



DISIS-2015-002-6

Definitive Interconnection System Impact Study Report

Group 6 Restudy

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Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
2/5/2016	SPP	Draft issued to Transmission Owners for review
2/12/2016	SPP	Report Issued (DISIS-2015-002). Some stability analysis still pending. Group 2, 6, 7, 15 and 16 Interconnection Request Results not included in this issue.
2/22/2016	SPP	Draft issued to Transmission Owners for Group 2, 6, and 7 review
2/29/2016	SPP	Report Issued (DISIS-2015-002) to include Group 2, 6, and 7 Results. Some stability analysis still pending. 15 and 16 Interconnection Request Results not included in this issue.
3/17/2016	SPP	Draft issued to Transmission Owners for Group 15, and 16 review
3/29/2016	SPP	Report Issued (DISIS-2015-002) to include Group 15 and 16 Results. Group 16 stability analysis still pending.
4/28/2016	SPP	Report Issued to include Group 16 stability analysis
8/01/2016	SPP	ReStudy to account for withdrawn projects.
8/04/2016	SPP	DISIS-2015-002-1 reposted for AECI Affected System Cost Allocation correction and update to Introduction Section Stand-Alone Language
11/29/2016	SPP	Restudy Power Flow Analysis for Group 1 only. Cost Allocation for all projects. To account for withdrawn Projects, Report Reposted (DISIS-2015-002-2)
7/10/2017	SPP	Restudy Power Flow Analysis for Group 1 only to account for withdrawn projects GEN-2011-051, GEN-2015-060, and GEN-2015-081. Report Reposted (DISIS-2015-002-3)

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
9/22/2017	SPP	<p>Restudy Analysis for Group 8 only to account for withdrawn projects GEN-2015-067. Report Reposted (DISIS-2015-002-4).</p> <p>Groups 2, 6, and 16 results to be posted once at a later date.</p>
11/2/2017	SPP	<p>Report Issued to include Groups 2, 6, and 16 restudy analysis. Additionally latest cost estimate for GEN-2015-063 Tap – Mathewson 345kV upgrade are included for the allocated Group 8 request.</p>
02/16/2018	SPP	<p>Restudy Analysis for Group 7 to reflect upgrade changes from the prior re-study.</p>
12/21/2018	SPP	<p>Restudy Analysis for Group 6 to account for withdrawn requests.</p>
01/9/2019	SPP	<p>Cluster total estimates in Section 5 and Conclusion, Revised costs in Appendix E and F.</p>

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SECTION 1: INTRODUCTION

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for generation interconnection requests received during the DISIS Queue Cluster Window which closed on September 30, 2015. The customers will be referred to in this study as the DISIS Interconnection Customers. This DISIS analyzes the impact of interconnecting new generation totaling 811.10 MW to the SPP Transmission System. The interconnecting SPP Transmission Owners include:

- American Electric Power West (AEPW)
- Basin Electric Power Cooperative (BPEC)
- Grand River Dam Authority (GRDA)
- Kansas City Power and Light\KCP&L Greater Missouri Operations (KCPL)
- Midwest Energy (MIDW)
- Nebraska Public Power District (NPPD)
- Oklahoma Gas and Electric (OKGE)
- Omaha Public Power District (OPPD)
- Southwestern Public Service (SPS)
- Southwestern Power Administration (SWPA)*
- Western Area Power Administration (WAPA)
- Westar Energy, Inc. (WERE)
- Western Farmers Electric Cooperative (WFEC)

*SWPA is a SPP Contract Participant

The generation interconnection requests included in this System Impact Study are listed in Appendix A by queue number, amount, requested interconnection service type, area, requested interconnection point, proposed interconnection point, and the requested in-service date¹.

The primary objective of this DISIS is to identify the system constraints, transient instabilities, and over-dutied equipment associated with connecting the generation to the area transmission system. The Impact Study and other subsequent Interconnection Studies are designed to identify required Transmission Owner Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to inject power into the grid at each specific point of interconnection.

¹ The generation interconnection requests in-service dates may need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customers that proceed to the Facility Study will be provided a new in-service date based on the completion of the Facility Study or as otherwise provided for in the GIP.

SECTION 2: MODEL DEVELOPMENT (STUDY ASSUMPTIONS)

SUBSECTION A: INTERCONNECTION REQUESTS INCLUDED IN THE CLUSTER

This DISIS includes all interconnection requests that were submitted during the DISIS Queue Cluster Window that met all of the requirements of the Generator Interconnection Procedures (GIP) that were in effect at the time this study commenced. [Appendix A](#) lists the interconnection requests that are included in this study.

SUBSECTION B: AFFECTED SYSTEM INTERCONNECTION REQUEST

Affected System Interconnection Requests included in this study are listed in [Appendix A](#) with the “ASGI” prefix. Affected System Interconnection Requests were only studied in “cluster” scenarios.

SUBSECTION C: PREVIOUSLY QUEUED INTERCONNECTION REQUESTS

The previous-queued requests included in this study are listed in [Appendix B](#). In addition to the Base Case Upgrades, the previous-queued requests and associated upgrades were assumed to be in-service and added to the Base Case models. These requests were dispatched as Energy Resource Interconnection Service (ERIS) resources with equal distribution across the SPP footprint. Prior-queued requests that requested Network Resource Interconnection Service (NRIS) were also dispatched in separate NRIS scenarios sinking into the area of the interconnecting transmission owner.

SUBSECTION D: DEVELOPMENT OF BASE CASES

POWER FLOW

The power flow models used for this study are based on the 2016-series Integrated Transmission Planning models used for the 2017 ITP-Near Term analysis. These models include:

- Year 1 2017 winter peak (17WP)
- Year 2 2018 spring (18G)
- Year 2 2018 summer peak (18SP)
- Year 5 2021 light (21L)
- Year 5 2021 summer (21SP)
- Year 5 2021 winter peak (21WP)
- Year 10 2026 summer peak (26SP)

DYNAMIC STABILITY

The dynamic stability models used for this study are based on the 2016-series SPP Model Development Working Group (MDWG) Models. These models include:

- Year 1 2017 winter peak (17WP)
- Year 2 2018 summer peak (18SP)
- Year 10 2026 summer peak (26SP)

SHORT CIRCUIT

The Year 2 and Year 10 dynamic stability summer peak models were used for short-circuit analysis.

BASE CASE UPGRADES

The facilities listed in the table below are part of the current SPP Transmission Expansion Plan, the Balanced Portfolio, or recently approved Priority Projects. These facilities have an approved Notification to Construct (NTC) or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The DISIS Interconnection Customers have not been assigned advancement costs for the projects listed below.

The DISIS Interconnection Customers' Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades. In some cases, the in-service date is beyond the allowable time a customer can delay. In this case, the Interconnection Customer may move forward with Limited Operation or remain in the DISIS Queue for additional study cycles. If, for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS Interconnection Customers.

SPP Notification to Construct (NTC) ID	UID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200223		OGE	Tatonga - Woodward District EHV 345 kV Ckt 2	3/1/2018
200223		OGE	Matthewson - Tatonga 345 kV Ckt 2	3/1/2018
200240		OGE	Chisholm - Gracemont 345 kV Ckt 1 (OGE)	3/1/2018
200255		AEP	Chisholm - Gracemont 345kV Ckt 1 (AEP)	3/1/2018
200255		AEP	Chisholm 345/230 kV Substation	3/1/2018
200255		AEP	Chisholm 230 kV	3/1/2018
200360		SPS	IMC #1 Tap - Livingston Ridge 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	Intrepid West - Potash Junction 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	IMC #1 Tap - Intrepid West 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	Cardinal - Targa 115 kV Ckt 1 Rebuild	5/31/2018
200360	51250	SPS	National Enrichment Plant - Targa 115 kV Ckt 1	12/15/2018
200391	51528	OGE	DeGrasse 345 kV Substation	6/1/2019
200391	51529	OGE	DeGrasse 345/138 kV Transformer	6/1/2019
200391	51530	OGE	DeGrasse - Knob Hill 138 kV New Line	6/1/2019
200391	51569	OGE	DeGrasse 138 kV Substation (OGE)	6/1/2019
200220		NPPD	Cherry Co. (Thedford) - Gentleman 345 kV Ckt 1	10/1/2019
200220		NPPD	Cherry Co. (Thedford) Substation 345 kV	10/1/2019
200220		NPPD	Cherry Co. (Thedford) - Holt Co. 345 kV Ckt 1	10/1/2019
200220		NPPD	Holt Co. Substation 345 kV	10/1/2019
200253	50441	NPPD	Neligh 345/115 kV Substation	4/1/2018
200309		SPS	Hobbs 345/230 kV Ckt 1 Transformer	6/1/2018
200309		SPS	Hobbs - Yoakum 345 kV Ckt 1	6/1/2020
200395		SPS	Tuco - Yoakum 345 kV Ckt 1	6/1/2020
200395		SPS	Yoakum 345/230 kV Ckt 1 Transformer	6/1/2020
200256	50722	SPS	Chaves - Price 115 kV Ckt 1 Rebuild	1/30/2018
200256	50723	SPS	CV Pines - Price 115 kV Ckt 1 Rebuild	1/30/2018

SPP Notification to Construct (NTC) ID	UID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200256	50724	SPS	Capitan - CV Pines 115 kV Ckt 1 Rebuild	1/30/2018
200282		SPS	China Draw - Yeso Hills 115 kV Ckt 1	6/1/2018
200282		SPS	Dollarhide - Toboso Flats 115 kV Ckt 1	6/1/2018
200309		SPS	Hobbs - Kiowa 345 kV Ckt 1	6/1/2018
200309		SPS	Kiowa 345 kV Substation	6/1/2018
200309		SPS	Kiowa - North Loving 345 kV Ckt 1	6/1/2018
200309		SPS	North Loving 345 kV Terminal Upgrades	6/1/2018
200309		SPS	China Draw - North Loving 345 kV Ckt 1	6/1/2018
200309		SPS	China Draw 345 kV Ckt 1 Terminal Upgrades	6/1/2018
200309		SPS	China Draw 345/115 kV Ckt 1 Transformer	6/1/2018
200309		SPS	North Loving 345/115 kV Ckt 1 Transformer	6/1/2018
200309		SPS	Kiowa 345/115 kV Ckt 1 Transformer	6/1/2018
200395	50924	SPS	Livingston Ridge 115 kV Substation Conversion	11/30/2017
200411		SPS	Livingston Ridge - Sage Brush 115 kV Ckt 1	6/1/2018
200309	50925	SPS	Sage Brush 115 kV Substation	12/16/2016
200309	50928	SPS	Largarto - Sage Brush 115 kV Ckt 1	12/15/2016
200309	50927	SPS	Lagarto 115 kV Substation	6/1/2018
200309	50951	SPS	Cardinal - Lagarto 115 kV Ckt 1	12/15/2016
200309	50967	SPS	Cardinal 115 kV Substation	12/15/2016
200411	50923	SPS	Ponderosa - Ponderosa Tap 115 kV Ckt 1	6/1/2017
200395		SPS	Canyon West - Dawn - Panda - Deaf Smith 115kV Ckt 1	12/15/2018
200369		SPS	Canyon East Sub - Randall County Interchange 115kV Ckt 1	12/31/2020
200359	11509	SPS	Carlisle 230/115kV transformer replacement	3/27/2018
200309		SPS	Hobbs - Yoakum - TUCO 345kV project	6/1/2018
200395		SPS	Terry County - Wolfforth 115kV Ckt 1 terminal equipment replacement	6/1/2018
200391		OGE	DeGrasse 345/138kV project	6/1/2019
200396		WFEC	DeGrasse 345/138kV project	12/31/2019
200395		SPS	Harrington East - Potter 230kV Ckt 1 terminal equipment replacement	6/1/2019
200228		WERE	Viola 345/138kV project	6/1/2018
200228		MKEC	Viola 345/138kV project	6/1/2018
200395		SPS	Seminole 230/115kV transformer Ckt 1 & 2 replacement	5/15/2018
200262		SPS	Yoakum County Interchange 230/115kV transformer Ckt 1 & 2 replacement	6/1/2019

CONTINGENT UPGRADES

The following facilities do not yet have approval. These facilities have been assigned to higher-queued interconnection customers. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. The DISIS Interconnection Customers, at this time, do not have cost responsibility for these facilities but may later be assigned cost if higher-queued customers terminate their Generation Interconnection Agreement or withdraw from the interconnection queue. The DISIS Interconnection Customer Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades.

All previously allocated projects have been completed.

POTENTIAL UPGRADES NOT IN THE BASE CASE

Any potential upgrades that do not have a Notification to Construct (NTC) and are not explicitly listed within this report have not been included in the base case. These upgrades include any identified in the SPP Extra-High Voltage (EHV) overlay plan, or any other SPP planning study other than the upgrades listed above in the previous section.

REGIONAL GROUPINGS

The interconnection requests listed in [Appendix A](#) are grouped into sixteen (16) active regional groups based on geographical and electrical impacts. These groupings are shown in [Appendix C](#). This restudy is a study of regional grouping 6 (South Texas Panhandle/New Mexico Area) only.

SUBSECTION E: DEVELOPMENT OF ANALYSIS CASES

POWER FLOW

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas are dispatched at 20% nameplate of maximum generation in the models. These projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the spring case, or in the “High VER” summer and winter peak cases. To study peaking units’ impacts, the Year 1 winter peak and Year 2 summer peak, Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested NRIS are dispatched in an additional analysis into the interconnecting Transmission Owner’s (T.O.) area at 100% nameplate with ERIS only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

Each interconnection request is included in the power flow analysis models as an equivalent generator(s) dispatched at the applicable percentage of the requested service amount with 0.95 power factor capability. The facility modeling includes explicit representation of equivalent Generator Step-Up (GSU) and main project transformer(s) with impedance data provided in the interconnection request. Equivalent collector system(s) as well as transmission lead line(s) shorter than 20 miles are added to the power flow analysis models with zero impedance branches.

DYNAMIC STABILITY

For each group, all interconnection requests are dispatched at 100% nameplate output while the other groups are dispatched at 20% output for VERs and 100% output for thermal requests.

- Each study group includes system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request within that group.
- Study Group 9 included an additional dispatch scenario to evaluate the Gerald Gentleman Station registered NERC flowgate #6006.
- Study Group 16 included system adjustments for the Miles City DC Tie, North Dakota – Canadian border – The phase shifting transformer to Saskatchewan Power (also known as B-10T), and reduction of WAPA (area 652) load and generation:
 - 2017 Winter Peak –
 - Miles City DC Tie– 200MW East to West transfer
 - B-10T – 65MW South to North transfer
 - 2018 Summer Peak –
 - Miles City DC Tie – 200MW East to West transfer
 - B-10T – 200MW North to South transfer
 - 1,100 MW reduction to load and generation (proxy for summer shoulder)
 - 2026 Summer Peak –
 - Miles City DC Tie – 200MW East to West transfer

Each interconnection request is included in the dynamic stability analysis models as an equivalent generator(s) dispatched at the applicable percentage of the aggregate generator nameplate capabilities provided in the interconnection request. The facility modeling includes explicit representation of equivalent Generator Step-up (GSU) transformer(s), equivalent collector system(s), main project transformer(s), and transmission lead line(s) with impedance data provided in the interconnection request.

SHORT CIRCUIT

The Year 2 and Year 10 dynamic stability Summer Peak models were used for this analysis.

SECTION 3: IDENTIFICATION OF NETWORK CONSTRAINTS (SYSTEM PERFORMANCE)

SUBSECTION A: THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously described.

For ERIS, thermal overloads are determined for system intact (n-0) greater than 100% of Rate A - normal and for contingency (n-n) greater than 100% of Rate B – emergency conditions.

The overloads are then screened to determine which interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (n-n),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Appropriate transmission reinforcements are identified to mitigate the constraints.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also assigned transmission reinforcements to mitigate the impacts.

SUBSECTION B: VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be identified to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP voltage criteria is applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria:

System Intact	Contingency
0.95 – 1.05 per unit	0.90 – 1.05 per unit

Areas and specific buses having more-stringent voltage criteria:

Areas/Facilities	System Intact	Contingency
AEPW – all buses EMDE High Voltage	0.95 – 1.05 per unit	0.92 – 1.05 per unit
WERE Low Voltage	0.95 – 1.05 per unit	0.93 – 1.05 per unit
WERE High Voltage	0.95 – 1.05 per unit	0.95 – 1.05 per unit
TUCO 230 kV Bus #525830	0.925 – 1.05 per unit	0.925 – 1.05 per unit
Wolf Creek 345 kV Bus #532797	0.985 – 1.03 per unit	0.985 – 1.03 per unit
FCS Bus #646251	1.001 – 1.047 per unit	1.001 – 1.047 per unit

First-Tier External Areas facilities 115 kV and greater.

Area	System Intact	Contingency
EES-EAI LAGN EES AMMO CLEC LAFA LEPA XEL MP SMMPA GRE OTP ALTW MEC MDU DPC ALTE	0.95 – 1.05 per unit	0.90 – 1.05 per unit
OTP-H (115kV+)	0.97 – 1.05 per unit	0.92 – 1.10 per unit
SPC	0.95 – 1.05 per unit	0.95 – 1.05 per unit

The constraints identified through the voltage scan are screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

SUBSECTION C: DYNAMIC STABILITY

Stability issues are considered for transmission reinforcement under ERIS. Generators that fail to meet low voltage ride-through requirements (FERC Order #661-A) or SPP’s stability requirements for damping or dynamic voltage recovery are assigned upgrades such that these requirements can be met.

SUBSECTION D: UPGRADES ASSIGNED

Thermal overloads that require transmission support to mitigate are discussed in [Section 8](#) and listed in [Appendix G-T](#) (Cluster Analysis). Voltage constraints that may require transmission support are discussed in [Section 8](#) and listed in [Appendix G-V](#) (Cluster Analysis). Constraints that are identified solely through the stability analysis are discussed in [Section 9](#) and the appropriate appendix for the detailed stability study of that Interconnection Request. All of these upgrades are cost assigned in [Appendix E](#) and [Appendix F](#).

Other network constraints not requiring transmission reinforcements are shown in [Appendix H-T](#) (Cluster Analysis). With a defined source and sink in a Transmission Service Request, this list of network constraints can be refined and expanded to account for all Network Upgrade requirements for firm transmission service. Additional constraints identified by multi-element contingencies are listed in [Appendix I](#).

In no way does the list of constraints in [Appendix G-T](#) (Cluster Analysis) identify all potential constraints that guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their 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.

SECTION 4: DETERMINATION OF COST ALLOCATED NETWORK UPGRADES

Cost Allocated Network Upgrades of Variable Energy Resources (VER) (solar/wind) generation interconnection requests are determined using the Year 2 spring model. Cost Allocated Network Upgrades of peaking units are determined using the Year 5 summer peak model. A PSS/E and MUST sensitivity analysis is performed to determine the DF with no contingency that each generation interconnection request has on each new upgrade. The impact each generation interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

Determine an impact factor for a given project for all responsible GI requests:

$$\text{Request X Impact Factor on Upgrade Project 1} = \text{PTDF}(\%)(X) \times \text{MW}(X) = X1$$

$$\text{Request Y Impact Factor on Upgrade Project 1} = \text{PTDF}(\%)(Y) \times \text{MW}(Y) = Y1$$

$$\text{Request Z Impact Factor on Upgrade Project 1} = \text{PTDF}(\%)(Z) \times \text{MW}(Z) = Z1$$

Determine each request's Allocation of Cost for that particular project:

$$\text{Request X's Project 1 Cost Allocation (\$)} = \frac{\text{Network Upgrade Project 1 Cost (\$)} \times X1}{X1 + Y1 + Z1}$$

Repeat previous for each responsible GI request for each Project.

