STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION BY GIBSON SOLAR LLC FOR CERTAIN DETERMINATIONS BY THE COMMISSION WITH RESPECT TO ITS JURISDICTION OVER PETITIONER'S ACTIVITIES AS A GENERATOR OF ELECTRIC POWER	**))))))**	**CAUSE NO. 45500**

GIBSON SOLAR LLC'S 2nd QUARTER 2023 REPORT

This 2nd Quarter 2023 Report ("Report") is filed as required by the Commission's Order in this Cause issued on June 23, 2021. The Order requires Gibson Solar LLC to file quarterly reports within 30 days of the end of each quarter during the period prior to achieving commercial operation. This Report provides the required information to the extent such information is known and available. The requested information is as follows:

(1) Any changes to the information provided in the Initial Report.

Changes during the 2nd quarter of 2023 occurred to the sections of the Initial Report identified below:

(8) The expected commercial operation date is on or before June 1, 2025.

(9) Gibson Solar LLC anticipates the engineering/construction timelines and critical milestones for the project as set forth below:

- Development work (including engineering, environmental studies, and other work) ongoing
- Full construction: 2023-2025
- Project commercial operation: no later than June 1, 2025

Gibson Solar LLC also reports that, although occurring after the end of the 2nd quarter of 2023, that it is the subject of a Build Transfer Agreement ("BTA") by and between Gibson Solar Generation LLC, as purchaser, and Gibson Solar CEI, LLC, as seller (i.e., Gibson Solar LLC's parent company). Northern Indiana Public Service Company LLC and Gibson Solar Generation LLC initiated Cause No. 45926 on July 27, 2023, for certain approvals of and related to the BTA. Gibson Solar LLC will timely file a Notice of Material Change

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reflecting a lower capacity of 200 MW_{AC} from its approved 280 MW_{AC} as required by Finding Paragraph 8.C. of the Order.

(2) Any reports of Interconnection System Impact Studies not previously submitted to the Commission.

A System Impact Study for MISO DPP-2019-Cycle Central Phase 3 is attached as Attachment 1.

(3) Copy of the GIA as filed with FERC.

The GIA has not yet been finalized.

(4) Notice of the establishment of an independent financial instrument, including its form and amount.

This has not been established yet.

(5) Achievement of construction milestones described in the GIA and such events as the procurement of major equipment, the receipt of major permits material to the construction and operation of the Facility, construction start-up, initial energization, and commercial operation.

As reported previously, Gibson Solar LLC obtained its Special Use Permit (SUP) from the Gibson County Board of Commissioners on April 5, 2022. Additionally, all PGIA milestone payments required to date have been made, including milestone payments needed to procure long lead resource and equipment orders.

(6) When commercial operation is achieved, the nameplate capacity, term and identity of a purchaser for any contracts then existing for utility sales, contingency plans (if any) detailing response plans to emergency conditions as required by state or local units of government, the interconnecting transmission owner and/or MISO, and the Facility's certified (or accredited) dependable capacity rating.

Not applicable.

VERIFICATION

The undersigned, Aron Branam, being first duly sworn upon his oath states that he is the Vice President, Development and Construction of Arevon Energy, Inc., and is responsible for overseeing Gibson Solar, LLC; that he prepared or supervised the preparation of Gibson Solar, LLC's 2nd Quarter 2023 Report; and that the statements contained therein are true to the best of his knowledge, information and belief.

Aron Branam

Aron Branam

STATE OF Arizona)
) **SS:**
COUNTY OF Maricopa)

18 Subscribed and sworn to before me, a Notary Public in and for said State and County, this 18 day of July 2023.

MAYA BRITT CALLAHAN
Notary Public - Arizona
Maricopa County
Commission # 646219
My Comm. Expires Apr 11, 2027

Signature

Maya Britt Callahan
Printed

My Commission Expires:

April 11, 2027

My County of Residence

Maricopa

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Dated this 28th day of July 2023.

Respectfully submitted,

David T. McGimpsey (21015-49)
DENTONS BINGHAM GREENEBAUM LLP
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Attorney for Petitioner,
Gibson Solar LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was electronically delivered this 28th day of July 2023, to the following:

T. Jason Haas, Esq.
Office of Utility Consumer Counselor
115 West Washington Street
Suite 1500 South
Indianapolis, Indiana 46204
thaas@oucc.in.gov
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An Attorney for Petitioner
Gibson Solar LLC

Attachment 1

SPP AFFECTED SYSTEM IMPACT STUDIES
MISO DPP-2019-CYCLE CENTRAL PHASE 3

SOUTHWEST POWER POOL, INC.

