SPP Definitive Affected System Impact Study for AECI Requests GIA-68 through GIA-91

Southwest Power Pool, Inc.

AFS Study

Project No. 133518

05/11/2022

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prepared for

Southwest Power Pool, Inc.
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0	Draft Issued for Review	10/08/2021
1	Final Issued for Release	11/08/2021
2	Final Report Updated from Preliminary to Definitive	05/11/2022

1.0 EXECUTIVE SUMMARY

Burns & McDonnell was retained by the Southwest Power Pool (SPP) to perform an Affected System Impact Study (ASIS) for ten (10) generation interconnection requests residing in neighboring system Associated Electric Cooperative Inc.'s generation interconnection queue (the "Study"). At this time, the Study only considered steady state analysis. The list of interconnection requests and their associated attributes for the purpose of the Study are provided in Table 1-1.

Table 1-1: AECI Study Units

Request	Study	Group	Type	Service	Status	Point of Interconnection	Requested Amount (MW)
GIA-68	DIS-17-2-PQ	12	Solar	ER/NR	GIA	Blackberry 345 kV	200
GIA-77	DIS-17-2-PQ	8	Gas	ER/NR	GIA	Chouteau 161 kV	50
GIA-78	DIS-17-2-PQ	8	Gas	ER/NR	GIA	Chouteau 161 kV	52
GIA-83	DIS-17-2-PQ	13	Wind	ER/NR	FS	McCredie 345 kV	1018
GIA-84	DIS-17-2-PQ	12	Solar	ER Only	FS	New Madrid 345 kV	196
GIA-85	DIS-17-2-PQ	12	Solar + Storage	ER/NR	FS	Morgan 345 kV	436
GIA-86	DIS-17-2-PQ	13	Solar	ER/NR	FS	Thomas Hill 69 kV	100
GIA-88	DIS-17-2-PQ	12	Solar	ER/NR	FS	Eudora 69 kV	86.5
GIA-90	DIS-17-2-PQ	13	Solar	ER/NR	SIS	Montgomery City 161 kV	100
GIA-91	DIS-17-2-PQ	13	Solar	ER/NR	SIS	Sedalia 69 kV	96

The study units were studied in sequential order starting with GIA-68 as the first study unit and GIA-91 as the last study unit. The purpose of the analysis was to determine the impacts of each study unit, on an independent basis, to the SPP transmission system. The study units were not studied as a cluster.

SPP was notified by AECI near the completion of the Study that study unit GIA-68 has withdrawn from the AECI interconnection queue. The withdraw of GIA-68 was deemed not material to the results of the lower queue study units within this Study, as such, the Study models and results presented herein remain to reflect the inclusion of GIA-68.

The Study has been conducted consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP-AECI Joint Operating Agreement (JOA) and SPP Business Practices to determine impacts to the SPP transmission system.

As the DISIS-2017-001 cluster is currently in Phase 2, SPP will consider the AECI study interconnection requests queued between the DISIS-2017-001 and DISIS-2017-002 clusters. More specifically, SPP will consider these requests lower queued to the MISO DPP-2017-AUG cluster and higher queued to the DISIS-2017-002 cluster. If these requests are later considered lower queued to the DISIS-2017-002 as a result of a transition plan between SPP and AECI for queue priority, a restudy of some or all AECI requests may be required.

1.1 Steady State Analysis Results

A power flow analysis was performed to evaluate the impact of the study units to the SPP transmission system. SPP's transmission system was evaluated if it was capable of operating within the normal ratings, emergency ratings, and voltage limits of applicable regional and local planning criteria. All higher queue requests and associated network upgrades to the study units were included in the Study. The additional inclusions and updates made to the Study are captured in Section 2.0.

Steady state analysis in the SPP transmission system resulted in criteria violations under the study conditions and events for GIA-85 and GIA-88. The transmission system elements that showed criteria violations did not require system reinforcement due to network upgrades already planned, update to the power flow models, or applicable operating guides. Table 1-2 shows the study units and their respective SPP network upgrade cost based on the Study.

Table 1-2: SPP Network Upgrade Cost Estimate

Request	Group	Type	Service	Point of Interconnection	SPP NU Cost Estimate
GIA-68	12	Solar	ER/NR	Blackberry 345 kV	$ 0
GIA-77	8	Gas	ER/NR	Chouteau 161 kV	$ 0
GIA-78	8	Gas	ER/NR	Chouteau 161 kV	$ 0
GIA-83	13	Wind	ER/NR	McCredie 345 kV	$ 0
GIA-84	12	Solar	ER Only	New Madrid 345 kV	$ 0
GIA-85	12	Solar + Storage	ER/NR	Morgan 345 kV	$ 0
GIA-86	13	Solar	ER/NR	Thomas Hill 69 kV	$ 0
GIA-88	12	Solar	ER/NR	Eudora 69 kV	$ 0
GIA-90	13	Solar	ER/NR	Montgomery City 161 kV	$ 0
GIA-91	13	Solar	ER/NR	Sedalia 69 kV	$ 0

1.2 Limitations

In the preparation of this report, the information provided to Burns & McDonnell by others was used by Burns & McDonnell to make certain assumptions with respect to conditions which may exist in the future. While Burns & McDonnell believes the assumptions made are reasonable for the purposes of this report, Burns & McDonnell makes no representation that the conditions assumed will, in fact, occur. In addition, while Burns & McDonnell has no reason to believe that the information provided by others, and on which this report is based, is inaccurate in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to Burns & McDonnell, the actual results will vary from those presented.

