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August 14, 2019

Dan Wolf
Executive Secretary
Public Utilities Commission
121 – 7th Place East, Suite 350
St. Paul, MN 55101

eFiled and eServed

RE: Dodge County Wind request for Suspension and Withdrawal
Suspension: PUC Dockets IP-6981/CN-17-306; IP-6981/WS-17- 307
Withdraw: PUC Docket IP-6981/TL-17-308

Dear Mr. Wolf:

Attached please find MISO DPP 2017 February West Area Phase 2 Study, released July 19, 2019.

I'm sending this comment as an individual, and not in the course of representation of any party. Moments ago, I received notice of the applicant's request to suspend the CoN and wind site permit proceedings, and its request to withdraw the application for transmission for the project (Docket IP-6981/TL-17-308).

Mindful of my prior comments regarding the size and type of transmission requested, that it's oversized and radial, and mindful of Commissioner Schuerger's comments at the most recent Commission meeting regarding the appropriateness of the 345kV transmission proposed, I believe the record should include the MISO study triggering the applicants' August 9, 2019 withdrawal of its MISO queue position J441 and today's requests for suspension and withdrawal. Thus, it's attached for your review and consideration.

Please let me know if you have any questions or require anything further.

Very truly yours,

Carol A. Overland
Attorney at Law

Siemens PTI Report R062-19

MISO DPP 2017 February West Area Phase 2 Study

Prepared for

MISO

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07/19/2019

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Revision History

Date	Rev.	Description
6/7/2019	A	Draft Report
7/1/2019	B	Incorporate SPP affected system analysis results
7/19/2019	C	Final Report

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Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate interconnection of the DPP 2017 February Phase 2 West Area Group (DPP West Area) generating facilities.

1.1 Project List

The DPP West Area study group has twelve generation projects with a combined nameplate rating of 1394 MW. The DPP West Area generating facilities are listed in Table ES-1. The modeling details and projects' slider diagrams are shown in Appendix B.

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

MISO Project #	Service Type	TO	County	State	Point Of Interconnection	Fuel Type	Max Output	SH MW	SPK MW	Stability MW
J441	NRIS	SMMPA	Dodge	MN	Byron 345 kV	Wind	170	170	26.52	170
J570	NRIS	MEC	Atchison	MO	Cooper-Atchison 345 kV	Wind	150	150	23.4	150
J718	NRIS	DPC	Fillmore	MN	Cherry Grove 69 kV	Solar	49.98	24.99	49.98	49.98
J721	NRIS	OTP	Codington, Deuel	SD	Big Stone South 345 kV	Wind	200	200	31.2	200
J739	NRIS	Xcel	Lyon	MN	Lyon County 345 kV	Wind	200	200	31.2	200
J741	NRIS	MDU	Emmons, Logan	ND	Wishek-Linton 115 kV	Wind	50.4	50.4	7.86	50.4
J746	NRIS	GRE	McHenry, McLean, Ward	ND	Stanton-McHenry 230 kV	Wind	200	200	31.2	200
J748	NRIS	MEC	Plymouth	IA	O'Brien-Raun 345 kV	Wind	200	200	31.2	200
J767	NRIS	ITCM	Hancock	IA	Lime Creek 161 kV sub	Wind	12	12	1.87	12
J768	NRIS	ITCM	Story	IA	Story Co 161 kV sub	Wind	12	12	1.87	12
J777	NRIS	ITCM	Franklin	IA	Whispering Willow 161 kV	Wind	99	99	15.44	99
J779	NRIS	MDU	Emmons, Logan	ND	Bismarck-Linton 115 kV	Wind	50.4	50.4	7.86	50.4

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

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

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

The reactive power requirement analysis results are summarized as following:

- J746 and J768 do not satisfy FERC Order 827 reactive power requirements.
- All other non-synchronous generation projects satisfy FERC Order 827 reactive power requirements.

1.3 Total Network Upgrades for all Projects

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

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

Project Num	ERIS Network Upgrades ($)													NRIS Network Upgrades ($)	Interconnection Substation TO NUs ($)	TO's Interconnection Facilities (TOIF)	SNU ($)	Total Network Upgrade Cost (Exclude TOIF & Affected System) ($)	M2 Received ($)	M3 Received ($)	M4 ($)
	Base Case NUs	MWEX Voltage Stability	MISO Thermal & Voltage	Transient Stability	Short Circuit	DPC LPC	GRE LPC	MDU LPC	OTP LPC	CIPCO AFS	MPC AFS	PJM AFS	SPP AFS								
J441	$83,439,491	$0	$1,384,598	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,991,390	$0	$1,652,226	$1,237,127	$0	$86,476,316	$1,211,664	$6,463,124	$9,620,475
J570	$58,038,260	$0	$19,295,335	$0	$0	$0	$13,490,609	$0	$0	$0	$0	$0	$304,458,010	$0	$12,500,000	$825,000	$0	$103,324,205	$809,119	$5,111,655	$14,744,067
J718	$0	$0	$146,132	$0	$0	$4,510,000	$0	$0	$0	$0	$0	$0	$9,910,878	$0	$1,300,000	$500,000	$0	$5,956,132	$198,577	$770,706	$221,943
J721	$21,610,679	$0	$41,923,164	$0	$0	$0	$12,949,076	$0	$0	$0	$0	$0	$73,577,740	$0	$1,000,000	$1,000,000	$16,629,571	$94,112,490	$1,753,858	$30,340,729	$0
J739	$20,432,410	$0	$47,616,313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$51,198,394	$0	$1,200,000	$3,000,000	$0	$69,248,723	$1,767,858	$15,646,019	$0
J741	$5,378,954	$0	$3,523,127	$0	$0	$0	$51,407,509	$3,410,166	$0	$0	$0	$0	$19,669,752	$3,133,654	$2,500,000	$450,000	$12,410,330	$81,763,740	$510,000	$6,395,895	$9,446,853
J746	$20,810,409	$0	$12,445,373	$0	$0	$0	$387,184,067	$419,106	$0	$0	$500,000	$0	$77,545,832	$1,966,940	$5,700,000	$475,000	$0	$428,525,894	$1,591,858	$29,883,222	$54,230,099
J748	$32,725,910	$0	$16,076,295	$0	$0	$0	$10,725,690	$0	$0	$0	$0	$0	$107,340,761	$0	$12,500,000	$825,000	$0	$72,027,895	$1,859,858	$7,369,538	$5,176,183
J767	$23,546,718	$0	$246,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,381,494	$0	$0	$0	$0	$23,793,418	$120,000	$1,817,232	$2,821,452
J768	$31,993,067	$0	$1,363,765	$0	$0	$0	$199,818	$0	$0	$0	$0	$0	$3,608,177	$0	$0	$0	$0	$33,556,651	$120,000	$648,980	$5,942,351
J777	$197,658,739	$0	$3,583,573	$0	$0	$0	$0	$0	$0	$1,000,000	$0	$0	$24,389,277	$7,460,000	$425,000	$350,000	$0	$209,127,312	$877,429	$5,949,754	$34,998,279
J779	$5,421,863	$0	$3,106,424	$0	$0	$0	$88,163,229	$170,728	$0	$0	$0	$0	$62,817,503	$699,407	$2,500,000	$450,000	$0	$100,061,651	$510,931	$6,917,580	$12,583,819
Total ($)	**$501,056,500**	**$0**	**$150,710,800**	**$0**	**$0**	**$4,510,000**	**$564,120,000**	**$4,000,000**	**$0**	**$1,000,000**	**$500,000**	**$0**	**$795,889,208**	**$13,260,000**	**$41,277,226**	**$9,112,127**	**$29,039,901**	**$1,307,974,427**	**$11,331,152**	**$117,314,432**	**$149,785,522**

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

1.4 Per Project Summary

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

1.4.1 J441 Summary

Network Upgrade	Cost	J441	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$83,439,491	Base Case NU Webster-Franklin-Morgan Valley 345 kV
Wabaco-Rochester 161 kV[1]	$11,000,000	$0	MISO SH
Wabaco-Alma 161 kV	$100,000	$100,000	MISO SH
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$631,187	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$653,412	MISO Reactive Power
Upgrade related to Cooper	$625,292,807	$33,991,390	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$118,815,480**	

