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MISO DPP 2017 February West Area Phase 3 Study

Prepared for

MISO

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9/12/2019	A	Draft Report
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Contents

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Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate interconnection of the DPP 2017 February Phase 3 West Area Group (DPP West Area) generating facilities.

1.1 Project List

The DPP West Area study group has two generation projects with a combined nameplate rating of 245 MW. The DPP West Area generating facilities are listed in Table ES-1. The modeling details and projects' slider diagrams are shown in Appendix B.

Table ES-1: Generating Facilities in DPP 2017 February West Area Group

MISO Project #	Service Type	TO	County	State	Point Of Interconnection	Fuel Type	ERIS Output	NRIS Output	SH MW	SPK MW	Stability MW
J718	NRIS	DPC	Fillmore	MN	Cherry Grove 69 kV	Solar	45	45	22.5	45	45
J748	NRIS	MEC	Plymouth	IA	O'Brien-Raun 345 kV	Wind	200	175	200	31.2	200

1.2 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

Non-synchronous generation projects in the DPP 2017 February West Area study group that did not have signed Generator Interconnection Agreement (GIA) or Provisional GIA (PGIA) on September 21, 2016 are required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

All non-synchronous generation projects in this study group are required to meet the reactive power requirements per FERC Order 827.

The reactive power requirement analysis results are summarized as following:

- Both J718 and J748 generation projects satisfy FERC Order 827 reactive power requirements.

1.3 Total Network Upgrades for all Projects

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection Service as of the System Impact Study report date. The total cost of network upgrades in the interconnection plan required for each generation project is listed in Table ES-2. The costs for Network Upgrades are planning level estimates and subject to revision in the facility studies.

Table ES-2: Total Cost of Network Upgrades for DPP 2017 February West Area Generation Projects

Project Num	ERIS Network Upgrades ($)								NRIS Network Upgrades ($)	Interconnection Substation TO NUs ($)	TO's Interconnection Facilities (TOIF)	SNU ($)	Total Network Upgrade Cost (Exclude TOIF & Affected System) ($)
	MWEX Voltage Stability	MISO Thermal & Voltage	Transient Stability	Short Circuit	DPC LPC	CIPCO AFS	PJM AFS	SPP AFS					
J718	$0	$0	$0	$0	$0	$500,000	$0	$31,016,261	$0	$1,300,000	$500,000	$0	$1,300,000
J748	$0	$0	$0	$0	$0	$0	$0	$229,663,267	$0	$12,500,000	$825,000	$0	$12,500,000
Total ($)	**$0**	**$0**	**$0**	**$0**	**$0**	**$500,000**	**$0**	**$260,679,528**	**$0**	**$13,800,000**	**$1,325,000**	**$0**	**$13,800,000**

The study was performed under the direction of MISO by Siemens PTI and an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

1.4 Per Project Summary

This section provides the estimated cost of Network Upgrades on a per project basis.

1.4.1 J718 Summary

Network Upgrade	Cost	J718	NUs Type
Hazleton-Dundee 161 kV	$500,000	$500,000	CIPCO AFS
Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	$101,400,000	$13,192,782	SPP AFS
Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	$11,810,905	$1,547,310	SPP AFS
Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	$57,278,451	$6,840,009	SPP AFS
Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	$4,173,779	$543,035	SPP AFS
Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	$67,188,955	$8,893,125	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$31,516,261**	

1.4.2 J748 Summary

Network Upgrade	Cost	J748	NUs Type
Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	$101,400,000	$88,207,218	SPP AFS
Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	$11,810,905	$10,263,596	SPP AFS
Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	$57,278,451	$50,438,442	SPP AFS
Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	$4,173,779	$3,630,744	SPP AFS
Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	$67,188,955	$58,295,831	SPP AFS
Build Nashua 345/161 kV xfmr Ckt 2	$9,413,718	$9,413,718	SPP AFS

Network Upgrade	Cost	J748	NUs Type
Build Post Rock 345/230 kV Xfmr Ckt 2	$9,413,718	$9,413,718	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$229,663,267**	

1.5 Study Compliance with NERC FAC-002-2 Standard

This DPP 2017 February West Area study was completed in compliance with NERC FAC-002-2:

R1.1: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s).

Section 3 covers summer peak steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities. Thermal and voltage upgrades required to interconnect the new generating facilities are also identified.

Section 4 covers summer shoulder steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities. Thermal and voltage upgrades required to interconnect the new generating facilities are also identified.

Section 5.1 covers reliability impact of the generating facilities per DPC Local Planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 6.1 covers reliability impact of the new generating facilities in the CIPCO affected systems.

Section 6.2 covers reliability impact of the new generating facilities in the PJM affected systems.

Section 6.3 covers reliability impact of the new generating facilities in the SPP affected systems.

Section 7 covers transient stability analysis results.

Section 8 covers voltage stability (PV) analysis on the MWEX System Operating Limit (SOL). Network Upgrades required for MWEX voltage stability are identified.

Section 9 covers short circuit reliability impact of the new generating facilities.

Section 10 covers Deliverability reliability impact of the new NRIS generating facilities.

R1.2: Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements.

Sections 2.2-2.4, Section 5, Section 6, and Section 7 all cover NERC Reliability Standard TPL-001-4.

Section 5.1 covers DPC LPC.

Section 6.1 covers CIPCO system planning criteria.

Section 6.2 covers PJM system planning criteria.

Section 6.3 covers SPP system planning criteria.

Section 8 (voltage stability analysis) covers individual system planning criteria (ATC).

Section 10 covers MISO system planning criteria.

R1.3: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions.

Section 3 and Section 4 cover MISO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.1 covers DPC's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.1 covers CIPCO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.2 covers PJM steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.3 covers SPP steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 7 covers transient stability studies under NERC category P0 to P7 contingencies (TPL-001-4).

Section 8 covers steady-state voltage stability assessment.

Section 9 covers short circuit assessment.

Section 10 covers MISO deliverability study (steady-state assessment) including NERC category P0 to P1 contingencies (TPL-001-4).

R1.4: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

Section 2.1, Section 2.2, Section 2.3, Section 2.4, Section 7.2, Section 7.3, and Section 7.4 cover study assumptions and system performance criteria.

Jointly coordinated recommendations can be found in Section 5.1 (MISO and DPC), Section 6.1 (MISO and CIPCO), Section 6.2 (MISO and PJM), Section 6.3 (MISO and SPP), and Section 8 (MISO and ATC). Results in Section 3, 4, 5, 6, 7, 9 and 10 have also been reviewed by PJM, SPP, and CIPCO.

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Section 1

Introduction

Two generation projects, listed in Table A-1 (Appendix A.1), have requested to interconnect to the MISO transmission network in the West Area and have advanced to the Definitive Planning Phase (DPP) 2017 February Phase 3 study (DPP West Area). All generating facilities have requested Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report presents the study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generating facilities in the DPP West Area Phase 3 study.

The study was performed under the direction of MISO by Siemens PTI and an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

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Section

2

Model Development and Study Criteria

2.1 Model Development

2.1.1 Benchmark Cases

DPP 2017 February West area power flow benchmark cases representing 2023 summer shoulder and summer peak conditions were developed from the MTEP18 models with LBA dispatch.

The benchmark cases for DPP 2017 February study were created as follows:

- MISO Prior queued generation projects and their associated Network Upgrades (NU) were modeled. Appendix A.2 lists all DPP 2016 August West Area Phase 3 Network Upgrades included in the models.
- DPP 2017 February generation projects in the West Area (DPP West Area, Table A-1) were modeled with offline status.
- DPP 2017 February generation projects in the Central Area (Table A-4), Michigan Area (Table A-5), and ATC Area (Table A-6) were modeled and dispatched.
- For MISO generation projects, their output was sunk to the MISO Classic (Appendix A.4, Table A-9), where generation was scaled uniformly;
- PJM generation projects were modeled and dispatched. The generation output was sunk to the PJM market (Appendix A.5, Table A-10), where generation was scaled uniformly.
- SPP generation projects were modeled and dispatched. The generation output was sunk to the SPP market (Appendix A.6, Table A-11), where generation was scaled uniformly. The Network Upgrades identified in the SPP DIS2016-001 and DIS2016-002 studies were also modeled.
- The Hickory Creek–Cardinal 345 kV project (MVP project 3127) was included in the 2023 models; the Hickory Creek-Cardinal 345 kV project has an in-service date of 12/31/2023.
- Models were further reviewed by the Ad Hoc study members (transmission owners and customers). Model corrections and changes were made based on the comments and feedback. These modeling changes are listed in Appendix A.2.
- Adjusted Square Butte DC to match the total output of the Bison (Bison 1 to 5) and Oliver County (Oliver County 1 and 2) wind farms.
- Adjusted CU DC to match the total output of Coal Creek generation units #1 and #2.
- MHEX interface transfer level is approximately 1074 MW in summer shoulder and 1742 MW in summer peak cases.

2.1.2 Study Cases

The summer peak study case was created by dispatching the DPP West Area generating facilities at the specified summer peak level (Table ES-1) from the benchmark cases.

The summer shoulder study case was created by dispatching the DPP West Area generating facilities at the specified summer shoulder level (Table ES-1) from the benchmark cases.

To mitigate low voltages on the SPP system, two fictitious SVCs (Table 2-1) were added to the summer shoulder cases as proxies for SPP upgrades to be identified by SPP in the affected system study.

Table 2-1: Fictitious SVCs Added Only in Summer Shoulder Case

Location	Bus #	SVC Mvar
Post Rock 345 kV	530583	350
Mingo 345 kV	531451	300

The MISO Classic was used for power balance, where generation was scaled uniformly.

Both study and benchmark power flow cases were solved with transformer tap adjustment enabled, area interchange disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled.

The interface transfer levels in the study cases are summarized in Table 2-2.

