GEN-2015-021 Impact Restudy for Generator Modification (Inverter Change)

August 2016
Generator Interconnection

Southwest Power Pool

Revision History

Date	Author	Change Description
8/01/2016	SPP	Restudy for Generator Modification (Inverter Change) issued.

Executive Summary

The GEN-2015-021 Interconnection Customer has requested a modification to its Generator Interconnection Request to change from twenty (20) AE 1000NX 1MW solar inverters to five (5) GE LV5 4MVA solar inverters. The nameplate power remains unchanged at 20MW.

The point of interconnection (POI) is the Sunflower Electric Power Corporation (SUNC) Johnson Corner 115kV Substation. ABB Inc. (ABB) performed the study for this modification request, and ABB's report on the study follows this summary.

The study models used were the 2016 winter, the 2017 summer, and the 2025 summer cases and included Interconnection Requests through DISIS-2015-001. The study showed that no stability problems were found with the contingencies studied during the summer and the winter peak conditions as a result of changing to the GE LV5 4.0MVA inverters. Additionally, GEN-2015-021 was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements.

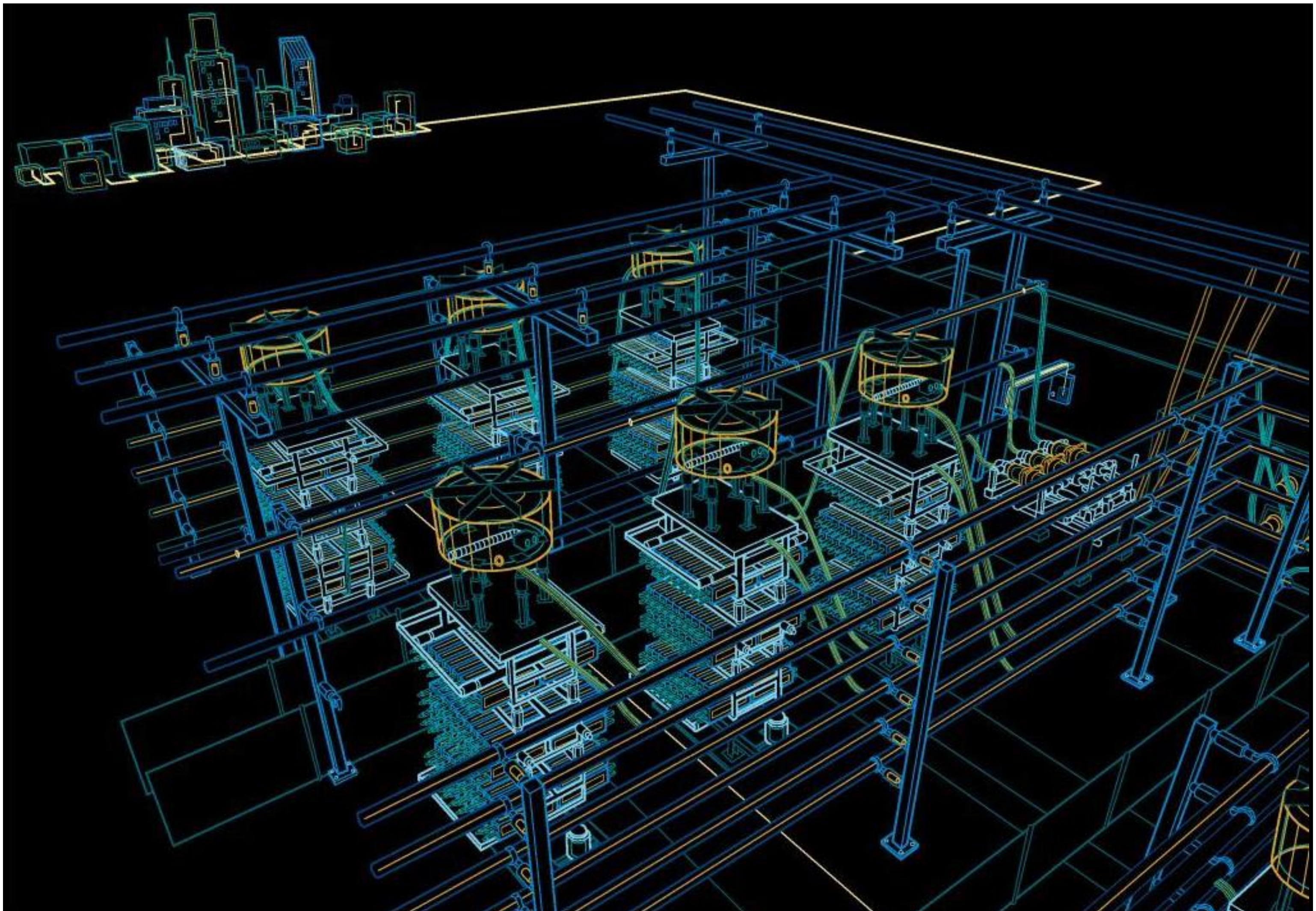
A power factor analysis was performed for the study and it was found that the GEN-2015-021 will be required to meet the 0.95 power factor lagging (providing vars) and 0.95 power factor leading (absorbing vars) at the POI. A short circuit analysis was performed and is detailed in the ABB report.

A low solar irradiance/no solar irradiance condition analysis was performed for this modification request. The analysis showed that the project will inject approximately 0.21Mvars into the POI during periods of low solar/no solar irradiance. Due to the low Mvar injection at the POI, GEN-2015-021 will not be required to have shunt reactors to offset the capacitive injection.

With the assumptions outlined in this report and with all required network upgrades in place, GEN-2015-021 will be able to reliably interconnect to the SPP transmission grid with the GE LV5 4MVA inverter.

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. If the Customer wishes to obtain deliverability to a specific customer, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS.



Southwest Power Pool

GEN-2015-021 System Impact Restudy for Generator Modification

Final Report

Report No. r00

08 July 2016

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SUMMARY

Southwest Power Pool (SPP) has commissioned ABB Inc. to perform a System Impact Restudy for Generator Modification for generation interconnection request GEN-2015-021 (20 MW PV farm at the Johnson Corner 115 kV bus located near the town of Stanton, Kansas).

Request	Size (MW)	Generator Model	POI
GEN-2015-021	20.0	GE LV5 4.0 MW	Johnson Corner 115kV (531424)

The objective of this study is to re-evaluate the impact of project GEN-2015-021 project at 100% of nameplate MW capacity on the existing and future transmission system. While the previous study was based on the PV farm comprising AE 1000NX 1 MW Solar Inverters, the present study is based on GE LV5 4 MW Solar Inverters.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low solar irradiance condition analysis. The following is a summary of study results.