JUNE 30, 2022

ELECTRIC POWER ENGINEERS

ENERGY ENGINEERING EXPERTS

GENERATION | TRANSMISSION | DISTRIBUTION

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Document Revisions

NO.	Revision	Date	PRD	CHK	APV
1	Draft Report Issued for Review	6/20/2022	EM	WB	WB
2	Final Report Issued for Posting	6/30/2022	WB	WB	WB

Introduction

MISO requested a preliminary affected system impact study (ASIS) from Southwest Power Pool (SPP) for the DPP-2019-Cycle Central Phase 3 cluster. The purpose of this analysis is to determine the preliminary impact of the MISO generator interconnection requests on the SPP transmission system under the assumption that all higher queued interconnection requests and network upgrades are in-service. Additionally, the analysis looked to identify the amount of Interconnection Service available to the projects resulting in no constraints requiring mitigation. This analysis evaluated 16 MISO interconnection requests in SPP cluster Groups 03 and 04, with a total generation capacity of 3,171 MW. While results from this analysis will be considered final, a restudy may be required should significant changes to the study assumptions occur[1]. The definitive study will not be considered final until all higher queued cluster studies are complete.

The generator interconnection requests analyzed in this ASIS are listed in **Appendix A** by queue number, amount, requested interconnection service type, area, and proposed interconnection point.

The Siemens Power Technologies International PSS/E Version 33.11.0 and PowerGem's TARA 2201 were used for this analysis. SPP provided the following DISIS-2017-002 BASE case models:

- Year 2 (2023) Summer Peak (23SP)
- Year 5 (2026) Light (26L)
- Year 5 (2026) Summer Peak (26SP)
- Year 5 (2026) Winter Peak (26WP)

EPE updated power flow cases to reflect the groups under study and developed a total of 32 cases, specifically 16 Base Cases (BC) and 16 Transfer Cases (TC). The power flow analysis was performed to determine if the transmission system could accommodate the injection from the current study cluster generator interconnection requests without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria Section.

The ASIS has been conducted consistent with Attachment V of the SPP Open Access Transmission Tariff (OATT), the SPP-MISO Joint Operating Agreement (JOA), and SPP Business Practices to determine impacts to the SPP transmission system.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a generator interconnection request. Because of this, the Customer may be required by the Transmission Provider to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of delivery or transmission service within SPP's transmission system. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on SPP's OASIS by the Customer.

[1] Significant changes to study assumptions include but are not limited to interconnection request withdrawals and/or changes to higher-queued Network Upgrades included in the Base Case.

Base Case Model Build and Dispatch

DC Scan

A DC scan was performed to determine which interconnection requests should be included in the analysis. The distribution factor (DFAX) cut-off criteria used (3%) for the DC scan was based on SPP's transmission distribution factor (TDF) criteria used to identify constraints and mitigations.

The results of the DC scan revealed that 16 projects from DPP-2019-Cycle Central Phase 3 met the DC screening criteria and hence were included in the analysis. **Table 1** provides a summary of the DC Scan analysis. Distribution factors were calculated using each project as the source system and the MISO Classic[2] region as the sink system. Detailed results for the DC scan can be found in **Table 2**.

Table 1: DC Scan Results by Queue Cluster

Queue Cycle	Region	3% DFAX Threshold	
		Include	Exclude
DPP-2019-Cycle P3	Central	16	60

Table 2: Detailed DC Scan Results

Results	
DC Scan Results	DPP-2019-Central-P 3_DC Scan Details Cl

Base Case Model Review and Grouping

SPP provided the following information to EPE:

1. List of interconnection requests for consideration in the analysis
2. List of all higher-queued interconnection requests and associated required upgrades
3. DISIS-2017-002 BASE cases
4. Latest MISO bench and study cases used for the DPP-2019-Cycle Central
5. Current study Network Upgrades previously identified by SPP for consideration in the analysis

The DPP-2019-Cycle Central Phase 3 ASIS included 16 generator interconnection requests in the MISO footprint. **Appendix A** lists the current study cluster generator interconnection requests included in the study. The DISIS-2017-002 BASE models are based on a modified version of the 2021 ITP cases and served as the starting point for the DPP-2019-Cycle Central analysis. The BASE models were derived by adding higher-queued interconnection requests not already existing in the model and their associated Network Upgrades[3]. The MISO West study generators, including all available collector system data, were added, and kept offline in the following BASE models:

[2] MISO Classic is defined as the PSSE areas of 207, 208, 210, 216, 217, 218, 219, 295, 296, 314, 333, 356, 357, 360, 361, 600, 608, 613, 615, 620, 627, 633, 635, 661, 680, 694, 696, 697, and 698.

