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GSEC ATTACHMENT K ANALYSIS-DRAFT PLAN

STUDY # 2017-7-27

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Golden Spread Electric Cooperative (GSEC),

for BGEC, GEC, and SPEC

July 27, 2017

Revision History

Date of Revision	**Author**	**Change Description**	**Comments**
07/27/2017	GSEC Staff	Initial Draft	Staff Review

Table of Contents

List of Figures

List of Tables

1. Introduction

In accordance with Section 4.2 of Attachment K to Golden Spread's Open Access Transmission Tariff (OATT), this Plan Development Scope sets out the scope, assumptions, methodologies and milestones for consideration as Golden Spread completes its Transmission Planning Process (TPP). The objective of this Plan Development Scope and the studies that will be prepared is to determine what impacts additional generation and new transmission projects will have on the Special Facilities Golden Spread owns on behalf of South Plains Electric Cooperative (SPEC), Big Country Electric Cooperative (BGEC), and Greenbelt Electric Cooperative (GEC) (collectively depicted in the map of showing the Golden Spread's members below) and which are covered under the Golden Spread OATT. It will be determined what, if any, actions need to be taken to ensure reliable power delivery over Special Facilities on behalf of third party customers and to the loads in these systems. Additionally, member cooperative buses will have the modeled, equivalent circuit modified to accurately represent load and power distribution throughout the member areas.

