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MISO DPP April 2018 East (ATC) Phase 2

System Impact Study Report

J986, J1000, J1002, J1003, J1009, J1010, J1011, J1042, J1051, J1053, J1085, J1101, J1121, J1153, J1154, J1171, J1183, and J1188

Prepared By:
Jeremy Voigt, P.E.
Senior Transmission Planning Engineer
Chengyue Guo
Consultant Transmission Planning Engineer
Damien Sommer, P.E.
Senior Transmission Planning Engineer
Mike Marz, P.E.
Principal Transmission Planning Engineer
Yi Li, P.E.
Consultant Transmission Planning Engineer
Joel Berry
Consultant Transmission Planning Engineer
Josh Kerr
Senior Transmission Planning Engineer
Jamal Khudai
Principal Transmission Planning Engineer

Approved By:
Paul Walter, P.E.
Manager, Resource Interconnection
April 27th, 2020

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1.0 EXECUTIVE SUMMARY

Eighteen (18) resource projects have requested to interconnect to the Midcontinent Independent System Operator (MISO) transmission network in the East (ATC) Area and are included in the Definitive Planning Phase 2018 April Phase 2 study (Apr 18 DPP Phase 2). All Generating Facilities, except one, have requested both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). J1183 has requested only ERIS.

This report presents the study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generator interconnection requests in the Apr 18 DPP Phase 2 study. The study was performed under the direction of MISO. The results for 2023 scenario are summarized below.

1.1 Project List

The Apr 18 DPP Phase 2 has eighteen (18) interconnection requests with a combined nameplate rating of 2,995.11 MW. The Apr 18 DPP Phase 2 generator interconnection requests are listed in Table 1.1-1. The one-line diagrams of the interconnection facilities are shown in Appendix C.

Table 1.1-1 – Generating Facilities in DPP April 2018 Phase 2 East (ATC) Area

MISO Queue #	Service Type	County, State	Point of Interconnection	Fuel Type	Inverter Model	Main Step-Up Transformer	Requested MW	Dispatch (MW)[1]			
								Batteries Discharging		Batteries Charging	
								23SH	23SUM	23SH	23SUM
J986	NRIS	Wood, WI	Port Edwards - Sand Lake 138-kV	Solar	50 x 3.18 MVA TMEIC Ninja 840 PVU-L0840GR Total Rated MVA = 159	One 34.5/138 kV 105/140/175 MVA Z=5.75%	149.76	74.88	149.76	74.88	149.76
J1000	NRIS	Grant, WI	Nelson Dewey - Lancaster 138-kV	Solar	17 x 3.5 MVA Power Electronics HEC-US V1500 FS3000CU15 Total Rated MVA = 58.3	One 34.5/138 kV 33/45/55 MVA Z=9.5%	50	25	50	25	50
J1002	NRIS	Waushara, WI	Wautoma 138-kV	Solar	33 x 3.5 MVA Power Electronics Freesun HEC-US V1500 FS3000CU15 Total Rated MVA = 115.5	One 34.5/138 kV 66/88/110 MVA Z=9.5%	99	49.5	99	49.5	99
J1003	NRIS	Dodge, WI	North Beaver Dam 69-kV	Solar	17 x 3.5 MVA Power Electronics Freesun HEC-US V1500 FS3000CU15 Total Rated MVA = 58.3	One 34.5/138 kV 33/55 MVA Z=8%	50	25	50	25	50
J1009	NRIS	Kenosha, WI	Pleasant Prairie-Racine 345-kV	Solar	108 x 4.05 MVA TMEIC Ninja 840 Total Rated MVA = 432	Two 345/34.5/13.8 kV 135/180/225 MVA Z=8.5%	400	200	400	200	400
J1010	NRIS	Kenosha, WI	Arcadian-Zion 345-kV	Solar	108 x 4.05 MVA TMEIC Ninja 840 Total Rated MVA = 432	Two 345/34.5/13.8 kV 135/180/225 MVA Z=8.5%	400	200	400	200	400
J1011	NRIS	Kenosha, WI	Arcadian-Zion 345-kV	Solar	108 x 4.05 MVA TMEIC Ninja 840 Total Rated MVA = 432	Two 345/34.5/13.8 kV 135/180/225 MVA Z=8.5%	400	200	400	200	400
J1042	NRIS	Walworth, WI	North Lake Geneva 138-kV	Solar	54 x 4.05 MVA TMEIC Ninja 840 Total Rated MVA = 216	One 138/34.5/13.8 kV 135/180/225 MVA Z=8.5%	200	100	200	100	200
J1051	NRIS	Jefferson, WI	Concord 138-kV	Battery	20 x 2.8 MVA TMEIC Ninja 840 Total Rated MVA = 55.555	One 34.5/138 kV 36/48/60 MVA Z=9%	50	50	50	-50	-50
J1053	NRIS	Jefferson, WI	Concord 138-kV	Solar	66 x 3.36 MVA TMEIC Ninja 840 Total Rated MVA = 222.2	Two 34.5/138 kV 69.6/92.8/116 MVA Z=9%	200	100	200	100	200
J1085	NRIS	Marathon, Taylor, Wood, WI	Gardner Park-Stone Lake 345-kV	Wind	120 x 2.7 MVA GE double fed induction machine with power converter Total Rated MVA = 324	Two 345/34.5/13.8 kV 102/136/170 MVA Z=8.5%	300	300	47.1	300	47.1
J1101	NRIS	Manitowoc, WI	Kewaunee 138-kV	Battery	17 x 1.29 MVA Power Electronics Fremaq FP1290 Total Rated MVA = 21.93	One 34.5/138 kV 15/20/25 MVA Z=8%	20	20	20	-20	-20
J1121	NRIS	Marathon, WI	Gardner Park-Stone Lake 345-kV	Solar	54 x 4.05 MVA TMEIC Ninja 840 Total Rated MVA = 216	One 345/34.5/13.8 kV 135/225 MVA Z=8.5%	200	100	200	100	200
J1153	NRIS	Sheboygan, WI	Holland 138-kV	Solar	50 x 3.3 MVA Power Electronics Freesun HEMFS3000M Total Rated MVA = 165	One 34.5/138 kV 100/133/167 MVA Z = 8.5%	150	75	150	75	150
J1154	NRIS	Jefferson, WI	Jefferson 138-kV	Solar	25 x 3.3 MVA Power Electronics Freesun HEM FS3000M Total Rated MVA = 82.5	One 34.5/138 kV 48/64/80 MVA Z=8.5%	75	37.5	75	37.5	75

J1171	NRIS	Dodge, WI	Butternut 138-kV	Solar	36 x 3 MVA Power Electronics HEC-US V1500 FS3001CU15 Total Rated MVA = 108	One 34.5/138 kV 100/120 MVA Z=6%	100	50	100	50	100
J1183	ERIS	Delta, MI	Garden Corners 138-kV	Solar	27 x 0.063 MVA CPS/Chint Power 50KTL Total Rated MVA = 1.69	Existing	1.35	0.675	1.35	0.675	1.35
J1188	NRIS	Rock, WI	Sheepskin 69-kV	Solar	18 x 3 MVA Power Electronics HEC-US V1500 FS3001CU15 Total Rated MVA = 54	One 34.5/69 kV 33/44/55 MVA Z=9.0%	50	25	50	25	50

[1] Per MISO BPM 015-r21 the following dispatch assumptions are applied for each Fuel Type.

a. Combined Cycle (CC) is dispatched to 50% of the Requested MW in the shoulder models, 100% in the summer peak models.
b. Solar is dispatched to 50% of the Requested MW in the shoulder models, 100% in the summer peak models.
c. Wind is dispatched to 100% of the Requested MW in the shoulder models, 15.6% in the summer peak models.
d. Battery is dispatched, both in charging and discharging modes, to 100% of the Requested MW in all study models.

1.2 Generating Facility Requirements

1.2.1 Voltage Schedule Requirement

ATC (Transmission Owner) requires all generators in its territory to maintain a voltage schedule at the Point of Interconnection (POI). The standard voltage schedule is 1.02 per unit as measured at the POI. This schedule may be changed by the Transmission Operator for specific power plants or specific conditions.

1.2.2 Power Factor Range Requirement

FERC Order 827 and ATC Criteria require all newly interconnecting generators interconnecting to ATC-owned Facilities to provide a power factor range for synchronous and non-synchronous (e.g. wind turbines, solar) generation of 0.95 leading (when a Generating Facility is consuming reactive power from the Transmission System) to 0.95 lagging (when a Generating Facility is supplying reactive power to the Transmission System). The Generating Facility must be capable of maintaining ATC's standard power factor range at all power output levels by providing dynamic reactive power at the following locations:

A. The POI for all synchronous generators
B. The high-side of the generator substation for all non-synchronous generators

For synchronous machines, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the POI. For non-synchronous machines, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the generator substation. Dynamic reactive power provided by non-synchronous generators must meet the following requirement from FERC order 827 Item 35:

> "Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses."

Therefore, static reactive power sources can only be used to make up for losses between the terminal of the machines and the high side of the generator substation for non-synchronous machines. All other reactive power to meet the power factor requirement must be provided by dynamic sources. Static sources can be switched on or off in the range of seconds and provide reactive power in large discrete blocks. Capacitor Banks are considered static sources of reactive power. Dynamic sources can provide variable amounts of reactive power in a few milliseconds. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), Flexible AC Transmission Systems (FACTS), inverters and synchronous condensers are all considered dynamic sources or reactive power.

Non-synchronous generation projects in the Apr 18 DPP Phase 2 study group 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.

The generation requests shown in Table 1.2.2-1 did not meet the dynamic reactive power requirements per FERC Order 827 and ATC Criteria at the time of the model completion and are required to provide additional dynamic reactive power sources. All other requests in this queue met FERC Order 827 and ATC Criteria for dynamic reactive power requirements.

Table 1.2.2-1 – Additional Dynamic Mvar to meet ATC Dynamic Inductive Power Factor Requirement and FERC Order 827 Power Factor Requirements

MISO Queue #	Type	Additional Dynamic Reactive Compensation (Mvar)
J1171	Asynchronous	-1.90
J1188	Asynchronous	-0.92

The generation requests shown in Table 1.2.2-2 did not meet the static reactive power requirements per ATC Criteria at the time of the model completion and are required to provide additional static reactive power sources. All other requests in this queue met FERC Order 827 and ATC Criteria for static reactive power requirements.

Table 1.2.2-2 – Additional Static Mvar to meet ATC Capacitive Power Factor and FERC Order 827 Power Factor Requirements

MISO Queue #	Type	Additional Static Shunt Compensation [1] (Mvar)
J1009	Asynchronous	35.6
J1010	Asynchronous	38.3
J1011	Asynchronous	35.6
J1042	Asynchronous	19.3
J1101	Asynchronous	0.7
J1121	Asynchronous	16.3
J1153	Asynchronous	8.4
J1171	Asynchronous	13.9
J1188	Asynchronous	10.1

[1] Additional compensation is required to meet the criteria at the POI Bus for synchronous Generating Facilities or the high-side of the generator substation for asynchronous Generating Facilities.

The generation requests shown in Table 1.2.2-3 need an assessment of power factor at low real power output levels. The additional Static Mvar required at low generation level are based on the information provided by the interconnection customers. All other requests in this queue do not need an assessment of power factor requirements at low real power output levels.

Table 1.2.2-3 – Assessment of Power Factor Requirements at Low Output Levels

MISO Queue #	P-Q Curve Type	Additional Static Mvar required at POI Bus (synchronous) or HV Bus (asynchronous) to meet ATC Power Factor Requirement
J1085	D-shape with restriction	10 Mvar Inductor for near zero generation
J1121	D-shape with restriction	1 Mvar Inductor for near zero generation

1.2.3 Island Detection and Operation

In circumstances where the Generating Facility has no governor controls and the transmission system design could result in an islanding condition for the outage of two transmission elements, ATC will develop operating solutions requiring generation curtailment when the next contingency could result in an island condition. ATC continues to work with developers and evaluate technical solutions (e.g. requiring customer to implement additional protection systems) that could be considered as alternatives to implementing the operating solutions.

This would apply to the following Generating Facilities from this DPP cycle that lack adequate governor controls to safely and reliably sustain an island with load.

- J1000
- J1153
- J1171

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 Energy Resource Interconnection Service and Network Resource Interconnection Service as of the SIS report date. The total cost of Network Upgrades required for each generator interconnection request is listed in Table 1.3-1. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies. All Interconnection Facility Project Diagrams are documented in Appendix C and all Network Upgrade Project Diagrams are documented in Appendix D (No project diagrams are developed for line uprates).

Table 1.3-1 – Total Cost of Network Upgrades for April 18 DPP Phase 2 Generator Interconnection Requests

MISO Queue #	Requested MW	ERIS Network Upgrades ($)				NRIS Network Upgrades ($)	Interconnection Facilities ($)		Shared Network Upgrade ($)	Total Cost of Network Upgrades (Exclude TOIF & Affected Systems) ($)	M2 Received ($)[1]	M3 Received ($)[2]	M4 Due ($)[9]
		Steady - State Thermal & Voltage	Transient Stability	Short Circuit	Affected System		TO Network Upgrades	TO-Owned Direct Assigned (TOIF)					
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]=[c]+[d]+[e]+[g]+[h]	[l] = $4000 x [b]	[m]= (10%of [k])-[l]	[n]= (20%of [k])-[l] –[m]
J986	149.76	5,019,433	0	1,020,779	659,824	0	6,740,635	258,407	0	12,780,847	599,040	776,690	1,180,439
J1000	50	0	0	0	0	0	6,441,458	252,140	0	6,441,458	200,000	0	1,088,292
J1002	99	1,530,127	0	715,969	887,272	0	2,618,981	627,686	0	4,865,077	396,000	0	577,015
J1003	50	0	0	23,253	410,328	2,798,507	366,697	664,689	0	3,188,457	200,000	0	437,691
J1009	400	0	0	7,486	6,050,000	0	10,951,322	734,406	0	10,958,808	1,600,000	0	591,762
J1010	400	0	0	19,659	6,520,000	0	2,753,837	1,086,443	0	2,773,496	1,600,000	0	0
J1011	400	0	0	16,831	25,368,000	0	2,753,837	1,086,443	0	2,770,668	1,600,000	0	0
J1042	200	0	0	440,000	1,950,000	13,825,209	750,098	627,259	0	15,015,307	800,000	258,992	1,944,069
J1051	50	0	0	85,306	896,378[7]	5,531,570	6,009,313	266,480	0	11,626,189	200,000	887,940	1,237,298
J1053	200	0	0	634,545	12,022,954[7]	22,121,983	6,009,313	266,480	0	28,765,841	1,200,000	1,969,396	2,583,772
J1085	300	6,192,900	0	0	4,061,000	11,400,000	11,492,260	1,803,929	0	29,085,160	1,200,000	547,326	4,069,706
J1101	20	0	0	0	0	0	0	0	0	0	80,000	0	0
J1121	200	2,064,300	0	0	10,349,000	7,600,000	11,492,261	1,028,212	0	21,156,561	800,000	521,010	2,910,302
J1153	150	0	0	0	12,579,000	0	4,106,408	651,073	0	4,106,408	600,000	0	221,282
J1154	75	0	0	18,256	0	5,994,932	0	0	0	6,013,188	800,000	0	402,638
J1171	100	0	0	207,918	670,000	5,097,259	1,521,698	819,868	0	6,826,875	400,000	0	965,375
J1183	1.35	0	0	0	0	0	0	0	0	0	5,400	0	0
J1188	50	0	0	220,000	760,211[8]	4,703,137	1,362,993	267,141	0	6,286,130	200,000	135,899	921,327
Total ($)	-	14,806,760	0	3,410,000	83,183,967	79,072,598	75,371,111	10,440,656	0	172,660,469	12,480,440	5,097,253	19,130,968

[1] M2: Milestone Payment dollars received by MISO.
[2] M3 = (10% of NU)-M2.
[3] ATC projects are estimated in ISD dollars with a 2.5% annual escalation rate and include a 10% contingency.
[4] Pre-Certification costs are not included.
[5] Transmission Owner shall also collect from Interconnection Customer a tax gross-up amount on the payments made to Transmission Owner using the Transmission Owner rate in effect at the time the payment is received from Interconnection Customer. The current Transmission Owner tax gross-up rate is 12.848%.
[6] TOIF: Non-reimbursable Transmission Owner Interconnection Facilities to which tax gross-up amount must also be applied.
[7] Cost is reflective of changing the point of change of ownership (PCO) for We Energies CTs and expanding Concord Substation.
[8] Rock Energy Coop and Alliant Energy Affected System upgrades are included.
[9] M4= (20% of NU)-M2-M3.
[10] Interconnection Facilities costs for J1085 and J1121 include the "J1085/J1121 POI – Stone Lake 345 kV, Move the existing 75 Mvar line-connected reactor from Gardner Park to J1085/J1121 POI" project, to be consistent with the Interconnection Facility report.

1.4 Stability Operating Restrictions Summary

For NERC Category P6 stability constraints, operating restrictions may be required during prior outages to avoid instability caused by the next event. A summary of all P6 operating restrictions for study generators found in the Apr 18 DPP WI Phase 2 studies are provided in Table 1.4-1. Maximum allowed real power outputs to mitigate P6 stability constraints during prior outages were identified for each generating facility. These constraints may be discussed in further detail in sections 2.3.8, 3, and 6.

Table 1.4-1 – NERC Category P6 Operating Restriction Analysis Result Summary

MISO Queue #	Max MW	NERC Category P6 (N-1-1) Event		Stability Max MW Allowed
		1st Contingency	2nd Contingency	
J986	150	[redacted]	[redacted]	110
J986 & J1002	249	[redacted]	[redacted]	200
J1000	50	[redacted]	[redacted]	50
J1000	50	[redacted]	[redacted]	0
J1002	99	[redacted]	[redacted]	99
J1010 & J1011	800	[redacted]	[redacted]	300
J1010 & J1011	800	[redacted]	[redacted]	680
J1042	200	[redacted]	[redacted]	200
J1085 & J1121	500	[redacted]	[redacted]	500
J1085 & J1121	500	[redacted]	[redacted]	280[1]
J1085 & J1121	500	[redacted]	[redacted]	450[2]
J1085 & J1121	500	[redacted]	[redacted]	397[2]
J1085 & J1121	500	[redacted]	[redacted]	417[3]

[1] J732 was at 577 MW, its PMax
[2] J732 was at 493 MW, an operating restriction identified in August 2017 DPP
[3] J732 was at 523 MW, an operating restriction identified in August 2017 DPP

1.5 In-Service Dates and Cost Estimates

ATC understands that the estimated in-service date may not align with the Interconnection Customer's Synchronization Date; however, negotiated and executed agreements, such as an Engineering and Procurement Agreement, can be used prior to the GIA execution date to expedite Network Upgrades. In absence of any special arrangement, typical times to develop a new Interconnection Facility is about 24-36 months after the GIA is executed, assuming no delays due to Interconnection Customer's permits, state processes, land acquisitions, deliverables (such as a finish graded substation site, etc.) It also assumes that system outages required to construct facilities can be obtained timely. The cost estimates for Interconnection Facilities are based on the in-service date provided in the Interconnection Customer's application data. Therefore, any change in in-service date will have impact on the cost estimates. The requested dates for Interconnection Facility in-service, synchronization, and commercial operation are summarized in Table 1.5-1.