2.0 BASE MODEL ASSUMPTIONS

2.1 BASE Cases

BASE cases represent the starting topology of the Study models, but not necessarily the dispatch of the Study models. The topology foundation of the Study models was the MISO AUG17-West ASIS, as provided by SPP, which was built from the 2019 ITP model set. As such, the BASE cases may contain higher queued network upgrades which may have not yet been issued an NTC. Any absent queue generator, including the study units, were added to the BASE cases. For the Study, four BASE cases with different seasonal dispatches and load levels were utilized for power flow analysis as listed in the Table 2-1.

Table 2-1: BASE Case Models

Base Case Year	Season/Condition
Year 2 (2020)	Summer
Year 5 (2024)	Light Load
Year 5 (2024)	Summer
Year 5 (2024)	Winter

2.2 AECI Study Units

Each study unit and its associated topology were obtained from the AECI generation interconnection study models, as provided by AECI. Table 2-2 lists the AECI study units that were added to the BASE cases. The study units were left offline in the BASE cases.

Table 2-2: AECI Study Units – Point of Interconnection

Request	Group	Type	Point of Interconnection
GIA-68	12	Solar	Blackberry 345 kV
GIA-77	8	Gas	Chouteau 161 kV
GIA-78	8	Gas	Chouteau 161 kV
GIA-83	13	Wind	McCredie 345 kV
GIA-84	12	Solar	New Madrid 345 kV
GIA-85	12	Solar + Storage	Morgan 345 kV
GIA-86	13	Solar	Thomas Hill 69 kV
GIA-88	12	Solar	Eudora 69 kV
GIA-90	13	Solar	Montgomery City 161 kV
GIA-91	13	Solar	Sedalia 69 kV

Study unit GIA-68 has withdrawn from the AECI interconnection queue, but the topology of GIA-68 remains in the cases. The impact of the GIA-68 withdraw was found to not be material on lower queue study units evaluated in this Study.

Dispatch of appropriate higher queue units is done in the Base Case (BC) setup whereas dispatch of appropriate study units is done in the Transfer Case (TC) setup. Both dispatch setups are described further in Section 3.0.

2.3 Topology Assumptions

Through coordination with SPP, the BASE cases were modified to reflect the most recent topology based on status of higher queue units, higher queue assigned network upgrades, and topology comparisons to the AECI reference case for the AECI system.

Conventional generators in the BASE cases within the SPP footprint that are not higher queue generators are considered Legacy units. The Legacy units are shown in Appendix B.

2.3.1 Higher Queue Requests

The status of the higher queue generators in SPP, MISO and AECI generation interconnection queues were referenced to update the BASE cases with the latest topology. Topology of withdrawn units were purged from the BASE cases and the contingency definitions for analysis updated appropriately. Generators that are not considered Legacy units or higher queue generators were assumed as withdrawn from their respective interconnection queue and purged from the BASE model. The higher queue generators and study units in the BASE cases are shown in Appendix C.

2.3.2 Higher Queue Assigned Network Upgrades

Network upgrades assigned to the higher queue generators were added or removed from the BASE cases based on the status of the generator in the interconnection queue and results from most recently completed analysis at the time of the Study. Higher queue network upgrades were modeled up to and including MISO DPP-2017-AUG study cycle. All the prior queue network upgrades added, modified, or deleted from the BASE cases are shown in Appendix D

The following DIS-17-1-PQ network upgrades assigned to GIA-61 were added to the BASE cases:

- Reconductor Maryville to Creston 161 kV line
- Rebuild Maryville to Bradyville 161 kV line
- Upgrade Maryville to Maryville 161 kV bus-tie
- Rebuild Maryville to Midway 161 kV line
- Rebuild Midway to Avenue City 161 kV line
- Rebuild Avenue City to St. Joseph 161 kV line
- Add second Nashua 345/161 kV transformer
- Rebuild Nashua to Roanridge 161 kV line

The DIS-17-2-PQ network upgrades and contingent upgrades assigned from MISO DPP-2017-AUG-West Phase III were included in the BASE cases. The following DIS-17-2-PQ network upgrades were added to the BASE cases:

- Build second Grand Forks 230/115 kV transformer
- Rebuild Split Rock – White 345 kV line
- Upgrade Split Rock 345 kV terminal equipment
- Rebuild Holt – Grand Prairie 345 kV line
- Rebuild Fort Thompson – Fort Randall 230 kV line #1
- Rebuild Fort Thompson – Lake Platte 230 kV line #1

The following DIS-16-2 network upgrades that were previously assigned were removed from the BASE cases as they are no longer applicable:

- Generator 2016-100 tap to Arcadia 345 kV line
- Riverside – Sapulpa 345 kV line #2
- Viola 345/230 kV transformer #2
- Keystone – Red Willow 345 kV line
- Post Rock – Red Willow 345 kV line.
- Antelope – Holt 345 kV line
- Replace Ft. Thompson 345/230 Transformer #1
- Replace Ft. Thompson 345/230 Transformer #2

The following AECI network upgrades assigned to DIS-16-2 study units were also added to the BASE cases:

- Rebuild Bevier – Macon Lake 69 kV line
- Rebuild Macon Lake – Axtell 69 kV line
- Rebuild Hamburg – Northboro 69 kV line
- Rebuild Linden – Phelps 69 kV line
- Upgrade Neosho – Sweetwater 69 kV line
- Rebuild Phelps – Rockport 69 kV line
- Add series reactor on Washburn – Seligman 69 kV line

2.3.3 AECI Model Comparison

The AECI transmission system as reflected in the BASE cases was compared to a set of reference AECI generation interconnection study cases, as provided by AECI. Topology differences were identified and discussed with both SPP and AECI. For any impedance differences greater than 5% threshold between the BASE cases and AECI cases, the impedance for the facility modeled in the AECI cases was applied to the BASE models. No dispatch adjustments were made to AECI generators in the BASE models. The following approved AECI model topology updates were captured in the BASE cases.