Table 2-2: Interface Transfer Levels in Steady State Study Cases

Interface	SH Case (MW)	SPK Case (MW)
MHEX	1073	1742
MWEX	1529	752
Arrowhead – Stone Lake 345 kV	627	274

2.2 Contingency Criteria

A variety of contingencies were considered for steady-state analysis:

- NERC Category P0 with system intact (no contingencies)
- NERC Category P1 contingencies
  - NERC Category P1 contingencies, at buses with a nominal voltage of 69 kV and above, in the following areas: CWLD (area 333), AMMO (area 356), AMIL (area 357), CWLP (area 360), SIPC (area 361), WEC (area 295), WEC MI (area 296), XCEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MPW (area 633), MEC (area 635), MDU (area 661), BEPC-MISO (area 663), MHEB (area 667), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698), CE (area 222), NPPD (area 640), OPPD (area 645), LES (area 650), WAPA (area 652), BEPC-SPP (area

659), AECI (area 330), MIPU (area 540), KCPL (area 541), KACY (area 542), INDN (area 545).
  - Multiple-element NERC Category P1 contingencies, in Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. The specified Category P1 contingency files are listed in Appendix A.7.
- NERC Category P2-P7 contingencies
  - Selected NERC Category P2-P7 contingencies provided by the Ad Hoc Study Group, in the study region of Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. The specified Category P2-P7 contingency files are listed in Appendix A.7.

For all contingency and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

2.3 Monitored Elements

The study area is defined in Table 2-3. Facilities in the study area were monitored for system intact and contingency conditions. Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal (PSS®E rate A) rating. Under NERC category P1-P7 conditions, branches were monitored for loading as shown in the column labeled "Post-Disturbance Thermal Limits".

Table 2-3: Monitored Elements

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
AECI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
AMIL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
AMMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
ATCLLC	69 kV and above	95% of Rate A	95% of Rate B	1.05/0.95	1.10/0.90
BEPC-MISO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
BEPC-SPP	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CWLD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CWLP	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
CE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
GMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.92/0.90
INDN	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.95	1.10/0.93
KACY	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
KCPL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
LES	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.96/0.95	1.05/0.96/0.95/0.94/ 0.93[3]
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04/ 0.99/0.97/0.96/0.95	1.15/1.10/0.94/0.90
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.10/0.95
MPW	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.06/0.92
NPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
OPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.10/0.92
PPI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
SIPC	69 kV and above	100% of Rate A	100% of Rate B	1.07/0.95	1.09/0.91
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.05/0.92

Notes

1: PSS®E Rate A, Rate B or Rate C

2: Limits dependent on nominal bus voltage

3: For facilities in Cedar Falls Utilities or Ames Municipal Utilities, post-contingency voltage limits are 1.05/0.94 for >200 kV, and 1.05/0.93 for others.

2.4 Performance Criteria

A branch is a thermal injection constraint if the branch is loaded above its applicable normal or emergency rating for the post-change case, and any of the following conditions are met:

1. the generator (NR/ER) has a larger than 20% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, or
2. the megawatt impact due to the generator is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility, or
3. the overloaded facility or the overload-causing contingency is at generator's outlet, or
4. for any other constrained facility, where none of the study generators meet one of the above criteria in 1), 2), or 3), however, the cumulative megawatt impact of the group of study generators (NR/ER) is greater than 20% of the applicable rating, then only those study generators whose individual MW impact is greater than 5% of the applicable rating and has DF greater than 5% (OTDF or PTDF) will be responsible for mitigating the cumulative MW impact constraint.

A bus is considered a voltage constraint if both of the following conditions are met. All voltage constraints must be resolved before a project can receive interconnection service.

1. the bus voltage is outside of applicable normal or emergency limits for the post-change case, and
2. the change in bus voltage is greater than 0.01 per unit.

All DPP 2017 February West Area study generators must mitigate thermal injection constraints and voltage constraints in order to obtain unconditional Interconnection Service.

Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the deliverability algorithm, to meet the system performance criteria for NERC category P0-P1 events, if the constraint demonstrates an incremental flow caused by the generator equal to or greater than 5% of the generator's maximum dispatch level in each case.

2.5 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

Non-synchronous generation projects in the DPP 2017 February West Area study group that did not have signed Generator Interconnection Agreement (GIA) or Provisional GIA (PGIA) by September 21, 2016 are required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

All non-synchronous generation projects in this study group are required to meet FERC Order 827 reactive power requirements.

Collector system and shunt compensation of DPP West projects are modeled, which are listed in Appendix A.1, Table A-3. An analysis was performed to study the FERC Order 827 reactive power requirements for the non-synchronous generation projects in the DPP 2017 February West study group. The analysis was performed as follows:

> Step 1: Verify that the total dynamic reactive power (reactive power from generators and dynamic compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the generator terminal bus. The verification in Step 1 was performed when generator data was submitted and modeled.
>
> Step 2: Verify that the total reactive power (reactive power from generators, dynamic compensation devices, and static compensation devices) in the plant can meet the reactive power range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. The testing procedure in Step 2 is described in the following:
>
> - Lock the high-side of the generator substation at 1.0 pu voltage by adding a fictitious SVC. This is to ensure that the test result is not affected by system conditions.
> - Lock the reactive power output of the generator at the maximum limit (Qmax). Make sure all shunt compensation devices within the substation are at the maximum capacitive output. Adjust transformer taps to ensure bus voltages within the substation are within 0.95 – 1.05 pu range. Measure real power and reactive power from the generator plant to the high-side of the generator

substation. Calculate the power factor to verify it satisfies the 0.95 lagging requirement.

- Lock the reactive power output of the generator at the minimum limit (Qmin). Make sure all shunt compensation devices within the substation are at the maximum inductive output. Adjust transformer taps to ensure bus voltages within the substation are within 0.95 – 1.05 pu range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify it satisfies the 0.95 leading requirement.

Appendix C lists reactive power requirement analysis results for the DPP West generation projects. The results are summarized as following:

- Both J718 and J748 generation projects satisfy FERC Order 827 reactive power requirements.

Section

3

Summer Peak Steady-State Analysis

Summer peak steady-state analysis was performed to identify thermal and voltage upgrades required to interconnect the generating facilities in the DPP 2017 February West Area group to the transmission system.

3.1 Study Procedure

3.1.1 Computer Programs

Steady-state analyses were performed using PSS®E version 33.12 and PSS®MUST version 12.0.1.

3.1.2 Study Methodology

A summer peak power flow case was created using the procedure described in Section 2.1. Fictitious SPP SVCs were not modeled. Nonlinear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP West Area generating facilities was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Network upgrades were identified to mitigate any summer peak constraints.

3.2 Summer Peak Contingency Analysis Results

The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows and voltages between benchmark case (without DPP West Area projects) and study case (with DPP West Area projects). Analysis was performed in the summer peak scenario using PSS®E and PSS®MUST.

3.2.1 System Intact Conditions

For NERC category P0 (system intact) conditions, no thermal or voltage constraints were identified (Table D-1, Table D-2).

3.2.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies.

All category P1 contingency solutions converge. There are no thermal or voltage constraints for P1 contingencies (Table D-3 and Table D-4).

Two category P2-P7 contingencies (Table D-7) do not converge, and their dc thermal results are listed in Table D-8. These contingencies do not converge in the benchmark or study cases. No mitigation plan is required for the study projects for these contingencies.

There are no thermal or voltage constraints for category P2-P7 contingencies in the summer peak scenario (Table D-5 and Table D-6).

3.3 Network Upgrades Identified in MISO ERIS Analysis for Summer Peak Scenario

There are no thermal or voltage constraints in the summer peak scenario.

Section 4

Summer Shoulder Steady-State Analysis

Summer shoulder steady-state analysis was performed to identify thermal and voltage upgrades required to interconnect the generating facilities in the DPP 2017 February West Area group to the transmission system.

4.1 Study Procedure

4.1.1 Computer Programs

Steady-state analyses were performed using PSS®E version 33.12 and PSS®MUST version 12.0.1.

4.1.2 Study Methodology

A summer shoulder power flow case was created using the procedure described in Section 2.1. Nonlinear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP West Area generating facilities was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Network upgrades were identified to mitigate any summer shoulder constraints.

4.2 Summer Shoulder Contingency Analysis Results

The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows and voltages between benchmark case (without DPP West Area projects) and study case (with DPP West Area projects). Analysis was performed in the summer shoulder scenario using PSS®E and PSS®MUST.

4.2.1 System Intact Conditions

For NERC category P0 (system intact) conditions, thermal constraints are listed in Table E-1, and voltage constraints are listed in Table E-2.

4.2.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies.

All category P1 contingency solutions converge. There are no thermal or voltage constraints for P1 contingencies (Table E-3, Table E-4).

Two category P2-P7 contingencies (Table E-7) do not converge, and their dc thermal results are listed in Table E-8. These contingencies do not converge in the benchmark or study cases. No mitigation plan is required for the study projects for these contingencies.

4.3 Network Upgrades Identified in MISO ERIS Analysis for Summer Shoulder Scenario

There are no thermal or voltage constraints in the summer shoulder scenario.

Section

5

Local Planning Criteria Analysis

Local Planning Criteria (LPC) analyses were performed to identify additional constraints per Transmission Owning Companies' LPC.

5.1 DPC Local Planning Criteria Analysis

Siemens PTI performed the LPC analysis based on DPC's Local Planning Criteria. The DPC LPC analysis details can be found in Appendix F.1.

The DPC LPC analysis consisted of steady-state contingency analysis for summer shoulder system conditions. DPC determined that the projects in Table 5-1 should be redispatched to their rated output per DPC LPC.

Table 5-1. Generation Dispatched to Pmax per DPC LPC Case

Gen Name	Bus #	Machine Id	Area	Fuel Type
J614	86144	1	ITCM	Wind
J718	87183	1	DPC	Solar
Crane Creek	693756	W	ITCM	Wind
Adams Wind	600058	W	ITCM	Wind
Adams Wind	615120	W	ITCM	Wind

5.1.1 Additional Network Upgrades Identified in DPC LPC Analysis

No thermal or voltage constraints were identified in the DPC LPC analysis. No additional Network Upgrades were required in the DPC LPC study.

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Section

6

Affected System Steady-State Analysis

Steady state analyses were performed to identify constraints in affected systems.

6.1 Affected System Analysis for CIPCO Company

Per CIPCO Affected System Planning Criteria, a CIPCO transmission facility is a constraint if it satisfies all three of the following conditions:

1. the branch is loaded above its applicable normal or emergency rating for the post-change case, and
2. the generator has a larger than 3% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, and
3. the loading increase of the overloaded facility is greater than 1 MVA compared with that in the pre-change case under system intact or contingency conditions.

AC contingency analysis was performed for this CIPCO affected system analysis, using the following benchmark and study cases:

- Summer peak benchmark and study cases
- Summer shoulder benchmark and study cases

All NERC category P0-P7 contingencies described in Section 2.2 were simulated. The CIPCO affected system was monitored.

