GEN-2015-083

Impact Restudy for Generator Modification (Turbine Change)

Published on August 2018

By Generator Interconnection

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
8/7/2018	Generator Interconnection		

EXECUTIVE SUMMARY

The GEN-2015-083 Interconnection Customer has requested a modification to its Interconnection Request. SPP has performed this system impact restudy to determine the effects of changing wind turbine generators from the previously studied fifty-four (54) GE 2.3MW wind turbine generators to fifty (50) GE 2.5MW as well as a POI change from Belle Plain to Sumner (one bus away). The total nameplate remains the same at 125 MW.

In this restudy the project uses fifty (50) GE 2.5MW wind turbine generators for an aggregate power of 125 MW. The point of interconnection (POI) for GEN-2015-083 is at Westar (WERE) Sumner 138kV substation. The Interconnection Customer has provided documentation that shows the GE 2.3MW wind turbine generators have a reactive capability of 0.95 lagging (providing VARS) and 0.95 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-2015-002 were used that analyzed the timeframes of 2016 winter, 2017 summer, and 2025 summer models.

Power flow analysis was performed. Cost Allocation remains the same. Interconnection costs decreased. No additional upgrades were identified.

The restudy showed that the stability analysis has determined with all previously assigned Network Upgrades in service, generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. 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. The requested modification is not considered Material.

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. Additionally, the project will be required to install approximately 6.5 Mvar of reactor shunts on its substation 138 kV 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 DISIS 2015-002 in place, GEN-2015-083 with the GE 2.5MW 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.

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.

CONTENTS

SECTION 1: INTRODUCTION

GEN-2015-083 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. This restudy evaluates the requested modification to change from fifty-four (54) GE 2.3MW wind turbine generators to fifty (50) GE 2.5MW, as well as a POI change from Belle Plain to Sumner (one bus away).

TABLE 2-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-083	125	GE 2.5MW (wind)	Sumner (532984)

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 2-2: GROUP 8 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	Vestes V90 1.8MW	Caney River 345kV (532780)
GEN-2007-025	299.2	GE 1.6MW	Viola 345kV (532798)
GEN-2008-013	300	G.E. 1.68MW	Hunter 345kV (515476)
GEN-2008-021	1261 Summer 1283 Winter	GENROU	Wolf Creek 345kV (532797)
GEN-2008-098	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2009-025	59.8	Siemens 2.3MW	Tap on the Deerck – Sincblk 69KV line (515528)
GEN-2010-003	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
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	150.4	GE 1.6MW	Creswell 138kV (532981)
KCPL Distributed: Osawatomie	76.0	GENROU (543078)	Paola 161kV
GEN-2012-032	300	Vestas V112 3.0MW	Tap Rose Hill-Sooner 345kV (562318)
GEN-2012-033	98.8	GE 1.62MW	Tap Bunch Creek-South 4th 138kV(562303)
GEN-2012-041	85 Summer 121.5 Winter	GENROU	Tap Rose Hill-Sooner 345kV (562318)

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-2013-029	300	Vestas V100 VCSS 2MW (583753, 583756)	Renfrow 345kV(515543)
GEN-2014-001	200.6	GE 1.7MW 100m (583853,583856)	Tap Wichita to Emporia Energy Center 345kV (562476)
GEN-2014-028	35 (Uprate) (Pgen=259W/256S)	GENROU	Riverton 161kV (547469)
GEN-2014-064	248.4	GE 2.3MW	Otter 138kV (514708)
ASGI-2014-014	56.4W/54.3S	GENROU	Ferguson 69kV (512664)
GEN-2015-001	200.0	Vestas V110 2.0MW	Ranch Road 345kV
GEN-2015-016	200.0	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV
GEN-2015-024	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-025	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-028	3.0 uprate to GEN-2009-025 for total 62.8MW	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Nardins 69kV
GEN-2015-030	200.1	GE 2.3MW	Sooner 345kV
ASGI-2015-004	54.300 Summer 56.364 Winter	GENSAL	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV (512735)

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 non-synchronous resource. The analyses were performed on three seasonal models, the modified versions of the 2016 winter peak, the 2017 summer 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.

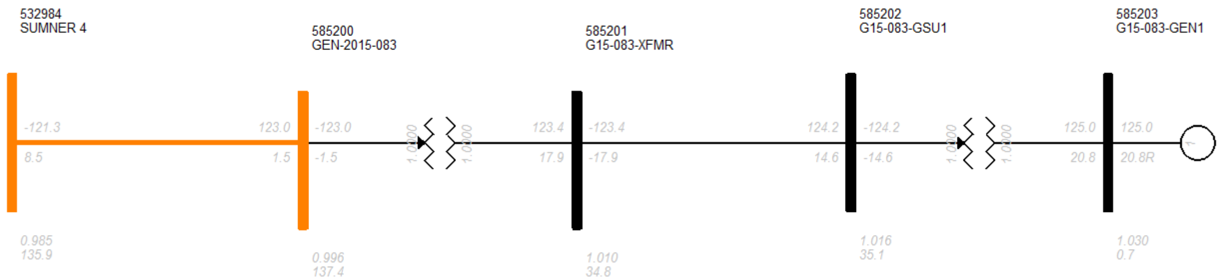
Power factor analysis results are in Appendix B

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.