- Update McCredie 345 kV topology to reflect 4 breaker ring – consolidation from two McCredie 345 kV buses to a single McCredie 345 kV bus
- Add Wright 345 kV bus, tapping the Labadie – Montgomery 345 kV line, new 345/161 kV transformer at Wright.
- Remove Mill Creek 161 kV and connected branches
- Add Clever 161/69 kV substation
- Close in bus tie on the St. Francis 161 kV bus as the units are no longer split between 161 kV and 345 kV systems
- Update the topology changes around the Kingdom City 69 kV bus
- Delete Enon 345/161 kV transformer #2 (duplication)

3.0 BC & TC CASE BUILD

The updated BASE models from Section 2.0 were utilized to create the Base Case (BC) and Transfer Case (TC) for each of the study units. The BC cases have higher queued generators dispatched up to, but not including the generator that is studied. The TC cases have the higher queued and applicable study unit(s) dispatched. The list of AECI study units and their associated attributes for the purpose of the Study are shown in Table 3-1.

Table 3-1: Study Units Dispatch

Request	Group	Type	Study Type	ERIS Dispatch			NRIS Dispatch		
				LL P_{MAX}	SP P_{MAX}	WP P_{MAX}	LL P_{MAX}	SP P_{MAX}	WP P_{MAX}
GIA-68	12	Solar	HVER/NRIS	200	200	200	200	200	200
GIA-77	8	Gas	LVER/NRIS	50	50	50	50	50	50
GIA-78	8	Gas	LVER/NRIS	52	52	52	52	52	52
GIA-83	13	Wind	HVER/NRIS	1018	1018	1018	1018	1018	1018
GIA-84	12	Solar	HVER	196	196	196	0	0	0
GIA-85	12	Solar + Storage	HVER/NRIS	436	436	436	436	436	436
GIA-86	13	Solar	HVER/NRIS	100	100	100	100	100	100
GIA-88	12	Solar	HVER/NRIS	86.5	86.5	86.5	86.5	86.5	86.5
GIA-90	13	Solar	HVER/NRIS	100	100	100	100	100	100
GIA-91	13	Solar	HVER/NRIS	96	96	96	96	96	96

3.1 AECI Assigned Network Upgrades

The network upgrades assigned to the study units through the AECI interconnection study process, at the time this Study was conducted, were included for the purpose of the analysis. These network upgrades were added to the applicable BC or TC power flow models for each of the study generators following queue priority. For instance, if a network upgrade is assigned to GIA-83, the GIA-83 network upgrades will not be included in the BC and TC cases created for the higher queue generators (GIA-68, GIA-77, GIA-78), and the BC cases for GIA-83. The network upgrades will be included in the TC cases for GI-83, and the BC and TC cases for the lower queue generators.

No AECI network upgrades were assigned to GIA-68, GIA-77, GIA-78, and GIA-90.

The AECI network upgrades for the remaining study units are listed below. The modeling information for each network upgrade was provided by AECI.

3.1.1 GIA-83 AECI Network Upgrades

The AECI network upgrades assigned to GIA-83 are listed below:

- Rebuild Kingdom City – Williamsburg 161 kV line
- Rebuild Williamsburg – Montgomery City 161 kV line

- Upgrade Kingdom City 161/69 kV transformers #2 and #3
- Rebuild Reform-Chamois 69 kV line segment
- Upgrade Thomas Hill 345/161 kV transformer #4
- Thomas Hill – Bevier area upgrades:
  - Move Thomas Hill – Meadville 161 kV line to Thomas Hill Bus #3
  - Move Thomas Hill – Salisbury 161 kV line to Thomas Hill Bus #4
  - Add Thomas Hill Bus #2 – Bevier 161 kV line
  - Add Bevier 161/69 kV transformer rated for 112/127 MVA
  - Remove Thomas Hill – Bevier 69 kV line

3.1.2 GIA-84 AECI Network Upgrades

The AECI network upgrades assigned to GIA-84 are listed below:

- Rebuild Green Forest – St. Francis 161 kV line.
- Rebuild Harviell – Poplar Bluff South 69 kV line.

3.1.3 GIA-85 AECI Network Upgrades

The AECI network upgrades assigned to GIA-85 are list below:

- Rebuild Brushcreek – Lebanon 69 kV line.
- Rebuild Mansfield – Seumour 69 kV line.
- Reconfigure the Morgan 345 kV substation and associated update to the P2 EHV contingency

3.1.4 GIA-86 AECI Network Upgrades

The AECI network upgrades assigned to GIA-86 are listed below:

- Upgrade Thomas Hill – Salisbury 161 kV line (changes if GIA-83 withdraws).
- Upgrade Milan – Unionville 69 kV line, included initially but was later dropped from the GIA-86 analysis.

3.1.5 GIA-88 AECI Network Upgrades

The AECI network upgrades assigned to GIA-88 are listed below:

- Rebuild Eudora – Morgan 69 kV line.
- Rebuild Eudora – Slagle 69 kV line.

3.1.6 GIA-91 AECI Network Upgrades

The AECI network upgrades assigned to GIA-91 are listed below:

- Rebuild Knobby - Turkey Creek 69 kV line.

3.2 Generation Classification

Generation fuel types determine the category in which the generator is assigned, which in turn dictates the dispatch percentage for the scenarios developed for the Study. Table 3-2 captures the category in which each generation type is assigned.