CIPCO thermal constraints identified in the affected system analysis are listed in Appendix G.1. The highest loading and potential network upgrades for summer shoulder system conditions are listed in Table 6-1. There are no CIPCO thermal constraints for summer peak conditions.

Table 6-1. CIPCO Summer Shoulder Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation	Cost ($)
				(MVA)	(%)				
J718	Hazleton-Dundee 161 kV	327.0	CIPCO ITCM	333.9	102.1	CEII Redacted	P1	CIPCO: Upgrade Dundee terminal to 3000 Amps ITCM: CIPCO LPC. $0	$500,000
J718	Hazleton-Dundee 161 kV	327.0	CIPCO ITCM	342.2	104.6	CEII Redacted	P2-P7	CIPCO: Upgrade Dundee terminal to 3000 Amps ITCM: CIPCO LPC. $0	

6.2 PJM Affected System Analysis

The PJM affected system analysis details (dated 6/11/2019) can be found in Appendix G.2.

6.2.1 Study Results

6.2.1.1 Overload on Quad Cities–ESS H471 345 kV line

To relieve the Quad Cities–ESS H471 345 kV line overload:

a. Existing 2019 baseline upgrade b2692.1: Mitigate sag limitations and upgrade conductor ratings of Cordova – Nelson, Quad Cities – ESS H471, and ESS H471 – Nelson 345 kV lines.

b. Existing 2019 baseline upgrade b2692.2: Replace station equipment at Nelson, ESS H471, and Quad Cities substations.

c. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J745, J748.

Based on PJM cost allocation criteria, 2017 February MISO DPP projects are not responsible for cost towards these upgrades.

6.2.1.2 Overload on Cordova–Nelson 345 kV line

To relieve the Cordova–Nelson 345 kV line overload:

a. Existing 2019 baseline upgrade b2692.1: Mitigate sag limitations and upgrade conductor ratings of Cordova – Nelson, Quad Cities – ESS H471, and ESS H471 – Nelson 345 kV lines.

b. Existing 2019 baseline upgrade b2692.2: Replace station equipment at Nelson, ESS H471, and Quad Cities substations.

c. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J748.

Based on PJM cost allocation criteria, 2017 February MISO DPP projects are not responsible for cost towards these upgrades.

6.2.1.3 Overload on ESS H471–Nelson 345 kV line

To relieve the ESS H471–Nelson 345 kV line overload:

d. Existing 2019 baseline upgrade b2692.1: Mitigate sag limitations and upgrade conductor ratings of Cordova – Nelson, Quad Cities – ESS H471, and ESS H471 – Nelson 345 kV lines.

e. Existing 2019 baseline upgrade b2692.2: Replace station equipment at Nelson, ESS H471, and Quad Cities substations.

f. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J748.

Based on PJM cost allocation criteria, 2017 February MISO DPP projects are not responsible for cost towards these upgrades.

6.2.1.4 Overload on Twin Branch–Argenta 345 kV line

To relieve the Twin Branch–Argenta 345 kV line overload:

a. PJM Network Upgrade: N5240. A sag check will be required for the ACSR ~ 954 ~ 45/7 ~ RAIL - Conductor Section 1 to determine if the line section can be operated above its emergency rating of 1409 MVA. $208,000.

The following 2017 February DPP projects contribute loading to this constraint: J584, J711, J740, J756, J748.

This upgrade is driven by a prior queue. Per PJM cost allocation rules, the 2017 February DPP projects presently do not receive any cost allocation for these upgrades.

6.2.2 Study Summary

The projects in MISO DPP 2017 February West Area group are not responsible for the cost of Network Upgrades per PJM cost allocation rules.

6.3 SPP Affected System AC Contingency Analysis

Southwest Power Pool (SPP) conducted an Affected System Impact Study (ASIS) to determine the impacts to the SPP transmission system due to the Interconnection Requests queued to the DPP-2017-FEB-West Phase 3 (DPPFEB17-West P3).

This affected system impact study has determined that several network upgrades are required for full interconnection service. These network upgrades and their associated cost allocation are outlined in Table 6-2.

Table 6-2: SPP Identified Network Upgrades with Cost Allocation

Network Upgrades	Upgrade Type	Service Type	Cost Allocation		
			Total NU Cost	J718	J748
Maywood – Zachary 345 kV Ckt 1	Previously Allocated	ER/NR	NA	$0	$0
Zachary – J541 POI 345 kV Ckt 1					
Zachary 345/161 kV Ckt 1 & 2					
Adair – Zachary 161 kV Ckt 1 & 2					
R-Plan	Previously Allocated	ER/NR	NTC 200220	$0	$0
Key Stone – Red Willow 345 kV Ckt 1			$20,200,894		
Red Willow – Post Rock 345 kV Ckt 1			$26,089,957		
Antelope - Grand Prairie 345 kV Ckt 1			$72,081,510		
Atwood Capacitive Reactive Support			$2,000,000		
Mingo 115kV Reactive Power Support			$1,992,248		
PH Run 115kV Reactive Power Support			$1,195,345		
Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	Current Study	ER/NR	$101,400,000	$13,192,782	$88,207,218
Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	Current Study	ER/NR	$11,810,905	$1,547,310	$10,263,596
Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	Current Study		$57,278,451	$6,840,009	$50,438,442
Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	Current Study		$4,173,779	$543,035	$3,630,744
Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	Current Study	NR Only	$67,188,955	$8,893,125	$58,295,831
Build Nashua 345/161 kV xfmr Ckt 2	Current Study	NR Only	$9,413,718	$0	$9,413,718
Build Post Rock 345/230 kV Xfmr Ckt 2	Current Study	NR Only	$9,413,718	$0	$9,413,718

Once the SPP DISIS 2016-002-1 restudy has concluded, SPP will evaluate the need for restudying the DPP-FEB-2017-West projects and lower queued projects affected by those study results and findings.

Affected System Steady-State Analysis

The SPP affected system analysis results (R2, 10/11/2019) for this study are in Appendix G.3.

Section

7

Stability Analysis

Stability analysis was performed to evaluate the transient stability and impact on the region of the generating facilities in the DPP 2017 February West study cycle.

7.1 Procedure

7.1.1 Computer Programs

Stability analysis was performed using PSS®E revision 33.12.

7.1.2 Study Methodology

A stability package representing 2023 summer shoulder (SH) conditions with generating facilities in the DPP 2017 February West Area group was created from the MTEP18 stability package. A benchmark case was created by removing the DPP West Area generating facilities from the study case. Disturbances were simulated to evaluate the transient stability and impact on the region of the generating facilities. If a study case simulation violates MISO transient stability criteria or the local TO's planning criteria, the simulation was repeated on the benchmark case to assess the impact of the generating facilities on the violation.

7.2 Case Development

7.2.1 Study Case

A study case representing 2023 shoulder (SH) conditions was developed from the MTEP18 stability package.

The stability study case was created using the same procedure as the steady state models, as described in Section 2.1.

The interface transfer levels are summarized in Table 7-1.

Table 7-1: Interface Transfer Levels in Stability Study Case

Interface	SH Case (MW)
MHEX	1074
MWEX	1537
Arrowhead – Stone Lake 345 kV	631

7.2.2 Benchmark Case

The DPP West Area generating facilities as described in Table A-1 (Appendix A.1) were removed from the study case. MISO Classic was used for power balance, where generation was scaled uniformly.

7.3 Disturbance Criteria

The stability simulations performed as part of this study considered all the regional and local contingencies listed in Table 7-2. Regional contingencies with pre-defined switching sequences were selected from the MISO MTEP18 study; switching sequences for local contingencies were developed based on the generic clearing times shown in Table 7-3. The admittance for local single line-to-ground (SLG) faults were estimated by assuming that the Thevenin impedance of the positive, negative and zero sequence networks at the fault point are equal.

Table 7-2: Regional and Local Disturbance Descriptions

CEII Redacted

Table 7-3: Generic Clearing Time Assumption

Voltage Level (kV)	Primary Clearing Time (cycle)	Backup Clearing Time (cycle)
345 kV	4	11
230 kV	5	13
161/138 kV	6	18
115 kV	6	20
69 kV	8	24

7.4 Performance Criteria

All generators must mitigate the stability constraints listed below in order to obtain any type of Interconnection Service:

- System instability
- Transient voltage constraint
- Damping violation

7.4.1 MISO Criteria

Stability simulation results are evaluated based on the following MISO criteria:

- All on-line generating units are stable
- No unexpected generator tripping
- Post-fault transient voltage limits: 1.2 per unit maximum, 0.7 per unit minimum.
- Per local TOs' planning criteria, specific transient voltage limits are applied to specific buses, areas or companies that have different requirements.
- All machine rotor angle oscillations must be positively damped with a minimum damping ratio of 0.81633% for disturbances with a fault or 1.6766% for line trips without a fault.

A bus is considered a transient voltage constraint if both of the following conditions are met. All transient voltage constraints must be resolved before a project can receive interconnection service.

1. the bus transient voltage is outside of specified transient voltage limits during transient period, and
2. the bus voltage is at least 0.01 per unit worse than the benchmark case voltage for the same contingency.

7.4.2 Local Planning Criteria

7.4.2.1 ATC Local Planning Criteria

ATC has the following local transient voltage recovery criteria. For facilities in the ATC footprint, transient voltage recovery is evaluated based on ATC's local planning criteria.

- Voltage recovery within 80 percent and 120 percent of nominal for between 2 and 20 seconds following the clearing of a disturbance.

7.4.2.2 ITCM Local Planning Criteria

ITCM has the following local transient voltage and damping criteria. For facilities in the ITCM footprint, transient voltages and dampings are evaluated based on ITCM's local planning criteria.

- Voltages at all busses on the Transmission Systems should not drop below 0.70 per unit after the first swing for more than 5 cycles. The duration for the minimum voltage dip starts after the first swing post clearing of fault.

- Voltage at all Transmission System buses should recover to the applicable post-contingency steady-state voltage level, within 1.0 second of the clearing of the fault.

- Rotor angle oscillation damping ratios are not to be less than 0.03.

7.4.2.3 MEC Local Planning Criteria

MEC has the following local transient voltage and damping criteria. For facilities in the MEC footprint, transient voltages and dampings are evaluated based on MEC's local planning criteria.