Table 1.5-1 – Requested Interconnection Facilities In-Service Dates, Synchronization Dates and Commercial Operation Dates

MISO Queue #	Requested Interconnection Facility In-service Date	Requested Synchronization Date	Requested Commercial Operation Date
J986	September 1, 2020	September 15, 2020	December 1, 2020
J1000	October 1, 2020	October 15, 2020	December 1, 2020
J1002	October 1, 2021	October 15, 2021	December 1, 2021
J1003	October 1, 2021	October 15, 2021	December 1, 2021
J1009	September 1, 2020	October 1, 2020	December 1, 2020
J1010	September 1, 2020	October 1, 2020	December 1, 2020
J1011	September 1, 2020	October 1, 2020	December 1, 2020
J1042	September 1, 2020	October 1, 2020	December 1, 2020
J1051	October 31, 2021	October 1, 2021	December 31, 2021
J1053	October 31, 2021	October 1, 2021	December 31, 2021
J1085	September 1, 2021	October 1, 2021	December 1, 2021
J1101	September 1, 2020	October 1, 2020	December 1, 2020
J1121	September 1, 2021	October 1, 2021	December 1, 2021
J1153	April 1, 2021	April 15, 2021	June 30, 2021
J1154	April 1, 2021	April 15, 2021	June 30, 2021
J1171	August 1, 2020	October 1, 2020	December 1, 2020
J1183	January 31, 2019	January 31, 2019	January 31, 2019
J1188	August 31, 2020	September 30, 2020	November 30, 2020

1.6 MTEP Projects

If a MISO Transmission Expansion Plan (MTEP) project(s) resolves the constraint, and that project(s) is approved by the MISO Board within (1) calendar year of the GIA execution or execution of an amendment thereof, then the Interconnection Customer will not be responsible for transmission upgrade(s) that would resolve the constraint. If that MTEP project(s) is not approved within one (1) calendar year of the GIA execution or execution of an amendment thereof, the Interconnection Customer will be responsible for those transmission upgrade(s).

MISO performed analysis and monitored upgrades that are not yet in service to identify upgrades which the study cycle projects are conditional upon in order to meet their requested service levels. Results are documented in Appendix M.

1.7 Further Study

The next step in the MISO Generator Interconnection Procedures is to perform additional SISs (if needed), Interconnection Customer Interconnection Facility Studies, and Network Upgrade Facility Studies. Those Facilities Studies will specify in more detail the time and cost of the equipment, engineering, procurement, and construction of the Interconnection Facilities and Network Upgrades identified in this report.

1.8 Compliance Summary

This study report partially meets NERC TPL-001-4 standard, FAC-002-2 standard, and ATC Planning Criteria. In ATC's annual Ten-Year Assessment (TYA) and MISO annual MTEP studies, additional compliance related studies will be performed for the generator interconnection requests with signed GIAs. Appendix J describes in detail the NERC standards and ATC Planning Criteria requirements met by this SIS report.

2.0 STEADY-STATE ANALYSIS

Steady-state analysis was performed to identify thermal and voltage upgrades required to interconnect the generator interconnection requests in the Apr 18 DPP Phase 2 to the transmission system. Detailed study assumptions, criteria, and methodologies are documented in Appendix A.

2.1 Model Development

2.1.1 Study Cases

Using the final DPP Apr 18 Phase 1 study cases as the starting point, four Phase 2 study cases for the steady-state thermal and voltage analysis were developed: 2023 summer peak batteries discharging, 2023 summer peak batteries charging, 2023 shoulder batteries discharging, and 2023 shoulder batteries charging. Major updates include:

- Removed generation requests in ATC and MISO areas that had dropped out of the MISO queue since the final Phase 1 study models were built. Removed any related Network Upgrades.

- Removed generation retirements in ATC and MISO areas since the final Phase 1 study models were built.
- Incorporated study generator POI changes and other modeling changes. J1000 POI moved from the Nelson Dewey Substation to the Nelson Dewey - Lancaster 138 kV line. J1053 reduced its MW request from 300 MW to 200 MW.

The Cardinal – Hickory Creek project was included in all study models, even though its in-service date is 12/31/2023. This is because it was defined as a required Network Upgrade in the DPP 2017 February Wisconsin Area Phase 1 SIS. The cases were reviewed by MISO, ATC and the Interconnection Customers. Based on this review, the cases were further modified to account for additional model updates.

The prior queued generator interconnection requests in the ATC system that are included in the study cases are listed in Table 2.1.1-1. Associated Network Upgrades were also included based on their expected in-service date.

Table 2.1.1-1 – Prior Queued Generator Interconnection Requests Not Yet In-Service, as of Apr 18 DPP Phase 1

MISO Queue #	Type	Control Area	Requested MW
J390	CC	ALTE	702
J505	Solar	WPS	99
J584	Wind	ALTE	60
J732	CC	WPS	561.5
J760	CC	ALTE	30
J807	Wind	ALTE	41.4
J818	Solar	WEC	149
J819	Wind	ALTE	99.9
J821	Wind	WPS	99.9
J831	CC	WEC	48
J849	Solar	MIUP	125
J850	Solar	ALTE	250
J855	Wind	ALTE	100
J864	Solar	ALTE	49.98
J870	Solar	ALTE	200
J871	Solar	ALTE	100
J878	Solar	WEC	200
J886	Solar	WPS	150
J928	Wind	MIUP	79.995
J947	Solar	ALTE	200

Public information related to the MISO Generator Interconnection Request queue can be found at:

https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

The four Phase 2 study cases (summer peak batteries discharging, summer peak batteries charging, shoulder batteries discharging, and shoulder batteries charging) dispatched generation within MISO according to section 6.1.1.1.2, Study Case Development, in the MISO BPM-015-r21.

All excess generation from this methodology is dispatched against all units in MISO Classic proportionally, excluding the units in the current DPP cycle. Scheduled firm transfers are ignored in this dispatch methodology.

2.1.2 Benchmark Cases

Using the final DPP Apr 18 Phase 1 benchmark cases as the starting point, two benchmark cases were used to benchmark system performance without the Apr 18 DPP Phase 2 generating facilities and were created by taking the Apr 18 DPP

Phase 2 Generating Facilities offline from the corresponding study cases. The MISO Classic was used for power balance, where generation was scaled in proportion to Pmax minus Pgen.

2.2 Reactive Power Requirements (FERC Order 827)

All synchronous and non-synchronous generation in this queue were evaluated to determine if the requests meet FERC Order 827 and ATC Planning Criteria. Refer to PLG-METH-0005 in Appendix B for details on the methodology used to determine power factor compliance. All of the reactive resources modeled in the assessment are summarized in Table 2.2-1.

Table 2.2-1 – Reactive Resources Modeled in Generator Interconnection Power Factor Analysis

MISO Queue #	Machines				Dynamic Reactive Devices			Static Reactive Devices		
	Description	Real Power (MW)	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)
J986	Solar	149.937	52.91	-52.91	None	N/A	N/A	6 * 4.2 Mvar Capacitor Banks	25.2	0
J1000	Solar	50	29.668	-29.668	None	N/A	N/A	None	0	0
J1002	Solar	99	59	-59	None	N/A	N/A	None	0	0
J1003	Solar	50	29.668	-29.668	None	N/A	N/A	None	0	0
J1009	Solar	400	163.2	-163.2	None	N/A	N/A	None	0	0
J1010	Solar	400	163.2	-163.2	None	N/A	N/A	None	0	0
J1011	Solar	400	163.2	-163.2	None	N/A	N/A	None	0	0
J1042	Solar	200	81.6	-81.6	None	N/A	N/A	None	0	0
J1051	Battery	51.0	19.49	-19.49	None	N/A	N/A	20 Mvar Capacitor Bank	20	0
J1053	Solar	199.6	96.6	-96.6	None	N/A	N/A	2 x 4 Mvar Capacitor Bank	8	0
J1085	Wind	300	145.3	-145.3	None	N/A	N/A	None	0	0
J1101	Battery	20	6.574	-6.574	None	N/A	N/A	3 Mvar Capacitor Bank	3	0
J1121	Solar	200	87.6	-87.6	None	N/A	N/A	None	0	0
J1153	Solar	150	68.7386	-68.7386	None	N/A	N/A	None	0	0
J1154	Solar	75	34.3693	-34.3693	None	N/A	N/A	None	0	0
J1171	Solar	102.58	33.92	-31.82	None	N/A	N/A	None	0	0
J1183	Solar and Wind[1]	103.015	39.0862	-39.0862	None	N/A	N/A	10.5 Mvar, 2 x 4.8 Mvar Capacitor Banks	20.1	0
J1188	Solar	51.29	16.960	-15.91	None	N/A	N/A	None	0	0

[1] Existing wind generations behind the J1183 POI are also considered for the analysis.

The dynamic capacitive power factor requirement analysis showed all requests meeting ATC Planning Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-2.

Table 2.2-2 – Assessment of Dynamic Capacitive Power Factor Requirement

MISO Queue #	Bus #	Capability at Machine Terminal Bus		Additional Dynamic Capacitive Reactive Power [1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement[2]?	Additional Requirement[3] (Mvar)
		Real Power (MW)	Capacitive Reactive Power (Mvar)				
J986	89860	149.9	52.90	0.0	0.94	Yes	0.0
J1000	40000	50.0	29.668	0.0	0.86	Yes	0.0
J1002	40020	99.0	58.743	0.0	0.86	Yes	0.0
J1003	40030	50.00	29.700	0.0	0.86	Yes	0.0
J1009	40090	400.0	163.2	0.0	0.93	Yes	0.0
J1010	40100	400.0	163.2	0.0	0.93	Yes	0.0
J1011	40110	400.0	163.2	0.0	0.93	Yes	0.0
J1042	40420	200.0	81.6	0.0	0.93	Yes	0.0
J1051	40510	51.0	19.49	0.0	0.93	Yes	0.0
J1053	40530	199.6	96.6	0.0	0.90	Yes	0.0
J1085	40850 40858	300.0	145.300	0.0	0.90	Yes	0.0
J1101	41010	20.000	6.574	0.0	0.95	Yes	0.0
J1121	41210	200.0	87.600	0.0	0.92	Yes	0.0
J1153	41530	150.0	68.739	0.0	0.91	Yes	0.0
J1154	40540	75	34.3693	0.0	0.91	Yes	0.0
J1171	40710	102.58	33.92	0.0	0.95	Yes	0.0
J1183	41830 693697 693704 693429	103.015	39.0862	0.0	0.93	Yes	0.0
J1188	41880	51.29	16.960	0.0	0.95	Yes	0.0

[1] Dynamic capacitive reactive power provided by Interconnection Customer owned equipment in addition to the machine.
[2] ATC requires a 0.95 ATC Capacitive Dynamic Power Factor.
[3] Additional dynamic reactive power required to meet ATC Capacitive Dynamic Power Factor.

The static capacitive power factor requirement analysis showed 9 of the 18 requests do not meet the ATC Criteria or FERC Order 827 requirements. The results are summarized in Table 2.2-3.

Table 2.2-3 – Assessment of Static Capacitive Power Factor Requirement

MISO Queue #	Point of Measurement	Capability at Point of Measurement[1]		Power Factor	Meets Requirement?	Additional Requirement (Mvar)
		Real Power (MW)	Reactive Power (Mvar)			
J986	89863	147.1	51.6	0.94	Yes	0.0
J1000	40003	49.2	19.9	0.93	Yes	0.0
J1002	40023	97	37	0.93	Yes	0.0
J1003	40033	49	20.2	0.92	Yes	0.0
J1009	40090	394.4	95.2	0.97	No	34.4
J1010	40100	394.4	95.2	0.97	No	34.4
J1011	40110	394.4	95.2	0.97	No	34.4
J1042	40420	197.0	45.6	0.97	No	17.1
J1051	990001	50	33.5	0.83	Yes	0.0
J1053	990001	197.6	63.4	0.95	Yes	0.0
J1085	40854	290.1	101.9	0.94	Yes	0.0
J1101	88604	19.8	5.8	0.96	No	0.7
J1121	40854	195.3	47.9	0.97	No	16.3
J1153	41533	147.8	40.2	0.96	No	8.4
J1154	41543	74	25.7	0.94	Yes	0.0
J1171	41713	100	19	0.98	No	13.9
J1183	693702	100.5	36.9	0.94	Yes	0.0
J1188	41883	50.6	6.5	0.99	No	10.1

[1] Point of Measurement is the POI Bus for synchronous machines and high side of generator substation for asynchronous machines.

The dynamic inductive power factor requirement analysis showed all but two of the requests meet ATC Criteria and FERC Order 827 requirements. J1171 and J1188 do not meet the ATC Criteria and FERC Order 827 requirements and must provide additional dynamic resources prior to Phase two. The results are summarized in Table 2.2-4.

Table 2.2-4 – Assessment of Dynamic Inductive Power Factor Requirement

MISO Queue #	Bus #	Capability at Machine Terminal		Additional Dynamic Inductive Reactive Power [1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement[2]?	Additional Requirement[3] (Mvar)
		Real Power (MW)	Inductive Reactive Power (Mvar)				
J986	89860	149.9	-52.9	0.0	0.94	Yes	0.0
J1000	40000	50.0	-29.668	0.0	0.86	Yes	0.0
J1002	40020	99.0	-58.7431	0.0	0.86	Yes	0.0
J1003	40030	50.00	-29.7	0.0	0.86	Yes	0.0
J1009	40090	400.0	-163.2	0.0	0.93	Yes	0.0
J1010	40100	400.0	-163.2	0.0	0.93	Yes	0.0
J1011	40110	400.0	-163.2	0.0	0.93	Yes	0.0
J1042	40420	200.0	-81.6	0.0	0.93	Yes	0.0
J1051	40510	200	-81.6	0.0	0.93	Yes	0.0
J1053	40530	199.6	-96.6	0.0	0.90	Yes	0.0
J1085	40850 40858	300.0	-145.300	0.0	0.90	Yes	0.0
J1101	41010	20.000	-6.574	0.0	0.95	Yes	0.0
J1121	41210	200.0	-87.600	0.0	0.92	Yes	0.0
J1153	41530	150.0	-68.7386	0.0	0.91	Yes	0.0
J1154	40540	75	-34.3693	0.0	0.91	Yes	0.0
J1171	40710	102.58	-31.82	0.0	0.96	No	-1.90
J1183	41830 693697 693704 693429	103.015	-39.0862	0.0	0.93	Yes	0.0
J1188	41880	51.29	-15.91	0.0	0.96	No	-0.92

[1] Dynamic inductive reactive power provided by Interconnection Customer owned equipment in addition to the machine.

[2] ATC requires a 0.95 ATC Inductive Dynamic Power Factor.

[3] Additional dynamic reactive power required to meet ATC Inductive Dynamic Power Factor.

The static inductive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-5.

Table 2.2-5 – Assessment of Static Inductive Power Factor Requirement

MISO Queue #	POI Bus (synchronous) or HV Bus (asynchronous)	MW at POI (synchronous) or HV Bus (asynchronous)	Mvar at POI (synchronous) or HV Bus (asynchronous)	POI (synchronous) or HV Bus (asynchronous) Power Factor	Meets 0.95 ATC Inductive Power Factor Requirement at POI Bus (synchronous) or HV Bus (asynchronous)?
J986	89863	147.1	-80.3	0.88	Yes
J1000	40003	49.0	-42.9	0.75	Yes
J1002	40023	96.4	-88.4	0.74	Yes
J1003	40033	48.7	-42.6	0.75	Yes
J1009	40090	393.2	-262.0	0.83	Yes
J1010	40100	393.2	-262.0	0.83	Yes
J1011	40110	393.2	-262.0	0.83	Yes
J1042	40420	196.5	-128.3	0.84	Yes
J1051	990001	50.0	-23.6	0.90	Yes
J1053	990001	197.2	-144.4	0.81	Yes
J1085	40854	289.2	193.9	0.83	Yes
J1101	886004	19.7	-10.2	0.89	Yes
J1121	40854	195.0	-132.4	0.83	Yes
J1153	41533	147.1	-106.3	0.81	Yes
J1154	41543	74.0	-42.8	0.87	Yes
J1171	41713	100.0	-46.1	0.91	Yes
J1183	693702	100.3	-61.7	0.85	Yes
J1188	41883	50.6	-26.7	0.88	Yes

The low output power factor requirement analysis showed all requests except J1085 and J1121 meet ATC Planning Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-6.

Table 2.2-6 – Assessment of Power Factor Requirements at Low Output Levels

MISO Queue #	P-Q Curve Type	Is Power Factor Evaluation Needed for Minimum Output Levels?	Additional Static Mvar required at POI Bus (synchronous) or HV Bus (asynchronous) to meet ATC Power Factor Requirement
J986	D-Shape	no	N/A
J1000	D-shape	no	N/A
J1002	D-shape	no	N/A
J1003	D-shape	no	N/A
J1009	D-shape	no	N/A
J1010	D-shape	no	N/A
J1011	D-shape	no	N/A
J1042	D-shape	no	N/A
J1051	D-shape	no	N/A
J1053	D-shape	No	N/A
J1085	D-shape with restriction	yes	10 Mvar Inductor for near zero generation
J1101	D-shape	no	N/A
J1121	D-shape with restriction	yes	1 Mvar Inductor for near zero generation
J1153	D-shape	no	N/A
J1154	D-shape	no	N/A
J1171	D-shape	no	N/A
J1183	D-shape	no	N/A
J1188	D-shape	no	N/A

2.3 NERC TPL Contingency Analysis Results

The incremental impact of the proposed generator interconnection on transmission facilities was evaluated by comparing steady state power flows and voltages between benchmark cases (without Apr 18 DPP Phase 2 projects) and study cases (with Apr 18 DPP Phase 2 projects). Post-contingency cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled. NERC TPL Category P contingencies that were studied are described in Table A.2.1-1 in Appendix A.

2.3.1 2023 Summer Peak Batteries Discharging

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2023 Summer Peak Discharging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2023 Summer Peak Discharging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.1. No voltage constraints were identified in the steady-state analyses.

Table 2.3.1 – 2023 Summer Peak Batteries Discharging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2023 Summer, Batteries Discharging	Sand Lake 138/69 kV transformer	ATC	P12	J986
	Wautoma 138/69 kV transformer	ATC	Base Case P12 P13 P21	J986 J1002
	J986 POI – Port Edwards 138 kV line	ATC	P12 P13 P21 P23	J986 J1002

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.2 2023 Summer Peak Batteries Charging

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2023 Summer Peak Charging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2023 Summer Peak Charging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.2. No voltage constraints were identified in the steady-state analyses.

Table 2.3.2 – 2023 Summer Peak Batteries Charging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2023 Summer, Batteries Charging	Sand Lake 138/69 kV transformer	ATC	P12	J986
	Wautoma 138/69 kV transformer	ATC	Base Case P12 P13 P21	J986 J1002
	J986 POI – Port Edwards 138 kV line	ATC	P12 P13 P21 P23	J986 J1002

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.3 2023 Shoulder Batteries Discharging

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2023 Shoulder Discharging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2023 Shoulder Discharging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.3. No voltage constraints were identified in the steady state analyses.

Table 2.3.3 – 2023 Shoulder Batteries Discharging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2023 Shoulder, Batteries Discharging	Lublin – Lublin Pump 69 kV line	DPC	P12 P23	J1085 J1121
	Lublin Tap – Lublin Pump 69 kV line	DPC	P12 P23	J1085 J1121
	Stone Lake 345/161 kV transformer	XEL	P12 P23	J1085 J1121

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.4 2023 Shoulder Batteries Charging

The study identified the steady-state thermal and voltage constraints that qualified as MISO Injection Constraints in the 2023 Shoulder Charging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2023 Shoulder Charging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.4. No voltage constraints were identified in the steady state analyses.

