===

GSEC ATTACHMENT K ANALYSIS-FINAL PLAN

STUDY # 2022-08-01

===

Golden Spread Electric Cooperative (GSEC),
for BGEC, GEC, and SPEC
August 1st, 2022

1. **Revision History**

Date of Revision	**Author**	**Change Description**	**Comments**
09/07/2022	GSEC Staff	Initial Draft	Staff Review
10/24/2022	GSEC Staff	Final Draft	No Comments Received

2. **Table of Contents**

3. List of Figures

4. List of Tables

1. **Introduction**

In accordance with Section 4.3 and 4.4 of Attachment K to Golden Spread's Open Access Transmission Tariff (OATT), Golden Spread hereby presents its 10-year Plan as part of its Transmission Planning Process (TPP). The Plan Development Scope and the studies that are used 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.

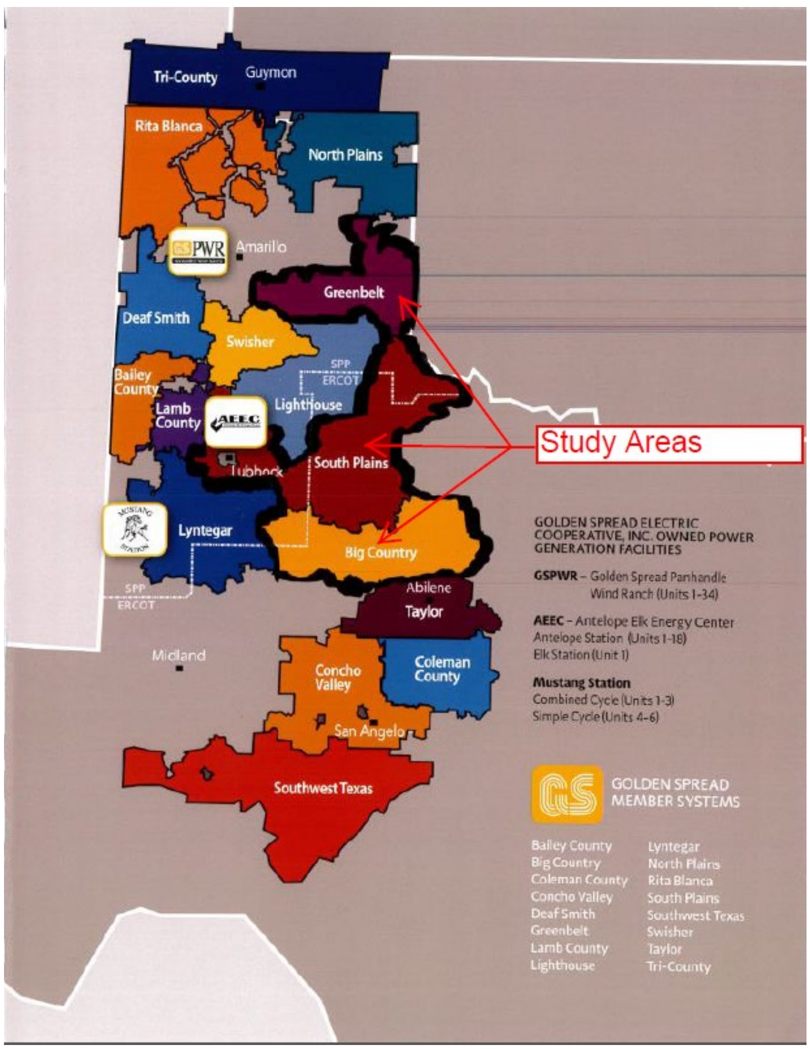

Figure 1: GSEC Service Territory with Study Area

2. Study Methodology

2.1 Study Scope

The SPEC, BCEC, 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 2022 ITP FINAL models were used to determine the effects of additional loads, generation, and transmission expected over the next ten years. The SPP 2022 ITP FINAL load flow models are the ones provided by SPP as used in their reliability studies. An ACCC contingency analysis was performed by using the software developed by Siemens PTI PSS®E v.34.9. The results of the analysis are shown in Section 3.1 of this document.

2.2 Study Process

Model Assumptions:

- 2022 ITP models with all 2021 approved upgrade projects included
  - No violations are present prior to running contingencies in the 2022 base model at the member cooperative buses
  - Model years 2022, 2023, 2024, 2027, and 2032 are studied
  - Spring, Fall, Light Load, Summer and Winter Peak Loads studied
  - Total of 17 models analyzed throughout study
-

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 was conducted using Siemens PTI PSS®E v34.9 Category P0, P1, and P2; contingency analysis was 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**

The studies were performed by the GSEC engineering group using the Siemens PTI Version PSS®E v34.9 software. The transmission models were developed from the models prepared by SPP through the annual model building process.

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.

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 were 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 would 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. Results

4.1 Potential Overload and Voltage Violations

After the analysis is complete, those buses and transmission lines that have violations due to the forecasted construction will be shown. The tables below give the format for a detailed list of the violations and the scenario for which it occurs.

4.2 BGEC Results

Table 2: Big Country Electric Cooperative Thermal Violation Report

Facility Name	Bus Number	Case	Contingency Name	Rate A (MVA)	Rate B (MVA)	Flow	Current Loading (%)
None							

Table 3: Big Country Electric Cooperative Voltage Violation Report

Facility Name	Bus Number	Case	Contingency Name	High Voltage	Low Voltage
None					

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 BG-Fluvanna and 526815 BG-Union) to be isolated from the system and have a voltage of 0 V; this portion of the BGEC system is entirely radial and has 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.

