# Appendix B

## MISO DPP 2017 August West Area Study Phase 3 Final Report

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# MISO DPP 2017 August West Area Study Phase 3 Final Report

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## Contents

## 1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2017 August West Area Phase 2 (West Area DPP 2). The study was performed under the direction of MISO and reviewed by 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 – American Transmission Company, Ameren, Basin Electric Power Cooperative, CIPCO, Cedar Falls, Dairyland Power Cooperative, Great River Energy, ITC Midwest, Montana-Dakota Utilities, MidAmerican, Minnesota Power, Ottertail Power, SMMPA, and Xcel Energy.

### 1.1. Project List

The interconnection requests for DPP 2017 August West Area had a total of 13 projects generation projects with a combined nameplate rating of 2207.78 MW (ERIS) & 600 MW (NRIS). The detailed list of West Area DPP 2 is shown below in Table 1, and the 2017 August West cycle originally kicked off on June 12, 2019.

**Table 1: List of DPP August 2017 West Area Phase 1 Projects**

| Project | Fuel Type | Transmission Owner | County | State | Service Requested | MW | POI | Interconnection Facility Self Fund Election |
|---|---|---|---|---|---|---|---|---|
| J545 | Wind | Xcel | Lincoln | MN | ERIS | 110 | Buffalo Ridge 115 kV | Yes |
| J628 | Wind | GRE | Grand Forks, Nelson | ND | ERIS | 400 | Prairie-Ramsey 230 kV | No |
| J722 | Wind | OTP | Codington, Deuel | SD | ERIS | 200 | Big Stone South 230 kV | Yes |
| J801 | Solar | DPC | Pierce | WI | ERIS | 74 | Crystal Cave – Rock Elm 161 kV | Yes |
| J803 | Solar | Xcel | Lyon | MN | ERIS | 32.5 | Tracy 69 kV | Yes |
| J836 | Wind | ITCM | Kossuth | IA | ERIS | 200 | Ledyard 345 kV | Yes |
| J874 | Solar | Xcel | Murray | MN | NRIS | 150 | Fenton-Chanarambie 115 kV | Yes |
| J877 | Solar | MEC | Palo Alto | IA | NRIS | 250 | Palo Alto 345 kV | Yes |
| J897 | Wind | GRE | Grand Forks | ND | ERIS | 190 | Ramsey-Prairie 230 kV | No |
| J898 | Wind | DPC | Fillmore, Mower | MN | ERIS | 100 | Beaver Creek-Rice 161 kV | Yes |
| J901 | Wind | Xcel | Redwood | MN | ERIS | 200 | Lyon County-Cedar Mountain 345 kV | Yes |
| J926 | Solar | Xcel | Saint Croix | WI | ERIS | 101.28 | Pine Lake – Apple River 161 kV | Yes |
| J946 | Solar | Xcel | Cass | ND | NRIS | 200 | Bison 345 kV | Yes |

### 1.2. Project Summary Network Upgrades

| J545 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J545 Cost Estimate ($)** | **NU Type** |
| Rebuild Split Rock-White 345 kV | $65,000,000 | $20,228,804 | SPP Thermal |
| Split Rock-Sioux City 345 kV Terminal Equipment Upgrade | $1,000,000 | $419,805 | SPP Thermal |
| **Total Cost Per Project:** | | **$20,648,609** | |