[3] Previously-assigned Network Upgrades from clusters equal to and higher than the MISO DPP-2019-Cycle West clusters were already included in the BASE cases.

- Year 2 (2023) Summer Peak (23SP)
- Year 5 (2026) Light (26L)
- Year 5 (2026) Summer Peak (26SP)
- Year 5 (2026) Winter Peak (26WP)

Higher-queued interconnection requests were included in the models, including the DISIS-2017-002 and MISO DPP-2019-Cycle West or before. If the interconnection request did not already exist in the model, it was modeled as out of service. Otherwise, the interconnection request was modified as necessary to reflect the nameplate capacity requested in the Generator Interconnection Agreement. Updates were also made to external interconnection requests, such as those in the MISO queue, to align the modeled capacity with the requested queue capacity. The higher-queued requests added or modified to the study models are listed in **Appendix B**.

EPE also identified significant deviations[4] between the DISIS-2017-002 BASE cases and the MISO DPP reference cases used for MISO DPP-2020-Cycle studies[5]. To incorporate updates to the MISO footprint, the MISO shoulder case was used to update MISO representation in the spring and light load seasons. The MISO summer peak case was used to update the MISO representation in the summer and winter peak seasons. The identified topology upgrades in the MISO Central, South, and West areas were added to the BASE models. The summary of the identified transmission topology changes that were incorporated is provided in **Appendix D**.

Grouping

The interconnection requests listed in **Appendix A** and **Appendix B** are grouped into five active regional groups. Grouping is determined by engineering judgement and electrical connectivity to SPP transmission. The SPP groupings are listed in **Table 3** below. The interconnection requests provided in the interconnection request database have been identified as being potentially impactful to the SPP transmission system due to electrical proximity to SPP facilities.

Table 3: All SPP Groupings

Group #	Area
01	SPP North
02	SPP North Central
03	SPP Central
04	SPP Southeast
05	SPP Southwest

Development of Base Cases (BC)

The number of Base Cases (BC) and Transfer Cases (TC) required for each impact study depends on the service requested and the fuel type of the study units. **Table 4** outlines the number of cases required per seasonal case for each dispatch scenario. **Table 6** describes the SPP dispatch criteria used for this analysis.

[4] Significant deviations would include additions/removals 161 kV+ facilities, changes to R, X, B, and L > 5% for 161 kV+ facilities, and generation differences > 10 MW for interconnection requests under consideration for inclusion in the analysis.

[5] Reference cases refers to the MISO DPP-2020-Cycle Central, South, and West Phase 1 models.

Table 4: SPP Seasons and Cases per Dispatch

Seasonal Case	ERIS HVER	ERIS LVER	NRIS
+2 Summer Peak (i.e. 23SP)	1 per group	1 per study	1 per study
+5 Light Load (i.e. 26L)	1 per group	--	1 per group
+5 Summer Peak (i.e. 26SP)	1 per group	1 per study	1 per study
+5 Winter Peak (i.e. 26WP)	1 per group	1 per study	1 per study

Four BASE power flow cases were provided as the starting point for this analysis. The two SPP regional groups (Groups 03 and 04) had three types of dispatch for their local generation: High-Variable Energy Resource (HVER), Low Variable Energy Resource (LVER), and Network Resource Interconnection Service (NRIS). The groups and the dispatch resulted in 32 cases with unique dispatches, as shown in **Table 5**. All in-scope higher-queued SPP and MISO generators listed in **Appendix B** were added and dispatched per criteria listed in **Table 6**.