Results of the Stability Analysis show no stability criteria violations for all studied disturbances for the three seasons.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to check whether the studied project meets FERC and SPP power factor requirements for solar farm interconnections. The solar farm is required to meet the 95% lagging (injecting MVAr into the grid) and 95% leading (absorbing MVAr from the grid) power factor requirements at the Point of Interconnection. See Section 4 of this report for details.

The Low Solar irradiance condition analysis shows that 0.21 MVAr of shunt reactance is required at the POI to bring the MVAr flow at the POI down to approximately zero under low solar irradiance conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

Contents

1 INTRODUCTION

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for Generator Modification for generation interconnection request GEN-2015-021 (20 MW PV farm at the Johnson Corner 115 kV bus located near the town of Stanton, Kansas) as shown in Table 1-1.

Table 1-1: Gen-2015-021 Generation Interconnection Request

Request	Size (MW)	Generator Model	POI
GEN-2015-021	20.0	GE LV5 4.0 MW	Johnson Corner 115kV (531424)

The objective of this study is to re-evaluate the impact of project GEN-2015-021 at 100% of nameplate MW capacity on the existing and future transmission system. While the previous study was based on the PV farm comprising AE 1000NX 1 MW Solar Inverters, the present study is based on GE LV5 4 MW Solar Inverters.

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low solar irradiance conditions analysis.

The study is performed for three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

SPP provided the study cases for all three system scenarios which include GEN-2015-021 modelled on the basis of AE 1000NX 1MW PV Inverters. The following changes were made by ABB to update the three cases.

- The proposed solar farm is modeled at 100% of nameplate, compared to 20% in the provided cases. Solar farm representation, including PV inverters reactive power capability limits, generator step-up transformer, and substation transformer, are updated based on the data provided by the Interconnection Customer. Collector system, and the 115 kV transmission line data are assumed same as represented in the SPP study cases.

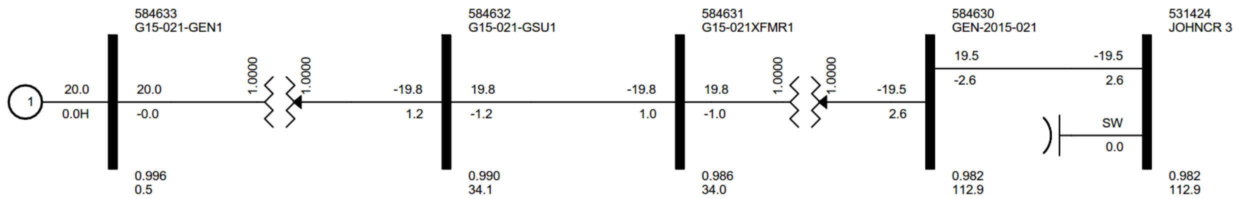
- The dynamic model of the AE 1000NX 1MW PV Inverters in the provided cases is replaced by the GE 4.0 MW inverter generator model.
- The dispatches of prior-queued projects summarized in Table 1-2 are increased from 20% of nameplate as in the provided cases to 100% by using the automation files provided by SPP.
- The generators in SPP footprint, defined by the automation file ("2015_MDWG_DIS1501_Scale_Subsystem.idv") provided by SPP, are re-dispatched down by incremental dispatch amounts of the proposed solar farm and prior-queued projects in**Error! Reference source not found.**

Table 1-2: Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2002-025A	150	GE 1.5 MW	Spearville 230kV (539695)
GEN-2004-014	154.5	GE 1.5 MW	Spearville 230kV (539695)
GEN-2005-012	250.7	Siemens 2.3MW	Ironwood 345kV (539803)
GEN-2006-021	100	Clipper 2.5MW	Flat Ridge 138kV (539638)
GEN-2007-040	200.1	Siemens 2.3MW	Buckner 345kV (531501)
GEN-2008-018	250	GE 1.85 MW	Finney 345kV (523853)
GEN-2008-079	98.9	Siemens 2.3MW	CRKCK 115kV line (539783)
GEN-2008-124	200.1	Siemens 2.3MW	Ironwood 345kV (539803)
GEN-2010-009	165.6	Siemens 2.3MW	Buckner 345kV (531501)
GEN-2010-045	197.8	Siemens 2.3MW	Buckner 345kV (531501)
GEN-2011-008	600	GE 1.6MW	Clark County 345kV (539800)
GEN-2011-016	200.1	Siemens 2.3MW	Ironwood 345kV
GEN-2012-007	96.0 Summer 120.0 Winter	GENSAL	Rubart 115kV (531200)
ASGI-2012-006	20.74 Summer 21.21 Winter	GENSAL	ABBK 69kV (531494)
GEN-2013-010	99	Siemens 3.0MW (583603)	GEN-2013-010 Tap 345kV (562334) (Tap on Spearville to Post Rock 345kV line)
GEN-2012-024	178.2	Vestas V117 3.3MW (54 generators)	Clark County 345kV (539800)

The one line diagram for the study project is shown in Figure 1-1.

Figure 1-1 : One Line Diagram for the Study Project



2 STABILITY ANALYSIS

In this study, ABB investigated the stability of the system for faults in the vicinity of the proposed plant as defined by SPP. The studied faults involve three-phase transformer faults with normal clearing, three-phase line faults with normal clearing and re-closing, and single-line-to-ground faults with stuck breaker (SB-1PH).

2.1 STABILITY ANALYSIS METHODOLOGY

Stability analysis is performed to determine whether the electric system would meet stability criteria following the addition of the GEN-2015-021 project. Stability analysis was performed using Siemens-PTI's PSS/E dynamics program V32.2.4. All the faults listed in Table 2 1 were simulated for 20 seconds.

Table 2-1 List of Faults for Stability Analysis

CONT NO	CONT NAME	Description
1	FLT06-3PH	3 phase fault on the Thistle 345KV (539801) to Clark County 345KV (539800) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). 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	FLT11-3PH	3 phase fault on the GEN-2013-010 tap to Spearville 345KV (531469) CKT 1 near Spearville. a. Apply fault at the Spearville 345kV bus (531469). 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	FLT12-3PH	3 phase fault on the Spearville 345KV (531469) to Buckner 345KV (531501) CKT 1 near Spearville. a. Apply fault at the Spearville 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	FLT13-3PH	3 phase fault on the Ironwood 345KV (539803) to Clark County 345KV (539800) CKT 1 near Clark County a. Apply fault at the Clark County 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	FLT15-3PH	3 phase fault on the Spearville 345KV (531469) to Spearville 230kV (539695) to Spearville 13.8kV (531468) XMFR CKT 1, near Spearville 345kV. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT16-3PH	3 phase fault on the Spearville 345KV (531469) to Spearville 115kv (539759) to Spearville 13.8kV (539960) XMFR CKT 1, near Spearville 345kV. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
7	FLT17-3PH	3 phase fault on the Buckner 345KV (531501) to Holcomb 345KV (531449) CKT 1 near Buckner. a. Apply fault at the Buckner 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	FLT20-3PH	3 phase fault on the Holcomb 345KV (531449) to Finney 345KV (523853) CKT 1 near Holcomb. a. Apply fault at the Holcomb 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	FLT21-3PH	3 phase fault on the Finney 345KV (523853) to Hitchland 345KV (523097) CKT 1 near Finney. a. Apply fault at the Finney 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	FLT23-3PH	3 phase fault on the Setab 345KV (531465) to Mingo 345KV (531451) CKT 1 near Setab. a. Apply fault at the Setab 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.
11	FLT24-3PH	3 phase fault on the Mingo 345KV (531451) to Red Willow 345KV (640325) CKT 1 near Mingo. a. Apply fault at the Mingo 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT35-PO	**Prior outage on the Spearville – Buckner 345kV line** 3 phase fault on GEN 2013-010-TAP (562334) to Post Rock (530583) a. Prior outage the Spearville (531469) to Buckner (531501) 345kV line (solve network for steady state solution) b. 3 phase fault on the GEN 2013-010-TAP (562334) to Post Rock (530583) 345kV line near GEN 2013-010-TAP c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT56-3PH	3 phase fault on the Johnson Corner (531424) to Johnson (531381) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 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	FLT57-3PH	3 phase fault on the Johnson Corner (531424) to Bear Creek (531473) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 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.