The cost allocation of each needed Network Upgrade is determined by the size of each request and its impact on the given project. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades.

SUBSECTION A: CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADES

Interconnection Customer shall be entitled to either credits or potentially incremental Long Term Congestion Rights (iLTCR), otherwise known as compensation, in accordance with Attachment Z2 of the SPP Tariff for any Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, and not refunded to the Interconnection Customer.

SECTION 5: REQUIRED INTERCONNECTION FACILITIES

The requirement to interconnect the requested generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in [Appendix F](#) by upgrade. The interconnection requirements for the cluster total an estimated **\$341 million**

Interconnection Facilities specific to each interconnection request are listed in [Appendix E](#). A preliminary one-line diagram for each request is listed in [Appendix D](#).

For an explanation of how required Network Upgrades and Interconnection Facilities were determined, refer to the section on “Identification of Network Constraints.”

SUBSECTION A: FACILITIES ANALYSIS

The interconnecting Transmission Owner for each Interconnection Request has provided its preliminary analysis of required Transmission Owner Interconnection Facilities and the associated Network Upgrades, shown in [Appendix D](#). This analysis was limited only to the expected facilities to be constructed by the Transmission Owner at the Point of Interconnection. These costs are included in the one-line diagrams in [Appendix D](#) and also listed in [Appendix E](#) and [F](#) as combined “Interconnection Costs”. If the one-lines and costs in [Appendix D](#) have been updated by the Transmission Owner’s Interconnection Facilities Study, those costs will be noted in the appendix. These costs will be further refined by the Transmission Owner as part of the Interconnection Facilities Study. Any additional Network Upgrades identified by this DISIS beyond the Point of Interconnection are defined and estimated by either the Transmission Owner or by SPP. These additional Network Upgrade costs will also be refined further by the Transmission Owner within the Interconnection Facilities Study.

SUBSECTION B: ENVIRONMENTAL REVIEW

For Interconnection Requests that result in an interconnection to, or modification to, the transmission facilities of the Western-UGP, a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

SECTION 6: AFFECTED SYSTEMS COORDINATION

The following procedures are in place to coordinate with Affected Systems.

- Impacts on Associated Electric Cooperative Inc. (AECI) – For any observed violations of thermal overloads on AECI facilities, AECI has been notified by SPP to evaluate the violations for impacts on its transmission system.
- Impacts on Midcontinent Independent System Operator (MISO) – Per SPP’s agreement with MISO, MISO will be contacted and provided a list of interconnection requests that proceed to move forward into the Interconnection Facilities Study Queue. MISO will then evaluate the Interconnection Requests for impacts and will be in contact with affected Interconnection Customers. For potential impacts see [Appendix H-T – Affected System](#) and [Appendix H-V – Affected System](#)
- Impacts on Minnkota Power Cooperative, Inc (MPC) – MPC will be contacted and provided a list of interconnection requests that proceed to move forward into the Interconnection Facilities Study Queue. MPC will then evaluate the Interconnection Requests for impacts. For potential impacts see [Appendix H-T – Affected System](#) and [Appendix H-V – Affected System](#)
- Impacts to other affected systems – For any observed violations of thermal overloads or voltage constraints, SPP will contact the owner of the facility for further information.

SECTION 7: POWER FLOW ANALYSIS

SUBSECTION A: POWER FLOW ANALYSIS METHODOLOGY

The ACCC function of PSS/E is used to simulate single element and special (i.e., breaker-to-breaker, multi-element, etc.) contingencies in portions or all of the modeled control areas of SPP as well as control areas external to SPP.

SUBSECTION B: POWER FLOW ANALYSIS

A power flow analysis is conducted for each Interconnection Customer's facility using modified versions of the year 1 winter peak season, the year 2 spring, year 2 summer peak season, year 5 summer and winter peak seasons, year 5 light load season, and year 10 summer peak seasonal models. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an ERIS request. Requests that are pursuing NRIS have an additional analysis conducted for displacing resources in the interconnecting Transmission Owner's balancing area.

SECTION 8: POWER FLOW RESULTS

SUBSECTION A: CLUSTER SCENARIO

The Cluster Scenario considers the Base Case as well as all Interconnection Requests in the DISIS Study Queue and all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

Constraints and associated mitigations for each Interconnection Request are summarized below. Details are contained in [Appendix G-T](#) and [Appendix G-V](#). Cost allocation for the Cluster Scenario is found in [Appendix E](#).

CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

Requests for this study group as well as prior-queued requests are listed in [Appendix C](#).

The following table outlines the incremental mitigation scenarios for Group 6.

Table 8-1 Group 6 Cluster Upgrade Scenarios

Scenario	Incremental Mitigation
0	None
2	Build Crawfish Draw 345 kV substation (Includes re-route of TUCO – Border 345 kV and TUCO – O.K.U. 345 kV)
	Build Crawfish Draw - Border 345 kV Ckt 2
	Build Border - Chisholm 345 kV Ckt 1
3	Advance NTC 200309 (17WP, 18G, & 18SP)
	Build Crawfish Draw 230 kV substation (includes re-route of TUCO – Swisher 230 kV Ckt 1)
	Build Crawfish Draw 345/230kV transformer
4	Terminal equipment on Newhart – Plant X 230 kV Ckt 1

The following network upgrades and model adjustments were required to resolve the non-converged constraints observed in Group 6.

Table 8-2 Group 6 Cluster Non-Convergence ERS Constraints

Monitored Elements	Mitigation
'BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1'	In addition to higher queued assigned upgrades the following current study upgrades were needed for model convergence: <ul style="list-style-type: none"> • Build Crawfish Draw 345 kV substation (Includes re-route of TUCO – Border 345 kV and TUCO – O.K.U. 345 kV) • Build Crawfish Draw - Border 345kV Ckt 2 • Build Border - Chisholm 345 kV Ckt 1
'OKLAUNION - TUCO INTERCHANGE 345KV CKT 1'	
'CHAVES COUNTY INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	Resolved by adjusting the San Juan Mesa Wind switch shunts.
'OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	

The following Group 6 cluster constraints were observed for system intact conditions.

Table 8-3 Group 6 Cluster System Intact ERS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'GRAPEVINE INTERCHANGE - NICHOLS STATION 230KV CKT 1'	318.69	104.01	System Intact	Non-converged ERS upgrades
'DEAF SMITH COUNTY INTERCHANGE - PLANT X STATION 230KV CKT 1'	318.69	124.0146	'NEWHART 230 - PLANT X STATION 230KV CKT 1'	
'CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 2'	1143	108.1801	'CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1'	Advance NTC 200309 (17WP, 18G, & 18SP)
'TOLK STATION EAST - TUCO INTERCHANGE 230KV CKT 1'	318.69	105.1516	'NEWHART 230 - PLANT X STATION 230KV CKT 1'	
'TUCO INTERCHANGE (GE M1022338) 345/230/13.2KV TRANSFORMER CKT 1'	644	109.6193	'TUCO INTERCHANGE (SIEM 8743066) 345/230/13.2KV TRANSFORMER CKT 2'	Build Crawfish Draw 230 kV substation (includes re-route of TUCO – Swisher 230 kV Ckt 1)
'TUCO INTERCHANGE (SIEM 8743066) 345/230/13.2KV TRANSFORMER CKT 2'	699	100.9941	'TUCO INTERCHANGE (GE M1022338) 345/230/13.2KV TRANSFORMER CKT 1'	
'NEWHART 230 - PLANT X STATION 230KV CKT 1'	318.69	106.4065	'DEAF SMITH COUNTY INTERCHANGE - PLANT X STATION 230KV CKT 1'	Build Crawfish Draw 345/230kV transformer
				Terminal equipment on Newhart – Plant X 230 kV Ckt 1

No Group 6 ERS voltage constraints were observed.

SUBSECTION B: LIMITED OPERATION

Limited Operation results are listed below. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customer may request additional scenarios for Limited Operation based on higher queued Interconnection Requests not being placed in service. Please refer to section 8 Subsection A for power flow constraint mitigation.

Table 8-5: Limited Operation Results

Interconnection Request	MW Requested	LOIS Available	Most Limiting Constraint
GEN-2015-020	100.00	0	Multiple
GEN-2015-056	101.20	0	Multiple
GEN-2015-068	300.00	0	Multiple
GEN-2015-075	51.50	0	Multiple
GEN-2015-079	129.20	0	Multiple
GEN-2015-080	129.20	0	Multiple

SUBSECTION C: CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their 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.

SECTION 9: STABILITY & SHORT CIRCUIT ANALYSIS

A stability and short-circuit analysis was conducted for each Interconnection Request using modified versions of the MDWG Models dynamic cases. The stability analysis assumes that all upgrades identified in the power flow analysis are in-service unless otherwise noted in the individual group stability study.

For each group, the interconnection requests are studied at 100% nameplate output while the other groups are dispatched at 20% output for Variable Energy Resource (VER) requests and 100% output for other requests. The output of the Interconnection Customer’s facility is offset in each model by a reduction in output of existing online SPP generation.

A synopsis is included for each group. The detailed stability study for each group can be found in the Appendices.

A preliminary short-circuit analysis was performed for this study and will be refined in the Interconnection Facilities Study with any additional required upgrades and cost assignment identified at that time.

9.1 POWER FACTOR REQUIREMENTS SUMMARY

Power Factor Requirements:

Request	Size (MW)	Point of Interconnection	Power Factor Requirement at POI*	
			Lagging (supplying)	Leading (absorbing)
GEN-2015-020	100	Oasis 115kV	0.95	0.95
GEN-2015-056	101.2	Crossroads 345kV	0.95	0.95
GEN-2015-068	300	Tuco 345kV	0.95	0.95
GEN-2015-075	51.48	Carlisle 69kV	0.95	0.95
GEN-2015-079	129.2	Tap Yoakum-Hobbs 230kV	0.95	0.95
GEN-2015-080	129.2	Tap Yoakum-Hobbs 230kV	0.95	0.95

*As the facility study agreement for each project was executed prior to the effective date in the compliance filing for FERC Order No. 827, reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

9.2 CLUSTER STABILITY AND SHORT-CIRCUIT SUMMARY

CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

New requests for this study group as well as prior-queued requests are listed in [Appendix C](#).

The Group 6 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Hobbs units: GEN-2015-079 & GEN-2015-080
- Tolk units: GEN-2015-056
- TUCO units: GEN-2015-068 & GEN-2015-075

Additionally, to evaluate the planned conversion of the Tolk units to operate normally as synchronous condensers except during Summer Peaks, the 2017 Winter Peak case included a reduction to the Tolk unit 1 maximum output to 175 MW and switched off Tolk unit 2.

The [Group 6 stability analysis](#) for this area was performed by Aneden Consulting (Aneden). With the new requests modeled, voltage instability, violations of voltage recovery criteria, and generation tripping off were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Build Crawfish Draw 345 kV substation
 - (Includes re-route of TUCO – Border 345 kV and TUCO – O.K.U. 345 kV)
- Build Crawfish Draw - Border 345 kV Ckt 2
- Build Border - Chisholm 345 kV Ckt 1
- Build Crawfish Draw 230 kV substation
 - (includes re-route of TUCO – Swisher 230 kV Ckt 1)
- Build Crawfish Draw 345/230kV transformer
- Sweetwater-Wheeler 230kV update relay settings

For certain contingencies at and near the POI of the higher queued GEN-2014-033 request, the PV solar generators (inverters) tripped offline due to frequency relays. The frequency protection relays set points were adjusted to prevent the unit from tripping on a known issue with PSS/E frequency calculations during low voltages associated with a nearby fault.

The results for the prior outage fault analysis, power factor analysis, and short circuit analysis will be included in a reposting of this report. The updated consultant report may note that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain system stability for subsequent circuit outages.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed (except as noted earlier), including violations of low-voltage ride-through requirements, for the probable contingencies studied.

SECTION 10: CONCLUSION

The minimum cost of interconnecting all new Group 6 generation interconnection requests included in this Definitive Interconnection System Impact Restudy is estimated at **\$341 million**, not including the exceptions noted in Section 5.

Allocated costs for Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E and F. For Interconnection Requests that result in an interconnection to, or modification of, the transmission facilities of the Western-UGP (WAPA), a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints. These interconnection costs do not include any cost of any Network Upgrades that are identified as required through the short circuit analysis. Potential over-duty circuit breakers capability will be identified by the Transmission Owner in the Interconnection Facilities Study.

The Interconnection Facilities Study will be revised, if needed, following the posting of this DISIS. The Interconnection Facilities Study may include additional study analysis, additional facility upgrades not yet identified by this DISIS, such as circuit breaker replacements and affected system facilities, and further refinement of existing cost estimates.

The required interconnection costs listed in Appendices E, and F, and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request (TSR) through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP Open Access Transmission Tariff (OATT).

APPENDICES

A: GENERATION INTERCONNECTION REQUESTS CONSIDERED FOR IMPACT STUDY

A: Generation Interconnection Requests Considered for Study

Request	Amount	Service	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date	In Service Date Delayed Until no earlier than*
ASGI-2015-006	9	ER	SWPA	Tupelo 138kV	Tupelo 138kV		TBD
GEN-2014-037	200	ER	SPS	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV	09/30/2017	TBD
GEN-2015-020	100	ER	SPS	Oasis 115kV	Oasis 115kV	12/01/2016	TBD
GEN-2015-034	200	ER	OKGE	Ranch Road 345kV	Ranch Road 345kV	10/31/2017	TBD
GEN-2015-045	20	ER	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV	Tap Lawton - Sunnyside (Terry Road) 345kV	12/01/2017	TBD
GEN-2015-046	300	ER	WAPA	Tande 345kV	Tande 345kV	12/01/2017	TBD
GEN-2015-047	297.8	ER	OKGE	Sooner 345kV	Sooner 345kV	12/01/2017	TBD
GEN-2015-048	200	ER	OKGE	Cleo Corner 138kV	Cleo Corner 138kV	12/01/2017	TBD
GEN-2015-052	300	ER	WERE	Tap Open Sky - Rose Hill 345kV	Tap Open Sky - Rose Hill 345kV	12/01/2017	TBD
GEN-2015-053	50	ER	NPPD	Antelope 115kV	Antelope 115kV	12/31/2017	TBD
GEN-2015-055	40	ER	WFEC	Erick 138kV	Erick 138kV	10/30/2016	TBD
GEN-2015-056	101.2	ER	SPS	Crossroads 345kV	Crossroads 345kV	12/01/2017	TBD
GEN-2015-057	100	ER	OKGE	Minco 345kV	Minco 345kV	12/01/2016	TBD
GEN-2015-062	4.5	ER	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV	03/01/2016	TBD
GEN-2015-063	300	ER	OKGE	Tap Woodring - Mathewson 345kV	Tap Woodring - Mathewson 345kV	12/01/2017	TBD
GEN-2015-064	197.8	ER	SUNCMKEC	Mingo 115kV	Mingo 115kV	11/01/2017	TBD
GEN-2015-065	202.4	ER	SUNCMKEC	Mingo 345kV	Mingo 345kV	11/01/2017	TBD
GEN-2015-066	248.4	ER	OKGE	Tap Cleveland - Sooner 345kV	Tap Cleveland - Sooner 345kV	12/01/2017	TBD
GEN-2015-068	300	ER	SPS	TUCO Interchange 345kV	TUCO Interchange 345kV	12/01/2017	TBD
GEN-2015-069	300	ER	WERE	Union Ridge 230kV	Union Ridge 230kV	12/01/2017	TBD
GEN-2015-071	200	ER	AEPW	Chisholm 345kV	Chisholm 345kV	09/30/2017	TBD
GEN-2015-073	200.1	ER/NR	WERE	Emporia Energy Center 345kV	Emporia Energy Center 345kV	12/31/2018	TBD
GEN-2015-075	51.5	ER	SPS	Carlisle 69kV	Carlisle 69kV	12/01/2018	TBD
GEN-2015-076	158.4	ER	NPPD	Belden 115kV	Belden 115kV	07/31/2017	TBD
GEN-2015-079	129.2	ER	SPS	Tap Yoakum - Hobbs Interchange 230kV	Tap Yoakum - Hobbs Interchange 230kV	10/01/2018	TBD
GEN-2015-080	129.2	ER	SPS	Tap Yoakum - Hobbs Interchange 230kV	Tap Yoakum - Hobbs Interchange 230kV	05/01/2019	TBD
GEN-2015-084	51.3	ER	AEPW	Hollis 138kV	Hollis 138kV	12/10/2018	TBD
GEN-2015-085	122.4	ER	AEPW	Altus Junction 138kV	Altus Junction 138kV	12/10/2018	TBD
GEN-2015-087	66	ER/NR	NPPD	Tap Fairbury - Hebron 115kV	Tap Fairbury - Hebron 115kV	01/01/2019	TBD
GEN-2015-088	300	ER/NR	NPPD	Tap Moore - Pauline 345kV	Tap Moore - Pauline 345kV	01/01/2019	TBD
GEN-2015-090	220	ER	WERE	Tap Thistle - Wichita 345kV Dbl CKT	Tap Thistle - Wichita 345kV Dbl CKT	12/01/2017	TBD
GEN-2015-092	250	ER	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV	Tap Lawton - Sunnyside (Terry Road) 345kV	12/01/2017	TBD
GEN-2015-093	250	ER	OKGE	Gracemont 345kV	Gracemont 345kV	12/01/2017	TBD
GEN-2015-096	149	ER	WAPA	Tap Belfied - Rhame 230kV	Tap Belfied - Rhame 230kV	12/31/2017	TBD
GEN-2015-098	100	ER	WAPA	Mingusville 230kV	Mingusville 230kV	12/15/2017	TBD

Request	Amount	Service	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date	In Service Date Delayed Until no earlier than*
Total:		5,848.20					

*In-Service Date for each request is to be determined after the Interconnection Facility Study is completed.