| J628 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J628 Cost Estimate ($)** | **NU Type** |
| Crookston-Falconer Uprate Jumper Replacement | $50,000 | $50,000 | ERIS Thermal |
| Rebuild J628-Prairie 230 kV Rebuild | $16,770,000 | $11,369,492 | ERIS Thermal |
| New J628-Prairie 230 kV 2nd Circuit | $22,360,000 | $15,159,322 | ERIS Thermal |
| J628J897 POI-Prairie 230 kV Circuit 1 (MPC AFS) | $500,000 | $338,983 | MPC Thermal |
| Grand Forks-Falconer Terminal Upgrades (MPC AFS) | $550,000 | $372,881 | MPC Thermal |
| Coleman-Prairie 69 kV Reconductor (MPC AFS) | $1,050,000 | $711,864 | MPC Thermal |
| Falconer-Oslo 115 kV Reconductor (MPC AFS) | $2,000,000 | $1,236,791 | MPC Thermal |
| Wilton-Winger 230 kV Re-sag (MPC AFS) | $400,000 | $220,927 | MPC Thermal |
| Mill Road-Master 69 kV Re-sag (MPC AFS) | $500,000 | $338,983 | MPC Thermal |
| Install Second Grand Forks 230/115 kV Transformer | $6,621,188 | $4,652,677 | SPP Thermal |
| **Total Cost Per Project:** | | **$34,451,920** | |

| J722 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J722 Cost Estimate ($)** | **NU Type** |
| Big Stone-Big Stone South 230 kV Circuit 1 Rebuild | $1,450,000 | $1,450,000 | ERIS Thermal |
| Big Stone-Big Stone South 230 kV Circuit 2 Rebuild | $1,400,000 | $1,400,000 | ERIS Thermal |
| Big Stone-Blair 230 kV Rebuild | $28,000,000 | $1,500,000 | ERIS Thermal |
| Rebuild Split Rock-White 345 kV | $65,000,000 | $44,771,196 | SPP Thermal |
| **Total Cost Per Project:** | | **$49,121,196** | |

| J801 |
|---|

| Network Upgrade | NU Cost Estimate ($) | J801 Cost Estimate ($) | NU Type |
|---|---|---|---|
| | $0 | $0 | |
| **Total Cost Per Project:** | | **$0** | |

| J803 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J803 Cost Estimate ($)** | **NU Type** |
| | $0 | $0 | |
| **Total Cost Per Project:** | | **$0** | |

| J836 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J836 Cost Estimate ($)** | **NU Type** |
| | $0 | $0 | |
| **Total Cost Per Project:** | | **$0** | |

| J874 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J874 Cost Estimate ($)** | **NU Type** |
| Split Rock-Sioux City 345 kV Terminal Equipment Upgrade | $1,000,000 | $580,195 | SPP Thermal |
| **Total Cost Per Project:** | | **$580,195** | |

| J877 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J877 Cost Estimate ($)** | **NU Type** |
| | $0 | $0 | |
| **Total Cost Per Project:** | | **$0** | |

| J897 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J897 Cost Estimate ($)** | **NU Type** |
| Rebuild J628-Prairie 230 kV Rebuild | $16,770,000 | $5,400,508 | ERIS Thermal |
| New J628-Prairie 230 kV 2nd Circuit | $22,360,000 | $7,200,678 | ERIS Voltage |
| J628J897 POI-Prairie 230 kV Circuit 1 (MPC AFS) | $500,000 | $161,017 | MPC Thermal |
| Grand Forks-Falconer Terminal Upgrades (MPC AFS) | $550,000 | $177,119 | MPC Thermal |
| Coleman-Prairie 69 kV Reconductor (MPC AFS) | $1,050,000 | $338,136 | MPC Thermal |
| Falconer-Oslo 115 kV Reconductor (MPC AFS) | $2,000,000 | $587,476 | MPC Thermal |

| | | | |
|---|---|---|---|
| Wilton-Winger 230 kV Re-sag (MPC AFS) | $400,000 | $104,940 | MPC Thermal |
| Mill Road-Master 69 kV Re-sag (MPC AFS) | $500,000 | $161,017 | MPC Thermal |
| Install Second Grand Forks 230/115 kV Transformer | $6,621,188 | $1,968,511 | SPP Thermal |
| **Total Cost Per Project:** | | **$16,099,402** | |