Table 3-2: Generation Type-Category Assignment

Generation Type	Generation Category
CC	Conventional
Coal	Conventional
Combined Cycle	Conventional
CT	Conventional
CT/ST	Conventional
Diesel	Conventional
Diesel CT	Conventional
Gas	Conventional
Gas Turbine	Conventional
Heat	Conventional
NG CT	Conventional
Retired Coal	Conventional
Steam	Conventional
Steam Turbine	Conventional
Thermal	Conventional
Waste Heat Recovery	Conventional
Battery	Renewable
Biomass	Conventional
Hydro	Conventional
Solar	Renewable
Wind	Renewable

From each BC case developed for the affected Regional Groups for this Study (Group 8, 12, and 13), AECI study units are added to the models in a sequential order and dispatched consistent with the SPP generation dispatch for power flow models defined in Table 3-4. The sequence and assignment of In Group (IG) and Out of Group (OG) for each of the study units is outlined in Table 3-3.

Table 3-3: Study Unit Sequence and Group Assignment

Study/TC	Gen Category	Group	BC			
			IG Renew	IG Conv	OG Renew	OG Conv
GIA-68	Renewable	12	-	-	-	-
GIA-77	Conventional	8	-	-	68	-
GIA-78	Conventional	8	-	77	68	-
GIA-83	Renewable	13	-	-	68	77, 78
GIA-84	Renewable	12	68	-	68, 83	77, 78
GIA-85	Renewable	12	68, 84	-	68, 83	77, 78
GIA-86	Renewable	13	83	-	68, 84, 85	77, 78
GIA-88	Renewable	12	68, 84, 85	-	83, 86	77, 78
GIA-90	Renewable	13	83, 86	-	68, 84, 85, 88	77, 78
GIA-91	Renewable	13	83, 86, 90	-	68, 84, 85, 88	77, 78

3.3 Higher Queue Generation Dispatch

In order to dispatch the higher queued generation and study units, three main scenarios are utilized:

- **High Variable Energy Resource (HVER)** – Renewable VERs are dispatched at maximum capability while conventional resources are let as-is or backed down to balance generation.
- **Low Variable Energy Resource (LVER)** – Conventional resources are dispatched at maximum capability while renewable VERs are dispatched at low capability.
- **Network Resource (NR)** – The conventional resources and renewable VERs dispatch levels vary depending upon the level of system integration being sought out by the generation facility. There are two sub-categories within the NR dispatch scenario:
  - Energy Resource Interconnection service (ERIS)
  - Network Resource Interconnection Service (NRIS)

Table 3-4 captures the dispatch methodology used for different study scenarios.

Table 3-4: Generation Dispatch Scenarios

Dispatch Type	Season	Service Type	Renewable in group	Renewable out of group	Conventional in group	Conventional out of group
ERIS HVER	Peak	All	100%	20%	0%*	0%*
	Light Load	All	100%	0%*	0%*	0%*
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Light Load	NRIS	100%	20%	100%	20%
	Peak	NRIS	100%	100%	100%	100%

* If Pgen of existing units in ITP model > expected GI fuel type dispatch, units are not adjusted. However, units may be included in scaling for sinking generation adjustments per dispatch procedures.

The higher queued generators in SPP, MISO, and AECI, and study generators in AECI are dispatched according to the dispatch scenarios outlined in the following subsections.

3.3.1 HVER Dispatch

For the HVER dispatch scenario, all renewable generation facilities are dispatched to 100% that are assigned to the same respective regional study group. For the light load scenario only, generators outside of the respective regional study group are left at 0% if the unit was offline or left as-is if online/dispatched. For the Peak scenarios, the generators outside of the respective regional study group are dispatched to 20%. The HVER dispatch assumptions are captured in Table 3-5.

Table 3-5: HVER Dispatch Assumptions

Dispatch Scenario	Season	Service	Group Status	Generation Category	Generator Dispatch
HVER	WP	ER	In	Renewable	100%
HVER	WP	ER/NR	In	Renewable	100%
HVER	WP	ER	In	Conventional	0%
HVER	WP	ER/NR	In	Conventional	0%
HVER	WP	ER	Out	Renewable	20%
HVER	WP	ER/NR	Out	Renewable	20%
HVER	WP	ER	Out	Conventional	0%
HVER	WP	ER/NR	Out	Conventional	0%
HVER	SP	ER	In	Renewable	100%
HVER	SP	ER/NR	In	Renewable	100%
HVER	SP	ER	In	Conventional	0%
HVER	SP	ER/NR	In	Conventional	0%
HVER	SP	ER	Out	Renewable	20%
HVER	SP	ER/NR	Out	Renewable	20%
HVER	SP	ER	Out	Conventional	0%
HVER	SP	ER/NR	Out	Conventional	0%
HVER	L	ER	In	Renewable	100%
HVER	L	ER/NR	In	Renewable	100%
HVER	L	ER	In	Conventional	0%
HVER	L	ER/NR	In	Conventional	0%
HVER	L	ER	Out	Renewable	0%
HVER	L	ER/NR	Out	Renewable	0%
HVER	L	ER	Out	Conventional	0%
HVER	L	ER/NR	Out	Conventional	0%

3.3.2 LVER Dispatch

For the LVER dispatch scenario, all conventional generation facilities are dispatched to 100% and all renewable generation facilities are dispatched to 20%. The LVER dispatch scenario is utilized on all

Winter and Summer BASE cases, but only used if there is a conventional resource in the study cluster. The LVER dispatch assumptions are captured in Table 3-6.