Note 1: J441 will assume cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.2 J570 Summary

Network Upgrade	Cost	J570	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$58,038,260	Base Case NU Webster-Franklin-Morgan Valley 345 kV
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$8,267	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$395,147	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$18,660,866	MISO Reactive Power

Network Upgrade	Cost	J570	NUs Type
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$170,020	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$31,195	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$29,841	MISO Reactive Power
GRE LPC Voltage NU	$564,120,000	$13,490,609	GRE LPC
Upgrade related to Cooper	$625,292,807	$304,458,010	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$395,282,215**	

1.4.3 J718 Summary

Network Upgrade	Cost	J718	NUs Type
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$96,294	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$49,838	MISO Reactive Power
Harmony-Harmony Municipal 69 kV	$10,000	$10,000	DPC LPC
Lime Springs Tap-Cherry Grove 69 kV	$2,100,000	$2,100,000	DPC LPC
Lime Springs Tap-Granger 69 kV	$2,400,000	$2,400,000	DPC LPC
Upgrade related to Cooper	$625,292,807	$9,910,878	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$14,567,010**	

1.4.4 J721 Summary

Network Upgrade	Cost	J721	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$21,610,679	Base Case NU Webster-Franklin-Morgan Valley 345 kV
Big Stone-Big Stone South 230 kV #1	$1,450,000	$1,450,000	MISO SH
Big Stone-Big Stone South 230 kV #2	$1,400,000	$1,400,000	MISO SH
Big Stone-Blair 230 kV	$28,235,800	$28,235,800	MISO SH
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$1,563,880	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$649,193	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$7,139,758	MISO Reactive Power

Network Upgrade	Cost	J721	NUs Type
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$567,341	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$441,950	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$475,242	MISO Reactive Power
GRE LPC Voltage NU	$564,120,000	$12,949,076	GRE LPC
Johnson Jct-Morris 115 kV (SNU)	$9,716,856	$5,283,328	SNU
Big Stone-Browns Valley 230 kV (SNU)	$285,086	$119,965	SNU
Big Stone-Blair 230 kV (SNU)	$150,183	$77,742	SNU
Hankinson-Wahpeton 230 kV (SNU, 2015Aug)	$400,000	$189,946	SNU
Hankinson-Wahpeton 230 kV (SNU, 2016Feb)	$1,050,000	$329,054	SNU
Johnson Jct-Ortonville 115 kV (SNU)	$16,850,000	$9,161,819	SNU
Big Stone 230-115-13.8 kV xfmr (SNU)	$3,250,000	$1,467,717	SNU
Upgrade related to Cooper	$625,292,807	$47,660,105	SPP AFS
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936	$7,737,888	SPP AFS
Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173	$18,179,747	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$166,690,230**	

1.4.5 J739 Summary

Network Upgrade	Cost	J739	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$20,432,410	Base Case NU Webster-Franklin-Morgan Valley 345 kV
Helena-Chub Lake 345 kV	$31,500,000	$31,500,000	MISO SH
Willmar-Granite Falls 230 kV	$8,000,000	$8,000,000	MISO SH
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$105,401	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$645,742	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$5,661,802	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$600,628	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$480,770	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV	$1,000,000	$621,971	MISO Reactive Power

Network Upgrade	Cost	J739	NUs Type
(619940)			
Upgrade related to Cooper	$625,292,807	$46,944,033	SPP AFS
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936	$4,254,361	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$119,247,117**	

1.4.6 J741 Summary

Network Upgrade	Cost	J741	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$5,378,954	Base Case NU Webster-Franklin-Morgan Valley 345 kV
J741 POI-Wishek 115 kV	$475,000	$475,000	MISO SH
Hankinson-Forman 230 kV	$50,000	$50,000	MISO SH
Oakes-Forman 230 kV	NA	$0 [1]	MISO SH
Oakes-Ellendale 230 kV	NA	$0 [1]	MISO SH
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$288,521	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$151,491	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$1,808,539	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$136,810	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$107,286	MISO Reactive Power
3×50 MVAR switched cap bank at Buffalo 345 kV (620358)	$5,000,000	$429,931	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$75,548	MISO Reactive Power
J302&503 POI-Heskett 230 kV	$2,500,000	$2,500,000	MDU LPC
additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	$1,500,000	$910,166	MDU LPC
GRE LPC Voltage NU	$564,120,000	$51,407,509	GRE LPC
Oakes-Forman 230 kV (SNU, 2015 Aug)	$300,000	$42,239	SNU
Oakes-Forman 230 kV (SNU, 2016 Feb)	$950,000	$158,460	SNU
Oakes-Forman 230 kV (SNU, Merricourt)	$112,750	$23,140	SNU
Oakes-Forman 230 kV (SNU, DPP 2016 Aug)	$19,900,000	$5,001,348	SNU
Oakes-Ellendale 230 kV (SNU, 2015 Aug)	$700,000	$97,901	SNU

Network Upgrade	Cost	J741	NUs Type
Oakes-Ellendale 230 kV (SNU, 2016 Feb)	$1,650,000	$273,844	SNU
Oakes-Ellendale 230 kV (SNU, 2016Aug)	$20,500,000	$5,322,211	SNU
J302&503 POI-Heskett 230 kV (SNU)	$9,000,000	$1,491,187	SNU
Wishek-Merricourt 230 kV (NRIS)	$5,800,000	$3,133,654	NRIS
Upgrade related to Cooper	$625,292,807	$12,381,657	SPP AFS
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936	$2,000,946	SPP AFS
Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173	$5,287,149	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$98,933,492**	

Note 1: NU cost is assigned to DPP 2016 Aug. projects. J741 will assume 100% cost responsibility if the projects assigned for this NU cost in DPP 2016 Aug. cycle are withdrawn.

1.4.7 J746 Summary

Network Upgrade	Cost	J746	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$20,810,409	Base Case NU Webster-Franklin-Morgan Valley 345 kV
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$558,530	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$6,951,870	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$526,376	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$418,061	MISO Reactive Power
3×50 MVAR switched cap bank at Buffalo 345 kV (620358)	$5,000,000	$3,795,586	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$194,951	MISO Reactive Power
additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	$1,500,000	$419,106	MDU LPC
GRE LPC Voltage NU	$564,120,000	$387,184,067	GRE LPC
Wishek-Merricourt 230 kV (NRIS)	$5,800,000	$1,966,940	NRIS
Sweetwater-Langdon 115 kV line	$500,000	$500,000	MPC AFS
Upgrade related to Cooper	$625,292,807	$48,651,589	SPP AFS
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936	$7,437,741	SPP AFS
Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173	$21,456,502	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$500,871,726**	

1.4.8 J748 Summary

Network Upgrade	Cost	J748	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$32,725,910	Base Case NU Webster-Franklin-Morgan Valley 345 kV
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$19,568	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$1,113,608	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$13,903,739	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$607,723	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$383,933	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$47,723	MISO Reactive Power
GRE LPC Voltage NU	$564,120,000	$10,725,690	GRE LPC
Upgrade related to Cooper	$625,292,807	$53,374,911	SPP AFS
Rebuild Tekamah - S1226 161 kV circuit 1	$19,431,803	$19,431,803	SPP AFS
Rebuild Raun - Tekamah 161 kV circuit 1	$34,534,047	$34,534,047	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$166,868,656**	

1.4.9 J767 Summary

Network Upgrade	Cost	J767	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$23,546,718	Base Case NU Webster-Franklin-Morgan Valley 345 kV
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$91,307	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$55,124	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$58,587	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$41,682	MISO Reactive Power
Upgrade related to Cooper	$625,292,807	$27,381,494	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$51,174,912**	