| J898 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J898 Cost Estimate ($)** | **NU Type** |
| Adams 345/161 kV Transformer Upgrade | $3,000,000 | $3,000,000 | ERIS Thermal |
| 161 kV Reconfigure into J898 POI Substation | $7,840,051 | $7,840,051 | ERIS Thermal |
| **Total Cost Per Project:** | | **$10,840,051** | |

| J901 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J901 Cost Estimate ($)** | **NU Type** |
| Helena-Chub Lake 2nd Circuit | $34,000,000 | $34,000,000 | ERIS Thermal |
| **Total Cost Per Project:** | | **$34,000,000** | |

| J926 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J926 Cost Estimate ($)** | **NU Type** |
| | $0 | $0 | |
| **Total Cost Per Project:** | | **$13,315,742** | |

| J946 | | | |
|---|---|---|---|
| **Network Upgrade** | **NU Cost Estimate ($)** | **J946 Cost Estimate ($)** | **NU Type** |
| Sheyenne-Mapleton Rebuild | $17,600,000 | $17,600,000 | ERIS Thermal |
| Big Stone-Blair 230 kV Rebuild | $28,000,000 | $26,500,000 | NRIS Thermal |
| Wahpeton-Fergus Falls 230 kV Structure Replacements | $800,000 | $800,000 | OTP LPC Thermal |
| Audubon-Lake Park 230 Structure Replacements | $100,000 | $100,000 | OTP LPC Thermal |
| Lake Park-Sheyenne 230 kV Structure Replacements | $600,000 | $600,000 | OTP LPC Thermal |
| Falconer-Oslo 115 kV Reconductor (MPC AFS) | $2,000,000 | $175,733 | MPC Thermal |
| Wilton-Winger 230 kV Re-sag (MPC AFS) | $400,000 | $74,132 | MPC Thermal |
| **Total Cost Per Project:** | | **$45,849,865** | |

## 1.3. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2017 August West Phase 1 reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

**Table 2: Total Cost of Network Upgrades for DPP 2017 August West Phase 1 Projects**

| Project | ERIS Network Upgrades ($) | | | | | NRIS Network Upgrades ($) | Interconnection Facilities ($) | | Shared Network Upgrades ($) |
|---|---|---|---|---|---|---|---|---|---|
| | Steady State | LPC Studies | Stability | Short Circuit | Affected System | Deliverability | TO Network Upgrades | TO – Owned Direct Assigned | |
| a | b | C | D | E | F | G | H | I | J |
| J545 | $0 | $0 | $0 | $0 | $20,648,609 | $0 | $2,010,000 | $2,290,000 | $0 |
| J628 | $26,528,814 | $50,000 | $0 | $0 | $7,873,106 | $0 | $2,814,490 | $940,127 | $0 |
| J722 | $4,350,000 | $0 | $0 | $0 | $44,771,196 | $0 | $1,250,000 | | $0 |
| J801 | $0 | $0 | $0 | $0 | $0 | $0 | $5,338,631 | $686,054 | $0 |
| J803 | $0 | $0 | $0 | $0 | $0 | $0 | $1,112,000 | $888,000 | $0 |
| J836 | $0 | $0 | $0 | $0 | $0 | $0 | $1,346,310 | $1,270,398 | $0 |
| J874 | $0 | $0 | $0 | $0 | $580,195 | $0 | $7,824,000 | $1,233,000 | $0 |
| J877 | $0 | $0 | $0 | $0 | $0 | $0 | $1,300,000 | $2,500,000 | $0 |
| J897 | $12,601,186 | $0 | $0 | $0 | $3,498,216 | $0 | $2,814,490 | $940,127 | $0 |
| J898 | $10,840,051 | $0 | $0 | $0 | $0 | $0 | $5,097,052 | $680,033 | $0 |
| J901 | $34,000,000 | $0 | $0 | $0 | $0 | $0 | $11,759,000 | $2,004,000 | $0 |
| J926 | $0 | $0 | $0 | $0 | $0 | $0 | $8,527,000 | $1,222,000 | $0 |
| J946 | $17,600,000 | $1,500,000 | $0 | $0 | $249,865 | $26,500,000 | $3,537,000 | $2,810,000 | $0 |
| Total | $105,920,051 | $1,550,000 | $0 | $0 | $77,621,187 | $26,500,000 | $54,729,973 | $17,463,739 | $0 |

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in Table 3. Shared Network Upgrades are shown in Table 4.

**Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)**

| Network Upgrade | TO | GI projects requiring upgrade for ERIS | GI projects requiring upgrade for NRIS | Cost of solution ($) | Self Fund Election |
|---|---|---|---|---|---|
| Sheyenne-Mapleton 115 kV Rebuild | XEL, OTP | J946 | | $17,600,000 | XEL Yes OTP Yes |
| Crookston-Falconer 115 kV Jumper Replacement | OTP | J628 | | $50,000 | Yes |
| New J628 POI– Prairie 230 kV 2nd Circuit | GRE | J628, J897 | | $22,360,000 | No |
| J628 POI-Prairie 230 kV Rebuild | GRE | J628, J897 | | $16,770,000 | No |
| Helena-Chub Lake 2nd Circuit | CAPX | J901 | | $34,000,000 | Yes |
| Big Stone-Big Stone South 230 kV Circuit 1 Rebuild | OTP | J722 | | $1,450,000 | Yes |
| Big Stone-Big Stone South 230 kV Circuit 2 Rebuild | OTP | J722 | | $1,400,000 | Yes |
| Adams 345/161 kV Transformer Upgrade | XEL | J898 | | $3,000,000 | Yes |
| 161 kV Reconfigure into J898 POI Substation | DPC | J898 | | $7,840,051 | Yes |
| Big Stone-Blair 230 kV Rebuild* | OTP/NWE/EREPC | | J946 | $28,235,800 | OTP Yes |
| Big Stone-Blair 230 kV CT adjustment and Structure Replacements (OTP LPC)* | OTP/NWE | J722 | | $1,500,000 | OTP Yes |
| Wahpeton-Fergus Falls 230 kV Structure Replacements (OTP LPC) | OTP | J946 | | $800,000 | Yes |
| Audubon-Lake Park 230 kV Structure Replacements (OTP LPC) | OTP | J946 | | $100,000 | Yes |
| Lake Park-Sheyenne 230 kV Structure Replacements (OTP LPC) | OTP | J946 | | $600,000 | Yes |
| J628J897 POI-Prairie 230 kV Circuit 1 (MPC AFS) | MPC | J628, J897 | | $500,000 | N/A |
| Grand Forks-Falconer Terminal Upgrades (MPC AFS) | MPC | J628, J897 | | $550,000 | N/A |
| Coleman-Prairie 69 kV Reconductor (MPC AFS) | MPC | J628, J897 | | $1,050,000 | N/A |
| Falconer-Oslo 115 kV Reconductor (MPC AFS) | MPC | J628, J897, J946 | | $2,000,000 | N/A |
| Wilton-Winger 230 kV Re-sag (MPC AFS) | MPC | J628, J897, J946 | | $400,000 | N/A |
| Mill Road-Master 69 kV Re-sag (MPC AFS) | MPC | J628, J897 | | $500,000 | N/A |
| Rebuild Split Rock-White 345 kV (SPP AFS) | WAPA/XEL | J545, J722 | | $65,000,000 | XEL Yes |
| Split Rock-Sioux City 345 kV Terminal Equipment Upgrade (SPP AFS) | WAPA/XEL | J545, J874 | | $1,000,000 | XEL Yes |
| Install Second Grand Forks 230/115 kV Transformer (SPP AFS) | WAPA | J628, J897 | | $6,621,188 | N/A |

***J722 responsible for the ERIS/OTP LPC costs and J946 responsible for the NRIS incremental costs for the Blair-Big Stone 230 kV constraint**

**Table 4: Shared Network Upgrades (Planning level cost estimates)**

| Shared Network Upgrade | TO | Higher queued projects associated with SNU | Study projects associated with SNU | Cost of solution ($) |
|---|---|---|---|---|
| | | | | |

**Note:**

1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.
3) Analysis performed shows that no August 2017 projects met the criteria for Shared Network Upgrade cost allocation.