SECTION 2: FACILITIES

A one-line drawing for the GEN-2015-083 generation interconnection request is shown in Figure 2-1. The POI is a new tap on the WERE Sumner 138kVsubstation.

FIIGURE 2-1: GEN-2015-083 ONE-LINE DIAGRAM



SECTION 3: POWER FLOW ANALYSIS

Power flow analysis was performed with DISIS-2016-001-1 models. The interconnection costs for GEN-2015-083 decreased from $6,713,963 to $4,453,966. The current study upgrade identified in DISIS-2016-001-1 (Rebuild Farber – Belle Plains 138 kV CKT 1) was necessary for voltage and thermal mitigations. Additionally, the previously allocated upgrade of GEN-2015-063 Tap – Matthewson 345 kV CKT 1 was also required. No additional upgrades were identified. The Cost Allocation for GEN-2016-060 remains the same.

TABLE 3-1: GEN-2016-060 NETWORK UPGRADES

Network Upgrade	POI at Belle Plains	POI at Sumner 138kV
Rebuild Farber – Belle Plains 138 kV CKT 1 (Current Study)	✓	✓
GEN-2015-063 Tap _Matthewson 345 kV CKT 1 (Previously Allocated)	✓	✓
Viola – Sumner County CKT 1 (Previously Allocated)	✓	

SECTION 3: 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 2015 series of Model Development Working Group (MDWG) dynamic study models including the 2016 winter peak, the 2017 summer 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

Forty-seven (47) contingencies were identified for use in this study and are listed in Table 3-1. 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 3-1: CONTINGENCIES EVALUATED

Contingency Number and Name		Description
1	FLT15-3PH	3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV 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	FLT69-3PH	3 phase fault on the SC10BEL4 (533063) to FARBER 4 (533042) 138 kV line circuit 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV 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	FLT70-3PH	3 phase fault on the SC10BEL4 (533063) to SUMNER 4 (532984) 138 kV line circuit 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV 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	FLT71-3PH	3 phase fault on the FARBER 4 (533042) to ELPASO 4 (533039) 138 kV line circuit 1, near FARBER 4. a. Apply fault at the FARBER 4 138 kV 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	FLT72-3PH	3 phase fault on the SUMNER 4 (532984) to OXFORD 4 (532982) 138 kV line circuit 1, near SUMNER 4. a. Apply fault at the SUMNER 4 138 kV 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.

Contingency Number and Name		Description
6	FLT73-3PH	3 phase fault on the SUMNER 4 (532984) to TIMBJCT4 (532992) 138 kV line circuit 1, near SUMNER 4. a. Apply fault at the SUMNER 4 138 kV 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	FLT114-SB	Stuck Breaker on FARBER 4 – SC10BEL 4 138 kV line a. Apply single-phase fault at FARBER 4 (533042) 138 kV b. After 16 cycles, trip the FARBER 4 (533042) to ELPASO 4 (533039) 138 kV line c. Trip the FARBER 4 (533042) to SC10BEL 4 (533063) 138 kV line, and remove the fault
8	FLT9001-3PH	3 phase fault on the OXFORD 4 (532982) to CRESWLN4 (532981) 138 kV line circuit 1, near OXFORD 4. a. Apply fault at the OXFORD 4 138 kV 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	FLT9002-3PH	3 phase fault on the SUMNER 4 (532984) to VIOLA 4 (533075) 138 kV line circuit 1, near SUMNER 4. a. Apply fault at the SUMNER 4 138 kV 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	FLT9003-3PH	3 phase fault on the SUMNER 4 (532984) to SC10BEL4 (533063) 138 kV line circuit 1, near SUMNER 4 a. Apply fault at the SUMNER 4 138 kV 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	FLT9004-3PH	3 phase fault on the VIOLA 4 (533075) 138 kV / VIOLA 7 (532798) 345 kV /(532832) 13.8 kV transformer, near VIOLA 4 138 kV. a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Contingency Number and Name		Description
12	FLT9005-3PH	3 phase fault on the VIOLA 4 (533075) to CLEARWT4 (533036) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV 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	FLT9006-3PH	3 phase fault on the VIOLA 4 (533075) to GILL S 4 (533046) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV 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	FLT9007-3PH	3 phase fault on the TIMBJCT4 (532992) 138 kV / TIMBJCT2 (533558) 69 kV /(533120) 13.8 kV transformer, near TIMBJCT4 138 kV. a. Apply fault at the TIMBJCT4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
15	FLT9008-3PH	3 phase fault on the VIOLA 7 (532798) to WICHITA7 (532796) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV 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	FLT9009-3PH	3 phase fault on the VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV 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	FLT9010-3PH	3 phase fault on the VIOLA 7 (532798) to FR2EAST7 (532792) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV 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.