15	FLT59-3PH	3 phase fault on the Syracuse (531437) to Tribune (531439) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT60-3PH	3 phase fault on the Syracuse (531437) to Williamson (531440) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 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.
17	FLT61-3PH	3 phase fault on the Tribune Switch (531438) to Palmer (531431) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT62-3PH	3 phase fault on the Tribune Switch (531438) to Selkirk (531434) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 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.
19	FLT63-3PH	3 phase fault on the Tribune Switch (531438) to Tribune (531439) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT64-3PH	3 phase fault on the Fletcher (531420) to PK_GOAB (531400) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 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.

21	FLT65-3PH	3 phase fault on the Fletcher (531420) to Williamson (531440) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT66-3PH	3 phase fault on the Fletcher (531420) to Holcomb (531448) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 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.
23	FLT67-3PH	3 phase fault on the Pioneer (531391) to Hickock (531378) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 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.
24	FLT68-3PH	3 phase fault on the Pioneer (531391) to PK_GOAB (531400) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 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.
25	FLT69-3PH	3 phase fault on the Pioneer (531391) to Grant Tap (531483) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 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.
26	FLT70-3PH	3 phase fault on the Pioneer (531391) to Ulysses Plant (531490) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 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.

27	FLT71-3PH	3 phase fault on the Pioneer Tap (531392) to CMX Tap (531203) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT72-3PH	3 phase fault on the Pioneer Tap (531392) to Plymel (531393) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
29	FLT73-3PH	3 phase fault on the Pioneer Tap (531392) to Sublette (531398) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT74-3PH	3 phase fault on the Pioneer Tap (531392) to Satanta Tap (531442) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
31	FLT32-PO	**Prior outage on the Johnson Corner – Bear Creek ckt 1** 3 phase fault on Johnson Corner (531424) to Johnson (531381) 115kV CKT 1 a. Prior outage Johnson Corner (531424) – Bear Creek (531473) 115kV ckt 1 (solve network for steady state solution) b. 3 phase fault on the Johnson Corner (531424) to Johnson (531381) ckt 1 c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

32	FLT31-PO	**Prior outage on the Johnson Corner – Johnson ckt 1** 3 phase fault on Johnson Corner (531424) to Bear Creek 115kV CKT 1 a. Prior outage Johnson Corner (531424) – Johnson (531381) 115kV ckt 1 (solve network for steady state solution) b. 3 phase fault on the Johnson Corner (531424) to Bear Creek (531473) 115kV ckt 1 c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
33	FLT33-SB	**Johnson Corner Stuck Breaker** a. Apply single phase fault at the Johnson Corner (531424) 115kV bus b. Wait 16 cycles, and then trip Johnson Corner (531424) – Johnson (531381) 115kV ckt 1 c. Trip Johnson Corner (531424) – Bear Creek (531473) 1115kV line d. clear fault
34	FLT34-SB	**Syracuse Stuck Breaker** a. Apply single phase fault at the Syracuse (531437) 115kV bus b. Wait 16 cycles, and then trip Syracuse (531437) – Tribune (531439) c. Trip Syracuse (531437) – Williams (531440) d. clear fault
35	FLT35-SB	**Fletcher Stuck Breaker** a. Apply single phase fault at the Fletcher (531420) 115kV bus b. Wait 16 cycles, and then trip Fletcher – Williams 115kV c. Trip Fletcher – PKGOAB 115kV c. clear fault
36	FLT36-SB	**Tribune Switch Stuck Breaker** a. Apply single phase fault at the Tribune Switch (531438) 115kV bus b. Wait 16 cycles, and then trip Tribune Switch (531438) to Palmer (531431) c. Trip Tribune Switch (531438) to Selkirk (531434) d. clear fault
37	FLT37-SB	**Tribune Switch Stuck Breaker** a. Apply single phase fault at the Tribune Switch (531438) 115kV bus b. Wait 16 cycles, and then trip Tribune Switch (531438) to Palmer (531431) c. Trip Tribune Switch (531438) to Tribune (531439) d. clear fault

38	FLT38-SB	**Fletcher Stuck Breaker** a. Apply single phase fault at the Fletcher (531420) 115kV bus b. Wait 16 cycles, and then trip Fletcher (531420) to Holcomb (531448) 115kV c. Trip Fletcher – PKGOAB 115kV c. clear fault
39	FLT39-SB	**Pioneer Stuck Breaker** a. Apply single phase fault at the Pioneer (531391) 115kV bus b. Wait 16 cycles, and then trip Pioneer (531391) to PK_GOAB (531400) c. Trip Pioneer (531391) to Hickock (531378) c. clear fault
40	FLT40-SB	**Pioneer Stuck Breaker** a. Apply single phase fault at the Pioneer (531391) 115kV bus b. Wait 16 cycles, and then trip Pioneer (531391) to PK_GOAB (531400) c. Trip Pioneer (531391) to Grant Tap (531483) c. clear fault

Single-line-to-ground faults were simulated with the standard method of applying fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network.

The Southwest Pool Disturbance Performance Criteria Requirements in Appendix A were used to evaluate system response during the initial transient period following a disturbance on the system. Generator responses and bus voltages (115 kV and above) in Areas 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), and 536 (WERE) were monitored to ensure that the system performance meets criteria. Rotor angles of nearby synchronous generators were plotted to verify whether the generators maintained synchronism and had adequate damping following system disturbances.

