SPP DISIS-2016-2 AFFECTED SYSTEM STUDY REPORT

INTRODUCTION

Associated Electric Cooperative Inc. (AECI), through coordination with the Southwest Power Pool (SPP), has updated the analysis for generator interconnection requests (GIRs) within the DISIS-2016-2 Study Cycle (the "Study Cycle") for an Affected System Study (AFS) evaluation on the AECI transmission system. The restudy has been conducted to include the following updates:

- Withdraw of Study Cycle Requests:
  - GEN-2016-162
  - GEN-2016-163

The Study Cycle requests under evaluation are shown in Table 1. The results of the analysis, as well as network upgrades assigned, are included in this executive summary.

Table 1: Study Cycle Requests

Project #	TO	Capacity	Service Type	Fuel Type	POI
GEN-2016-149	WERE	302.0	ER	Wind	Stranger Creek 345kV
GEN-2016-150	WERE	302.0	ER	Wind	Stranger Creek 345kV
GEN-2016-157	KCPL	252.0	ER	Wind	West Gardner 345kV
GEN-2016-158	KCPL	252.0	ER	Wind	West Gardner 345kV
GEN-2016-174	WERE	302.0	ER	Wind	Stranger Creek 345kV
GEN-2016-176	WERE	302.0	ER	Wind	Stranger Creek 345kV
GEN-2016-091	AEP	303.6	ER	Wind	Gracemont-Lawton East Side 345kV
GEN-2016-118	OKGE	288.0	ER	Wind	Dover Switchyard 138 kV Line
GEN-2016-119	OKGE	600.0	ER	Wind	Spring Creek-Sooner 345kV
GEN-2016-128	OKGE	176.0	ER	Wind	Woodring 345kV
GEN-2016-133	AEP	187.5	ER	Wind	Riverside 345kV Substation
GEN-2016-134	AEP	187.5	ER	Wind	Riverside 345kV Substation
GEN-2016-137	AEP	187.5	ER	Wind	Riverside 345kV Substation
GEN-2016-138	AEP	187.5	ER	Wind	Riverside 345kV Substation
GEN-2016-141	AEP	350.0	ER	Wind	Riverside 345kV Substation
GEN-2016-142	AEP	350.0	ER	Wind	Riverside 345kV Substation
GEN-2016-145	AEP	175.0	ER	Wind	Riverside 345kV Substation
GEN-2016-146	AEP	175.0	ER	Wind	Riverside 345kV Substation

MODEL ASSUMPTIONS

The 2017 Series Long-Term Study Group (LTSG) models as developed by SERC Reliability Corporation (SERC) were provided by AECI as a basis for the power flow analysis. Each of the SERC member transmission planners is responsible for submitting system modeling data to SERC for development of the power flow models. Table 2 provides the models used to perform the power flow analysis for the steady state analysis.

Table 2: Study Models

Planning Horizon	Case Filename	Case Description	Case Acronym
Near-Term	LTSG22L-final.sav	2022 Light Load	2022L
	LTSG22H-final.sav	2022 Shoulder	2022H
	LTSG22S-final.sav	2022 Summer Peak	2022S
	LTSG22W-final.sav	2022 Winter	2022W
Longer-Term	LTSG27S-final.sav	2027 Summer Peak	2027S
	LTSG27W-final.sav	2027 Winter	2027W

GENERATION ASSUMPTIONS

Each of the power flow models for the steady state analysis was modified to include appropriate AECI higher-queued generation interconnection requests. Higher-queued projects from AECI's generation interconnection queue were added to the power flow analysis cases at the appropriate level of dispatch consistent with requirements for a NRIS study defined in AECI's GI Study Guidelines document as shown in Table 3.

Table 3: AECI Higher Queue Requests

Case	GIR	Type	Size (MW)	Dispatch (MW)
2022S 2027S ERIS: 10% NRIS: 100%	GI-053	NRIS	238.0	238.0
	GI-061	NRIS	242.0	242.0
2022W 2027W ERIS: 40% NRIS: 100%	GI-053	NRIS	238.0	238.0
	GI-061	NRIS	242.0	242.0
2022L ERIS: 60% NRIS: 100%	GI-053	NRIS	238.0	238.0
	GI-061	NRIS	242.0	242.0
2022H ERIS: 100% NRIS: 100%	GI-053	NRIS	238.0	238.0
	GI-061	NRIS	242.0	242.0

Existing wind generation in the AECI area, as shown in Table 4, was dispatched at its respective maximum facility outputs.

