.6   -89.65
532769 [LANG   7    345.00] AMP    16546.3   -86.14
532770 [MORRIS 7    345.00] AMP    12508.8   -85.51
532771 [RENO   7    345.00] AMP    12114.8   -86.28
532774 [SWISVAL7    345.00] AMP    16054.5   -85.34
532791 [BENTON 7    345.00] AMP    18696.4   -85.76
532798 [VIOLA   7   345.00] AMP    13234.1   -85.42
532829 [WICH11 1    13.800] AMP    50308.8   -87.27
532830 [WICH12 1    13.800] AMP    50486.2   -87.65
533040 [EVANS N4    138.00] AMP    40966.9   -87.19
539801 [THISTLE7    345.00] AMP    15375.1   -85.82
583851 [G14-001XFMR134.500] AMP    12905.3   -87.73
583854 [G14-001XFMR234.500] AMP    12845.6   -87.63
515375 [WWRDEHV7    345.00] AMP    19883.6   -86.08
515543 [RENFROW7    345.00] AMP    12020.5   -84.71
532721 [EEC U1      16.000] AMP    77920.2   -88.56
532722 [EEC U2      24.000] AMP   113343.8   -88.66
532729 [EVAN SVC    8.0000] AMP   140019.4   -88.33
532766 [JEC N  7    345.00] AMP    23340.5   -87.53
532773 [SUMMIT 7    345.00] AMP    10961.1   -86.10
532792 [FR2EAST7    345.00] AMP     6336.6   -85.79
532794 [ROSEHIL7    345.00] AMP    18028.5   -85.80
532797 [WOLFCRK7    345.00] AMP    15925.7   -86.83
532807 [RENO 1X1    14.400] AMP    45040.1   -87.92
532808 [LANG   1    14.400] AMP    36094.4   -87.64
532809 [MORRIS1X1   14.400] AMP    31270.0   -87.61
532810 [RENO 2X1    14.400] AMP    44831.3   -87.96
532815 [SWISV1X1    14.400] AMP    36174.1   -87.91
532819 [SWISV2X2    14.400] AMP   743940.0    76.68
532821 [BENTN1 1    13.800] AMP    23669.9   -88.67
532822 [BENTN2 1    13.800] AMP    45029.4   -87.32
532832 [VIOLA1X1    13.800] AMP    55948.7   -85.77
532856 [SWISVAL6    230.00] AMP    21332.2   -85.42
532863 [MORRIS 6    230.00] AMP    13334.2   -85.33
532986 [BENTON 4    138.00] AMP    27867.3   -85.80
533041 [EVANS S4    138.00] AMP    40966.9   -87.19
533065 [SG12COL4    138.00] AMP    22482.6   -85.63
533075 [VIOLA  4    138.00] AMP    20425.7   -85.84
533304 [LANG   3    115.00] AMP    14362.4   -85.07
533390 [MAIZEW 4    138.00] AMP    27455.3   -85.43
533416 [RENO   3    115.00] AMP    29647.5   -86.45
539800 [CLARKCOUNTY7345.00] AMP    12376.1   -85.60