SPP requires generators relying on newer technologies to comply with low voltage ride through requirements as stipulated in FERC Order 661A. See Appendix G of the "Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment V Generator Interconnection Procedures (GIP)"[1]. According to these requirements, such generators should not be tripped off line for faults by under voltage relay actuation. Generator speeds of pre-queued projects were also monitored to ensure they stay online under system contingencies. For contingencies that result in a prior queued project tripping off-line, SPP requires those contingencies to be re-run with the prior queued project's voltage and frequency tripping disabled.

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[1] http://sppoasis.spp.org/documents/swpp/transmission/studies/Attachment_V_GIP.pdf

2.2 STUDY RESULTS

No disturbances (including all n-1 and stuck breaker disturbances) showed instability problems or voltage violations for three seasons. The proposed PV farm rode through all faults without tripping. The only exception was stuck-breaker Fault FLT-33SB; fault and loss of Johnson Corner (531424) – Johnson (531381) 115kV ckt 1 and Johnson Corner (531424) – Bear Creek (531473) ckt 1 115kV line. This fault isolates the proposed PV farm from the transmission grid, resulting in it tripping off-line. Fault results are summarized in Table 2-2, Table 2-3, and Table 2-4, which show results for the 2016 Winter Peak case, the 2017 Summer Peak case, and the 2025 Summer Peak case, respectively. The "Volt CI Violation" in the table refers to bus voltages exceeding the range of 0.7 pu. or 1.2 pu, 2.5 second after fault clearing, and the "Volt CII Violation" refers to end bus voltages exceeding the range of 0.9 pu. or 1.1 pu at the end of the simulation.

Table 2-2 Study Results Summary, 2016 Winter Peak

Index	Fault File Name	16WP Case		
		Stable?	Volt CI Violation	Volt CII Violation
1	FLT06-3PH	Stable	No	No
2	FLT11-3PH	Stable	No	No
3	FLT12-3PH	Stable	No	No
4	FLT13-3PH	Stable	No	No
5	FLT15-3PH	Stable	No	No
6	FLT16-3PH	Stable	No	No
7	FLT17-3PH	Stable	No	No
8	FLT20-3PH	Stable	No	No
9	FLT21-3PH	Stable	No	No
10	FLT23-3PH	Stable	No	No
11	FLT24-3PH	Stable	No	No
12	FLT35-PO	Stable	No	No
13	FLT56-3PH	Stable	No	No
14	FLT57-3PH	Stable	No	No
15	FLT59-3PH	Stable	No	No
16	FLT60-3PH	Stable	No	No
17	FLT61-3PH	Stable	No	No
18	FLT62-3PH	Stable	No	No
19	FLT63-3PH	Stable	No	No
20	FLT64-3PH	Stable	No	No
21	FLT65-3PH	Stable	No	No
22	FLT66-3PH	Stable	No	No
23	FLT67-3PH	Stable	No	No
24	FLT68-3PH	Stable	No	No
25	FLT69-3PH	Stable	No	No
26	FLT70-3PH	Stable	No	No
27	FLT71-3PH	Stable	No	No
28	FLT72-3PH	Stable	No	No
29	FLT73-3PH	Stable	No	No
30	FLT74-3PH	Stable	No	No
31	FLT32-PO	Stable	No	No
32	FLT31-PO	Stable	No	No
33	FLT33-SB**	Stable	No	No
34	FLT34-SB	Stable	No	No
35	FLT35-SB	Stable	No	No
36	FLT36-SB	Stable	No	No
37	FLT37-SB	Stable	No	No
38	FLT38-SB	Stable	No	No
39	FLT39-SB	Stable	No	No

Index	Fault File Name	16WP Case		
		Stable?	Volt CI Violation	Volt CII Violation
40	FLT40-SB	Stable	No	No

Note: Proposed project (GEN-2015-021) tripped due to islanding.

Table 2-3 Study Results Summary, 2017 Summer Peak

Index	Fault File Name	17SP Case		
		Stable?	Volt CI Violation	Volt CII Violation
1	FLT06-3PH	Stable	No	No
2	FLT11-3PH	Stable	No	No
3	FLT12-3PH	Stable	No	No
4	FLT13-3PH	Stable	No	No
5	FLT15-3PH	Stable	No	No
6	FLT16-3PH	Stable	No	No
7	FLT17-3PH	Stable	No	No
8	FLT20-3PH	Stable	No	No
9	FLT21-3PH	Stable	No	No
10	FLT23-3PH	Stable	No	No
11	FLT24-3PH	Stable	No	No
12	FLT35-PO	Stable	No	No
13	FLT56-3PH	Stable	No	No
14	FLT57-3PH	Stable	No	No
15	FLT59-3PH	Stable	No	No
16	FLT60-3PH	Stable	No	No
17	FLT61-3PH	Stable	No	No
18	FLT62-3PH	Stable	No	No
19	FLT63-3PH	Stable	No	No
20	FLT64-3PH	Stable	No	No
21	FLT65-3PH	Stable	No	No
22	FLT66-3PH	Stable	No	No
23	FLT67-3PH	Stable	No	No
24	FLT68-3PH	Stable	No	No
25	FLT69-3PH	Stable	No	No
26	FLT70-3PH	Stable	No	No
27	FLT71-3PH	Stable	No	No
28	FLT72-3PH	Stable	No	No
29	FLT73-3PH	Stable	No	No
30	FLT74-3PH	Stable	No	No
31	FLT32-PO	Stable	No	No
32	FLT31-PO	Stable	No	No
33	FLT33-SB**	Stable	No	No
34	FLT34-SB	Stable	No	No
35	FLT35-SB	Stable	No	No
36	FLT36-SB	Stable	No	No
37	FLT37-SB	Stable	No	No
38	FLT38-SB	Stable	No	No
39	FLT39-SB	Stable	No	No
40	FLT40-SB	Stable	No	No

Note: Proposed project (GEN-2015-021) tripped due to islanding.

Table 2-4 Study Results Summary, 2025 Summer Peak

Index	Fault File Name	25SP Case Stable?	Volt CI Violation	Volt CII Violation
1	FLT06-3PH	Stable	No	No
2	FLT11-3PH	Stable	No	No
3	FLT12-3PH	Stable	No	No
4	FLT13-3PH	Stable	No	No
5	FLT15-3PH	Stable	No	No
6	FLT16-3PH	Stable	No	No
7	FLT17-3PH	Stable	No	No
8	FLT20-3PH	Stable	No	No
9	FLT21-3PH	Stable	No	No
10	FLT23-3PH	Stable	No	No
11	FLT24-3PH	Stable	No	No
12	FLT35-PO	Stable	No	No
13	FLT56-3PH	Stable	No	No
14	FLT57-3PH	Stable	No	No
15	FLT59-3PH	Stable	No	No
16	FLT60-3PH	Stable	No	No
17	FLT61-3PH	Stable	No	No
18	FLT62-3PH	Stable	No	No
19	FLT63-3PH	Stable	No	No
20	FLT64-3PH	Stable	No	No
21	FLT65-3PH	Stable	No	No
22	FLT66-3PH	Stable	No	No
23	FLT67-3PH	Stable	No	No
24	FLT68-3PH	Stable	No	No
25	FLT69-3PH	Stable	No	No
26	FLT70-3PH	Stable	No	No
27	FLT71-3PH	Stable	No	No
28	FLT72-3PH	Stable	No	No
29	FLT73-3PH	Stable	No	No
30	FLT74-3PH	Stable	No	No
31	FLT32-PO	Stable	No	No
32	FLT31-PO	Stable	No	No
33	FLT33-SB**	Stable	No	No
34	FLT34-SB	Stable	No	No
35	FLT35-SB	Stable	No	No
36	FLT36-SB	Stable	No	No
37	FLT37-SB	Stable	No	No
38	FLT38-SB	Stable	No	No
39	FLT39-SB	Stable	No	No
40	FLT40-SB	Stable	No	No

Note: Proposed project (GEN-2015-021) tripped on islanded condition.