Table 2.3.4 – 2023 Shoulder Batteries Charging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2023 Shoulder, Batteries Charging	Lublin – Lublin Pump 69 kV line	DPC	P12 P23	J1085 J1121
	Lublin Tap – Lublin Pump 69 kV line	DPC	P12 P23	J1085 J1121
	Stone Lake 345/161 kV transformer	XEL	P12 P23	J1085 J1121

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

2.3.5 Network Upgrades Identified in ERIS Analysis

Based on the steady-state analyses, the worst loading of each facility under "No Load Loss Allowed" NERC TPL Planning Events that meets MISO Injection Constraint criteria is shown in Table 2.3.5-1. Potential Network Upgrades are also included. Good faith Cost Estimates of the ERIS thermal Network Upgrades identified in the steady-state analysis for the 2023 scenarios are listed in Table 2.3.5-2. Detailed cost allocations are provided in Section 9.

Table 2.3.5-1 – ERIS Network Upgrades Identified to Address MISO Steady-State Injection Constraints

Steady-State Injection Constraint	Responsible Generator(s)	Facility Owner	Study Case	Applicable Rating (MVA)	Worst Loading (%)	"No Load Loss Allowed" NERC TPL Planning Event	Network Upgrades
Sand Lake 138/69 kV transformer	J986	ATC	23SUM, Batteries Charging	60	108.1	[redacted]	Sand Lake 138/69 kV transformer, replacement
Wautoma 138/69 kV transformer	J986 J1002	ATC	23SUM, Batteries Discharging	65	131.7	[redacted]	Wautoma 138/59 kV transformer, replacement
J986 POI – Port Edwards 138 kV line	J986 J1002	ATC	23SUM, Batteries Charging	153	104.3	[redacted]	J986 POI – Port Edwards 138 kV line, uprate
Lublin – Lublin Pump 69 kV line	J1085 J1121	DPC	23SH, Batteries Discharging	25	135.44	[redacted]	Lublin – Lublin Pump 69 kV line, uprate
Lublin Tap – Lublin Pump 69 kV line	J1085 J1121	DPC	23SH, Batteries Discharging	25	129.7	[redacted]	Lublin Tap – Lublin Pump 69 kV line, uprate
Stone Lake 345/161 kV transformer	J1085 J1121	XCEL	23SH, Batteries Charging	515.2	110.4	[redacted]	Stone Lake 345/161 kV transformer, replacement

Table 2.3.5-2 – ERIS Network Upgrades and Cost Estimates

Steady-State Injection Constraint	Facility Owner	Network Upgrade	Cost ($)[1,2,3]
Sand Lake 138/69 kV transformer	ATC	Sand Lake 138/69 kV transformer, replacement	3,105,696
Wautoma 138/69 kV transformer	ATC	Wautoma 138/59 kV transformer, replacement	2,859,187
J986 POI – Port Edwards 138 kV line	ATC	J986 POI – Port Edwards 138 kV line, uprate	584,677
Lublin – Lublin Pump 69 kV line	DPC	Lublin – Lublin Pump 69 kV line, uprate	364,865
Lublin Tap – Lublin Pump 69 kV line	DPC	Lublin Tap – Lublin Pump 69 kV line, uprate	4,135,135
Stone Lake 345/161 kV transformer	XCEL	Stone Lake 345/161 kV transformer, replacement	3,757,200[4]

[1] All Network Upgrades were estimated on the generator ISD dollars.
[2] ATC Network Upgrades included a 10% contingency.
[3] No contingency was included for the Stone Lake transformer upgrade project according to Xcel Energy.
[4]Cost Estimate is the APR-18 ERIS network upgrade cost ($7,655,700) minus the AUG-17 NRIS network upgrade cost ($3,898,500) to replace the transformer

2.3.6 Network Upgrade Alternatives Considered

All the ERIS network upgrades identified in Table 2.3.3-2 are direct upgrades of the ERIS thermal constraint facilities to ATC, DPC, and XCEL design standards and considered as least-cost solutions. Therefore, no other alternatives were examined for those solutions.

2.3.7 Potential Operating Restriction

The purpose of the study is to identify potential steady-state operating restrictions for study generators under prior outage conditions and raise awareness of these potential operating restrictions to customers. Real-time steady-state thermal constraints due to NERC Category P6 events (N-1-1) will be mitigated in the day-ahead and real-time market through the MISO binding constraint and other operating procedures. The study was performed on study models with final ERIS Network Upgrades and NRIS Network Upgrades included. Based on ATC generator operating restriction study methodology as described in Appendix A, the worst potential steady-state operating restrictions for study generators were identified and summarized in Tables 2.3.7-1 and 2.3.7-2. If multiple P6 (N-1-1) events resulted in the same MW restriction, only the worst N-1-1 event (highest loading % on the constraint) was listed. The full NERC Category P6 steady-state study results were documented in Appendix F. Operating restrictions could occur if either of the contingent elements are out of service.

Table 2.3.7-1 – Worst Steady-State Operating Restrictions with ERIS and NRIS Network Upgrades Included, Batteries Discharging Models

MISO Queue #	Model	Worst NERC Category P6 (N-1-1) Event		Max MW Allowed
		1st Contingency	2nd Contingency	
J986	23SH	[redacted]	[redacted]	0.00
J1000	23SH	[redacted]	[redacted]	0.00[1]
J1002	23SUM	[redacted]	[redacted]	44.65
J1003	-	[redacted]	[redacted]	-
J1009	-	[redacted]	[redacted]	-
J1010	23SUM	[redacted]	[redacted]	82.29
J1011	23SUM	[redacted]	[redacted]	82.29
J1042	23SUM	[redacted]	[redacted]	0.00
J1051	-	[redacted]	[redacted]	-
J1053	-	[redacted]	[redacted]	-
J1085	23SH	[redacted]	[redacted]	0.00
J1101	-	[redacted]	[redacted]	-
J1121	23SH	[redacted]	[redacted]	0.00
J1153	-	[redacted]	[redacted]	-
J1154	-	[redacted]	[redacted]	-
J1171	-	[redacted]	[redacted]	-
J1183	-	[redacted]	[redacted]	-
J1188	-	[redacted]	[redacted]	-

[1] A higher rating on the constrained Ebenezer – Eden 138 kV line than what is currently in the study model is expected after Cardinal – Hickory Creek project which will likely reduce the restriction.

Table 2.3.7-2 – Worst Steady-State Operating Restrictions with ERIS and NRIS Network Upgrades Included, Batteries Charging Models

MISO Queue #	Model	Worst NERC Category P6 (N-1-1) Event		Max MW Allowed
		1st Contingency	2nd Contingency	
J986	23SH	[redacted]	[redacted]	0.00
J1000	23SH	[redacted]	[redacted]	0.00[1]
J1002	23SUM	[redacted]	[redacted]	44.65
J1003	-	[redacted]	[redacted]	-
J1009	-	[redacted]	[redacted]	-
J1010	23SUM	[redacted]	[redacted]	82.29
J1011	23SUM	[redacted]	[redacted]	82.29
J1042	23SUM	[redacted]	[redacted]	0.00
J1051	-	[redacted]	[redacted]	-
J1053	-	[redacted]	[redacted]	-
J1085	23SH	[redacted]	[redacted]	0.00
J1101	23SH	[redacted]	[redacted]	0.00[2]
J1121	23SH	[redacted]	[redacted]	0.00
J1153	-	[redacted]	[redacted]	-
J1154	-	[redacted]	[redacted]	-

J1171	-	[redacted]	[redacted]	-
J1183	-	[redacted]	[redacted]	-
J1188	-	[redacted]	[redacted]	-

[1] A higher rating on the constrained Ebenezer – Eden 138 kV line than what is currently in the study model is expected after Cardinal – Hickory Creek project which will likely reduce the restriction.
[2] J1101 would not be allowed to be in charging mode under this scenario.

2.3.8 Additional Studies for J1085 and J1121

Due to unique concerns with the location of the J1085 and J1121 POI, ATC performed the following additional studies.

1. Shunt Reactor Need and Sizing Study

   This study reviewed the need for a line-connected shunt reactor on the Stone Lake – J1085/J1121 POI 345 kV line [redacted]. The results show that a line-connected shunt reactor is required at the J1085/J1121 POI and relocating the existing 75 Mvar reactor from Gardner Park Substation to the J1085/J1121 POI is the solution to address the potential overvoltage issues [redacted]. The detailed study report is included in Appendix K.

Table 2.3.8-1 – ERIS Network Upgrades Identified

System Constraints	Facility Owner	Network Upgrade	ISD (For Cost Estimate Only)	Cost ($)
Overvoltage on J1085/J1121 POI – Stone Lake 345 kV line [redacted]	ATC	J1085/J1121 POI – Stone Lake 345 kV, Move the existing 75 Mvar line-connected reactor from Gardner Park to J1085/J1121 POI	09/01/2020	N/A[1]

[1] The cost of this project was included in the Interconnection Facilities cost, due to construction needs.

2. Steady State Voltage Stability Study of MWEX

   Voltage stability analysis was performed using the 2023 shoulder discharging study case to determine if the April 2018 DPP cycle projects, including J1085 and J1121, could cause or contribute to voltage stability violations on MWEX (Minnesota Wisconsin Export Interface). MWEX is the summation of the flows on the AS King – Eau Claire 345 kV line measured at AS King and the Arrowhead 230 kV phase shifting transformer measured at the Minnesota Power 230 kV side of the Arrowhead substation. The voltage is measured at the Arrowhead 230 kV bus.

   Based on the study results, no steady-state voltage instability issues on MWEX were identified in the 2023 shoulder discharging study case and MWEX voltage stability margins are greater than 10%. No Network Upgrades were required. The detailed study report is included in Appendix K.

3. Steady State Voltage Stability Sensitivity Study of J1085/J1121 with Local P6 Outages

This analysis was performed on the 2023 shoulder discharging study case to determine if J1085 and J1121 could cause voltage stability violations under P6 (N-1-1) outage conditions.

The results show that a voltage collapse could occur with J732, J1085, and J1121 operating at less than their maximum requested capabilities under select NERC Category P6 contingencies. Operating restrictions will be required under certain prior outage scenarios as shown in the table below. The detailed study report is included in Appendix K.

Table 2.3.8-2: J1085/J1121 Operating Restrictions Based on Voltage Stability Study

Prior Outage	Worst Next Event	J1085/J1121 Max Allowed Combined Output (MW)	J732 Net Real Power Output (MW)[1]
[redacted]	[redacted]	397	493
[redacted]	[redacted]	417	523

[1]These operating restrictions on J732 were identified in the August 2017 DPP J732 stability study.

4. Tripping Systems Need and Redesign at the Stone Lake, J1085/J1121 POI, and Gardner Park 345 kV Substations

   The existing Cross Tripping System (CTS) and Over-Voltage Tripping System (OVTS) requirements at Arrowhead, Stone Lake, and Gardner Park were created to avoid overvoltages [redacted].

   The study results show that the existing Stone Lake – Gardner Park CTS and OVTS requires modification to incorporate the new J1085/J1121 POI Substation and to avoid high voltage violations under different dispatch scenarios of J732, J1085, and J1121. The new CTS and OVTS requirements at the Stone Lake, J1085/J1121 POI, and Gardner Park can be found in the report in Appendix K. The costs to modify the CTS are included in the cost estimate for the J1085/J1121 POI 345 kV Substation.

5. J1085/J1121 Stability Sensitivity Analysis

   The stability analysis documented in Section 3.9 of this report indicates that under the following two P6 events, J732 becomes unstable with J1085 and J1121 at maximum real power output, and both J1085 and J1121 violate ATC's voltage stability criteria. Operating restrictions are determined under these prior outage scenarios and summarized in Section 3.9.

   - [redacted]
   - [redacted]

The stability sensitivity analysis is performed to determine if or how the status of the following local reactive power compensation devices would affect stability operation restrictions of J1085 and J1121 under the two P6 events.

- Arrowhead 345 kV capacitor bank (status: 0 Mvar, 1x75 Mvar, 2x75 Mvar)
- Stone Lake 345 kV capacitor bank and reactor (status: -75 Mvar, 0 Mvar, 75 Mvar)
- J1085/J1121 POI 345 kV reactor (status: -75 Mvar, 0 Mvar)

The results show that, under the prior outage of J1085/J1121 POI – Gardner Park 345 kV line, the status of local reactive power compensation devices and the output of J732 result in more operation restrictions on J1085 and J1121. The worst operating restriction is listed in the table below. A detailed summary of operation restrictions of J1085 and J1121 stability sensitivity study can be found in the report in Appendix K.

Table 2.3.8-3: Worst J1085/J1121 Operating Restriction Based on the Sensitivity Study

Prior Outage	Faulted Element	J1085/J1121 Max Allowed Combined Output (MW)	J732 Net Real Power Output (MW)[1]
[redacted]	[redacted]	190	493

[1]This operating restriction on J732 was identified in the August 2017 DPP J732 stability study.

3.0 STABILITY ANALYSIS

Stability analysis in Section 3 was performed using TSAT V18 to evaluate the stability performance of the generating facilities in the Apr 18 DPP WI Phase 2. Detailed study assumptions, criteria, and methodology are documented in Appendix A. For generators that require Electromagnetic transient (EMT) stability analysis using Power Systems Computer-Aided Design (PSCAD), results are documented in Section 6 of the report.

Stability plots consist of generator rotor angles, generator real power output, generator reactive power output, generator terminal voltages, and transmission bus voltages for each simulation. Simulations were performed with a 9-cycle flat start followed by the appropriate disturbance. Simulations were run for a 20-second duration.

3.1 Model Development

3.1.1 Study Case

A stability study case representing the 2023 shoulder load condition was developed by MISO and reviewed by ATC and Interconnection Customers. The model was developed and studied in TSAT v18. TSAT, like PSSE, is a root mean squared (RMS) based program that only models a network's positive sequence quantities. The stability study case included final ERIS Network Upgrades and

NRIS Network Upgrades. All units under study were dispatched to 100% of PMAX. Additionally, the following local units were also dispatched to 100% of PMAX to meet ATC Planning Criteria:

- J732
- J807
- J818
- J819
- J821
- J831
- J849
- J850
- J855
- J864
- J870/J871
- J878
- J886
- J928
- J947
- Columbia 1 and 2
- J390 CT1, CT2, and ST
- Riverside CT1, CT2, and ST
- Christiana 1, 2, and 3
- Glacier Hills Wind Farm
- Quiltblock Wind Farm
- Concord 1, 2, 3, and 4
- Elm Road 1 and 2
- Point Beach 1 and 2
- Weston 2, 3, 4, 31, and 32
- Oak Creek 5, 6, 7, and 8
- Paris 1, 2, 3, and 4
- South Fond du Lac 1, 2, 3, and 4

3.1.2 Benchmark Case

The Apr 18 DPP WI Phase 2 generating facilities were removed from the study case. The MISO Classic methodology, where generation was scaled in proportion to Pmax minus Pgen, was used for power balance.

Faults were simulated using the 2023 shoulder study case. If a transient stability criteria constraint was identified, the same disturbance was repeated in the benchmark case.

3.2 J986 and J1002 Stability Study

3.2.1 J986 and J1002 Stability Results

Complete fault definitions and stability results for J986 and J1002 can be found in Appendix G.

Under all faults for J986 and J1002, the simulations show the system meeting all transient stability criteria.

3.2.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J986 and J1002 generating facilities.

3.2.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J986 and J1002 generating facilities.

3.2.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J986 and J1002 are provided in Tables 3.2.4-1 through 3.2.4.-4.

Table 3.2.4-1 – J986 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.45	1	Yes
Low Voltage	0.60	5	Yes
Low Voltage	0.70	10	Yes
Low Voltage	0.88	20	Yes
High Voltage	1.40	0.16	Yes
High Voltage	1.20	1	Yes
High Voltage	1.18	2	Yes
High Voltage	1.16	3	Yes
High Voltage	1.12	5	Yes

Table 3.2.4-2 – J1002 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.10	0.6	Yes
Low Voltage	0.50	1.9	Yes
High Voltage	1.15	3.0	Yes
High Voltage	1.40	0.0	Yes

Table 3.2.4-3 – J986 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	57.0	0.016	0.0	Yes
Low Frequency	58.5	33	32.8	Yes
Low Frequency	59.0	540	242.5	Yes
High Frequency	60.6	540	429.5	Yes
High Frequency	61.8	2	0.0	Yes
High Frequency	63.3	0.016	0.0	Yes

Table 3.2.4-4 – J1002 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	56.5	0.0	0.0	Yes
Low Frequency	57.5	10.0	0.0	Yes
Low Frequency	61.5	30.0	21.0	Yes
High Frequency	62.5	0.0	0.0	Yes

3.3 J1000 Stability Study

3.3.1 J1000 Stability Results

Complete fault definitions and stability results for J1000 can be found in Appendix G. Table 3.3.1-1 summarizes the results with stability constraints.

Table 3.3.1-1 – Stability Constraints for J1000

Event	Prior Outage	Faulted Element	Angular/Voltage Stability	IBR Stability Assessment
P6.6	[redacted]	[redacted]	OK	P, Q and V oscillations
P6.10	[redacted]	[redacted]	OK	J1000 trips

The P6.6 fault was also run in the SW WI PSCAD study (section 6.1) and it did not find any oscillations. This inconsistency between the PSCAD and TSAT models needs to be resolved in Phase 3. Until the model inconsistency is resolved, ATC will use the more conservative result between PSCAD and TSAT . It is up to the Interconnection Customer to resolve this model inconsistency.

The J1000 plant is tripping on voltage protection relays for the P6.10 fault. Under all other faults for J1000, the simulations show the system meeting all transient stability criteria.

3.3.2 Network Upgrades Identified in the Stability Study

J1000 needs to supply updated voltage relay settings that eliminates unit tripping during the P6.10 fault simulated. If J1000 cannot provide a setting that eliminates the tripping, then a network upgrade or operating restriction will need to be developed.

3.3.3 Operating Restrictions Identified in the Stability Study

The maximum allowable J1000 real power output under prior outages conditions to mitigate P6 stability constraints are shown in Table 3.3.3-1.

Table 3.3.3-1 – J1000 Prior Outage Stability Operating Restrictions

Event	Prior Outage	Faulted Element	Maximum Real Power Output
			To Maintain IBR Stability
P6.6	[redacted]	[redacted]	0 MW

3.3.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1000 are provided in Tables 3.3.4-1 and 3.3.4-2.

Table 3.3.4-1 – J1000 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.10	0.6	Yes
Low Voltage	0.50	1.9	Yes
High Voltage	1.15	3.0	Yes
High Voltage	1.40	0.0	Yes

Table 3.3.4-2 – J1000 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	56.5	0.0	0.0	Yes
Low Frequency	57.5	10.0	0.0	Yes
Low Frequency	61.5	30.0	21.0	Yes
High Frequency	62.5	0.0	0.0	Yes

3.4 J1003 Stability Study

3.4.1 J1003 Stability Results

Complete fault definitions and stability results for J1003 can be found in Appendix G.

Under all faults for J1003, the simulations show the system meeting all stability criteria.

3.4.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1003 generating facility.

3.4.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1003 generating facilities.

3.4.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1003 are provided in Tables 3.4.4-1 and 3.4.4-2.