Table 4: AECI Existing Wind Dispatch

Name	Type	Size (MW)	SP, LL, SH Dispatch (MW)	WP Dispatch (MW)
Bluegrass Ridge Wind	NRIS	56.7	56.7	56.7
Cow Branch Wind	NRIS	50.4	50.4	50.4
Conception Wind	NRIS	50.4	50.4	50.4
Lost Creek Wind	NRIS	150.0*	150.0	150.0
Osage Wind	NRIS	150.0	150.0	150.0

*Generator capacity increased to 168 MW after the DISIS-2016 cluster window closed. Reference AECI GI-060

Review of the models found that the dispatch at Nodaway also needed to be updated. After discussion with AECI, the dispatch was updated, as shown in Table 5.

Table 5: Nodaway Dispatch

Scenario	Nodaway Dispatch Percentage
Winter	100%
Summer	100%
Shoulder	100%
Light Load	0%

TOPOLOGY ASSUMPTIONS

Further review of the power flow models found several modeling parameters that were not included in the models. After confirming with AECI, the cases were updated to properly reflect AECI's transmission system.

Review of the models found an erroneous load modeled at Hamburg 69 kV substation that was removed from the models. Table 6 shows the amount of load per season that was removed.

Table 6: Hamburg Load Removed

Scenario	Load
2022L	4.05 MW
2022H	7.02 MW
2022S	7.22 MW
2022W	5.62 MW

Scenario	Load
2027S	7.52 MW
2027W	5.85 MW

Review of the models found that the Linden to Hamburg 69 kV was not modeled in the 2017 Series cases. This line was added to the model, using the upgrade characteristics provided by AECI. Table 7 shows the line characteristics that were modeled.

Table 7: Hamburg-Linden Update

Line	R (pu)	X (pu)	B (pu)	MVA (SP)	MVA (WP)	Length (mi)
Hamburg - Linden 69 kV Line	0.105433	0.257405	0.004422	70	85	16.3

The power flow models used as base cases for AECI's GI-061 Facility Study were used as base cases for the AFS analysis. As a result, some higher queued case updates needed to be removed from the cases and some needed to be included.

GI-053 was included as a higher queue project for this analysis. As a result, GI-053 network upgrades were included in the models, as listed below:

- Rebuild Bethany-Pattonsburg 69 kV, 11.35 miles, utilize 336 ASCR conductor to be designed for 100ºC
- Rebuild Clyde-Stanberry 69 kV, 5.00 miles, utilize 336 ASCR conductor to be designed for 100ºC
- Uprate Rockport-Atchison 69 kV to 100ºC, 3.30 miles

GI-061 was also included as a higher queue project for this analysis. GI-061 network upgrades were incorporated into the models, as listed below.

- Rebuild Gentry-Fairport 161 kV, 9.901 miles, utilize 1192.5 ACSR conductor to be designed for 100ºC
- Rebuild Nodaway-Gentry 161 kV, 20.65 miles, utilize 1192.5 ACSR conductor to be designed for 100ºC
- Upgrade Maryville 161/69 kV transformer #1 to 56 MVA unit

- Rebuild Fairport-Darlington 69 kV, 12.5 miles, utilize 336 ACSR conductor to be designed for 100ºC
- Rebuild Darlington-Stanberry 69 kV, 10.22 miles, utilize 336 ACSR conductor to be designed for 100ºC

ANALYSIS 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-001-4 Planning Standard Table I 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 further impacts of the Study Cycle projects, 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 P1 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 projects to have a thermal impact on the system, the Study Cycle projects must cause a thermal violation and have a three percent (3%) or greater increase in flow on the facility based upon its rating.

In order for the Study Cycle projects to have a voltage impact on the system, the Study Cycle projects must cause the voltage violation and have a two percent (2%) or greater change in the voltage.

Contingency conditions were studied for all AECI and SPP member areas. Facilities in AECI's system (Area 330) were monitored against the thermal and voltage limits outlined above for the applicable event.

The NERC Reliability Standard TPL-001-4 contingency events studied are described in more detail below:

- Planning Event P0 Analysis: All transmission facilities defined in the monitored areas above were assessed with all elements in-service.

- Planning Event P1 Analysis: Analysis was performed for single loss of all transmission lines and transformers within AECI and SPP member areas.

Mitigations and system improvements for impacted facilities as a result of the Study Cycle projects were developed and studied in coordination with AECI.

ANALYSIS RESULTS

Steady state analysis showed new thermal violations on nine (9) facilities due to the addition of the Study Cycle projects as shown in Table 8. Eight (8) of these facilities are AECI owned facilities.