Figure 2-1 shows the response of the studied generator following fault FLT06-3PH for 2016 Winter Peak case. The active and reactive power output and terminal voltage are plotted to show the generator response.

All the simulation plots are included in Appendix B.

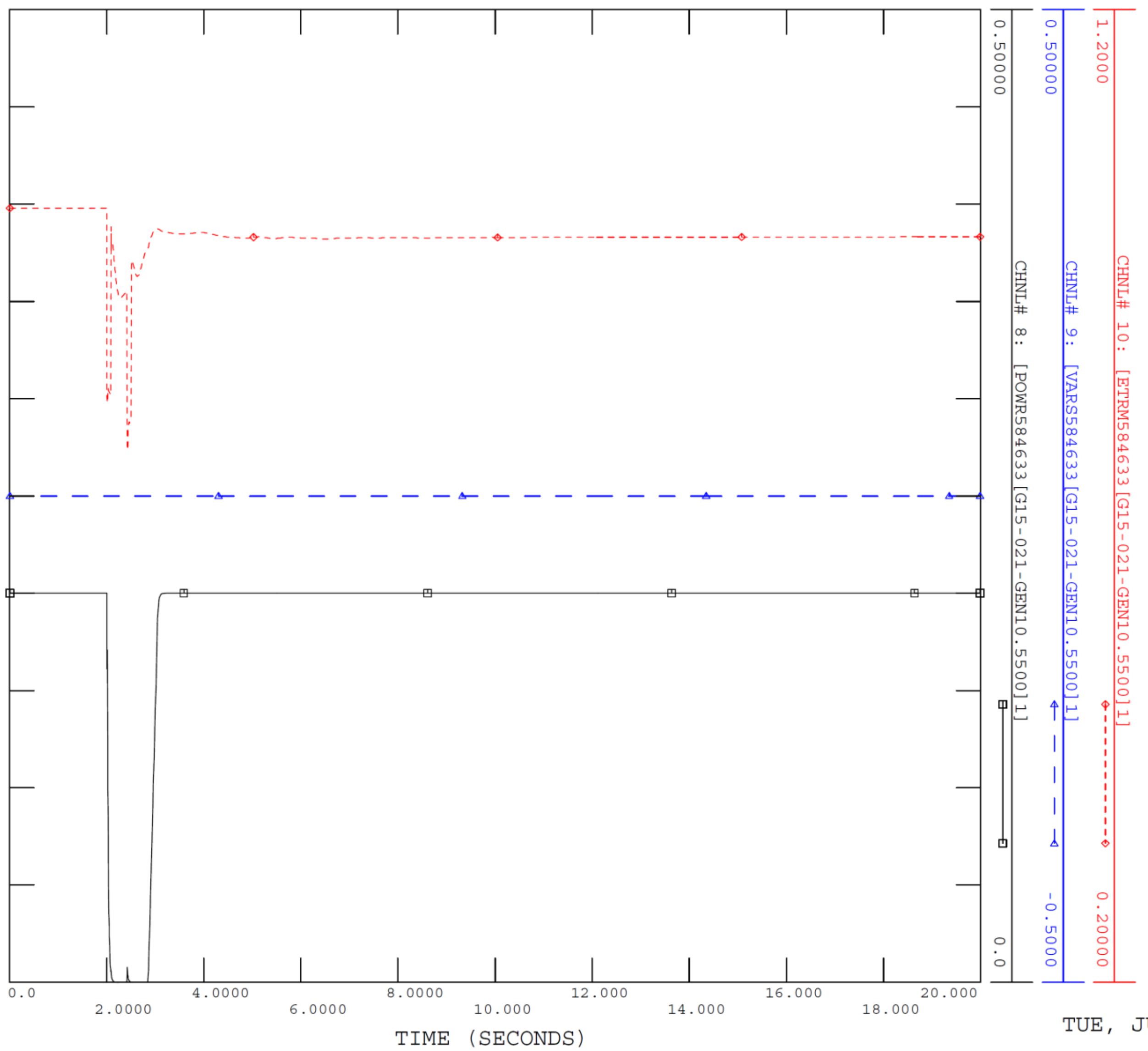


Figure 2-1: GEN-2015-021 Response Following Fault FLT06-3PH for 2016 Winter Peak Case

3 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on the 2017 Summer Peak and 2025 Summer Peak power flow cases using the PSS/E program. Three-phase symmetrical fault current levels were calculated at up to five buses away from the point of interconnection. Table 3-1 tabulates the calculated three-phase fault current levels at buses rated 69 kV and above.

Table 3-1: Three-Phase Fault Currents

2017 SP			2025 SP		
Number	**Name**	**3PH(Amp)**	**Number**	**Name**	**3PH(Amp)**
531473	BEARCRK3 115.00	2773.5	531473	BEARCRK3 115.00	2763.2
531474	RICHFLD2 69.000	1258.0	531474	RICHFLD2 69.000	1265.2
531475	MANTERT2 69.000	1955.1	531475	MANTERT2 69.000	1961.8
531483	GRANTTP3 115.00	4973.7	531483	GRANTTP3 115.00	4952.4
531490	ULYSPLT3 115.00	3982.8	531490	ULYSPLT3 115.00	3966.5
531491	BIG BOW 3 115.00	3097.1	531491	BIG BOW 3 115.00	3082.0
531378	HICKOCK3 115.00	5915.3	531378	HICKOCK3 115.00	5900.5
531381	JOHNSON2 115.00	2810.3	531381	JOHNSON2 115.00	2791.9
531382	MANTER 2 69.000	1614.3	531382	MANTER 2 69.000	1621.3
531390	PIONEER2 69.000	3926.7	531390	PIONEER2 69.000	3916.5
531391	PIONEER3 115.00	6070.1	531391	PIONEER3 115.00	6046.5
584630	GEN-2015-021115.00	2754.3	584630	GEN-2015-021115.00	2734.1
531400	PK_GOAB3 115.00	4951.3	531400	PK_GOAB3 115.00	4933.8
531383	JOHNCR 2 69.000	2232.2	531383	JOHNCR 2 69.000	2238.1
531420	FLETCHR3 115.00	6835.1	531420	FLETCHR3 115.00	6815.3
531424	JOHNCR 3 115.00	2757.9	531424	JOHNCR 3 115.00	2737.6
531431	PALMER3 115.00	3064.5	531431	PALMER3 115.00	3062.0
531434	SELKIRK3 115.00	3926.2	531434	SELKIRK3 115.00	3917.7
531437	SYRACUS3 115.00	3583.3	531437	SYRACUS3 115.00	3573.2
531438	TRIB SW3 115.00	3566.3	531438	TRIB SW3 115.00	3561.6
531439	TRIBUNE3 115.00	3489.4	531439	TRIBUNE3 115.00	3484.8
531440	WILLIAM3 115.00	3746.5	531440	WILLIAM3 115.00	3735.4
531448	HOLCOMB3 115.00	22123.8	531448	HOLCOMB3 115.00	22199.9