Table 3.4.4-1 – J1003 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.10	0.6	Yes
Low Voltage	0.50	1.9	Yes
High Voltage	1.15	3.0	Yes
High Voltage	1.40	0.0	Yes

Table 3.4.4-2 – J1003 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	56.5	0.0	0.0	Yes
Low Frequency	57.5	10.0	0.0	Yes
Low Frequency	61.5	30.0	21.0	Yes
High Frequency	62.5	0.0	0.0	Yes

3.5 J1009 Stability Study

3.5.1 J1009 Stability Results

Complete fault definitions and stability results for J1009 can be found in Appendix G.

Under all faults for J1009, the simulations show the system meeting all transient stability criteria.

3.5.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1009 generating facility.

3.5.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1009 generating facilities.

3.5.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1009 are provided in Tables 3.5.4-1 and 3.5.4-2.

Table 3.5.4-1 – J1009 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.45	1	Yes
Low Voltage	0.75	3	Yes
Low Voltage	0.90	5	Yes
High Voltage	1.10	2	Yes
High Voltage	1.20	1	Yes
High Voltage	1.40	0.16	Yes

Table 3.5.4-2 – J1009 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	57.0	0.16	0.0	Yes
Low Frequency	58.0	60	4.4	Yes
Low Frequency	59.0	180	242.5	No
High Frequency	61.0	180	112.2	Yes
High Frequency	62.0	5	0.0	Yes
High Frequency	63.0	0.16	0.0	Yes

3.6 J1010 and J1011 Stability Study

3.6.1 J1010 and J1011 Stability Results

Complete fault definitions and stability results for J1010 and J1011 can be found in Appendix G.

Under all faults for J1010 and J1011, the simulations show the system meeting all transient stability criteria.

3.6.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1010 and J1011 generating facilities.

3.6.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1010 and J1011 generating facilities.

3.6.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1010 and J1011 are provided in Tables 3.6.4-1 and 3.6.4-2.

Table 3.6.4-1 – J1010 and J1011 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.45	1	Yes
Low Voltage	0.75	3	Yes
Low Voltage	0.90	5	Yes
High Voltage	1.10	2	Yes
High Voltage	1.20	1	Yes
High Voltage	1.40	0.16	Yes

Table 3.6.4-2 – J1010 and J1011 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.0	0.16	0.0	Yes
Low Frequency	58.0	60	4.4	Yes
Low Frequency	59.0	180	242.5	No
High Frequency	61.0	180	112.2	Yes
High Frequency	62.0	5	0.0	Yes
High Frequency	63.0	0.16	0.0	Yes

3.7 J1042 Stability Study

3.7.1 J1042 Stability Results

Complete fault definitions and stability results for J1042 can be found in Appendix G

Under all faults for J1042, the simulations show the system meeting all transient stability criteria.

3.7.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of J1042 generating facility.

3.7.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1042 generating facilities.

3.7.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1042 are provided in Tables 3.7.4-1 and 3.7.4-2.

Table 3.7.4-1 – J1042 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.001	0.2	Yes
Low Voltage	0.43	0.4	Yes
Low Voltage	0.63	2.1	Yes
Low Voltage	0.73	3.1	Yes
Low Voltage	0.89	10	Yes
High Voltage	1.11	10	Yes
High Voltage	1.18	1.1	Yes
High Voltage	1.20	0.6	No
High Voltage	1.24	0.25	Yes
Low Voltage	0.001	0.2	Yes

Table 3.7.4-2 – J1042 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.0	0.075	0.0	Yes
High Frequency	72.0	0.075	0.0	Yes

3.8 J1051 and J1053 Stability Study

3.8.1 J1051 and J1053 Stability Results

Complete fault definitions and stability results for J1051 and J1053 can be found in Appendix G.

However, there were six faults where the active power of J1051 does not recover to full output after the fault as summarized in Table 3.8.1-1 below. These were rerun after disabling the power plant controller model and the active power recovered correctly. The J1051 power plant model should be reviewed and updated to address the issue prior to Phase 3.

Table 3.8.1-1

Event	Prior Outage	Faulted Element	Active Power does not Recover to Full Output
P1.2.3	[redacted]	[redacted]	X
J1154_P6.3	[redacted]	[redacted]	X
J1154_P7.1	[redacted]	[redacted]	X
P6.2	[redacted]	[redacted]	X
P6.5	[redacted]	[redacted]	X
P6.12	[redacted]	[redacted]	X

Under all faults for J1051 and J1053, the simulations show the system meeting all transient stability criteria.

3.8.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1051 and J1053 generating facilities.

3.8.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1051 and J1053 generating facilities.

3.8.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1051 and J1053 are provided in Tables 3.8.4-1 - 3.8.4-4. The tests were run with J1051 discharging and charging. Six of the voltage relay settings for J1053 do not ride through PRC-024-2 "No Trip Zone" and should be changed.

Table 3.8.4-1 – J1051 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"? (discharge/charge)
Low Voltage	0.45	0.50	Yes/Yes
Low Voltage	0.60	5.00	Yes/Yes
Low Voltage	0.70	10.00	Yes/Yes
Low Voltage	0.88	20.00	Yes/Yes
High Voltage	1.12	5.00	Yes/Yes
High Voltage	1.16	3.00	Yes/Yes
High Voltage	1.18	2.00	Yes/Yes
High Voltage	1.20	1.00	Yes/Yes
High Voltage	1.40	0.16	Yes/Yes

Table 3.8.4-2 – J1053 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"? (discharge/charge)
Low Voltage	0.45	0.16	Yes/Yes
Low Voltage	0.65	0.3	Yes/No
Low Voltage	0.75	2	Yes/Yes
Low Voltage	0.90	3	Yes/No
High Voltage	1.10	1	No/No
High Voltage	1.15	0.5	No/No
High Voltage	1.18	0.2	No/No
High Voltage	1.20	0.16	No/No

Table 3.8.4-3 – J1051 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.0	10.00	0.0	Yes
Low Frequency	59.0	600.00	242.5	Yes
High Frequency	60.6	650.00	429.5	Yes
High Frequency	61.8	10.00	0.0	Yes
High Frequency	63.3	2.00	0.0	Yes

Table 3.8.4-4 – J1053 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.8	0.16	0.0	Yes
Low Frequency	59.5	1792	1792.0	Yes
High Frequency	60.5	600.66	600.7	Yes
High Frequency	61.8	0.16	0.0	Yes

3.9 J1085 and J1121 Stability Study

3.9.1 J1085 and J1121 Stability Results

Complete fault definitions and stability results for J1085 and J1121 can be found in Appendix G. Table 3.9.1-1 summarizes the results with stability constraints.

The J1085 model did not initialize correctly and as a result the output was questionable. MISO replaced the J1085 model with a generic GE model that had been used in previous studies. To avoid the unit tripping off line, the voltage and frequency relay elements were all disabled for the generic GE model.

The Interconnection Customer should provide a revised model and relay settings for J1085 to address these issues prior to phase 3. If the generator continues to trip with the updated relay settings, projects to prevent this will have to be developed.

Table 3.9.1-1 – Stability Constraints for J1085 and J1121

Event	Prior Outage	Faulted Element	Angular/Voltage Stability	IBR Stability
P6.7	[redacted]	[redacted]	J732 Unstable	P, Q, V oscillations
P6.11	[redacted]	[redacted]	J732 Unstable	P, Q, V oscillations

Under all other faults for J1085 and J1121, the simulations show the system meeting all transient stability criteria with the generic model.

3.9.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required in phase 2, based on the generic models used, for the interconnection of the J1085 and J1121 generating facilities.

3.9.3 Operating Restrictions Identified in the Stability Study

The maximum allowed real power outputs after prior outages were identified for the J1085 and J1121 generating facilities to mitigate P6 stability constraints. See Table 3.9.3-1 below.

Table 3.9.3-1 – J1085 and J1121 Stability Operating Restrictions

Event	Prior Outage	Faulted Element	Maximum Real Power Output To Maintain IBR Stability and Other Voltage and Oscillation Criteria (MW)
P6.11	[redacted]	[redacted]	300
P6.7	[redacted]	[redacted]	450

3.9.4 LVRT Requirement for Wind Generators (FERC Order 661/661-A)

Per FERC orders 661/661-A all wind generating plants requesting to interconnect after January 1, 2007 must meet the following Low Voltage Ride Through (LVRT) requirement:

> Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

This standard applies to J1085, a wind generating plant. The three-phase-ground fault (3PG) portion of FERC Order 661/661-A is met by the customers provided LVRT durations as shown in Table 3.9.4-1. The single-line-ground (SLG) with delayed clearing portion of FERC Order 661/661-A is met because J1085 did not trip on the customer provided LVRT settings for any SLG plus delayed clearing faults (P4 and P5 events).

Table 3.9.4-1: J1085 FERC Order 661/661-A 3PG LVRT Compliance Data

MISO Queue #	FERC Required LVRT Duration (sec)	Interconnection Customer Provided LVRT Duration (sec)
J1085	0.15	0.45

3.9.5 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1085 and J1121 are provided in Table 3.9.5-1 and 3.9.5-2. One of the frequency relay settings for J1121 does not meet PRC-024-2 requirements and should be changed.

Table 3.9.5-1 – J1085 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.15	0.2	Yes
Low Voltage	0.30	0.7	Yes
Low Voltage	0.50	1.2	Yes
Low Voltage	0.75	1.9	Yes
High Voltage	1.10	1	Yes
High Voltage	1.15	0.1	Yes

Table 3.9.5-2 – J1121 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.45	1.00	Yes
Low Voltage	0.75	3.00	Yes
Low Voltage	0.90	5.00	Yes
High Voltage	1.10	2.00	Yes
High Voltage	1.20	1.00	Yes
High Voltage	1.40	0.16	Yes

Table 3.9.5-3 – J1085 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	54.0	1	0.0	Yes
Low Frequency	57.5	10	0.0	Yes
High Frequency	63.0	10	0.0	Yes
High Frequency	66.0	1	0.0	Yes

Table 3.9.5-4 – J1121 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	57.0	0.16	0.0	Yes
Low Frequency	58.0	60.000	4.4	Yes
High Frequency	59.0	180.00	242.5	No
High Frequency	61.0	180.00	112.2	Yes
High Frequency	62.0	5.00	0.0	Yes
High Frequency	63.0	0.16	0.0	Yes

3.10 J1101 Stability Study

3.10.1 J1101 Stability Results

Complete fault definitions and stability results for J1101 can be found in Appendix G.

The J1101 model did not initialize correctly and as a result the output was questionable. MISO replaced the J1101 model with a generic model. The Interconnection Customer should provide a revised model for J1101 for phase 3.

Under all faults for J1101, the simulations showed the system meeting all transient stability criteria with the generic model.

3.10.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1101 generating facility with the generic model.

3.10.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1101 generating facilities.

3.10.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1101 are provided in Tables 3.10.4-1 and 3.10.4-2. The tests were completed with the battery discharging and charging. All voltage relay settings for J1101 do not meet PRC-024-2 requirements and should be revised prior to phase 3.

Table 3.10.4-1 – J1101 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"? (discharge/charge)
Low Voltage	0.45	0.15	No/No
Low Voltage	0.65	0.30	Yes/No
Low Voltage	0.75	2.00	No/No
Low Voltage	0.90	3.00	No/No
High Voltage	1.10	1.00	No/No
High Voltage	1.15	0.50	No/No
High Voltage	1.18	0.20	No/No
High Voltage	1.20	0.00	No/No

Table 3.10.4-2 – J1101 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.0	0.01	0.0	Yes
Low Frequency	63.0	0.01	0.0	Yes

3.11 J1153 Stability Study

3.11.1 J1153 Stability Results

Complete fault definitions and stability results for J1153 can be found in Appendix G. Table 3.11.1-1 summarizes the results with stability constraints.

Table 3.11.1-1 – Stability Constraints for J1153

Event	Fault	Angular Stability	Transient Voltage Recovery
P4.2.1	[redacted]	OK	J1153 trips

The J1153 plant trips for under voltage protection on this P4.2.1 fault. The plant also experiences unacceptable momentary cessation. Both P and Q go to zero and stay there for several seconds during the PRC-024 low voltage curve. In several other plots the Q of the plant is staying near 0 instead of controlling voltage at the POI. Several runs were repeated with the power plant controller disabled and the plant Mvar response was acceptable. This indicates there is a modeling issue at J1153 and the Interconnection Customer should provide a revised model for phase 3.

Under all other faults for J1153, the simulations showed the system meeting all stability criteria.

3.11.2 Network Upgrades Identified in the Stability Study

J1153 needs to provide updated relay settings that eliminates the voltage tripping during the P4.2.1 fault. If J1153 cannot provide relay settings that fix the tripping, then a network upgrade will need to be developed.

3.11.3 **Operating Restrictions Identified in the Stability Study**

No stability operating restrictions were identified for the J1153 generating facilities.

3.11.4 **PRC-024-2 Analyses**

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1153 are provided in Tables 3.11.4-1 and 3.11.4-2. Three of the voltage relay settings for J1153 do not meet PRC-024-2 requirements and should be changed. One of the frequency relay settings for J1153 does not meet PRC-024-2 requirements and should be changed.

Table 3.11.4-1 – J1153 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.880	5.000	Yes
Low Voltage	0.880	4.000	Yes
Low Voltage	0.880	3.000	No
Low Voltage	0.880	2.000	No
Low Voltage	0.880	1.000	No
High Voltage	1.150	6.000	Yes
High Voltage	1.400	0.160	Yes
High Voltage	1.500	0.010	Yes

Table 3.11.4-2 – J1153 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	56.5	2000.0	0.0	Yes
Low Frequency	59.3	30.0	805.2	No
High Frequency	60.7	1000.0	307.0	Yes
High Frequency	62.5	30.0	0.0	Yes
High Frequency	63.0	30.0	0.0	Yes

3.12 J1154 Stability Study

3.12.1 **J1154 Stability Results**

Complete fault definitions and stability results for J1154 can be found in Appendix G.

The J1154 plant experiences unacceptable momentary cessation. Both P and Q go to zero and stay there for several seconds during the PRC-024 low voltage curve. In several other plots the Q of the plant is staying near 0 instead of controlling voltage at the POI. Several runs were repeated with the power plant controller disabled and the plant Mvar response was acceptable. This indicates there is a modeling issue at J1154 and the Interconnection Customer should provide a revised model for phase 3.

Under all other faults for J1154, the simulations show the system meeting all stability criteria.

3.12.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1154 generating facility.

3.12.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1154 generating facilities.

3.12.4 PRC-024-2 Analysis

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1154 are provided in Tables 3.12.4-1 and 3.12.4-2. Three of the voltage relay settings for J1154 do not meet PRC-024-2 requirements and should be changed. One of the frequency relay settings for J1154 does not meet PRC-024-2 requirements and should be changed.

Table 3.12.4-1 – J1154 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.880	5.000	Yes
Low Voltage	0.880	4.000	Yes
Low Voltage	0.880	3.000	No
Low Voltage	0.880	2.000	No
Low Voltage	0.880	1.000	No
High Voltage	1.150	6.000	Yes
High Voltage	1.400	0.160	Yes
High Voltage	1.500	0.010	Yes

Table 3.12.4-2 – J1154 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	56.5	2000.0	0.0	Yes
Low Frequency	59.3	30.0	805.2	No
High Frequency	60.7	1000.0	307.0	Yes
High Frequency	62.5	30.0	0.0	Yes
High Frequency	63.0	30.0	0.0	Yes

3.13 J1171 Stability Study

3.13.1 J1171 Stability Results

Complete fault definitions and stability results for J1171 can be found in Appendix G. Under all faults for J1171, the simulations show the system meeting all stability criteria.

3.13.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1171 generating facility.

3.13.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1171 generating facilities.

3.13.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1171 are provided in Tables 3.13.4-1 and 3.13.4-2. Six of the frequency relay settings for J1171 do not meet PRC-024-2 requirements and will need to be changed. The active power does not recover in the high and low voltage tests. This is usually an indication of an inaccurate power plant controller model. The Interconnection Customer should review and provide a revised stability model prior to phase 3.

Table 3.13.4-1 – J1171 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.400	1.000	Yes
Low Voltage	0.500	2.000	Yes
Low Voltage	0.600	3.000	Yes
Low Voltage	0.700	4.000	Yes
Low Voltage	0.800	5.000	Yes
High Voltage	1.100	5.000	Yes
High Voltage	1.200	4.000	Yes
High Voltage	1.300	3.000	Yes
High Voltage	1.400	2.000	Yes
High Voltage	1.500	1.000	Yes

Table 3.13.4-2 – J1171 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	57.5	6.0	0.0	Yes
Low Frequency	58.0	7.0	4.4	Yes
High Frequency	58.5	8.0	32.8	No
High Frequency	59.0	9.0	242.5	No
High Frequency	59.5	10.0	1792.0	No
High Frequency	60.5	10.0	600.7	No
High Frequency	61.0	9.0	112.2	No
High Frequency	61.5	8.0	21.0	No
High Frequency	62.0	7.0	0.0	Yes
High Frequency	62.5	6.0	0.0	Yes

3.14 J1183 Stability Study

3.14.1 J1183 Stability Results

MISO ran the stability assessment in TSAT for this cycle. ATC does not have a TSAT model for the HVDC device at Mackinac. As a result, any TSAT study in the U.P. would be deficient. J1183 will be studied with PSCAD and the stability results from that model will be used for this cycle. ATC is currently working with ABB to get an updated HVDC PSCAD model and the applicant is working to develop an accurate J1183 PSCAD model.

3.14.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades will be determined from the PSCAD study.

3.14.3 Operating Restrictions Identified in the Stability Study

P6 analysis will be completed in the PSCAD study.

3.14.4 PRC-024-2 Analyses

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1183 are provided in Tables 3.14.4-1 and 3.14.4-2.

Table 3.14.4-1 – J1183 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Voltage	0.001	0.160	Yes
Low Voltage	0.500	1.100	Yes
Low Voltage	0.880	2.000	No
High Voltage	1.100	2.000	Yes
High Voltage	1.200	0.160	Yes

Table 3.14.4-2 – J1183 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 "No Trip Zone"?
Low Frequency	56.5	0.16	0.0	Yes
Low Frequency	58.5	300.00	32.8	Yes
High Frequency	61.2	300.00	57.4	Yes
High Frequency	62.0	0.16	0.0	Yes

3.15 J1188 Stability Study

3.15.1 J1188 Stability Results

Complete fault definitions and stability results for J1188 can be found in Appendix G.

Under all faults for J1188, the simulations show the system meeting all stability criteria.

3.15.2 Network Upgrades Identified in the Stability Study

Stability Network Upgrades are not required for the interconnection of the J1188 generating facility.

3.15.3 Operating Restrictions Identified in the Stability Study

No stability operating restrictions were identified for the J1188 generating facilities.

3.15.4 PRC-024-2 Analysis

PRC-024 Analysis was completed for each generator using the methodology outlined in Appendix A section A.2.5 and the customer provided frequency and voltage trip settings. Results for J1188 are provided in Tables 3.15.4-1 and 3.15.4-2. Six of the frequency relay settings for J1188 do not meet PRC-024-2 requirements and should be changed. The active power does not recover in the high and low voltage tests. The Interconnection Customer should review and provide a revised stability model prior to phase 3.

