SPP DISIS-2018-001 AFS STUDY REPORT

INTRODUCTION

Associated Electric Cooperative Inc. (AECI), through coordination with the Southwest Power Pool (SPP), has updated the Study Analysis to account for the latest Prior Queued (PQ) assumptions. These assumptions were updated for the generator interconnection requests (GIRs) within the DISIS-2018-001 Study Cycle (the "Study Cycle") for an Affected System Study (AFS) evaluation on the AECI transmission system (the "Study"). The full list of Study Cycle requests included in the Study is listed in Table 1.. The full list of Study Cycle requests included in the Study is listed in Table 1.

Table 1: Study Cycle Requests Evaluated

Project #	TO	Capacity (MW)	Service Type	Fuel Type	POI	Cluster Group
GEN-2018-015	SPS	252	ER/NR	Solar	Tuco-Oklaunion 345kV Line	05 SOUTHWEST
GEN-2018-025	OPPD	200	ER	Battery/Storage	Fort Calhoun 345kV Substation	02 NEBRASKA
GEN-2018-026	OGE	100	ER	Battery/Storage	Mustang 138kV Substation	04 SOUTHEAST
GEN-2018-027	AEP	100	ER	Battery/Storage	Tulsa Power Station 38kV Substation	04 SOUTHEAST
GEN-2018-028	AEP	200	ER	Battery/Storage	Tulsa North 138kV Substation	04 SOUTHEAST
GEN-2018-029	OGE	100	ER	Battery/Storage	Horseshoe Lake 138kV Substation	04 SOUTHEAST
GEN-2018-031	INDN	50	ER	Battery/Storage	Blue Valley 161kV Substation	03 CENTRAL
GEN-2018-032	WERE	310	ER	Wind	Neosho 345kV Substation	03 CENTRAL
GEN-2018-033	OPPD	200	ER	Battery/Storage	Cass County 345kV Substation	02 NEBRASKA
GEN-2018-037	OPPD	100	ER	Battery/Storage	Looping in OPPD (S1211) (S1220) (S1211) (S1299) 161kV	02 NEBRASKA
GEN-2018-043	OPPD	500	ER	Solar	Ft. Calhoun - Raun 345 kV Line Break	02 NEBRASKA
GEN-2018-048	OGE	300	ER	Solar	Pecan Creek 345kV Substation	04 SOUTHEAST
GEN-2018-050	AEP	200	ER	Solar	Longwood 345kV Substation	04 SOUTHEAST
GEN-2018-055	AEP	252	ER/NR	Solar	Terry Road 345kV station (shared with Rush Springs Windfarm on a common gen-tie)	04 SOUTHEAST
GEN-2018-057	WERE	203.4	ER/NR	Solar	Gordon Evans 138kV	03 CENTRAL
ASGI-2018-003	KCPL	20	ER	Solar	Appleton 69kV Substation	03 CENTRAL
ASGI-2018-006	KCPL	20	ER	Solar	Metz 69kV Substation	03 CENTRAL
ASGI-2018-007	KCPL	20	ER	Solar	Salisbury 161kV Substation	03 CENTRAL

Network upgrades from the following studies were added to models prior to the addition of the Study Cycle requests to help alleviate loadings:

- Network Upgrades from AECI GI-101/102 requests.

The Network Upgrades included from these requests are detailed in Table 6. Should these upgrades no longer be tagged to the higher queued studies, AECI may restudy the Study Cycle.

INPUTS AND ASSUMPTIONS

Each of the SERC member transmission planners is responsible for submitting system modeling data to SERC for development of the power flow models. Power flow analysis utilized the latest Long-Term Working Group (LTWG) models as developed by SERC Reliability Corporation (SERC). Each of the power flow models for the steady state analysis was modified to include appropriate higher-queued generation interconnection requests.

Modeling parameters in the SPP DISIS 2018-001 steady state models were referenced for each of the Study Cycle requests.

Full details of the inputs and assumptions are provided in Appendix A.

METHODOLOGY

Steady state analysis was performed to confirm the reliability impacts on the AECI system under a variety of system conditions and outages. AECI's transmission system must be capable of operating within the applicable normal ratings, emergency ratings, and voltage limits of AECI planning criteria. AECI is a member of SERC, one of eight Electric Reliability Organizations under the North American Electric Reliability Corporation (NERC). As a member of SERC, AECI develops its planning criteria consistent with NERC Reliability Planning Standards and the SERC planning criteria. The NERC TPL-001-5 Planning Standard Table 1 requires that, for normal and contingency conditions, line and equipment loading shall be within applicable thermal limits, voltage levels shall be maintained within applicable limits, all customer demands shall be supplied (except as noted), and stability of the network shall be maintained.