Table 5: DPP-2019-Cycle Central P3 Study Cases

Seasonal Case	ERIS HVER	ERIS LVER	NRIS
+2 Summer Peak (i.e. 23SP)	1 per group	1 per study	1 per study
+5 Light Load (i.e. 26L)	1 per group	--	1 per group
+5 Summer Peak (i.e. 26SP)	1 per group	1 per study	1 per study
+5 Winter Peak (i.e. 26WP)	1 per group	1 per study	1 per study
DPP-2019-Cycle Central P3	**32 Cases (16 BC/16 TC)**		

SPP region generation offset caused by the prior-queued generators' dispatch was balanced using the load ratio share (LRS) and uniform scale. The LRS determined where generation adjustments were required. The generation offset was sunk using a uniform scale across all non-queue and non-nuclear units in each area.

LRS was not used in non-SPP regions. Instead, generation offset was adjusted using a uniform scale across all non-queue and non-nuclear units in the region. Dispatched cases were solved without area interchange, and the system swing generation was kept as close as possible between the BASE case, BC case, and TC case.

Development of Analysis Cases (TC)

All in-scope higher-queued and current study interconnection requests were dispatched as per criteria listed in **Table 6**. For existing SPP interconnection requests included in the scope, if the existing generation dispatch (P_{GEN}) was greater than the expected GI dispatch criteria, the generation was left as-is. If the existing generation dispatch (P_{GEN}) was less than the expected GI dispatch criteria, it was dispatched up to the defined amount.

Generation adjustments are dispatched against legacy[6] conventional generation[7] in the host TO footprint. For the HVER dispatch scenario, all renewable generation facilities are dispatched to 100% within the studied group and at 0% outside of the study group if the unit was offline or dispatched at 0 MW. Legacy resources and higher-queued conventional units are used to balance generation changes in the HVER

[6] Generators that are found in the SPP footprint in the DISIS BASE cases that do not map to the SPP generator mapping sheet are considered "legacy".

[7] The conventional units included in the sink excluded non-adjustable generation such as hydro/run-of-river.

scenarios. The HVER dispatch scenario was used with all cases including Winter, Summer, and Light Load DISIS BASE cases.

For the Low-Variable Energy Resource (LVER) dispatch scenario, all conventional generation facilities are dispatched to 100%. The code 00 for this scenario represents that the entire SPP footprint is included as being in-group. Legacy resources are used to balance generation changes. The LVER dispatch scenario is utilized in Winter and Summer DISIS BASE cases but only used if there is a conventional resource in the current study.

For the Network Resource (NR) dispatch scenario, the dispatch levels for the renewable and conventional generation facilities are determined based on the level of system integration being requested (ERIS and NRIS). For Light Load, dispatches are group-based. For Winter and Summer, the entire SPP footprint is considered “in-group” for the study (like the LVER dispatch scenario). Legacy resources are used to balance generation changes.

For this analysis, MISO’s partial NRIS was taken into account for the NR dispatch, whereas ERIS-only capacity was not dispatched in the NR dispatch scenarios.

Each current study interconnection request was included in the power flow analysis models as an equivalent generator dispatched at the applicable percentage of the requested service amount with 0.95 power factor capability. The facility modeling includes explicit representation of equivalent generator step-up (GSU) and main power transformer(s) with impedance data provided in the interconnection request. All equivalent collector system branches and transmission tie-lines shorter than 20 miles in length are modeled as zero-impedance branches.

Table 6: SPP Dispatch Criteria

Dispatch Type	Season	Groups	Service Type	Renewable in group	Renewable out of group	Conventional in group	Conventional out of group
ERIS HVER	All	01, 02, 03, 04, 05	All	100%	N/A[8]	N/A[8]	N/A[8]
ERIS LVER	Peak	00	All	20%	20%	100%	100%
NRIS	Light Load	01, 02, 03, 04, 05	ERIS	N/A[8]	N/A[8]	N/A[8]	N/A[8]
			NRIS	100%	N/A[8]	N/A[8]	N/A[8]
	Peak	00NR	ERIS	N/A[8]	N/A[8]	N/A[8]	N/A[8]
			NRIS	100%	100%	100%	100%

[8] If units are already online in the model, the dispatch is left as-is. These units may be included in the sink subsystem.

Study Methodology Criteria

Solve Parameters

The following solution parameters were used:

- 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

Thermal Overloads

Network constraints are identified using PowerGEM TARA AC Contingency Calculation (ACCC) analysis on the entire cluster grouping dispatched at the various levels.

For Energy Resource Interconnection Service (ERIS):

For ERIS, thermal overloads are determined for system intact (N-0) (greater than or equal to 100% of Rate A/normal) and contingency (N-1) (greater than or equal to 100% of Rate B/emergency) conditions.