539802 [THISTLE T1  13.800] AMP     8108.3   -88.41
539804 [THISTLE4    138.00] AMP    16241.3   -86.30
```

542965	[W.GRDNR7 345.00]	AMP	23770.8	-85.51
583852	[G14-001-GSU134.500]	AMP	12208.7	-84.65
583855	[G14-001-GSU234.500]	AMP	11380.6	-81.79
515376	[WWRDEHV4 138.00]	AMP	25278.0	-85.29
515458	[BORDER 7345.00]	AMP	4990.8	-86.19
515476	[HUNTERS7 345.00]	AMP	12130.6	-84.68
515544	[RENFROW4 138.00]	AMP	13455.8	-84.70
515545	[RENFRO11 13.800]	AMP	48195.1	-87.17
515621	[OPENSKY7 345.00]	AMP	11154.8	-86.70
515795	[WWDEHV31 13.800]	AMP	60657.6	-87.74
515799	[WWDEHV21 13.800]	AMP	60314.7	-87.68
531469	[SPERVIL7 345.00]	AMP	14201.8	-85.79
532652	[JEC U2 26.000]	AMP	188846.8	-89.11
532653	[JEC U3 26.000]	AMP	188150.5	-89.10
532723	[EEC GT1 13.800]	AMP	50255.9	-89.24
532724	[EEC GT2 13.800]	AMP	50292.1	-89.24
532725	[EEC GT3 18.000]	AMP	67628.2	-89.37
532751	[WCGS U1 25.000]	AMP	207406.2	-88.00
532765	[HOYT 7 345.00]	AMP	15332.0	-85.77
532767	[GEARY 7 345.00]	AMP	9811.4	-86.35
532795	[FR2WEST7 345.00]	AMP	5109.0	-85.82
532799	[WAVERLY7 345.00]	AMP	14732.6	-86.54
532800	[LATHAMS7 345.00]	AMP	10313.2	-85.57
532805	[JEC 13 1 14.400]	AMP	33398.8	-88.29
532806	[JEC 26 1 14.400]	AMP	33609.4	-88.28
532813	[SUMMIT 1 14.400]	AMP	30613.1	-87.12
532826	[ROSEH1 1 13.800]	AMP	39126.4	-88.54
532827	[ROSEH5 1 13.800]	AMP	38889.1	-88.54
532831	[ROSEH3 1 13.800]	AMP	39063.1	-88.54
532851	[AUBURN 6 230.00]	AMP	13420.0	-83.83
532852	[JEC 6 230.00]	AMP	24599.5	-87.76
532853	[LAWHILL6 230.00]	AMP	13501.3	-85.39
532857	[TECHILL6 230.00]	AMP	11213.8	-84.35
532862	[MCDOWEL6 230.00]	AMP	6849.2	-84.97
532873	[SUMMIT 6 230.00]	AMP	13581.0	-85.51
532874	[UNIONRG6 230.00]	AMP	7314.1	-83.10
532890	[MORRIS2X1 13.800]	AMP	38840.2	-88.70
532984	[SUMNER 4 138.00]	AMP	9855.9	-82.76
532988	[BELAIRE4 138.00]	AMP	18536.8	-84.71
532990	[MIDIAN 4 138.00]	AMP	10141.1	-80.55
533015	[BENTLEY4 138.00]	AMP	12243.3	-84.35
533024	[29TH 4 138.00]	AMP	19297.7	-85.03
533035	[CHISHLM4 138.00]	AMP	22196.0	-84.73
533036	[CLEARWT4 138.00]	AMP	16965.4	-84.85
533046	[GILL S 4 138.00]	AMP	26938.5	-85.12
533053	[LAKERDG4 138.00]	AMP	18931.2	-85.54
533054	[MAIZE 4 138.00]	AMP	23119.4	-85.10