In evaluating the impacts of the Study Cycle requests, the following thermal and voltage limits were applied to the analysis for P0 or normal system conditions:

- Thermal Limits within Applicable Rating – Applicable Rating shall be defined as the Normal Rating. The thermal limit shall be 100% of Rating A.

- Voltage Limits within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage. Voltage limits shall be set at plus or minus five percent (+/- 5%), 0.95 p.u. - 1.05 p.u. for systems operating at 60 kV or above on load serving buses.

The following thermal and voltage limits were applied to the analysis for contingency conditions under P1 and P2EHV planning events:

- Thermal Limits within Applicable Rating – Applicable Rating shall be defined as the Emergency Rating. The thermal limit shall be 100% of Rating B.
- Voltage Limits within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%), 0.90 p.u. – 1.05 p.u. for systems operating at 60 kV or above on load serving buses.

In order for the Study Cycle requests to have a negative impact (i.e. criteria violation) on the system, the Study Cycle must cause a three percent (3%) or greater increase in flow on an overloaded facility based upon the rating of the facility. In order for the Project to have a negative voltage impact on the system, the Project must cause a voltage violation and have a two percent (2%) or greater change in the voltage.

System upgrades are required for constraints resulting from the addition of the Study Cycle requests under P0, P1, P2.1, P2.2 (EHV only), and P2.3 (EHV only) system conditions. For the purpose of this study, P2.1 events are included as part of the P1 contingency file. As such, these events will be denoted as a P1 event in the results. All improvements were developed and studied in coordination with AECI.

AECI will perform an annual limited operations study which will indicate seasonal operating limits for SPP/MISO/AECI generation interconnection requests that will reach commercial operation in the 12-month horizon but whose AECI network upgrades have not yet been energized.

STEADY STATE ANALYSIS RESULTS

Steady state analysis results showed three (3) constraint reported on the AECI transmission system, as shown in Table 2, which is attributed to the Study Cycle requests. Transmission upgrades were evaluated to mitigate the impacts reported from the analysis as a result of the Study Cycle requests. Simulations were performed on each of the scenarios with the identified network upgrade and contingent network upgrades included.

The upgrades shown in Table 5 were evaluated in order to mitigate the reported steady state constraints for the Study Cycle requests; results from the simulations found that the network upgrades were able to mitigate the reported overload conditions as shown in Table 2.

Table 2: Steady State Constraints for the Study Cycle Requests with Upgrades

Constraint ID	Event	Monitored Facility	Contingency	Season	Base Loading	Project Loading	Upgrade Loading
NU01	P1	301168 2MANSFL 69.000 301174 2SEYMOR 69.000 1	OPEN LINE FROM BUS 301161 [5LOGAN 161.00] TO BUS 549970 [CLAY 5161.00] CKT 1	27L	108.5	111.7	54.9
NU02	P2EHV	300045 7MORGAN 345.00 301622 5MORGANXF1 161.00 1	OPEN BRANCH FROM BUS 300042 [7HUBEN 345.00] TO BUS 300045 [7MORGAN 345.00] CKT 1 OPEN BRANCH FROM BUS 300045 [7MORGAN 345.00] TO BUS 549984 [BROOKLINE 7345.00] CKT 1	27W	101.8	106.0	63.4
				32S	95.8	100.3	59.8
				32W	104.6	109.0	65.2
NU03	P1	301123 2WSTPL3 69.000 301549 5WPLAINE 161.00 2	OPEN LINE FROM BUS 300123 [5WPLAINW 161.00] TO BUS 301123 [2WSTPL3 69.000] CKT 1	32W	94.1	110.1	78.3[1]

Table 2 shows stressed modeling conditions in which the Base Loading represents models built with higher queue generation requests in service, but without network upgrades tagged to those higher queue requests. Multiple iterations of solutions, which include higher queued network upgrades when applicable, were tested to alleviate both the Base Loading and the additional loading contributed by the Study Cycle (Project Loading). Table 2 lists facilities in which Project Loading cannot be mitigated by any applicable higher queue upgrades and in which a negative impact due to the Study Cycle is still present.