1.4.10 J768 Summary

Network Upgrade	Cost	J768	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$31,993,067	Base Case NU Webster-Franklin-Morgan Valley 345 kV
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$16,381	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$1,312,053	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$30,469	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$4,863	MISO Reactive Power
GRE LPC Voltage NU	$564,120,000	$199,818	GRE LPC
Upgrade related to Cooper	$625,292,807	$3,608,177	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$37,164,828**	

1.4.11 J777 Summary

Network Upgrade	Cost	J777	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$197,658,739	Base Case NU Webster-Franklin-Morgan Valley 345 kV
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$233,187	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$2,624,638	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$442,262	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$283,487	MISO Reactive Power
Hazleton-Dundee 161 kV	$500,000	$500,000	CIPCO AFS
Liberty-Hickory Crk 161 kV	$500,000	$500,000	CIPCO AFS
Iowa Falls Industrial-Farm Tap 69 kV (NRIS)	$10,000	$10,000	NRIS
Iowa Falls Industrial 161-69 kV xfmr (NRIS)	$3,000,000	$3,000,000	NRIS
Wall Lake-Wright 161 kV (NRIS)	$500,000	$500,000	NRIS
Wright 161-69 kV xfmr (NRIS)	$1,750,000	$1,750,000	NRIS
Iowa Falls Industrial-Wellsburg 161 kV (NRIS)	$2,200,000	$2,200,000	NRIS
Upgrade related to Cooper	$625,292,807	$24,389,277	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$234,091,589**	

1.4.12 J779 Summary

Network Upgrade	Cost	J779	NUs Type
Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$5,421,863	Base Case NU Webster-Franklin-Morgan Valley 345 kV
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$14,363	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$145,415	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$1,881,612	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$132,304	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$103,524	MISO Reactive Power
3×50 MVAR switched cap bank at Buffalo 345 kV (620358)	$5,000,000	$774,484	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,000,000	$54,724	MISO Reactive Power
additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	$1,500,000	$170,728	MDU LPC
GRE LPC Voltage NU	$564,120,000	$88,163,229	GRE LPC
Wishek-Merricourt 230 kV (NRIS)	$5,800,000	$699,407	NRIS
Upgrade related to Cooper	$625,292,807	$12,541,286	SPP AFS
Rebuild Bismark - Hilken 230kV circuit 1	$22,290,721	$22,290,721	SPP AFS
Rebuild Bismark - Hilken 230kV circuit 2	$22,290,721	$22,290,721	SPP AFS
Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173	$5,694,775	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project		**$160,379,154**	

1.5 Study Compliance with NERC FAC-002-2 Standard

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

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

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

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

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

Section 5.2 covers reliability impact of the generating facilities per OTP Local Planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 5.3 covers reliability impact of the generating facilities per MDU Local Planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 5.4 covers reliability impact of the generating facilities per DPC Local Planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

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

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

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

Section 6.4 covers reliability impact of the new generating facilities in the SPP affected systems.

Section 7 covers transient stability analysis results.

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

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

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

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

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

Section 5.1 covers GRE Local Planning Criteria (LPC).

Section 5.2 covers OTP LPC.

Section 5.3 covers MDU LPC.

Section 5.4 covers DPC LPC.

Section 6.1 covers CIPCO system planning criteria.

Section 6.2 covers MPC system planning criteria.

Section 6.3 covers PJM system planning criteria.

Section 6.4 covers SPP system planning criteria.

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

Section 10 covers MISO system planning criteria.

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

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

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

Section 5.2 covers OTP's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.3 covers MDU's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.4 covers DPC's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

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

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

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

Section 6.4 covers SPP steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

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

Section 8 covers steady-state voltage stability assessment.

Section 9 covers short circuit assessment.

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

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

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

Jointly coordinated recommendations can be found in Section 5.1 (MISO and GRE), Section 5.2 (MISO and OTP), Section 5.3 (MISO and MDU), Section 5.4 (MISO and DPC), Section 6.1 (MISO and CIPCO), 6.2 (MISO and MPC), 6.3 (MISO and PJM), 6.4 (MISO and SPP), and Section 8 (MISO and ATC). Results in Section 3, 4, 5, 6, 7, 9 and 10 have also been reviewed by PJM, SPP, CIPCO, and MPC.

Section

1

Introduction

Twelve generation projects, listed in Table A-1 (Appendix A.1), have requested to interconnect to the MISO transmission network in the West Area and have advanced to the Definitive Planning Phase (DPP) 2017 February Phase 2 study (DPP West Area). All generating facilities have requested Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report presents the study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generating facilities in the DPP West Area Phase 2 study.

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

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Section

2

Model Development and Study Criteria

2.1 Model Development

2.1.1 Benchmark Cases

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

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

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

2.1.2 Study Cases

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

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

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

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

Location	Bus #	SVC Mvar
Post Rock 345 kV	530583	600
Mingo 345 kV	531451	350
St. Joseph 345 kV	541199	400

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

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

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

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

Interface	SH Case (MW)	SPK Case (MW)
MHEX	1072	1742
MWEX	1603	752
Arrowhead – Stone Lake 345 kV	655	274

2.2 Contingency Criteria

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

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

WPS (area 696), MGE (area 697), UPPC (area 698), CE (area 222), NPPD (area 640), OPPD (area 645), LES (area 650), WAPA (area 652), BEPC-SPP (area 659), AECI (area 330), MIPU (area 540), KCPL (area 541), KACY (area 542), INDN (area 545).
  - Multiple-element NERC Category P1 contingencies, in Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. The specified Category P1 contingency files are listed in Appendix A.7.
- NERC Category P2-P7 contingencies
  - Selected NERC Category P2-P7 contingencies provided by the Ad Hoc Study Group, in the study region of Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. The specified Category P2-P7 contingency files are listed in Appendix A.7.

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

2.3 Monitored Elements

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

Table 2-3: Monitored Elements

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

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

Notes

1: PSS®E Rate A, Rate B or Rate C

2: Limits dependent on nominal bus voltage

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

2.4 Performance Criteria

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

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

applicable rating and has DF greater than 5% (OTDF or PTDF) will be responsible for mitigating the cumulative MW impact constraint.

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

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

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

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

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

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

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

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

Step 1: Verify that the total dynamic reactive power (reactive power from generators and dynamic compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the generator terminal bus. The verification in Step 1 was performed when generator data was submitted and modeled.

Step 2: Verify that the total reactive power (reactive power from generators, dynamic compensation devices, and static compensation devices) in the plant can meet the reactive power range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. The testing procedure in Step 2 is described in the following:

- Lock the high-side of the generator substation at 1.0 pu voltage by adding a fictitious SVC. This is to ensure that the test result is not affected by system conditions.
- Lock the reactive power output of the generator at the maximum limit (Qmax). Make sure all shunt compensation devices within the substation are at the

maximum capacitive output. Adjust transformer taps to ensure bus voltages within the substation are within 0.95 – 1.05 pu range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify it satisfies the 0.95 lagging requirement.

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

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

- J746 and J768 do not satisfy FERC Order 827 reactive power requirements.
- All other non-synchronous generation projects satisfy FERC Order 827 reactive power requirements.

Section

3

Summer Peak Steady-State Analysis

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

3.1 Study Procedure

3.1.1 Computer Programs

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

3.1.2 Study Methodology

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

3.2 Summer Peak Contingency Analysis Results

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

3.2.1 System Intact Conditions

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

3.2.2 Post Contingency Conditions

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

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

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

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

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

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

Section

4

Summer Shoulder Steady-State Analysis

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

4.1 Study Procedure

A summer shoulder power flow case was created using the procedure described in Section 2.1. Due to low post-contingent voltages in the initial power flow case, steady-state analysis was performed in the following three-step procedure:

- Step 1: With fictitious SPP SVCs added to the case at Post Rock, Mingo, and St. Joseph (Table 2-1), a non-linear (AC) contingency analysis (Stage-1 ACCC) was performed to identify thermal and voltage constraints.
- Step 2: Based on the identified thermal and voltage constraints in the Stage-1 ACCC, project justification analysis was performed to determine Network Upgrades (NUs) required to interconnect the DPP West Area projects. These selected NUs are called Base Case NUs.
- Step 3: The Base Case NUs were added to the Stage-1 models to create Stage-2 models. Stage-2 ACCC was performed to identify any remaining thermal and voltage constraints.