533062	[ROSEHIL4 138.00]	AMP	30719.9	-86.07
533074	[45TH ST4 138.00]	AMP	27833.8	-85.59
533127	[F2EAST11 13.800]	AMP	58491.9	-85.48
533128	[F2EAST21 13.800]	AMP	58500.9	-85.50
533131	[FR2ELV11 34.500]	AMP	14226.8	-88.38
533132	[FR2ELV21 34.500]	AMP	14175.8	-88.37
533301	[EAST ST3 115.00]	AMP	9182.5	-82.00
533305	[MORRIS 3 115.00]	AMP	12257.0	-86.27
533306	[READING3 115.00]	AMP	6379.0	-73.71
533307	[PRAIRIE3 115.00]	AMP	9232.2	-82.38
533413	[CIRCLE 3 115.00]	AMP	29229.8	-86.58
533415	[DAVIS 3 115.00]	AMP	9142.5	-82.80
533429	[MOUNDRG3 115.00]	AMP	9739.4	-83.21
533438	[WMCPHER3 115.00]	AMP	15899.6	-85.75
533653	[WOLFCRK2 69.000]	AMP	5904.6	-87.21
539638	[FLATRDG3 138.00]	AMP	14611.5	-85.28
539803	[IRONWOOD7 345.00]	AMP	13733.7	-85.75
539805	[ELMCREEK7 345.00]	AMP	5716.2	-85.76
542966	[WGARDNR5 161.00]	AMP	21882.6	-86.22
542968	[STILWEL7 345.00]	AMP	23397.1	-85.77
542977	[CRAIG 7 345.00]	AMP	20623.9	-85.55
542981	[LACYGNE7 345.00]	AMP	24553.6	-86.84
543649	[WGAR T11 13.800]	AMP	15675.3	-89.75
560000	[G11-14-TAP 345.00]	AMP	13234.2	-86.31
562075	[G11-051-TAP 345.00]	AMP	16560.6	-86.42
579351	[GEN-2007-062345.00]	AMP	8518.7	-86.01
582008	[GEN-2011-008345.00]	AMP	9955.2	-75.05
582019	[GEN-2011-019345.00]	AMP	19883.6	-86.08

582020	[GEN-2011-020345.00]	AMP	19883.6	-86.08
583370	[GEN-2012-024345.00]	AMP	9850.0	-83.01
583750	[GEN-2013-029345.00]	AMP	10664.1	-84.23
514715	[WOODRNG7 345.00]	AMP	16294.3	-84.75
514785	[WOODWRD4 138.00]	AMP	20614.7	-83.21
514796	[IODINE-4 138.00]	AMP	7079.5	-79.71
514825	[KAYWIND7 345.00]	AMP	11127.9	-86.69
515394	[KEENAN 4 138.00]	AMP	9025.6	-84.97
515398	[OUSPRT 4 138.00]	AMP	9577.7	-82.08
515407	[TATONGA7 345.00]	AMP	16154.6	-86.58
515477	[CHSHLMV7 345.00]	AMP	12114.5	-84.68
515546	[GRANTCO4 138.00]	AMP	6660.0	-81.26
515554	[BVRCNTY7 345.00]	AMP	14129.3	-86.25
515569	[MDFRDTP4 138.00]	AMP	11176.0	-83.34
515576	[RANCHRD7 345.00]	AMP	12175.1	-86.69
520409	[SAND RDG_138138.00]	AMP	9907.7	-82.97
525832	[TUCO_INT 7345.00]	AMP	11532.4	-86.03
530592	[SMOKYHL6 230.00]	AMP	6955.7	-84.32
531468	[SPERTER1 13.800]	AMP	12843.3	-89.74
531501	[BUCKNER7 345.00]	AMP	10609.4	-86.10
532651	[JEC U1 26.000]	AMP	180143.5	-88.90