Contingency Number and Name		Description
18	FLT9011-3PH	3 phase fault on the GILL S 4 (533046) to GILL W 4 (533045) 138 kV line circuit Z1, near GILL S 4. a. Apply fault at the GILL S 4 138 kV 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	FLT9012-3PH	3 phase fault on the CLEARWT4 (533036) to GODDARD2 (533880) 138 kV line circuit 1, near CLEARWT4. a. Apply fault at the CLEARWT4 138 kV 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	FLT9013-3PH	3 phase fault on the CLEARWT4 (533036) to MILANTP4 (539675) 138 kV line circuit 1, near CLEARWT4. a. Apply fault at the CLEARWT4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
21	FLT9014-3PH	3 phase fault on the CLEARWT4 (533036) to GILL W 4 (533045) 138 kV line circuit 1, near CLEARWT4. a. Apply fault at the CLEARWT4 138 kV 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	FLT9015-3PH	3 phase fault on the CRESWLN4 (532981) 138 kV / CRESWLN2 (533543) 69 kV /(533081) 13.2 kV transformer, near CRESWLN4 138 kV. a. Apply fault at the CRESWLN4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
23	FLT9016-3PH	3 phase fault on the CRESWLN4 (532981) to MIDLTNT4 (514804) 138 kV line circuit 1, near CRESWLN4. a. Apply fault at the CRESWLN4 138 kV 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.

Contingency Number and Name		Description
24	FLT9017-3PH	3 phase fault on the CRESWLN4 (532981) to SLATECRK4 (533070) 138 kV line circuit 1, near CRESWLN4. a. Apply fault at the CRESWLN4 138 kV 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	FLT9001-PO1	Prior Outage of SUMNER 4 to SC10BEL4 138 kV line; 3 phase fault on the OXFORD 4 (532982) to CRESWLN4 (532981) 138 kV line circuit 1, near OXFORD 4. a. Apply fault at the VIOLA 4 138 kV 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	FLT9007-PO1	Prior Outage of SUMNER 4 to SC10BEL4 138 kV line; 3 phase fault on TIMBJCT (532992) 138 kV/TIMBJCT2 (533558) 69 kV/TIMBJCT1 (533120) 13.2 kV transformer near TIMBJCT 138 kV a. Apply fault at the TIMBJCT 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
27	FLT9004-PO1	Prior Outage of SUMNER 4 to SC10BEL4 138 kV line; 3 phase fault on the VIOLA 4 (533075) 138 kV / VIOLA 7 (532798) 345 kV /(532832) 13.8 kV transformer, near VIOLA 4 138 kV a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
28	FLT9005-PO1	Prior Outage of SUMNER 4 to SC10BEL4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to CLEARWT4 (533036) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV 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.

Contingency Number and Name		Description
29	FLT9006-PO1	Prior Outage of SUMNER 4 to SC10BEL4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to GILL S 4 (533046) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV 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	FLT9007-PO2	Prior Outage of SUMNER 4 to OXFORD 4 138 kV line; 3 phase fault on TIMBJCT (532992) 138 kV/TIMBJCT2 (533558) 69 kV/TIMBJCT1 (533120) 13.2 kV transformer near TIMBJCT 138 kV a. Apply fault at the TIMBJCT 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
31	FLT9004-PO2	Prior Outage of SUMNER 4 to OXFORD 4 138 kV line; 3 phase fault on the VIOLA 4 (533075) 138 kV / VIOLA 7 (532798) 345 kV / (532832) 13.8 kV transformer, near VIOLA 4 138 kV a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
32	FLT9005-PO2	Prior Outage of SUMNER 4 to OXFORD 4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to CLEARWT4 (533036) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
33	FLT9006-PO2	Prior Outage of SUMNER 4 to OXFORD 4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to GILL S 4 (533046) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV 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.