Table 3.15.4-1 – J1188 PRC-024-2 Voltage Protection Relay Settings Results

Relay Type	Voltage Threshold (p.u.)	Relay Time (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Voltage	0.400	1.000	Yes
Low Voltage	0.500	2.000	Yes
Low Voltage	0.600	3.000	Yes
Low Voltage	0.700	4.000	Yes
Low Voltage	0.800	5.000	Yes
High Voltage	1.100	5.000	Yes
High Voltage	1.200	4.000	Yes
High Voltage	1.300	3.000	Yes
High Voltage	1.400	2.000	Yes
High Voltage	1.500	1.000	Yes

Table 3.15.4-2 – J1188 PRC-024-2 Frequency Protection Relay Settings Results

Relay Type	Frequency Threshold (Hz)	Relay Time (Sec)	Minimum Required Relay Time at This Frequency (Sec)	Ride Through PRC-024-2 “No Trip Zone”?
Low Frequency	57.5	6.0	0.0	Yes
Low Frequency	58.0	7.0	4.4	Yes
High Frequency	58.5	8.0	32.8	No
High Frequency	59.0	9.0	242.5	No
High Frequency	59.5	10.0	1792.0	No
High Frequency	60.5	10.0	600.7	No
High Frequency	61.0	9.0	112.2	No
High Frequency	61.5	8.0	21.0	No
High Frequency	62.0	7.0	0.0	Yes
High Frequency	62.5	6.0	0.0	Yes

3.16 Summary of Operating Restriction Identified in the Stability Analysis

For NERC Category P6 stability constraints, operating restrictions may be required during prior outages to avoid instability caused by the next event. A summary of all P6 operating restrictions for study generators found in the Apr 18 DPP WI Phase 2 studies are provided in Table 3.16-1. Maximum allowed real power outputs to mitigate P6 stability constraints during prior outages were identified for each generating facility.

Table 3.16-1 – P6 Stability Operating Restrictions

Stability Operating Restriction Analysis Result Summary				
MISO Queue #	Max MW	Worst NERC Category P6 (N-1-1) Event		TSAT Stability Max MW Allowed
		1st Contingency	2nd Contingency	
J1000	50	[redacted]	[redacted]	0
J1085 & J1121	500	[redacted]	[redacted]	300 (1)
J1085 & J1121	500	[redacted]	[redacted]	450 (2)

[1]J732 must be at 100% for this limit
[2]J732 was at 493 MW for this limit

3.17 Network Upgrades Identified in the Stability Analysis

There are outstanding items that need to be addressed by some Interconnection Customers to fix their stability models. If the models cannot be fixed prior to phase 3 then network upgrades may be developed. No network upgrades were identified in the Phase 2 studies.

4.0 SHORT CIRCUIT ANALYSIS

Short Circuit analysis was performed in Phase 2 with the final ERIS and NRIS network upgrade projects included in ATC Protection CAPE (Computer-Aided Protection Engineering) models, which include all ATC-owned substations, all ATC local distribution customer owned substations, as well as limited buses into ATC neighboring systems (MP, ComEd, XCEL, DPC, ITC). The analysis was performed according to ATC short circuit analysis methodology as described in Appendix A. Short circuit analysis results for facilities under MISO functional control are described in this section. For each substation under MISO functional control that shows a bus having fault current (SLG) increased by 10% or more, ATC will perform detailed grounding grid analysis if in-house grounding grid modeling is available at the time of the study. The short circuit results for the substations that do not pass the detailed grounding analysis (i.e. not meeting the safety criteria) are provided. Short circuit analysis results for facilities that are not under MISO functional control are described in Section 7 as they are considered as affected system. Tenants for Joint Use substations are provided in Table 9.1-3 in Section 9.

4.1 ATC Short Circuit Analysis

4.1.1 ATC Short Circuit Study Results

Maximum and minimum fault duty was calculated at the POI for each generator request and results are summarized in Table 4.1.1-1, Table 4.1.1-2, Table 4.1.1-3 and Table 4.1.1-4.

Table 4.1.1-1 – Outage Assumptions for Minimum Fault Duty Calculations

MISO Queue #	Contingency
J986	[redacted]
J1000	[redacted]
J1002	[redacted]
J1003	[redacted]
J1009	[redacted]
J1010	[redacted]
J1011	[redacted]
J1042	[redacted]
J1051	[redacted]
J1053	[redacted]
J1085	[redacted]
J1101	[redacted]
J1121	[redacted]
J1153	[redacted]
J1154	[redacted]
J1171	[redacted]
J1183	[redacted]
J1188	[redacted]

Table 4.1.1-2 – Maximum and Minimum Fault Duty at POIs

Location	Maximum Fault Duty (Amps)		Minimum Fault Duty (Amps)	
	Single-Phase	Three-Phase	Single-Phase	Three-Phase
J986 POI without J986	6,389	7,655	1,577	2,172
J986 POI with J986	9,868	8,505	4,191	3,017
J1000 POI without J1000	6,529	8,612	1,796	2,904
J1000 POI with J1000	6,895	9,094	2,022	3,388
J1002 POI without J1002	4,714	6,007	2,943	3,743
J1002 POI with J1002	6,502	7,613	4,715	5,356
J1003 POI without J1003	7,776	7,459	2,769	4,296
J1003 POI with J1003	9,568	8,412	5,432	5,234
J1009 POI without J1009	21,871	25,910	14,853	17,618
J1009 POI with J1009	24,427	26,784	17,380	18,492
J1010 POI without J1010	16,074	17,352	10,224	10,006
J1010 POI with J1010	18,303	18,226	12,081	10,879
J1011 POI without J1011	16,299	17,366	10,382	10,019
J1011 POI with J1011	18,303	18,226	12,081	10,879
J1042 POI without J1042	9,856	12,464	4,475	5,114
J1042 POI with J1042	12,936	13,552	6,958	6,204
J1051 POI without J1051	22,342	20,523	15,002	14,418
J1051 POI with J1051	22,911	20,796	15,667	14,691
J1053 POI without J1053	18,631	19,116	9,905	13,015
J1053 POI with J1053	22,911	20,796	15,667	14,691
J1085 POI without J1085	7,473	8,193	2,635	2,314
J1085 POI with J1085	8,795	8,831	3,796	2,952
J1101 POI without J1101	23,795	21,981	15,452	14,616
J1101 POI with J1101	23,978	22,091	15,643	14,726
J1121 POI without J1121	7,453	8,393	2,754	2,514
J1121 POI with J1121	8,795	8,831	3,796	2,952
J1153 POI without J1153	4,608	6,499	1,086	1,489
J1153 POI with J1153	7,532	7,473	3,170	2,464
J1154 POI without J1154	10,272	14,132	5,128	7,313
J1154 POI with J1154	14,241	15,113	8,717	8,296
J1171 POI without J1171	7,081	9,415	1,967	3,030
J1171 POI with J1171	8,274	9,948	3,270	3,562
J1183 POI without J1183	4,102	4,030	2,950	2,548
J1183 POI with J1183	4,109	4,038	2,957	2,556
J1188 POI without J1188	7,707	8,773	5,419	5,591
J1188 POI with J1188	9,124	9,330	6,636	6,148

Table 4.1.1-3 – Maximum Fault Thevenin Equivalent Data

Location	Positive Sequence (Ohm)	Negative Sequence (Ohm)	Zero Sequence (Ohm)	Three-Phase Thevenin X/R Ratio	Single-Phase Thevenin X/R Ratio	Three-Phase ANSI 37.010 X/R Ratio	Single-Phase ANSI 37.010 X/R Ratio
J986 POI without J986	2.03926 + j10.2008	2.04293 + j10.2079	3.77740 + j16.1492	5.00	4.65	5.64	6.04
J986 POI with J986	2.03926 + j10.2008	2.04293 + j10.2079	0.76393 + j6.46306	5.00	5.55	5.23	5.72
J1000 POI without J1000	1.45987 + j9.18874	1.46086 + j9.18871	3.63786 + j17.7963	6.29	5.52	6.82	6.52
J1000 POI with J1000	1.45987 + j9.18874	1.46086 + j9.18871	3.63786 + j17.7963	6.29	5.52	6.82	6.52
J1002 POI without J1002	3.16254 + j12.8813	3.16649 + j12.8825	5.27988 + j23.5677	4.07	4.25	4.45	4.99
J1002 POI with J1002	2.02768 + j10.2678	2.03006 + j10.2687	2.65304 + j15.5920	5.06	5.38	10.24	9.46
J1003 POI without J1003	1.28343 + j5.18235	1.28514 + j5.18295	0.70752 + j4.64513	4.04	4.58	4.70	5.56
J1003 POI with J1003	1.28367 + j5.18280	1.28537 + j5.18340	0.50335 + j3.37546	4.04	4.47	4.70	5.31
J1009 POI without J1009	0.42400 + j7.67520	0.47277 + j7.78372	2.14003 + j11.6915	18.10	8.94	19.68	11.33
J1009 POI with J1009	0.42410 + j7.67614	0.47289 + j7.78469	1.46834 + j9.72499	18.10	10.65	19.68	17.04
J1010 POI without J1010	0.65206 + j12.3222	0.67957 + j12.4346	1.49106 + j14.6059	18.90	13.95	21.49	21.80
J1010 POI with J1010	0.65237 + j12.3251	0.67989 + j12.4376	0.94563 + j11.6231	18.89	15.97	21.49	23.21
J1011 POI without J1011	0.65097 + j12.3119	0.67842 + j12.4242	1.34758 + j14.0940	18.91	14.51	21.49	23.18
J1011 POI with J1011	0.65237 + j12.3251	0.67989 + j12.4376	0.94563 + j11.6231	18.89	15.97	21.49	23.21
J1042 POI without J1042	0.96118 + j6.58669	0.97551 + j6.62864	2.16740 + j11.2428	6.85	5.96	7.19	7.05
J1042 POI with J1042	0.96121 + j6.58681	0.97555 + j6.62876	0.92981 + j7.22575	6.85	7.13	7.19	8.69
J1051 POI without J1051	0.40433 + j4.20851	0.42297 + j4.41159	0.29921 + j3.07619	10.41	10.38	16.70	18.02
J1051 POI with J1051	0.40433 + j4.20851	0.42297 + j4.41159	0.27820 + j2.94083	10.41	10.46	16.70	18.09
J1053 POI without J1053	0.40433 + j4.20851	0.42297 + j4.41159	0.53802 + j4.32664	10.41	9.48	16.70	15.01
J1053 POI with J1053	0.40433 + j4.20851	0.42297 + j4.41159	0.27820 + j2.94083	10.41	10.46	16.70	18.09
J1085 POI without J1085	2.02115 + j25.5809	2.13737 + j25.5886	5.13975 + j33.4175	12.66	9.10	14.84	17.12
J1085 POI with J1085	2.02707 + j25.6180	2.14363 + j25.6258	3.463604+ j27.2721	12.64	10.29	14.84	17.64
J1101 POI without J1101	0.26184 + j3.85052	0.29743 + j3.84321	0.29279 + j3.00313	14.71	12.55	29.83	21.70
J1101 POI with J1101	0.26184 + j3.85052	0.29743 + j3.84321	0.29300 + j2.97424	14.71	12.52	29.83	21.65
J1121 POI without J1121	2.02707 + j25.6180	2.14363 + j25.6258	5.95726 + j36.0284	12.64	8.62	14.84	16.55
J1121 POI with J1121	2.02385 + j25.6167	2.14025 + j25.6246	3.46360 + j27.2723	12.66	10.29	14.84	17.65

J1153 POI without J1153	1.35460 + j12.1778	1.37568 + j12.1786	5.61475 + j26.8109	8.99	6.13	9.24	6.74
J1153 POI with J1153	1.35460 + j12.1778	1.37568 + j12.1786	1.07100 + j11.9155	8.99	9.54	9.24	11.85
J1154 POI without J1154	0.73254 + j5.58960	0.74480 + j5.60510	3.41008 + j11.5522	7.63	4.65	8.03	4.83
J1154 POI with J1154	0.69112 + j5.42570	0.70255 + j5.44037	1.11128 + j6.46875	7.85	6.92	9.25	10.49
J1171 POI without J1171	1.06512 + j8.39199	1.06603 + j8.39818	7.81430 + j15.4513	7.88	3.24	8.92	4.57
J1171 POI with J1171	1.06623 + j8.39630	1.06714 + j8.40250	5.12612 + j12.8661	7.87	4.09	8.92	7.21
J1183 POI without J1183	5.03211 + j24.7229	5.04593 + j24.6908	3.68507 + j20.0887	4.91	5.05	5.97	6.07
J1183 POI with J1183	5.03211 + j24.7229	5.04593 + j24.6908	3.68507 + j20.0887	4.91	5.05	5.97	6.07
J1188 POI without J1188	0.93734 + j4.44269	0.94127 + j4.44243	0.95461 + j6.35940	4.74	5.38	7.70	9.30
J1188 POI with J1188	0.97092 + j4.51788	0.97499 + j4.51758	0.65702 + j4.89442	4.65	5.35	7.70	8.82

Table 4.1.1-4 – Minimum Fault Thevenin Equivalent Data

Location	Positive Sequence (Ohm)	Negative Sequence (Ohm)	Zero Sequence (Ohm)	Three-Phase Thevenin X/R Ratio	Single-Phase Thevenin X/R Ratio	Three-Phase ANSI 37.010 X/R Ratio	Single-Phase ANSI 37.010 X/R Ratio
J986 POI without J986	9.18513 + j35.5046	9.18904 + j35.5050	18.8124 + j75.8591	3.87	3.95	4.50	4.63
J986 POI with J986	9.18513 + j35.5046	9.18904 + j35.5050	0.65026 + j9.36200	3.87	4.22	4.50	4.95
J1000 POI without J1000	3.79533 + j27.1674	3.79962 + j27.1670	17.7776 + j76.3222	7.16	5.15	7.41	5.76
J1000 POI with J1000	3.79533 + j27.1674	3.79962 + j27.1670	17.7776 + j76.3222	7.16	5.15	16.54	6.55
J1002 POI without J1002	4.73585 + j20.7408	4.74248 + j20.7406	7.95694 + 37.7954	4.38	4.55	4.78	5.37
J1002 POI with J1002	2.43198 + j14.6700	2.43521 + j14.6703	3.01944 + j20.7182	6.03	6.35	12.97	11.43
J1003 POI without J1003	2.92895 + j8.79427	2.93024 + j8.79582	7.67979 + j23.3822	3.00	3.03	3.14	3.11
J1003 POI with J1003	2.92987 + j8.79550	2.93116 + j8.79705	1.64515 + j8.14091	3.00	3.43	3.14	3.66
J1009 POI without J1009	0.64771 + j11.2871	0.67202 + 11.3585	2.60196 + j17.3911	17.43	10.21	18.08	12.33
J1009 POI with J1009	0.64794 + j11.2891	0.67226 + j11.3606	1.52174 + j13.3365	17.42	12.66	18.08	18.08
J1010 POI without J1010	1.19791 + j22.5785	1.25654 + j22.8859	1.10776 + j19.4910	18.85	18.24	23.70	25.21
J1010 POI with J1010	1.19894 + j22.5882	1.25764 + j22.8959	0.61968 + j14.4976	18.84	19.50	23.70	25.82
J1011 POI without J1011	1.19424 + j22.5440	1.25263 + j22.8505	0.93833 + j18.5778	18.88	18.90	23.70	26.28
J1011 POI with J1011	1.19894 + j22.5882	1.25764 + j22.8959	0.61968 + j14.4976	18.84	19.50	23.70	25.82
J1042 POI without J1042	2.13383 + j15.4325	2.16063 + j15.4337	3.59436 + j21.9587	7.23	6.70	7.75	7.90

J1042 POI with J1042	2.13402 + j15.4332	2.16082 + j15.4344	0.91191 + j10.4766	7.23	7.94	7.75	9.05
J1051 POI without J1051	0.80702 + j6.19908	0.81336 + j6.20119	0.66323 + j5.64386	7.68	7.90	8.10	10.15
J1051 POI with J1051	0.80702 + j6.19908	0.81336 + j6.20119	0.57869 + j5.20540	7.68	8.01	8.11	10.03
J1053 POI without J1053	0.80702 + j6.19908	0.81336 + j6.20119	2.59048 + j11.8814	7.68	5.77	8.11	8.18
J1053 POI with J1053	0.80702 + j6.19908	0.81336 + j6.20119	0.57869 + j5.20540	7.68	8.01	8.11	10.03
J1085 POI without J1085	9.15775 + j105.775	9.16744 + j105.875	5.31644 + j75.2967	11.55	12.14	12.52	15.68
J1085 POI with J1085	9.26936 + j106.413	9.27928 + j106.514	2.52607 + j49.7035	11.48	12.46	12.52	14.76
J1101 POI without J1101	0.54387 + j5.97531	0.57296 + j5.96556	0.49063 + j5.09305	10.99	10.60	27.45	22.12
J1101 POI with J1101	0.54387 + j5.97531	0.57296 + j5.96556	0.49137 + j5.01053	10.99	10.54	27.45	22.01
J1121 POI without J1121	9.26936 + j106.413	9.27927 + j106.514	7.42358 + j90.3049	11.48	11.68	12.52	16.14
J1121 POI with J1121	9.26936 + j106.413	9.27928 + j106.514	2.52607 + j49.7035	11.48	12.46	12.52	14.76
J1153 POI without J1153	6.23808 + j53.0730	6.25496 + j53.0660	18.1161 + j111.492	8.51	7.11	8.74	8.52
J1153 POI with J1153	6.23808 + j53.0730	6.25496 + j53.0660	0.44833 + j17.7637	8.51	9.57	8.74	9.85
J1154 POI without J1154	1.33285 + j10.8125	1.35699 + j10.8033	6.75387 + j24.0281	8.11	4.83	8.91	4.99
J1154 POI with J1154	1.19312 + j10.2143	1.21473 + j10.2064	1.08752 + j9.03473	8.56	8.43	11.15	12.53
J1171 POI without J1171	4.24938 + j25.9452	4.26711 + j25.9547	15.3962 + j67.1836	6.11	4.98	6.21	5.08
J1171 POI with J1171	4.26313 + j25.9860	4.28092 + j25.9955	4.35306 + j33.1200	6.10	6.60	6.21	7.93
J1183 POI without J1183	10.1413 + j46.4645	10.1526 + j46.4393	3.83710 + j22.5713	4.58	4.79	6.08	6.18
J1183 POI with J1183	10.1413 + j46.4645	10.1526 + j46.4393	3.83710 + j22.5713	4.58	4.79	6.08	6.18
J1188 POI without J1188	1.50937 + j6.96266	1.51448 + j6.96283	1.02757 + j7.75127	4.61	5.35	9.08	10.57
J1188 POI with J1188	1.59540 + j7.14852	1.60080 + j7.14863	0.67535 + j5.67677	4.48	5.16	9.08	9.98

Breaker duty analysis results for over duty breakers are summarized in Table 4.1.1-5 and Table 4.1.1-6.

Table 4.1.1-5 – Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
None	N/A	N/A	N/A

Table 4.1.1-6 – Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
None	N/A	N/A	N/A

Ground fault analysis results are summarized in Table 4.1.1-7.