532739	[GILL SVC 8.0000]	AMP	93717.5	-87.89
532772	[STRANGR7 345.00]	AMP	21971.1	-85.95
532775	[87TH 7 345.00]	AMP	19289.6	-85.58
532780	[CANEYRV7 345.00]	AMP	9774.0	-85.51
532793	[NEOSHO 7 345.00]	AMP	16047.0	-84.51
532801	[ELKRVR17 345.00]	AMP	9122.5	-85.47
532804	[HOYT 1 14.400]	AMP	31478.9	-87.85
532817	[UNIONRG1 13.200]	AMP	18226.5	-87.60
532834	[GEARY1X1 13.800]	AMP	67911.7	-87.21
532854	[LEC U5 6 230.00]	AMP	13372.5	-85.29
532855	[MIDLAND6 230.00]	AMP	12044.5	-84.98
532861	[EMANHAT6 230.00]	AMP	9684.8	-85.61
532871	[CIRCLE 6 230.00]	AMP	10621.8	-85.30
532872	[EMCPHER6 230.00]	AMP	9444.5	-84.39
532880	[AUBURN 1 14.400]	AMP	65619.0	-87.02
532882	[LAWHILL1 13.800]	AMP	55065.5	-88.23
532886	[TECHILL1 13.800]	AMP	57161.2	-88.21
532892	[CIRCLE 1 13.800]	AMP	56631.8	-89.26
532896	[SUMIT2 1 13.800]	AMP	47777.2	-88.92
532897	[SUMIT3 1 13.800]	AMP	48818.0	-86.55
532898	[MCDOWL 1 13.800]	AMP	30148.8	-87.78
532982	[OXFORD 4 138.00]	AMP	8984.7	-82.84
532987	[BUTLER 4 138.00]	AMP	9969.0	-79.54
532991	[WEAVER 4 138.00]	AMP	21765.1	-83.86
532992	[TIMBJCT4 138.00]	AMP	5600.2	-83.23
533012	[HALSTDS4 138.00]	AMP	9446.1	-83.92
533013	[MOUND 4 138.00]	AMP	7925.1	-83.61
533016	[WWUPLNT4 138.00]	AMP	8944.3	-84.08
533029	[59TH ST4 138.00]	AMP	18501.9	-83.61
533031	[BURNSTP4 138.00]	AMP	4485.4	-76.65
533037	[COMOTAR4 138.00]	AMP	18247.2	-84.52
533038	[COWSKIN4 138.00]	AMP	19405.6	-84.56
533039	[ELPASO 4 138.00]	AMP	24854.2	-84.14
533045	[GILL W 4 138.00]	AMP	26938.5	-85.12
533049	[HOOVERN4 138.00]	AMP	18751.9	-84.92
533060	[NOEASTE4 138.00]	AMP	20009.1	-84.58
533063	[SC10BEL4 138.00]	AMP	9535.3	-81.61
533064	[17TH 4 138.00]	AMP	17822.9	-84.48
533068	[STEARMN4 138.00]	AMP	19564.9	-84.16
533082	[MIDIAN 1 13.200]	AMP	19784.9	-83.47
533097	[MOUN 2X1 13.800]	AMP	7468.4	-89.42
533103	[CHISOLM1 13.200]	AMP	22406.5	-85.33
533106	[GILL S 1 13.200]	AMP	17364.5	-89.57
533107	[GILL S 2 13.200]	AMP	17364.5	-89.57
533129	[F2WEST11 13.800]	AMP	53654.9	-85.53
533130	[F2WEST21 13.800]	AMP	53414.4	-85.56
533133	[FR2WLV11 34.500]	AMP	13754.0	-88.30
533134	[FR2WLV21 34.500]	AMP	13732.9	-88.28
533135	[ECLCT1 1 34.500]	AMP	12482.4	-87.16