[1] Loading with transformer tap adjustment.

CONTINGENT FACILITY RESULTS

One (1) facility was reported as Contingent Facilities with the addition of the Study Cycle requests, as shown in Table 3. Contingent Facilities are those facilities identified that are the responsibility of higher-queued generators or are included in the Transmission Provider's transmission expansion plan and that if not included in the Study may otherwise be the responsibility of the Study Cycle requests as necessary to interconnect to the transmission system.

The transmission upgrades for the Contingent Facilities were evaluated in order to confirm that the planned system adjustments were sufficient to mitigate the overload seen for the addition of the Study Cycle requests. Simulations were performed on each of the scenarios with the identified network upgrade and contingent network upgrades included. The upgrades shown in Table 6 were evaluated in order to mitigate the reported constraints as listed in Table 3 below.

Table 3: Steady State Contingent Constraints for the Study Cycle Requests with Upgrades

Constraint ID	Event	Monitored Facility	Season	Base Loading	Project Loading	Upgrade Loading	Contingent Generator(s)
CF01	P1	300651 2LAMR 69.000 300794 5LAMAR 161.00 1	27S	107.5	112.4	68.9	SPP DISIS-2017-002
			27W	106.0	110.8	71.4	
			32S	107.6	111.8	68.7	
			32W	104.8	109.9	69.8	
	P2EHV		27H	95.7	100.5	62.5	
			27S	110.8	115.3	70.8	
			27W	106.6	111.4	71.8	
			32S	111.1	115.5	71.0	
			32W	105.7	110.8	70.3	

NEIGHBORING SYSTEM RESULTS

The Study has identified impacts from the Study Cycle requests on the AECI ties with neighboring systems. The most limiting component of the AECI owned portion of the facility was evaluated and if found inadequate, a network upgrade for the AECI equipment was determined. Network upgrades for transmission facilities limited by non-AECI equipment are not captured and may need to be coordinated with the appropriate transmission owner.

One (1) facility was reported on the AECI tie with the addition of the Study Cycle requests. The most severe constraints are shown in Table 4.

Table 4: Steady State Neighboring System Constraints for the Study Cycle Requests

Constraint ID	Event	Monitored Facility	Area	Season	Base Loading	Project Loading
AFS01	P1	300098 5MOCITYB2 161.00 541248 LBRTYST5 161.00 1	AECI/KCPL	27S	103.1	109.4
				27W	102.9	106.9
				32S	99.5	105.6
				32W	105.5	109.2

NETWORK UPGRADES

Transmission upgrades were evaluated to mitigate the impacts reported from the analyses as a result of the Study Cycle projects. The upgrades shown in Table 5 were evaluated in order to mitigate the reported steady state constraints for the Study Cycle as listed in Table 2.

Table 5: Network Upgrades for the Study Cycle Constraints

ID	Monitored Facility	Option/Description
NU01	301168 2MANSFL 69.000 301174 2SEYMOR 69.000 1	Rebuild Mansfield-Seymour 69 kV with 336 ACSR, 100C (10.6 miles). Upgrade terminal equipment/switches to new conductor rating.
NU02	300045 7MORGAN 345.00 301622 5MORGANXF1 161.00 1	Replace the Morgan 345/161 kV transformer with a unit rated 712 MVA Summer and 811 MVA Winter. Upgrade 161 kV breaker switchers, equipment, bus, and relay limits to 3,000 amps.
NU03	301123 2WSTPL3 69.000 301549 5WPLAINE 161.00 2	Overload reported able to be mitigated with the adjustments of transformer taps; no upgrade required.

The upgrades shown in Table 6 were evaluated in order to mitigate the reported steady state contingent constraints for the Study Cycle as listed in Table 3.