B: PRIOR-QUEUED INTERCONNECTION REQUESTS

B: Prior Queued Interconnection Requests

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
ASGI-2010-006	150	AECI	Remington 138kV	
ASGI-2010-010	42.2	SPS	Lovington 115kV	
ASGI-2010-010	42.2	SPS	Lovington 115kV	
ASGI-2010-010	42.2	SPS	Lovington 115kV	
ASGI-2010-010	42.2	SPS	Lovington 115kV	
ASGI-2010-010	42.2	SPS	Lovington 115kV	
ASGI-2010-020	30	SPS	Tap LE-Tatum - LE-Crossroads 69kV	
ASGI-2010-021	15	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV	
ASGI-2011-001	27.3	SPS	Lovington 115kV	
ASGI-2011-002	20	SPS	Herring 115kV	12/1/2010
ASGI-2011-002	20	SPS	Herring 115kV	12/1/2010
ASGI-2011-003	10	SPS	Hendricks 69kV	
ASGI-2011-004	20	SPS	Pleasant Hill 69kV	
ASGI-2012-002	18.15	SPS	FE-Clovis Interchange 115kV	
ASGI-2012-006	22.5	SUNCMKEC	Tap Hugoton - Rolla 69kV	
ASGI-2013-001	11.5	SPS	PanTex South 115kV	
ASGI-2013-002	18.4	SPS	FE Tucumcari 115kV	
ASGI-2013-003	18.4	SPS	FE Clovis 115kV	
ASGI-2013-004	36.6	SUNCMKEC	Morris 115kV	
ASGI-2013-004	36.6	SUNCMKEC	Morris 115kV	
ASGI-2013-004	36.6	SUNCMKEC	Morris 115kV	
ASGI-2013-005	1.65	SPS	FE Clovis 115kV	
ASGI-2014-014	56.4	GRDA	Ferguson 69kV	
ASGI-2014-014	56.4	GRDA	Ferguson 69kV	
ASGI-2014-014	56.4	GRDA	Ferguson 69kV	
ASGI-2015-001	6.132	SUNCMKEC	Ninnescah 115kV	
ASGI-2015-002	2	SPS	SP-Yuma 69kV	
ASGI-2015-004	56.364	GRDA	Coffeyville City 69kV	
ASGI-2015-004	56.364	GRDA	Coffeyville City 69kV	
ASGI-2015-004	56.364	GRDA	Coffeyville City 69kV	
GEN-2001-014	94.5	WFEC	Ft Supply 138kV	06/30/2007
GEN-2001-026	74.25	WFEC	Washita 138kV	10/01/2003
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-033	180	SPS	San Juan Tap 230kV	10/01/2002
GEN-2001-036	80	SPS	Norton 115kV	10/01/2002
GEN-2001-037	102	OKGE	FPL Moreland Tap 138kV	10/01/2002
GEN-2001-039A	104	SUNCMKEC	Shooting Star Tap 115kV	unknown
GEN-2001-039M	100	SUNCMKEC	Central Plains Tap 115kV	12/01/2008
GEN-2002-004	200	WERE	Latham 345kV	09/30/2003
GEN-2002-004	200	WERE	Latham 345kV	09/30/2003

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2002-005	123	WFEC	Red Hills Tap 138kV	12/31/2006
GEN-2002-008	240	SPS	Hitchland 345kV	11/01/2007
GEN-2002-008	240	SPS	Hitchland 345kV	11/01/2007
GEN-2002-008	240	SPS	Hitchland 345kV	11/01/2007
GEN-2002-008IS	40.5	WAPA	Edgeley 115kV [Pomona 115kV]	
GEN-2002-009	79.8	SPS	Hansford 115kV	09/30/2006
GEN-2002-009IS	40	WAPA	Ft Thompson 69kV [Hyde 69kV]	
GEN-2002-022	239.2	SPS	Bushland 230kV	12/15/2006
GEN-2002-022	239.2	SPS	Bushland 230kV	12/15/2006
GEN-2002-023N	0.8	NPPD	Harmony 115kV	On-Line
GEN-2002-025A	150	SUNCMKEC	Spearville 230kV	06/01/2006
GEN-2003-004	100	WFEC	Washita 138kV	12/01/2005
GEN-2003-005	100	WFEC	Anadarko - Paradise (Blue Canyon) 138kV	12/01/2006
GEN-2003-005	100	WFEC	Anadarko - Paradise (Blue Canyon) 138kV	12/01/2006
GEN-2003-006A	201.6	SUNCMKEC	Elm Creek 230kV	unknown
GEN-2003-006A	201.6	SUNCMKEC	Elm Creek 230kV	unknown
GEN-2003-019	250	MIDW	Smoky Hills Tap 230kV	11/01/2006
GEN-2003-019	250	MIDW	Smoky Hills Tap 230kV	11/01/2006
GEN-2003-020	159.1	SPS	Martin 115kV	06/01/2007
GEN-2003-020	159.1	SPS	Martin 115kV	06/01/2007
GEN-2003-021N	75	NPPD	Ainsworth Wind Tap 115kV	10/01/2005
GEN-2003-021N	75	NPPD	Ainsworth Wind Tap 115kV	10/01/2005
GEN-2003-022	120	AEPW	Weatherford 138kV	12/31/2004
GEN-2004-014	154.5	SUNCMKEC	Spearville 230kV	11/15/2005
GEN-2004-020	27	AEPW	Weatherford 138kV	12/31/2005
GEN-2004-023	20.6	WFEC	Washita 138kV	12/01/2005
GEN-2004-023N	75	NPPD	Columbus Co 115kV	01/01/2009
GEN-2005-003	30.6	WFEC	Washita 138kV	12/01/2005
GEN-2005-003IS	100	WAPA	Nelson 115kV	
GEN-2005-008	120	OKGE	Woodward 138kV	07/31/2007
GEN-2005-008IS	50	WAPA	Hilken 230kV [Ecklund 230kV]	
GEN-2005-012	248.4	SUNCMKEC	Ironwood 345kV	12/31/2015
GEN-2005-012	248.4	SUNCMKEC	Ironwood 345kV	12/31/2015
GEN-2005-013	199.8	WERE	Caney River 345kV	11/01/2007
GEN-2006-001IS	10	XEL	Marshall 115kV	
GEN-2006-002	100.8	AEPW	Sweetwater 230kV	12/31/2006
GEN-2006-002	100.8	AEPW	Sweetwater 230kV	12/31/2006
GEN-2006-002IS	51	WAPA	Wessington Springs 230kV	
GEN-2006-006IS	10	XEL	Marshall 115kV	
GEN-2006-015IS	50	WAPA	Hilken 230kV [Ecklund 230kV]	
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV	06/01/2007
GEN-2006-020N	42	NPPD	Bloomfield 115kV	01/01/2009
GEN-2006-020S	20	SPS	DWS Frisco 115kV	09/01/2007
GEN-2006-021	94	SUNCMKEC	Flat Ridge Tap 138kV	05/31/2008
GEN-2006-024S	18.9	WFEC	Buffalo Bear Tap 69kV	12/31/2007
GEN-2006-026	604	SPS	Hobbs 230kV & Hobbs 115kV	06/01/2008
GEN-2006-026	604	SPS	Hobbs 230kV & Hobbs 115kV	06/01/2008
GEN-2006-026	604	SPS	Hobbs 230kV & Hobbs 115kV	06/01/2008
GEN-2006-031	75	MIDW	Knoll 115kV	On-Line
GEN-2006-035	224	AEPW	Sweetwater 230kV	12/01/2008
GEN-2006-035	224	AEPW	Sweetwater 230kV	12/01/2008
GEN-2006-037N1	73.1	NPPD	Broken Bow 115kV	01/01/2010
GEN-2006-038N005	79.9	NPPD	Broken Bow 115kV	12/01/2010
GEN-2006-038N019	79.9	NPPD	Petersburg North 115kV	05/01/2011
GEN-2006-043	98.9	AEPW	Sweetwater 230kV	08/01/2008
GEN-2006-044	370	SPS	Hitchland 345kV	10/01/2010
GEN-2006-044	370	SPS	Hitchland 345kV	10/01/2010
GEN-2006-044	370	SPS	Hitchland 345kV	10/01/2010
GEN-2006-044	370	SPS	Hitchland 345kV	10/01/2010
GEN-2006-044N	40.5	NPPD	North Petersburg 115kV	01/01/2010
GEN-2006-046	129.6	OKGE	Dewey 138kV	12/31/2009
GEN-2007-011N08	81	NPPD	Bloomfield 115kV	01/01/2009
GEN-2007-013IS	50	WAPA	Wessington Springs 230kV	
GEN-2007-014IS	100	WAPA	Wessington Springs 230kV	
GEN-2007-015IS	100	WAPA	Hilken 230kV [Ecklund 230kV]	
GEN-2007-017IS	166	WAPA	Ft Thompson-Grand Island 345kV	
GEN-2007-018IS	234	WAPA	Ft Thompson-Grand Island 345kV	
GEN-2007-020IS	16	WAPA	Nelson 115kV	
GEN-2007-021	201	OKGE	Tatonga 345kV	08/01/2009
GEN-2007-021	201	OKGE	Tatonga 345kV	08/01/2009
GEN-2007-025	299.2	WERE	Viola 345kV	12/31/2009
GEN-2007-025	299.2	WERE	Viola 345kV	12/31/2009
GEN-2007-040	200.1	SUNCMKEC	Buckner 345kV	12/15/2010
GEN-2007-043	200	OKGE	Minco 345kV	12/01/2009
GEN-2007-044	300	OKGE	Tatonga 345kV	12/01/2009
GEN-2007-044	300	OKGE	Tatonga 345kV	12/01/2009
GEN-2007-044	300	OKGE	Tatonga 345kV	12/01/2009
GEN-2007-044	300	OKGE	Tatonga 345kV	12/01/2009
GEN-2007-046	200	SPS	Hitchland 115kV	12/31/2011
GEN-2007-046	200	SPS	Hitchland 115kV	12/31/2011
GEN-2007-050	170.2	OKGE	Woodward EHV 138kV	10/01/2009
GEN-2007-050	170.2	OKGE	Woodward EHV 138kV	10/01/2009
GEN-2007-052	135	WFEC	Anadarko 138kV	05/01/2009
GEN-2007-052	135	WFEC	Anadarko 138kV	05/01/2009

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2007-052	135	WFEC	Anadarko 138kV	05/01/2009
GEN-2007-062	423.6	OKGE	Woodward EHV 345kV	12/31/2011
GEN-2007-062	423.6	OKGE	Woodward EHV 345kV	12/31/2011
GEN-2008-003	101.2	OKGE	Woodward EHV 138kV	08/31/2009
GEN-2008-008IS	5	WAPA	Nelson 115kV	
GEN-2008-013	300	OKGE	Hunter 345kV	10/01/2010
GEN-2008-013	300	OKGE	Hunter 345kV	10/01/2010
GEN-2008-018	249.75	SPS	Finney 345kV	12/31/2012
GEN-2008-018	249.75	SPS	Finney 345kV	12/31/2012
GEN-2008-021	42	WERE	Wolf Creek 345kV	On-Line
GEN-2008-022	299.7	SPS	Crossroads 345kV	09/01/2011
GEN-2008-022	299.7	SPS	Crossroads 345kV	09/01/2011
GEN-2008-022	299.7	SPS	Crossroads 345kV	09/01/2011
GEN-2008-023	148.8	AEPW	Hobart Junction 138kV	12/01/2010
GEN-2008-023	148.8	AEPW	Hobart Junction 138kV	12/01/2010
GEN-2008-037	99	WFEC	Slick Hills 138kV	11/30/2011
GEN-2008-044	197.8	OKGE	Tatonga 345kV	12/01/2011
GEN-2008-044	197.8	OKGE	Tatonga 345kV	12/01/2011
GEN-2008-047	298.9	OKGE	Beaver County 345kV	12/31/2012
GEN-2008-047	298.9	OKGE	Beaver County 345kV	12/31/2012
GEN-2008-051	322	SPS	Potter County 345kV	12/31/2010
GEN-2008-079	98.9	SUNCMKEC	Crooked Creek 115kV	12/01/2010
GEN-2008-086N02	201	NPPD	Meadow Grove 230kV	unknown
GEN-2008-086N02	201	NPPD	Meadow Grove 230kV	unknown
GEN-2008-092	200.5	MIDW	Post Rock 230kV	12/01/2011
GEN-2008-092	200.5	MIDW	Post Rock 230kV	12/01/2011
GEN-2008-098	100.8	WERE	Waverly 345kV	12/31/2011
GEN-2008-119O	60	OPPD	S1399 161kV	12/31/2009
GEN-2008-123N	89.66	NPPD	Tap Pauline - Guide Rock (Rosemont) 115kV	12/31/2016
GEN-2008-124	200.1	SUNCMKEC	Ironwood 345kV	01/01/2016
GEN-2008-129	80	KCPL	Pleasant Hill 161kV	05/01/2009
GEN-2008-129	80	KCPL	Pleasant Hill 161kV	05/01/2009
GEN-2009-001IS	200	WAPA	Groton-Watertown 345kV	
GEN-2009-006IS	90	WAPA	Mission 115kV	
GEN-2009-007IS	100	WAPA	Mission 115kV	
GEN-2009-008	198.69	MIDW	South Hays 230kV	09/01/2011
GEN-2009-018IS	99.5	WAPA	Groton 115kV	
GEN-2009-020	48.3	MIDW	Walnut Creek 69kV	12/31/2011
GEN-2009-020AIS	130.5	WAPA	Tripp Junction 115kV	
GEN-2009-020AIS	130.5	WAPA	Tripp Junction 115kV	
GEN-2009-025	59.8	OKGE	Nardins 69kV	12/31/2011
GEN-2009-026IS	110	WAPA	Dickenson-Heskett 230kV	
GEN-2009-040	72	WERE	Marshall 115kV	12/31/2012
GEN-2010-001	299.7	OKGE	Beaver County 345kV	01/01/2012
GEN-2010-001	299.7	OKGE	Beaver County 345kV	01/01/2012
GEN-2010-001IS	99	WAPA	Bismarck-Glenham 230kV	
GEN-2010-003	100.8	WERE	Waverly 345kV	12/31/2011
GEN-2010-003IS	34	WAPA	Wessington Springs 230kV	
GEN-2010-005	299.2	WERE	Viola 345kV	12/01/2012
GEN-2010-005	299.2	WERE	Viola 345kV	12/01/2012

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2010-006	205	SPS	Jones 230kV	06/01/2012
GEN-2010-009	165.6	SUNCMKEC	Buckner 345kV	12/01/2011
GEN-2010-011	29.7	OKGE	Tatonga 345kV	12/31/2011
GEN-2010-014	358.8	SPS	Hitchland 345kV	12/31/2013
GEN-2010-014	358.8	SPS	Hitchland 345kV	12/31/2013
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-036	4.6	WERE	6th Street 115kV	08/01/2012
GEN-2010-040	298.45	OKGE	Cimarron 345kV	11/30/2011
GEN-2010-040	298.45	OKGE	Cimarron 345kV	11/30/2011
GEN-2010-041	10.29	OPPD	S1399 161kV	12/31/2011
GEN-2010-046	56	SPS	TUCO Interchange 230kV	05/01/2013
GEN-2010-051	200	NPPD	Tap Hoskins - Twin Church (Dixon County) 230kV	12/15/2012
GEN-2010-055	4.5	AEPW	Wekiwa 138kV	12/31/2011
GEN-2010-057	201	MIDW	Rice County 230kV	08/01/2012
GEN-2011-008	600	SUNCMKEC	Clark County 345kV	12/01/2015
GEN-2011-008	600	SUNCMKEC	Clark County 345kV	12/01/2015
GEN-2011-008	600	SUNCMKEC	Clark County 345kV	12/01/2015
GEN-2011-010	100.8	OKGE	Minco 345kV	12/01/2012
GEN-2011-011	50	KCPL	Iatan 345kV	12/31/2010
GEN-2011-014	198	OKGE	Tap Hitchland - Woodward Dbl Ckt (GEN-2011-014 Tap) 345kV	12/31/2013
GEN-2011-016	200.1	SUNCMKEC	Ironwood 345kV	12/01/2013
GEN-2011-018	73.6	NPPD	Steele City 115kV	12/01/2013
GEN-2011-019	175	OKGE	Woodward 345kV	12/31/2012
GEN-2011-020	165.6	OKGE	Woodward 345kV	12/31/2012
GEN-2011-022	299	SPS	Hitchland 345kV	12/31/2012
GEN-2011-022	299	SPS	Hitchland 345kV	12/31/2012
GEN-2011-025	78.76	SPS	Tap Floyd County - Crosby County 115kV	06/30/2012
GEN-2011-027	120	NPPD	Tap Hoskins - Twin Church (Dixon County) 230kV	12/31/2012
GEN-2011-037	7	WFEC	Blue Canyon 5 138kV	01/01/2012
GEN-2011-040	111	OKGE	Carter County 138kV	12/31/2012
GEN-2011-040	111	OKGE	Carter County 138kV	12/31/2012
GEN-2011-045	205	SPS	Jones 230kV	06/01/2013
GEN-2011-046	27	SPS	Lopez 115kV	06/01/2013
GEN-2011-048	175	SPS	Mustang 230kV	03/01/2013
GEN-2011-049	250.7	OKGE	Border 345kV	12/31/2013
GEN-2011-050	108	AEPW	Santa Fe Tap 138kV	12/31/2013
GEN-2011-054	300	OKGE	Cimarron 345kV	11/30/2013
GEN-2011-054	300	OKGE	Cimarron 345kV	11/30/2013
GEN-2011-056	3.6	NPPD	Jeffrey 115kV	06/30/2012
GEN-2011-056A	3.6	NPPD	John 1 115kV	06/30/2012

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2011-056B	4.5	NPPD	John 2 115kV	06/30/2012
GEN-2011-057	150	WERE	Creswell 138kV	12/31/2013
GEN-2012-001	61.2	SPS	Cirrus Tap 230kV	11/30/2012
GEN-2012-004	41.4	OKGE	Carter County 138kV	12/31/2013
GEN-2012-004	41.4	OKGE	Carter County 138kV	12/31/2013
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-007	120	SUNCMKEC	Rubart 115kV	04/01/2014
GEN-2012-012IS	75	WAPA	Wolf Point-Circle 115kV	
GEN-2012-014IS	99.5	WAPA	Groton 115kV	
GEN-2012-020	478	SPS	TUCO 230kV	09/30/2015
GEN-2012-020	478	SPS	TUCO 230kV	09/30/2015
GEN-2012-021	4.8	LES	Terry Bundy Generating Station 115kV	08/01/2013
GEN-2012-024	178.2	SUNCMKEC	Clark County 345kV	12/31/2015
GEN-2012-028	74	WFEC	Gotebo 69kV	12/01/2014
GEN-2012-032	299	OKGE	Open Sky 345kV	11/30/2014
GEN-2012-032	299	OKGE	Open Sky 345kV	11/30/2014
GEN-2012-033	98.06	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV	12/01/2014
GEN-2012-034	7	SPS	Mustang 230kV	06/01/2013
GEN-2012-035	7	SPS	Mustang 230kV	06/01/2013
GEN-2012-036	7	SPS	Mustang 230kV	06/01/2013
GEN-2012-037	203	SPS	TUCO 345kV	03/01/2015
GEN-2012-041	121.5	OKGE	Ranch Road 345kV	04/15/2015
GEN-2013-001IS	90	WAPA	Summit-Watertown 115kV	
GEN-2013-002	50.6	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2	12/31/2013
GEN-2013-007	100	OKGE	Tap Prices Falls - Carter 138kV	12/31/2014
GEN-2013-008	1.2	NPPD	Steele City 115kV	12/31/2013
GEN-2013-009IS	19.5	WAPA	Redfield NW 115kV	
GEN-2013-011	30	AEPW	Turk 138kV	unknown
GEN-2013-012	147	OKGE	Redbud 345kV	11/30/2014
GEN-2013-012	147	OKGE	Redbud 345kV	11/30/2014
GEN-2013-012	147	OKGE	Redbud 345kV	11/30/2014
GEN-2013-012	147	OKGE	Redbud 345kV	11/30/2014
GEN-2013-016	203	SPS	TUCO 345kV	12/01/2016
GEN-2013-019	73.6	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2	06/30/2014
GEN-2013-022	25	SPS	Norton 115kV	05/01/2015
GEN-2013-027	148.4	SPS	Tap Tolk - Yoakum 230kV	03/31/2016
GEN-2013-028	559.5	GRDA	Tap N Tulsa - GRDA 1 345kV	04/16/2016
GEN-2013-028	559.5	GRDA	Tap N Tulsa - GRDA 1 345kV	04/16/2016