- Generator bus transient voltage limits shall adhere to the high voltage duration and low voltage duration curve in Attachment 2 of NERC PRC-024, which is:
  - Generator bus transient over voltage limits (after fault clearing): 1.2 pu voltage from 0.0 to and including 0.2 s; 1.175 pu voltage from 0.2 to and including 0.5 s; 1.15 pu voltage from 0.5 to and including 1.0 s; 1.1 pu voltage for greater than 1.0 s.
  - Generator bus transient low voltage limits (after fault clearing): may be less than 0.45 pu voltage from 0 to 0.15 seconds; Voltage shall remain above 0.45 pu from 0.15 to 0.3 s; Voltage shall remain above 0.65 pu from 0.3 to 2.0 s; Voltage shall remain above 0.75 pu from 2.0 to 3.0 s; Voltage shall recover to 0.9 pu after 3 s.

- Load bus transient voltage limits:
  - Load bus transient over voltage limits (after fault clearing): 1.6 pu voltage from 0.01 to and including 0.04 s; 1.2 pu voltage from 0.04 to and including 0.5 s; 1.1 pu voltage from 0.5 to and including 5 s; and 1.05 pu voltage for greater than 5 s. These voltage limits also apply to buses without loads or generators.
  - Load bus transient low voltage limits (after fault clearing): may be less than 0.7 pu voltage from 0 to 2 s; Voltage shall remain above 0.7 pu from 2 to 20 s; Voltage shall recover to 0.9 pu after 20 s.

- Angular transient stability minimum damping ratio (ζ) should not be less than 0.03.

7.5 Stability Results

The contingencies listed in Table 7-2 were simulated using the summer shoulder study case with inclusion of the Base Case NU and Reactive Power NU. If a transient stability criteria violation was identified, the same disturbance was repeated in the benchmark case.

Appendix H.2 contains plots of generator rotor angles, generator power output, generator terminal voltages, bus voltages, and branch flows for each simulation. Simulations were performed with a 2.0 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 12-second duration.

Stability study results summary is in Appendix H, Table H-1. The following stability related issues were identified.

7.5.1 Transient High Voltage Violations

Under two disturbances listed in Table 7-4, voltage at buses listed in Table 7-4 exceeds 1.2 per unit for ¾ of a cycle (12 milliseconds) after faults are cleared. These transient high voltages have less than 0.01 per unit increase compared with those in the benchmark case, as shown in Table 7-4. These voltage violations are outside of the 0 to 10 Hz frequency bandwidth covered by transient stability simulation tools such as PSS®E, so these results are not reliable[1], and the voltage spikes are not categorized as constraints.

Because transient high voltages in the study case have less than 0.01 per unit increase compared with those in the benchmark case, projects in DPP 2017 February West cycle are not responsible for mitigating the identified transient high voltage violations.

Table 7-4: Transient Voltages above 1.2 per unit

CEII Redacted

7.6 Network Upgrades Identified in Stability Analysis

No additional Network Upgrades are required in the stability analysis.

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[1] North American Electric Reliability Corporation, Integrating Inverter-Based Resources into Low Short Circuit Strength Systems, 2017.

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Section 8

MWEX Voltage Stability Study

ATC performed steady state voltage stability analysis. Voltage stability analysis is required to determine if the initial conditions of the DPP system models under study are in a stable state as defined by Power-Voltage (PV) curves of the Minnesota Wisconsin Export Interface (MWEX) for the worst contingency.

As shown in Table 8-1, the Pre-DPP and Post-DPP scenarios in the 2023SH case do not violate ATC Planning Criteria by the nose voltage of the PV curve not exceeding 0.95 p.u. In addition, sufficient margin is maintained, therefore Network Upgrades related to voltage stability will NOT be assigned to the Interconnection Customers, based on the assumptions used in this analysis.

The MWEX voltage stability study details can be found in Appendix I.

Table 8-1: MWEX Margins to Collapse in the 2023SH Cases

	Real Power Flow (MW)							
	AHD-SLK[1]	MWEX				Margin to Nose[2]		
Case	N-0 Initial Condition	N-0 I.C.[3]	N-1 I.C.[3]	N-1 I.C. After Phase Shift[4]	N-1 Nose	(MW)	(%)	Notes
Pre-DPP	630.6	1537	765.4	694.7	791.3	96.6	12.2	Voltage Stable Sufficient Margin [5]
Post-DPP	626.4	1525.4	761.8	693.4	796.6	103.2	12.9	Voltage Stable Sufficient Margin [5]

Notes:

1. As described in the active MWEX Operating Guide, the AHD-SLK interface is a single element PTDF interface measured at the Minnesota Power 230 kV side of the Arrowhead 230 kV phase shifter.
2. Margin to Nose is defined as:
   a. "Margin to Nose (MW)" = "MWEX N-1 Nose" – "N-1 Initial Condition After Phase Shift"
   b. "Margin to Nose (%)" = "Margin to Nose (MW)" / "MWEX N-1 Nose"
3. Initial Condition flows were measured in the base cases with an intact system and the worst contingency plus operation of various control systems as needed with all transformer taps, switched shunts, and PARs locked.
4. Arrowhead PAR modeled as changing from neutral tap to a maximum of the 14th tap in the retard direction. Arrowhead PAR controls are presently set to stop tapping once flow through the PAR is less than 697 MW or 14 taps are reached.
   a. If the N-1 I.C. is less than 697 MW, then the N-1 I.C. After Phase Shift is listed as N/A because the PAR will not operate.
5. ATC Planning Criteria requires a 10% voltage stability margin.

6. ATC Planning Criteria requires Vnose < Vmin.
   a. In the Pre-DPP and Post-DPP cases the voltage is measured at the MP Arrowhead 230 kV bus. Per MP's Planning Criteria, the post-contingent minimum voltage is 0.95 p.u. at the MP Arrowhead 230 kV bus.

Section

9

Short Circuit Analysis

9.1 J718 Short Circuit Study

The J718 short circuit study was performed by DPC. Based on the expected fault contribution by J718, DPC will not require any circuit breaker upgrades. DPC does not have the circuit breaker interrupting ratings of other utilities and cannot evaluate their interrupting capability.

Study details can be found in Appendix J.1.

9.2 J748 Short Circuit Study

The J748 short circuit study was performed by MEC. The study results show that the 3PH fault current is 12,721 A (increased by 972 A) and the SLG fault current is 11,036 A (increased by 1,495 A) at the 345 kV interconnection substation. Based on the Transmission Owner’s short circuit criteria, interconnection of the J748 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.2.

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Section

10

Deliverability Study

10.1 Project Description

Interconnection requests requesting Network Resource Interconnection Services (NRIS) were considered for deliverability analysis.

10.2 Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS).

If the generator is determined as not fully deliverable, the customer can choose either to change his project to an Energy Resource (ER) project or proceed with the system upgrades that will make the generator fully deliverable.

Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100 % of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

10.3 Study Methodology

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at "https://cdn.misoenergy.org/Generator_Deliverability_Study_Methodology108139.pdf".

10.4 Determining the MW restriction

If one facility is overloaded based on the assessed "severe yet credible dispatch" scenario described in the study methodology, and the generator under study is in the "Top 30 DF List" (see white paper for detail), part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

If the result is larger than the maximum output of the generator, 100% of this generator's output is not deliverable.

The generator is also responsible for any NEW base case (pre-shift) overload or NEW "severe yet credible dispatch overload" where the generator is not in the "Top 30 DF List", if the generator's DF is greater than 5%. Please see white paper for detail. The formula above also applies to these situations.

10.5 2023 Deliverability Study Result

10.5.1 J718

J718 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**45 MW (100%)**

10.5.2 J748

J748 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**175 MW (100%)**

Section 11

Shared Network Upgrades Analysis

The Shared Network Upgrade (SNU) test for Network Upgrades driven by higher queued interconnection project was performed for this System Impact Study.

No SNUs were identified in this study.

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Section

12

Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

12.1 Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

12.2 ERIS Network Upgrades Proposed for DPP West Area Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the MISO ERIS analyses, LPC analyses, and Affected System Analyses. The total costs of ERIS network upgrades are summarized in Table 12-1.

Table 12-1: Summary of ERIS Network Upgrades

Category of Network Upgrades	Cost ($)
Network Upgrades Identified in MWEX Voltage Stability analysis	$0
Additional Thermal Network Upgrades Identified in MISO Steady-State Analysis	$0
Additional Reactive Power Network Upgrades for Voltage Constraints	$0
Network Upgrades Identified in Stability Analysis	$0
Network Upgrades Identified in Short Circuit Analysis	$0
Network Upgrades Identified in DPC LPC Analysis	$0
Network Upgrades Identified in CIPCO AFS	$500,000
Network Upgrades Identified in PJM AFS	$0
Network Upgrades Identified in SPP AFS	$260,679,526
Shared Network Upgrades	$0
Total	**$261,179,526**

ERIS network upgrades are listed below.

Table 12-2: Network Upgrades Required for MWEX Voltage Stability

NUs	Miles	Cost ($)
No additional NUs		$0

Table 12-3: Thermal Network Upgrades in MISO Steady-State Analysis

Network Upgrades	Owner	Cost ($)
No NUs		$0

Table 12-4: Additional Reactive Power NUs Required for Voltage Constraints

Network Upgrades	Owner	Cost ($)
No NUs		$0

Table 12-5: Network Upgrades Required for Transient Stability

Network Upgrades	Owner	Cost ($)
No additional NUs		$0

Table 12-6: Network Upgrades in Short Circuit Analysis

Network Upgrades	Owner	Cost ($)
No additional NUs		$0

Table 12-7: DPC Local Planning Criteria Network Upgrades

Network Upgrades	Owner	Cost ($)
No additional NUs		$0

Table 12-8: CIPCO Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Hazleton-Dundee 161 kV	CIPCO ITCM	CIPCO: Upgrade Dundee terminal to 3000 Amps ITCM: CIPCO LPC. $0	$500,000

Table 12-9: PJM Affected System Network Upgrades

Mitigation Required	Total Cost ($)
No NUs	$0

Table 12-10: SPP Affected System Network Upgrades

Mitigation Required	Upgrade Cost
Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	$101,400,000
Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	$11,810,905
Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	$57,278,451
Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	$4,173,779
Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	$67,188,955
Build Nashua 345/161 kV xfmr Ckt 2	$9,413,718
Build Post Rock 345/230 kV Xfmr Ckt 2	$9,413,718

Table 12-11: Shared Network Upgrades

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
No SNUs					$0

12.3 Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Post Case. For constraints identified in the shoulder peak scenario, the MW impact is calculated using the shoulder peak post-DPP case. The MW impact on constraints identified in the summer peak scenario is calculated using the summer peak post-DPP case. With all Group Study generation projects dispatched in the Post Case, all thermal and voltage constraints will be identified and a distribution factor from each project on each constraint will be obtained.

