CIPCO AFFECTED SYSTEM IMPACT STUDIES

CIPCO IR24 & IR32

SOUTHWEST POWER POOL, INC.

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Document Revisions

NO.	Revision	Date	PRD	CHK	APV
1	Draft Report Issued for Review	3/3/2021	RB	WB	WB
2	Revision 1	4/5/2021	WB	WB	WB

Introduction

Central Iowa Power Cooperative (CIPCO) requested a definitive affected system impact study from SPP for CIPCO interconnection projects IR24 & IR32. The purpose of this analysis was to determine the impact of the CIPCO generation interconnection requests on the SPP transmission system. Additionally, the analysis looked to identify the amount of Interconnection Service available to the projects resulting in no constraints requiring mitigation. This analysis evaluated two (2) CIPCO interconnection requests in SPP cluster Groups 9 with a total generation capacity of 112 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 generation interconnection requests analyzed in this Affected System Impact Study 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 2002 were used for this analysis. SPP provided the following DISIS-2017-001 BASE case models:

- Year 1 (2020) Summer Peak (20SP)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)

EPE updated power flow cases to reflect the groups under study and developed a total of Sixteen (16) cases, specifically 8 Base Cases (BC) and 8 Transfer Cases (TC). The power flow analysis was performed to determine if the transmission system can accommodate the injection from the current study cluster generation interconnection requests without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria Section.

The Affected System Impact Study (ASIS) has been conducted consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) and SPP Business Practices to determine impacts to the SPP transmission system.

[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

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-2017-001 BASE cases.
4. Current study network upgrades previously identified by SPP for consideration in the analysis.

The CIPCO Affected System Impact Study included two (2) generation interconnection requests ("GIRs") in the CIPCO footprint. **Appendix A** lists the current study cluster generation interconnection requests included in the study. The DISIS-2017-001 BASE models are based on modified version of the 2019 ITP cases and served as the starting point for the IR24 & IR32 analysis. The BASE models were derived by adding higher queued interconnection requests not already existing in the model and their associated network upgrades[2]. The CIPCO study generators, including all available collector system data, were added, and kept offline in BASE models listed below:

- Year 1 (2020) Summer Peak (20SP)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)

Higher queued projects were included in the models, including the DISIS-2017-001 cluster or before and MISO DPP Feb-17 and prior. If the interconnection request was not already existing 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 Generation 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 included in this study are listed in **Appendix B**. Note that DISIS-2016-002 projects and upgrades were already included in the BASE cases.

As the DISIS-2017-001 phase 2 network upgrades are not expected be finalized until April 2021, two scenarios were evaluated to mitigate constraints identified from the transfer case (1) without any network upgrades included from the FEB-17, GIA-61 and DISIS-2017-001 cluster and (2) with FEB-17 West, GIA-61 and DISIS-2017-001 Phase 1 upgrades added as needed to mitigate constraints.

[2] The DISIS-2017-001 BASE model did not contain network upgrades from the FEB17-West, GIA-61 or DISIS-2017-001 cluster even though those clusters are higher queued.

Grouping

The interconnection requests listed in **Appendix A** and **Appendix B** are grouped into sixteen (16) active regional groups. The SPP groupings are listed in **Table 1** 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 1: All SPP Groupings

Group #	Area	Group #	Area
1	Woodward, OK	10	Southeast OK/Northeast TX
2	Hitchland, OK	12	Northwest AR
3	Spearville, KS	13	Northwest MO
4	Northwest KS	14	South Central OK
6	South TX Panhandle/New Mexico	15	East SD
7	Southwest OK	16	West ND
8	North OK/South Central KS	17	West SD
9	Nebraska	18	East ND

Development of Base Cases (BC Cases)

The number of base cases (BC) and transfer cases (TC) required for each impact study depends on the service requested and fuel type of the study units. **Table 2** outlines the number of cases required per seasonal case for each dispatch scenario. **Table 4** describes SPP dispatch criteria used for this analysis.