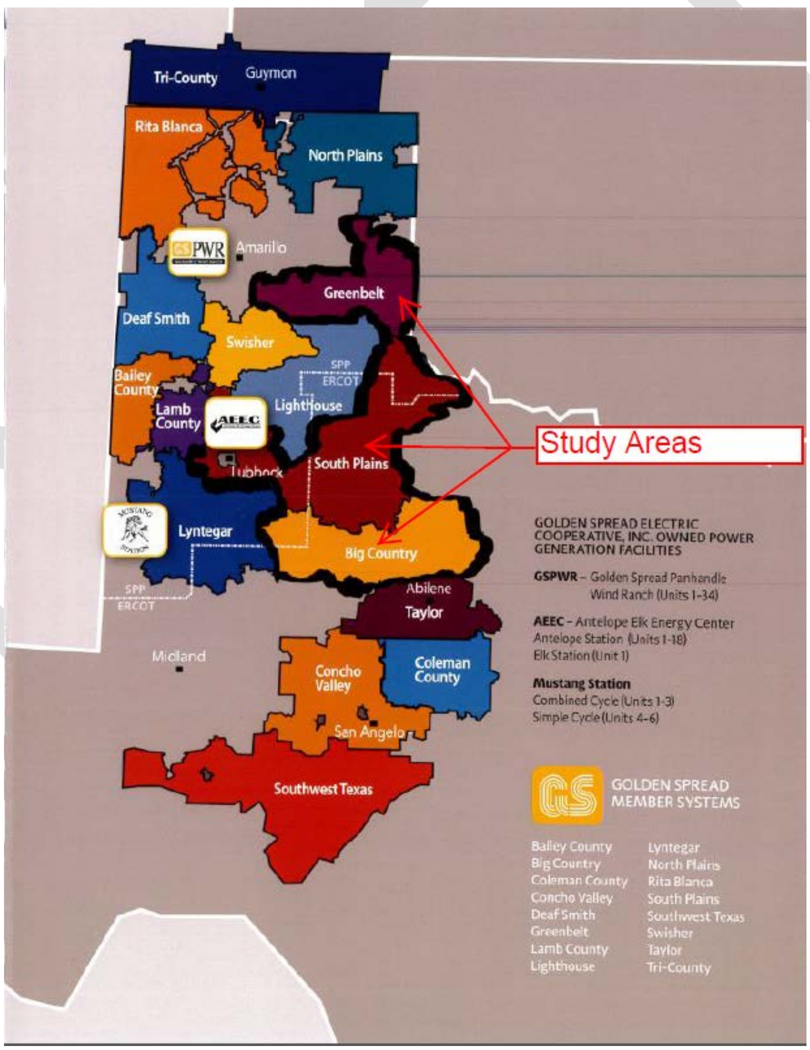

Figure 1: GSEC Service Territory with Study Area

2. Study Methodology

2.1 Study Scope

The SPEC, BGEC, and GEC Special Facilities included in this study are in the Texas Panhandle/South Plains areas, and are supplied power by Golden Spread through the Southwest Power Pool (SPP) power grid. There is one existing transmission customer on the SPEC Special Facilities that delivers power to the SPP power grid. There are currently no transmission or interconnection requests in the queue. The SPP 2017 ITPNT FINAL models will be used to determine the effects of additional loads, generation, and transmission expected over the next ten years. The SPP 2017 ITPNT FINAL load flow models are the provided by SPP as used in their reliability studies. An ACCC contingency analysis will be performed by using the software developed by PTI Version PSS®E 33. The results of the analysis will be shown in the format set out in Section 4 of this document.

Before the study can be started, all the 2017 ITPNT models will be modified to accurately represent the actual load distribution system of the member cooperatives rather than using an equivalent circuit.

2.2 Study Process

Model Assumptions:

- 2017 ITPNT models with all 2016 approved upgrade projects included
  - No violations are present prior to running contingencies in the 2016 base model at the member cooperative buses
  - Model years 2016, 2017, 2018, 2021, and 2026 are studied
  - Summer and Winter Peak Loads studied
  - Total of 28 models were analyzed throughout study
  - Previous loads modeled for member cooperatives are accurate and equivalent prior to modifications

2.3 Study Criteria

The criteria used for this study is outlined below and is taken from the NERC Transmission Planning (TPL) Reliability Standards.

Category P0 –
System Performance Under Normal (No Contingency, or N-0) Conditions (Category P0) as referenced in Table 1 of NERC Standard TPL-001-4

- Voltage: 0.95 to 1.05 per unit
- Line Loading: 100 percent of continuous rating
- Transformer Loading: 100% of highest 65 °C rating

Category P1-P2 Events –
AC contingency analysis (N-1) System Performance Following Loss of a Single Element (Category P1-P2) as referenced in Table 1 of NERC Standard TPL-001-4

- Voltage: 0.95 to 1.05 per unit (PRPA)
- Line Loading: 100 percent of continuous rating or emergency rating if applicable

- Transformer Loading: 100% of highest 65 °C rating

The analysis will be conducted using PTI PSS®E 33 Category P0, P1, and P2; contingency analysis will be performed with and without the approved changes and the system performance was assessed per the NERC Reliability Standards TPL-001-4. Only new violations, which include overloads above 100 percent of the system element rating, voltages below 0.95 per unit under contingency, and voltages above 1.05 per unit under contingency observed only after the addition of generation, load or new transmission, will be reported.

3. Procedure

Prior to any simulations, IDEV files were written into the PSSE/E software to expand cooperative-owned buses in the simulation. The individual loads for each cooperative were originally grouped as a single load tied to the transmission providers bus, making for an inaccurate representation of customer power distribution and loss-of-service during contingencies.

The studies were performed by the GSEC engineering group using the Siemens-PTI PSS/E computer simulation software version 33.9.0. The transmission models were developed from the models prepared by SPP. Previous planning and operational studies by GSEC, the SPP, and Southwestern Public Service (SPS) have concluded the heavy summer loading scenarios cover the most critical system conditions over the range of forecasted system demand levels. Both heavy and light load scenarios were studied for the near-term planning horizons (for the 2016, 2017, and 2018 years) and heavy load scenarios for the long-term planning horizons (for the 2021 and 2026 years) to conduct a thorough assessment for all seasons. Transmission topology and system demand were modified based on which season and year are studied; heavier loads are used in the summer and winter seasons.