Table 6: Network Upgrades for the Study Cycle Contingent Constraints

Constraint ID	Monitored Facility	Network Upgrade
-	500 SHOALCR 161.00 300036 5ELATHRP 161.00 1	**Contingent on GI-101/102:** Construct a new 161 kV switchyard called Shoal Creek ~0.5 miles east of Rockies Express. Cut existing REX-Osborn 161 kV line in/out of new switchyard. Cut existing REX-Lathrop 161 kV line in/out of new switchyard. - Build a new 27.8 mile long 161 kV circuit between Shoal Creek and Missouri City utilizing 1192 ACSS at 200C. - Line will be overbuilt on the 69 kV line from Turney - Lathrop Load - Lathrop - Holt - Summerset - Kearney - Missouri City. The 69 kV lines will be replaced with 336 ACSR at 100C. - Add a new 161 kV terminal and reconfigure Missouri City 161 kV bus to accommodate the new 161 kV line between Missouri City and Shoal Creek. - Add second 161/69 kV transformer to Lathrop rated for 56 MVA Summer, 63 MVA Winter. Leave existing transformer in service. - Rebuild 2.2 mile long Lathrop-Lathrop East 161 kV line to 1192 ACSR at 1200C. - Upgrade jumpers at Lathrop East and Lathrop on line to 1192 ACSR. - Replace disconnect switches at Lathrop on line to 2,000 amp switches. - Rebuild 23.2 mile long Missouri City-Lathrop 161 kV line to 1192 ACSS at 200C. - Upgrade jumpers at Lathrop and Missouri City on line to 1192 ACSS at 200C. - Upgrade relay limits at Missouri City to 477 MVA Summer, 595 MVA Winter minimum. - Rebuild 12.2 mile long Osborn-Shoal Creek 161 kV line to 1192 ACSS at 200C. - Upgrade jumpers at Osborn on line to 1192 ACSS at 200C. - Replace disconnect switches at Osborn to 2,000-amp switches. - Replace bushing CTs at Osborn on line to 2,000 base amps. - Rebuild 5.2 mile long Shoal Creek-Lathrop East 161 kV line to 1192 ACSS at 200C. - Upgrade jumpers at Lathrop East on line to 1192 ACSS at 200C.
-	300036 5ELATHRP 161.00 300091 5LATHRP 161.00 1	
-	300091 5LATHRP 161.00 301563 5MOCITYB1 161.00 1	
-	300297 2HOLT 69.000 300311 2SMRSET 69.000 1	
-	300107 5OSBORN 161.00 300290 2OSBORN 69.000 1	
-	300192 2RCKWOLT 69.000 300292 2CAMERN 69.000 1	
-	300192 2RCKWOLT 69.000 300293 2CAMRNJ 69.000 1	
-	300290 2OSBORN 69.000 301629 2OSBORNTPS 69.000 1	
-	300292 2CAMERN 69.000 301629 2OSBORNTPS 69.000 1	
-	300293 2CAMRNJ 69.000 300312 2TURNEY 69.000 1	
-	300297 2HOLT 69.000 300302 2LATHRP 69.000 1	
-	300302 2LATHRP 69.000 301627 2LATHRPLD 69.000 1	
-	300312 2TURNEY 69.000 300316 2LATHRPEMG 69.000 1	

Constraint ID	Monitored Facility	Network Upgrade
-	300316 2LATHRPEMG 69.000 301627 2LATHRPLD 69.000 1	
CF01	300651 2LAMR 69.000 300794 5LAMAR 161.00 1	**Contingent on SPP DISIS-2017-002** Install a second Lamar 161/69 kV xfmr rated at 84 MVA Summer, 95 MVA Winter unit.

No upgrades were evaluated for the neighboring system constraints listed in Table 4. The upgrades for these impacts may need to be resolved through coordination with the transmission owner as listed in Table 7 below.

Table 7: Neighboring System Constraints

Constraint ID	Monitored Facility	Network Upgrade
AFS01	300098 5MOCITYB2 161.00 541248 LBRTYST5 161.00 1	KCPL owned; no upgrade evaluated.

AECI developed non-binding, good faith estimates of the timing and cost estimates for upgrades needed as a result of the addition of the Study Cycle requests as shown in Table 8.

Table 8: Network Upgrade Costs

ID	Option/Description	Estimated Cost	Estimated Lead Time (Months)[2]
NU01	Rebuild Mansfield-Seymour 69 kV with 336 ACSR, 100C (10.6 miles). Upgrade terminal equipment/switches to new conductor rating.	$6,400,000	24
NU02	Replace the Morgan 345/161 kV transformer with a unit rated 712 MVA Summer and 811 MVA Winter. Upgrade 161 kV breaker switchers, equipment, bus, and relay limits to 3,000 amps.	$14,600,000	60
NU03	Overload reported able to be mitigated with the adjustments of transformer taps; no upgrade required.	-	-
	Total Cost:	$21,000,000	

Cost allocations for each of the impacted facilities are discussed in the Cost Allocation section below.