Table 2: SPP Seasons and Cases per Dispatch

Seasonal Case	ERIS HVER	ERIS LVER	NRIS
+1 Summer Peak (i.e. 20SP)	1 per group	1 per study	1 per study
+5 Light Load (i.e. 24L)	1 per group	--	1 per group
+5 Summer Peak (i.e. 24SP)	1 per group	1 per study	1 per study
+5 Winter Peak (i.e. 24WP)	1 per group	1 per study	1 per study

Four (4) BASE power flow cases were provided as the starting point for this analysis. The SPP regional group (Group 9) had two types of dispatch for their local generation: High-Variable Energy Resource (HVER) and Network Resource Interconnection Service (NRIS). The groups and the dispatch resulted in 16 cases with unique dispatches, as shown in **Table 3**.

Table 3: CIPCO Study Cases

Seasonal Case	ERIS HVER	ERIS LVER	NRIS
+1 Summer Peak (i.e. 20SP)	1 per group	--	1 per study
+5 Light Load (i.e. 24L)	1 per group	--	1 per group
+5 Summer Peak (i.e. 24SP)	1 per group	--	1 per study
+5 Winter Peak (i.e. 24WP)	1 per group	--	1 per study
CIPCO	**16 Cases (8 BC/8 TC)**		

All in-scope higher queued SPP and MISO generators listed in **Appendix B** were added and dispatched per criteria listed in **Table 4**. SPP region generation offset caused by the 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. On the other hand, LRS was not used in non-SPP regions, and the 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 Cases)

All in-scope higher-queued and current study interconnection requests were dispatched as per criteria listed in **Table 4**. 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[3] conventional generation[4] in the host TO footprint. For the High Variable Energy Resource (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 scenarios. The HVER dispatch scenario was used with all cases including Winter, Summer, Spring, 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 upon the level of system integration being requested (ERIS and NRIS). For Spring and 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 accounted for the in NR dispatch, where 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 project 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.

[3] 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” generators.

[4] Excluding non-adjustable generation such as hydro/run-of-river

Table 4: SPP Dispatch Criteria

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

* If units are already online in the model, the dispatch is left as-is.

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 found by 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 for 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% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (N-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Non-converged contingencies shall also be considered for limited operation service.

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% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

Contingencies

The contingency set includes all SPP control area branches and ties 69kV 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 65kV – 999kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659
  - SPP External Areas for 100kV – 999kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP T.O. Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP T.O. 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 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 65kV – 999kV 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 (69kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA		0.90 – 1.05 pu
KACY		
SWPA		
OKGE		
OMPA		
WFEC		
SWPS		
MIDW		
SUNC		
KCPL		
INDN		
SPRM		

NPPD		
WAPA		
WERE L-V		0.93 – 1.05 pu
WERE H-V		0.95 – 1.05 pu
EMDE L-V		0.90 – 1.05 pu
EMDE H-V		0.92 – 1.05 pu
LES		0.90 – 1.05 pu
OPPD		

SPP Buses with more stringent voltage criteria:

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

Affected System Areas (115kV+):

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

<table>
<tr><td>SMMPA</td><td rowspan="3"></td><td></td></tr>
<tr><td>GRE</td><td>0.90 – 1.10 pu</td></tr>
<tr><td>OTP</td><td>0.90 – 1.05 pu</td></tr>
<tr><td>OTP-H (115kV+)</td><td>0.97 – 1.05 pu</td><td>0.92 – 1.10 pu</td></tr>
<tr><td>ALTW</td><td rowspan="7">0.95 – 1.05 pu</td><td rowspan="3">0.90 – 1.05 pu</td></tr>
<tr><td>MEC</td></tr>
<tr><td>MDU</td></tr>
<tr><td>SPC</td><td>0.95 – 1.05 pu</td></tr>
<tr><td>DPC</td><td rowspan="2">0.90 – 1.05 pu</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 pu voltage

Identification of Network Constraints

ERIS Thermal Non-Converged Constraint Identification and Mitigation

There were no non-converged thermal constraints identified for Group 9 ERIS interconnection requests.

ERIS Thermal System Intact and Contingency Constraint Identification and Mitigation

There were no system intact or contingency thermal constraints identified for Group 9 ERIS interconnection requests.

ERIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Groups 9 ERIS interconnection requests.

NRIS Thermal Non-Converged Constraint Identification and Mitigation

There were no non-converged thermal constraints identified for Group 9 NRIS interconnection requests.