## 2. FERC Order 827 Compliance Review

The Final Rule of FERC Order 827 "Reactive Power Requirements for Non-Synchronous Generation", which was issued June 16, 2016, stated that "Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be 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." As such, this Final Rule applies to all non-synchronous projects included in the DPP 2017 August West study cycle.

In this study, the power factor at the high-side of the generator substation for each project was calculated and reviewed. The study method is to set Qgen of each study project at its Qmax, solve the case, then record the P and Q injection on the high side of the generator substation to calculate the lagging power factor (injecting VAR to the system). The same process is then repeated by setting Qgen at Qmin to calculate the leading power factor (absorbing VAR from the system).

The results show that not all projects meet FERC Order 827 requirements. Additional reactive support will be needed for these projects to meet the FERC requirement on reactive power capability prior to the completion of their GIA.

**Table 5: FERC Order 827 Review Results**

| Project | Pmax (MW) | Reactive Power Capability (MVAr) | Proposed VAR Compensation | VAR Injection | | | VAR Absorption | | | Meet FERC Order 827 Requirement? | Add'l VAR Needed (MVAr) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | P (MW) | Q (MVar) | Lagging p.f (pu) | P (MW) | Q (MVAr) | Leading p.f. (pu) | | |
| J545 | 110 | ±37 | 3 x6 Mvar Cap | 108.4 | 51.3 | 0.904 | 107.9 | -50.2 | -0.907 | Yes | |
| J628 | 400 | ±133 | 6 x 8 MVAr Cap | 397.5 | 128.4 | 0.952 | 396.2 | -145.5 | -0.939 | No | 2.3 |
| J722 | 200 | ±67 | 3 x 8 MVAr Cap | 198.6 | 56.7 | 0.962 | 198.0 | -114.9 | -0.865 | No | 8.6 |
| J801 | 74 | ±36.4 | N/A | 73.1 | 29.1 | 0.929 | 72.8 | -46.2 | -0.844 | Yes | |
| J803 | 33 | ±13.25 | N/A | 32.5 | 8.6 | 0.967 | 32.4 | -21.6 | -0.832 | No | 2.1 |
| J836 | 205 | ±95.5 | N/A | 201.7 | 56.0 | 0.964 | 200.2 | -169.0 | -0.764 | No | 10.3 |
| J874 | 150 | ±72.6 | N/A | 147.6 | 42.8 | 0.960 | 145.6 | -129.1 | -0.748 | No | 5.7 |
| J877 | 250 | ±121 | N/A | 247.2 | 79.5 | 0.952 | 245.7 | -187.9 | -0.794 | No | 1.8 |
| J897 | 190 | ±43 | 2 x 8 MVAr Cap | 188.0 | 64 | .946 | 185.8 | -144.4 | -0.793 | Yes | |
| J898 | 100 | ±19.72 | 1 x 8 MVAr Cap | 99.1 | 9.9 | 0.995 | 98.8 | -43.2 | -0.916 | No | 22.7 |
| J901 | 200 | ±35.12 | 2 x 8 MVAr Cap | 198.1 | 0.6 | 1.000 | 197.4 | -103.9 | -0.885 | No | 64.5 |
| J926 | 101.3 | ±33.29 | N/A | 99.0 | 22.2 | 0.9757 | 98 | -57.8 | -0.861 | No | 10.33 |
| J946 | 210 | ±69.4 | 2 x 20 MVAr Cap | 200 | 74.4 | 0.865 | 124.9 | -68.1 | -0.878 | Yes | |

## 3. Model Development and Study Assumptions

### 3.1. Base Case Models

The origin of the DPP 2017 August West models is based on the MTEP 18 series models with the Bench Cases including all prior-queued projects and their associated network upgrades known through the DPP February West Phase 3 analysis, while the Study Cases contain all of the interconnection requests in DPP 2017 August West Phase 3.