4 POWER FACTOR ANALYSIS

4.1 POWER FACTOR ANALYSIS METHODOLOGY

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for solar farm interconnections. All N-1, three phase stability faults shown in Table 4-1 were analyzed based on power flow analysis (faults are not applied in power flow; instead, post-fault steady-state performance is simulated by tripping relevant transmission facilities that operate to clear the fault). The power factor requirements for the solar farm were determined to maintain the voltage at the POI to the schedule voltage which is the higher of the POI voltage in the provided base case or 1.0 per unit.

The study project solar farm as modeled was turned off for the power factor analysis. The solar farm was replaced by a generator at the high side bus (Johnson Corner 115 kV bus; bus 531424) with the MW of the solar farms at the POI and no var capability. A var generator at the same bus was modeled. The MW and Mvar injections at the POI were recorded for calculating the power factors. The most lagging and most leading power factors among all the disturbances determine the minimum power factor range capability required for the studied solar farm.

Per FERC and SPP requirements, if the power factor needed to maintain the scheduled voltage is less than 0.95 lagging or leading, the requirement is determined on the basis of 0.95 lagging or leading.

If the required power factor at the POI is beyond the capability of the studied PV inverter, the approximate size of the additional capacitors were determined.

4.2 STUDY RESULTS

In accordance with SPP procedures, the power factor requirements for the solar farm were determined to maintain the POI voltage at 1.0 pu. Contingencies were simulated by tripping relevant transmission facilities that operate to clear faults. Contingency FLT06-3PH (loss of Thistle – Clark County double-circuit 345 kV line) showed the lowest lagging power factor for all three seasons. The PV farm is unable to maintain the POI voltage at 1.0 pu following this and other contingencies. Table 4-1 summarizes the power factor analysis results. Detailed power factor analysis results for each studied contingency are provided in Appendix C. The MVAr injections at the POI shown in Appendix C are from the VAR generator only. In all of the simulated contingencies, the 24 MVAr (2X12 MVAr) switched shunt capacitors modelled in the SPP study cases at the Johnson Corner 115 kV bus was delivering 0 MVAr (i.e., the two 12 MVAr capacitor banks were switched out). Contingency FLT06-3PH shows a maximum injection of 31.1 MVAr from the VAR generator in 2016 winter peak scenario (i.e., 31.1 MVAr is required to maintain 1.0 pu voltage at the POI). With the 24 MVAr shunt capacitor at the Johnson Corner 115 kV bus switched in, an additional compensation of 7.1 MVAr is required to maintain the POI voltage at 1.0 pu. Per SPP and FERC requirements, the generating facility shall be designed to meet the requirement of 95% lagging (providing vars) and 95% leading (absorbing vars) at the Point of Interconnection.

Table 4-1 Power Factor Analysis Results

Request	Size (MW)	Generator Model	POI	Scenario	Final PF
GEN-2015-021	20.0	GE LV5 4.0 MW (PV inverter)	Johnson Corner 115kV (531424)	16WP	0.54 lagging
				17SP	0.64 lagging
				25SP	0.57 lagging

Notes:

Leading is when the generator is absorbing reactive power from the transmission grid. Lagging is when the generator is providing reactive power to the transmission grid.

5 LOW SOLAR IRRADIANCE CONDITIONS ANALYSIS

In this study, ABB investigated the GEN-2015-021 project for low solar irradiance conditions, since the interconnected solar farm is connected at a 115kV bus.

5.1 Low Solar Irradiance Conditions Analysis Methodology

Low solar irradiance conditions analysis is performed to determine the required shunt reactor size at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

For each studied scenario, the studied PV generator was switched out of service with the collector system as modeled remaining in service. The resulting reactive power injection into the transmission network coming from the capacitance of the project's transmission lines and collector cables was measured. Then, the required shunt reactor size was calculated to bring the MVAr flow into the POI down to approximately zero.

5.2 Study Results

Table 5-1 summarizes the Low Solar irradiance conditions analysis results. It is shown that 0.21 MVAr shunt reactor at the substation high side bus (531424) is required to bring the MVAr flow in the POI down to approximately zero under low/no solar conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

Table 5-1 Low Solar Irradiance Conditions Analysis Results

Scenario	Reactive Power Injection at POI (MVAr)	Bus 531424 Volt (pu)	Required Shunt Reactor (MVAr)
16WP	0.21	0.9997	**0.21**
17SP	0.20	0.9816	**0.21**
25SP	0.21	0.9908	**0.21**

6 CONCLUSIONS

A System Impact Restudy for Generator Modification for generation interconnection request GEN-2015-021 (20.0 MW solar farm connected at the Johnson Corner 115 kV bus) was performed.

The objective of this study was to re-evaluate the impact of project GEN-2015-021 on existing and future system performance based on an updated solar farm design (PV inverter-generators) as specified by the Interconnection Customer.

The study is performed for three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low solar irradiance condition analysis. The following is a summary of study results.

Results of the Stability Analysis show no stability criteria violations for all studied disturbances on all three seasons.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to check whether the studied project meets FERC and SPP power factor requirements for solar farm interconnections. The solar farm will be required to meet the 95% lagging (injecting MVAr into the grid) and 95% leading (absorbing MVAr from the grid) power factor requirements at the Point of Interconnection. See Section 4 of this report for details.