4.2 Step 1 – Stage-1 ACCC Analysis

Fictitious SPP SVCs at Post Rock, Mingo, and St. Joseph (Table 2-1) were added to the Stage-1 summer shoulder case. The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows between benchmark case (without DPP West Area projects) and study case (with DPP West Area projects). Analysis was performed in the summer shoulder scenario using PSS®E and PSS®MUST.

4.2.1 Stage-1 System Intact Conditions

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

4.2.2 Stage-1 Post Contingency Conditions

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

For P1 contingencies in the summer shoulder scenario, thermal constraints are listed in Table E-2.

For P2-P7 contingencies in the summer shoulder scenario, thermal constraints are listed in Table E-3.

Non-converged contingencies are listed in Table E-4, and their dc thermal results are listed in Table E-5.

4.2.3 Worst Thermal Constraints in the Stage-1 ACCC

Table 4-1 lists the worst thermal constraints identified in the Stage-1 ACCC for the summer shoulder scenario.

Table 4-1: Shoulder Thermal Constraints, Maximum Screened Loading, Stage-1 ACCC

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
J741	J741 POI-Wishek 115 kV	44	MDU	48.0	109.2	CEII Redacted	P0
J570	St. Joseph-Cooper 345 kV	1195	NPPD GMO	1308.5	109.5	CEII Redacted	P0
J570,J739,J748, J768	St. Joseph-Cooper 345 kV	1195	NPPD GMO	1826.8	152.9	CEII Redacted	P1
J721	Split Rock-White 345 kV	717.1	XEL WAPA	851.8	118.8	CEII Redacted	P1
J721,J739	Split Rock-White 345 kV	717.1	XEL WAPA	875.5	122.1	CEII Redacted	P2-P7
J739	Helena-Chub Lake 345 kV	1792.6	XEL GRE	2029.9	113.2	CEII Redacted	P1
J739	Helena-Chub Lake 345 kV	1792.6	XEL GRE	2028.3	113.1	CEII Redacted	P2-P7
J739	Willmar-Granite Falls 230 kV	264.9	GRE WAPA	278.1	105.0	CEII Redacted	P1
J721	Big Stone-Big Stone South 230 kV #1	605	OTP	769.0	127.1	CEII Redacted	P1
J721	Big Stone-Big Stone South 230 kV #1	605	OTP	769.0	127.1	CEII Redacted	P2-P7
J721	Big Stone-Big Stone South 230 kV #2	605	OTP	770.2	127.3	CEII Redacted	P1
J721	Big Stone-Big Stone South 230 kV #2	605	OTP	770.2	127.3	CEII Redacted	P2-P7
J721	Big Stone-Blair 230 kV	582.7	OTP WAPA	706.2	121.2	CEII Redacted	P1

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
J721	Big Stone-Blair 230 kV	582.7	OTP WAPA	698.6	119.9	CEII Redacted	P2-P7
J741	Hankinson-Forman 230 kV	451.2	OTP	461.2	102.2	CEII Redacted	P1
J741	Oakes-Forman 230 kV	527	OTP	560.1	106.3	CEII Redacted	P1
J741	Oakes-Ellendale 230 kV	527	OTP MDU	569.4	108.0	CEII Redacted	P1
J768	Plaza-Marshalltown 161 kV	291	ITCM	297.1	102.1	CEII Redacted	P2-P7
J768	Plaza-Timber Creek 161 kV	291	ITCM	301.5	103.6	CEII Redacted	P2-P7
J777	Wellsburg-Iowa Falls Industrial 161 kV	262	ITCM	267.3	102.0	CEII Redacted	P2-P7
J777	Wellsburg-Marshalltown 161 kV	327	ITCM	356.2	108.9	CEII Redacted	P2-P7
J767	Lime Creek 161 kV bus tie	335	ITCM	366.5	109.4	CEII Redacted	P1
J767	Lime Creek 161 kV bus tie	335	ITCM	601.6	179.6	CEII Redacted	P2-P7
J767	Emery-Lime Creek 161 kV #2	330	ITCM	363.8	110.2	CEII Redacted	P2-P7
J767	Killdeer 345-161 kV xfmr	446	ITCM	557.9	125.1	CEII Redacted	P2-P7
J768	Timber Creek-Marshalltown 161 kV	291	ITCM	293.3	100.8	CEII Redacted	P2-P7
J441,J718	Adams-Beaver Creek 161 kV	264	ITCM DPC	283.8	107.5	CEII Redacted	P1
J441	Hazleton-Mitchell Co 345 kV	995	ITCM	998.1	100.3	CEII Redacted	P1

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
J441	Hazleton-Mitchell Co 345 kV	995	ITCM	1085.8	109.1	CEII Redacted	P2-P7
J767	Barton-Lime Creek 161 kV	240	ITCM	257.1	107.1	CEII Redacted	P1
J767	Barton-Lime Creek 161 kV	240	ITCM	288.5	120.2	CEII Redacted	P2-P7
J570,J721,J739, J741,J746,J748, J768,J777,J779	Bondurant-Montezuma 345 kV	1189	MEC	1194.0	100.4	CEII Redacted	P0
J570,J739,J767, J768,J777	Bondurant-Montezuma 345 kV	1189	MEC	1275.8	107.3	CEII Redacted	P1
J777	Union Tap-Butler 161 kV	410	MEC	431.2	105.2	CEII Redacted	P1
J777	Union Tap-Butler 161 kV	410	MEC	428.8	104.6	CEII Redacted	P2-P7
J777	Ackley-Franklin 161 kV	410	MEC	436.3	106.4	CEII Redacted	P1
J777	Ackley-Franklin 161 kV	410	MEC	433.9	105.8	CEII Redacted	P2-P7
J777	Ackley-Butler 161 kV	410	MEC	436.3	106.4	CEII Redacted	P1
J777	Ackley-Butler 161 kV	410	MEC	433.9	105.8	CEII Redacted	P2-P7

4.3 Step 2 – Project Justification Analysis

Based on the identified thermal and voltage constraints in the Stage-1 ACCC, the Ad Hoc group proposed to include the Webster-Franklin-Morgan Valley 345 kV line as a Base Case NU. Project justification analysis was performed considering the following aspects:

1) Evaluate the Stage-1 identified thermal constraints relieved by the NU.

2) Evaluate the Stage-1 identified thermal constraints aggravated by the NU.

3) Evaluate new constraints caused by the NU.

4) Model the transmission NUs in the summer shoulder case.

4.3.1 Project Justification in Iowa Area

The Webster-Franklin-Morgan Valley 345 kV line (Table 4-2) was selected as required NU. Iowa area project justification details are in Appendix E.2.1.

Table 4-2: Transmission NUs Evaluated in Central-East Iowa Area

Transmission NUs	Miles
Webster-Franklin-Morgan Valley 345 kV	
1. Webster-Franklin 345 kV	49.2
2. Franklin-Morgan Valley 345 kV	138

In summary, the following Base Case NUs (Table 4-3) are required:

Table 4-3: MISO Base Case NUs

NUs	Miles	Cost ($)
Webster-Franklin 345 kV	49.2	$117,000,000
Franklin-Morgan Valley 345 kV	138	$384,056,500
Total		**$501,056,500**

4.4 Step 3 – Stage-2 ACCC Analysis

The following projects have been justified based on the studies in Steps 1 and 2:

- MISO Base Case NU
  - Webster-Franklin 345 kV line
  - Franklin-Morgan Valley 345 kV line

The Base Case NUs were added to create Stage-2 models. AC contingency analysis was performed using the Stage-2 models to identify any remaining thermal and voltage constraints.

4.4.1 Stage-2 System Intact Conditions

For NERC category P0 (system intact) conditions, thermal constraints are listed in Table E-7, and voltage constraints are listed in Table E-8.