Table 3-6: LVER Dispatch Assumptions

Dispatch Scenario	Season	Service	Group Status	Generation Category	Generator Dispatch
LVER	WP	ER	In	Renewable	20%
LVER	WP	ER/NR	In	Renewable	20%
LVER	WP	ER	In	Conventional	100%
LVER	WP	ER/NR	In	Conventional	100%
LVER	WP	ER	Out	Renewable	20%
LVER	WP	ER/NR	Out	Renewable	20%
LVER	WP	ER	Out	Conventional	100%
LVER	WP	ER/NR	Out	Conventional	100%
LVER	SP	ER	In	Renewable	20%
LVER	SP	ER/NR	In	Renewable	20%
LVER	SP	ER	In	Conventional	100%
LVER	SP	ER/NR	In	Conventional	100%
LVER	SP	ER	Out	Renewable	20%
LVER	SP	ER/NR	Out	Renewable	20%
LVER	SP	ER	Out	Conventional	100%
LVER	SP	ER/NR	Out	Conventional	100%

3.3.3 NR Dispatch

For the NR dispatch scenario, the dispatch levels for the renewable and conventional generation facilities are determined based upon the type of system integration being requested (ERIS & NRIS). For Light Load, dispatches are group based. For Winter and Summer, all generators are considered “in-group” for the study (similar to the LVER dispatch scenario). It should be noted that the NRIS dispatch respects MISO’s allowance of partial NRIS, where only the NRIS amount is dispatched in the NRIS dispatch scenarios. The NR dispatch assumptions are captured in Table 3-7.

Table 3-7: NR Dispatch Assumptions

Dispatch Scenario	Season	Service	Group Status	Generation Category	Generator Dispatch
NR	L	ER	In	Renewable	0%
NR	L	ER/NR	In	Renewable	100%
NR	L	ER	In	Conventional	0%
NR	L	ER/NR	In	Conventional	100%
NR	L	ER	Out	Renewable	0%
NR	L	ER/NR	Out	Renewable	20%
NR	L	ER	Out	Conventional	0%
NR	L	ER/NR	Out	Conventional	20%

Dispatch Scenario	Season	Service	Group Status	Generation Category	Generator Dispatch
NR	WP	ER	In	Renewable	0%
NR	WP	ER/NR	In	Renewable	100%
NR	WP	ER	In	Conventional	0%
NR	WP	ER/NR	In	Conventional	100%
NR	WP	ER	Out	Renewable	0%
NR	WP	ER/NR	Out	Renewable	100%
NR	WP	ER	Out	Conventional	0%
NR	WP	ER/NR	Out	Conventional	100%
NR	SP	ER	In	Renewable	0%
NR	SP	ER/NR	In	Renewable	100%
NR	SP	ER	In	Conventional	0%
NR	SP	ER/NR	In	Conventional	100%
NR	SP	ER	Out	Renewable	0%
NR	SP	ER/NR	Out	Renewable	100%
NR	SP	ER	Out	Conventional	0%
NR	SP	ER/NR	Out	Conventional	100%

3.4 Higher Queue Generation Dispatch Offset

3.4.1 SPP Units

SPP uses a Load Ratio Share methodology to make generation adjustments for the Legacy units. Load Ratio Share is the ratio of a transmission customer's network load to the total load of the SPP system. For dispatching higher queued generators, the Load Ratio Share determines the proportion of Legacy generation adjustment for each individual area within the SPP system.

The total amount of SPP generation adjustments is displaced against non-nuclear Legacy resource reserves (Pgen-Pmin). In all cases, Legacy units remained online. For each SPP area, the amount to offset will be determined based on the Load Ratio Share for the individual area.

3.4.2 MISO Units

The total amount of MISO higher queue generation adjustments is displaced against non-nuclear MISO Classic region generation reserves (Pgen-Pmin) using an area scaling (uniform) approach while respecting machine limits.

3.4.3 AECI Units

The total amount of AECI higher queue generation and study unit adjustments is displaced against non-nuclear generation reserves (Pgen-Pmin) using an area scaling (uniform) approach while respecting machine limits to the AECI neighboring system clusters defined in Table 3-8. In all cases, Legacy units remained online.

Table 3-8: AECI Neighboring System Clusters

Area Number	Area Name	Cluster	Scaled Portion
327	EES-EAI	AECI-1	1/6
515	SWPA	AECI-23	2/6
520	AEPW	AECI-23	
523	GRDA	AECI-23	
524	OKGE	AECI-23	
525	WFEC	AECI-23	
544	EMDE	AECI-23	
546	SPRM	AECI-23	
536	WERE	AECI-23	
541	KCPL	AECI-23	
545	INDN	AECI-23	
526	SPS	AECI-23	
531	MIDW	AECI-23	
542	KACY	AECI-23	
640	NPPD	AECI-4	1/6
652	WAPA	AECI-4	
641	HAST	AECI-4	
642	GRIS	AECI-4	
645	OPPD	AECI-4	
650	LES	AECI-4	
659	BEPC-SPP	AECI-4	
333	CWLD	AECI-5	1/6
356	AMMO	AECI-5	
357	AMIL	AECI-5	
627	ALTW	AECI-5	
635	MEC	AECI-5	
347	TVA	AECI-6	1/6

4.0 STUDY METHODOLOGY

4.1 Steady State Analysis Methodology

A power flow analysis was performed using PowerGEM TARA software to evaluate the impact of the AECI study units to the SPP transmission system. SPP's transmission system must be capable of operating within the applicable normal ratings, emergency ratings, and voltage limits based on SPP's and any applicable local planning criteria.

4.1.1 Thermal Impact Criteria

Thermal overloads are determined for system intact (N-0) conditions when transmission facilities are loaded greater than or equal to 100% of the normal rating (Rate A). For contingency (N-1) conditions, thermal overloads are determined when transmission facilities are loaded greater than or equal to 100% of the emergency rating (Rate B).