SPP approved base cases were selected based on case availability where load, generation, and transmission topologies were updated as necessary. The cases include both existing and planned facilities, expected system conditions, and any effects that out-of-service equipment will have on the electric system. Normal operating procedures and the effects of all control devices and protection systems are modeled. Reactive power resources are also included in this study to ensure adequate availability to meet any system requirements.

Each of the studied cooperative's 10-year load forecast was calculated and updated in the model. GSEC uses the "high" load forecasts from each cooperative for reliability margin to reflect any uncertainties in the projected conditions. All projected firm transfers are modeled based on the data for loads, resources, obligations, and interchanges with each approved SPP base case.

Cooperative loads from each case were calculated from the SPP model and used throughout the duration of this study. SPP equivalent loads (prior to the inclusion of the cooperative buses in the SPP model) were taken from the February and June 2016 model and, in conjunction with GSEC-SCADA information, an allocation factor was determined for each cooperative substation bus load. The allocation factor was calculated by dividing the megawatt demand at each individual cooperative substation by the total megawatt load of the SPP bus. Once verified, each cooperative's substation allocation factor was multiplied by the total load on the SPP bus to determine the cooperative's adjusted load for the 16S0 case.

With the allocation factor established, the cooperative loads for the remaining cases were determined by multiplying this factor with the total bus load for the remaining cases.

Contingencies selected for system performance are Category P1 and P2, which will identify any severe system impacts in the study areas due to any single contingency; all buses and branches are monitored for criteria violations. The contingencies are simulated using the Matrix routine written for contingency analysis on the PSS/E computer simulation software. The parameters are as follows and are based off the SPP load flow criteria:

Table 1: PSSE Settings

Settings	Base Case	ACCC Case
Solutions	FDNS	ACCC
Tap Adjustment	Stepping	Stepping
Area Interchange Control	Tie Lines and Loads	Tie Lines and Loads (Disabled for Generator Outage)
VAR Limits	Apply Immediately	Apply Immediately
Phase Shift Adjustment	Yes	Yes

All buses and branches in the SPP base model are monitored for any transmission violations. The study results are reviewed and assessed for compliance with SPP and NERC standards. Planned upgrades, additions, or corrective actions needed to meet the performance requirements are included in this report.

A stability simulation will exhibit positive damping if a line defined by the peaks of the machine relative to the rotor angle swing curves tends to intersect a second line connecting the valleys of the curves with the passing of time (based on FAC-014-2 criteria). Corresponding lines on bus voltage swing curves will intersect in the same manner. A stability simulation which satisfies these conditions will be defined as stable. A case will be defined as marginally stable if it appears to have zero percent damping and voltage dips are within the SPP criteria limits.

Transient stability refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators

- Following fault clearing for Category P1 and P2 events, voltage may not dip more than 25% of the pre-fault voltage at load buses, more than 30% at non-load buses, or more than 20% for more than 20 cycles at load buses. Frequency should not dip below 59.6 Hz for 9 cycles or more at a load bus

NERC Standards require that the system remain stable and no cascading occurs for Category P1-P2 Events. Cascading is defined in the NERC Glossary as “The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.” A potential triggering event for a cascading scenario will be investigated if one of the following occurs:

- A generator pulls out of synchronism in transient stability simulations. Loss of synchronism occurs when a rotor angle swing is greater than 180 degrees. Rotor angle swings greater than 180 degrees may also be the result of a generator becoming disconnected from the system
- A transmission element experiences thermal overload and its transmission limit is exceeded

Per the current NERC TPL-001-4, results from analysis performed by SPS and SPP for the requirement **R4** did not indicate a lack of stability which would affect the cooperatives as supplied through the SPS system.