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2013-029	299	OKGE	Renfrow 345kV	12/15/2015
GEN-2013-029	299	OKGE	Renfrow 345kV	12/15/2015
GEN-2013-030	300	OKGE	Beaver County 345kV	12/15/2015
GEN-2013-032	202.5	NPPD	Antelope 115kV	12/31/2016
GEN-2013-033	28	MIDW	Knoll 115kV	12/31/2015
GEN-2013-033	28	MIDW	Knoll 115kV	12/31/2015
GEN-2013-033	28	MIDW	Knoll 115kV	12/31/2015
GEN-2014-001	200.6	WERE	Tap Wichita - Emporia Energy Center (GEN-2014-001 Tap) 345kV	07/15/2014
GEN-2014-001IS	103.7	WAPA	Newell-Maurine 115kV	
GEN-2014-002	10.5	OKGE	Tatonga 345kV (GEN-2007-021 POI)	12/31/2014
GEN-2014-003	15.8	OKGE	Tatonga 345kV (GEN-2007-044 POI)	12/31/2014
GEN-2014-003IS	91	WAPA	Culbertson 115kV	
GEN-2014-004	4	NPPD	Steele City 115kV (GEN-2011-018 POI)	unknown
GEN-2014-004IS	384.2	WAPA	Charlie Creek 345kV	
GEN-2014-005	5.7	OKGE	Minco 345kV (GEN-2011-010 POI)	unknown
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-006IS	125	WAPA	Williston 115kV	
GEN-2014-010IS	150	WAPA	Neset 115kV	
GEN-2014-013	73.4	NPPD	Meadow Grove (GEN-2008-086N2 Sub) 230kV	12/31/2014
GEN-2014-014IS	151.5	WAPA	Belfield-Rhame 230kV	
GEN-2014-020	99.1	AEPW	Tuttle 138kV	12/31/2014
GEN-2014-021	300	KCPL	Tap Nebraska City - Mullin Creek (Holt) 345kV	12/01/2016
GEN-2014-021	300	KCPL	Tap Nebraska City - Mullin Creek (Holt) 345kV	12/01/2016
GEN-2014-025	2.4	MIDW	Walnut Creek 69kV	10/15/2015
GEN-2014-028	35	EMDE	Riverton 161kV	01/01/2016
GEN-2014-031	35.8	NPPD	Meadow Grove 230kV	10/01/2015
GEN-2014-032	10.2	NPPD	Meadow Grove 230kV	10/01/2015
GEN-2014-032	10.2	NPPD	Meadow Grove 230kV	10/01/2015
GEN-2014-033	70	SPS	Chaves County 115kV	12/31/2016
GEN-2014-034	70	SPS	Chaves County 115kV	12/31/2016
GEN-2014-035	30	SPS	Chaves County 115kV	12/31/2016
GEN-2014-039	73.4	NPPD	Friend 115kV	12/01/2016
GEN-2014-040	319.7	SPS	Castro 115kV	09/01/2016
GEN-2014-056	250	OKGE	Minco 345kV	12/31/2016
GEN-2014-057	249.9	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV	12/31/2016
GEN-2014-064	248.4	OKGE	Otter 138kV	12/01/2016
GEN-2015-001	200	OKGE	Ranch Road 345kV	12/31/2016
GEN-2015-004	52.9	OKGE	Border 345kV	05/15/2017
GEN-2015-005	200.1	KCPL	Tap Nebraska City - Sibley (Ketchem) 345kV	12/31/2017

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2015-005	200.1	KCPL	Tap Nebraska City - Sibley (Ketchem) 345kV	12/31/2017
GEN-2015-007	160	NPPD	Hoskins 345kV	12/31/2016
GEN-2015-013	120	WFEC	Synder 138kV	12/01/2016
GEN-2015-014	150	SPS	Tap Cochran - Lehman 115kV	12/01/2016
GEN-2015-015	154.56	OKGE	Road Runner 138kV	07/31/2016
GEN-2015-016	200	KCPL	Tap Marmaton - Centerville 161kV	12/31/2017
GEN-2015-021	20	SUNCMKEC	Johnson Corner 115kV	12/31/2016
GEN-2015-023	300.7	NPPD	Holt County 345kV	12/31/2019
GEN-2015-023	300.7	NPPD	Holt County 345kV	12/31/2019
GEN-2015-024	217.7	WERE	Tap Thistle - Wichita 345kV Dbl CKT	12/31/2016
GEN-2015-025	215.9	WERE	Tap Thistle - Wichita 345kV Dbl CKT	12/31/2016
GEN-2015-029	161	OKGE	Tatonga 345kV	12/01/2016
GEN-2015-030	200.1	OKGE	Sooner 345kV	12/01/2017
Gray County Wind (Montezuma)	110	SUNCMKEC	Gray County Tap 115kV	
Llano Estacado (White Deer)	80	SPS	Llano Wind 115kV	
MPC00100	99	OTP	Langdon 115 kV	
MPC00200	60	OTP	Langdon 115 kV	
MPC00200	60	OTP	Langdon 115 kV	
MPC00300	40.5	OTP	Langdon 115 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC00500	378.8	OTP	Maple River 230 kV	
MPC01200	98.9	OTP	Maple River 230 kV	
MPC01300	455	OTP	Square Butte 230 kV	
MPC02100	100	OTP	Center - Mandan 230 kV	
NPPD Distributed (Broken Bow)	8.3	NPPD	Broken Bow 115kV	
NPPD Distributed (Buffalo County Solar)	10	NPPD	Kearney Northeast	
NPPD Distributed (Burt County Wind)	12	NPPD	Tekamah & Oakland 115kV	
NPPD Distributed (Burt County Wind)	12	NPPD	Tekamah & Oakland 115kV	
NPPD Distributed (Burwell)	3	NPPD	Ord 115kV	
NPPD Distributed (Columbus Hydro)	45	NPPD	Columbus 115kV	
NPPD Distributed (Columbus Hydro)	45	NPPD	Columbus 115kV	
NPPD Distributed (Columbus Hydro)	45	NPPD	Columbus 115kV	
NPPD Distributed (North Platte - Lexington)	54	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV	
NPPD Distributed (North Platte - Lexington)	54	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV	
NPPD Distributed (North Platte - Lexington)	54	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV	
NPPD Distributed (Ord)	11.9	NPPD	Ord 115kV	
NPPD Distributed (Stuart)	2.1	NPPD	Ainsworth 115kV	
SPS Distributed (Carson)	10	SPS	Martin 115kV	
SPS Distributed (Dumas 19th St)	20	SPS	Dumas 19th Street 115kV	
SPS Distributed (Dumas 19th St)	20	SPS	Dumas 19th Street 115kV	
SPS Distributed (Etter)	20	SPS	Etter 115kV	
SPS Distributed (Etter)	20	SPS	Etter 115kV	
SPS Distributed (Hopi)	10	SPS	Hopi 115kV	

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
SPS Distributed (Jal)	10	SPS	S Jal 115kV	
SPS Distributed (Lea Road)	10	SPS	Lea Road 115kV	
SPS Distributed (Monument)	10	SPS	Monument 115kV	
SPS Distributed (Moore E)	25	SPS	Moore East 115kV	
SPS Distributed (Moore E)	25	SPS	Moore East 115kV	
SPS Distributed (Ocotillo)	10	SPS	S_Jal 115kV	
SPS Distributed (Sherman)	20	SPS	Sherman 115kV	
SPS Distributed (Sherman)	20	SPS	Sherman 115kV	
Sunray	49.5	SPS	Valero 115kV	
Total:	55,925.1			

C: STUDY GROUPINGS

C. Study Groups

GROUP 1: WOODWARD AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-014	94.5	WFEC	Ft Supply 138kV
GEN-2001-037	102	OKGE	FPL Moreland Tap 138kV
GEN-2005-008	120	OKGE	Woodward 138kV
GEN-2006-0245	18.9	WFEC	Buffalo Bear Tap 69kV
GEN-2006-046	129.6	OKGE	Dewey 138kV
GEN-2007-021	201	OKGE	Tatonga 345kV
GEN-2007-043	200	OKGE	Minco 345kV
GEN-2007-044	300	OKGE	Tatonga 345kV
GEN-2007-050	170.2	OKGE	Woodward EHV 138kV
GEN-2007-062	423.6	OKGE	Woodward EHV 345kV
GEN-2008-003	101.2	OKGE	Woodward EHV 138kV
GEN-2008-044	197.8	OKGE	Tatonga 345kV
GEN-2010-011	29.7	OKGE	Tatonga 345kV
GEN-2010-040	298.45	OKGE	Cimarron 345kV
GEN-2011-010	100.8	OKGE	Minco 345kV
GEN-2011-019	175	OKGE	Woodward 345kV
GEN-2011-020	165.6	OKGE	Woodward 345kV
GEN-2011-054	300	OKGE	Cimarron 345kV
GEN-2014-002	10.5	OKGE	Tatonga 345kV (GEN-2007-021 POI)
GEN-2014-003	15.8	OKGE	Tatonga 345kV (GEN-2007-044 POI)
GEN-2014-005	5.7	OKGE	Minco 345kV (GEN-2011-010 POI)
GEN-2014-020	99.1	AEPW	Tuttle 138kV
GEN-2014-056	250	OKGE	Minco 345kV
GEN-2015-029	161	OKGE	Tatonga 345kV
PRIOR QUEUED SUBTOTAL	3,670.45		
GEN-2015-048	200	OKGE	Cleo Corner 138kV
GEN-2015-057	100	OKGE	Minco 345kV
GEN-2015-093	250	OKGE	Gracemont 345kV
CURRENT CLUSTER SUBTOTAL	550.00		
AREA TOTAL	4,220.45		

GROUP 2: HITCHLAND AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2011-002	20	SPS	Herring 115kV
ASGI-2013-001	11.5	SPS	PanTex South 115kV
GEN-2002-008	240	SPS	Hitchland 345kV
GEN-2002-009	79.8	SPS	Hansford 115kV
GEN-2002-022	239.2	SPS	Bushland 230kV
GEN-2003-020	159.1	SPS	Martin 115kV
GEN-2006-020S	20	SPS	DWS Frisco 115kV
GEN-2006-044	370	SPS	Hitchland 345kV
GEN-2007-046	200	SPS	Hitchland 115kV
GEN-2008-047	298.9	OKGE	Beaver County 345kV
GEN-2008-051	322	SPS	Potter County 345kV
GEN-2010-001	299.7	OKGE	Beaver County 345kV
GEN-2010-014	358.8	SPS	Hitchland 345kV
GEN-2011-014	198	OKGE	Tap Hitchland - Woodward Dbl Ckt (GEN-2011-014 Tap) 345kV
GEN-2011-022	299	SPS	Hitchland 345kV
GEN-2013-030	300	OKGE	Beaver County 345kV
Llano Estacado (White Deer)	80	SPS	Llano Wind 115kV
SPS Distributed (Carson)	10	SPS	Martin 115kV
SPS Distributed (Dumas 19th St)	20	SPS	Dumas 19th Street 115kV
SPS Distributed (Etter)	20	SPS	Etter 115kV
SPS Distributed (Moore E)	25	SPS	Moore East 115kV
SPS Distributed (Sherman)	20	SPS	Sherman 115kV
PRIOR QUEUED SUBTOTAL	3,591.00		
GEN-2014-037	200	SPS	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV
CURRENT CLUSTER SUBTOTAL	200.00		
AREA TOTAL	3,791.00		

GROUP 3: SPEARVILLE AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2012-006	22.5	SUNCMKEC	Tap Hugoton - Rolla 69kV
ASGI-2015-001	6.132	SUNCMKEC	Ninnescah 115kV
GEN-2001-039A	104	SUNCMKEC	Shooting Star Tap 115kV
GEN-2002-025A	150	SUNCMKEC	Spearville 230kV
GEN-2004-014	154.5	SUNCMKEC	Spearville 230kV
GEN-2005-012	248.4	SUNCMKEC	Ironwood 345kV
GEN-2006-021	94	SUNCMKEC	Flat Ridge Tap 138kV
GEN-2007-040	200.1	SUNCMKEC	Buckner 345kV
GEN-2008-018	249.75	SPS	Finney 345kV
GEN-2008-079	98.9	SUNCMKEC	Crooked Creek 115kV
GEN-2008-124	200.1	SUNCMKEC	Ironwood 345kV
GEN-2010-009	165.6	SUNCMKEC	Buckner 345kV
GEN-2011-008	600	SUNCMKEC	Clark County 345kV
GEN-2011-016	200.1	SUNCMKEC	Ironwood 345kV
GEN-2012-007	120	SUNCMKEC	Rubart 115kV
GEN-2012-024	178.2	SUNCMKEC	Clark County 345kV
GEN-2015-021	20	SUNCMKEC	Johnson Corner 115kV
Gray County Wind (Montezuma)	110	SUNCMKEC	Gray County Tap 115kV
PRIOR QUEUED SUBTOTAL	2,922.28		
AREA TOTAL	2,922.28		

GROUP 4: NORTHWEST KANSAS AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2013-004	36.6	SUNCMKEC	Morris 115kV
GEN-2001-039M	100	SUNCMKEC	Central Plains Tap 115kV
GEN-2003-006A	201.6	SUNCMKEC	Elm Creek 230kV
GEN-2003-019	250	MIDW	Smoky Hills Tap 230kV
GEN-2006-031	75	MIDW	Knoll 115kV
GEN-2008-092	200.5	MIDW	Post Rock 230kV
GEN-2009-008	198.69	MIDW	South Hays 230kV
GEN-2009-020	48.3	MIDW	Walnut Creek 69kV
GEN-2010-057	201	MIDW	Rice County 230kV
GEN-2013-033	28	MIDW	Knoll 115kV
GEN-2014-025	2.4	MIDW	Walnut Creek 69kV
PRIOR QUEUED SUBTOTAL	1,342.09		
GEN-2015-064	197.8	SUNCMKEC	Mingo 115kV
GEN-2015-065	202.4	SUNCMKEC	Mingo 345kV
CURRENT CLUSTER SUBTOTAL	400.20		
AREA TOTAL	1,742.29		

GROUP 6: SOUTH TEXAS PANHANDLE/NEW MEXICO AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-010	42.2	SPS	Lovington 115kV
ASGI-2010-020	30	SPS	Tap LE-Tatum - LE-Crossroads 69kV
ASGI-2010-021	15	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV
ASGI-2011-001	27.3	SPS	Lovington 115kV
ASGI-2011-003	10	SPS	Hendricks 69kV
ASGI-2011-004	20	SPS	Pleasant Hill 69kV
ASGI-2012-002	18.15	SPS	FE-Clovis Interchange 115kV
ASGI-2013-002	18.4	SPS	FE Tucumcari 115kV
ASGI-2013-003	18.4	SPS	FE Clovis 115kV
ASGI-2013-005	1.65	SPS	FE Clovis 115kV
ASGI-2015-002	2	SPS	SP-Yuma 69kV
GEN-2001-033	180	SPS	San Juan Tap 230kV
GEN-2001-036	80	SPS	Norton 115kV
GEN-2006-018	168.1	SPS	TUCO Interchange 230kV
GEN-2006-026	604	SPS	Hobbs 230kV & Hobbs 115kV
GEN-2008-022	299.7	SPS	Crossroads 345kV
GEN-2010-006	205	SPS	Jones 230kV
GEN-2010-046	56	SPS	TUCO Interchange 230kV
GEN-2011-025	78.76	SPS	Tap Floyd County - Crosby County 115kV
GEN-2011-045	205	SPS	Jones 230kV
GEN-2011-046	27	SPS	Lopez 115kV
GEN-2011-048	175	SPS	Mustang 230kV
GEN-2012-001	61.2	SPS	Cirrus Tap 230kV
GEN-2012-020	478	SPS	TUCO 230kV
GEN-2012-034	7	SPS	Mustang 230kV
GEN-2012-035	7	SPS	Mustang 230kV
GEN-2012-036	7	SPS	Mustang 230kV
GEN-2012-037	203	SPS	TUCO 345kV
GEN-2013-016	203	SPS	TUCO 345kV
GEN-2013-022	25	SPS	Norton 115kV
GEN-2013-027	148.4	SPS	Tap Tolk - Yoakum 230kV
GEN-2014-033	70	SPS	Chaves County 115kV
GEN-2014-034	70	SPS	Chaves County 115kV
GEN-2014-035	30	SPS	Chaves County 115kV
GEN-2014-040	319.7	SPS	Castro 115kV
GEN-2015-014	150	SPS	Tap Cochran - Lehman 115kV
SPS Distributed (Hopi)	10	SPS	Hopi 115kV
SPS Distributed (Jal)	10	SPS	S Jal 115kV
SPS Distributed (Lea Road)	10	SPS	Lea Road 115kV
SPS Distributed (Monument)	10	SPS	Monument 115kV
SPS Distributed (Ocotillo)	10	SPS	S_Jal 115kV
Sunray	49.5	SPS	Valero 115kV
PRIOR QUEUED SUBTOTAL	4,160.46		
GEN-2015-020	100	SPS	Oasis 115kV
GEN-2015-056	101.2	SPS	Crossroads 345kV
GEN-2015-068	300	SPS	TUCO Interchange 345kV
GEN-2015-075	51.5	SPS	Carlisle 69kV
GEN-2015-079	129.2	SPS	Tap Yoakum - Hobbs Interchange 230kV
GEN-2015-080	129.2	SPS	Tap Yoakum - Hobbs Interchange 230kV

CURRENT CLUSTER SUBTOTAL	811.10	
AREA TOTAL	4,971.56	

GROUP 7: SOUTHWEST OKLAHOMA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-026	74.25	WFEC	Washita 138kV
GEN-2002-005	123	WFEC	Red Hills Tap 138kV
GEN-2003-004	100	WFEC	Washita 138kV
GEN-2003-005	100	WFEC	Anadarko - Paradise (Blue Canyon) 138kV
GEN-2003-022	120	AEPW	Weatherford 138kV
GEN-2004-020	27	AEPW	Weatherford 138kV
GEN-2004-023	20.6	WFEC	Washita 138kV
GEN-2005-003	30.6	WFEC	Washita 138kV
GEN-2006-002	100.8	AEPW	Sweetwater 230kV
GEN-2006-035	224	AEPW	Sweetwater 230kV
GEN-2006-043	98.9	AEPW	Sweetwater 230kV
GEN-2007-052	135	WFEC	Anadarko 138kV
GEN-2008-023	148.8	AEPW	Hobart Junction 138kV
GEN-2008-037	99	WFEC	Slick Hills 138kV
GEN-2011-037	7	WFEC	Blue Canyon 5 138kV
GEN-2011-049	250.7	OKGE	Border 345kV
GEN-2012-028	74	WFEC	Gotebo 69kV
GEN-2015-004	52.9	OKGE	Border 345kV
GEN-2015-013	120	WFEC	Synder 138kV
PRIOR QUEUED SUBTOTAL	1,906.55		
GEN-2015-055	40	WFEC	Erick 138kV
GEN-2015-071	200	AEPW	Chisholm 345kV
GEN-2015-084	51.3	AEPW	Hollis 138kV
GEN-2015-085	122.4	AEPW	Altus Junction 138kV
CURRENT CLUSTER SUBTOTAL	413.70		
AREA TOTAL	2,320.25		

GROUP 8: NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-006	150	AECI	Remington 138kV
ASGI-2014-014	56.4	GRDA	Ferguson 69kV
ASGI-2015-004	56.364	GRDA	Coffeyville City 69kV
GEN-2002-004	200	WERE	Latham 345kV
GEN-2005-013	199.8	WERE	Caney River 345kV
GEN-2007-025	299.2	WERE	Viola 345kV
GEN-2008-013	300	OKGE	Hunter 345kV
GEN-2008-021	42	WERE	Wolf Creek 345kV
GEN-2008-098	100.8	WERE	Waverly 345kV
GEN-2009-025	59.8	OKGE	Nardins 69kV
GEN-2010-003	100.8	WERE	Waverly 345kV
GEN-2010-005	299.2	WERE	Viola 345kV
GEN-2010-055	4.5	AEPW	Wekiwa 138kV
GEN-2011-057	150	WERE	Creswell 138kV
GEN-2012-032	299	OKGE	Open Sky 345kV
GEN-2012-033	98.06	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV
GEN-2012-041	121.5	OKGE	Ranch Road 345kV
GEN-2013-012	147	OKGE	Redbud 345kV
GEN-2013-028	559.5	GRDA	Tap N Tulsa - GRDA 1 345kV
GEN-2013-029	299	OKGE	Renfrow 345kV
GEN-2014-001	200.6	WERE	Tap Wichita - Emporia Energy Center (GEN-2014-001 Tap) 345kV