533136	[ECLCT2 1 34.500]	AMP	12405.7	-87.06
533151	[AUBURN 3 115.00]	AMP	21863.8	-84.10
533163	[HOYT 3 115.00]	AMP	22821.4	-85.69
533171	[OSAGE J3 115.00]	AMP	5146.0	-72.86
533182	[TECHILE3 115.00]	AMP	30072.2	-82.97

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533250 [LWRNCHL3    115.00] AMP    26398.8   -83.85
533309 [WEMPORI3    115.00] AMP     9764.1   -81.50
533335 [MCDOWEL3    115.00] AMP    17750.1   -85.57
533336 [GEARY  3    115.00] AMP    17132.3   -86.56
533359 [UNIONRG3    115.00] AMP     3629.9   -87.43
533372 [PHILIPS3    115.00] AMP    12636.1   -84.35
533380 [SPRGCRK3    115.00] AMP     3919.7   -71.57
533381 [SUMMIT 3    115.00] AMP    17634.8   -86.49
533391 [MAIZEE 4    138.00] AMP    21667.2   -84.93
533412 [ARKVALJ3    115.00] AMP    10164.6   -70.45
533414 [CITIES 3    115.00] AMP     9089.7   -83.17
533419 [HEC    3    115.00] AMP    26679.1   -86.23
533421 [HEC GT 3    115.00] AMP    28332.6   -86.58
533422 [HEC U4 3    115.00] AMP    27523.3   -86.19
533426 [MANVILE3    115.00] AMP    11761.5   -83.99
533428 [MCPHER 3    115.00] AMP    15854.0   -86.01
533439 [WHEATLD3    115.00] AMP     8955.0   -84.34
533444 [DAVIS  1    34.500] AMP     3299.4   -85.90
533506 [DAVIS  2    69.000] AMP     7698.6   -82.65
533597 [MIDIAN 2    69.000] AMP    12319.6   -81.94
533626 [BURLJCT2    69.000] AMP     4891.3   -85.85
533629 [CC2SHAR2    69.000] AMP     4572.9   -81.38
533786 [CHISHLM2    69.000] AMP    17682.4   -85.15
533795 [GILL E 2    69.000] AMP    33174.6   -85.25
533796 [GILL W 2    69.000] AMP    33174.6   -85.25
539631 [FLATRWD3    138.00] AMP     9674.4   -83.60
539639 [ELMCREK6    230.00] AMP     8196.3   -85.17
539668 [HARPER 4    138.00] AMP     5541.6   -78.95
539674 [BARBER 4    138.00] AMP     7949.6   -83.61
539675 [MILANTP4    138.00] AMP     6529.4   -74.97
539695 [SPEARVL6    230.00] AMP    12713.7   -86.78
539759 [SPRVL  3    115.00] AMP    11678.8   -87.64
539806 [ELMCREEK1   13.800] AMP    69634.3   -86.78
539809 [IRONWOOD 1 7345.00] AMP    13733.7   -85.75
539960 [SPRVL-T     13.800] AMP    27394.2   -89.19
541198 [PECULR 7    345.00] AMP    19603.5   -85.57