For ERIS analysis, in order for a study unit to have an impact on the transmission system, the reported facility must be overloaded in the TC case and the study unit must meet one of the distribution factor criteria below on the reported facility:

- 3% distribution factor for system intact conditions (N-0), or
- 20% distribution factor for contingency conditions (N-1)

For NRIS analysis, in order for a study unit to have an impact on the transmission system, the reported facility must be overloaded in the TC case and the study unit must meet the distribution factor criteria below on the reported facility:

- 3% distribution factor for system intact conditions (N-0) or for contingency conditions (N-1)

4.1.2 Voltage Impact Criteria

Voltage violations are determined for system intact (N-0) and contingency (N-1) conditions if the reported bus voltages exceed the voltage criteria shown in Table 4-1.

Table 4-1: Study Voltage Criteria

Transmission Owner/ Bus Number	System Intact Condition	Contingency Condition
SWPA	0.95 – 1.05	0.90 – 1.05
AEPW	0.95 – 1.05	0.92 – 1.05
GRDA	0.95 – 1.05	0.90 – 1.05
OKGE	0.95 – 1.05	0.90 – 1.05
WFEC	0.95 – 1.05	0.90 – 1.05
SWPS	0.95 – 1.05	0.90 – 1.05
OMPA	0.95 – 1.05	0.90 – 1.05
MIDW	0.95 – 1.05	0.90 – 1.05

Transmission Owner/ Bus Number	System Intact Condition	Contingency Condition
SEPC	0.95 – 1.05	0.90 – 1.05
WERE-L (69 kV – 200 kV)	0.93 – 1.05	0.93 – 1.05
WERE-H (200 kV and above)	0.95 – 1.05	0.95 – 1.05
KCPL	0.95 – 1.05	0.90 – 1.05
KACY	0.95 – 1.05	0.90 – 1.05
EMDE-L	0.95 – 1.05	0.90 – 1.05
EMDE-H	0.95 – 1.05	0.90 – 1.05
INDN	0.95 – 1.05	0.90 – 1.05
SPRM	0.95 – 1.05	0.90 – 1.05
NPPD	0.95 – 1.05	0.90 – 1.05
LES	0.95 – 1.05	0.90 – 1.05
OPPD	0.95 – 1.05	0.90 – 1.05 (below 161 kV) 0.95 – 1.05 (161 kV and above)
WAPA	0.95 – 1.05	0.90 – 1.05
532797 Wolf Creek	0.985 – 1.03	0.99 – 1.03
646251 FCS	1.001863 – 1.047205	0.95 – 1.05 (161 kV and above)

For ERIS and NRIS analysis, in order for a study unit to have a voltage impact on the transmission system, the bus voltage delta between the BC and TC case must be 2% or greater and the study unit must meet the distribution factor criteria below:

- 3% distribution factor under system intact conditions (N-0) on any one facility defined in the reported event associated with voltage violation

4.1.3 Non-converged Impact Criteria

Non-converged conditions are reported as the model experiencing a voltage collapse or limit exceedance in the solution when attempting to rebalance the power flows flowing an outage(s) on the transmission system. These conditions were reviewed to determine if solution adjustments or model adjustments could be made to resolve the non-converged condition. If no adjustment was able to be made, then the distribution factor from the study unit was found for each of the transmission facilities that made up the defined outage that resulted in non-convergence.

For ERIS and NRIS analysis, in order for a study unit to have a non-converged impact on the transmission system, the reported non-converged condition must be reported in the TC case and the study unit must meet the distribution factor criteria below:

- 3% distribution factor under system intact conditions (N-0) on any one facility defined in the reported non-converged event

4.2 Contingencies

The contingency set includes all SPP control area branches and ties 69 kV and above, first-tier non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

- All branches, ties, shunts, and generators within the following areas:
  - SPP Internal Areas for 65 kV – 999 kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659
  - SPP External Areas for 100 kV – 999 kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP TO Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP TO Specific Op-Guide Implementation

4.3 ACCC Solution Settings

The following solution parameters were applied in performing the analysis:

- Fixed slope decoupled Newton-Raphson
- Tap Adjustment – stepping
- Switch shunt adjustments – enable all
- Area interchange disabled
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Must solve within five iterations, three or less is preferred (BASE, BC, and TC development only)

4.4 Mitigation Development

Transmission reinforcements were developed to mitigate any study unit impact in violation of the criteria defined in Section 4.1. Coordination with the appropriate Transmission Owner(s) of a given reported facility, along with the involvement of SPP, was conducted to determine the appropriate reinforcement and associated upgrade costs.

5.0 STEADY STATE ANALYSIS RESULTS

The impact of the study units was evaluated under the assumptions and methodology presented in Section 2.0, Section 3.0, and Section 4.0. The results presented below have been compiled and summarized to report the impacts due to the addition of each study unit. A complete set of detailed results from the steady state analysis are found in Appendix A.

5.1 NRIS Analysis

5.1.1 GIA-68

For GIA-68, NRIS impacts were observed on several facilities as shown in Table 5-1.