Contingency Number and Name		Description
34	FLT69-PO2	Prior Outage of SUMNER 4 to OXFORD 4 138 kV line; 3 phase fault on the SC10BEL4 (533063) to FARBER 4 (533042) 138 kV line circuit 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
35	FLT9001-PO3	Prior Outage of SUMNER 4 to TIMBMJCT4 138 kV line; 3 phase fault on the OXFORD 4 (532982) to CRESWLN4 (532981) 138 kV line circuit 1, near OXFORD 4. a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
36	FLT9004-PO3	Prior Outage of SUMNER 4 to TIMBMJCT4 138 kV line; 3 phase fault on the VIOLA 4 (533075) 138 kV / VIOLA 7 (532798) 345 kV / (532832) 13.8 kV transformer, near VIOLA 4 138 kV a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
37	FLT9005-PO3	Prior Outage of SUMNER 4 to TIMBMJCT4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to CLEARWT4 (533036) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.3 phase fault on the VIOLA 4 (533075) to CLEARWT4 (533036) 138 kV line circuit 1, near VIOLA 4 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	FLT9006-PO3	Prior Outage of SUMNER 4 to TIMBMJCT4 138 kV line; 3 phase fault on the VIOLA 4 (533075) to GILL S 4 (533046) 138 kV line circuit 1, near VIOLA 4 a. Apply fault at the VIOLA 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.3 phase fault on the VIOLA 4 (533075) to GILL S 4 (533046) 138 kV line circuit 1, near VIOLA 4 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.

Contingency Number and Name		Description
39	FLT69-PO3	Prior Outage of SUMNER 4 to TIMBMJCT4 138 kV line; 3 phase fault on the SC10BEL4 (533063) to FARBER 4 (533042) 138 kV line circuit 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.3 phase fault on the SC10BEL4 (533063) to FARBER 4 (533042) 138 kV line circuit 1, near SC10BEL4. 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	FLT9001-PO4	Prior Outage of SUMNER 4 to VIOLA 4 138 kV line; 3 phase fault on the OXFORD 4 (532982) to CRESWLN4 (532981) 138 kV line circuit 1, near OXFORD 4. a. Apply fault at the TIMBJCT 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
41	FLT9007-PO4	Prior Outage of SUMNER 4 to VIOLA 4 138 kV line; 3 phase fault on TIMBJCT (532992) 138 kV/TIMBJCT2 (533558) 69 kV/TIMBJCT1 (533120) 13.2 kV transformer near TIMBJCT 138 kV a. Apply fault at the TIMBJCT 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
42	FLT69-PO4	Prior Outage of SUMNER 4 to VIOLA 4 138 kV line; 3 phase fault on the SC10BEL4 (533063) to FARBER 4 (533042) 138 kV line circuit 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV 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.
43	FLT9100-SB	Stuck Breaker on OXFORD 4 – SUMNER 4 138 kV line a. Apply single-phase fault at OXFORD 4 (532982) 138 kV b. After 16 cycles, trip the OXFORD 4 (532982) 138 kV Bus and remove the fault
44	FLT9200-SB	Stuck Breaker on SC10BEL4 - SUMNER 4 138 kV line a. Apply single-phase fault at SC10BEL4 (533063) 138 kV b. After 16 cycles, trip the SC10BEL4 (533063) 138 kV Bus and remove the fault
45	FLT9300-SB	Stuck Breaker on TIMBJCT4 - SUMNER 4 138 kV line a. Apply single-phase fault at TIMBJCT4 (532992) 138 kV b. After 16 cycles, trip the TIMBJCT4 (532992) 138 kV Bus and remove the fault

Contingency Number and Name		Description
46	FLT9400-SB	Stuck Breaker on CRESWLN4 (532981) 138 kV/CRESWLN2 (533543) 69 kV/CRESW2 1 (533081) 13.2 kV transformer near 138kV a. Apply single-phase fault at CRESWLN4 (532981) 138kV b. After 16 cycles, trip the CRESWLN4 (532981) 138 kV/CRESWLN2 (533543) 69 kV/CRESW2 1 (533081) 13.2 kV transformer c. Trip the CRESWLN4 (532981) 138 kV/CRESWLN2 (533543) 69 kV/CRESW1 1 (533080) 13.2 kV transformer, and remove the fault
47	FLT9500-SB	Stuck Breaker on VIOLA 4 - SUMNER 4 138kV line a. Apply single-phase fault at VIOLA 4 (533075) 138kV b. After 16 cycles, trip the VIOLA 4 (533075) to SUMNER 4 (532984) 138 kV line b. Trip the VIOLA 4 (533075) 138 kV / VIOLA 7 (532798) 345 kV / (532832) 13.8 kV transformer, and remove the fault

RESULTS

The stability analysis was performed and the results are summarized in Table 3-2. Based on the stability results and with all network upgrades in service, GEN-2015-083 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 3-2: STABILITY ANALYSIS RESULTS

Contingency Number and Name		2015SP	2015WP	2025SP
1	FLT15-3PH	Stable	Stable	Stable
2	FLT69-3PH	Stable	Stable	Stable
3	FLT70-3PH	Stable	Stable	Stable
4	FLT71-3PH	Stable	Stable	Stable
5	FLT72-3PH	Stable	Stable	Stable
6	FLT73-3PH	Stable	Stable	Stable
7	FLT114-SB	Stable	Stable	Stable