Constraints which are mitigated by one or a subset of NU are identified. The MW contribution on these constraints from each generating facility is calculated in the Post Case without any network upgrades. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each generating facility on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of NU is:

$$\text{Project A cost portion of NU} = \text{Cost of NU} \times \left(\frac{\mathrm{Max}(\text{Project A MW contribution on constraint})}{\sum_i \mathrm{Max}(\text{Project i MW contribution on constraint})}\right)$$

12.4 Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

The Distribution Factor (DF) from each generating facility is calculated on the constraints identified in the steady-state analysis in the Post Case without any network upgrades. For a reactive power network upgrade required for mitigating voltage constraints identified in the steady-state AC contingency analysis and stability analysis, DFs are calculated under the most critical contingency on all branches (proxy branches for reactive power network upgrade) connecting at the constraint bus. For a reactive power network upgrade required for mitigating MWEX voltage stability constraints identified in the voltage stability analysis, DFs are calculated under the most critical contingency on all branches (proxy branches) connecting to the high voltage side of the transformer, where the voltage collapse occurs.

For each thermal constraint, the maximum MW contribution (increasing flow) from each generating facility is calculated. MW contribution from one generating facility is set as zero if the constraint is not categorized as MISO ERIS constraint or affected system constraint for that specific generating facility.

For reactive power network upgrades, or MWEX network upgrades and other voltage stability network upgrades, generators with positive net MW impact (harming the constraint) on all branches connected at the constraint bus will be responsible for mitigating these constraints.

Additional NRIS Network Upgrades are allocated to the impacting NRIS projects. ERIS Network Upgrades will be allocated to the impacting projects only based on the ERIS results.

Transient stability Network Upgrades are allocated based on projects causing instability. If multiple projects are causing instability, cost allocation will be based on pro rata share of total MW of all projects causing instability.

The calculated DF results and the MW contribution on each constraint are in Appendix K.1 for the 2023 scenario.

Finally, the cost allocation for each NU is calculated based on the MW contribution of each generating facility, as detailed in Appendix K.2 for the 2023 scenario.

Assuming all generating facilities in the DPP 2017 February West Area group advance, a summary of the costs for total NUs (NUs for ERIS, NRIS, and Interconnection Facilities) allocated to each generating facility is listed in Table 12-12.

Table 12-12: Summary of Total NU Costs Allocated to Each Generation Project

Project	Max Output (MW)	Total Cost of NU per Project ($)	$/MW	Share %
J718	45	$32,816,261	$729,250	11.93%
J748	200	$242,163,267	$1,210,816	88.07%
Total/Average	**245.0**	**$274,979,528**	**$970,033**	**100.00%**

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Appendix

A

Model Development for Steady-State and Stability Analysis

A.1 DPP 2017 February Generation Projects

Table A-1: DPP 2017 February West Area Projects

MISO Project #	State	County	Trans. Owner	Point Of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J718	MN	Fillmore	DPC	Cherry Grove 69 kV	45	45	Solar	NRIS
J748	IA	Plymouth	MEC	O'Brien-Raun 345 kV	200	175	Wind	NRIS

Table A-2: Dynamic Modeling for DPP West Area Projects

MISO Project #	Turbine / Inverter	Generator Reactive Power Capability (power factor)
J718	15 TMEIC PVH-L3200GR inverters rated at 3200 kVA (3000 kW)	± 16.77 Mvar
J748	80 GE 2.5 MW	± 0.9

Table A-3: Collector System and Shunt Compensation Modeling for DPP West Area Non-Synchronous Projects

MISO Project #	Generator Modeling	Collector System Modeling	Shunt Compensation
J718	One 45 MW unit	R=0.00789 pu X=0.00697 pu B=0.00391 pu	6x0.9 MVAR capacitor bank on 34.5kV system
J748	Two 100 MW units	Circuit #1: R=0.0145 pu X=0.0147 pu B=0.0689 pu Circuit #2: R=0.0145 pu X=0.0147 pu B=0.0689 pu	1x12 MVAR capacitor bank on 34.5kV system

Table A-4: DPP 2017 February Central Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J734	IL	Ford	Ameren	Gibson City South 138 kV sub	11.5	CT	NRIS Only
J740	IN	Jasper, Pulaski	NIPS	Reynolds 345 kV sub	200	Wind	NRIS
J753	KY	Breckinridge	BREC	Hardinsburg 161 kV sub	100	Solar	NRIS
J754	IN	Montgomery	DEI	Cayuga-Nucor 345kV	303.6	Wind	NRIS
J756	IL	Logan	Ameren	Fogarty-Mason City West 138 kV	202.4	Wind	NRIS
J757	IL	Morgan, Sangamon	Ameren	Meredosia-Austin 345 kV	303.6	Wind	NRIS
J759	IN	Spencer	HE	Troy 161 kV sub	70	Solar	NRIS
J762	KY	Meade	BREC	Meade 161 kV sub	200	Solar	NRIS
J783	IN	Spencer	Vectren	Grandview 69 kV sub	70	Solar	NRIS

Table A-5: DPP 2017 February Michigan Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J646	MI	Macomb	ITCT	Carbob 120 kV sub	1.6	Landfill Gas	ERIS
J717	MI	Isabella	METC	Tapped on Edenville Junction-Warren 138 kV line at 3.5 miles from Warren substation	200.1	Wind	NRIS
J728	MI	Isabella	METC	Tapped on Edenville Junction-Warren 138 kV line at 3.5 miles from Warren substation	186.3	Wind	NRIS
J752	MI	Tuscola	ITCT	Ringle 345 kV sub	100	Wind	NRIS
J758	MI	Calhoun	METC	Verona-Foundry 138 kV	200	Solar	NRIS

Table A-6: DPP 2017 February ATC Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J584	WI	Green	ATC	Blacksmith Tap-Spring Grove 69 kV	60	Wind	NRIS
J703	MI	Marquette	ATC	New sub looping National-Freeman 138 kV and Presque Isle-Empire 138 kV	128.1	CT	NRIS
J704	MI	Baraga	ATC	M38 138 kV sub	54.9	CT	NRIS

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J760	WI	Rock	ATC	Townline 345 kV sub	30	CC	NRIS

A.2 DPP 2016 August West Area Phase 3 Network Upgrades

Table A-7: DPP 2016 August West Phase 3 NUs

Constraint	Owner	Mitigation
J530 POI-Montezuma 345 kV	MEC	Structure Replacements
J530 POI-Hills 345 kV	MEC	Reconductor / Terminal Equipment Upgrades.
J302&J503 POI-Heskett 230 kV	MDU	Line Clearance Mitigation. New Rating: 343 MVA.
J611-Maryville 161 kV	MEC GMO	MEC: Reconductor from POI substation to Missouri border point of ownership change with KCPL. GMO: NU is not required unless it is identified as constraint in affected system study.
Adams 345-161-13.8 kV xfmr	XEL	Lock Adams xfmr tap at neutral position
Split Rock-White 345 kV	XEL WAPA	Line is currently rated 1075 MVA for SN/SE no mitigation required
Helena-Scott Co 345 kV	XEL WAPA	Rebuild Helana to Scott County (18 miles) with 2-0954 ACSS conductor
Rice 161-69 kV xfmr	SMMPA	SMMPA: MOD project # 110359 to increase the Rice 161/69kV transformer to 190 MVA rating as per the GIA J614
Hankinson-Forman 230 kV	OTP	Line clearance mitigations.
Oakes-Forman 230 kV	OTP	Replacement of terminal equipment and complete rebuild of the 23.3 mile line.
Oakes-Ellendale 230 kV	OTP MDU	MDU: MDU owns the Ellendale Terminal. It is rated for 776 MVA OTP: Complete rebuild of the 24 mile line.
Parnell-J438 POI 161 kV	ITCM MEC	ITCM: ITCM terminal rated 335/335 MVA SN/SE. $0 MEC: Structure Replacements. $250,000
Henry Co-Jeff 161 kV	ITCM NEMO	ITCM: ITCM line rating 229/229 MVA SN/SE. $0 NEMO: Per ITCM record NEMO terminal limit is 223 MVA which is sufficient. $0
Wapello-Jeff 161 kV	ITCM	Line rated 251/251 MVA SN/SE
Ottumwa 345-161 kV xfmr	ITCM	Ottumwa 345-161 kV xfmr ratings have been updated to 467/534 MVA SN/SE. $0
Grimes-Sycamore 345 kV #2	MEC	Add new 345 kV breaker at Grimes to eliminate this common breaker failure contingency.
Bondurant-Sycamore 345 kV	MEC	Structure Replacements
Bondurant-Montezuma 345 kV	MEC	Structure Replacements. $600,000. New rating is 1,189 MVA.
Harmony-Cresco 69 kV	DPC	Rebuild line with 477 ACSR
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	ITCM	2×75 Mvar switched cap bank at Killdeer 345 kV (631199)
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	ITCM	2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)

Constraint	Owner	Mitigation
2x150 Mvar switched cap bank at Hills 345 kV (636400)	MEC	2x150 Mvar switched cap bank at Hills 345 kV (636400)
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	MRES	1×50 Mvar switched cap bank at McLeod 230 kV (619940)
J302&J503 POI-Heskett 230 kV	MDU	Line rebuild
Merricourt-Ellendale 230 kV	MDU	Rebuild Line with high temp. conductor New Rating: 440 MVA
Oakes-Ellendale 230 kV	OTP MDU	MDU: MDU owns the Ellendale Terminal. It is rated for 776 MVA OTP: Complete rebuild of the 24 mile line: $20.5 M. Not applicable for MDU LPC
Zackary 345/161 kV transformer	Ameren	Add Second 560 MVA 345/161 kV transformer
Adair-Zackary 161 kV	Ameren	Add second 161 kV line between Adair and Zachary
Adair 161 kV bus tie 2-3	Ameren	Bus tie to be upgraded to 2000 A as part of the Zachary-Ottumwa MVP project
Novelty 161 -69 kV xfmr	AECI	Replace with 84 MVA.
South River-Emerson 161 kV	AECI	Upgrade 600 A disconnect switches at South River.