Table 4.1.1-7 – Buses with 10% or More Fault Current Increase in SLG Analysis

SUBSTATION	BUS	kV	BEFORE (AMPS)	AFTER (AMPS)	% Change
CHAFFEE CREEK	831500	69	3900.5	4372.8	12.11
ELKHORN	908600	138	7837.7	8632.2	10.14
NORTH LAKE GENEVA	908500	138	9840.5	12936.2	31.46
NORTH LAKE GENEVA	908501	138	9840.5	12936.2	31.46
NORTH LAKE GENEVA	808300	69	8925.8	9421.8	5.56
PORT EDWARDS	924100	138	9755.4	11388.6	16.74
PORT EDWARDS	924101	138	9755.4	11388.6	16.74
PORT EDWARDS	924102	138	9755.4	11388.6	16.74
PORT EDWARDS	835800	69	14620.1	15381.7	5.21
PORT EDWARDS	835900	69	14620.1	15381.7	5.21
SAND LAKE	994000	69	3409.4	5815.7	70.58
SAND LAKE	924150	138	4228.3	5559.1	31.47
SAND LAKE	993900	138	4226.6	5555.8	31.45
SARATOGA	924000	138	9264	10719	15.71
SARATOGA	924001	138	9264	10719	15.71
SARATOGA	979700	115	10309.4	11212.9	8.76
SARATOGA	835200	69	4931.8	5066.2	2.73
SHEEPSKIN	910400	69	7704	9124.1	18.43
SHEEPSKIN	992700	69	7704	9124.1	18.43
WAUTOMA	923500	138	4056.5	6502.2	60.29
WAUTOMA	828600	69	6266.5	8321.4	32.79

4.1.2 ATC Short Circuit Study Results

ATC short circuit Network Upgrades are summarized in Table 4.1.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 4.1.2-1 – Network Upgrade Required for ATC Facilities

SUBSTATION	Total Cost ($)
CHAFFEE CREEK	220,000
ELKHORN[1]	220,000
NORTH LAKE GENEVA	220,000
PORT EDWARDS	220,000
SAND LAKE	220,000
SARATOGA	220,000
SHEEPSKIN	220,000
WAUTOMA	220,000

Note[1]: Elkhorn Substation was identified for potential grounding upgrade in DPP Aug-17 Phase 3 system impact study.

4.2 Alliant Short Circuit Analysis

Some Alliant owned facilities under MISO functional control are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

4.2.1 Short Circuit Study Results

Alliant breaker duty analysis results are summarized in Table 4.2.1-1 and Table 4.2.1-2.

Table 4.2.1-1 – Alliant Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 4.2.1-2 – Alliant Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Alliant ground fault analysis results are summarized in Table 4.2.1-3.

Table 4.2.1-3 – Alliant Buses with 10% or More Fault Current Increase in SLG Analysis

SUBSTATION	BUS	kV	BEFORE (AMPS)	AFTER (AMPS)	% Change
HANCOCK	883300	69	3108.4	4229.1	36.05
HOLLYWOOD	894800	138	9083.9	10518	15.79
ROEDER	923400	138	4418.7	4908.5	11.08

4.2.2 Network Upgrades Identified in the Short Circuit Analysis

Alliant short circuit Network Upgrades are summarized in Table 4.2.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 4.2.2-1 – Network Upgrade Required for Alliant Facilities

Substation	Total Cost ($)
HANCOCK	220,000
HOLLYWOOD	220,000
ROEDER	220,000

4.3 We Energies Short Circuit Analysis

Some We Energies owned facilities under MISO functional control are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

4.3.1 Short Circuit Study Results

We Energies Breaker duty analysis results are summarized in Table 4.3.1-1 and Table 4.3.1-2.

Table 4.3.1-1 – We Energies Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 4.3.1-2 – We Energies Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

We Energies ground fault analysis results are summarized in Table 4.3.1-3.

Table 4.3.1-3 – We Energies Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
BARK RIVER	926000	138	9591.5	11771.5	22.73
BARK RIVER	926001	138	9591.5	11771.5	22.73
BUTTERNUT	926900	138	7062.5	8274.1	17.16
BUTTERNUT	927000	138	7062.5	8274.1	17.16
CONCORD SW YD	888700	138	18574.4	24919.5	34.16
CONCORD SW YD	888701	138	18574.4	24919.5	34.16
CONCORD SW YD	928300	138	18574.4	24919.5	34.16
CONCORD SW YD	888800	138	18881.9	24872.7	31.73

4.3.2 Network Upgrades Identified in the Short Circuit Analysis

We Energies short circuit Network Upgrades are summarized in Table 4.3.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 4.3.2-1 – Network Upgrade Required for We Energies Facilities

Substation	Total Cost ($)
BARK RIVER	220,000
BUTTERNUT	220,000
CONCORD SW YD	550,000

5.0 TRANSFORMER ENERGIZATION ANALYSIS

5.1 Transformer Energization Study Results

Transformer Energization Analysis were performed based on ATC transformer initial energization criteria as described in Appendix A. The 2023 shoulder model (batteries charging) was used with all identified ERIS and NRIS Network Upgrades included. The results are summarized in Table 5.1-1. No constraints (Vmin inrush below 70%) were found.

Table 5.1-1 – Inrush Calculations Using Shoulder Model

Generation Project	Transformer(s)		PSSE POI	Fault	Vmin Inrush (pu)	
	Number	Windings	Bus #	Current (A)	Raw	Multiplier
J986	1	2	89864	6392	0.731	0.840
J1000	1	2	40004	7714	0.930	1.069
J1002	1	2	699235	5414	0.828	0.952
J1003	1	2	698222	7136	0.847	0.975
J1009	2	3	40095	22515	0.955	1.098
J1010	2	3	999901	14023	0.930	1.069
J1011	2	3	999901	14023	0.931	1.070
J1042	1	3	699085	11184	0.812	0.933
J1051	1	2	40517	12173	0.868	0.999
J1053	1	2	40517	12173	0.904	1.040
J1053	2	2	40517	12173	0.904	1.040
J1085	1	3	40854	8811	0.896	1.031
J1085	2	3	40854	8802	0.892	1.026
J1101	1	2	699620	19787	0.985	1.132
J1121	1	3	40854	8906	0.893	1.027
J1153	1	2	699288	6356	0.792	0.911
J1154	1	2	699340	12206	0.825	0.949
J1171	1	2	699270	8643	0.758	0.871
J1183	1	2	693701	3207	0.818	0.940
J1188	1	2	699104	7219	0.859	0.987

6.0 PSCAD ANALYSIS

ATC performed a low short circuit strength screening analysis for all inverter-based resources in the DPP-2018-April East (ATC) Area Phase 1 which determined that the following requests were connecting to relatively weaker portions of the ATC system that would require further electromagnetic transient (EMT) analysis in PSCAD:

- J986
- J1000
- J1002
- J1010
- J1011
- J1042
- J1085
- J1121
- J1153
- J1183

PSCAD requires much more data and processing time than traditional steady state and dynamics software packages used in transmission planning such that system wide area models do not exist. To study the generators connecting to weaker portions of the ATC system, six different local models were produced including:

- Southwest Wisconsin (SW WI) Model
- Southeast Wisconsin (SE WI) Model
- J1153 Model
- J986/J1002 Model
- J1085/J1121 Model
- J1183 Model

6.1 SW WI PSCAD Study

Details of the SW WI PSCAD model can be found in Appendix L.

6.1.1 SW WI PSCAD Study Results

The SW WI analysis found that J1000 would trip on fast frequency protection settings for the two following P6 events:

- [redacted]
- [redacted]

J1000 will need to change the plant's frequency protection setting such that the plant rides through these events or operating restriction to mitigate this event will be determined as part of Phase 3 of the System Impact Study.

All other events studied were found to be stable for all elements monitored. Full results of the SW WI PSCAD study are summarized in Table 6.1.1-1 below. Full detailed results for all PSCAD results are included in Appendix L.

Table 6.1.1-1 – SW WI PSCAD Results

TPL	Fault Description	Fault Type	Plants Monitored											
			J807	J819	J850	J855	J864	J870	J871	J947	J395	J584	J1000	J1188
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.3	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P4.5	[redacted]	1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P6.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	J1000 Trips	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK
P6.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	J1000 Trips	OK
		1PG	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

6.1.2 Network Upgrades Identified in the SW WI PSCAD Study

No network upgrades were identified to mitigate constraints from the Phase 2 SW WI PSCAD study.

6.1.3 Operating Restrictions Identified in the SW WI PSCAD Study

No operating restrictions were identified to mitigate constraints from the Phase 2 SW WI PSCAD study. However, if J1000 cannot provide updated frequency protection settings such that the plant rides through the two unstable P6s detailed in section 6.1.1 operating restrictions will have to be determined in Phase 3.

6.2 SE WI PSCAD Study

Details of the SE WI PSCAD model can be found in Appendix L.

6.2.1 SE WI PSCAD Study Results

The SE WI analysis found that J850, J878, J1042, J1010, and J1011 all exhibited undamped P, Q, and V oscillations and Paris gas plant exhibited undamped machine angle response for the P6 contingency [redacted].

The SE WI analysis found that J1010, and J1011 repeatedly re-enter fault ride through mode after the fault is cleared for the P6 contingency [redacted].

All other events studied were found to be stable for all elements monitored. Full results of the SE WI PSCAD study are summarized in Table 6.2.1-1 below. Full detailed results for all PSCAD results are included in Appendix L.

Table 6.2.1-1 – SE WI PSCAD Results

TPL	Fault Description	Fault Type	Plants Monitored					
			J850	J878	J1042	J1010	J1011	Paris Gas
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK
P1.2	[redacted]	3PG	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK
P6	[redacted]	3PG	undamped	undamped	undamped	undamped	undamped	undamped
		1PG	undamped	undamped	undamped	undamped	undamped	undamped
P6	[redacted]	3PG	OK	OK	OK	re-enters fault ride through mode post fault	re-enters fault ride through mode post fault	OK
		1PG	OK	OK	OK	re-enters fault ride through mode post fault	re-enters fault ride through mode post fault	OK
P6	[redacted]	3PG	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK
P6	[redacted]	3PG	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK
P6	[redacted]	3PG	OK	OK	OK	OK	OK	OK
		1PG	OK	OK	OK	OK	OK	OK
P7	[redacted]	1PG	OK	OK	OK	OK	OK	OK

6.2.2 Network Upgrades Identified in the SE WI PSCAD Study

Results from the SE WI PSCAD study were still being finalized at the date of this draft.

6.2.3 Operating Restrictions Identified in the SE WI PSCAD Study

For P6 stability constraints, operating restrictions may be required during prior outages to avoid instability caused by the next event. For P6s that showed instability in the SE WI, PSCAD analysis was performed to determine which generators were causing the instability as detailed in Appendix L. For all unstable P6s in the SE WI PSCAD study it was determined that instability was caused by the addition of the J1010 and J1011 interconnection requests. The maximum allowed real power outputs after prior outages are shown in Table 6.2.3-1 below.

Table 6.2.3-1 – SE WI PSCAD Identified Operating Restrictions

Event	Prior Outage	Faulted Element	Maximum Real Power Output of J1010/J1011
			To Maintain IBR Stability and Other Voltage and Oscillation Criteria (MW)
P6	[redacted]	[redacted]	300
P6	[redacted]	[redacted]	680

6.3 J1153 PSCAD Study

Details of the J1153 PSCAD model can be found in Appendix L.

6.3.1 J1153 PSCAD Study Results

The J1153 analysis found that J1153 was not providing Mvars to control voltage to meet the ATC voltage schedule and not recovering to full power output for a P4.5 event consisting [redacted].

All other events studied were found to be stable for all elements monitored. Full results of the J1153 PSCAD study are summarized in Table 6.3.1-1 below. Full detailed results for all PSCAD results are included in Appendix L.

Table 6.3.1-1 – J1153 PSCAD Results

TPL	Fault Description	Fault Type	Plants Monitored
			J1153
P1.2	[redacted]	3PG	OK
		1PG	OK
P4.5	[redacted]	3PG	J1153 not providing Mvars to control voltage and not recovering to full power output

P6	[redacted]	3PG	OK
		1PG	OK
P6	[redacted]	3PG	OK
		1PG	OK

6.3.2 Network Upgrades Identified in the J1153 PSCAD Study

No network upgrades were identified to mitigate constraints from the Phase 2 J1153 PSCAD study. However, J1153 will need to tune the controls of the plant to provide Mvars to control voltage and recover to full power output under the P4.5 contingency listed in Table 6.3.1-1.

6.3.3 Operating Restrictions Identified in the J1153 PSCAD Study

No operating restrictions were identified to mitigate constraints from the Phase 2 J1153 PSCAD study.

6.4 J986/J1002 PSCAD Study

Details of the J986/J1002 PSCAD model can be found in Appendix L.

6.4.1 J986/J1002 PSCAD Study Results

The J986/J1002 analysis found that J986 trips on the contingency of [redacted]. This fault was rerun with all of the protection settings disabled and the response was also found to be undamped so operating restrictions were determined to mitigate this event.

The J986/J1002 analysis found that J986 and J1002 were undamped over the last two seconds of the simulation for the contingency of [redacted]. Operating restrictions were derived to mitigate this constraint and are detailed in section 6.4.3.

The J986/J1002 analysis found that J1002 trips on the contingency of [redacted]. J1002 will need to change the plant's frequency protection setting such that the plant rides through these events or operating restriction to mitigate this event will be determined as part of Phase 3 of the System Impact Study.

All other events studied were found to be stable for all elements monitored. Full results of the J986/J1002 PSCAD study are summarized in Table 6.4.1-1 below. Full detailed results for all PSCAD results are included in Appendix L.

Table 6.4.1-1 – J986/J1002 PSCAD Results

TPL	Fault Description	Fault Type	Plants Monitored	
			J986	J1002
P1.2	[redacted]	3PG	OK	OK
		1PG	OK	OK
P4.5	[redacted]	1PG	OK	OK
P6	[redacted]	3PG	J986 trips	J986 trips
		1PG	J986 trips	J986 trips
P6	[redacted]	3PG	undamped	undamped
		1PG	undamped	undamped
P6	[redacted]	3PG	J1002 trips	J1002 trips
		1PG	J1002 trips	J1002 trips

6.4.2 Network Upgrades Identified in the J986/J1002 PSCAD Study

No network upgrades were identified to mitigate constraints from the Phase 2 J986/J1002 PSCAD study.

6.4.3 Operating Restrictions Identified in the J986/J1002 PSCAD Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. The maximum allowed real power outputs after prior outages were identified for the J986 and J1002 generating facilities to mitigate P6 stability constraints. See Table 6.4.3-1 below.

Table 6.4.3-1 – J986/J1002 PSCAD Identified Operating Restrictions

Event	Prior Outage	Faulted Element	Maximum Real Power Output of J986/J1002 To Maintain IBR Stability and Other Voltage and Oscillation Criteria (MW)
P6	[redacted]	[redacted]	110 (J986 restriction only)
P6	[redacted]	[redacted]	200 (J986/J1002 combined restriction)

6.5 J1085/J1121 PSCAD Study

Details of the J1085/J1121 PSCAD model can be found in Appendix L.

6.5.1 J1085/J1121 PSCAD Study Results

The J1085/J1121 analysis found that J732, J1085, and J1121 are all unstable for a P6 event [redacted].

All other events studied were found to be stable for all elements monitored. Full results of the J1085/J1121 PSCAD study are summarized in Table 6.5.1-1 below. Full detailed results for all PSCAD results are included in Appendix L.

Table 6.5.1-1 – J1085/J1121 PSCAD Results

TPL	Fault Description	Fault Type	Plants Monitored		
			J732	J1085	J1121
P1.2	[redacted]	3PG	OK	OK	OK
		1PG	OK	OK	OK
P4.5	[redacted]	1PG	OK	OK	OK
P6	[redacted]	3PG	OK	OK	OK
		1PG	OK	OK	OK
P6	[redacted]	3PG	OK	OK	OK
		1PG	OK	OK	OK
P6	[redacted]	3PG	loses synchronism	tripped	undamped
		1PG	loses synchronism	tripped	undamped

6.5.2 Network Upgrades Identified in the J1085/J1121 PSCAD Study

No network upgrades were identified to mitigate constraints from the Phase 2 J1085/J1121 PSCAD study.

6.5.3 Operating Restrictions Identified in the J1085/J1121 PSCAD Study

For P6 stability constraints operating restrictions may be required during prior outages to avoid instability caused by the next event. The maximum allowed real power outputs after prior outages were identified for the J1085 and J1121 generating facilities to mitigate P6 stability constraints. See Table 6.5.3-1 below.

Table 6.5.3-1 – J1085/J1121 PSCAD Identified Operating Restrictions

Event	Prior Outage	Faulted Element	Maximum Real Power Output of J1085/J1121
			To Maintain IBR Stability and Other Voltage and Oscillation Criteria (MW)
P6	[redacted]	[redacted]	280

6.6 J1183 PSCAD Study

The J1183 PSCAD model was found to be deficient when it was tested per ATC's modeling requirements. The PSCAD study will be completed once the Interconnection Customer provides an updated PSCAD model.

6.7 Summary of Operating Restriction Identified in the PSCAD Analysis

For NERC Category P6 stability constraints, operating restrictions may be required during prior outages to avoid instability caused by the next event. A summary of all P6 operating restrictions found in the PSCAD analysis for study generators in Apr 18 DPP WI Phase 2 is provided in Table 6.7-1 below. Maximum allowed real power outputs after prior outages were identified for generating facility to mitigate P6 stability constraints.

Table 6.7.1-1 – Summary of All PSCAD Identified Operating Restrictions

MISO Queue #	Max MW	Worst NERC Category P6 (N-1-1) Event		PSCAD Analysis Max MW Allowed
		1st Contingency	2nd Contingency	
J986	150	[redacted]	[redacted]	110
J986/J1002	249	[redacted]	[redacted]	200
J1010/J1011	800	[redacted]	[redacted]	300
		[redacted]	[redacted]	680
J1085/J1121	500	[redacted]	[redacted]	280

7.0 AFFECTED SYSTEM ANALYSIS

Short Circuit analysis on affected system modelled in ATC Protection CAPE models was performed in Phase 2 with the final ERIS and NRIS network upgrade projects included. PJM affected system analysis was provided in Section 7.3.

7.1 Alliant Affected System Short Circuit Analysis

Some Alliant owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.1.1 Short Circuit Study Results

Alliant breaker duty analysis results are summarized in Table 7.1.1-1 and Table 7.1.1-2.

Table 7.1.1-1 – Alliant Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin
none	N/A	N/A	N/A

Table 7.1.1-2 – Alliant Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin

none	N/A	N/A	N/A

Alliant ground fault analysis results are summarized in Table 7.1.1-3.

Table 7.1.1-3 – Alliant Buses with 10% or More Fault Current Increase in SLG Analysis

SUBSTATION	BUS	kV	BEFORE (AMPS)	AFTER (AMPS)	% Change
BEAVER DAM 3RD ST	822300	69	6171.7	7053.6	14.29
CENTER ST	822400	69	5991	6736.6	12.45
DANA CORP	810800	69	5739.7	6536.1	13.88
PLAINFIELD (ALTE)	831400	69	2264.6	3117.1	37.64
SAUNDERS CREEK	810600	69	5958.4	6680.4	12.12
SILVER LAKE (ALTE)	828400	69	4227.9	4903.7	15.98
VULCAN CHEM	836100	138	9495.6	11062	16.50
VULCAN CHEM	836101	138	9495.6	11062	16.50

7.1.2 Network Upgrades Identified in the Short Circuit Analysis

Alliant short circuit Network Upgrades are summarized in Table 7.1.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.1.2-1 – Network Upgrade Required for Alliant Facilities

Substation	Total Cost ($)
BEAVER DAM 3RD ST	220,000
CENTER ST	220,000
DANA CORP	220,000
PLAINFIELD (ALTE)	220,000
SAUNDERS CREEK	220,000
SILVER LAKE (ALTE)	220,000
VULCAN CHEM	220,000

7.2 Adams-Columbia Electric Cooperative Affected System Short Circuit Analysis

Some Adams-Columbia Co-Op owned facilities are modeled in the ATC Protection model and were evaluated in the short circuit analysis.