Prior queued network upgrades are documented in the following System Impact Study reports

MISO DPP 2017 February West Area Phase 3 Study section 4.3
https://cdn.misoenergy.org/GI-DPP-2017-FEB-West-Phase3_System_Impact_Report_PUBLIC391580.pdf
MISO DPP 2016 August West Area Phase 3 Study section 4.3
https://cdn.misoenergy.org/GI-DPP-2016-AUG-West-Phase3-Final-Public394324.pdf
MISO DPP 2016 February West Area Phase 3 Study section 2.8
https://cdn.misoenergy.org/GI-DPP-2016-FEB-West-Phase3-Final-Public394321.pdf

- Bench Cases
    - DPP_AUG17_West_2023SH90_Bench_P3_FINAL_210210
    - DPP_AUG17_West_2023SUM_Bench_P3_FINAL_210210
- Study Cases
    - DPP_AUG17_West_2023SH90_Study_P3_FINAL_210210
    - DPP_AUG17_West_2023SUM_Study_P3_FINAL_210210

### 3.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

### 3.3. Contingencies

The following contingencies were considered in the steady state analysis:

1) NERC Category P0 (system intact -- no contingencies)
2) NERC Category P1 contingencies
    a. Single element outages, at buses with a nominal voltage of 68 kV and above
    b. Multiple element NERC Category P1 contingencies
3) NERC Category P2-P7 contingencies
4) For all the contingencies 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.

### 3.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2017 August West generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.11.0, TSAT version 18, and TARA version 1801d.

### 3.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the applicable rating (normal or emergency) of the overloaded facility, or
4) For any other constrained facility, where none of the Study Generators meet one of the above criteria, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) will be responsible for mitigating the cumulative MW impact constraint, or
5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or

6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

1) The bus voltage is outside of the 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 generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of 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 P1 events, if DFAX due to the study generator is equal to or greater than 5%.

# 4. Backbone Network Upgrade Analysis

An analysis was performed to determine the need for any backbone network upgrades for this cycle. Voltage and thermal issues were not significant enough to justify the inclusion of a backbone upgrade in this analysis.

# 5. Thermal Analysis

The thermal analysis results for 2017 August West group show generator projects causing constraints. The details pertaining to the thermal analysis can be found in Appendix A.

# 6. Voltage Analysis

The voltage analysis results for summer peak models show that the no study generators cause any voltage constraints. The shoulder peak analysis does indicate that three contingencies result in a voltage collapse condition that will require mitigation by the August 2017 study group. The details pertaining to the voltage analysis can be found in Appendix B. The shoulder peak analysis identified some voltage constraints in the area of northwest Minnesota. One point of interconnection voltage constraint was identified in Iowa region.

# 7. Stability Analysis

A voltage stability analysis was performed for the Minnesota-Wisconsin Export Interface (MWEX). The results of that analysis indicate that the August 2017 Study group does not aggravate the interface and no network upgrades were therefore identified. The full analysis is included in appendix C.

Transient stability analysis was performed for the August 2017 Study group. Results of the analysis are included in Appendix E. No additional Network Upgrades were identified in the Stability Analysis.

# 8. Short Circuit Analysis

Short circuit analysis for the proposed projects are included in appendix F.

# 9. Affected System Impact Study

Affected System analysis are in Appendix G.

# 10. Deliverability Analysis

## 10.1. Introduction

Generator interconnection projects must pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an

Energy Resource (ER) project or to 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 study generators are tested at 100% of NRIS request level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C. The TARA tool will dispatch the top 30 deliverable units that are prior queued or existing for the identified flowgates. Then TARA will dispatch study NRIS units that meet the criteria to determine the network upgrades that required to ensure the study generator is deliverable.