The overloads are then screened to determine which generator interconnection requests have at least:

- 3% DFAX for system intact conditions (N-0),
- 20% DFAX upon outage-based conditions (N-1), or
- 3% DFAX on contingent elements that resulted in a non-converged solution, or
- 5% DFAX on contingent elements and the sum of all MW impacts from requests with at least 5% DF equals at least 20% of the facilities emergency rating.

Non-converged contingencies shall also be considered for Limited Operation.

For Network Resource Interconnection Service (NRIS):

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DFAX. If so, these constraints are also considered for transmission reinforcement under NRIS.

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

Monitored Facilities

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first-tier non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Factor (PTDF) Flowgates for SPP and first-tier non-SPP control areas are monitored. Additional NERC Flowgates are monitored in second-tier or greater non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

- All branches (thermal)/buses (voltage) and ties within the following areas:
    - SPP Internal Areas for 60 kV – 999 kV facilities:
        - 515 – 546, 640 – 659
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

Voltage

For non-converged power flow solutions that are determined to be caused by a lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP Areas (69 kV+)

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AEPW</td><td rowspan="13">0.95 – 1.05 p.u.</td><td>0.92 – 1.05 p.u.</td></tr>
<tr><td>GRDA</td><td rowspan="12">0.90 – 1.05 p.u.</td></tr>
<tr><td>SWPA</td></tr>
<tr><td>OKGE</td></tr>
<tr><td>OMPA</td></tr>
<tr><td>WFEC</td></tr>
<tr><td>SWPS</td></tr>
<tr><td>MIDW</td></tr>
<tr><td>SUNC</td></tr>
<tr><td>KCPL</td></tr>
<tr><td>INDN</td></tr>
<tr><td>SPRM</td></tr>
<tr><td>NPPD</td></tr>
</table>

WAPA		
WERE LV		0.93 – 1.05 p.u.
WERE HV		0.95 – 1.05 p.u.
EMDE LV		0.90 – 1.05 p.u.
EMDE HV		0.92 – 1.05 p.u.
LES		0.90 – 1.05 p.u.
OPPD		

SPP Buses With More Stringent Voltage Criteria

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230 kV 525830	0.925 – 1.05 p.u.	0.925 – 1.05 p.u.
Wolf Creek 345 kV 532797	0.985 – 1.03 p.u.	0.985 – 1.03 p.u.
FCS 161 kV 646251	1.001 – 1.047 p.u.	1.001 – 1.047 p.u.

Affected System Areas (115 kV+)

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 p.u.	0.90 – 1.05 p.u.
EES-EAI		
LAGN		
EES		
AMMO		
CLEC		
LAFA		
LEPA		
XEL		
MP		
SMMPA		

<table>
<tr><td>GRE</td><td rowspan="2"></td><td>0.90 – 1.10 p.u.</td></tr>
<tr><td>OTP</td><td>0.90 – 1.05 p.u.</td></tr>
<tr><td>OTP-H (115 kV+)</td><td>0.97 – 1.05 p.u.</td><td>0.92 – 1.10 p.u.</td></tr>
<tr><td>ALTW</td><td rowspan="6">0.95 – 1.05 p.u.</td><td rowspan="3">0.90 – 1.05 p.u.</td></tr>
<tr><td>MEC</td></tr>
<tr><td>MDU</td></tr>
<tr><td>SPC</td><td>0.95 – 1.05 p.u.</td></tr>
<tr><td>DPC</td><td rowspan="2">0.90 – 1.05 p.u.</td></tr>
<tr><td>ALTE</td></tr>
</table>

The constraints identified through the voltage scan are then screened for the following for each interconnection request.

- 3% DF on the contingent element and
- 2% change in p.u. voltage

Identification of Network Constraints

ERIS Thermal Non-Converged Constraint Identification and Mitigation

There were no ERIS non-converged constraints identified for single contingency conditions.

ERIS Thermal System Intact and Contingency Constraint Identification and Mitigation

One ERIS thermal constraint was identified for single contingency conditions. **Table 7** below summarizes the ERIS thermal constraint and associated mitigation.

Table 7: ERIS Thermal Constraints

Monitored Facility	Mitigation
Miner to Sikeston 161 kV	Replace the disconnect switches and CTs at Sikeston

ERIS Voltage Constraint Identification and Mitigation

There were no ERIS voltage constraints identified for single contingency conditions.