542955 [LAC G1 1    22.000] AMP   220790.5   -88.58
542956 [LAC G2 1    24.000] AMP   201895.1   -88.77
542969 [STILWEL5    161.00] AMP    37553.9   -85.75
542978 [CRAIG  5    161.00] AMP    37357.5   -85.60
543049 [CEDRCRK5    161.00] AMP    26189.1   -84.88
543054 [CEDARNL5    161.00] AMP    12423.4   -84.50
543077 [PLSTVAL5    161.00] AMP     8996.4   -83.31
543105 [BULLCRK5    161.00] AMP    19500.0   -86.32
543132 [BNSF   5    161.00] AMP    17750.8   -85.39
543641 [CRAI T11    13.800] AMP    12258.4   -89.13
543642 [CRAI T22    13.800] AMP    19074.2   -88.18
543643 [CRAI T33    13.800] AMP    18739.1   -88.83
543647 [STIL T11    13.800] AMP    18863.5   -89.81
543648 [STIL T22    13.800] AMP    19793.8   -89.77
560242 [G11-017-TAP 345.00] AMP     9976.2   -85.26
562701 [GEN-2006-006345.00] AMP    14201.8   -85.79
572091 [GEN-2008-098345.00] AMP    12562.6   -86.35
579352 [G07-062XFMR134.500] AMP    20232.1   -88.20
579355 [G07-062XFMR234.500] AMP    20235.0   -88.14
579358 [G07-062-HV-2345.00] AMP     6506.9   -85.99
579480 [GEN-2008-124230.00] AMP    19857.1   -85.73
581112 [GEN-2011-014345.00] AMP     9942.0   -85.43
582016 [GEN-2011-016345.00] AMP     7662.2   -81.65
582108 [G11-008XFMR134.500] AMP    17571.9   -86.72
582119 [G11-019XFMR134.500] AMP    36792.3   -88.25
582120 [G11-020XFMR134.500] AMP    36793.5   -88.26
582308 [G11-008XFMR234.500] AMP    15335.0   -87.10
582708 [G-2011-008-1345.00] AMP     8923.1   -71.03
583090 [GEN-2011-049345.00] AMP     4534.5   -86.06
583110 [GEN-2011-051345.00] AMP    16560.6   -86.42
583371 [G12-024XFMR134.500] AMP    19423.2   -87.18
583751 [G13-029XFMR134.500] AMP    23182.6   -86.67
583754 [G13-029XFMR234.500] AMP    22299.6   -86.48
583820 [GEN-2013-035345.00] AMP    11178.6   -85.79
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APPENDIX D

CHARGING CURRENT COMPENSATION ANALYSIS

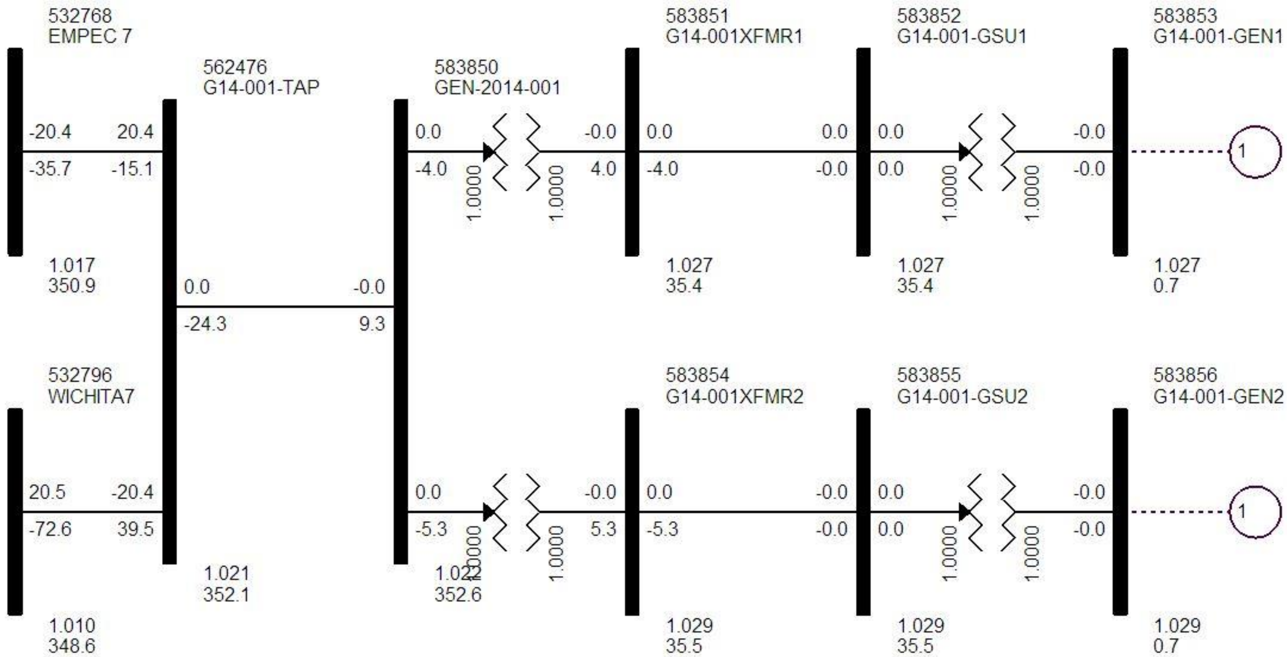

Figure D-1: GEN-2014-001 with generators off and no shunt reactors

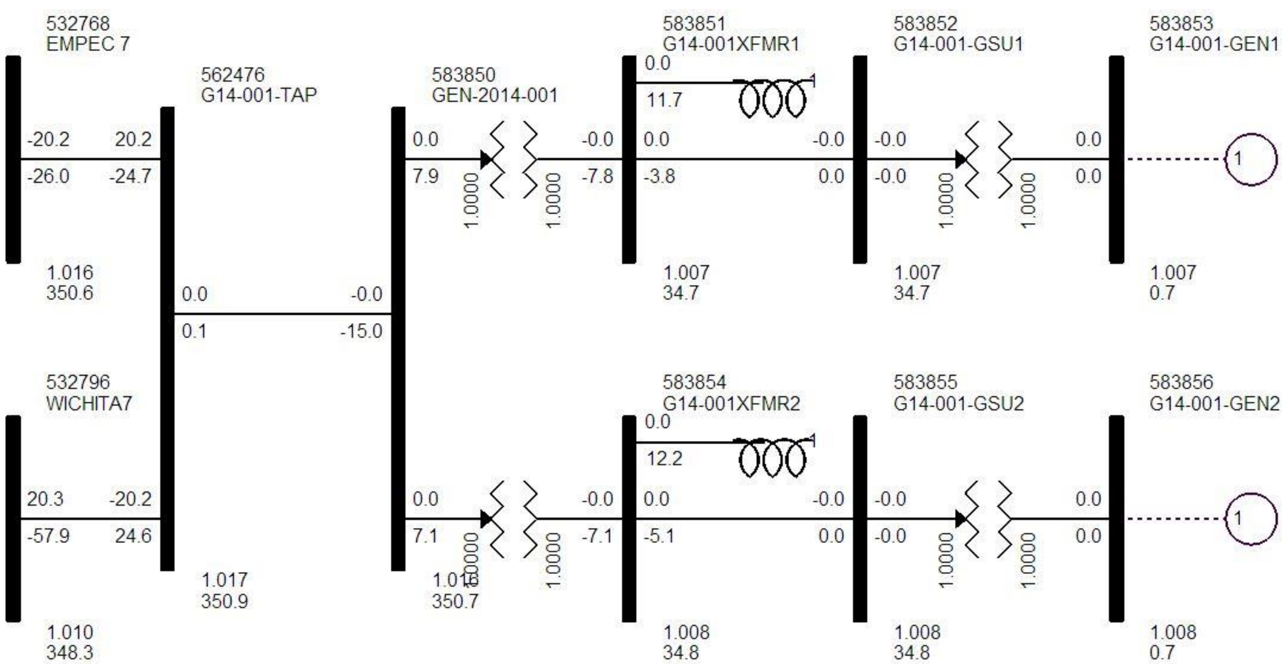

Figure D-2: GEN-2014-001 with generator turned off and shunt reactor added to the low side of the substation 345/34.5kV transformer