Table 5-1: GIA-68 NRIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P23:345:AECI:7MORGAN:324_5bc	110.8	0.05292
2024 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P23:345:AECI:7MORGAN:324_5bc	114.4	0.05297
2024 WP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P23:345:AECI:7MORGAN:324_5bc	131.1	0.05325
2020 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	P42:345:SPRM-AECI:STUCK BKR SIM17	118.0	0.03195
2024 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	P42:345:SPRM-AECI:STUCK BKR SIM17	128.0	0.03183
2024 WP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	174	AECI/SPRM	P42:345:SPRM-AECI:STUCK BKR SIM17	107.0	0.03201
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:GRDA:GRDA CB9580	102.3	0.08119
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:GRDA:GRDA CB9580	113.0	0.08048
2024 WP	532937 NEOSHO 5 161 547469 RIV4525 161 1	243	WERE/EMDE	P23:345:AECI:7BLACKBERRY:653tc	105.1	0.1016

No voltage or non-converged NRIS impacts were observed for GIA-68.

5.1.2 GIA-77

For GIA-68, NRIS impacts were observed on several facilities as shown in Table 5-4.

Table 5-2: GIA-77 NRIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	126.7	1
2024 L	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	125.4	1
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	126.9	1
2024 WP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	971	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	114.8	1

No voltage or non-converged NRIS impacts were observed for GIA-77.

5.1.3 GIA-78

For GIA-78, NRIS impacts were observed on several facilities as shown in Table 5-5.

Table 5-3: GIA-78 NRIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	131.7	1
2024 L	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	130.3	1
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	131.9	1
2024 WP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	971	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	120.3	1

No voltage or non-converged NRIS impacts were observed for GIA-78.

5.1.4 GIA-83

For GIA-83, no NRIS thermal, voltage or non-converged impacts were observed.

5.1.5 GIA-85

For GIA-85, NRIS impacts were observed on several facilities as shown in Table 5-4.

Table 5-4: GIA-85 NRIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	124.1	0.08796
2024 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	134.4	0.08803
2024 WP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	145.0	0.08822
2020 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	P22:345:SPRM-AECI:17	149.7	0.07467
2024 L	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	P22:345:SPRM-AECI:17	113.6	0.0746
2024 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	P22:345:SPRM-AECI:17	159.2	0.07456
2024 WP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	174	AECI/SPRM	P22:345:SPRM-AECI:17	130.8	0.07473
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:GRDA:GRDA CB12380	101.7	0.05717
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:GRDA:GRDA CB12380	107.4	0.05738

No voltage or non-converged NRIS impacts were observed for GIA-85.

5.1.6 GIA-86

For GIA-86, no NRIS thermal, voltage or non-converged impacts were observed.

5.1.7 GIA-88

For GIA-88, NRIS impacts were observed on several facilities as shown in Table 5-5.

Table 5-5: GI-88 NRIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	127.6	0.04219
2024 SP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	137.8	0.04227
2024 WP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	P22:345:SPRM-AECI:17	148.4	0.04245
2020 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	300045 7MORGAN 345 549984 BROOKLINE 7 345 1	131.5	0.04421
2024 SP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	130	AECI/SPRM	300045 7MORGAN 345 549984 BROOKLINE 7 345 1	106.2	0.05494
2024 WP	300101 5MORGAN 161 549969 BROOKLINE 5 161 1	174	AECI/GRDA	300045 7MORGAN 345 549984 BROOKLINE 7 345 1	102.9	0.04428
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:AECI:7SPORTSMAN:12380	103.7	0.03451
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P23:345:GRDA:GRDA CB12380	107.9	0.0382

No voltage or non-converged NRIS impacts were observed for GIA-88.

5.1.8 GIA-90

For GIA-90, no NRIS thermal, voltage or non-converged impacts were observed.

5.1.9 GIA-91

For GIA-91, no NRIS thermal, voltage or non-converged impacts were observed.

5.2 ERIS Analysis

5.2.1 GIA-68

For GIA-68, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.2 GIA-77

For GIA-77, ERIS impacts were observed on several facilities as shown in Table 5-6.

Table 5-6: GIA-77 ERIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	126.6	1
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	126.7	1
2024 WP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	971	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	114.7	1

No voltage or non-converged ERIS impacts were observed for GIA-77.

5.2.3 GIA-78

For GIA-78, NRIS impacts were observed on several facilities as shown in Table 5-7.

Table 5-7: GIA-78 ERIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2020 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	131.5	1
2024 SP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	873	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	131.7	1
2024 WP	300069 5CHOTEAU1 161 512648 MAID 5 161 1	971	AECI/GRDA	P12:161:AECI:SPRTMN-CHOTEAU	120.2	1

No voltage or non-converged ERIS impacts were observed for GIA-78.

5.2.4 GIA-83

For GIA-83, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.5 GIA-84

For GIA-84, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.6 GIA-85

For GIA-85, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.7 GIA-86

For GIA-86, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.8 GIA-88

For GIA-88, a single ERIS impact was observed on a facility as shown in Table 5-8.

Table 5-8: GIA-88 ERIS Impacts

Case	Constraint	Rating (MVA)	Area Name	Worst Contingency	Worst Loading (%MVA)	Dfax
2024 WP	300101 5MORGAN 161 547478 DAD368 5 161 1	188	AECI/EMDE	Base Case	103.1	0.04567

No voltage or non-converged ERIS impacts were observed for GIA-88.

5.2.9 GIA-90

For GIA-90, no ERIS thermal, voltage or non-converged impacts were observed.

5.2.10 GIA-91

For GIA-91, no ERIS thermal, voltage or non-converged impacts were observed.

6.0 TRANSMISSION REINFORCEMENTS

The reported impacts for each of the study units were evaluated for mitigation through coordination with the applicable Transmission Owner(s) and SPP.