4. <u>Results</u>

The tables below give a comprehensive list of the violations found during the study, along with resolutions or recommended mitigations. Note that the contingencies listed below do not account for repeat violations. Several violations are repeated in each year and season, and mitigation is the same for each scenario. The violations are categorized into tables for each cooperative violation that occurs. A violation occurs when, following a P-1 or P-2 contingency event, the per unit voltage on any bus exceeds 1.05 p.u., or drops below 0.9 p.u. For P-0 events, the nominal bus voltage must be between 0.95 p.u. and 1.05 p.u. All the cooperative buses in this study met the P-0 criteria throughout all scenarios.

The tables below are a list of violations in each cooperative and the contingency which caused the violation. Advised mitigations are recommended based on best engineering practices, while considering any known future projects. Note that mitigations with * represent contingencies that require additional engineering work, or are in the process of being mitigated prior to this report. A more detailed explanation is given, if necessary, following each cooperative's contingency table.

4.1 BGEC Results

Table 2: Big Country Electric Cooperative Violation Report

Violated Bus	Case	High/Low Voltage	Contingency	Mitigation
526814 BG-Fluvanna2	26S0	Low	526814 BG-Fluvanna to 526821 BG-JSTBG_TP	(*) See Explanation/ Possible Mitigations
80103 BG_Union	26S0	Low	526814 BG-Fluvanna to 526821 BG-JSTBG_TP	(*) See Explanation/ Possible Mitigations

During the analysis, the only event that caused issues in the BGEC system occurred during the 526814 BG-Fluvanna to 526821 BG-JSTBG_TP contingency. The outage causes two BGEC buses (526814 and 80103) to be isolated from the system and have a voltage of 0 V; this portion of the BGEC system is entirely radial and have no means of restoring power to the two cooperative buses. Both buses are close to or within a mile of ONCOR lines, and can potentially be tied into the ERCOT grid to provide back-up power during a contingency event; this configuration was previously discussed between GSEC and BGEC. The nearby ERCOT buses are Brazos Wind Switch (18255) and the Snyder sub (1305). Both lines are 138 kV, and would require a transformer to restore the 69 kV power to the buses. At the time of this report, BGEC and GSEC have chosen not to budget this project. Depending on system loading conditions, BGEC may also be able to restore all or a portion of this load through distribution ties to adjacent substations that remain in service under this contingency.

All other contingencies that occurred in the BGEC area either did not have a major effect on the cooperative buses, or could be mitigated through normal operating procedures. These procedures require adjustments to normally open (N.O.) and normally closed (N.C.) lines to restore/maintain power service; these are considered normal operator procedures and are not included in this report.

4.2 GEC Results

Table 3: Greenbelt Electric Cooperative Violation Report

Violated Bus	Case	High/Low Voltage	Contingency	Mitigation
80901 GB-Wheeler	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80902 GB-Salt Creek	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80903 GB-Kelton	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80904 GB-Huff	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80905 GB-Huff	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80906 GB-Huff	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80907 GB-Tee Point	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80908 GB-Ft. Elliott	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797
80909 GB-Ft. Elliott	18S5	High	Wheeler XFMR Out-of-Service (523776)	Adjust Howard 115 kV Cap-523797

After analysis, it was determined that the current equipment in place is adequate for any contingencies that GEC may experience. The only potential loss-of-service contingency that any GEC bus would see is during a loss of service on the Wheeler transformer, and can be mitigated by taking the capacitor out of service on the Howard bus (523797). Additional contingencies may require adjustments to normally open (N.O.) and normally closed (N.C.) lines to restore/maintain power service, but these are considered normal operator procedures and are not included in this report.

4.3 SPEC Results

Table 4: South Plains Electric Cooperative Violation Report

Violated Bus	Case	High/Low Voltage	Contingency	Mitigation
526130 SP-Carlisle2	17S5	High	Carlisle XFMR Out-of-Service (526158)	Adjust Carlisle 69 kV Cap-526159
81831 SP-Abern_TF	18S5	Low	525731 SP-Abernathy to 525816 TUCO_INT2	(*) See Explanation/ Possible Mitigations
81830 SP-Aber Tap	18S5	Low	525731 SP-Abernathy to 525816 TUCO_INT2	(*) See Explanation/ Possible Mitigations
81829 SP-Cotton CT	18S5	Low	525731 SP-Abernathy to 525816 TUCO_INT2	(*) See Explanation/ Possible Mitigations
81828 SP-CountyLin	18S5	Low	525731 SP-Abernathy to 525816 TUCO_INT2	(*) See Explanation/ Possible Mitigations
526469/526475 Yuma XFMR	26S0	High Flow Violation	System Intact Flow Violation	(*) See Explanation/ Possible Mitigations