4.4.2 Stage-2 Post Contingency Conditions

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

All category P1 contingency solutions converge. For P1 contingencies in the summer shoulder scenario, thermal constraints are listed in Table E-9, and voltage constraints are listed in Table E-10.

Seven category P2-P7 contingencies (Table E-13) do not converge in the benchmark or study cases. No mitigation plan is required for the study projects for these non-converged contingencies. The dc thermal results for non-converged contingencies are listed in Table E-14.

For P2-P7 contingencies in the summer shoulder scenario, thermal constraints are listed in Table E-11, and voltage constraints are listed in Table E-12.

4.4.3 Summer Shoulder Worst Thermal Constraints in the Stage-2 ACCC

Table 4-5 lists the worst thermal constraints identified in the Stage-2 ACCC for the summer shoulder scenario.

Table 4-4: Summer Shoulder Thermal Constraints, Maximum Screened Loading, Stage-2 ACCC

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J741	J741 POI-Wishek 115 kV	44	MDU	48.0	109.2	CEII Redacted	P0	Line clearance mitigation.
J570	St. Joseph-Cooper 345 kV	1195	NPPD GMO	1257.7	105.2	CEII Redacted	P0	NU is not required unless it is identified as constraint in affected system study.
J570,J739,J748, J768	St. Joseph-Cooper 345 kV	1195	NPPD GMO	1745.7	146.1	CEII Redacted	P1	NU is not required unless it is identified as constraint in affected system study.
J721,J739	Split Rock-White 345 kV	717.1	XEL WAPA	874.7	122.0	CEII Redacted	P1	XEL: Line is currently rated 1075 MVA for SN/SE no mitigation required. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.
J721,J739	Split Rock-White 345 kV	717.1	XEL WAPA	897.3	125.1	CEII Redacted	P2-P7	XEL: Line is currently rated 1075 MVA for SN/SE no mitigation required. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.
J739	Helena-Chub Lake 345 kV	1792.6	XEL GRE	1918.6	107.0	CEII Redacted	P1	GRE: Add 2nd circuit to the Helena-Chub Lake 345 kV line. XEL: Add 345 kV breaker at Helena.
J739	Helena-Chub Lake 345 kV	1792.6	XEL GRE	1917.2	107.0	CEII Redacted	P2-P7	GRE: Add 2nd circuit to the Helena-Chub Lake 345 kV line. XEL: Add 345 kV breaker at Helena.
J739	Willmar-Granite Falls 230 kV	264.9	GRE WAPA	269.6	101.8	CEII Redacted	P1	GRE: rebuild 17.75 miles of 230 kV line. $8,000,000 WMU: WMU portion of line is rated 296 MVA and is NOT limiting.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J721	Big Stone-Big Stone South 230 kV #1	605	OTP	760.3	125.7	CEII Redacted	P1	Line will be required to be fully rebuilt with a larger conductor as well as replacement of terminal equipment at Big Stone.
J721	Big Stone-Big Stone South 230 kV #1	605	OTP	760.4	125.7	CEII Redacted	P2-P7	Line will be required to be fully rebuilt with a larger conductor as well as replacement of terminal equipment at Big Stone.
J721	Big Stone-Big Stone South 230 kV #2	605	OTP	761.4	125.9	CEII Redacted	P1	Line will be required to be fully rebuilt with a larger conductor.
J721	Big Stone-Big Stone South 230 kV #2	605	OTP	761.5	125.9	CEII Redacted	P2-P7	Line will be required to be fully rebuilt with a larger conductor.
J721	Big Stone-Blair 230 kV	582.7	OTP NWE	712.7	122.3	CEII Redacted	P1	OTP: Line will be required to be fully rebuilt with a larger conductor. $12,750,000. NWE: Rebuild 18.17 miles of 230 kV to achieve a rating of 712.7 MVA. $15,485,800
J721	Big Stone-Blair 230 kV	582.7	OTP NWE	701.7	120.4	CEII Redacted	P2-P7	OTP: Line will be required to be fully rebuilt with a larger conductor. $12,750,000. NWE: Rebuild 18.17 miles of 230 kV to achieve a rating of 712.7 MVA. $15,485,800
J741	Hankinson-Forman 230 kV	451.2	OTP	458.3	101.6	CEII Redacted	P1	Clearance mitigation required.
J741	Oakes-Forman 230 kV	527	OTP	557.8	106.1	CEII Redacted	P1	Rating after DPP 2016 Aug NU is SN/SE = 684/684 MVA. Cost assigned to DPP 2017 Feb study projects is $0.
J741	Oakes-Ellendale 230 kV	527	OTP MDU	566.9	107.6	CEII Redacted	P1	Rating after DPP 2016 Aug NU is SN/SE = 713/713 MVA. Cost assigned to DPP 2017 Feb study projects is $0.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J767	Lime Creek 161 kV bus tie	335	ITCM	486.5	145.2	CEII Redacted	P2-P7	ITCM rating 589/655 MVA SN/SE. $0
J441	Wabaco-Rochester 161 kV	221.1	DPC	318.6	144.1	CEII Redacted	P1	MTEP Appendix A project
J441	Wabaco-DPC_MN 161 kV	291.0	DPC	302.3	103.9	CEII Redacted	P1	Increase rating of Alma-Wabaco 161 from 291 MVA to 303 MVA.
J441	Alma-DPC_MN 161 kV	291.0	DPC	301.2	103.5	CEII Redacted	P2-P7	Increase rating of Alma-Wabaco 161 from 291 MVA to 303 MVA.

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

The MISO Base Case thermal NUs and cost are listed in Table 4-5. Additional thermal NUs and cost are listed in Table 4-6, and additional reactive power NUs and cost are listed in Table 4-7.

Table 4-5: MISO Base Case NUs

NUs	Miles	Cost ($)
Webster-Franklin 345 kV	49.2	$117,000,000
Franklin-Morgan Valley 345 kV	138	$384,056,500
Total		**$501,056,500**

Table 4-6: Additional Thermal NUs

Constraint	Owner	Mitigation	Cost ($)
J741 POI-Wishek 115 kV	MDU	Line clearance mitigation.	$475,000
St. Joseph-Cooper 345 kV	NPPD GMO	NU is not required unless it is identified as constraint in affected system study.	$0
Split Rock-White 345 kV	XEL WAPA	XEL: Line is currently rated 1075 MVA for SN/SE no mitigation required. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.	$0
Helena-Chub Lake 345 kV	XEL GRE	GRE: Add 2nd circuit to the Helena-Chub Lake 345 kV line. XEL: Add 345 kV breaker at Helena.	$31,500,000
Willmar-Granite Falls 230 kV	GRE WAPA	GRE: rebuild 17.75 miles of 230 kV line. $8,000,000 WMU: WMU portion of line is rated 296 MVA and is NOT limiting.	$8,000,000
Big Stone-Big Stone South 230 kV #1	OTP	Line will be required to be fully rebuilt with a larger conductor as well as replacement of terminal equipment at Big Stone.	$1,450,000
Big Stone-Big Stone South 230 kV #2	OTP	Line will be required to be fully rebuilt with a larger conductor.	$1,400,000
Big Stone-Blair 230 kV	OTP NWE	OTP: Line will be required to be fully rebuilt with a larger conductor. $12,750,000. NWE: Rebuild 18.17 miles of 230 kV to achieve a rating of 712.7 MVA. $15,485,800	$28,235,800
Hankinson-Forman 230 kV	OTP	Clearance mitigation required.	$50,000
Oakes-Forman 230 kV	OTP	Rating after DPP 2016 Aug NU is SN/SE = 684/684 MVA. Cost assigned to DPP 2017 Feb study projects is $0.	$0

Constraint	Owner	Mitigation	Cost ($)
Oakes-Ellendale 230 kV	OTP MDU	Rating after DPP 2016 Aug NU is SN/SE = 713/713 MVA. Cost assigned to DPP 2017 Feb study projects is $0.	$0
Lime Creek 161 kV bus tie		ITCM rating 589/655 MVA SN/SE. $0	$0
Wabaco-Rochester 161 kV		MTEP Appendix A project	$0
Wabaco-DPC_MN 161 kV		Increase rating of Alma-Wabaco 161 from 291 MVA to 303 MVA.	$100,000