A.3 Model Review Comments

Table A-8: Model Review Comments

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
GRE	ND230OutletSummer.idv	x	x	x
MISO	HCK-CARDINAL-MVP.idv	x	x	x
MISO	FEB17Corrections.py	x	x	x
MDU	RMV_J405.py	x	x	x
MISO	Correct_CE-Nelson.py	x	x	x
Ameren	Ameren_Correction.py	x	x	x
OTP	Correct_Cass Lk Cap.py	x	x	x
OTP	Correct J436-J437.py	x	x	x
OTP	Correct J736-J442-J721.py	x	x	x
MRES	18Series_2023SH90_MRES.idv	x		x
MRES	18Series_2023S_MRES.idv		x	
MPC	MPC_Correction.py	x	x	x
MPC	SH-Dispatch MPC prior queued.py	x		x
MPC	PK-Dispatch MPC prior queued.py		x	
CIPCO	Add IR-21.py	x	x	x
CIPCO	SH-Dispatch IR-21.py	x		x
CIPCO	PK-Dispatch IR-21.py		x	
ICs	IC Corrections.py	x	x	x
MISO	TrueUp-1.py	x	x	x
MISO	RMV J414.py	x	x	x
MISO	RMV J415.py	x	x	x
MISO	RMV J439.py	x	x	x
MISO	RMV J459.py	x	x	x
MISO	RMV J511.py	x	x	x
MISO	RMV J575.py	x	x	x
MISO	RMV J577.py	x	x	x
MISO	RMV J593.py	x	x	x
MISO	RMV J594.py	x	x	x
MISO	RMV J596.py	x	x	x

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
MISO	RMV J597.py	x	x	x
MISO	RMV J599.py	x	x	x
MISO	RMV J607.py	x	x	x
MISO	RMV J613.py	x	x	x
MISO	RMV J615.py	x	x	x
MISO	RMV J638.py	x	x	x
SPTI	RMV_Backbone-NUs.py	x		x
SPTI	RMV MWEX-NUs.py	x		x
J747_J748	J747-748.py	x	x	x
J747_J748	J747-J748.dyr			x
J476	J476_POI-Chng.py	x	x	x
MH	MH-BP3-DCTxf-raito-2017on.py	x	x	x
MDU	Correct_G14-004.py	x	x	x
SPP	RMV_SPP-Withdrawn.py	x	x	x
SPP	RMV_SPP-2014-013.py	x	x	x
ATC	2017FebDPP_ATC_Update_SH_v3.idv	x		x
ATC	2017FebDPP_ATC_Update_PK_v3.idv		x	
ATC	Turn Off_PSQI.py	x	x	x
ATC	Dispatch_J703-J704.py	x	x	x
MEC	Fix PJM.py	x	x	x
MEC	Disp_J438-J455-J412_SH.py	x		x
MEC	Disp_J438-J455-J412_PK.py		x	
MEC	Turn off reactors.py	x		x
MEC	Turn Off_Marshalltown_SH.py	x		x
MDU	MDU Corrections.py	x	x	x
MRES	JohnsonJct-Ortonville_Rebuild.idv	x	x	x
MISO	RMV-Lathrop-Cap.py	x	x	x
MISO	Correct-Bus_Zn.py	x	x	x
ICs	J458.py	x	x	x
ICs	J522.py	x	x	x
ICs	J556.py	x	x	x
ICs	J570.py	x	x	x
ICs	J707.py	x	x	x

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
ICs	J731_SH.py	x		x
ICs	J731_PK.py		x	
ICs	J733_SH.py	x		x
ICs	J733_PK.py		x	
ICs	J739.py	x	x	x
ICs	J776 DPP_SH.py	x		x
ICs	J776 DPP_PK.py		x	
ICs	J780.py	x	x	x
ICs	J718.py	x	x	x
MISO	Change-WMOD.py	x	x	x
MISO	TO_fixes.py	x	x	x
MRES	MRES Fergus Falls to Silver Lake_Rateing-Correction	x	x	x
ITCM	ITCM Rating Corrections.py	x	x	x
MDU	MDU-Update_MISO18_2017FebDPP_181126.idv	x	x	x
MPC	MPC-retire-6Prairie115Caps.idv	x	x	x
MPC	MPC-Withdraw-Ash4.idv	x	x	x
MISO	Correct_J441_Collector Imp.py	x	x	x
ICs	DPP-FEB17-J721-SC.idv	x	x	x
Changes applied to Phase 2				
SPP	RMV GEN-2015-053.py	x	x	x
SPP	RMV GEN-2015-098.py	x	x	x
SPP	RMV GEN-2016-108.py	x	x	x
SPP	RMV GEN-2016-152.py	x	x	x
PJM	RMV_PJM-Withdrawn_Prjs.py	x	x	x
MISO	J441 reduction_SH.py	x		x
MISO	J441 reduction_SPK.py		x	
MISO	RMV J458.py	x	x	x
MISO	RMV J522.py	x	x	x
MISO	RMV J556.py	x	x	x
MISO	RMV J707.py	x	x	x
MISO	RMV J731.py	x	x	x
MISO	RMV J733.py	x	x	x
MISO	RMV J745.py	x	x	x

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
MISO	RMV J747.py	x	x	x
MISO	RMV J761.py	x	x	x
MISO	RMV J766.py	x	x	x
MISO	RMV J769.py	x	x	x
MISO	RMV J770.py	x	x	x
MISO	RMV J771.py	x	x	x
MISO	RMV J776.py	x	x	x
MISO	RMV J780.py	x	x	x
MISO	RMV J711.py	x	x	x
MISO	RMV J457.py	x	x	x
MISO	RMV J637.py	x	x	x
MISO	RMV J572.py	x	x	x
MISO	RMV 2016 Aug DPP Ph2 NUs.py	x	x	x
MISO	RMV Stronach NU.idv	x	x	x
MISO	Ellendale Sw Reactor LPC.idv	x	x	x
MISO	Ellendale FSC LPC.idv	x	x	x
MISO	Ellendale345_FSC_BSSE_20190115.dyr			x
MISO	Add NUs 2016 Aug DPP Ph3.py	x	x	x
MISO	RMV_Backbone-NUs_SH.py	x		x
MISO	RMV_Backbone-NUs_SPK.py		x	
MISO	Remove MWEX NUs.py	x	x	x
SPTI	Bus Info Correction.py	x	x	x
SPTI	Correct Qlim_SPK.py		x	
SPTI	Update Fictitious SVC.py	x		x
MISO	Big-Stone-Blair230.py	x	x	x
MDU	MDU_Updates-DPP_2017_Feb_West_Ph2_ALL_Models.idv	x	x	x
MPC	MPC-fixrtngs-MISO18_2017FebDPP-Ph2-ALL.idv	x	x	x
MEC	2017FEB Ph2 MEC SH90 Updates.py	x		x
MEC	2017FEB Ph2 MEC SUM Updates.py		x	
MEC	MEC-DPP2017FEB West Ph2 2023 Cat P1 04.17.2019.con	x	x	
MEC	MEC-DPP2017FEB West Ph2 2023 Cat P2 04.17.2019.con	x	x	
MEC	MEC-DPP2017FEB West Ph2 2023 Cat P5 04.17.2019.con	x	x	
MEC	MEC-DPP2017FEB West Ph2 2023 Cat P7 04.17.2019.con	x	x	

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
MISO	Aug16-NU.py	x	x	x
MISO	SPP_Study_Voltage_Solutions.py	x	x	x
J718	J718.py	x	x	x
SPTI	Killdeer_SWS.py	x	x	x
OTP	Feb17DPP2ModelReview_OTP_4-23-19.idv	x	x	x
DPC	DPC_Comment.py	x	x	x
SPTI	RMV_GEN-2015-087.py	x	x	x
J441	J441.py	x	x	x
MDU	MDU_Updates-DPP_2017_Feb_West_Ph2_ALL_Models_v2.idv	x	x	x
SPTI	POSTROC_fic_SWS.py	x		x
SPTI	St_Joe_250_SVC.py	x		x
SPTI	Webster-Franklin-Morgan.py	x	x	x
SPTI	RMV_fic_SVC_Franklin.py			x
J718	J718_r2.py	x	x	x
MPC	Ashtabula_GE_WECC_Generic_20MAR18.dyr			x
MPC	Langdon_GE_WECC_Generic_20MAR18.dyr			x
J718	J718.dyr			x
OTP	2023SSH-MISO18-OTP-Load-Model.dyr			x
OTP	OTP_generator_dynamics_models_23-Apr-2019.dyr			x
OTP	OTP_PRC-024_models_22-Mar-2019.dyr			x
OTP	OTP_switched_shunt_models_21-Mar-2019.dyr			x
OTP	OTP_UVLS+UFLS_models_26-Mar-2019.dyr			x
Changes applied to Phase 3				
SPP	RMV GEN-2016-054.py	x	x	x
MISO	RMV St Joe SVC.py	x		x
MISO	Update Mingo SVC.py	x		x
MISO	Update PostRock SVC.py	x		x
MISO	RMV J441.py	x	x	x
MISO	RMV J570.py	x	x	x
MISO	RMV J721.py	x	x	x
MISO	RMV J739.py	x	x	x
MISO	RMV J741.py	x	x	x
MISO	RMV J746.py	x	x	x

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
MISO	RMV J767.py	x	x	x
MISO	RMV J768.py	x	x	x
MISO	RMV J777.py	x	x	x
MISO	RMV J779.py	x	x	x
MISO	RMV J708.py	x	x	x
MISO	RMV Franklin SVC.py	x	x	x
MISO	J718 SH.idv	x		x
MISO	J718 PK.idv		x	
MISO	RMV BaseCase NUs.py	x	x	x
MISO	Update J728_SH.py	x		x
MISO	Update J728_PK.py		x	
MISO	Update J718.py	x	x	x
DPC	cherrygrove_split_20190814.idv	x	x	x
MEC	MEC_DPP_2017_FEB_West_Ph3_SH-SUM_Updates.py	x	x	x
MEC	MEC Comments.py	x	x	x
CIPCO	Add CIPCO-20_SH.idv	x		x
CIPCO	Add CIPCO-20_PK.idv		x	
CIPCO	IR20_VS3103.dyr			x