NRIS Thermal System Intact and Contingency Constraint Identification and Mitigation

There were no system intact or contingency thermal constraints identified for Group 9 NRIS interconnection requests. Several NRIS thermal constraints were resolved by contingent network upgrades. **Table 5** below summarizes the NRIS thermal constraints and associated contingent mitigations. All contingent mitigations listed below are currently assigned to the higher queued AECI interconnection request GIA-61.

Table 5 : NRIS Contingent Thermal Constraints

Monitored Facility	Mitigation
Maryville to Maryville 161 kV Bus-Tie Upgrade	Maryville to Maryville 161 kV Bus-Tie Upgrade
Maryville to Midway 161 kV	Rebuild Maryville to Midway 161 kV
Midway to Avenue City 161 kV	Rebuild Midway to Avenue City 161 kV
Avenue City to St Joseph 161 kV	Rebuild Avenue City to St Joseph 161 kV
Nashua 345/161 kV Transformer	Add 2nd Nashua 345/161 kV Transformer

NRIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Group 9 NRIS interconnection requests.

Network Upgrade Cost Estimates, Alternative Solutions, and Limited Operation Availability

Network Upgrade Cost Estimates

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

SPP utilizes the one-year-out spring seasonal model for Variable Energy Resources (VERs). The five-year-out summer peak seasonal model is used for conventional fuel type generators. If both fuel types are being studied, both 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 generation 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 Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective power transfer distribution factors (PTDF) for the project have been determined, the cost allocation for Generation 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 ($) = $\frac{\text{Network Upgrade Project 1 Cost (\$)} * X1}{X1 + Y1 + Z1}$

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 6** lists the allocated costs for Network Upgrades assigned to current study projects.

Table 6: Network Upgrade Cost Estimates

Interconnection Request	Size	ERIS	NRIS	Total	ERIS Total	NRIS Total	Total
IR24	56	$0	$0	$0	$0	$0	$0
IR32	56	$0	$0	$0			

It should be noted that network upgrades associated with higher-queued projects are also considered as contingent upgrades. 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. **The interconnection customers, at this time, do not have cost responsibility for these contingent facilities but may later be assigned cost if higher-queued customers terminate their interconnection request.** The network upgrades 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 evaluated the most limiting of these constraints for each current study request and identifies an amount of available interconnection 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:

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

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 Power Flow Analysis Limited Operation amount for each request.

Limited Operation Results are listed below in **Table 7**. 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 7: Limited Operation Results

Interconnection Request	Group	Service Type	Available MW Before Mitigation	Most Limiting Constraint
IR24	09 NEB	ERIS	56	None
		NRIS	56	None
IR32	09 NEB	ERIS	56	None
		NRIS	56	None

Power Flow Analysis

The results of the power flow analysis for interconnection requests under study are embedded in **Table 8**.

Table 8: Power Flow Analysis Results

Results	
Thermal Constraints	CIPCO_Thermal_Constraints.xlsx
Voltage Constraints	N/A
Network Upgrades and Cost Allocation Calculations	CIPCO_Network_Upgrades_Cost_Allocat

Conclusion

A power flow analysis was performed to determine the impact of two (2) CIPCO GIRs on the SPP transmission system. The results of the Power Flow analysis identified several contingent constraints and no additional system constraints required mitigation. Therefore, no CIPCO project has any cost allocation or limited operation availability assigned.

Appendix A: Current Study Interconnection Requests

ERIS

Generation Interconnection Number	Study	Group	Type	G PMAX	SP PMAX	WP PMAX	Service	GEN Area	Point of Interconnection
IR24	CIPCO	09 NEB	Wind	56	56	56	ER/NR	ALTW	New 69kV substation near Prescott REC
IR32	CIPCO	09 NEB	Wind	56	56	56	ER/NR	ALTW	Murray Junction 69 kV substation

NRIS

Generation Interconnection Number	Study	Group	Type	G PMAX	SP PMAX	WP PMAX	Service	GEN Area	Point of Interconnection
IR24	CIPCO	09 NEB	Wind	56	56	56	ER/NR	ALTW	New 69kV substation near Prescott REC
IR32	CIPCO	09 NEB	Wind	56	56	56	ER/NR	ALTW	Murray Junction 69 kV substation

Appendix B: Higher Queued Interconnection Requests

Higher_Queued_Int
erconnection_Requ

Appendix C: Higher Queued Network Upgrades

Higher_Queued_Network_Upgrades.xlsx