NRIS Thermal Non-Converged Constraint Identification and Mitigation

There were no NRIS non-converged constraints identified for single contingency (N-1) conditions.

NRIS Thermal System Intact and Contingency Constraint Identification and Mitigation

One NRIS thermal constraint was identified for single contingency conditions. **Table 8** below summarizes the NRIS thermal constraint and associated mitigation.

Table 8: NRIS Thermal Constraints

Monitored Facility	Mitigation
Miner to Sikestion 161 kV	Replace the disconnect switches and CTs at Sikeston

NRIS Voltage Constraint Identification and Mitigation

There were no NRIS voltage constraints identified for system intact, single contingency, and multiple contingency conditions.

Network Upgrades

Cost Estimates

Preliminary cost estimates provided in this analysis are subject to change.

SPP utilizes the five-year-out light load seasonal model for wind fuel type generators and the two-year-out summer peak seasonal model for solar fuel type generators. The two-year-out summer peak seasonal model is used for conventional fuel type generators. If all fuel types are being studied, all sets of models are utilized. Project distribution factors on the identified upgrades, under system intact conditions, are used to determine cost allocation. The impact each generator interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three generator interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for each project has been determined, the cost allocation for generator interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

- Request X, Upgrade Project 1 = PTDF (%)(X) * MW(X) = X1
- Request Y, Upgrade Project 1 = PTDF (%)(Y) * MW(Y) = Y1
- Request Z, Upgrade Project 1 = PTDF (%)(Z) * MW(Z) = Z1

Allocation of Cost for a particular project:

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

Repeat previous for each responsible GI request for each Project.

If the current study interconnection request requires a Network Upgrade for full interconnection service, the study resource will determine the Limited Operation amount available to the request prior to all required Network Upgrades being in-service. **Table 9** lists the allocated costs for Network Upgrades assigned to current study projects.

Network Upgrades consisting of devices such as reactive support in the form of SVCs, capacitor banks, etc. follow the same process shown above with a small difference. The PTDF used is the highest distribution factor (absolute value) from all elements (branches/transformers) connected to the device's location. As an example, a reactive device is connected at bus A. A given project's distribution factors on lines connected to bus A are as follows:

- Branch A-B, Project 1; DFAX = 2%
- Branch A-C, Project 1; DFAX = 4%
- Branch A-B, Project 2; DFAX = -2%
- Branch A-C, Project 2; DFAX = 1%

The resultant PTDFs are:

- Project 1 PTDF = 4%
- Project 2 PTDF = 2%

Table 9: Network Upgrade Cost Estimates

Interconnection Request	ERIS MW	NRIS MW	ERIS	NRIS	Total	ERIS Total	NRIS Total	Total
J1191	64	64	$0	$0	$0	$225,000	$0	$225,000
J1202	68.4	68.4	$0	$0	$0			
J1208	80	80	$0	$0	$0			
J1209	80	80	$0	$0	$0			
J1213	60	60	$0	$0	$0			
J1216	185	185	$0	$0	$0			
J1231	125	125	$0	$0	$0			
J1241	165	165	$0	$0	$0			
J1268	150	70	$0	$0	$0			
J1299	149	149	$225,000	$0	$225,000			
J1303	95	95	$0	$0	$0			
J1306	200	200	$0	$0	$0			
J1311	150	150	$0	$0	$0			
J1352	100	100	$0	$0	$0			
J1488	500	500	$0	$0	$0			
J1490	1000	940	$0	$0	$0			

It should be noted that Network Upgrades associated with higher-queued projects are also considered as Contingent Facilities. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. **While current study interconnection customers do not have cost responsibility for contingent facilities, they may later be assigned cost if higher-queued customers terminate their interconnection request.** The Network Upgrades assumed in-service in the BASE models associated with higher-queued projects are listed in **Appendix C.**

Limited Operation Availability

The results of the power flow identified the system constraints that require mitigation. The Limited Operation analysis identifies an amount of available interconnection service based on the most limiting of these constraints for each current study request. **As the Limited Operation amount is calculated using the transfer cases developed for this study, the amount available is dependent upon all higher queued interconnection requests and Network Upgrades being in-service.**

Power flow analysis results included the thermal overload amount, circuit rating, size, and TDF of each current study request. An initial Limited Operation amount is calculated by identifying the impact of each request on each constraint and identifying a reduced size of each request proportional to the thermal constraint that would result in a circuit loading within the applicable rating. The Limited Operation amount is calculated according to the following equation:

$$\text{Limited Operation amount} = \text{Request MW} - \frac{\text{MVA Rating} * (\text{Overload p.u.} - 1)}{\text{Request TDF}}$$

With the initial Limited Operation amount request sizes applied to the study cases, ACCC is repeated to verify that the thermal constraints are not observed, or the calculation and verification are repeated until all thermal constraints are mitigated.