### 10.2. 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 has a DF greater than 5%, 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.

### 10.3. Deliverability Study Results

The deliverability analysis assumes all ERIS upgrades as those upgrades are required for the study group to interconnection to the transmission system. With all the MISO analysis ERIS upgrades assumed as well as the prior queued network upgrades, the deliverability analysis determined no new constraints for projects that are requesting NRIS service. If a constraint is identified, the deliverability is calculated by taking the NRIS Request amount subtracting the calculated shared deductible. The shared deduction is the amount by which each study generator affecting a given flowgate must be scaled down in order to prevent loading violations on the flowgate. The deduction is proportionally taken from each study generator affecting a particular flowgate. If a particular monitored element becomes a flowgate under multiple contingencies, the contingency with the highest total shared deduction is used.

#### 10.3.1. J874

This generator is determined to be fully deliverable for 150 MW, contingent upon the ERIS system upgrades and assumed prior queued network upgrades.

#### 10.3.2. J877

This generator is determined to be fully deliverable for 250 MW, contingent upon the ERIS system upgrades and assumed prior queued network upgrades.

#### 10.3.3. J946

This generator requires a rating of 807 MVA for the Big Stone-Blair 230 kV line to be deliverable to 200 MWs. The ERIS upgrade for J722 is only enables for a Rating of 700 MVA and a full rebuild will be necessary to have the rating reach the required 807 MVA identified in the Deliverability analysis. J946 is responsible for the incremental cost of the mitigation for Big Stone-Blair 230 kV line rebuild.

## 11. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) Analysis tests for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study. SNUs were not identified for DPP 2017 August West Area Projects.

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations appear in Table 6.

**Table 6: Maximum MW Impact and SNU Cost Allocations**

| Network Upgrades | Project Study Cycle | Projects sharing cost | MW Contribu tion | Total NU Cost ($) | Cost Responsibility ($) |
|---|---|---|---|---|---|
| | | | | | |

## 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 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 identified in System Impact Study was provided by the corresponding transmission owning company.

### 12.2. 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 Study Case.

<u>Cost Allocation Methodology for Thermal Constraints</u>

1. With all Study Group generation projects dispatched in the Study Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of one NU is:

$$\frac{Project\ A\ cost\ portion\ of\ NU}{Cost\ of\ NU} = \frac{Max(Proj.A\ MW\ contribution\ on\ constraint)}{\sum_i Max(Proj.i\ MW\ contrution\ on\ constraint)}$$

6. The total NU costs for each project are calculated if more than one NU is required.

<u>Cost Allocation Methodology for Voltage Constraints</u>

Cost allocation of voltage constraint driven network upgrades will be determined by the pro rata share of the voltage impact each project has on the most constrained bus under the most constraining contingency. The voltage impact of each project will be calculated by locking all voltage regulating equipment in the model and then backing out each GI project one at a time to identify each project's impact to the constraint. In severe instances of voltage collapse where projects cannot be backed out one at a time, they will be added one at a time to determine their impact to the constraint.

As the number and types of constraints increases, mitigating the constraints individually may result in higher overall costs. In instances when mitigation(s) resolve multiple types of constraints (such as thermal +

voltage or thermal + voltage + transient stability) the cost is allocated based off the ratio share of the total cost of the independent mitigations in order to equitably allocate the cost to all parties contributing to constraints. In summary, only the lowest cost mitigation option will be constructed, but for cost allocation purposes the independent mitigations are required.

**Appendix A – Thermal Analysis Results**

**Appendix B – Voltage Constraints**

**Appendix C – MWEX Voltage Stability**

**Appendix D – Cost Allocation**

**Appendix E – Transient Stability Analysis**

**Appendix F – Local Planning Criteria Studies**

**Appendix G – Short Circuit Studies**

**Appendix H – Affected Systems Studies**

**Appendix I – Deliverability Results**