7.2.1 Short Circuit Study Results

Adams-Columbia Co-Op Breaker duty analysis results are summarized in Table 7.2.1-1 and Table 7.2.1-2.

Table 7.2.1-1 – Adams-Columbia Co-Op Over Duty Breakers Found in SLG Analysis

Breaker Name	Breaker Rating	Base Case SLG Margin	Study Case SLG Margin

none	N/A	N/A	N/A

Table 7.2.1-2 – Adams-Columbia Co-Op Over Duty Breakers Found in 3PG Analysis

Breaker Name	Breaker Rating	Base Case 3PG Margin	Study Case 3PG Margin
none	N/A	N/A	N/A

Adams-Columbia Co-Op ground fault analysis results are summarized in Table 7.2.1-3.

Table 7.2.1-3 – Adams-Columbia Co-Op Buses with 10% or More Fault Current Increase in SLG Analysis

Substation	Bus Name	Bus Voltage (kV)	SLG Fault Current Before (Amps)	SLG Fault Current After (Amps)	Change (%)
ACEC HANCOCK	831100	69	3097.5	4209	35.88
ACEC RICHFORD	831000	69	3668.7	4072.8	11.01
ACEC WAUTOMA	829500	69	4250.1	4959.5	16.69
ACEC WILD ROSE PUMP	993800	69	3341.4	3683.8	10.25

7.2.2 Network Upgrades Identified in the Short Circuit Analysis

Adams-Columbia Co-Op short circuit Network Upgrades are summarized in Table 7.2.2-1. Details on cost estimating/allocation methodology and cost allocations are provided in Section 9.

Table 7.2.2-1 – Network Upgrade Required for Adams-Columbia Co-Op Facilities

Substation	Total Cost ($)
ACEC HANCOCK	220,000
ACEC RICHFORD	220,000
ACEC WAUTOMA	220,000
ACEC WILD ROSE PUMP	220,000

7.3 PJM Affected System Steady State Contingency Analysis

PJM performed the PJM affected system analysis and the report can be found in Appendix H. Eight PJM Affected System Network Upgrades have cost allocations to the study generators in Apr 18 DPP Phase 2 group. Detailed cost allocations are provided in Section 9. The PJM affected system study will be updated in Phase 3 to incorporate all appropriate model updates.

8.0 DELIVERABILITY STUDY

Generator interconnection requests 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 either choose to elect the amount of NRIS available without upgrades or build 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.

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at

https://cdn.misoenergy.org/Generator_Deliverability_Study_Methodology108139.pdf

8.1 Study Summary

The summary of MISO deliverability results based on the 2023 summer peak study model is shown in the following tables.

Table 8.1-1 below lists the deliverability results with ERIS Network Upgrades included in the NRIS analysis. Minimum NR Deliverable is the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew. Maximum NR Deliverable is the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction.

Table 8.1-1 – NRIS Analysis Summary

MISO Queue #	Area	NR Tested	Minimum NR Deliverable (MW)	Maximum NR Deliverable (MW)
J986	ATC	149.76	149.76	149.76
J1000	ATC	50	50	50
J1002	ATC	99	99	99
J1003	ATC	50	0	17.1
J1009	ATC	400	400	400
J1010	ATC	400	400	400
J1011	ATC	400	400	400
J1042	ATC	200	80.58	91.78
J1051	ATC	50	0	17.1
J1053	ATC	200	9.57	68.26
J1085	ATC	300	263.67	278.2
J1101	ATC	20	20	20
J1121	ATC	200	163.67	185.47
J1153	ATC	150	150	150
J1154	ATC	75	0	11.84
J1171	ATC	100	34.16	47.38
J1183	ATC	0	0	0
J1188	ATC	50	0	0

Table 8.1-2 below lists all of the NRIS constraints from the deliverability study and the identified NRIS Network Upgrades. Both ERIS Network Upgrades and NRIS Network Upgrades must be made for 100% NRIS, i.e. fully deliverable. Please note, if a NRIS Network Upgrade entirely or partially changes the scope of an ERIS Network Upgrade, only the cost difference between the NRIS upgrade and the ERIS

upgrade will be eligible for NRIS Network Upgrade cost allocation. Detailed NRIS Network Upgrade cost allocation calculations are provided in Section 9.

Table 8.1-2 – Network Upgrades Needed to Address MISO Identified NRIS Steady-State Injection Constraints

NRIS Thermal Constraints	Required NRIS Network Upgrades	Mitigation Type	Responsible Generators	NRIS Network Upgrade Cost Estimates ($) [a]	ERIS Network Upgrade (Required for Same Constraint) Cost Estimate ($) [b]	Previous Cycle ERIS/NRIS Network Upgrade (Identified for Same Constraint) Cost Estimate ($) [c]	Cost Used for NRIS Network Upgrade Allocation ($) [c] = [a] - [b]
40515 CONCRD 2 138 699293 COONEY 138 1 40518 CONCRD 7 138 699477 RUBICON 138 1 699293 COONEY 138 699470 SUMMIT3 138 1 699470 SUMMIT3 138 699469 SUMMIT2 138 Z	Concord - Bark River 138 kV, New Line	NR	J1003, J1051, J1053, J1154	31,742,736	0	0	31,742,736
698884 JEFRSN5 138 699375 CRWFSH R 138 1	Jefferson - Crawfish River 138 kV, Uprate	NR	J1154, J1188	927,904	0	0	927,904
699375 CRWFSH R 138 699283 CONCRD 4 138 1	Crawfish River - Concord 138 kV, Uprate	NR	J1154, J1188	2,141,449	0	0	2,141,449
602017 ST LAKE5 161 681541 WASHCO 5 161 1	Stone Lake - Washco 161 kV, Rebuild	NR	J1085, J1121	19,000,000	0	0	19,000,000
694106 ROR BUS1 138 699062 MRE 138 138 1	Rock River - Marine 138 kV, Partial Rebuild	NR	J1188	2,467,049	0	0	2,467,049
698090 BOL 138 138 699086 ELK 138 138 1	Bristol - Elkhorn 138 kV, Uprate	NR	J1188	194,895	0	0	194,895
699085 NLG 138 138 699360 NLK GV T 138 1	North Lake Geneva - North Lake Geneva Tap 138 kV, Uprate	NR	J1042, J1188	53,430	0	0	53,430
699086 ELK 138 138 699085 NLG 138 138 1	Elkhorn - North Lake Geneva 138 kV, Uprate	NR	J1188	580,677	0	45,400	535,277
699175 NFL 138 138 699677 AVIATION 138 1	North Fond du Lac - Aviation 138 kV, Partial Rebuild	NR	J1003, J1171	7,086,740	0	0	7,086,740
699360 NLK GV T 138 699267 BRLGTN1 138 1	North Lake Geneva Tap - Burlington 138 kV, Rebuild	NR	J1042, J1188	10,692,501	0	280,383	10,412,118
699512 UNVRSTY 138 699357 MUKWONGO 138 1	University - Mukwonago 138 kV, Partial Rebuild[1]	NR	J1042, J1188	4,511,000	0	0	4,511,000

[1]Cost is based on rebuilding section of line; network upgrade facility study may show that structures do not need to be replaced which would result in lower cost for the project

8.2 Per Project Summary

8.2.1 J986

J986 Deliverable (NRIS) Amount in 2023 Case: 149.76 MW (Conditional on ERIS upgrades and case assumptions)	149.76 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		149.76		149.76					

8.2.2 J1000

J1000 Deliverable (NRIS) Amount in 2023 Case: 50 MW (Conditional on ERIS upgrades and case assumptions)	50 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		50		50					

8.2.3 J1002

J1002 Deliverable (NRIS) Amount in 2023 Case: 99 MW (Conditional on ERIS upgrades and case assumptions)	99 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		99		99					

8.2.4 J1003

J1003 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	50 MW Requested								

Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
40515 CONCRD 2 138 699293 COONEY 138 1	1092.28	0	32.9	17.1	0.1003	J1003, J1051, J1053, J1154	$809,026	$31,742,736	
699293 COONEY 138 699470 SUMMIT3 138 1	570.61	0	17.18	32.82	0.1003	J1003, J1051, J1053, J1154	$809,026	$31,742,736	
699470 SUMMIT3 138 699469 SUMMIT2 138 Z	156	0	5.6	44.4	0.1003	J1003, J1051, J1053, J1154	$809,026	$31,742,736	
699175 NFL 138 138 699677 AVIATION 138 1	84.49	0	23.7	26.3	0.0951	J1003, J1051, J1053, J1154	$809,026	$31,742,736	
		50		50					

8.2.5 J1009

J1009 Deliverable (NRIS) Amount in 2023 Case: 400 MW (Conditional on ERIS upgrades and case assumptions)	400 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		400		400					

8.2.6 J1010

J1010 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	400 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		400		400					

8.2.7 J1011

J1011 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	400 MW Requested								

Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		400		400					

8.2.8 J1042

J1042 Deliverable (NRIS) Amount in 2023 Case: 80.58 MW (Conditional on ERIS upgrades and case assumptions)	200								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699512 UNVRSTY 138 699357 MUKWONGO 138 1	119.42	80.58	104.2	95.8	0.0898	J1042, J1188	$3,936,992	$4,511,000	
699360 NLK GV T 138 699267 BRLGTN1 138 1	115.6	84.4	108.22	91.78	0.3424	J1042, J1188	$9,836,141	$10,692,501	
699085 NLG 138 138 699360 NLK GV T 138 1	12.91	187.09	12.58	187.42	0.5598	J1042, J1188	$52,076	$53,430	
		200		200					

8.2.9 J1051

J1051 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	50 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
40515 CONCRD 2 138 699293 COONEY 138 1	190.6	0	32.9	17.1	0.5307	J1003, J1051, J1053, J1154	$5,531,570	$31,742,736	
40518 CONCRD 7 138 699477 RUBICON 138 1 C	169.99	0	30.47	19.53	0.4669	J1003, J1051, J1053, J1154	$5,531,570	$31,742,736	
699470 SUMMIT3 138 699469 SUMMIT2 138 Z	121.02	0	21.62	28.38	0.5307	J1003, J1051, J1053, J1154	$5,531,570	$31,742,736	
699293 COONEY 138 699470 SUMMIT3 138 1	109.76	0	19.61	30.39	0.5307	J1003, J1051, J1053, J1154	$5,531,570	$31,742,736	
		50		50					

8.2.10 J1053

J1053 Deliverable (NRIS) Amount in 2023 Case: 9.4 MW (Conditional on ERIS upgrades and case assumptions)	200 MW Requested								

Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
40515 CONCRD 2 138 699293 COONEY 138 1	190.6	9.4	131.74	68.26	0.5307	J1003, J1051, J1053, J1154	$22,121,983	$31,742,736	
40518 CONCRD 7 138 699477 RUBICON 138 1 C	169.99	30.01	60.93	139.07	0.4669	J1003, J1051, J1053, J1154	$22,121,983	$31,742,736	
699470 SUMMIT3 138 699469 SUMMIT2 138 Z	121.02	78.98	43.2	156.8	0.5307	J1003, J1051, J1053, J1154	$22,121,983	$31,742,736	
699293 COONEY 138 699470 SUMMIT3 138 1	109.76	90.24	39.22	160.78	0.5307	J1003, J1051, J1053, J1154	$22,121,983	$31,742,736	
		200		200					

8.2.11 **J1085**

J1085 Deliverable (NRIS) Amount in 2023 Case: 263.67 MW (Conditional on ERIS upgrades and case assumptions)	300 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
602017 ST LAKE5 161 681541 WASHCO 5 161 1	36.33	263.67	21.8	278.2	0.2528	J1085, J1121	$11,400,000	$19,000,000	
		300		300					

8.2.12 **J1101**

J1101 Deliverable (NRIS) Amount in 2023 Case: 20 MW (Conditional on ERIS upgrades and case assumptions)	20 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		20		20					

8.2.13 **J1121**

J1121 Deliverable (NRIS) Amount in 2023 Case: 163.67 MW (Conditional on ERIS upgrades and case assumptions)	200 MW Requested								

Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
602017 ST LAKE5 161 681541 WASHCO 5 161 1	36.33	163.67	14.53	185.47	0.2528	J1085, J1121	$7,600,000	$19,000,000	
		200		200					

8.2.14 **J1153**

J1153 Deliverable (NRIS) Amount in 2023 Case: 150 MW (Conditional on ERIS upgrades and case assumptions)	150 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
		150		150					

8.2.15 **J1154**

J1154 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	75 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
40515 CONCRD 2 138 699293 COONEY 138 1	466.37	0	49.4	25.6	0.2112	J1003, J1051, J1053, J1154	$3,280,156	$31,742,736	
40518 CONCRD 7 138 699477 RUBICON 138 1 C	439.99	0	45.7	29.3	0.1805	J1003, J1051, J1053, J1154	$3,280,156	$31,742,736	
699470 SUMMIT3 138 699469 SUMMIT2 138 Z	303.93	0	32.43	42.57	0.2112	J1003, J1051, J1053, J1154	$3,280,156	$31,742,736	
699293 COONEY 138 699470 SUMMIT3 138 1	275.65	0	29.41	45.59	0.2112	J1003, J1051, J1053, J1154	$3,280,156	$31,742,736	
699375 CRWFSH R 138 699283 CONCRD 4 138 1	63.16	11.84	63.16	11.84	0.2644	J1154, J1188	$1,894,065	$2,141,449	
698884 JEFRSN5 138 699375 CRWFSH R 138 1	52.5	22.5	52.5	22.5	0.2644	J1154, J1188	$820,711	$927,904	
		75		75					

8.2.16 **J1171**

J1171 Deliverable (NRIS) Amount in 2023 Case: 34.16 MW (Conditional on ERIS upgrades and case assumptions)	100 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699175 NFL 138 138 699677 AVIATION 138 1	65.84	34.16	47.38	52.62	0.1217	J1003, J1171	$5,097,259	$7,086,740	
		100		100					

8.2.17 **J1188**

J1188 Deliverable (NRIS) Amount in 2023 Case: 0 MW (Conditional on ERIS upgrades and case assumptions)	50 MW Requested								
Next Constraint for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	Single Deduction	Minimum Level of Service Attainable (MW) *This would be the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew	Shared Deduction	Maximum level of service Attainable (MW) *This would be the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction	Max DF	Projects Associated With NRIS Constraint	NRIS Cost Allocated to Project	Total NRIS Cost of Upgrade	Notes
699360 NLK GV T 138 699267 BRLGTN1 138 1	422.33	0	27.06	22.94	0.0802	J1042, J1188	$575,977	$10,692,501	
699086 ELK 138 138 699085 NLG 138 138 1	329.22	0	329.22	0	0.0924	J1188	$535,277	$535,277	
698090 BOL 138 138 699086 ELK 138 138 1	132.38	0	132.38	0	0.0508	J1188	$194,895	$194,895	
699512 UNVRSTY 138 699357 MUKWONGO 138 1	203.74	0	26.05	23.95	0.0525	J1042, J1188	$574,008	$4,511,000	
699375 CRWFSH R 138 699283 CONCRD 4 138 1	177.47	0	20.5	29.5	0.0518	J1154, J1188	$247,384	$2,141,449	
699085 NLG 138 138 699360 NLK GV T 138 1	124.29	0	3.15	46.85	0.0581	J1042, J1188	$1,354	$53,430	
698884 JEFRSN5 138 699375 CRWFSH R 138 1	123.83	0	14.31	35.69	0.0518	J1154, J1188	$107,193	$927,904	
694106 ROR BUS1 138 699062 MRE 138 138 1	68.32	0	68.32	0	0.0896	J1188	$2,467,049	$2,467,049	
		50		50					

8.3 Network Upgrade Alternatives Considered

All but one of the NRIS network upgrades identified in Table 8.1-2 are direct upgrades of the constraint facilities to ATC, DPC, and XCEL design standards and considered as least-cost solutions at this point. Therefore, no other alternatives were examined.

For the Concord – Bark River 138 kV new line, ATC will consider other alternatives in Phase 3.

9.0 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 System Impact Study report date. The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

9.1 ERIS Network Upgrades Proposed for Apr 18 DPP Phase 2 Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the ERIS analysis. The ERIS network upgrades include thermal network upgrades and voltage support network upgrades identified in the steady-state analysis, stability network upgrades identified in the dynamic stability analysis, short circuit network upgrades identified in the short circuit analysis. EMT stability network upgrades identified in the PSCAD analysis and network upgrades identified in the affected system analysis. For DPP April 2018 East (ATC) Phase 2 group, the total costs of ERIS network upgrades for the 2023 scenario are summarized in Tables 9.1-1, 9.1-2, 9.1-3, 9.1-4, 9.1-5, 9.1-6 and 9.1-7.

Table 9.1-1 – ERIS Network Upgrades Identified in Steady State Analysis

Steady-State Injection Constraint	Facility Owner	Network Upgrade	ISD (For Cost Estimate Only)	Cost ($)[1,2,3]
Sand Lake 138/69 kV transformer	ATC	Sand Lake 138/69 kV transformer, replacement	09/01/2020	3,105,696
Wautoma 138/69 kV transformer	ATC	Wautoma 138/59 kV transformer, replacement	09/01/2020	2,859,187
J986 POI – Port Edwards 138 kV line	ATC	J986 POI – Port Edwards 138 kV line, uprate	09/01/2020	584,677
Lublin – Lublin Pump 69 kV line	DPC	Lublin – Lublin Pump 69 kV line, uprate	09/01/2021	364,865
Lublin Tap – Lublin Pump 69 kV line	DPC	Lublin Tap – Lublin Pump 69 kV line, uprate	09/01/2021	4,135,135
Stone Lake 345/161 kV transformer	XCEL	Stone Lake 345/161 kV transformer, replacement	09/01/2021	3,757,200[4]
Overvoltage on J1085/J1121 POI – Stone Lake 345 kV line	ATC	J1085/J1121 POI – Stone Lake 345 kV, Move the existing 75 Mvar line-connected reactor from Gardner Park to J1085/J1121 POI	09/01/2021	N/A[5]

[1] All Network Upgrades were estimated on the earliest ISD dollars of responsible generator.
[2] ATC Network Upgrades included a 10% contingency.
[3] No contingency was included for the Stone Lake transformer upgrade project according to Xcel Energy.
[4] Cost Estimate is the APR-18 ERIS cost ($7,655,700) minus the AUG-17 NRIS cost ($3,898,500) to replace the transformer
[5] The cost of this project was included in the Interconnection Facilities cost, due to construction needs.

Table 9.1-2 – ERIS Network Upgrades in Dynamic Stability Analysis

Constraint	Facility Owner	Network Upgrade	Cost ($)
None	-	-	-

Table 9.1-3 – ERIS Network Upgrades in Short Circuit Analysis (Part 1 – Substations Under MISO Functional Control)

Substation	Facility Owner	Tenants for Joint Use Substations	Total Cost ($)
BARK RIVER	We Energies	ATC	220,000
BUTTERNUT	We Energies	ATC	220,000
CHAFFEE CREEK	ATC	-	220,000
CONCORD SW YD	We Energies	ATC	550,000
ELKHORN[1]	ATC	City of Elkhorn	220,000
HANCOCK	Alliant	ATC	220,000
HOLLYWOOD	Alliant	ATC	220,000
NORTH LAKE GENEVA	ATC	Alliant	220,000
PORT EDWARDS	ATC	Alliant	220,000
ROEDER	Alliant	ATC	220,000
SAND LAKE	ATC	-	220,000
SARATOGA	ATC	Alliant	220,000
SHEEPSKIN	ATC	Alliant	220,000

WAUTOMA	ATC	Alliant	220,000

[1]Elkhorn Substation was identified for potential grounding upgrade in DPP Aug-17 Phase 3 System Impact Study.