A.4 MISO Classic as the Study Sink

Table A-9: MISO Classic as the Study Sink

Area #	Area Name
207	HE
208	DEI
210	SIGE
216	IPL
217	NIPS
218	METC
219	ITC
295	WEC
296	MIUP
314	BREC
333	CWLD
356	AMMO
357	AMIL
360	CWLP
361	SIPC
600	Xcel
608	MP
613	SMMPA
615	GRE
620	OTP
627	ALTW
633	MPW
635	MEC
661	MDU
663	BEPC-MISO
680	DPC
694	ALTE
696	WPS
697	MGE
698	UPPC

A.5 PJM Market as PJM Projects Sink

Table A-10: PJM Market as PJM Projects Sink

Area #	Area Name
201	AP
202	ATSI
205	AEP
209	DAY
212	DEO&K
215	DLCO
222	CE
225	PJM
226	PENELEC
227	METED
228	JCP&L
229	PPL
230	PECO
231	PSE&G
232	BGE
233	PEPCO
234	AE
235	DP&L
236	UGI
237	RECO
320	EKPC
345	DVP

A.6 SPP Market as SPP Projects Sink

Table A-11: SPP Market as SPP Projects Sink

Area #	Area Name
515	SWPA
520	AEPW
523	GRDA
524	OKGE
525	WFEC
526	SPS
527	OMPA
531	MIDW
534	SUNC
536	WERE
540	GMO

Area #	Area Name
541	KCPL
542	KACY
544	EMDE
545	INDN
546	SPRM
640	NPPD
645	OPPD
650	LES
652	WAPA
659	BEPC-SPP

A.7 Contingency Files used in Steady-State Analysis

Table A-12: List of Contingencies used in Steady-State Analysis

Contingency File Name	Description	2023
Automatic single element contingencies	Single element outages at buses 69 kV and above in the study region	x
CC Bipole Events.con	Specified category P1, P7 contingencies in GRE Coal Creek	x
CIPCO DPP-2017-FEB-P6.con	Specified category P6 contingencies in CIPCO	x
MEC-DPP2017FEB West Ph3 2023 Cat P1 04.17.2019.con	Specified category P1 contingencies in MEC	x
MEC-DPP2017FEB West Ph3 2023 Cat P2 04.17.2019.con	Specified category P2 contingencies in MEC	x
MEC-DPP2017FEB West Ph3 2023 Cat P5 04.17.2019.con	Specified category P5 contingencies in MEC	x
MEC-DPP2017FEB West Ph3 2023 Cat P7 04.17.2019.con	Specified category P7 contingencies in MEC	x
OTP_P1_22-October-2018.con	Specified category P1 contingencies in OTP	x
OTP_P2_22-October-2018.con	Specified category P2 contingencies in OTP	x
OTP_P5_19-June-2018.con	Specified category P5 contingencies in OTP	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_ATC_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in ATC	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_ATC_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in ATC	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_West_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in West	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_West_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in West	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_IL-MO_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in IL, MO	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_IL-MO_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in IL, MO	x

Appendix

B

Model Data

B.1 Power Flow Model Data

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B.2 Dynamic Model Data

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B.3 2023 Slider Diagrams

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Appendix

C

Reactive Power Requirement Analysis Results (FERC Order 827)

Table C-1: Reactive Power Requirements Analysis Results

Project #	HV Side Bus #	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Lagging Power Factor at HV Side	Meet Lagging Power Factor Req.?	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Leading Power Factor at HV Side	Meet Leading Power Factor Req.?
J718	87180	44.4	16	0.9408	Yes	44.3	-24.1	0.8784	Yes
J748	87486	194.4	76	0.9314	Yes	193.6	-135.2	0.8199	Yes

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Appendix

D

2023 Summer Peak Contingency Analysis Results

D.1 2023 Summer Peak (SPK) Constraints

Table D-1: 2023 SPK System Intact Thermal Constraints

Table D-2: 2023 SPK System Intact Voltage Constraints

Table D-3: 2023 SPK Category P1 Thermal Constraints

Table D-4: 2023 SPK Category P1 Voltage Constraints

Table D-5: 2023 SPK Category P2-P7 Thermal Constraints

Table D-6: 2023 SPK Category P2-P7 Voltage Constraints

Table D-7: 2023 SPK Non-Converged Contingencies

Table D-8: 2023 SPK Non-Converged Contingencies DCCC Results

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Appendix E

2023 Summer Shoulder Contingency Analysis Results

E.1 2023 Summer Shoulder (SH) Constraints

Table E-1: 2023 SH System Intact Thermal Constraints

Table E-2: 2023 SH System Intact Voltage Constraints

Table E-3: 2023 SH Category P1 Thermal Constraints

Table E-4: 2023 SH Category P1 Voltage Constraints

Table E-5: 2023 SH Category P2-P7 Thermal Constraints

Table E-6: 2023 SH Category P2-P7 Voltage Constraints

Table E-7: 2023 SH Non-Converged Contingencies

Table E-8: 2023 SH Non-Converged Contingencies DCCC Results

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Appendix

F

Local Planning Criteria Analysis Results

F.1 DPC LPC Analysis

Below is the DPC local planning criteria analysis report.

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Appendix

G

Affected System Contingency Analysis Results

G.1 CIPCO Affected System Analysis Results

Table G-1: 2023 SPK CIPCO Affected System Analysis Results

Table G-2: 2023 SH CIPCO Affected System Analysis Results

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G.2 PJM Affected System Study Results

Below is the PJM affected system study report provided by PJM.

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G.3 SPP Affected System Study Results

Below is the SPP affected system study report provided by SPP.

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Appendix

H

Transient Stability Results

H.1 2023 Summer Shoulder Stability Results Summary

Stability simulation was performed in the 2023 summer shoulder Phase 3 case.

Stability study results are summarized in Table H-1.

Table H-1: 2023 Summer Shoulder Phase 3 Stability Analysis Results Summary

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H.2 2023 Summer Shoulder Stability Plots

Plots of stability simulations for 2023 summer shoulder Phase 3 study case are in separate files which are listed below:

AppendixH2_2023SH_DPP 2017Feb-West_Ph3_Study_Plots.zip

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Appendix

I

MWEX Voltage Study

Below is the MWEX voltage stability study report provided by ATC.

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Appendix

J

Short Circuit Analysis

J.1 J718 Short Circuit Study

J.2 J748 Short Circuit Study

J718 - Short Circuit Study by DPC
6/5/2019

Dairyland Power Cooperative (DPC) performed a short-circuit study around the proposed 50 MW solar farm in Fillmore County, MN, to help determine the interrupting fault currents at the nearby substations, as well as any potential circuit breaker upgrades.
DPC used CAPE as the short-circuit program and relied on DPC's own CAPE database to perform the short-circuit analysis. The MiEnergy's Cherry Grove distribution substation was used as the point of interconnection and since the final location of the site has not been finalized at the time of this study, the tap line was assumed to have zero impedance for maximum fault current. The solar farm was modeled according to the data received from the developer.

The study consisted of performing 3-phase faults and single-phase faults on all the buses on DPC's network with and without the proposed generation in service, then computing the difference in fault current. Substations that had a greater than 5% fault current increase were listed in Table 1 and Table 2, as well as the corresponding fault current contribution seen from the proposed generation.
There is a potential for the Spring Valley line to be looped onto the Cherry Grove line, which could increase the fault current at some of the nearby substations. DPC performed a second short circuit study reflecting this scenario. Table 2 shows the result of the second short circuit study.
Based on the expected fault contribution by J718, DPC will not require any circuit breaker upgrades. DPC does not have the circuit breaker interrupting ratings of other utilities and cannot evaluate their interrupting capability.

SYSTEM ONE LINE DIAGRAM

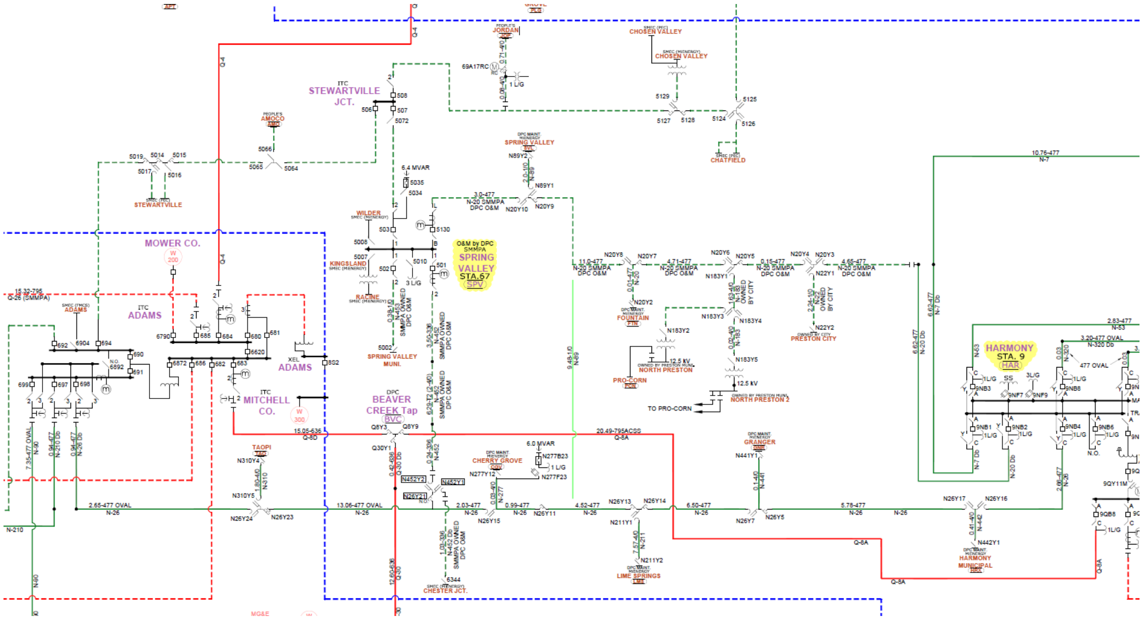

Table 1: System normal, with and without the proposed generation.