The Low Solar irradiance condition analysis shows that 0.21 MVAr of shunt reactance is required at the POI to bring the MVAr flow at the POI down to approximately zero under low solar irradiance conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

APPENDIX A SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE CRITERIA REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements (“Requirements”) shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

   $$\text{SPPR} = \frac{\text{Peak Rotor Angle of 2}^{\text{nd}}\text{ Positive Swing Peak}}{\text{Peak Rotor Angle of 1}^{\text{st}}\text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% ≥ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio ≥ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

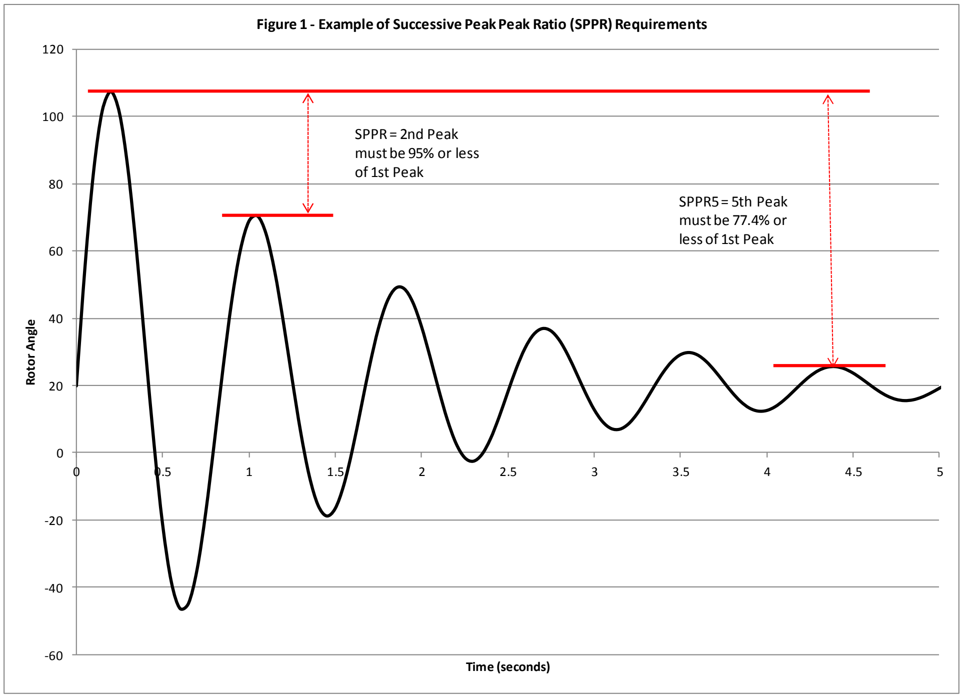
   $$\text{SPPR5} = \frac{\text{Peak Rotor Angle of 5}^{\text{th}}\text{ Positive Swing Peak}}{\text{Peak Rotor Angle of 1}^{\text{st}}\text{ Positive Swing Peak}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR5) x 100% ≥ 22.6%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.



TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit. All post-transient voltages must fall between the 0.90 pu and 1.1 pu range at the end of the simulations. Check pre-fault voltage checks to ensure they fall within the 0.90 pu and 1.1 pu.

Qualitatively, this Requirement is shown in Figure 2 below.

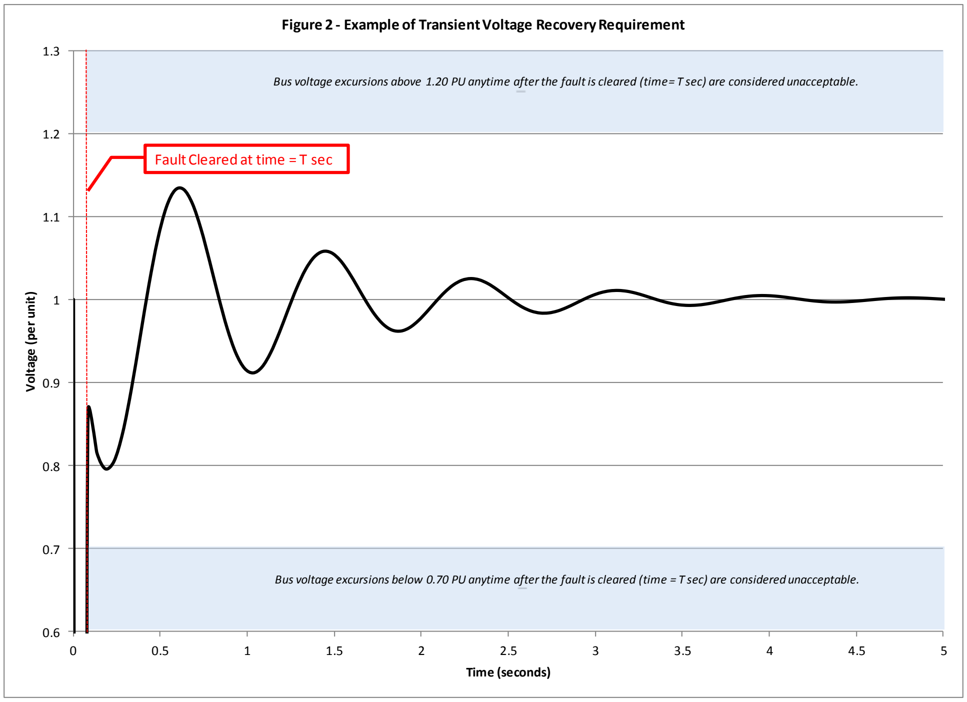


Figure 2 - Example of Transient Voltage Recovery Requirement
Bus voltage excursions above 1.20 PU anytime after the fault is cleared (time= T sec) are considered unacceptable.
Fault Cleared at time = T sec
Bus voltage excursions below 0.70 PU anytime after the fault is cleared (time = T sec) are considered unacceptable.
Voltage (per unit)
Time (seconds)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5

APPENDIX B SIMULATION PLOTS FOR STABILITY ANALYSIS

APPENDIX C POWER FACTOR ANALYSIS RESULTS

All the contingency numbers shown in this appendix match with the fault numbers shown in Table 2-1.