GEN-2014-028	35	EMDE	Riverton 161kV
GEN-2014-064	248.4	OKGE	Otter 138kV
GEN-2015-001	200	OKGE	Ranch Road 345kV
GEN-2015-015	154.56	OKGE	Road Runner 138kV
GEN-2015-016	200	KCPL	Tap Marmaton - Centerville 161kV
GEN-2015-024	217.7	WERE	Tap Thistle - Wichita 345kV Dbl CKT
GEN-2015-025	215.9	WERE	Tap Thistle - Wichita 345kV Dbl CKT
GEN-2015-030	200.1	OKGE	Sooner 345kV
PRIOR QUEUED SUBTOTAL	5,215.18		
GEN-2015-034	200	OKGE	Ranch Road 345kV
GEN-2015-047	297.8	OKGE	Sooner 345kV
GEN-2015-052	300	WERE	Tap Open Sky - Rose Hill 345kV
GEN-2015-062	4.5	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV
GEN-2015-063	300	OKGE	Tap Woodring - Mathewson 345kV
GEN-2015-066	248.4	OKGE	Tap Cleveland - Sooner 345kV
GEN-2015-069	300	WERE	Union Ridge 230kV
GEN-2015-073	200.1	WERE	Emporia Energy Center 345kV
GEN-2015-090	220	WERE	Tap Thistle - Wichita 345kV Dbl CKT
CURRENT CLUSTER SUBTOTAL	2,070.80		
AREA TOTAL	7,285.98		

GROUP 9: NEBRASKA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-023N	0.8	NPPD	Harmony 115kV
GEN-2003-021N	75	NPPD	Ainsworth Wind Tap 115kV
GEN-2004-023N	75	NPPD	Columbus Co 115kV
GEN-2006-020N	42	NPPD	Bloomfield 115kV
GEN-2006-037N1	73.1	NPPD	Broken Bow 115kV
GEN-2006-038N005	79.9	NPPD	Broken Bow 115kV
GEN-2006-038N019	79.9	NPPD	Petersburg North 115kV
GEN-2006-044N	40.5	NPPD	North Petersburg 115kV
GEN-2007-011N08	81	NPPD	Bloomfield 115kV
GEN-2007-017IS	166	WAPA	Ft Thompson-Grand Island 345kV
GEN-2007-018IS	234	WAPA	Ft Thompson-Grand Island 345kV
GEN-2008-086N02	201	NPPD	Meadow Grove 230kV
GEN-2008-119O	60	OPPD	S1399 161kV
GEN-2008-123N	89.66	NPPD	Tap Pauline - Guide Rock (Rosemont) 115kV
GEN-2009-040	72	WERE	Marshall 115kV
GEN-2010-041	10.29	OPPD	S1399 161kV
GEN-2010-051	200	NPPD	Tap Hoskins - Twin Church (Dixon County) 230kV
GEN-2011-018	73.6	NPPD	Steele City 115kV
GEN-2011-027	120	NPPD	Tap Hoskins - Twin Church (Dixon County) 230kV
GEN-2011-056	3.6	NPPD	Jeffrey 115kV
GEN-2011-056A	3.6	NPPD	John 1 115kV
GEN-2011-056B	4.5	NPPD	John 2 115kV
GEN-2012-021	4.8	LES	Terry Bundy Generating Station 115kV
GEN-2013-002	50.6	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2
GEN-2013-008	1.2	NPPD	Steele City 115kV
GEN-2013-019	73.6	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2
GEN-2013-032	202.5	NPPD	Antelope 115kV
GEN-2014-004	4	NPPD	Steele City 115kV (GEN-2011-018 POI)
GEN-2014-013	73.4	NPPD	Meadow Grove (GEN-2008-086N2 Sub) 230kV
GEN-2014-031	35.8	NPPD	Meadow Grove 230kV

GEN-2014-032	10.2	NPPD	Meadow Grove 230kV
GEN-2014-039	73.4	NPPD	Friend 115kV
GEN-2015-007	160	NPPD	Hoskins 345kV
GEN-2015-023	300.7	NPPD	Holt County 345kV
NPPD Distributed (Broken Bow)	8.3	NPPD	Broken Bow 115kV
NPPD Distributed (Buffalo County Solar)	10	NPPD	Kearney Northeast
NPPD Distributed (Burt County Wind)	12	NPPD	Tekamah & Oakland 115kV
NPPD Distributed (Burwell)	3	NPPD	Ord 115kV
NPPD Distributed (Columbus Hydro)	45	NPPD	Columbus 115kV
NPPD Distributed (North Platte - Lexington)	54	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV
NPPD Distributed (Ord)	11.9	NPPD	Ord 115kV
NPPD Distributed (Stuart)	2.1	NPPD	Ainsworth 115kV
PRIOR QUEUED SUBTOTAL	2,921.95		
GEN-2015-053	50	NPPD	Antelope 115kV
GEN-2015-076	158.4	NPPD	Belden 115kV
GEN-2015-087	66	NPPD	Tap Fairbury - Hebron 115kV
GEN-2015-088	300	NPPD	Tap Moore - Pauline 345kV
CURRENT CLUSTER SUBTOTAL	574.40		
AREA TOTAL	3,496.35		

GROUP 10: SOUTHEAST OKLAHOMA/NORTHEAST TEXAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.00		

GROUP 12: NORTHWEST ARKANSAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2013-011	30	AEPW	Turk 138kV
PRIOR QUEUED SUBTOTAL	30.00		
AREA TOTAL	30.00		

GROUP 13: NORTHWEST MISSOURI AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2008-129	80	KCPL	Pleasant Hill 161kV
GEN-2010-036	4.6	WERE	6th Street 115kV
GEN-2011-011	50	KCPL	Iatan 345kV
GEN-2014-021	300	KCPL	Tap Nebraska City - Mullin Creek (Holt) 345kV
GEN-2015-005	200.1	KCPL	Tap Nebraska City - Sibley (Ketchum) 345kV
PRIOR QUEUED SUBTOTAL	634.70		
AREA TOTAL	634.70		

GROUP 14: SOUTH CENTRAL OKLAHOMA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2011-040	111	OKGE	Carter County 138kV
GEN-2011-050	108	AEPW	Santa Fe Tap 138kV
GEN-2012-004	41.4	OKGE	Carter County 138kV
GEN-2013-007	100	OKGE	Tap Prices Falls - Carter 138kV
GEN-2014-057	249.9	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV
PRIOR QUEUED SUBTOTAL	610.30		
ASGI-2015-006	9	SWPA	Tupelo 138kV
GEN-2015-045	20	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV
GEN-2015-092	250	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV
CURRENT CLUSTER SUBTOTAL	279.00		
AREA TOTAL	889.30		

GROUP 15: E-SOUTH DAKOTA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-009IS	40	WAPA	Ft Thompson 69kV [Hyde 69kV]
GEN-2007-013IS	50	WAPA	Wessington Springs 230kV
GEN-2007-014IS	100	WAPA	Wessington Springs 230kV
GEN-2009-001IS	200	WAPA	Groton-Watertown 345kV
GEN-2009-018IS	99.5	WAPA	Groton 115kV
GEN-2010-001IS	99	WAPA	Bismarck-Glenham 230kV
GEN-2010-003IS	34	WAPA	Wessington Springs 230kV
GEN-2012-014IS	99.5	WAPA	Groton 115kV
GEN-2013-001IS	90	WAPA	Summit-Watertown 115kV
GEN-2013-009IS	19.5	WAPA	Redfield NW 115kV
GEN-2014-001IS	103.7	WAPA	Newell-Maurine 115kV
PRIOR QUEUED SUBTOTAL	935.20		
AREA TOTAL	935.20		

GROUP 16: W-NORTH DAKOTA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2005-008IS	50	WAPA	Hilken 230kV [Ecklund 230kV]
GEN-2006-015IS	50	WAPA	Hilken 230kV [Ecklund 230kV]
GEN-2007-015IS	100	WAPA	Hilken 230kV [Ecklund 230kV]
GEN-2009-026IS	110	WAPA	Dickenson-Heskett 230kV
GEN-2012-012IS	75	WAPA	Wolf Point-Circle 115kV
GEN-2014-003IS	91	WAPA	Culbertson 115kV
GEN-2014-004IS	384.2	WAPA	Charlie Creek 345kV
GEN-2014-006IS	125	WAPA	Williston 115kV
GEN-2014-010IS	150	WAPA	Neset 115kV
GEN-2014-014IS	151.5	WAPA	Belfield-Rhame 230kV
MPC01300	455	OTP	Square Butte 230 kV
MPC02100	100	OTP	Center - Mandan 230 kV
PRIOR QUEUED SUBTOTAL	1,841.70		
GEN-2015-046	300	WAPA	Tande 345kV
GEN-2015-096	149	WAPA	Tap Belfied - Rhame 230kV
GEN-2015-098	100	WAPA	Mingusville 230kV
CURRENT CLUSTER SUBTOTAL	549.00		
AREA TOTAL	0.00		

GROUP 17: W-SOUTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2006-002IS	51	WAPA	Wessington Springs 230kV
GEN-2009-006IS	90	WAPA	Mission 115kV
GEN-2009-007IS	100	WAPA	Mission 115kV
GEN-2009-020AIS	130.5	WAPA	Tripp Junction 115kV
PRIOR QUEUED SUBTOTAL	371.50		
AREA TOTAL	0.00		

GROUP 18: E-NORTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-008IS	40.5	WAPA	Edgeley 115kV [Pomona 115kV]
GEN-2005-003IS	100	WAPA	Nelson 115kV
GEN-2006-001IS	10	XEL	Marshall 115kV
GEN-2006-006IS	10	XEL	Marshall 115kV
GEN-2007-020IS	16	WAPA	Nelson 115kV
GEN-2008-008IS	5	WAPA	Nelson 115kV
MPC00100	99	OTP	Langdon 115 kV
MPC00200	60	OTP	Langdon 115 kV
MPC00300	40.5	OTP	Langdon 115 kV
MPC00500	378.8	OTP	Maple River 230 kV
MPC01200	98.9	OTP	Maple River 230 kV
PRIOR QUEUED SUBTOTAL	858.70		
AREA TOTAL	0.00		

CLUSTER TOTAL (CURRENT STUDY)	5,848.2	MW
PQ TOTAL (PRIOR QUEUED)	31,012.1	MW
CLUSTER TOTAL (INCLUDING PRIOR QUEUED)	36,860.3	MW

D: PROPOSED POINT OF INTERCONNECTION ONE-LINE DIAGRAMS

Link to 2015 Facility Study Reports: <http://opsportal.spp.org/Studies/GenList?yearTypeId=135>

GEN-2015-020

See Posted Interconnection Facilities Study for GEN-2015-020

GEN-2015-056

See Posted Interconnection Facilities Study for GEN-2015-056

GEN-2015-068

See Posted Interconnection Facilities Study for GEN-2015-068

GEN-2015-075

See Posted Interconnection Facilities Study for GEN-2015-075

GEN-2015-079

See Posted Interconnection Facilities Study for GEN-2015-079

GEN-2015-080

See Posted Interconnection Facilities Study for GEN-2015-080

E: COST ALLOCATION PER REQUEST

Appendix E. Cost Allocation Per Request

(Including Previously Allocated Network Upgrades*)

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-020			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$4,096,647	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$24,535,714	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$3,611,663	\$24,764,205
GEN-2015-020 Interconnection Costs See One-Line Diagram.	Current Study	\$9,288,597	\$9,288,597
Newhart - Plant X 230kV CKT 1 Replace terminal equipment	Current Study	\$50,161	\$200,000
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$41,582,782	
GEN-2015-056			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$4,511,006	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$27,140,866	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$3,464,944	\$24,764,205
GEN-2015-056 Interconnection Costs See One-Line Diagram.	Current Study	\$5,636,099	\$5,636,099
Newhart - Plant X 230kV CKT 1 Replace terminal equipment	Current Study	\$54,873	\$200,000
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$40,807,788	
GEN-2015-068			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$17,473,209	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$103,934,922	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$10,121,916	\$24,764,205
GEN-2015-068 Interconnection Costs See One-Line Diagram.	Current Study	\$4,831,332	\$4,831,332
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$136,361,379	
GEN-2015-075			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$2,660,771	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$15,925,444	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$2,583,893	\$24,764,205
GEN-2015-075 Interconnection Costs See One-Line Diagram.	Current Study	\$508,838	\$508,838
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$21,678,946	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-079			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$6,379,183	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$38,207,199	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$2,490,895	\$24,764,205
GEN-2015-079 Interconnection Costs See One-Line Diagram.	Current Study	\$6,382,720	\$6,382,720
Newhart - Plant X 230kV CKT 1 Replace terminal equipment	Current Study	\$47,483	\$200,000
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$53,507,480	
GEN-2015-080			
Border - Chisholm 345kV CKT 1 Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations	Current Study	\$6,379,183	\$41,500,000
Crawfish Draw - Border 345kV CKT 2 Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border	Current Study	\$38,207,199	\$247,951,345
Crawfish Draw 345/230kV Substation Upgrade Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2	Current Study	\$2,490,895	\$24,764,205
GEN-2015-080 Interconnection Costs See One-Line Diagram.	Current Study	\$0	\$0
Newhart - Plant X 230kV CKT 1 Replace terminal equipment	Current Study	\$47,483	\$200,000
Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay Update relay settings	Current Study	TBD	TBD
Tuco - Yoakum - Hobbs 345kV CKT 1 Build Tuco - Yoakum - Hobbs 345kV CKT 1 per SPP-NTC-200309 UID: 50447, 50451, 50452, 50457	Previously Allocated		\$241,826,483
	Current Study Total	\$47,124,760	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
TOTAL CURRENT STUDY COSTS:		\$341,063,136	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

F: COST ALLOCATION PER PROPOSED STUDY NETWORK UPGRADE

Appendix F. Cost Allocation by Upgrade

Border - Chisholm 345kV CKT 1 \$41,500,000

Build 24 miles of new 345 kV from Border (OKGE) - Chisholm (AEP); Upgrade Border and Chisholm substations

GEN-2015-020	\$4,096,647
GEN-2015-056	\$4,511,006
GEN-2015-068	\$17,473,209
GEN-2015-075	\$2,660,771
GEN-2015-079	\$6,379,183
GEN-2015-080	\$6,379,183

Total Allocated Costs	\$41,500,000
------------------------------	---------------------

Crawfish Draw - Border 345kV CKT 2 \$247,951,345

Build approximately 194 miles of second circuit 345kV from Crawfish Draw - Border

GEN-2015-020	\$24,535,714
GEN-2015-056	\$27,140,866
GEN-2015-068	\$103,934,922
GEN-2015-075	\$15,925,444
GEN-2015-079	\$38,207,199
GEN-2015-080	\$38,207,199

Total Allocated Costs	\$247,951,345
------------------------------	----------------------

Crawfish Draw 345/230kV Substation Upgrade \$24,764,205

Tap Border-Tuco and Tuco - OKU 3 miles from TUCO, build Crawfish Draw 345kV substation, add 345/230 kV xfmr, and tie on TUCO-Swisher 2

GEN-2015-020	\$3,611,663
GEN-2015-056	\$3,464,944
GEN-2015-068	\$10,121,916
GEN-2015-075	\$2,583,893
GEN-2015-079	\$2,490,895
GEN-2015-080	\$2,490,895

Total Allocated Costs	\$24,764,205
------------------------------	---------------------

GEN-2015-020 Interconnection Costs \$9,288,597

See One-Line Diagram.

GEN-2015-020	\$9,288,597
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Total Allocated Costs	\$9,288,597
------------------------------	--------------------

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

GEN-2015-056 Interconnection Costs			\$5,636,099
See One-Line Diagram.			
	GEN-2015-056		\$5,636,099
	Total Allocated Costs	\$5,636,099	
GEN-2015-068 Interconnection Costs			\$4,831,332
See One-Line Diagram.			
	GEN-2015-068		\$4,831,332
	Total Allocated Costs	\$4,831,332	
GEN-2015-075 Interconnection Costs			\$508,838
See One-Line Diagram.			
	GEN-2015-075		\$508,838
	Total Allocated Costs	\$508,838	
GEN-2015-079 Interconnection Costs			\$6,382,720
See One-Line Diagram.			
	GEN-2015-079		\$6,382,720
	Total Allocated Costs	\$6,382,720	
GEN-2015-080 Interconnection Costs			\$0
See One-Line Diagram.			
	GEN-2015-080		\$0
	Total Allocated Costs	\$0	
Newhart - Plant X 230kV CKT 1			\$200,000
Replace terminal equipment			
	GEN-2015-020		\$50,161
	GEN-2015-056		\$54,873
	GEN-2015-079		\$47,483
	GEN-2015-080		\$47,483
	Total Allocated Costs	\$200,000	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Sweetwater - Wheeler 230kV CKT 1 SNLOS1 Relay

TBD

Update relay settings

GEN-2015-020	TBD
GEN-2015-056	TBD
GEN-2015-068	TBD
GEN-2015-075	TBD
GEN-2015-079	TBD
GEN-2015-080	TBD

Total Allocated Costs

TBD

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

G-T: THERMAL POWER FLOW ANALYSIS (CONSTRAINTS REQUIRING TRANSMISSION REINFORCEMENT)

Legend:

Column	Definition
Solution	Solution Method
Group	Model Case Identification: <ul style="list-style-type: none"> • ##ALL: ERIS-HVER • 00: ERIS-LVER • ##NR or 00NR: NRIS
Scenario	Upgrade Scenario Identification
Season	Model Year and Season
Source	Gen ID producing the TDF above the limit for the constraint
Monitored Element	Monitored Bus Identification
Rate A	Planning Term Normal Rating
Rate B	Planning Term Emergency Rating
TDF	Transfer Distribution Factor for the Source
TC%LOADING	Post-transfer, loading percent for system intact or contingency
Contingency	Contingency Description

G-V: VOLTAGE POWER FLOW ANALYSIS (CONSTRAINTS REQUIRING TRANSMISSION REINFORCEMENT)

Legend:

Column	Definition
Solution	Solution Method
Group	Model Case Identification: <ul style="list-style-type: none"> • ##ALL: ERIS-HVER • 00: ERIS-LVER • ##NR or 00NR: NRIS
Scenario	Upgrade Scenario Identification
Season	Model Year and Season
Source	Gen ID producing the TDF above the limit for the constraint
Monitored Element	Monitored Bus Identification
BC Voltage (pu)	Pre-transfer, post-contingency voltage
TC Voltage (pu)	Post-transfer, post-contingency voltage
Voltage Differ (pu)	TC Voltage - BC Voltage
VINIT (pu)	Post-transfer, pre-contingency (system intact) voltage
VMIN (pu)	Lower Voltage Limit
VMAX (pu)	Upper Voltage Limit
TDF	Transfer Distribution Factor for the Source
Contingency	Contingency Description

SOLUTION GROUP	SCENARIO	SEASON	SOURCE	MONITORED ELEMENT	BC Voltage (PU)	TC Voltage (PU)	Voltage Differ (PU)	VINIT (PU)	VMIN (PU)	VMAX(PU)	TDF	CONTINGENCY	COMMENTS
No voltage constraints observed.													