				Fault Current (Amps)					
				1-phase fault			**3-phase fault**		
Substation	**Site type**	**Owner**	**Voltage**	**Base**	**With J718**	**Difference**	**Base**	**With J718**	**Difference**
Amoco	Distribution	People's	69	1878	1887	0%	3248	3280	1%
Cherry Grove	Distribution	MiEnergy	69	2457	5999	144%	4361	5066	16%
Chester Junction	Distribution	MiEnergy	69	1015	1018	0%	1819	1831	1%
Fountain	Distribution	MiEnergy	69	2093	2108	1%	3543	3597	1%
Granger	Distribution	MiEnergy	69	3311	4151	25%	5427	5895	9%
Harmony Municipal	Distribution	MiEnergy	69	5859	6399	9%	8035	8443	5%
Jordan	Distribution	People's	69	1847	1854	0%	3151	3175	1%
Lime Springs	Distribution	MiEnergy	69	1435	1856	29%	2475	2796	13%
Spring Valley	Distribution	MiEnergy	69	1488	1495	0%	2563	2587	1%
Spring Valley	Transmission	SMMPA	69	1699	1707	1%	2951	2982	1%
Spring Valley Muni.	Distribution	SMMPA	69	1650	1658	0%	2857	2886	1%
Stewartville	Transmission	ITC	69	1870	1879	0%	3223	3256	1%
Taopi	Distribution	DPC	69	4431	4880	10%	6604	6982	6%

Table 2: Spring Valley looped, with and without the proposed generation.

				Fault Current (Amps)					
				1-phase fault			**3-phase fault**		
Substation	Site type	Owner	Voltage	**Base**	**With J718**	**Difference**	**Base**	**With J718**	**Difference**
Amoco	Distribution	People's	69	2119	2224	5%	3619	3779	4%
Cherry Grove	Distribution	MiEnergy	69	3104	6895	122%	5323	6028	13%
Chester Junction	Distribution	MiEnergy	69	2876	4756	65%	4937	5506	12%
Fountain	Distribution	MiEnergy	69	2455	2630	7%	4142	4426	7%
Granger	Distribution	MiEnergy	69	3462	4163	20%	5605	6036	8%
Harmony Municipal	Distribution	MiEnergy	69	5894	6406	9%	8052	8454	5%
Jordan	Distribution	People's	69	2096	2195	5%	3515	3650	4%
Lime Springs	Distribution	MiEnergy	69	1532	1874	22%	2611	2925	12%
Spring Valley	Distribution	MiEnergy	69	2099	2371	13%	3555	3873	9%
Spring Valley	Transmission	SMMPA	69	2872	3518	23%	4851	5248	8%
Spring Valley Muni.	Distribution	SMMPA	69	2736	3316	21%	4604	4977	8%
Stewartville	Transmission	ITC	69	2098	2199	5%	3553	3702	4%
Taopi	Distribution	DPC	69	4576	4912	7%	6820	7169	5%

CRITICAL ENERGY INFRASTRUCTURE INFORMATION NOTICE

The materials contained in this document include Critical Energy Infrastructure Information (CEII). All materials designated as CEII must be handled and protected per the requirements in FERC CEII Policy. There may be additional requirements for CEII materials in the future.

J748 Short Circuit Study Performed by MEC

The scope of this DPP short circuit facilities study is a review of the available fault current at the proposed 345 kV interconnection substation for MISO generation queue request J748, a proposed 200 MW wind farm, and nearby substations both with and without the Interconnection Customer interconnected. J748 was assumed to interconnect off the Raun-Cherokee County 345 kV line. The fault currents were used to identify if any existing MidAmerican circuit breakers become overdutied because of the proposed Interconnection Customer based on the system configuration. Additional buses owned by third parties are listed for informational purposes and would need to be evaluated by the respective bus owner. The study reviewed single-line-to-ground (SLG) fault current levels and three phase (3PH) fault current levels.

The Interconnection Customer is in an ongoing DPP study cycle of the MISO generation interconnection process where the system impact study is not complete. As a result, the short circuit study is preliminary and does not include changes to the transmission system and/or the generators in the area that may be required when the DPP study results are known. The results of the short circuit analysis are summarized in Table 1.

The results of the short circuit analysis showed the three phase fault current at the 345 kV interconnection substation bus to be 11,749 Amps without the Interconnection Customer included and 12,721 Amps with the Interconnection Customer included (based upon the assumed modeling information for the generator step-up transformer, wind turbines, grounding transformers, and other collector system assumptions). These assumptions affect the results. For example, the preliminary generator step-up transformer information may be different from the impedances from the transformer test report. In specifying equipment or completing equipment settings such as voltage control systems, the Interconnection Customer should be aware that fault currents are subject to change and may increase or decrease at the interconnection point because of additions and/or retirements of the transmission system and/or area generation as well as for system contingencies.

As shown in the table, the changes in fault current at buses more than a couple buses away from the point of interconnection are comparatively small. Based on MidAmerican’s short circuit criteria, no MidAmerican short circuit constraints appear for the Interconnection Customer’s project. The study results are subject to change based on the outcome of the DPP study or if project design considerations change from those that were studied.

A protective relay coordination review will be required if the Interconnection Customer’s project proceeds, and the Interconnection Customer will be required to provide relay settings to MidAmerican. In addition, continued communication and coordination will be required for the parties to meet NERC Standard PRC-001 and PRC-005 and/or future standards.

Table 1. Single-Line-to-Ground (SLG) and Three Phase (3PH) Fault Currents with and without J748

						SLG Fault Current Comparison				**3 Ph Fault Current Comparison**		
Bus Number	Bus Name	English Name	Base kV	Area Num	Owner	Base SLG w/o new wind farm	SLG with new wind farm	SLG Difference w/ wind farm vs Base		Base 3PH w/o new wind farm	3PH with new wind farm	3PH Difference w/ wind farm vs Base
87487	J748POI	J748 POI	345	635	MEC	9,541	11,036	1,495		11,749	12,721	972
87486	J748GENTIE	J748 IC Sub	345	635	IC	NA	9,958	9,958		NA	11,562	11,562
65400	J506 POI	J506 POI (Cherokee)	345	635	MEC	9,882	11,098	1,216		11,857	12,731	874
635200	RAUN 3	Raun	345	635	MEC	27,014	27,189	175		25,612	25,915	303
635400	HIGHLND 3	Highland	345	635	MEC	10,879	11,311	432		12,839	13,350	511
15010	A345	J506 IC Sub	345	635	IC	9,856	11,061	1,205		11,821	12,689	868
635252	J412 POI 3	J412 POI	345	635	MEC	8,973	8,981	7		10,899	10,921	22
652564	SIOUXCY3	Sioux City	345	652	WAPA	12,406	12,425	19		14,397	14,459	62
640226	HOSKINS3	Hoskins	345	640	NPPD	8,855	8,858	4		9,904	9,916	12
645451	S3451 3	Sub 3451	345	645	OPPD	14,390	14,394	4		18,300	18,314	14
635201	RAUN 5	Raun	161	635	MEC	30,509	30,573	64		26,768	26,877	109
635368	OBRIEN 3	O'Brien	345	635	MEC	12,100	12,310	210		14,158	14,507	349
635206	IDA CO 3	Ida County	345	635	MEC	9,040	9,046	6		10,699	10,719	20
601006	SPLT RK3	Split Rock	345	600	Xcel	8,142	8,147	5		9,302	9,317	16
652552	SIOUXCY2	Sioux City	230	652	WAPA	19,022	19,042	20		19,040	19,089	49
640520	ANTELOPE 3	Antelope	345	640	NPPD	3,182	3,183	1		4,703	4,705	3
640342	SHELCRK3	Shell Creek	345	640	NPPD	8,772	8,774	1		9,522	9,526	4
640228	HOSKINS7	Hoskins	115	640	NPPD	19,022	19,025	3		17,667	17,675	8
645454	S3454 3	Sub 3454	345	645	OPPD	16,407	16,408	1		20,374	20,381	7
645459	S3459 3	Sub 3459	345	645	OPPD	16,707	16,709	2		19,899	19,907	8
646251	S1251 5	Sub 1251	161	645	OPPD	25,750	25,755	5		27,763	27,775	12
635202	NEAL S 5	Neal South	161	635	MEC	19,936	19,959	23		18,629	18,679	50
635203	NEAL N 5	Neal North	161	635	MEC	28,118	28,171	53		25,393	25,488	95
635220	INTCHG 5	Interchnage	161	635	MEC	11,338	11,345	7		14,737	14,767	30
635230	LIBERTY5	Liberty	161	635	MEC	26,639	26,688	49		24,780	24,872	92
640377	TEKAMAH5	Tekamah	161	645	OPPD	7,167	7,167	1		9,381	9,383	3

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Appendix

K

2023 Cost Allocation Results

K.1 Distribution Factor (DF) and MW Contribution Results for Cost Allocation in 2023

Table K-1: Distribution Factor and MW Contribution on Constraints for Thermal NU Cost Allocation

Table K-2: Distribution Factor and MW Contribution on Voltage Constraints for NU Cost Allocation

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K.2 Cost Allocation Details

Table K-3: Network Upgrades Cost Allocation in 2023

Table K-3: Network Upgrades Cost Allocation in 2023

Monitored Element	English Name	Cost	J718	J748	Upgrade for
631051 HAZLTON L2 5 161 631101 DUNDEE 5 161 1	Hazleton-Dundee 161 kV	$500,000	$500,000	$0	CIPCO AFS
Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	Reroute Cooper - St Joseph and Nebraska City - Holt County 345 kV through a new Nemeha County station, Reroute Fairport – St Joseph and Mullen Creek – Ketchem 345 kV through a new Dekalb County station.	$101,400,000	$13,192,782	$88,207,218	SPP AFS
Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	Rebuild 13.3 miles of 345 kV from St. Joe – DeKalb	$11,810,905	$1,547,310	$10,263,596	SPP AFS
Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	Rebuild 64.5 miles of 345 kV from Nemaha – St. Joe	$57,278,451	$6,840,009	$50,438,442	SPP AFS
Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	Rebuild 4.7 miles of 345 kV from Nemaha – Cooper	$4,173,779	$543,035	$3,630,744	SPP AFS
Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	Rebuild 75.66 miles of 345 kV from Red Willow - Mingo	$67,188,955	$8,893,125	$58,295,831	SPP AFS
Build Nashua 345/161 kV xfmr Ckt 2	Build Nashua 345/161 kV xfmr Ckt 2	$9,413,718	$0	$9,413,718	SPP AFS
Build Post Rock 345/230 kV Xfmr Ckt 2	Build Post Rock 345/230 kV Xfmr Ckt 2	$9,413,718	$0	$9,413,718	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project	**Total Cost Per Project for Actual NRIS Elections for each Project**	**$261,179,526**	**$31,516,261**	**$229,663,267**	

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