C.1 GEN-2015-021 2016 Winter Peak Case

The GEN-2015-021 POI voltage is 0.9756 pu in the 2016 winter peak pre-project case (i.e. without GEN-2015-021 project and all prior-queued projects dispatch at 100% nameplate). Therefore, the power factor requirements for the solar farm were determined to maintain the voltage at the POI to 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-20	-6.1	0.96	Lagging
Contingency	**1**	**-20**	**-31.1**	**0.54**	**Lagging**
Contingency	2	-20	-10.4	0.89	Lagging
Contingency	3	-20	-10.5	0.89	Lagging
Contingency	4	-20	-7.1	0.94	Lagging
Contingency	5	-20	-6.1	0.96	Lagging
Contingency	6	-20	-6.1	0.96	Lagging
Contingency	7	-20	-1.5	1.00	Lagging
Contingency	8	-20	-13.8	0.82	Lagging
Contingency	9	-20	-15.9	0.78	Lagging
Contingency	10	-20	-12.8	0.84	Lagging
Contingency	11	-20	-10.9	0.88	Lagging
Contingency	12	-20	-11.3	0.87	Lagging
Contingency	13	-20	-1.9	1.00	Lagging
Contingency	14	-20	-1.9	1.00	Lagging
Contingency	15	-20	-7.8	0.93	Lagging
Contingency	16	-20	-3.5	0.99	Lagging
Contingency	17	-20	-6.4	0.95	Lagging
Contingency	18	-20	-7.0	0.94	Lagging
Contingency	19	-20	-6.8	0.95	Lagging
Contingency	20	-20	-14.1	0.82	Lagging
Contingency	21	-20	-3.6	0.98	Lagging
Contingency	22	-20	-8.2	0.93	Lagging
Contingency	23	-20	-4.8	0.97	Lagging
Contingency	24	-20	-13.7	0.83	Lagging
Contingency	25	-20	0.0	1.00	Lagging
Contingency	26	-20	-5.5	0.96	Lagging
Contingency	27	-20	-5.4	0.97	Lagging
Contingency	28	-20	-19.7	0.71	Lagging
Contingency	29	-20	-5.3	0.97	Lagging
Contingency	30	-20	-7.4	0.94	Lagging
Contingency	33	-20	0.0	1.00	Lagging
Contingency	34	-20	-4.6	0.97	Lagging
Contingency	35	-20	-7.5	0.94	Lagging
Contingency	36	-20	-7.0	0.94	Lagging
Contingency	37	-20	-7.0	0.94	Lagging
Contingency	38	-20	-9.9	0.90	Lagging
Contingency	39	-20	-13.1	0.84	Lagging
Contingency	40	-20	-3.1	0.99	Lagging

C.2 GEN-2015-021 2017 Summer Peak Case

The GEN-2015-021 POI voltage is 0.9812 pu in the provided 2017 summer peak pre-project case (i.e. without GEN-2015-021 project and all prior-queued projects dispatch at 100% nameplate). Therefore, the power factor requirements for the solar farm were determined to maintain the voltage at the POI to 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-20	-5.1	0.97	Lagging
Contingency	**1**	**-20**	**-24**	**0.64**	**Lagging**
Contingency	2	-20	-8.8	0.92	Lagging
Contingency	3	-20	-9.7	0.90	Lagging
Contingency	4	-20	-5.7	0.96	Lagging
Contingency	5	-20	-5	0.97	Lagging
Contingency	6	-20	-5.1	0.97	Lagging
Contingency	7	-20	-2.3	0.99	Lagging
Contingency	8	-20	-8.4	0.92	Lagging
Contingency	9	-20	-15.2	0.80	Lagging
Contingency	10	-20	-10.4	0.89	Lagging
Contingency	11	-20	-7.9	0.93	Lagging
Contingency	12	-20	-9.6	0.90	Lagging
Contingency	13	-20	-2.4	0.99	Lagging
Contingency	14	-20	0	1.00	Lagging
Contingency	15	-20	-6.8	0.95	Lagging
Contingency	16	-20	-2.8	0.99	Lagging
Contingency	17	-20	-5.1	0.97	Lagging
Contingency	18	-20	-7.1	0.94	Lagging
Contingency	19	-20	-6.3	0.95	Lagging
Contingency	20	-20	-6.7	0.95	Lagging
Contingency	21	-20	-3.3	0.99	Lagging
Contingency	22	-20	-2.9	0.99	Lagging
Contingency	23	-20	-8.4	0.92	Lagging
Contingency	24	-20	-6.4	0.95	Lagging
Contingency	25	-20	0	1.00	Lagging
Contingency	26	-20	-17.2	0.76	Lagging
Contingency	27	-20	-4	0.98	Lagging
Contingency	28	-20	-6.3	0.95	Lagging
Contingency	29	-20	-4.7	0.97	Lagging
Contingency	30	-20	-6.4	0.95	Lagging
Contingency	33	-20	0	1.00	Lagging
Contingency	34	-20	-5.7	0.96	Lagging
Contingency	35	-20	-1.6	1.00	Lagging
Contingency	36	-20	-6.5	0.95	Lagging
Contingency	37	-20	-6.5	0.95	Lagging
Contingency	38	-20	-6	0.96	Lagging
Contingency	39	-20	-11.3	0.87	Lagging
Contingency	40	-20	0	1.00	Lagging

C.3 GEN-2015-021 2025 Summer Peak Case

The GEN-2015-021 POI voltage is 0.9904 pu in the provided 2025 summer peak pre-project case (i.e. without GEN-2015-021 project and all prior-queued projects dispatch at 100% nameplate). Therefore, the power factor requirements for the solar farm were determined to maintain the voltage at the POI to 1.0 pu. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-20	-11.4	0.87	Lagging
Contingency	**1**	**-20**	**-29.1**	**0.57**	**Lagging**
Contingency	2	-20	-15.1	0.80	Lagging
Contingency	3	-20	-15.3	0.79	Lagging
Contingency	4	-20	-12.2	0.85	Lagging
Contingency	5	-20	-11.4	0.87	Lagging
Contingency	6	-20	-11.4	0.87	Lagging
Contingency	7	-20	-4	0.98	Lagging
Contingency	8	-20	-16	0.78	Lagging
Contingency	9	-20	-21.5	0.68	Lagging
Contingency	10	-20	-16.7	0.77	Lagging
Contingency	11	-20	-14.5	0.81	Lagging
Contingency	12	-20	-15.8	0.78	Lagging
Contingency	13	-20	-5.4	0.97	Lagging
Contingency	14	-20	-4.6	0.97	Lagging
Contingency	15	-20	-12.9	0.84	Lagging
Contingency	16	-20	-8.5	0.92	Lagging
Contingency	17	-20	-11.5	0.87	Lagging
Contingency	18	-20	-13.3	0.83	Lagging
Contingency	19	-20	-12.5	0.85	Lagging
Contingency	20	-20	-13.5	0.83	Lagging
Contingency	21	-20	-9	0.91	Lagging
Contingency	22	-20	-9.3	0.91	Lagging
Contingency	23	-20	-15.3	0.79	Lagging
Contingency	24	-20	-13.1	0.84	Lagging
Contingency	25	-20	-5.5	0.96	Lagging
Contingency	26	-20	-22	0.67	Lagging
Contingency	27	-20	-10	0.89	Lagging
Contingency	28	-20	-13	0.84	Lagging
Contingency	29	-20	-11.1	0.87	Lagging
Contingency	30	-20	-12.5	0.85	Lagging
Contingency	33	-20	0	1.00	Lagging
Contingency	34	-20	-10.5	0.89	Lagging
Contingency	35	-20	-7.5	0.94	Lagging
Contingency	36	-20	-12.7	0.84	Lagging
Contingency	37	-20	-12.7	0.84	Lagging
Contingency	38	-20	-12.4	0.85	Lagging
Contingency	39	-20	-19.1	0.72	Lagging
Contingency	40	-20	-4.9	0.97	Lagging