Southwest Power Pool, Inc.

*H-T: THERMAL POWER FLOW ANALYSIS (OTHER CONSTRAINTS NOT
REQUIRING TRANSMISSION REINFORCEMENT)*

Available upon request

Southwest Power Pool, Inc.

*H-T-AS: AFFECTED SYSTEM THERMAL POWER FLOW ANALYSIS (CONSTRAINTS
FOR POTENTIAL UPGRADES)*

Available upon request

Southwest Power Pool, Inc.

*H-V-AS: AFFECTED SYSTEM VOLTAGE POWER FLOW ANALYSIS (CONSTRAINTS
FOR POTENTIAL UPGRADES)*

Available upon request

I: POWER FLOW ANALYSIS (CONSTRAINTS FROM MULTI-CONTINGENCIES)

Available upon request

J: DYNAMIC STABILITY ANALYSIS REPORTS



Aneden
Consulting

**Submitted to
Southwest Power Pool**



Report On

**Definitive Interconnection System Impact Study
DISIS-2015-002 Study Group 6
ReStudy#6**

Revision R1

Date of Submittal
December 21, 2018

anedenconsulting.com

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APPENDICES

APPENDIX A: SPP Disturbance Performance Requirements
APPENDIX B: DISIS-2015-002 Group 6 Generator Dynamic Models
APPENDIX C: Dynamic Stability Simulation Plots

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to complete the reactive power and dynamic stability analysis as part of the Definitive Interconnection System Impact Study DISIS-2015-002 ReStudy #6 (ReStudy#6) for South Texas Panhandle/New Mexico Area, defined as Group 6. The purpose of the analyses was to identify impacts to the transmission system caused by the active interconnection requests in Group 6.

The DISIS-2015-002 Group 6 currently includes six generation interconnection requests shown in Table ES-1 below.

Table ES-1: DISIS-2015-002-6 Interconnection Projects Evaluated

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-020	100	Eaton Power Xpert Solar 1.67MW (584623) (solar)	Oasis 115kV (524874)
GEN-2015-056	101	GE 2.3 MW (wind)	Crossroads 345kV (527656) (Tap Eddy (527802) to Tolk (525549))
GEN-2015-068	300	GE 2.0 MW (wind)	Tuco 345kV (525832)
GEN-2015-075	51.5	GE 4.0MVA Inverter (solar)	Carlisle 69kV (526159)
GEN-2015-079	129.2	GE LV5 3.8 M (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)
GEN-2015-080	129.2	GE LV5 3.8 MW (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)

Aneden performed reactive power and dynamic stability analyses using DISIS-2015-002-6 study models developed to reflect the system conditions for the current study generation interconnection requests - 2017 winter peak (2017WP), 2018 summer peak (2018SP) and 2026 summer peak (2026SP). All analyses were performed using the Siemens PTI PSS/E software version 33 and the results are summarized below.

The stability analysis was performed without any mitigation in order to identify the potential system criteria violations prior to developing mitigation solutions. There were several fault conditions that caused the system to become unstable or caused transient voltage and post-contingency voltage violations in the pre-mitigation cases. Based on the results of the steady state analysis, the following mitigation upgrades were evaluated in the subsequent reactive power and dynamic stability analyses:

1. Crawfish Draw 345kV Substation
 - Crawfish Draw 345/230 kV Transformer
 - Crawfish Draw – Swisher 230kV line
 - Crawfish Draw – Tuco 230kV line
 - Remove Tuco – Swisher 230kV line
2. Crawfish Draw-Border 345kV CKT 1
3. Crawfish Draw-Border 345kV CKT 2
4. Crawfish Draw-TUCO 345kV CKT 1

5. Crawfish Draw-TUCO 345kV CKT 2
6. Crawfish Draw-OKU 345kV CKT 1
7. Border-Chisholm 345kV CKT 1

An additional adjustment to the Sweetwater-Wheeler 230kV relay settings may be required based on results of the dynamic stability analysis.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis or low-irradiance analysis, performed using all three models showed the following shunt reactor sizes may be needed at each project collector substation high voltage bus:

1. GEN-2015-020 – 0.6 MVAR
2. GEN-2015-056 – 8.6 MVAR
3. GEN-2015-068 – 10.2 MVAR
4. GEN-2015-075 – 4 MVAR
5. GEN-2015-079 & GEN-2015-080 – 2 MVAR

The dynamic stability analysis was performed using the three loading scenarios 2017WP, 2018SP and 2026SP simulating up to 129 faults that included three-phase and single-line-to-ground faults including faults with stuck breakers. The results of the dynamic stability analysis show that after implementing the upgrades listed above, there was no generation tripping or system instability observed as a result of interconnecting all study projects at 100%.

The results of the dynamic stability analysis showed that there were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the Group 6 interconnection requests stayed connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to complete the reactive power analysis and dynamic stability analysis as part of the Definitive Interconnection System Impact Study DISIS-2015-002 ReStudy #6 (ReStudy#6) for South Texas Panhandle/New Mexico Area, defined as Group 6. The purpose of the analyses was to identify impacts to the transmission system caused by the active interconnection requests in Group 6.

The active DISIS-2015-002 Group 6 projects studied in this ReStudy#6 are listed below in Table 1-1 below.

Table 1-1: Active DISIS-2015-002 Group 6 Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-020	100	Eaton Power Xpert Solar 1.67MW (584623) (solar)	Oasis 115kV (524874)
GEN-2015-056	101	GE 2.3 MW (wind)	Crossroads 345kV (527656) (Tap Eddy (527802) to Tolk (525549))
GEN-2015-068	300	GE 2.0 MW (wind)	Tuco 345kV (525832)
GEN-2015-075	51.5	GE 4.0MVA Inverter (solar)	Carlisle 69kV (526159)
GEN-2015-079	129.2	GE LV5 3.8 M (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)
GEN-2015-080	129.2	GE LV5 3.8 MW (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)

1.1 Scope

The Study included reactive power and dynamic stability analyses. The methodology, assumptions and results of the analyses are presented in the following four main sections:

1. Study Assumptions and Criteria
2. Reactive Power Analysis
3. Dynamic Stability Analysis
4. Conclusions

1.2 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Study Assumptions and Criteria

The reactive power and dynamic stability analyses were performed using the PTI PSS/E software version 33.7. The main assumptions and criteria applied in the study are summarized in the sections below.

2.1 Study System

The study system consisted of generators and transmission buses at or above 115 kV within the monitored areas listed in Table 2-1 below.

Table 2-1: Monitored Areas

Area Number	Name
520	AEPW
524	OKGE
525	WFEC
526	SPS
531	MIDW
534	SUNC
536	WERE

2.2 Study Models

The short-circuit analysis and dynamic stability analysis were completed using the models developed by SPP from the 2016 SPP Model Development Working Group (MDWG) PSS/E models. The 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak study conditions were used to develop the DISIS-2015-002-6 models and in the analyses presented in this report. Table 2-2 summarizes the study models used for each analysis.

Table 2-2: Study Models

Case Name	Reactive Power	Dynamic Stability
17W_DIS15026_G06_M2-1	X	X
18S_DIS15026_G06_M2-1	X	X
26S_DIS15026_G06_M2-1	X	X

2.3 Group 6 Interconnection Request Configuration

The modeling configuration for each of the six Group 6 in the study models are shown in Figure 2-1 through Figure 2-5.

Figure 2-1: GEN-2015-020 Single Line Diagram

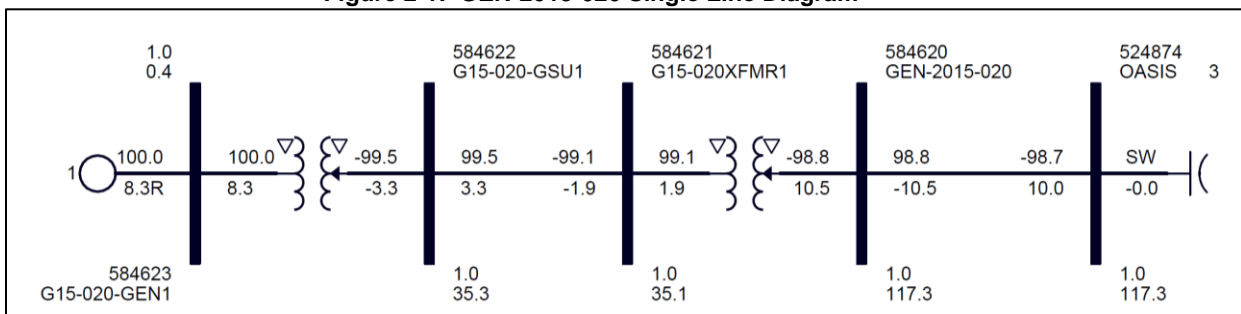


Figure 2-2: GEN-2015-056 Single Line Diagram

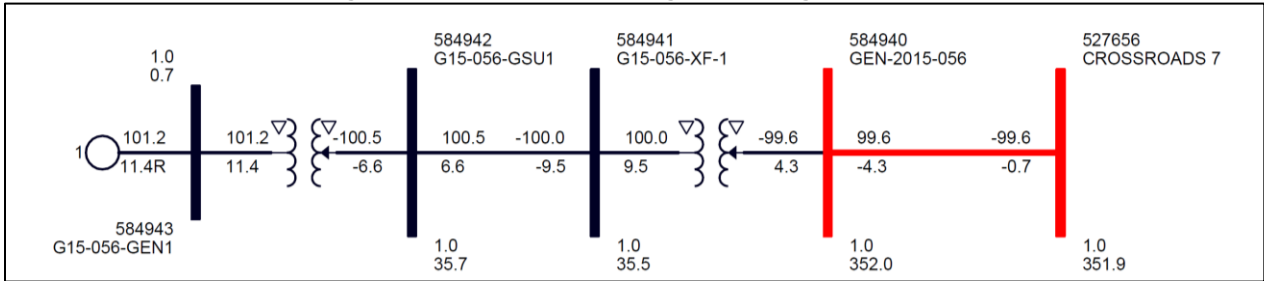


Figure 2-3: GEN-2015-068 Single Line Diagram

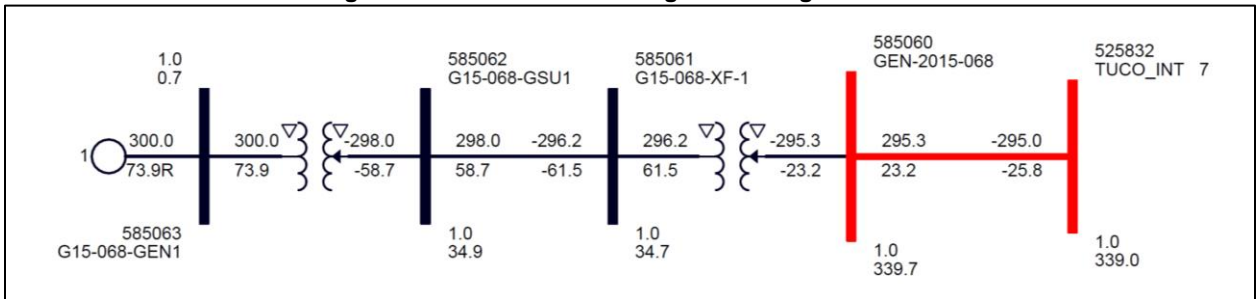


Figure 2-4: GEN-2015-075 Single Line Diagram

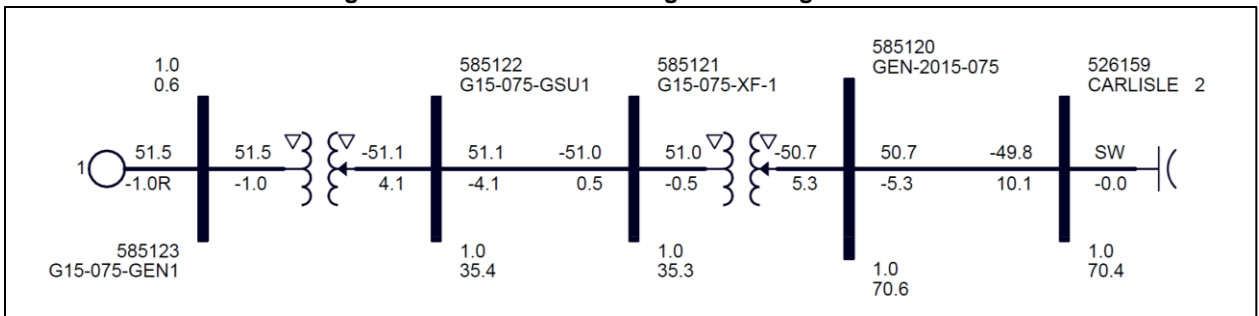
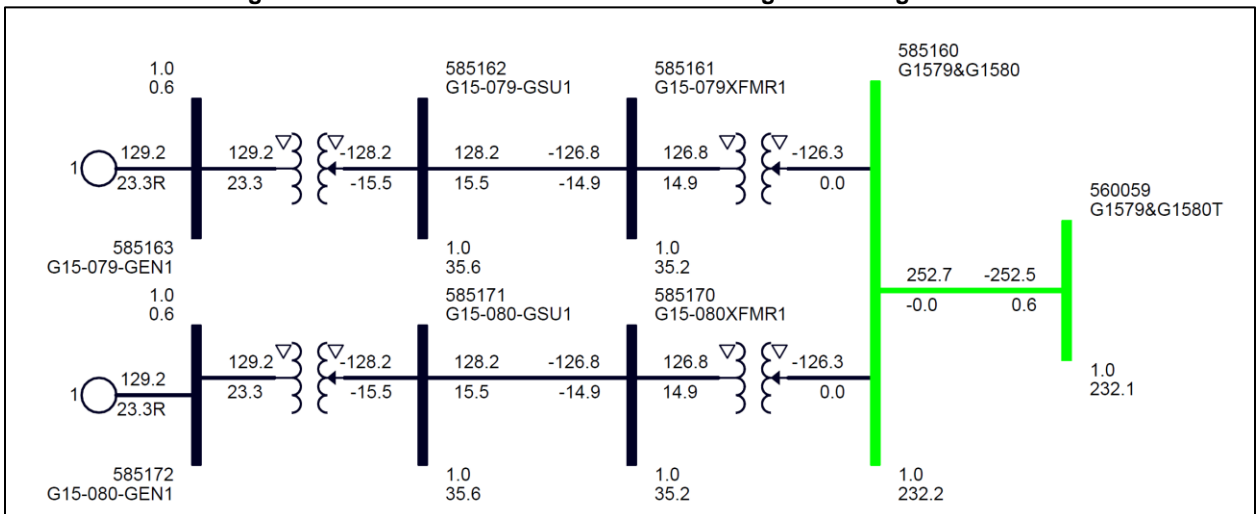


Figure 2-5: GEN-2015-079 & GEN-2015-080 Single Line Diagram



2.4 Dynamic Performance Requirements

The dynamic stability analysis results were assessed according to the following excerpt from SPP's Disturbance Performance Requirements. The complete document is provided in Appendix A.

“Machine Rotor Angles shall exhibit well damped angular oscillations following a disturbance on the Bulk Electric System for all NERC TPL-001-4 P1 through P7 events. Machines with rotor angle deviations greater than or equal to 16 degrees (measured as absolute maximum peak to absolute minimum peak) shall be evaluated against SPPR1 or SPPR5 requirements below. Machines with rotor angle deviations less than 16 degrees which do not exhibit convergence shall be evaluated on an individual basis. Rotor angle deviations will be calculated relative to the system swing machine.

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

1. Successive Positive Peak Ratio One (SPPR1) must be less than or equal to 0.95 where

SPPR1 is calculated as follows:

$$\text{SPPR1} = \frac{\text{Peak Rotor Angle of 2nd Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of 1st Positive Peak minus Minimum Value}} \leq 0.95$$

-or- $\text{Damping Factor \%} = (1 - \text{SPPR1}) \times 100\% \geq 5\%$

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:

$$\text{Damping Ratio} \geq 0.0081633$$

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where

SPPR5 is calculated as follows:

$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of 6th Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of 1st Positive Peak minus Minimum Value}} \leq 0.774$$

-or- $\text{Damping Factor \%} = (1 - \text{SPPR5}) \times 100\% \geq 22.6\%$

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:

$$\text{Damping Ratio} \geq 0.0081633$$

Bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.”

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis or low-irradiance analysis, was performed for the Group 6 projects to determine the reactive power contribution from each project’s interconnection line and collector transformer and cables during low/no generator output conditions while each project is still connected to the grid and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

3.1 Methodology and Criteria

Each Group 6 project generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the study project substation high side bus to bring the MVAR flow into the POI down to approximately zero.

3.2 Results

The results from the reactive power analysis showed that the Group 6 projects each required varying shunt reactance at the high side of the project substation, to reduce the POI MVAR to zero. This represents the contributions from each project’s collector systems. Figure 3-1 through Figure 3-5 illustrates the shunt reactor size required to reduce the POI voltage to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Table 3-1: Shunt Reactors for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVar)		
			17WP	18SP	26SP
GEN-2015-020	524874	OASIS 3	0.6	0.6	0.6
GEN-2015-056	527656	CROSSROADS 7	8.6	8.6	8.6
GEN-2015-068	525832	TUCO_INT 7	10.2	10.2	10.2
GEN-2015-075	526159	CARLISLE 2	4	4	4
GEN-2015-079 & GEN-2015-080	560059	G1579&G1580T	2	2	2