Table 8: Steady State Results

Monitored Facility	Zone Name	Season	Rating (MVA)	Base Loading (%MVA)	Project Loading (%MVA)
300097 5MARYVL 161.00 652560 CRESTON5 161.00 1	NW/WAPA-IA	22L	208	90.2	101.6
300120 5THMHILB1 161.00 300172 2TMHILL 69.000 2	CENTRAL	27S	150	99.3	102.4
300132 5THMHLB2 161.00 300172 2TMHILL 69.000 1	CENTRAL	27S	150	99.3	102.5
300179 2HAMBRG 69.000 300184 2NORTHB 69.000 1	NW	22H	35	98.0	103.7

Monitored Facility	Zone Name	Season	Rating (MVA)	Base Loading (%MVA)	Project Loading (%MVA)
		22S		98.6	105.3
300181 2LINDEN 69.000 300185 2PHELPS 69.000 1	NW	27S	35	92.4	100.6
300185 2PHELPS 69.000 300186 2ROCKPT 69.000 1	NW	22H	35	99.3	106.7
		22S		97.7	106.4
300387 2BEVIER 69.000 300400 2MACNLK 69.000 1	NORTHEAST	22W	51	95.6	103.6
		27W		96.1	104.2
300388 2AXTELL 69.000 300400 2MACNLK 69.000 1	NORTHEAST	22H	46	97.0	105.9
		22S		93.6	103.2
300388 2AXTELL 69.000 300401 2MACNTP 69.000 1	NORTHEAST	27S	46	97.4	107.3

- The Maryville to Creston 161 kV line was reported as a new impact in the 2022 Light Load cases for the loss of the Maryville AECI/KCPL bus tie. The Maryville to Creston line is a tie-line with KCPL and is not owned by AECI; as a result, no mitigations are required.
- The Thomas Hill 69/161 kV transformers #1 and #2 were reported as new impacts in the 2027 Summer Peak case for the loss each other. Adjusting the transformer taps mitigates these overloads; as a result, no upgrades are required.
- The Hamburg to Northboro 69 kV line was reported as a new impact in the 2022 Shoulder and 2022 Summer Peak case for the loss of the Rockport to Atchison 69 kV line.
- The Phelps to Rockport 69 kV line was reported as a new impact in the 2022 Shoulder case as well as the 2022 Summer Peak case for the loss of the Hamburg to Northboro 69 kV line.
- The Linden to Phelps 69 kV line was reported as a new impact in the 2027 Summer Peak case for the loss of the Hamburg to Northboro 69 kV line.
- The Bevier to Macon Lake 69 kV line was reported as a new impact in the 2022 and 2027 Winter cases for the loss of the Thomas Hill to McCredie 345 kV line.
- The Macon Lake to Axtell to Macon Tap 69 kV line was reported as a new impact in the 2022 Shoulder, as well as the 2022 and 2027 Summer Peak cases, for the loss of the Thomas Hill to Adair 161 kV line.

MITIGATIONS

Transmission upgrades were evaluated to mitigate the impacts reported from the analyses as a result of the Study Cycle projects. The following upgrades were evaluated in order to mitigate the reported overloads.

- Rebuild the 18-mile-long Hamburg to Northboro 69 kV line to 336 ACSR.
- Rebuild the 4.4-mile-long Phelps to Rockport 69 kV line to 336 ACSR.
- Rebuild the 11.4-mile-long Linden to Phelps 69 kV line to 336 ACSR.
- Rebuild the 4.136-mile-long Bevier to Macon Lake 69 kV line to 477 ACSR.
- Rebuild the 2.2-mile-long Macon Lake to Axtell to Macon Tap 69 kV line to 477 ACSR.

Simulations were performed on each of the scenarios with the identified network upgrade included. Results from the simulations found that the network upgrades were able to mitigate the reported overload conditions as shown in Table 9.

Table 9: Steady State Results with Upgrades

Monitored Facility	Zone Name	Season	Rating (MVA)	Base Loading (%MVA)	Project Loading (%MVA)	Upgrades Loading (%MVA)
300179 2HAMBRG 69.000 300184 2NORTHB 69.000 1	NW	22H	70	98.0	103.7	54.8
		22S		98.6	105.3	55.6
300181 2LINDEN 69.000 300185 2PHELPS 69.000 1	NW	27S	70	92.4	100.6	52.8
300185 2PHELPS 69.000 300186 2ROCKPT 69.000 1	NW	22H	70	99.3	106.7	55.4
		22S		97.7	106.4	55.3
300387 2BEVIER 69.000 300400 2MACNLK 69.000 1	NORTHEAST	22W	107	95.6	103.6	51.1
		27W		96.1	104.2	51.4
300388 2AXTELL 69.000 300400 2MACNLK 69.000 1	NORTHEAST	22H	88	97.0	105.9	58.0
		22S		93.6	103.2	56.5
300388 2AXTELL 69.000 300401 2MACNTP 69.000 1	NORTHEAST	27S	88	97.4	107.3	59.2

No additional constraints were reported with the inclusion of the identified upgrade. As a result, no additional upgrades were identified for the Study Cycle projects from steady state analysis.