[2] Estimated Lead Time is the estimated time to place a network upgrade in service once AECI has received Provision of Security equal to the total Estimated Cost of the Network Upgrade.

COST ALLOCATION

Network upgrade costs are allocated to each of the Study Cycle projects based on the worst MW impact[3] each project had on the constraint and as described in the steps below:

1. Determine the MW impact each Study Cycle project had on each constraint using the size of each request:

$$Project\ X\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (X) * MW\ (X) = X1$$

$$Project\ Y\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (Y) * MW\ (Y) = Y1$$

$$Project\ Z\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (Z) * MW\ (Z) = Z1$$

2. Determine the maximum MW% impact each generator has as a percentage of the total Study Cycle impact on a given constraint.

$$X2\ =\ Project\ X\ MW\ impact\ \%\ = \frac{X1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

$$Y2\ =\ Project\ Y\ MW\ impact\ \%\ = \frac{Y1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

$$Z2\ =\ Project\ Z\ MW\ impact\ \%\ = \frac{Z1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

3. Apply three percent (3%) MW impact De Minimis Threshold: If a Study Cycle project MW% impact is less than 3% for a particular constraint then the project MW% impact is adjusted to 0 for that constraint and the Study Cycle project will not be allocated cost for that particular constraint.

4. Determine the cost allocated to each remaining Study Cycle project for each upgrade using the total cost of a given upgrade:

$$Project\ X\ Upgrade\ 1\ Cost\ Allocation\ (\$) = \frac{Network\ Upgrade\ 1\ Cost\ (\$) * X2}{X2 + Y2 + Z2}$$

The associated cost allocation of the network upgrades to each of the Study Cycle projects is shown below in Table 9. Further breakdown of costs is provided in Appendix B.

[3] All negative MW impacts (helpers) were set to 0 MW impact.

Table 9: Network Upgrade Cost Allocation

Project	Cluster Group	POI	MW	Estimated Cost
ASGI-2018-003	03 CENTRAL	Appleton 69kV Substation	20	$ -
ASGI-2018-006	03 CENTRAL	Metz 69kV Substation	20	$ 290,833
ASGI-2018-007	03 CENTRAL	Salisbury 161kV Substation	20	$ -
GEN-2018-015	05 SOUTHWEST	Tuco-Oklaunion 345kV Line	252	$ 1,083,269
GEN-2018-025	02 NEBRASKA	Fort Calhoun 345kV Substation	200	$ -
GEN-2018-026	04 SOUTHEAST	Mustang 138kV Substation	100	$ -
GEN-2018-027	04 SOUTHEAST	Tulsa Power Station 38kV Substation	100	$ 424,259
GEN-2018-028	04 SOUTHEAST	Tulsa North 138kV Substation	200	$ 2,473,837
GEN-2018-029	04 SOUTHEAST	Horseshoe Lake 138kV Substation	100	$ -
GEN-2018-031	03 CENTRAL	Blue Valley 161kV Substation	50	$ -
GEN-2018-032	03 CENTRAL	Neosho 345kV Substation	310	$ 11,956,670
GEN-2018-033	02 NEBRASKA	Cass County 345kV Substation	200	$ -
GEN-2018-037	02 NEBRASKA	Looping in OPPD (S1211) (S1220) (S1211) (S1299) 161kV	100	$ -
GEN-2018-043	02 NEBRASKA	Ft. Calhoun - Raun 345 kV Line Break	500	$ -
GEN-2018-048	04 SOUTHEAST	Pecan Creek 345kV Substation	300	$ 1,200,507
GEN-2018-050	04 SOUTHEAST	Longwood 345kV Substation	200	$ -
GEN-2018-055	04 SOUTHEAST	Terry Road 345kV station (shared with Rush Springs Wind farm on a common gen-tie)	252	$ 736,778
GEN-2018-057	03 CENTRAL	Gordon Evans 138kV	203	$ 2,833,847
		Total Cost:		$ 21,000,000

VERSION HISTORY

Version Number and Date	Author	Change Description
V0 – 07/11/2023	AECI	Initial release
V1 – 06/19/2024	AECI	Withdrawal of seven (7) SPP requests from Study Cycle Withdrawal of MISO, SPP, and AECI higher queued requests
V2 – 02/06/2025	AECI	Withdrawal of MISO, SPP, and AECI higher queued requests