Figure 3-1: GEN-2015-020 Shunt Reactor

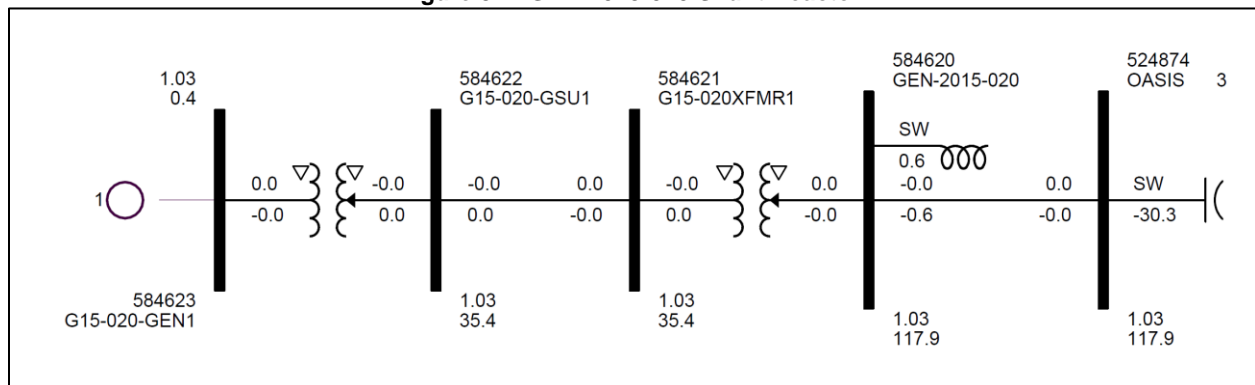


Figure 3-2: GEN-2015-056 Shunt Reactor

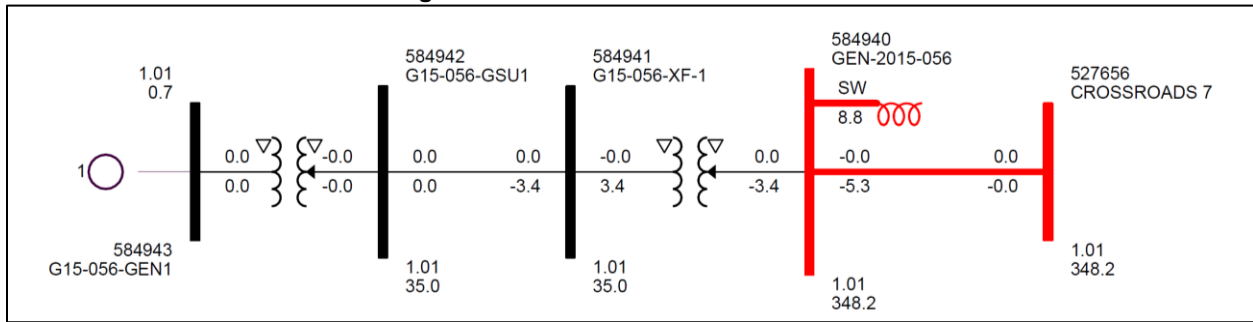


Figure 3-3: GEN-2015-068 Shunt Reactor

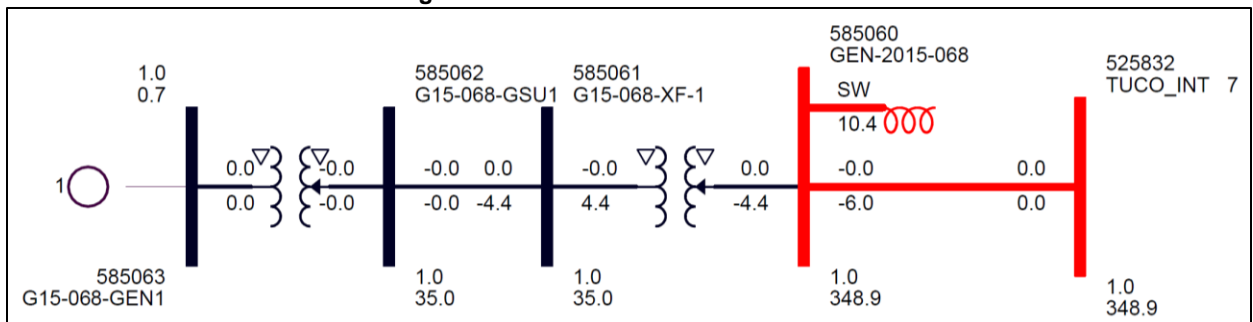


Figure 3-4: GEN-2015-075 Shunt Reactor

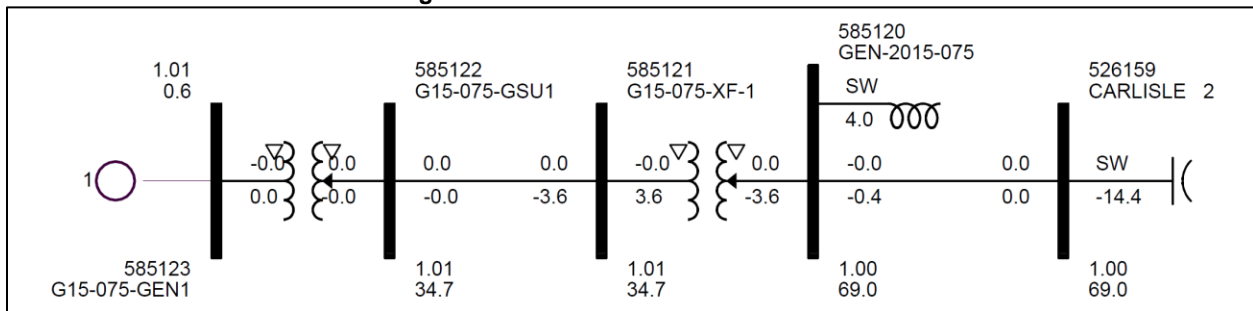
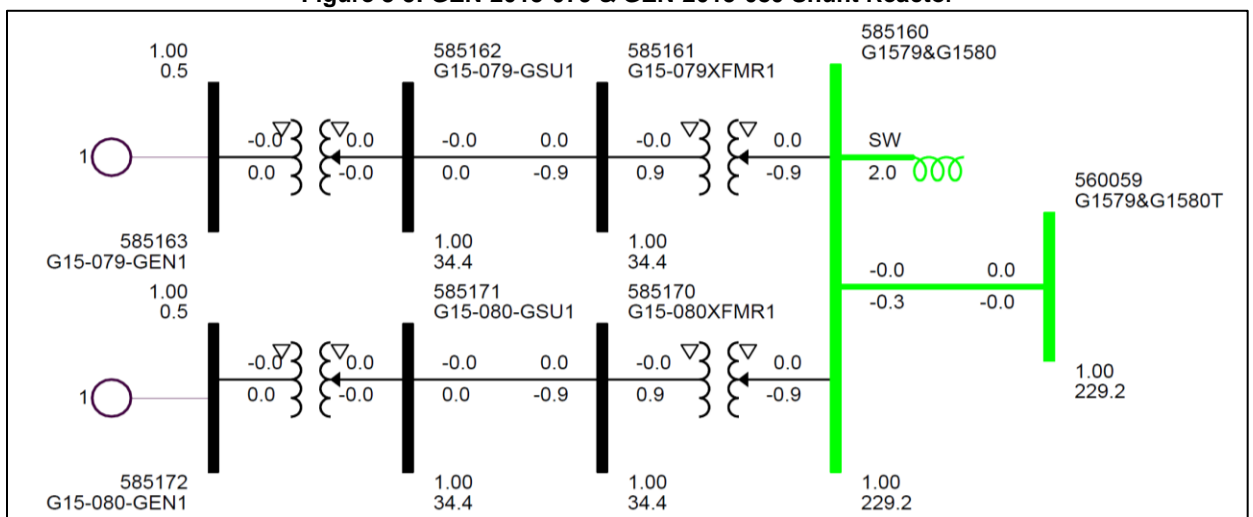


Figure 3-5: GEN-2015-079 & GEN-2015-080 Shunt Reactor



4.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to assess the system performance and identify any system stability issues associated with DISIS-2015-002 ReStudy#6 Group 6 interconnection requests. The analysis was performed according to SPP's Disturbance Performance Requirements. The Group 6 project dynamic modeling data is provided in Appendix B. The simulation plots can be found in Appendix C.

4.1 Methodology and Criteria

The dynamic stability analysis was performed using the DISIS-2015-002 (Group 6) study models described in Section 2.2 above. The power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the immediate system and the dynamic data. The dynamics model data for the DISIS-2015-002 (Group 6) requests is provided in Appendix B. The stability analysis was performed using PSS/E version 33.7.

During the fault simulations, the active power (PELEC), reactive power (QELEC), terminal voltage (ETERM), and frequency (FREQ) were monitored for the Group 6 generation interconnection requests. The machine rotor angle for synchronous machines and speed for asynchronous machines within ten (10) buses away from the POI of each of the Group 6 projects and within the study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC) and 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

4.2 Fault Definitions

Aneden developed one hundred twenty-nine (129) faults including three-phase line faults with reclosing, three-phase transformer faults with normal clearing and single-line-to-ground (SLG) fault with stuck breaker. The single-line-to-ground fault impedance values were determined by applying a fault on the base case large enough to produce a 0.6 pu voltage value on the faulted bus. The fault events are described in Table 4-1 below. These contingencies were applied to the 2017 winter peak, 2018 summer peak, and the 2026 summer peak models. Note that some of the fault definitions were adjusted to accommodate post-mitigation configuration changes made during the network upgrade analysis.

Table 4-1: Fault Definitions

Fault ID	Fault Description
FLT01-3PH	3 phase fault on Chaves County 115 kV (527482) to Samson 115 kV (527546) CKT 1, near Chaves County. a. Apply fault at the Chaves County 115 kV bus. b. Clear fault after 5 cycles and trip 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.
FLT02-3PH	3 phase fault on Chaves County 115 kV (527482) to Urton 115 kV (527501) CKT 1, near Chaves County. a. Apply fault at the Chaves County 115 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 4-1 continued

Fault ID	Fault Description
FLT03-3PH	3 phase fault on the Chaves County 115 kV (527482) to Chaves County 230 kV (527483) to Chaves County 13.2 kV (527478) XFMR CKT 1, near Chaves County 115 kV. a. Apply fault at the Chaves County 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT04-3PH	3 phase fault on Chaves County 230 kV (527483) to San Juan Tap 230 kV (524885) CKT 1, near Chaves County. a. Apply fault at the Chaves County 230 kV bus. b. Clear fault after 5 cycles and trip 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.
FLT05-3PH	3 phase fault on Chaves County 230 kV (527483) to Eddy North 230 kV (527799) CKT 1, near Chaves County. a. Apply fault at the Chaves County 230 kV bus. b. Clear fault after 5 cycles and trip 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.
FLT06-3PH	3 phase fault on Samson 115 kV (527546) to Roswellian 115 kV (527564) CKT 1, near Samson. a. Apply fault at the Samson 115 kV bus. b. Clear fault after 5 cycles and trip 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.
FLT07-3PH	3 phase fault on Urton 115 kV (527501) to Roswell City 115 kV (527522) CKT 1, near Urton. a. Apply fault at the Urton 115 kV bus. b. Clear fault after 5 cycles and trip 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.
FLT10-SB	Single phase fault with stuck breaker at Chaves County (527482) a. Apply fault at the Chaves 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Chaves County 115 kV (527482)/ 230 kV (527483)/13.2 kV (527479) transformer d. Chaves County (527482) - Samson (527546) 115 kV
FLT11-3PH	3 phase fault on the FE-Bailey County (525028) to FE-Curry (524822) 115 kV line circuit 1, near FE-Bailey County. a. Apply fault at the FE-Bailey County 115 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.
FLT13-3PH	3 phase fault on the FE-Bailey County 115 kV (525028) to Bailey County 2 69 kV (525027) to Bailey transformer 1 13.2 kV (525025) XFMR CKT 1, near FE-Bailey County 115 kV. a. Apply fault at the FE-Bailey County 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT14-3PH	3 phase fault on the FE-Bailey County (525028) to EMU&VLY Tap (525019) 115 kV line circuit 1, near FE-Bailey County. a. Apply fault at the FE-Bailey County 115 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.
FLT15-3PH	3 phase fault on the FE-Curry (524822) to DS#20 (524669) 115 kV line circuit 1, near FE-Curry. a. Apply fault at the FE-Curry 115 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.

Table 4-1 continued

Fault ID	Fault Description
FLT16-3PH	3 phase fault on the FE-Curry (524822) to Norris Tap (524764) 115 kV line circuit 1, near FE-Curry. a. Apply fault at the FE-Curry 115 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.
FLT17-3PH	3 phase fault on the FE-Curry (524822) to Clovis (524773) 115 kV line circuit 1, near FE-Curry. a. Apply fault at the FE-Curry 115 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.
FLT18-3PH	3 phase fault on the FE-Curry (524822) to FE_Clovis2 (524838) 115 kV line circuit 1, near FE-Curry. a. Apply fault at the FE-Curry 115 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.
FLT19-3PH	3 phase fault on the FE-Curry (524822) to Roosevelt (524908) 115 kV line circuit 2, near FE-Curry. a. Apply fault at the FE-Curry 115 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.
FLT20-3PH	3 phase fault on the FE-Curry 115 kV (524822) to Curry 69 kV (524821) to Curry 13.2 kV (524819) XFMR CKT 1, near FE-Curry 115 kV. a. Apply fault at the FE-Curry 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT21-3PH	3 phase fault on the Oasis (524874) to Perimeter (524797) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 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.
FLT22-3PH	3 phase fault on the Oasis (524874) to FE-Chzplt (524863) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 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.
FLT23-3PH	3 phase fault on the FE-Chzplt (524863) to Norris Tap (524764) 115 kV line circuit 1, near FE-Chzplt. a. Apply fault at the FE-Chzplt 115 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.
FLT24-3PH	3 phase fault on the Perimeter (524797) to Cannon Top (524790) 115 kV line circuit 1, near Perimeter. a. Apply fault at the Perimeter 115 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.
FLT25-3PH	3 phase fault on the Oasis (524874) to Portales (524924) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 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.

Table 4-1 continued

Fault ID	Fault Description
FLT26-3PH	3 phase fault on the Portales (524924) to Roosevelt (524908) 115 kV line circuit 1, near Oasis. a. Apply fault at the Portales 115 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.
FLT27-3PH	3 phase fault on the Portales 115 kV (524924) to Portales 69 kV (524923) to Portales 13.2 kV (524921) XFMR CKT 1, near Portales 115 kV. a. Apply fault at the Portales 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT28-3PH	3 phase fault on the Oasis 115 kV (524874) to Oasis 230 kV (524875) to Oasis 13.2 kV (524872) XFMR CKT 1, near Oasis 115 kV. a. Apply fault at the Oasis 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT29-3PH	3 phase fault on the Oasis (524875) to San Juan Tap (524885) 230 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 230 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.
FLT30-3PH	3 phase fault on the Oasis (524875) to SW_4k33 (524915) 230 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 230 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.
FLT31-3PH	3 phase fault on the Oasis (524875) to Pleasant Hill (524770) 230 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 230 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.
FLT34-3PH	3 phase fault on the Swisher (525213) to Amarillo South (524415) 230 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 230 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.
FLT35-3PH	3 phase fault on the Amarillo South (524415) to Swisher (525213) 230 kV line circuit 1, near Amarillo South. a. Apply fault at the Amarillo South 230 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.
FLT36-3PH	3 phase fault on the Swisher 230 kV (525213) to Swisher 115 kV (525212) to Swisher 13.2 kV (525211) XFMR CKT 1, near Swisher 230 kV. a. Apply fault at the Swisher 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT37-3PH*	3 phase fault on the Swisher (525213) to Tuco Int (525830) 230 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 230 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.
FLT38-3PH	3 phase fault on the Swisher (525213) to Newhart (525461) 230 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 230 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.

Table 4-1 continued

Fault ID	Fault Description
FLT39-3PH	3 phase fault on the Amarillo South 230 kV (524415) to Amarillo South 115 kV (524414) to Amarillo South 13.2 kV (524410) XFMR CKT 1, near Amarillo South 230 kV. a. Apply fault at the Amarillo 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT40-3PH	3 phase fault on the Amarillo South (524415) to Nichols (524044) 230 kV line circuit 1, near Amarillo South. a. Apply fault at the Amarillo South 230 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.
FLT41-3PH	3 phase fault on the Amarillo South (524415) to Randal (524365) 230 kV line circuit 1, near Amarillo South. a. Apply fault at the Amarillo South 230 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.
FLT42-SB	Single phase fault with stuck breaker at Swisher (525213) a. Apply fault at the Swisher 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Swisher 230 kV (525213)/ 115 kV (525212)/13.2 kV (525211) transformer d. Swisher (525213) – Crawfish Draw (560021) 230 kV
FLT43-3PH*	3 phase fault on the Tuco Int (525832) to OKU (511456) 345 kV line circuit 1, near Tuco Int. a. Apply fault at the Tuco Int 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 30 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.
FLT45-3PH*	3 phase fault on the Tuco Int (525832) to Border (515458) 345 kV line circuit 1, near Tuco. a. Apply fault at the Tuco 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.
FLT46-3PH	3 phase fault on the Tuco 345 kV (525832) to Tuco 230 kV (525830) to Tuco 13.2 kV (525824) XFMR CKT 1, near Tuco 345 kV bus. a. Apply fault at the Tuco 345 kV bus. b. Clear fault after 5 cycles by tripping the transformer
FLT47-3PH**	3 phase fault on the Tuco (525832) to Yoakam (526936) 345 kV line circuit 1, near Tuco. a. Apply fault at the Tuco (525832) 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.
FLT48-3PH	3 phase fault on the OKU (511456) to Oklaun (599891) 345 kV line circuit 1, near OKU. a. Apply fault at the OKU 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line and remove the fault. c. Block the DC tie at OKU.
FLT49-3PH	3 phase fault on the OKU (511456) to L.E.S (511468) 345 kV line circuit 1, near OKU. a. Apply fault at the OKU 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line, block the HVDC. 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.
FLT52-3PH	3 phase fault on the Plant X (525481) to Deaf Smith (524623) 230 kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 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.

Table 4-1 continued

Fault ID	Fault Description
FLT54-3PH	3 phase fault on the Deaf Smith (524623) to Bushland (524267) 230 kV line circuit 1, near Deaf Smith. a. Apply fault at the Deaf Smith 230 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.
FLT55-3PH	3 phase faults on the Deaf Smith 230 kV (524623) to Deaf Smith 115 kV (524622) to Deaf Smith 13.2 kV (524620) XFMR CKT 1, near Deaf Smith 230 kV. a. Apply fault at the Deaf Smith 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT56-3PH	3 phase fault on the Plant X (525481) to Tolk East (525524) 230 kV line circuit 2, near Plant X. a. Apply fault at the Plant X 230 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.
FLT57-3PH	3 phase fault on the Plant X (525481) to Newhart (525461) 230 kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 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.
FLT58-3PH	3 phase fault on the Plant X (525481) to Tolk West (525531) 230 kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 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..
FLT59-3PH	3 phase fault on the Plant X (525481) to Sundown (526435) 230 kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 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.
FLT60-3PH	3 phase fault on the Plant X 230 kV (525481) to Plant X 115 kV (525480) to Plant X 13.2 kV (525479) XFMR CKT 1, near Plant X 230 kV. a. Apply fault at the Plant X 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT61-SB	Single phase fault with stuck breaker on the Tolk West (525531) to Plant X (525481) 230 kV circuit #1 line, near Tolk West. a. Apply fault at the Tolk West 230 kV bus. b. Run 5 cycles, and then open Plant X end of the faulted line. c. Run 10 cycles, and then clear the fault and disconnect Tolk West 230 kV bus (525531).
FLT62-SB	Single phase fault with stuck breaker on the Tolk East (525524) to Plant X (525481) 230 kV line circuit #2, near Tolk East. a. Apply fault at the Tolk East 230 kV bus. b. Run 5 cycles, and then open Plant X end of the faulted line. c. Run 10 cycles, and then clear the fault and disconnect Tolk East 230 kV bus (525524).
FLT63-3PH	3 phase fault on the Mustang (527149) to Amocowasson (526784) 230 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 230 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.
FLT64-3PH	3 phase fault on the Mustang 230 kV (527149) to Mustang 115 kV (527146) to Mustang 13.2 kV (527143) XFMR CKT 1, near Mustang 230 kV. a. Apply fault at the Mustang 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 4-1 continued

Fault ID	Fault Description
FLT65-3PH	3 phase fault on the Mustang (527149) to Yoakum (526935) 230 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 230 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.
FLT66-3PH	3 phase fault on the Mustang (527149) to Seminole (527276) 230 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 230 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.
FLT67-3PH	3 phase fault on the Seminole 230 kV (527276) to Seminole 115 kV (527275) to Seminole 13.2 kV (527273) XFMR CKT 1, near Seminole 230 kV. a. Apply fault at the Seminole 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT68-3PH	3 phase fault on the Amocowasson (526784) to BRU_SUB 6 (527009) 230 kV line circuit 1, near Amocowasson. a. Apply fault at the Amocowasson 230 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.
FLT69-3PH	3 phase fault on the Yoakum (526935) to G13-027-TAP (562480) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 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.
FLT70-3PH	3 phase fault on the Yoakum 230 kV (526935) to Yoakum 115 kV (526934) to Yoakum 13.2 kV (526932) XFMR CKT 2, near Yoakum 230 kV. a. Apply fault at the Yoakum 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT71-3PH	3 phase fault on the Mustang (527146) to Denver North (527130) 115 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 115 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.
FLT72-3PH	3 phase fault on the Mustang (527146) to Seagraves (527202) 115 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 115 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.
FLT73-3PH	3 phase fault on the Mustang (527146) to Denver South (527136) 115 kV line circuit 2, near Mustang. a. Apply fault at the Mustang 115 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.
FLT74-3PH	3 phase fault on the Mustang (527146) to Shell Co (527062) 115 kV line circuit 1, near Mustang. a. Apply fault at the Mustang 115 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.
FLT75-3PH	3 phase fault on the Yoakum (526935) to Amoco-SS (526460) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 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.