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

COST ALLOCATION

Network upgrade costs were allocated to each of the Study Cycle projects based on the MW impact each project had on the constraint under the conditions reported 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 cost allocated to each Study Cycle project for each upgrade using the total cost of a given upgrade:

$$Project\ X\ Upgrade\ 1\ Cost\ Allocation\ (\$) = \frac{Network\ Upgrade\ 1\ Cost\ (\$) * X1}{X1 + Y1 + Z1}$$

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 projects as shown in Table 10.

Table 10: Network Upgrade Costs

ID	Option / Description		Cost*
1	Rebuild the 18-mile-long Hamburg to Northboro 69 kV line to 336 ACSR		$7,434,000
2	Rebuild the 4.4-mile-long Phelps to Rockport 69 kV line to 336 ACSR		$1,817,000
3	Rebuild the 11.4-mile-long Linden to Phelps 69 kV line to 336 ACSR		$4,708,000
4	Rebuild the 4.136-mile-long Bevier to Macon Lake 69 kV line to 477 ACSR		$2,938,000
5	Rebuild the 2.2-mile-long Macon Lake to Axtell to Macon Tap 69 kV line to 477 ACSR		$1,562,000
	*Includes engineering and contingencies	Total Cost:	$18,459,000

The associated cost allocation of the network upgrades to each of the Study Cycle projects is provided below.

Study Cycle Project	POI	MW	Cost Allocation per Upgrade ID ($) 1	2	3	4	5	Total Cost
GEN-2016-091	Gracemont-Lawton East Side 345kV	303.6	$200,509	$49,403	$133,953	$92,767	$50,000	**$526,632**
GEN-2016-118	Dover Switchyard 138 kV Line	288	$217,486	$53,114	$148,248	$104,762	$54,457	**$578,068**
GEN-2016-119	Spring Creek-Sooner 345kV	600	$482,407	$117,162	$326,499	$232,805	$120,772	**$1,279,646**
GEN-2016-128	Woodring 345kV	176	$143,684	$35,322	$98,362	$69,143	$34,890	**$381,401**
GEN-2016-133	Riverside 345kV Substation	187.5	$149,246	$36,613	$99,273	$74,570	$42,888	**$402,591**
GEN-2016-134	Riverside 345kV Substation	187.5	$149,246	$36,613	$99,273	$74,570	$42,888	**$402,591**
GEN-2016-137	Riverside 345kV Substation	187.5	$149,246	$36,613	$99,273	$74,570	$42,888	**$402,591**
GEN-2016-138	Riverside 345kV Substation	187.5	$149,246	$36,613	$99,273	$74,570	$42,888	**$402,591**
GEN-2016-141	Riverside 345kV Substation	350	$278,593	$68,345	$185,310	$139,198	$80,057	**$751,503**
GEN-2016-142	Riverside 345kV Substation	350	$278,593	$68,345	$185,310	$139,198	$80,057	**$751,503**
GEN-2016-145	Riverside 345kV Substation	175	$139,296	$34,172	$92,655	$69,599	$40,029	**$375,752**
GEN-2016-146	Riverside 345kV Substation	175	$139,296	$34,172	$92,655	$69,599	$40,029	**$375,752**
GEN-2016-149	Stranger Creek 345kV	302	$938,128	$228,419	$572,962	$292,954	$150,688	**$2,183,151**
GEN-2016-150	Stranger Creek 345kV	302	$938,128	$228,419	$572,962	$292,954	$150,688	**$2,183,151**
GEN-2016-174	Stranger Creek 345kV	302	$938,128	$228,419	$572,962	$292,954	$150,688	**$2,183,151**
GEN-2016-176	Stranger Creek 345kV	302	$938,128	$228,419	$572,962	$292,954	$150,688	**$2,183,151**
GEN-2016-157	West Gardner 345kV	252	$602,319	$148,417	$378,033	$275,415	$143,702	**$1,547,887**
GEN-2016-158	West Gardner 345kV	252	$602,319	$148,417	$378,033	$275,415	$143,702	**$1,547,887**
Total Cost		**4879.6**	**$7,434,000**	**$1,817,000**	**$4,708,000**	**$2,938,000**	**$1,562,000**	**$18,459,000**