Table 4-7: Additional Reactive Power NUs Required for Voltage Constraints

Network Upgrades	Owner	Cost ($)
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	OTP	$2,000,000
additional 1x150 MVAR switched cap bank at Franklin 345 kV (1)	MEC	$4,000,000
200 MVAR SVC at Montezuma 345 kV (635730)	MEC	$60,000,000
1x150 MVAR switched cap bank at Tiffin 345 kV (636420)	MEC	$4,000,000
1x50 MVAR switched cap bank at Salem 161 kV (631061)	ITCM	$3,000,000
3x50 MVAR switched cap bank at Buffalo 345 kV (620358)	OTP	$5,000,000
additional 1x30 Mvar switched cap bank at HUC-McLeod 230 kV (619940)	MRES	$1,500,000

Section

5

Local Planning Criteria Analysis

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

5.1 GRE Local Planning Criteria Analysis

GRE determined that the GRE LPC should be applied to project J746 because the project utilizes GRE-owned transmission to access to the MISO network.

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

5.1.1 Additional Network Upgrades Identified in GRE LPC Analysis

Except the thermal constraints or NUs identified in MISO ACCC analysis, no additional thermal constraints were identified in the GRE LPC analysis.

Three options of Network Upgrades have been studied. All the three options can mitigate system instability and voltage collapse under the permanent CUDC bipole disturbance, with similar performance on transient low voltage violations.

Considering stability performance and cost of Network Upgrades, the Center-Ellendale 345 kV option is selected as the Network Upgrades for mitigating the identified system instability and voltage collapse.

To mitigate the steady-state voltage collapse, transient instability, and transient voltage collapse identified in the GRE LPC study, additional Network Upgrades are listed in Table 5-1.

Table 5-1. Additional Network Upgrades for Constraints Identified in GRE LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
Voltage collapse under CUDC bipole contingencies and voltage constraints under other contingencies	GRE MPC MDU	Build Center-Ellendale 345 kV line	$406,750,000
Voltage collapse under CUDC bipole contingencies and voltage constraints under other contingencies	XEL	2nd 1×75 MVAR MSC at Bison 345 kV (601067)	$4,000,000
Transient instability and voltage collapse under CUDC bipole disturbance	OTP	150 MVAR SVC at Jamestown 345 kV (620369)	$24,370,000

Constraint	Owner	Mitigation	Cost ($)
Transient instability and voltage collapse under CUDC bipole disturbance	MPC	200 MVAR SVC at Winger 230 kV (657758)	$25,000,000
Transient instability and voltage collapse under CUDC bipole disturbance	GRE	200 MVAR SVC at River Road 345 kV (615664)	$50,000,000 [1]
Transient instability and voltage collapse under CUDC bipole disturbance	MPC	200 MVAR SVC at Prairie 345 kV (657946)	$50,000,000
Transient instability and voltage collapse under CUDC bipole disturbance	XEL	3rd 1×75 MVAR MSC at Bison 345 kV (601067) (total of 3×75 MVAR)	$4,000,000

Note 1: This cost is subject to be updated.

5.2 OTP Local Planning Criteria Analysis

Siemens PTI performed the LPC analysis based on OTP's Local Planning Criteria. The OTP LPC analysis details can be found in Appendix F.2.

The OTP LPC analysis consisted of steady-state contingency analysis for summer peak, summer shoulder, and light load no wind (LLNW) conditions. OTP utilized a DF cutoff of 20% on facilities under outlet contingencies of the interconnecting projects to determine local units that should be adjusted for the OTP LPC study. OTP utilized neighboring areas to the west to determine the LLNW scenario.

5.2.1 Additional Network Upgrades Identified in OTP LPC Analysis

All thermal constraints identified in the OTP LPC analysis were previously identified in the MISO ACCC analysis.

With MISO reactive power NUs applied, no voltage constraints were identified in the OTP LPC analysis. No high voltage constraints were identified on OTP buses under the LLNW condition.

No additional NUs are required in the OTP LPC study.

5.3 MDU Local Planning Criteria Analysis

MDU determined that J741 has a 20% DF on the outlets of Tatanka, Foxtail, J436, J437, J488, J458, J302, J457, J503 and J607. An MDU LPC analysis is required for J741 per Section 3.2 of the MDU LPC. The MDU LPC analysis consisted of steady-state contingency analysis and transient stability analysis for summer shoulder conditions.

Siemens PTI performed the LPC analysis based on MDU's Local Planning Criteria. The MDU LPC analysis details can be found in Appendix F.3.

5.3.1 Additional Network Upgrades Identified in MDU LPC Analysis

In addition to thermal constraints previously identified in the MISO ACCC analysis, one new thermal constraint was identified in the MDU LPC. No steady state voltage constraints were identified.

An additional 1×50 MVAR fast switched capacitor at Ellendale 230 kV bus is required to mitigate system instability and local voltage collapse in the Ellendale area. Total fast switched capacitors installed at Ellendale 230 kV bus will be 5×50 MVAR, with one 1×50 MVAR MSC spare unit (not used).

Further study is recommended using detailed EMT models to verify that Tatanka Wind, Foxtail Wind, J436, J437, J488, G359, J302, and J503 can operate at a CSCR of around 1.21.

The J721 Interconnection Customer (IC) is required to consult with the manufacturer for actual high voltage ride through (HVRT) capability and provide updated relay settings.

Additional Network Upgrades required in the MDU LPC study are listed in Table 5-2.

Table 5-2. Additional Network Upgrades for Constraints Identified in MDU LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
J302&503 POI-Heskett 230 kV	MDU	Line rebuild	$2,500,000
System instability and local voltage collapse	MDU	Additional 1×50 MVAR fast switched capacitor at Ellendale 230 kV	$1,500,000

5.4 DPC Local Planning Criteria Analysis

Siemens PTI performed the LPC analysis based on DPC's Local Planning Criteria. The DPC LPC analysis details can be found in Appendix F.4.

The DPC LPC analysis consisted of steady-state contingency analysis for summer shoulder system conditions. DPC determined that the projects in Table 5-3 should be redispatched to their rated output per DPC LPC.

Table 5-3. Generation Dispatched to Pmax per DPC LPC Case

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

5.4.1 Additional Network Upgrades Identified in DPC LPC Analysis

In addition to thermal constraints previously identified in the MISO ACCC analysis, three new thermal constraints were identified in the DPC LPC. No voltage constraints were identified.

Additional Network Upgrades required in the DPC LPC study are listed in Table 5-4.

Table 5-4. Additional Network Upgrades for Constraints Identified in DPC LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
Harmony-Harmony Municipal 69 kV	DPC	Relay Load Limit issues, relay setting changes	$10,000
Lime Springs Tap-Cherry Grove 69 kV	DPC	Rebuild 5.5 miles of line with 636 ACSR	$2,100,000
Lime Springs Tap-Granger 69 kV	DPC	Rebuild 6.5 miles of line with 636 ACSR	$2,400,000

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Section

6

Affected System Steady-State Analysis

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

6.1 Affected System Analysis for CIPCO Company

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

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

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

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

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

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

Table 6-1. CIPCO Summer Shoulder Thermal Constraints, Maximum Screened Loading, Stage-2 ACCC

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation	Cost
				(MVA)	(%)				
J768	Prarie Creek-Square D 115 kV	164	CIPCO ITCM	182.0	111.0	CEII Redacted	P2-P7	CIPCO: No mitigation needed	$0
J767,J777	Hazleton-Dundee 161 kV	327	CIPCO ITCM	374.1	114.4	CEII Redacted	P1	CIPCO: Upgrade Dundee terminal to 3000 A. $500,000. ITCM: CIPCO LPC. $0	$500,000
J767,J777	Hazleton-Dundee 161 kV	327	CIPCO ITCM	382.4	116.9	CEII Redacted	P2-P7	CIPCO: Upgrade Dundee terminal to 3000 A. $500,000. ITCM: CIPCO LPC. $0	
J777	Liberty-Hickory Crk 161 kV	327	CIPCO ITCM	377.6	115.5	CEII Redacted	P1	CIPCO: Upgrade Liberty terminal to 3000 A. $500,000. ITCM: CIPCO LPC: $0	$500,000
J768,J777	Liberty-Hickory Crk 161 kV	327	CIPCO ITCM	409.0	125.1	CEII Redacted	P2-P7	CIPCO: Upgrade Liberty terminal to 3000 A. $500,000. ITCM: CIPCO LPC: $0	

6.2 MPC Affected System Analysis

The MPC affected system analysis details can be found in Appendix G.2.