Power flow analysis results for voltage violations are then further mitigated by identifying the contribution of each request and determination of the required impact reduction is conducted and verified through ACCC to determine the Limited Operation amount for each request.

Limited Operation results are listed below in **Table 10**. Limited Operation Results of 0 MW are used to provide a conservative limit due to non-convergence and voltage violation results that cannot be calculated using the above formula. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customers may request additional scenarios for Limited Operation based on higher-queued interconnection requests not being placed in service.

Table 10: Limited Operation Results

Interconnection Request	Group	Service Type	Requested MW	Available MW Before Mitigation	Most Limiting Constraint
J1191	03	ERIS	64	64	None
		NRIS	64	64	
J1202	03	ERIS	68.4	68.4	None
		NRIS	68.4	68.4	
J1208	03	ERIS	80	80	None
		NRIS	80	80	
J1209	03	ERIS	80	80	None
		NRIS	80	80	
J1213	03	ERIS	60	60	None
		NRIS	60	60	
J1216	03	ERIS	185	185	None
		NRIS	185	185	
J1231	04	ERIS	125	125	None
		NRIS	125	125	
J1241	03	ERIS	165	165	None
		NRIS	165	165	
J1268	03	ERIS	150	150	None
		NRIS	70	70	
J1299	04	ERIS	149	140	J1087 POI to Kelso 161 kV
		NRIS	149	140	
J1303	03	ERIS	95	95	None
		NRIS	95	95	
J1306	03	ERIS	200	200	None
		NRIS	200	200	
J1311	03	ERIS	150	150	None
		NRIS	150	150	
J1352	03	ERIS	100	100	None
		NRIS	100	100	
J1488	03	ERIS	500	500	None
		NRIS	500	500	
J1490	03	ERIS	1000	100	None
		NRIS	940	940	

Power Flow Analysis Results

The results of the power flow analysis for interconnection requests under study are embedded in **Table 11**.

Table 11: Power Flow Analysis Results

Results	
Non-convergence Constraints	DPP-2019-Central-P3_Non Convergent (
Thermal Constraints	DPP-2019-Central-P3_Thermal Constrair
Voltage Constraints	DPP-2019-Central-P3_Voltage Constraint
Network Upgrades and Cost Allocation Calculation	DPP-2019-Central-P3_Network Upgrade

Conclusion

A power flow analysis was performed to determine the impact of sixteen (16) MISO generator interconnection requests on the SPP transmission system. The results of the power flow analysis identified one contingent constraint that require mitigation. The Limited Operation analysis evaluated the most limiting of these constraints for each current study request and identified an amount of available interconnection service[9]. The minimum cost of interconnecting all-new generator interconnection requests included in this analysis is estimated at $225,000. Allocated costs for Network Upgrades are listed in **Table 9**.

The study results identified one ERIS constraint. Full ERIS capacity is available for projects J1191, J1202, J1208, J1209, J1213, J1216, J1231, J1241, J1268, J1303, J1306, J1311, J1352, J1488 and J1490 as they do not have identified ERIS constraints/upgrades. Generator project J1299 requires one ERIS upgrade to be in service before interconnection service is available. Full NRIS interconnection service capacity is available for projects J1191, J1202, J1208, J1209, J1213, J1216, J1231, J1241, J1268, J1303, J1306, J1311, J1352, J1488, and J1490. Project J1299 requires the identified ERIS upgrade to be in service before NRIS capacity is available.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a generator interconnection request. Because of this, the Customer may be required by the Transmission Provider to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

[9] Limited Operation availability is only valid under the study assumptions indicated in this report.

Nothing in this study should be construed as a guarantee of delivery or transmission service within SPP's transmission system. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on SPP's OASIS by the Customer.

Appendix A

Appendix A -
Current Study Interc

Appendix B

Appendix B -
Higher Queued Inte

Appendix C

Appendix C -
Higher Queued Netv

Appendix D

Appendix D - MISO
Topology Updates C