6.1 GIA-68 NRIS Mitigations

6.1.1 Choteau to Maid 161 line

For the thermal violation on the Choteau to Maid 161 kV line, GRDA and AECI utilize the Choteau Power Plant Emergency Operating Guide to relieve the overload on the line. In accordance with the operating guide, real time or first contingency (N-1) that could cause transmission system loading issues would result in restricting the output of the Chouteau plants. In the event of such restrictions, AECI and GRDA System Operators, both directly and through their respective Reliability Coordinators (RC), will coordinate their actions to relieve any real or potential overloads. Therefore, no system upgrade is required to mitigate the thermal overload on the Choteau to Maid 161 kV line.

6.1.2 Morgan to Dadeville 161 kV line

For the thermal violation on the Morgan to Dadeville 161 kV line, the line rating was to be updated in the power flow models as a part of the 2021 MDWG modeling process, based on feedback received from EMDE. The Morgan to Dadeville 161 kV line reflected both Summer and Winter rating of 188 MVA. The rating of the line was updated to the following:

- Summer Rating (A/B): 290/290 MVA limited by EMDE 795 ACSR line conductors
- Winter Rating (A/B): 334/334 MVA limited by AECI Bus CT

The updated ratings were captured in the power flow models and rerunning the steady state analysis did not show system criteria violations on the Morgan to Dadeville 161 kV line thereby not requiring any system upgrades for mitigation.

6.1.3 Morgan to Brookline 161 kV line

For the thermal violation on the Morgan to Brookline 161 kV line, the line rating was not accurate in the power flow models based on comments received from SPRM and AECI. The Morgan to Brookline 161 kV line reflected a Summer and Winter rating of 130 MVA and 174 MVA respectively. The rating of the line was updated to the following:

- Summer Rating (A/B): 227/227 MVA limited by AECI line conductors
- Winter Rating (A/B): 277/277 MVA limited by AECI line conductors

The updated ratings were captured in the power flow models and rerunning the steady state analysis did not show system criteria violations on the Morgan to Brookline 161 kV line thereby not requiring any system upgrades for mitigation.

6.1.4 Neosho to Riverton 161 kV line

For the thermal violation on the Neosho to Riverton 161 kV linel, the impedance and rating in the model did not reflect the latest plans for the facility based on comments from EMDE. The Neosho to Riverton 161 kV line reflected a Summer and Winter rating of 243 MVA. Based on the Transmission Service upgrade NTC_ID 210570, the impedance and the rating referenced from the 2021 ITP models was updated in the power flow cases to the following:

- R/X/B: 0.00346 p.u. / 0.06172 p.u. / 0.05549 p.u.
- Rating (A/B): 754/836 MVA across all seasons.

The impedance and rating changes were captured in the power flow models and rerunning the steady state analysis did not show any new system criteria violations on or downstream of the Neosho to Riverton 161 kV line thereby not requiring any new system upgrades for mitigation.

6.2 GIA-77 NRIS and ERIS Mitigations

The thermal impact reported for GIA-77 was also reported for GIA-68:

- Choteau to Maid 161 kV line

The operating guide present in Section 6.1.1 for GIA-68 is applicable for GIA-77 mitigation. Therefore, no system upgrade is required to mitigate the thermal overload on the Choteau to Maid 161 kV line.

6.3 GIA-78 NRIS and ERIS Mitigations

The thermal impact reported for GIA-78 was also reported for GIA-68:

- Choteau to Maid 161 kV line

The operating guide present in Section 6.1.1 for GIA-68 is applicable for GIA-78 mitigation. Therefore, no system upgrade is required to mitigate the thermal overload on the Choteau to Maid 161 kV line.

6.4 GIA-85 NRIS Mitigations

Each of the thermal impacts reported for GIA-85 were also reported for GIA-68:

- Choteau to Maid 161 kV line
- Morgan to Dadeville 161 kV line
- Morgan to Brookline 161 kV line

Each of the transmission reinforcements present in Section 6.1 for GIA-68 are applicable for GIA-85 mitigations. Rerunning the steady state analysis with the upgrades described did not show any new system criteria violations on or downstream of the reported facilities thereby not requiring any new system upgrades for mitigation.

6.5 GIA-88 NRIS and ERIS Mitigations

Each of the thermal impacts reported for GIA-88 were also reported for GIA-68:

- Choteau to Maid 161 kV line
- Morgan to Dadeville 161 kV line
- Morgan to Brookline 161 kV line

Each of the transmission reinforcements present in Section 6.1 for GIA-68 are applicable for GIA-88 mitigations. Rerunning the steady state analysis with the upgrades described did not show any new system criteria violations on or downstream of the reported facilities thereby not requiring any new system upgrades for mitigation.

6.6 Network Upgrade Costs

No new network upgrades were identified as required in the SPP system to interconnect the AECI study units as evaluated in the Study. As a result, the AECI study units do not have any SPP affected system costs as shown in Table 6-1.

Table 6-1: Study Unit Network Upgrade Costs

Request	Group	Type	Service	Point of Interconnection	Cost Estimate
GIA-68	12	Solar	ER/NR	Blackberry 345 kV	$ 0
GIA-77	8	Gas	ER/NR	Chouteau 161 kV	$ 0
GIA-78	8	Gas	ER/NR	Chouteau 161 kV	$ 0
GIA-83	13	Wind	ER/NR	McCredie 345 kV	$ 0
GIA-84	12	Solar	ER Only	New Madrid 345 kV	$ 0
GIA-85	12	Solar + Storage	ER/NR	Morgan 345 kV	$ 0
GIA-86	13	Solar	ER/NR	Thomas Hill 69 kV	$ 0
GIA-88	12	Solar	ER/NR	Eudora 69 kV	$ 0
GIA-90	13	Solar	ER/NR	Montgomery City 161 kV	$ 0
GIA-91	13	Solar	ER/NR	Sedalia 69 kV	$ 0

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