Table 9.1-4 – ERIS Affected System Network Upgrades (Part 2 – Affected System)

Substation	Facility Owner	Total Cost ($)
ACEC HANCOCK	Adams-Columbia Coop	220,000
ACEC RICHFORD	Adams-Columbia Coop	220,000
ACEC WAUTOMA	Adams-Columbia Coop	220,000
ACEC WILD ROSE PUMP	Adams-Columbia Coop	220,000
BEAVER DAM 3RD ST	Alliant	220,000
CENTER ST	Alliant	220,000
DANA CORP	Alliant	220,000
PLAINFIELD (ALTE)	Alliant	220,000
SAUNDERS CREEK	Alliant	220,000
SILVER LAKE (ALTE)	Alliant	220,000
VULCAN CHEM	Alliant	220,000

Table 9.1-5 – ERIS Network Upgrades Identified in PSCAD Analysis

Electromagnetic Transient Instability Identified for the following generators	Facility Owner	Network Upgrade	ISD (For Cost Estimate Only)	Cost ($)
None	-	-	-	-

Table 9.1-6 – ERIS PJM Affected System Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
Rosecreans;B- Libertyville; B Ckt 1 345 kV line	ComEd	Upgrade Rosecreans;B- Libertyville; B Ckt 1 345 kV line	20,090,000
Zion Sta;B- Waukegan;B 345 kV line	ComEd	Upgrade Zion Sta;B- Waukegan;B 345 kV line	19,500,000
Zion Sta;0B- Waukegan;R 345 kV line	ComEd	Upgrade Zion Sta;0B- Waukegan;R 345 kV line	23,300,000
Libertyville; B –P HTS; 117 B 345 Ckt 1 line	ComEd	Upgrade Libertyville; B –P HTS; 117 B 345 Ckt 1 line	5,500,000
Libertyville; R –P HTS; 117 R 345 Ckt 1 line	ComEd	Upgrade Libertyville; R –P HTS; 117 R 345 Ckt 1 line	9,300,000
Crete;EC- 17ST John 345 kV Ckt 1 (1)	ComEd	Upgrade Crete;EC- 17ST John 345 kV Ckt 1 (1)	150,000
Crete;EC- 17ST John 345 kV Ckt 1 (2)	ComEd	Upgrade Crete;EC- 17ST John 345 kV Ckt 1 (2)	143,000
East Frankford – Crete EC;B	ComEd	Upgrade East Frankford – Crete EC;B	668,000

Table 9.1-7 – ERIS Shared Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
None	-	-	-

9.2 NRIS Network Upgrades Proposed for Apr 18 DPP Phase 2 Projects

Network upgrades for Network Resource Interconnection Service (NRIS) were identified in the MISO's deliverability analysis and listed in the Table 9.2-1 below.

Table 9.2-1 – NRIS Network Upgrades Identified

Network Upgrade	Facility Owner	ISD (For Cost Estimate Only)[1]	Cost Used for NRIS Cost Allocation ($)[2]
Concord - Bark River 138 kV, New Line	ATC	4/01/2021	31,742,736
Jefferson - Crawfish River 138 kV, Uprate	ATC	8/31/2021	927,904
Crawfish River - Concord 138 kV, Uprate	ATC	8/31/2021	2,141,449
Stone Lake - Washco 161 kV, Rebuild	DPC	9/01/2021	19,000,000
Rock River - Marine 138 kV, Partial Rebuild	ATC	8/31/2021	2,467,049
Bristol - Elkhorn 138 kV, Uprate	ATC	8/31/2021	194,895
North Lake Geneva - North Lake Geneva Tap 138 kV, Uprate	ATC	8/31/2021	53,430
Elkhorn - North Lake Geneva 138 kV, Uprate	ATC	8/31/2021	535,277
North Fond du Lac - Aviation 138 kV, Partial Rebuild	ATC	8/01/2021	7,086,740
North Lake Geneva Tap - Burlington 138 kV, Rebuild	ATC	8/31/2021	10,412,118
University - Mukwonago 138 kV, Partial Rebuild[3]	ATC	8/31/2021	4,511,000

[1]All Network Upgrades were estimated on the earliest ISD dollars of responsible generators.
[2]ATC Network Upgrades included a 10% contingency.
[3]Cost is based on rebuilding section of line; network upgrade facility study may show that structures do not need to be replaced which would result in a lower cost for the project.

9.3 Cost Allocation Methodology for Thermal Network Upgrades

The costs of Network Upgrades (NU) for a set of generation projects (one or more subgroups or entire group with identified NU) are based off the MW impact of the worst-case scenario for each specific generator project. Basically, whatever the highest MW impact (increasing flow) is for that particular generator where the constraint is identified and requires NU is how it should be calculated.

Constraints which are mitigated by one or a subset of NU are identified. The highest MW contribution on these constraints from each generating facility is calculated in the MISO DPP study models 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:

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

9.4 Cost Estimating and Allocation Methodology for Short Circuit Upgrades

For each breaker shown to be loaded above 100% of rating a new breaker will be scoped and the cost of that upgrade will be assigned by to generators based on the MW impact provided from each generator for the worst case loading of the breaker.

For each ATC substation that shows a bus having fault current (SLG) increased by 10% or more, ATC will perform detailed grounding grid analysis if in-house grounding grid modeling is available at the time of the study. For the substations that pass the detailed grounding analysis (i.e. meet the safety criteria), they will be removed from the cost allocation process. For the remaining substations, costs are assigned for ground grid upgrades at that substation.

Only one cost estimate is scoped per substation regardless of the number of buses at that substation that show a 10% or greater increase in fault current. The largest fault current value at a substation in the After Case will determine the ground grid upgrade costs. If the largest fault current is above 20 kA, the upgrades are assigned a cost estimate of $550,000. If the largest fault current is at or below 20 kA, the upgrades are assigned a cost estimate of $220,000 for ground grid upgrades only.

Once costs are determined, they are allocated proportionally to study generators that have a greater than 3% of the total of all current queue study generator contributing fault currents under the single line-ground short circuit fault simulation at the identified substation, requiring potential grounding grid upgrades.

This methodology is applied to both ATC and non-ATC facilities modeled in ATC Protection models. For non-ATC facilities, it is interconnection customer's responsibility to work with facility owners to further refine costs, and implementation of the mitigation projects (if needed). These are placeholder costs until facility studies are performed. Based on those results, costs are adjusted.

9.5 Cost Allocation Tables

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 issued date of the System Impact Study report.

Assuming all generating facilities in the DPP 2018 April East (ATC) Phase 2 group advance, Table 9.5-1, Table 9.5-2, Table 9.5-3, Table 9.5-4, Table 9.5-5, and Table 9.5-6 show how the costs for ERIS steady-state Network Upgrades, short-circuit Network Upgrades, EMT stability Network Upgrades, PJM affected system Network Upgrades and NRIS Network Upgrades allocated to responsible generating facilities.

Table 9.5-1 – ERIS Steady-State Thermal Network Upgrade Costs Allocated to Each Generation Project

Required ERIS Network Upgrades	Worst MW Impact, % Cost Allocation				Total MW Impact	Cost Allocation ($)			
	J986	J1002	J1085	J1121		J986	J1002	J1085	J1121
Sand Lake 138/69 kV transformer, replacement	26.61, 100.00	-	-	-	26.61	3,105,696	-	-	-
Wautoma 138/59 kV transformer, replacement	29.00, 51.83	26.95, 48.17	-	-	55.95	1,481,952	1,377,235	-	-
J986 POI – Port Edwards 138 kV line, uprate	110.76, 73.85	39.22, 26.15	-	-	149.98	431,785	152,892	-	-
Lublin – Lublin Pump 69 kV line, uprate	-	-	2.54, 75.00	0.85, 25.00	3.38	-	-	273,649	91,216
Lublin Tap – Lublin Pump 69 kV line, uprate	-	-	2.54, 75.00	0.85, 25.00	3.38	-	-	3,101,351	1,033,784
Stone Lake 345/161 kV transformer, replacement[1]	-	-	134.61, 75.00	44.87, 25.00	179.48	-	-	2,817,900	939,300
Total ERIS Steady State Thermal Network Upgrade Cost ($) Allocated to Each Generator						**5,019,433**	**1,530,127**	**6,192,900**	**2,064,300**

Table 9.5-2 – ERIS Short-Circuit Network Upgrade Costs Allocated to Each Generation Project (Part 1 – Substations Under MISO Functional Control)

SUBSTATION	Facility Owner	Total Cost ($)	ERIS Short Circuit Network Upgrades Allocated to Each Generation Project																	
			J986	J1000	J1002	J1003	J1009	J1010	J1011	J1042	J1051	J1053	J1085	J1101	J1121	J1153	J1154	J1171	J1183	J1188
HANCOCK	Alliant	$220,000	$106,649	$0	$113,351	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
HOLLYWOOD	Alliant	$220,000	$206,997	$0	$13,003	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ROEDER	Alliant	$220,000	$42,607	$0	$154,140	$23,253	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CHAFFEE CREEK	ATC	$220,000	$82,669	$0	$137,331	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ELKHORN	ATC	$220,000	$0	$0	$0	$0	$0	$0	$0	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NORTH LAKE GENEVA	ATC	$220,000	$0	$0	$0	$0	$0	$0	$0	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PORT EDWARDS	ATC	$220,000	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SAND LAKE	ATC	$220,000	$113,018	$0	$106,982	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SARATOGA	ATC	$220,000	$198,457	$0	$21,543	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SHEEPSKIN	ATC	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$220,000
WAUTOMA	ATC	$220,000	$50,381	$0	$169,619	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BARK RIVER	We Energies	$220,000	$0	$0	$0	$0	$7,486	$19,659	$16,831	$0	$21,216	$154,809	$0	$0	$0	$0	$0	$0	$0	$0
BUTTERNUT	We Energies	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,082	$0	$0	$0	$0	$0	$207,918	$0	$0
CONCORD SW YD	We Energies	$550,000	$0	$0	$0	$0	$0	$0	$0	$0	$64,090	$467,654	$0	$0	$0	$0	$18,256	$0	$0	$0
Total ERIS Short Circuit NU Cost ($) Allocated to Each Generator			**$1,020,779**	**$0**	**$715,969**	**$23,253**	**$7,486**	**$19,659**	**$16,831**	**$440,000**	**$85,306**	**$634,545**	**$0**	**$0**	**$0**	**$0**	**$18,256**	**$207,918**	**$0**	**$220,000**

Note: Elkhorn Substation was identified for potential grounding upgrade in DPP Aug-17 Phase 3 system impact study.

Table 9.5-3 – ERIS Short-Circuit Network Upgrade Costs Allocated to Each Generation Project (part 2 – Affected System)

SUBSTATION	Facility Owner	Total Cost ($)	ERIS Short Circuit Network Upgrades Allocated to Each Generation Project																	
			J986	J1000	J1002	J1003	J1009	J1010	J1011	J1042	J1051	J1053	J1085	J1101	J1121	J1153	J1154	J1171	J1183	J1188
ACEC HANCOCK	Adams-Columbia Coop	$220,000	$106,649	$0	$113,351	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACEC RICHFORD	Adams-Columbia Coop	$220,000	$68,551	$0	$151,449	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACEC WAUTOMA	Adams-Columbia Coop	$220,000	$50,543	$0	$169,457	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACEC WILD ROSE PUMP	Adams-Columbia Coop	$220,000	$50,753	$0	$169,247	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BEAVER DAM 3RD ST	Alliant	$220,000	$0	$0	$0	$209,557	$0	$0	$0	$0	$0	$10,443	$0	$0	$0	$0	$0	$0	$0	$0
CENTER ST	Alliant	$220,000	$0	$0	$7,096	$200,771	$0	$0	$0	$0	$0	$12,133	$0	$0	$0	$0	$0	$0	$0	$0
DANA CORP	Alliant	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$220,000
PLAINFIELD (ALTE)	Alliant	$220,000	$112,962	$0	$107,038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SAUNDERS CREEK	Alliant	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$220,000
SILVER LAKE (ALTE)	Alliant	$220,000	$50,364	$0	$169,636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VULCAN CHEM	Alliant	$220,000	$220,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total ERIS Short Circuit NU Cost ($) Allocated to Each Generator			**$659,824**	**$0**	**$887,272**	**$410,328**	**$0**	**$0**	**$0**	**$0**	**$0**	**$22,576**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$440,000**

Table 9.5-4 – ERIS EMT Stability Network Upgrade Costs Allocated to Each Generation Project

None

Table 9.5-5 – PJM Affected System Costs Allocated to Each Generation Project

Network Upgrade	Total Cost ($)	PJM Affected System Costs Allocated to Each Generation Project ($)																	
		J986	J1000	J1002	J1003	J1009	J1010	J1011	J1042	J1051	J1053	J1085	J1101	J1121	J1153	J1154	J1171	J1183	J1188
Upgrade Rosecreans;B- Libertyville; B Ckt 1 345 kV line	20,090,000	0	0	0	0	4,500,000	4,390,000	4,390,000	1,260,000	0	1,400,000	1,230,000	0	1,030,000	1,220,000	0	670,000	0	0
Upgrade Zion Sta;B- Waukegan;B 345 kV line	19,500,000	0	0	0	0	0	0	8,418,000	0	0	3,974,000	0	0	2,969,000	4,139,000	0	0	0	0
Upgrade Zion Sta;0B- Waukegan;R 345 kV line	23,300,000	0	0	0	0	0	0	10,430,000	0	0	4,920,000	0	0	3,670,000	4,280,000	0	0	0	0
Upgrade Libertyville; B –P HTS; 117 B 345 Ckt 1 line	5,500,000	0	0	0	0	0	0	0	0	0	0	1,110,000	0	2,080,000	2,310,000	0	0	0	0
Upgrade Libertyville; R –P HTS; 117 R 345 Ckt 1 line	9,300,000	0	0	0	0	1,550,000	2,130,000	2,130,000	690,000	0	810,000	760,000	0	600,000	630,000	0	0	0	0
Upgrade Crete;EC- 17ST John 345 kV Ckt 1 (1)	150,000	0	0	0	0	0	0	0	0	0	0	150,000	0	0	0	0	0	0	0
Upgrade Crete;EC- 17ST John 345 kV Ckt 1 (2)	143,000	0	0	0	0	0	0	0	0	0	0	143,000	0	0	0	0	0	0	0
Upgrade East Frankford – Crete EC;B	668,000	0	0	0	0	0	0	0	0	0	0	668,000	0	0	0	0	0	0	0
Total Network Upgrade Costs (millions of $):	**78,651,000**	0	0	0	0	**6,050,000**	**6,520,000**	**25,368,000**	**1,950,000**	0	**11,104,000**	**4,061,000**	0	**10,349,000**	**12,579,000**	0	**670,000**	0	0

Table 9.5-6 – NRIS Network Upgrade Costs Allocated to Each Generation Project, Part 1

Required NRIS Network Upgrades	Worst MW Impact and % Cost Allocation Details Provided by MISO								
	J1003	J1042	J1051	J1053	J1085	J1121	J1154	J1171	J1188
Concord - Bark River 138 kV, New Line	15.06, 2.55	-	102.97, 17.43	411.80, 69.69	-	-	61.06, 10.33	-	-
Jefferson - Crawfish River 138 kV, Uprate	-	-	-	-	-	-	19.83, 88.45	-	2.59, 11.55
Crawfish River - Concord 138 kV, Uprate	-	-	-	-	-	-	19.83, 88.45	-	2.59, 11.55
Stone Lake - Washco 161 kV, Rebuild	-	-	-	-	75.84, 60.00	50.56, 40.00	-	-	-
Rock River - Marine 138 kV, Partial Rebuild	-	-	-	-	-	-	-	-	100%
Bristol - Elkhorn 138 kV, Uprate	-	-	-	-	-	-	-	-	100%
North Lake Geneva - North Lake Geneva Tap 138 kV, Uprate	-	111.94, 97.47	-	-	-	-	-	-	2.91, 2.53
Elkhorn - North Lake Geneva 138 kV, Uprate	-	-	-	-	-	-	-	-	100%
North Fond du Lac - Aviation 138 kV, Partial Rebuild	4.75, 28.07	-	-	-	-	-	-	12.17, 71.93	-
North Lake Geneva Tap - Burlington 138 kV, Rebuild	-	68.48, 94.47	-	-	-	-	-	-	4.01, 5.53
University - Mukwonago 138 kV, Partial Rebuild	-	17.97, 87.28	-	-	-	-	-	-	2.62, 12.72

Table 9.5-6 – NRIS Network Upgrade Costs Allocated to Each Generation Project, Part 2

Required NRIS Network Upgrades	Cost Allocation ($)								
	J1003	J1042	J1051	J1053	J1085	J1121	J1154	J1171	J1188
Concord - Bark River 138 kV, New Line	809,026	-	5,531,570	22,121,983	-	-	3,280,156	-	-
Jefferson - Crawfish River 138 kV, Uprate	-	-	-	-	-	-	820,711	-	107,193
Crawfish River - Concord 138 kV, Uprate	-	-	-	-	-	-	1,894,065	-	247,384
Stone Lake - Washco 161 kV, Rebuild	-	-	-	-	11,400,000	7,600,000	-	-	-
Rock River - Marine 138 kV, Partial Rebuild	-	-	-	-	-	-	-	-	2,467,049
Bristol - Elkhorn 138 kV, Uprate	-	-	-	-	-	-	-	-	194,895
North Lake Geneva - North Lake Geneva Tap 138 kV, Uprate	-	52,076	-	-	-	-	-	-	1,354
Elkhorn - North Lake Geneva 138 kV, Uprate	-	-	-	-	-	-	-	-	535,277
North Fond du Lac - Aviation 138 kV, Partial Rebuild	1,989,481	-	-	-	-	-	-	5,097,259	-
North Lake Geneva Tap - Burlington 138 kV, Rebuild	-	9,836,141	-	-	-	-	-	-	575,977
University - Mukwonago 138 kV, Partial Rebuild	-	3,936,992	-	-	-	-	-	-	574,008
Total NRIS Network Upgrade Cost ($) Allocated To Each Generator	**2,798,507**	**13,825,209**	**5,531,570**	**22,121,983**	**11,400,000**	**7,600,000**	**5,994,932**	**5,097,259**	**4,703,137**

10.0 AVAILABLE APPENDIX DOCUMENTS (NOT ATTACHED)

Appendix A – Study Criteria, Methodology, and Assumptions

Appendix B – ATC Planning Criteria and Generation Facility Interconnection Guide

Appendix C – Interconnection Facility Project Diagrams

Appendix D – Network Upgrade Project Diagrams
Note: Project Diagrams were not developed for line uprate projects.

Appendix E – Steady State Power Flow Results

Appendix F – Steady State Operating Restriction Study Results

Appendix G – Dynamic Stability Results

Appendix H – PJM Affected System Study Results

Appendix I – MISO Deliverability Study Results

Appendix J – Assessed System Performance Reference

Appendix K – J1085/J1121 Additional Studies

Appendix L – PSCAD Study Results

Appendix M – Conditions to GIA