Table 4-1 continued

Fault ID	Fault Description
FLT76-3PH	3 phase fault on the Yoakum (526935) to BRU_SUB 6 (527009) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 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.
FLT77-3PH	3 phase fault on the Yoakum (526935) to GEN-2015-079 Tap (560059) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 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.
FLT78-SB	Single phase fault with stuck breaker at Mustang (527149) a. Apply fault at the Mustang 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Mustang 230 kV (527149) /115 kV (527146)/13.2 kV (527143) transformer d. Mustang (527149) - Amocowasson (526784) 230 kV
FLT79-SB	Single phase fault with stuck breaker on the Tolk West (525531) to GEN-2013-027 (562480) 230 kV line, near Tolk West. a. Apply fault at the Tolk West 230 kV bus. b. Run 5 cycles, and then open GEN-2013-027 end of the faulted line. c. Run 10 cycles, and then clear the fault and disconnect Tolk West 230 kV bus (525531).
FLT80-SB	Single phase fault with stuck breaker on the Yoakum (526935) to GEN-2013-027 (562480) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 kV bus. b. Run 5 cycles, and then open GEN-2013-027 end of the faulted line. c. Run 10 cycles, and then clear the fault and open Yoakum end of the line in (b) and trip Yoakum (526935) to Yoakum 115 (526934)/13.2 kV (526931) transformer circuit #1.
FLT81-SB	Single phase fault with stuck breaker on the Yoakum (526935) to Amoco-SS (526460) 230 kV line, near Yoakum. a. Apply fault at the Yoakum 230 kV bus. b. Run 5 cycles, and then open Amoco-SS end of the faulted line. c. Run 10 cycles, and then clear the fault and trip Yoakum 230 kV (526935) bus.
FLT84-3PH	3 phase fault on the Woodward (515375) to Border (515458) 345 kV line circuit 1, near Woodward. a. Apply fault at the Woodward 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.
FLT85-3PH	3 phase fault on the Tuco (525830) to Carlisle (526161) 230 kV line circuit 1, near Tuco. a. Apply fault at the Tuco 230 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.
FLT86-3PH	3 phase fault on the Tuco (525830) to Tolk East (525524) 230 kV line circuit 1, near Tuco. a. Apply fault at the Tuco 230 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.
FLT87-3PH	3 phase fault on the Tuco (525830) to Jones (526337) 230 kV line circuit 1, near Tuco. a. Apply fault at the Tuco 230 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.

Table 4-1 continued

Fault ID	Fault Description
FLT88-3PH	3 phase fault on the Tuco 230 kV (525830) to Tuco 115 kV (525828) to Tuco 13.2 kV (525819) XFMR CKT 2, near Tuco 230 kV. a. Apply fault at the Tuco 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT91-SB*	Single phase fault with stuck breaker at Tuco (525832) a. Apply fault at the Tuco 345 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Tuco 345 kV (525832) /230 kV (525830) /13.2 kV (525824) transformer d. Tuco (525832) -- OKU (511456) 345 kV
FLT92-3PH	3 phase fault on the Crossroads (527656) to Tolk (525549) 345 kV line circuit 1, near Crossroads. a. Apply fault at the Crossroads 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.
FLT93-3PH	3 phase fault on the Crossroads (527656) to Eddy County (527802) 345 kV line circuit 1, near Crossroads. a. Apply fault at the Crossroads 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.
FLT94-3PH	3 phase fault on the Tolk 345 kV (525549) to Tolk Tap 230 kV (525543) to Tolk 13.2 kV (525537) XFMR CKT 1, near Tolk 345 kV. a. Apply fault at the Tolk 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
FLT95-3PH	3 phase fault on the Eddy County 345 kV (527802) to Eddy North 230 kV (527799) to Eddy 13.2 kV (527796) XFMR CKT 1, near Eddy County 345 kV. a. Apply fault at the Eddy County 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
FLT96-3PH	3 phase fault on the Atoka (527786) to CV-Dayton (527821) 115 kV line circuit 1, near Atoka. a. Apply fault at the Atoka 115 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.
FLT97-3PH	3 phase fault on the Atoka (527786) to CV-Irishhill (528116) 115 kV line circuit 1, near Atoka. a. Apply fault at the Atoka 115 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.
FLT98-3PH	3 phase fault on the Atoka (527786) to Eagle Creek (527711) 115 kV line circuit 1, near Atoka. a. Apply fault at the Atoka 115 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.
FLT99-3PH	3 phase fault on the CV-Dayton (527821) to Eddy South (527793) 115 kV line circuit 1, near CV-Dayton. a. Apply fault at the CV-Dayton 115 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.
FLT100-3PH	3 phase fault on the CV-Irishhill (528116) to CV-Lakewood (528109) 115 kV line circuit 1, near CV-Irishhill. a. Apply fault at the CV-Irishhill 115 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.

Table 4-1 continued

Fault ID	Fault Description
FLT101-3PH	3 phase fault on the Eagle Creek (527711) to Seven Rivers (528094) 115 kV line circuit 1, near Eagle Creek. a. Apply fault at the Eagle Creek 115 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.
FLT102-3PH	3 phase fault on the Eagle Creek (527711) to Eddy North (527798) 115 kV line circuit 1, near Eagle Creek. a. Apply fault at the Eagle Creek 115 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.
FLT105-3PH	3 phase fault on the Carlisle (526160) to LP-Doud Tap (526162) 115 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 115 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.
FLT106-3PH	3 phase fault on the Carlisle 115 kV (526160) to Carlisle 230 kV (526161) to Carlisle 13.2 kV (526157) XFMR CKT 1, near Carlisle 115 kV bus. a. Apply fault at the Carlisle 115 kV bus. b. Clear fault after 5 cycles by tripping the transformer
FLT107-3PH	3 phase fault on the Carlisle (526160) to SP-Erskine (526109) 115 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 115 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.
FLT108-3PH	3 phase fault on the Carlisle (526160) to Murphy (526192) 115 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 115 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.
FLT109-3PH	3 phase fault on the LG-Clauene (526491) to Terry County (526736) 115 kV line circuit 1, near LG-Clauene. a. Apply fault at the LG-Clauene 115 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.
FLT111-3PH	3 phase fault on the Terry County (526736) to Prentice (526792) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 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.
FLT112-3PH	3 phase fault on the Terry County (526736) to Denver North (527130) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 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.
FLT113-3PH	3 phase fault on the Terry County (526736) to Sulphur (527262) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 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.

Table 4-1 continued

Fault ID	Fault Description
FLT114-3PH	3 phase fault on the Terry County 115 kV (526736) to Terry County 69 kV (526735) to Terry County 13.2 kV (526733) XFMR CKT 1, near Terry County 115 kV. a. Apply fault at the Terry County 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT115-3PH	3 phase fault on the Terry County (526736) to Wolf Forth (526524) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 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.
FLT116-3PH	3 phase fault on the LG-Clauene (526491) to LG-Leveland (526484) 115 kV line circuit 1, near LG-Clauene. a. Apply fault at the LG-Clauene 115 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.
FLT117-3PH	3 phase fault on the Seagraves (527202) to Sulphur (527262) 115 kV line circuit 1, near Seagraves. a. Apply fault at the Seagraves 115 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.
FLT118-3PH	3 phase fault on the Seagraves (527202) to LG-Plshill (527194) 115 kV line circuit 1, near Seagraves. a. Apply fault at the Seagraves 115 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.
FLT119-3PH	3 phase fault on the Denver South (527136) to San Andreas (527105) 115 kV line circuit 1, near Denver South. a. Apply fault at the Denver South 115 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.
FLT120-3PH	3 phase fault on the Denver South (527136) to Shell C2 (527036) 115 kV line circuit 1, near Denver South. a. Apply fault at the Denver South 115 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.
FLT121-3PH	3 phase fault on the Denver South 115 kV (527136) to Denver City 69 kV (527125) to Denver South 13.2 kV (527123) XFMR CKT 2, near Denver South 115 kV. a. Apply fault at the Denver South 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT126-3PH	3 phase fault on the GEN-2015-079 Tap (560059) to Hobbs (527894) 230 kV line circuit 1, near GEN-2015-079 Tap. a. Apply fault at the GEN-2015-079 Tap 230 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.
FLT127-3PH	3 phase fault on the Hobbs (527894) to Andrews (528604) 230 kV line circuit 1, near Hobbs. a. Apply fault at the Hobbs 230 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.

Table 4-1 continued

Fault ID	Fault Description
FLT128-3PH	3 phase fault on the Hobbs (527894) to Cunningham (527867) 230 kV line circuit 1, near Hobbs. a. Apply fault at the Hobbs 230 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.
FLT129-3PH	3 phase fault on the Hobbs 230 kV (527894) to Hobbs 115 kV (527891) to Hobbs 13.2 kV (527889) XFMR CKT 2, near Hobbs 230 kV. a. Apply fault at the Hobbs 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT131-SB	Single phase fault with stuck breaker at Chaves County (527482) a. Apply fault at the Chaves 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Chaves County 230 kV (527483)/ 115 kV (527482)/13.2 kV (527478) transformer d. Chaves County (527482) - Urton (527501) 115 kV
FLT133-SB	Single phase fault with stuck breaker at Oasis (524874) a. Apply fault at the Oasis 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Oasis (524874) - FE-CHZPLT (524863) 115 kV d. Oasis (524874) - Portales (524924) 115 kV
FLT134-SB	Single phase fault with stuck breaker at Amarillo South (524415) a. Apply fault at the Amarillo South 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Amarillo South (524415) - Nichols (524044) 230 kV d. Amarillo South (524415) - Randall (524365) 230 kV
FLT135-SB*	Single phase fault with stuck breaker at Tuco Int (525832) a. Apply fault at the Tuco Int 345 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Tuco Int (525832) - Border (515458) 345 kV d. Tuco Int (525832) - Yoakum (526936) 345 kV
FLT136-SB	Single phase fault with stuck breaker at Deafsmith (524623) a. Apply fault at the Deafsmith 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Deafsmith 230 kV (524623)/115 kV (524622)/13.8 kV (524620) transformer d. Deafsmith (524623) - Bushland (524267) 230 kV
FLT137-SB	Single phase fault with stuck breaker at Mustang (527149) a. Apply fault at the Mustang 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Mustang (527149) - Seminole (527276) 230 kV d. Mustang (527149) - Yoakum (526935) 230 kV
FLT138a-SB	Single phase fault with stuck breaker at EDDY_CNTY (527802) a. Apply fault at the Eddy County 345 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Eddy County 345 kV (527802)/230 kV (527799)/13.2 kV (527796) transformer d. Eddy County (527802) - Crossroads (527656) 345 kV
FLT138b-SB	Single phase fault with stuck breaker at Tolk (525549) a. Apply fault at the Tolk 345 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Tolk 345 kV (525549)/230 kV (525543)/13.2 kV (525537) transformer d. Tolk (525549) - Crossroads (527656) 345 kV
FLT139-SB	Single phase fault with stuck breaker at Atoka (527786) a. Apply fault at the Atoka 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Atoka (527786) - Eagle Creek (527711) 115 kV d. Atoka (527786) - Irish Hill (528116) 115 kV

Table 4-1 continued

Fault ID	Fault Description
FLT140-SB	Single phase fault with stuck breaker at Carlisle (526160) a. Apply fault at the Carlisle 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Carlisle (526160) - Murphy (526192) 115 kV d. Carlisle (526160) - Erskine (526109) 115 kV
FLT141-SB	Single phase fault with stuck breaker at Terry County (526736) a. Apply fault at the Terry County 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Terry County (526736) - Wolforth (526524) 115 kV d. Terry County (526736) - Denver (527130) 115 kV
FLT142-SB	Single phase fault with stuck breaker at Mustang (527146) a. Apply fault at the Mustang 115 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Mustang (527146) - Seagraves (527202) 115 kV d. Mustang (527146) - Denver S (527136) 115 kV
FLT143-SB	Single phase fault with stuck breaker at Hobbs (527894) a. Apply fault at the Hobbs 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Hobbs (527894) - Andrews (528604) 230 kV d. Hobbs (527894) - Cunningham (527867) 230 kV
FLT9001-3PH***	3 phase fault on the TUCO_INT 7 (525832) to CRAWFISH_DR (560022) 345 kV line circuit 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 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.
FLT9003-3PH (FLT43-M)***	3 phase fault on the CRAWFISH_DR (560022) to O.K.U.-7 (511456) 345 kV line circuit 1, near CRAWFISH_DR. a. Apply fault at the CRAWFISH_DR 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.
FLT9004-3PH (FLT45-M)***	3 phase fault on the CRAWFISH_DR (560022) to BORDER 7 (515458) 345 kV line circuit 1, near CRAWFISH_DR. a. Apply fault at the CRAWFISH_DR 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.
FLT9007-3PH***	3 phase fault on the BORDER 7 (515458) to WWRDEHV7 (515375) 345 kV line circuit 1, near BORDER 7. a. Apply fault at the BORDER 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.
FLT9008-3PH***	3 phase fault on the BORDER 7 (515458) to CHISHOLM7 (511553) 345 kV line circuit 1, near BORDER 7. a. Apply fault at the BORDER 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.

Table 4-1 continued

Fault ID	Fault Description
FLT9009-3PH***	3 phase fault on the POTTER_CO 7 (523961) to HITCHLAND 7 (523097) 345 kV line circuit 1, near POTTER_CO 7. a. Apply fault at the POTTER_CO 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.
FLT9100-SB (FLT91-SB-M)***	Single phase fault with stuck breaker at Crawfish Draw (560022) a. Apply fault at the Crawfish Draw 345 kV bus. b. Clear fault after 16 cycles and trip the following elements c. CRAWFISH_DR 345 kV (560022) to CRAWFISH_DR2 230 kV (560021) to CRAWFISH_DRT 13.2 kV (560023) XFMR CKT 1 d. Crawfish Draw (560022) -- OKU (511456) 345 kV

*Do not apply to the mitigation cases, **Does not apply to the 17W case, ***Mitigation cases only

4.1 Pre-Mitigation Results

Table 4-2 shows the results with critical transient voltage recovery and stability or damping violations observed in each of the study models prior to including additional upgrades. In addition, the pre-contingency voltage at Oklaunion 345 kV bus in the 2017WP were about 0.91 pu which resulted in post-fault voltage violations for all the simulated fault events.

Table 4-2: Select Group 6 Dynamic Stability – Pre-Mitigation

Fault ID	17WP			18SP			26SP		
	Volt. Recov.	Post Cont. Volt	Stability	Volt. Recov.	Post Cont. Volt	Stability	Volt. Recov.	Post Cont. Volt	Stability
FLT34-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Pass	Stable
FLT35-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Pass	Stable
FLT37-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Pass	Stable
FLT43-3PH	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT45-3PH	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT49-3PH	Fail	Fail*	Unstable	Fail	Pass	Damping Violation	Pass	Pass	Stable
FLT52-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Fail	Stable
FLT54-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Pass	Stable
FLT66-3PH	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Fail	Stable
FLT84-3PH	Fail	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT85-3PH	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT86-3PH	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT87-3PH	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT91-SB	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT135-SB	Pass	Fail*	Damping Violation	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT136-SB	Pass	Fail*	Poorly Damped	Pass	Fail	Poorly Damped	Pass	Pass	Stable
FLT137-SB	Pass	Fail*	Stable	Pass	Fail	Stable	Pass	Fail	Stable
FLT140-SB	Pass	Fail*	G15-075 Trip	Pass	Pass	G15-075 Trip	Pass	Pass	Stable

4.2 Post-Mitigation Results

Table 4-3 shows the results of the fault events applied to each of the study models with the following network upgrades identified in the steady state analysis performed by SPP applied. The associated stability plots are provided in Appendix C. There were no damping or voltage recovery violations observed during the simulated faults. The Group 6 projects stayed

Table 4-3 continued

Fault ID	17WP			18SP			26SP		
	Volt. Recov.	Post Cont. Volt	Stability	Volt. Recov.	Post Cont. Volt	Stability	Volt. Recov.	Post Cont. Volt	Stability
FLT140-SB	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT141-SB	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT142-SB	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT143-SB	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9001-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9002-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9003-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9004-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9005-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9006-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9007-3PH	No Violation	No Violation	Stable**	No Violation	No Violation	Stable	No Violation	No Violation	Stable
FLT9008-3PH	No Violation	No Violation	Stable**	No Violation	No Violation	Stable	No Violation	No Violation	Stable***
FLT9009-3PH	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable***
FLT9100-SB	No Violation	No Violation	Stable	No Violation	No Violation	Stable	No Violation	No Violation	Stable

*GEN-2014-033 (583956) frequency relay trip settings can be extended to PSS/E software limitation.

** Group 7 project GEN-2015-084 (585213) high voltage relay can be disabled to prevent tripping

*** Sweetwater-Wheeler 230kV tripped on out-of-step relay (SLNOS1). Stability was maintained with the line tripping permitted and also with the relay disabled.

5.0 Conclusions

The purpose of this ReStudy#6 was to evaluate the impacts of the DISIS-2015-002 (Group 6) active generation interconnection projects on the SPP transmission system as shown in Table 5-1. The Reactive Power Analysis and Dynamic Stability analysis were performed for the evaluation using the PTI PSS/E version 33.7 software. The 2017 winter peak, 2018 summer peak and 2026 summer peak models were used in the study.

Table 5-1: Group 6 Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-020	100	Eaton Power Xpert Solar 1.67MW (584623) (solar)	Oasis 115kV (524874)
GEN-2015-056	101	GE 2.3 MW (wind)	Crossroads 345kV (527656) (Tap Eddy (527802) to Tolk (525549))
GEN-2015-068	300	GE 2.0 MW (wind)	Tuco 345kV (525832)
GEN-2015-075	51.5	GE 4.0MVA Inverter (solar)	Carlisle 69kV (526159)
GEN-2015-079	129.2	GE LV5 3.8 M (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)
GEN-2015-080	129.2	GE LV5 3.8 MW (solar)	Tap Yoakum (526935) to Hobbs (527894) 230 kV (560059)

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis or low-irradiance analysis, performed using all three models showed that the projects may require shunt reactors on their collector substation high voltage bus:

1. GEN-2015-020 – 0.6 MVAR
2. GEN-2015-056 – 8.6 MVAR
3. GEN-2015-068 – 10.2 MVAR
4. GEN-2015-075 – 4 MVAR
5. GEN-2015-079 & GEN-2015-080 – 2 MVAR

The shunt reactors are needed to reduce the reactive power transfer at the POI to approximately zero during low/no-wind or low-irradiance conditions while the generation interconnection project remained connected to the grid.

The dynamic stability analysis was performed using the three loading scenarios 2017WP, 2018SP and 2026SP simulating up to 129 faults that included three-phase and single-line-to-ground faults including faults with stuck breakers. The pre-mitigation results showed that there were several transient voltage recovery and stability/damping criteria violations observed confirming the need for network upgrades.

The steady state upgrades developed by SPP to resolve steady state system performance violations were tested with the dynamic stability models and the results showed that there were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events

with the exception of the adjustment to the Sweetwater-Wheeler 230kV relay settings. Additionally, the Group 6 interconnection requests stayed connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.