Contingency Number and Name		2015SP	2015WP	2025SP
8	FLT9001-3PH	Stable	Stable	Stable
9	FLT9002-3PH	N/A	N/A	Stable
10	FLT9003-3PH	Stable	Stable	Stable
11	FLT9004-3PH	N/A	N/A	Stable
12	FLT9005-3PH	N/A	N/A	Stable
13	FLT9006-3PH	N/A	N/A	Stable
14	FLT9007-3PH	Stable	Stable	Stable
15	FLT9008-3PH	Stable	Stable	Stable
16	FLT9009-3PH	Stable	Stable	Stable
17	FLT9010-3PH	Stable	Stable	Stable
18	FLT9011-3PH	Stable	Stable	Stable
19	FLT9012-3PH	N/A	N/A	Stable
20	FLT9013-3PH	Stable	Stable	Stable
21	FLT9014-3PH	Stable	Stable	Stable
22	FLT9015-3PH	Stable	Stable	Stable
23	FLT9016-3PH	Stable	Stable	Stable
24	FLT9017-3PH	Stable	Stable	Stable
25	FLT9001-PO1	Stable	Stable	Stable
26	FLT9007-PO1	Stable	Stable	Stable
27	FLT9004-PO1	N/A	N/A	Stable
28	FLT9005-PO1	N/A	N/A	Stable
29	FLT9006-PO1	N/A	N/A	Stable
30	FLT9007-PO2	Stable	Stable	Stable
31	FLT9004-PO2	Stable	Stable	Stable
32	FLT9005-PO2	Stable	Stable	Stable

Contingency Number and Name		2015SP	2015WP	2025SP
33	FLT9006-PO2	Stable	Stable	Stable
34	FLT69-PO2	Stable	Stable	Stable
35	FLT9001-PO3	Stable	Stable	Stable
36	FLT9004-PO3	N/A	N/A	Stable
37	FLT9005-PO3	N/A	N/A	Stable
38	FLT9006-PO3	N/A	N/A	Stable
39	FLT69-PO3	Stable	Stable	Stable
40	FLT9001-PO4	N/A	N/A	Stable
41	FLT9007-PO4	N/A	N/A	Stable
42	FLT69-PO4	N/A	N/A	Stable
43	FLT9100-SB	Stable	Stable	Stable
44	FLT9200-SB	Stable	Stable	Stable
45	FLT9300-SB	Stable	Stable	Stable
46	FLT9400-SB	Stable	Stable	Stable
47	FLT9500-SB	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 9 and 10 in Table 3-1 simulated the LVRT contingencies. GEN-2015-083 met the LVRT requirements by staying on line and the transmission system remaining stable.

SECTION 4: 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 4-1. The detailed power factor analysis tables are in Appendix B. Since the GE 2.5 MW wind turbines as studied have a reactive capability (of 0.95 lagging and 0.95 leading), the generation facility may require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI.

TABLE 4-1: STABILITY ANALYSIS RESULTS

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement at POI	
				Lagging [b]	Leading [c]
GEN-2015-083	125	50 GE 2.5 MW generators	Sumner (532984)	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.

SECTION 5: 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 5-1. One line drawings used in the analysis are shown in Appendix D: Low Wind Analysis.

TABLE 5-1: SUMMARY OF SHUNT REACTOR REQUIREMENTS

Request	Capacity	POI	Approximate Shunt Reactor Required
GEN-2015-083	125MW	Sumner (532984)	6.5 Mvar

The results shown are for the 2025 summer case. The other two cases (2016 winter and 2017 summer) were almost identical since the generation plant design is the same in all cases.

SECTION 6: SHORT CIRCUIT ANALYSIS

The short circuit analysis was performed on the 2017 & 2025 Summer Peak power flow cases 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.

Short Circuit Analysis was conducting using flat conditions with the following PSS/E ASCCC program settings:

- BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
- GENERATOR P=0, Q=0
- TRANSFORMER 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

Results
The results of the short circuit analysis are shown in Appendix C.

SECTION 7: CONCLUSION

The SPP GEN-2015-083 Impact Restudy evaluated the impact of interconnecting the project shown below in Table 6-1.

TABLE 6-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-083	125MW	50 GE 2.5MW generators	Sumner (532984)

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2015-083 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied. The requested modification is not considered Material.

A low-wind/no-wind condition analysis was performed for this modification request. The project will be required to install a total of approximately 6.5 Mvar of reactor shunts on its substation 138kV bus. 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.