6.2.1 Study Summary

Minnkota Power Cooperative (MPC) performed an Affected System Analysis (ASA) to determine impacts of generators in the MISO DPP 2017 February study cycle on MPC facilities and any network upgrades required to mitigate those impacts. Steady-state power flow anlaysis, steady-state contingency analysis, and dynamic stability analysis were performed for the J746 generating facility.

Power flow and contingency analyses were performed for summer peak and summer shoulder conditions. Dynamic stability analysis was performed for summer shoulder conditions. The MPC ASA cases were built from the DPP Stage 2 cases, so the only DPP 2017 February NU included in the cases are the Base Case NU, which are in Iowa and will not affect the results of the MPC ASA

The Bison 345 kV bus voltage is an ERIS constraint. Three options were identified to mitigate the Bison voltage constraint:

- 3x60 Mvar shunt capacitors at Maple River 230 kV substation, or
- 3x50 Mvar shunt capacitors at Buffalo 345 kV substation, or
- 9x15 Mvar shunt capacitors at Buffalo 115 kV substation.

Minnkota will require installation of capacitors at Maple River if the Bison voltage constraint is not mitigated by MISO Network Upgrades.

The Sweetwater-Langdon 115 kV line is an NRIS constraint.

- Sweetwater-Langdon 115 kV line
  - Upgrade to 82.5 MVA is required

No transient stability constraints were identified on the MPC system for the J746 project.

6.2.2 Network Upgrades

Network Upgrades are shown in Table 6-2; costs are planning level estimates and subject to revision in the facility studies.

Table 6-2. Minnkota ASA Mitigation Summary

Constraint	Mitigation	Cost	NU Type
Bison 345 kV voltage.	3x60 Mvar shunt capacitors at Maple River 230 kV substation, or 3x50 Mvar shunt capacitors at Buffalo 345 kV substation, or 9x15 Mvar shunt capacitors at Buffalo 115 kV substation.	$3,000,000 [1]	ERIS
Sweetwater-Langdon 115 kV line	Clearance mitigation required.	$500,000	NRIS

Note 1: MISO ERIS analysis requires installation of a 3x50 MVAR shunt capacitor at the Buffalo 345 kV substation. This MPC ASA NU is not required if the MISO Reactive Power NU moves forward.

6.3 PJM Affected System Analysis

The PJM affected system analysis details (dated 6/11/2019) can be found in Appendix G.3.

6.3.1 Study Results

6.3.1.1 Overload on Quad Cities–ESS H471 345 kV line

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

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

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

c. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J777, J739, J441, J721, J741, J745, J767, J768, J779, J746, J748, and J570.

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

6.3.1.2 Overload on Cordova–Nelson 345 kV line

To relieve the Cordova–Nelson 345 kV line overload:

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

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

c. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J777, J739, J441, J721, J741, J767, J768, J779, J746, J748, and J570.

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

6.3.1.3 Overload on ESS H471–Nelson 345 kV line

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

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

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

f. Cost estimate: $24.6 M

The 2017 February MISO DPP projects that contribute loading to this flowgate are: J777, J739, J441, J721, J741, J767, J768, J779, J746, J748, and J570.

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

6.3.1.4 Overload on Twin Branch–Argenta 345 kV line

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

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

The following 2017 February DPP projects contribute loading to this constraint: J584, J711, J740, J441, J756, J767, J739, J777, J746, J721, J741, J779, J768, J748, J757, and J570.

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

6.3.2 Study Summary

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

6.4 SPP Affected System AC Contingency Analysis

Southwest Power Pool (SPP) conducted an Affected System Impact Study (ASIS) to evaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the Mid-Continent Independent System Operation (MISO) Transmission System.

A steady-state thermal and voltage analysis as well as Transfer Distribution Factor analysis was performed to determine the impact the MISO GIRs have on the SPP system.

Potential mitigations for constraints identified in the SPP affected system are listed in Table 6-1.

The SPP affected system analysis results (Revision 1, 7/15/2019) for this study are in Appendix G.4.

Table 6-1: SPP Identified Network Upgrades with Cost Allocation

Mitigation Required	Type	Cost Allocation	Upgrade Cost
Cooper - Stranger Creek 345 kV circuit 1 Rebuild of Cooper - St. Joseph 345kV circuit 1 Rebuild of Cooper - Fairport - St. Joseph 345kV circuit 1 Dekalb & Nemaha county 345kV substations Additional COOPER_S mitigation as determined in Facility Study	ERIS/NRIS	J441: $33,991,390 J570: $304,458,010 J718: $9,910,878 J721: $47,660,105 J739: $46,944,033 J741: $12,381,657 J746: $48,651,589 J748: $53,374,911 J767: $27,381,494 J768: $3,608,177 J777: $24,389,277 J779: $12,541,286	$625,292,807
Rebuild Bismark - Hilken 230kV circuit 1	ERIS/NRIS	J779: $22,290,721	$22,290,721
Rebuild Bismark - Hilken 230kV circuit 2	ERIS/NRIS	J779: $22,290,721	$22,290,721
Rebuild Tekamah - S1226 161 kV circuit 1	NRIS Only	J748: $19,431,803	$19,431,803
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	NRIS Only	J721: $7,737,888 J739: $4,254,361 J741: $2,000,946 J746: $7,437,741	$21,430,936
Rebuild Raun - Tekamah 161 kV circuit 1	NRIS Only	J748: $34,534,047	$34,534,047
Rebuild Mingo - Setab 345 kV circuit 1	NRIS Only	J721: $18,179,747 J741: $5,287,149 J746: $21,456,502 J779: $5,694,775	$50,618,173

Section
7

Stability Analysis

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

7.1 Procedure

7.1.1 Computer Programs

Stability analysis was performed using PSS®E revision 33.12.

7.1.2 Study Methodology

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

7.2 Case Development

7.2.1 Study Case

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

The stability study case was created using the same procedure as the steady state models, as described in Section 2.1. The stability case includes the Base Case NU and Reactive Power NU identified in the MISO steady state analysis.

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

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

Interface	SH Case (MW)
MHEX	1074
MWEX	1578
Arrowhead – Stone Lake 345 kV	647

7.2.2 Benchmark Case

The DPP West Area generating facilities were removed from the study case. MISO Classic was used for power balance, where generation was scaled uniformly.

7.3 Disturbance Criteria

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

Table 7-2: Regional and Local Disturbance Descriptions

CEII Redacted

Table 7-3: Generic Clearing Time Assumption

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

7.4 Performance Criteria

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

- System instability
- Transient voltage constraint
- Damping violation

7.4.1 MISO Criteria

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

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

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

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

7.4.2 Local Planning Criteria

7.4.2.1 ATC Local Planning Criteria

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

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

7.4.2.2 ITCM Local Planning Criteria

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

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

- Voltage at all Transmission System buses should recover to the applicable post-contingency steady-state voltage level (ITCM post-disturbance limits in Table 2 3), within 1.0 second of the clearing of the fault.