Upon completion of this analysis, several SPEC buses saw service disruptions because of contingency events. The only event that does not require further investigation is the Carlisle transformer contingency (230/115 kV transformer out-of-service). This event is mitigated by taking the 69 kV capacitor bank out of service (on the SPS-Carlisle bus).

During the 18S5 case, the 525731 SP-Abernathy to 525816 TUCO_INT2 contingency causes a loss-of-service to SPEC buses 81828 – 81831. To restore service, a normally open line is closed on the west side of the buses. When this happens, the 525635 Lamb_CNTY2 to 525650 LC-Lttlfld2 line (also west of the affected buses) experiences a high flow violation due to the additional load. This was shown to SPEC representatives, and determined that SPEC must shed load to keep the system intact, as well as keep the cooperative buses in-service. Upon review of SPEC owned assets, SPEC determined it would be able to transfer 4 MW of load to adjacent substations not affected by this contingency. The cooperative must determine what other load it is able to shed in order to stabilize the system if the SPS TOP requires SPEC to shed load (based off simulations, this will require an additional 4-5 MW load to be shed).

In the 26S0 case, the load at the Yuma transformer (526469 to 526475) has exceeded the maximum MVA rating (50 MVA), causing the line/transformer to overload. Rather than replace the transformer, SPEC is in the process of converting the 81807 SP-Upland load from 69 kV to the 115 kV system. This project will provide approximately 35 MW of relief for the Yuma 115/69 kV transformer. In addition to this, a N.O. line can be closed, providing service to the 81807 SP-Upland from the 81818 SP-SW-2533 bus. It is GSEC’s recommendation to continue investigating a voltage-system conversion for the Upland load. All other contingencies that can potentially affect cooperative buses can be mitigated through normal operation procedures.

4.4 Recommended Projects

Based upon the analysis discussed in Sections 4.1, 4.2, and 4.3, the following table lists the projects recommended by GSEC, and the timeframe in which these projects should be completed. These recommendations are based on discussions with the respective cooperatives, as well as best engineering decisions and information available at the time.

Table 5: GSEC Recommended Projects

Cooperative	Recommendation	Completion By
BGEC	Build a N.O. line to ERCOT lines approximately 1 mile away or transfer load to adjacent distribution substations.	Summer of 2026
SPEC	Determine the load South Plains can shed from the affected buses	Summer of 2018
SPEC	Convert the load at 81807 SP-Upland from 69 kV to 115 kV	Summer of 2026

The BGEC project that is recommended in the above table has been discussed prior to this report between the cooperative and GSEC. Further investigation into this recommendation will be done by BGEC, but the cooperative does not have this project currently budgeted. There are continuing discussions related to the recommendation in this report. The path moving forward for BGEC will be to shed load during the applicable contingency.

5. TPP Milestones

Golden Spread intends to follow the following milestones with respect to its TPP, concluding in the Final Plan contemplated by Attachment K:

Table 6: TPP Milestones

Activity	**Date**
Posting of Notice Soliciting Input	May 1, 2017
Comments Due on Notice Soliciting Input	May 31, 2017
Posting of this Plan Development Scope	June 5, 2017
Comments Due on Plan Development Scope	July 5, 2017
Studies Conducted	July 20, 2017
Draft Plan Posted	July 27, 2017
Stakeholder Meeting	August 7, 2017
Comments on Draft Plan	August 28, 2017
Final Plan Posted	September 5, 2017