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

Case	Outage Label	Pgen (MW)	QGEN (MVAr)	PF	Leading Lagging
16WP	FLT15	125	21.68627	0.985	Lagging
16WP	FLT69	125	24.10172	0.982	Lagging
16WP	FLT70	125	24.17275	0.982	Lagging
16WP	FLT71	125	26.06281	0.979	Lagging
16WP	FLT72	125	-5.804245	0.999	Leading
16WP	FLT73	125	-1.597905	1.000	Leading
16WP	FLT9001	125	-5.099016	0.999	Leading
16WP	FLT9003	125	24.17275	0.982	Lagging
16WP	FLT9007	125	-8.480408	0.998	Leading
16WP	FLT9008	125	21.68627	0.985	Lagging
16WP	FLT9009	125	1.851644	1.000	Lagging
16WP	FLT9010	125	-0.0931992	1.000	Leading
16WP	FLT9011	125	1.692081	1.000	Lagging
16WP	FLT9013	125	3.93846	1.000	Lagging
16WP	FLT9014	125	6.004606	0.999	Lagging
16WP	FLT9015	125	3.65591	1.000	Lagging
16WP	FLT9016	125	25.95339	0.979	Lagging
16WP	FLT9017	125	-7.467247	0.998	Leading
16WP	UNFAULTED	125	1.7552	1.000	Lagging
17SP	FLT15	125	7.035601	0.998	Lagging
17SP	FLT69	125	0.818457	1.000	Lagging
17SP	FLT70	125	-0.0383099	1.000	Leading
17SP	FLT71	125	6.534454	0.999	Lagging
17SP	FLT72	125	-10.90503	0.996	Leading
17SP	FLT73	125	1.133902	1.000	Lagging

Case	Outage Label	Pgen (MW)	QGEN (MVAr)	PF	Leading Lagging
17SP	FLT9001	125	-9.441909	0.997	Leading
17SP	FLT9003	125	-0.0383099	1.000	Leading
17SP	FLT9007	125	-6.345002	0.999	Leading
17SP	FLT9008	125	7.035601	0.998	Lagging
17SP	FLT9009	125	-5.483699	0.999	Leading
17SP	FLT9010	125	-6.161466	0.999	Leading
17SP	FLT9011	125	-3.017931	1.000	Leading
17SP	FLT9013	125	-5.090569	0.999	Leading
17SP	FLT9014	125	-4.470612	0.999	Leading
17SP	FLT9015	125	-6.407546	0.999	Leading
17SP	FLT9016	125	-2.841096	1.000	Leading
17SP	FLT9017	125	-9.526103	0.997	Leading
17SP	UNFAULTED	125	-5.579602	0.999	Leading
25SP	FLT15	125	0.648969	1.000	Lagging
25SP	FLT69	125	-7.745823	0.998	Leading
25SP	FLT70	125	-8.768277	0.998	Leading
25SP	FLT71	125	-1.409599	1.000	Leading
25SP	FLT72	125	-13.1085	0.995	Leading
25SP	FLT73	125	2.136209	1.000	Lagging
25SP	FLT9001	125	-14.84279	0.993	Leading
25SP	FLT9002	125	1.89629	1.000	Lagging
25SP	FLT9003	125	-8.768277	0.998	Leading
25SP	FLT9004	125	-0.809785	1.000	Leading
25SP	FLT9005	125	-4.412814	0.999	Leading
25SP	FLT9006	125	-5.386446	0.999	Leading
25SP	FLT9007	125	-5.109126	0.999	Leading
25SP	FLT9008	125	0.648969	1.000	Lagging

Case	Outage Label	Pgen (MW)	QGEN (MVAr)	PF	Leading Lagging
25SP	FLT9009	125	-6.931538	0.998	Leading
25SP	FLT9010	125	-2.863758	1.000	Leading
25SP	FLT9011	125	-3.967323	0.999	Leading
25SP	FLT9012	125	-4.264443	0.999	Leading
25SP	FLT9013	125	-5.504511	0.999	Leading
25SP	FLT9014	125	-5.692423	0.999	Leading
25SP	FLT9015	125	-4.872952	0.999	Leading
25SP	FLT9016	125	-5.921418	0.999	Leading
25SP	FLT9017	125	-11.19366	0.996	Leading
25SP	UNFAULTED	125	-6.516462	0.999	Leading