4.3 GEC Results

Table 4: Greenbelt Electric Cooperative Thermal Violation Report

Facility Name	Bus Number	Case	Contingency Name	Rate A (MVA)	Rate B (MVA)	Flow	Current Loading (%)
None							

Table 5: Greenbelt Electric Cooperative Voltage Violation Report

Facility Name	Bus Number	Case	Contingency Name	High Voltage	Low Voltage
GB-HUFF 3 115.00	523807	23G, 23S, & 24S	523776 [WHEELER 3115.00] - 523797 [HOWARD 3115.00] CKT 1	Yes	
GB-F_ELI_TP 3115.00	523808	24S	523776 [WHEELER 3115.00] - 523797 [HOWARD 3115.00] CKT 1	Yes	

After analysis, it was determined that a high voltage violation occurs at the GB-HUFF 115kV bus. This can be mitigated through adjustment of the tap changer on the GB-HUFF 115/69kV transformer. Additionally, a similar high voltage situation occurs on the GB-F_ELI-TP 115kV bus. Turning off the capacitor bank at 523772 - COBRN_CREEK3 115kV bus along with tap changer adjustments on the GB-HUFF 115/69kV transformer will mitigate this violation. All other contingencies/violations can be resolved through system adjustments and/or transmission line switching to restore electric service.

4.4 SPEC Results

Table 6: South Plains Electric Cooperative Thermal Violation Report

Facility Name	Bus Number	Case	Contingency Name	Rate A (MVA)	Rate B (MVA)	Flow	Current Loading (%)
None							

Table 7: South Plains Electric Cooperative Voltage Violation Report

Facility Name	Bus Number	Case	Contingency Name	High Voltage	Low Voltage
SP-QUAKER 3115.00	526243	22W, 23W, & 24W	526213 [ALLEN 3115.00] - 526268 [LUBBCK_STH 3115.00] CKT 1	Yes	
SP-QUAKER 269.000	526244	23W	526213 [ALLEN 3115.00] - 526268 [LUBBCK_STH 3115.00] CKT 1	Yes	
SP-FRANKFRD 3115.00	526199	23W, 24W	526213 [ALLEN 3115.00] - 526268 [LUBBCK_STH 3115.00] CKT 1	Yes	

Upon completion of this analysis, high voltage violations exist for several busses in the SPEC system. This can be mitigated through tap changer adjustments at the 230/115kV Carlisle Interchange, so no projects were proposed. Additionally, several SPEC buses saw service disruptions because of contingency events. When the 525731 SP-Abernathy to 525816 TUCO_INT2 contingency is analyzed for system impacts, there is a loss-of-service to SPEC buses 525730, 525731, 525732, 525733, and 525734. To restore service, a normally open line is closed on the west side of the buses. When this happens, there is a low voltage violation that occurs on SPEC busses 525730, 525731, 525732, 525733, and 525734. This occurs for all cases where irrigation load is particularly high. This can be mitigated by a few different potential projects. The first being through adding a 2-stage 14.4MVAR capacitor bank at the SP-Abernathy Delivery Point (DP) for use during this contingency event. No load shed or switching would be required to bring voltage back up to allowable emergency limits. Second, add a single stage 7.2MVAR capacitor bank and transfer a minimum of 4MW of load from SP-Cotton Center, SP-County Line, and SP-Abernathy to adjacent substations not affected by this contingency. Lastly, converting the SP-Cotton Center load from 69kV to 115kV transmission service would mitigation the low voltage violations when the 525731 SP-Abernathy to 525816 TUCO_INT2 line is lost, and service is restored through the N.O. point. This would require relocation of the substation with two 115kV transmission line sources within 5 miles to the east and 4 miles north. This brings the voltage up for the SP-County Line and SP-Cotton Center DPs to an acceptable limit for the cases where irrigation load is high. This was discussed with SPEC representatives and determined that SPEC would need to verify it would be able to transfer 4 MW of load to adjacent substations not affected by this contingency.

4.5 Recommended Projects

Based upon the analysis discussed in Sections 4.2, 4.3, and 4.4, 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 8: 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.	
SPEC	Transfer 4MW to adjacent subs and load shed 4-5MW of additional load	Summer 2023
SPEC	Install two stage 14.4MVAR Capacitor Bank at 525732 ABERNTHY2	Summer 2023
SPEC	Install single stage 7.2 MVAR Capacitor Bank at 525732 ABERNTHY2 and additionally transfer a minimum of 4MW of load to adjacent SPEC's substations	Summer 2023
SPEC	Convert SP-Cotton Center to 115kV Transmission service	Summer 2023

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. Further discussion with SPEC would be needed for a definitive path forward to acceptably resolve the issues identified.

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:

Activity	**Date**
Posting of Notice Soliciting Input	May 9, 2022
Comments Due on Notice Soliciting Input	June 8, 2022
Posting of this Plan Development Scope	June20, 2022
Comments Due on Plan Development Scope	July 20, 2022
Studies Conducted	August 18, 2022
Stakeholder Meeting	August 18, 2022
Draft Plan Posted	September 7, 2022
Comments on Draft Plan	October 7, 2022
Revised Plan (if necessary)	October 14, 2022
Final Plan Posted	October 24, 2022