APPENDIX C: SHORT CIRCUIT ANALYSIS

17SP

Bus Distance From POI	BUS NUMBER	BUS NAME	kV	AREA	ZONE	3 Phase Fault Current (kA) GenON	GenOFF	Difference (ON - OFF) From POI	BUS NUMBER
0	532984	SUMNER 4	138	536	1537	7.659	7.168	0.491	6.85%
1	532982	OXFORD 4	138	536	1537	7.268	6.863	0.405	5.90%
1	532992	TIMBJCT4	138	536	1537	4.972	4.802	0.170	3.55%
1	533063	SC10BEL4	138	536	1537	8.475	8.158	0.317	3.88%
1	585200	GEN-2015-083	138	536	1537	3.561	N/A	N/A	N/A
2	532981	CRESWLN4	138	536	1537	7.321	7.148	0.173	2.41%
2	532985	TCROCK 4	138	536	1537	4.692	4.540	0.152	3.34%
2	533042	FARBER 4	138	536	1537	15.484	15.297	0.188	1.23%
3	514804	MIDLTNT4	138	524	566	7.482	7.381	0.101	1.37%
3	533070	SLATECRK	138	536	1537	4.298	4.240	0.057	1.35%
3	533039	ELPASO 4	138	536	1537	24.403	24.212	0.191	0.79%
4	515381	PECKHMT4	138	524	566	8.050	7.966	0.084	1.05%
4	521198	CHILOCCO	138	525	575	5.871	5.806	0.066	1.13%
4	533029	59TH ST4	138	536	1537	17.459	17.406	0.053	0.31%
4	533032	BU11PON4	138	536	1537	14.867	14.819	0.048	0.33%
4	533062	ROSEHIL4	138	536	1537	30.758	30.636	0.123	0.40%
4	533066	64TH 4	138	536	1537	14.215	14.171	0.044	0.31%
4	533068	STEARMN4	138	536	1537	19.480	19.411	0.070	0.36%
5	514759	NEWKIRK4	138	524	566	8.409	8.331	0.078	0.94%
5	533046	GILL S 4	138	536	1537	22.309	22.262	0.047	0.21%
5	532991	WEAVER 4	138	536	1537	21.875	21.792	0.083	0.38%
5	532794	ROSEHIL7	345	536	1537	18.858	18.814	0.044	0.23%
5	533048	HARRY 4	138	536	1537	13.483	13.446	0.037	0.28%
5	533030	BOEING 4	138	536	1537	16.958	16.913	0.045	0.26%

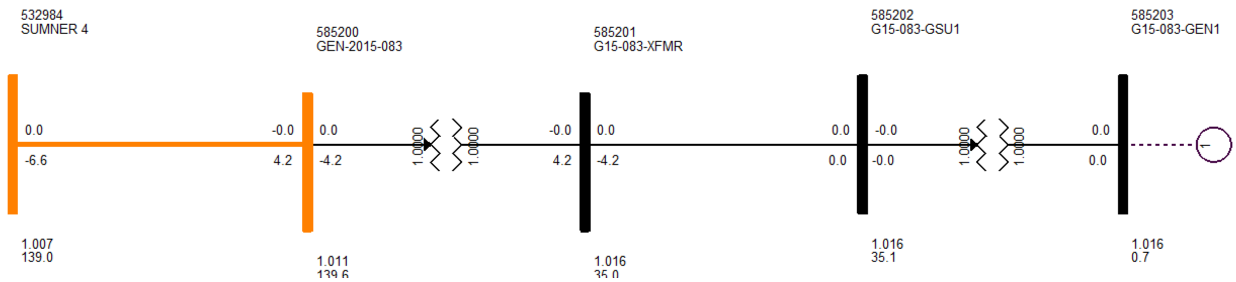
25SP

Bus Distance From POI	BUS NUMBER	BUS NAME	kV	AREA	ZONE	3 Phase Fault Current (kA) GenON	GenOFF	Difference (ON - OFF) Change	%
0	532984	SUMNER 4	138	536	1537	10.500	10.011	0.489	4.88%
1	532982	OXFORD 4	138	536	1537	9.470	9.107	0.363	3.99%
1	532992	TIMBJCT4	138	536	1537	5.795	5.674	0.122	2.14%
1	533063	SC10BEL4	138	536	1537	9.900	9.667	0.233	2.41%
1	533075	VIOLA 4	138	536	1537	22.332	22.236	0.096	0.43%
1	585200	GEN-2015-083	138	536	1537	3.967	N/A	N/A	N/A
2	532981	CRESWLN4	138	536	1537	8.031	7.920	0.111	1.40%
2	532985	TCROCK 4	138	536	1537	5.418	5.312	0.106	2.00%
2	533042	FARBER 4	138	536	1537	16.338	16.217	0.121	0.75%
2	533036	CLEARWT4	138	536	1537	22.099	22.048	0.051	0.23%
2	533046	GILL S 4	138	536	1537	28.848	28.765	0.083	0.29%
2	532798	VIOLA	345	536	1537	13.470	13.449	0.021	0.16%
3	514804	MIDLTNT4	138	524	566	7.861	7.800	0.061	0.78%
3	533070	SLATECRK	138	536	1537	4.496	4.462	0.034	0.76%
3	533039	ELPASO 4	138	536	1537	25.680	25.545	0.136	0.53%
3	533045	GILL W 4	138	536	1537	28.848	28.765	0.083	0.29%
3	533880	GODDARD2	138	536	1537	19.237	19.214	0.023	0.12%
3	539675	MILANTP4	138	534	1541	7.148	7.148	0.000	0.00%
3	533029	59TH ST4	138	536	1537	19.131	19.080	0.051	0.27%
3	515543	RENFROW7	345	524	566	11.828	11.821	0.007	0.06%
3	532792	FR2EAST7	345	536	1537	6.635	6.631	0.004	0.06%
3	532796	WICHITA7	345	536	1537	24.745	24.714	0.031	0.12%
3	533044	GILL E 4	138	536	1537	28.848	28.765	0.083	0.29%
4	515381	PECKHMT4	138	524	566	8.384	8.334	0.050	0.60%
4	521198	CHILOCCO	138	525	575	6.098	6.059	0.039	0.64%
4	533032	BU11PON4	138	536	1537	15.161	15.130	0.032	0.21%
4	533062	ROSEHIL4	138	536	1537	31.619	31.532	0.087	0.28%
4	533066	64TH 4	138	536	1537	14.509	14.480	0.029	0.20%
4	533068	STEARMN4	138	536	1537	20.020	19.971	0.049	0.25%
4	533072	WACO 4	138	536	1537	23.837	23.784	0.053	0.22%
4	533041	EVANS S4	138	536	1537	42.437	42.370	0.067	0.16%
4	539668	HARPER 4	138	534	1541	6.003	6.007	-0.004	-0.07%
4	539676	MILAN 4	138	534	1541	4.251	4.253	-0.002	-0.04%
4	515476	HUNTERS7	345	524	566	12.408	12.406	0.001	0.01%
4	583750	GEN-2013	345	524	566	10.477	10.472	0.005	0.05%
4	515544	RENFROW4	138	524	566	13.624	13.622	0.002	0.01%
4	532795	FR2WEST7	345	536	1537	5.490	5.488	0.002	0.05%
4	532771	RENO 7	345	536	1535	11.554	11.555	-0.001	-0.01%
4	532791	BENTON 7	345	536	1537	19.502	19.471	0.031	0.16%
4	560033	G1524&G1	345	536	1537	19.633	19.620	0.014	0.07%
4	562476	G14-001-	345	536	1537	11.033	11.033	-0.001	-0.01%
4	533040	EVANS N4	138	536	1537	42.437	42.370	0.067	0.16%
4	533051	INTERST4	138	536	1537	17.689	17.667	0.022	0.13%
4	515477	CHSHLMV7	345	524	566	12.391	12.389	0.001	0.01%
5	514759	NEWKIRK4	138	524	566	8.734	8.688	0.046	0.53%
5	532991	WEAVER 4	138	536	1537	22.405	22.349	0.057	0.25%

5	532794	ROSEHIL7	345	536	1537	19.152	19.118	0.034	0.18%
5	533048	HARRY 4	138	536	1537	13.722	13.698	0.024	0.18%
5	533030	BOEING 4	138	536	1537	17.358	17.326	0.032	0.18%
5	533034	CENTENN4	138	536	1537	16.870	16.853	0.017	0.10%
5	533053	LAKERDG4	138	536	1537	19.270	19.251	0.019	0.10%
5	533074	45TH ST4	138	536	1537	29.635	29.599	0.036	0.12%
5	539000	RAGO 4	138	534	1541	3.655	3.657	-0.003	-0.07%
5	539001	ANTHONY4	138	534	1541	3.666	3.669	-0.003	-0.07%
5	539638	FLATRDG4	138	534	1541	14.973	14.978	-0.005	-0.03%
5	539004	MAYFLD 4	138	534	1541	3.787	3.789	-0.002	-0.05%
5	514715	WOODRNG7	345	524	566	17.238	17.240	-0.003	-0.02%
5	515546	GRANTCO4	138	524	566	6.278	6.279	-0.001	-0.01%
5	515569	MDFRDTP4	138	524	566	11.006	11.004	0.002	0.02%
5	520409	RENFROW4	138	525	587	9.998	9.999	-0.001	-0.01%
5	578530	FR3	345	536	1537	5.092	5.090	0.002	0.04%
5	532773	SUMMIT 7	345	536	1535	10.678	10.679	-0.001	-0.01%
5	533416	RENO 3	115	536	1535	25.673	25.676	-0.003	-0.01%
5	532797	WOLFCRK7	345	536	1536	15.728	15.724	0.003	0.02%
5	532986	BENTON 4	138	536	1537	28.321	28.278	0.043	0.15%
5	539801	THISTLE7	345	534	1529	15.627	15.628	-0.001	-0.01%
5	584659	G15024G1	345	536	1537	6.721	6.720	0.001	0.01%
5	532768	EMPEC 7	345	536	1534	17.278	17.284	-0.005	-0.03%
5	583850	GEN-2014	345	536	1537	7.551	7.552	-0.001	-0.01%
5	533065	SG12COL4	138	536	1537	21.794	21.777	0.017	0.08%
5	533390	MAIZEW 4	138	536	1537	28.204	28.171	0.033	0.12%
5	533050	HOOVERS4	138	536	1537	19.138	19.115	0.023	0.12%

APPENDIX D: LOW WIND ANALYSIS

FIIGURE D-1: GEN-2015-083 WITH GENERATION OFF AND NO SHUNT REACTOR



FIIGURE D-1: GEN-2015-083 WITH GENERATION OFF AND SHUNT REACTOR