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

7.4.2.3 MEC Local Planning Criteria

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

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

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

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

7.5 Stability Results

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

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

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

7.5.1 Instantaneous Frequency Relay Tripping

Under the disturbances listed in Table 7-4, several generators were tripped by instantaneous frequency protection when 3PH faults are applied near their POI buses. In PSS®E, local bus frequency deviation is calculated from the change in local bus angle. Bus voltage angle changes caused by network convergence failure will yield incorrect calculated local bus frequency. Frequency excursions that cause instantaneous frequency protection to operate during the fault are the result of the network solution failing to converge and should be ignored.

These instantaneous frequency relay models were disabled for all stability simulation results in Appendix H which are discussed below.

Table 7-4: Disturbance Causing Instantaneous Frequency Protection Tripping

Disturbance Name	Description	NERC Cat.	Tripping Cause
0754_w_mec_p12	CEII Redacted	P1-2	J455 Wind farm (631248, 631249) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
0800_w_mp_p12_fds_sqbutte	CEII Redacted	P1-2	Bison Wind farm (608891 - 608898) was tripped by instantaneous frequency protection set to <57 or >62 Hz for 0.0 sec. This was caused by non-converged network

Disturbance Name	Description	NERC Cat.	Tripping Cause
			solution during the fault.
0824_w_otp_p12_el3_center	CEII Redacted	P1-2	Bison Wind farm (608891 - 608898) was tripped by instantaneous frequency protection set to <57 or >62 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.
0887_w_xel_p12	CEII Redacted	P1-2	G287 Wind farm (600101, 600112 - 600114) was tripped by instantaneous frequency protection set to <56.5 or >62.5 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.
1198_w_gre_p12	CEII Redacted	P1-2	J441 Wind farm (84413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
1436_w_otp_p12	CEII Redacted	P1-2	J721 Wind farm (87216, 87217) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
1677_w_otp_p12_fds_sqbutte	CEII Redacted	P1-2	Bison Wind farm (608891 - 608898) was tripped by instantaneous frequency protection set to <57 or >62 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.
2104_w_itcm_p12	CEII Redacted	P1-2	J768 Wind farm (631153) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
2263_w_xel_py9s	CEII Redacted	P1-2	J441 Wind farm (84413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
Byron_3ph_NROC_345	CEII Redacted	P1-2	J441 Wind farm (84413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
Byron_3ph_PL-VLLY_345	CEII Redacted	P1-2	J441 Wind farm (84413) was tripped by instantaneous frequency protection set to

Disturbance Name	Description	NERC Cat.	Tripping Cause
			<57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
Byron_3ph_345_161_xfmr	CEII Redacted	P1-3	J441 Wind farm (84413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
Wishek_3ph_J302_J503_230	CEII Redacted	P1-2	J741 Wind farm (87413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
Wishek_3ph_MERRCRT_230	CEII Redacted	P1-2	J741 Wind farm (87413) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
J748-POI_3ph_J506-POI_345	CEII Redacted	P1-2	J748 Wind farm (87480) was tripped by instantaneous frequency protection set to <55 or >65 Hz for 0.1 sec. This was caused by non-converged network solution during the fault.
J748-POI_3ph_HIGHLND_345	CEII Redacted	P1-2	J748 Wind farm (87480) was tripped by instantaneous frequency protection set to <55 or >65 Hz for 0.1 sec. This was caused by non-converged network solution during the fault.
LimeCk_3ph_COLBY_161	CEII Redacted	P1-2	J767 Wind farm (631152) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
StoryCo_3ph_M-TOWN_161	CEII Redacted	P1-2	J768 Wind farm (631153) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
StoryCo_3ph_FERNALD_161	CEII Redacted	P1-2	J768 Wind farm (631153) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.

Disturbance Name	Description	NERC Cat.	Tripping Cause
NUTHTCH_3ph_IAFIND_161	CEII Redacted	P1-2	G573 Wind farm (629118 - 629119) and G947 Wind farm (629120) were tripped by instantaneous frequency protection set to <57 or >61 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.
NUTHTCH_3ph_FRANKLN_161	CEII Redacted	P1-2	G573 Wind farm (629118 - 629119) and G947 Wind farm (629120) were tripped by instantaneous frequency protection set to <57 or >61 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.
ESTBMRK_3ph_BISMARK_115	CEII Redacted	P1-2	J779 Wind farm (87793) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
ESTBMRK_3ph_BISEXP_115-smh181231	CEII Redacted	P1-2	J779 Wind farm (87793) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
ESTBMRK_3ph_26TH&D_115-smh181231	CEII Redacted	P1-2	J779 Wind farm (87793) was tripped by instantaneous frequency protection set to <57 or >63.5 Hz for 0.01 sec. This was caused by non-converged network solution during the fault.
0823_w_otp_p12_ec3_center	CEII Redacted	P1-2	Bison Wind farm (608891 - 608898) was tripped by instantaneous frequency protection set to <57 or >62 Hz for 0.0 sec. This was caused by non-converged network solution during the fault.

7.5.2 High / Low Voltage Ride Through Violations

Under the disturbances listed in Table 7-5, several generators were tripped by their high or low voltage protection during faults. The Interconnection Customers (ICs) and Transmission Owners (TOs) are required to consult with manufacturers for actual turbine / inverter high voltage ride through (HVRT) or low voltage ride through (LVRT) capability and provide updated relay settings.

Stability simulations were performed two times with these voltage relays enabled and with these voltage relays disabled.

Table 7-5: High / Low Voltage Ride Through Issues

Disturbance Name	Description	NERC Cat.	Tripping Cause
0715_w_itcm_p12	CEII Redacted	P1-2	Poch Prairie wind farm (636038) was tripped by high voltage relay (>1.15 pu for 0.017 second)
0754_w_mec_p12	CEII Redacted	P1-2	Highland wind farm (635407, 635408, 635409) was tripped by low voltage relay (0.15 pu for 0.02 second)
0828_w_otp_p43	CEII Redacted	P4-3	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
0858_w_xel_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
0864_w_xel_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
0869_w_xel_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
0871_w_xel_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
1434_w_otp_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
1436_w_otp_p12	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
J570-POI_3ph_ATCHSN_345	CEII Redacted	P1-2	FRMR CTY wind farm (635020) tripped by low voltage relay (<0.75 or >1.2 pu for 0.0 second)
J570-POI_3ph_COOPER_345	CEII Redacted	P1-2	FRMR CTY wind farm (635020) tripped by low voltage relay (<0.75 or >1.2 pu for 0.0 second)
J570-POI_SLG_ATCHSN_345	CEII Redacted	P5-2	FRMR CTY wind farm (635020) tripped by low voltage relay (<0.75 or >1.2 pu for 0.0 second)
J570-POI_SLG_COOPER_345	CEII Redacted	P5-2	FRMR CTY wind farm (635020) tripped by low voltage relay (<0.75 or >1.2 pu for 0.0 second)
BSSOUTH_3ph_BIGSTONE_230-2	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)

Disturbance Name	Description	NERC Cat.	Tripping Cause
BSSOUTH_3ph_230_345_xfmr-1	CEII Redacted	P1-3	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
LimeCkL1_3ph_LimeCkL2_161	CEII Redacted	P1-2	J767 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
LimeCk_3ph_161-69_xfmr	CEII Redacted	P1-3	J767 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
LimeCkL1_SLG_LimeCkL2_161	CEII Redacted	P5-2	J767 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
LimeCk_SLG_161-69_xfmr	CEII Redacted	P5-3	J767 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P11_230_OTP_BigStone_Gen	CEII Redacted	P1-1	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P12_230_OTP_BigStone-BigStoneSouth-ckt1	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P12_230_OTP_BigStone-Blair	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P12_230_OTP_BigStone-Hankinson	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P12_345_OTP_BigStoneSouth-BrookingsCo	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P12_345_OTP_BigStoneSouth-Ellendale	CEII Redacted	P1-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P13_230_OTP_BigStone_IntXfmr	CEII Redacted	P1-3	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P13_345_OTP_BigStoneSouth_Xfmr1	CEII Redacted	P1-3	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)
P42_345_OTP_BigStoneSouth-BrookingsCo_3715stk	CEII Redacted	P4-2	J721 wind farm was tripped by high voltage relay (>1.241 pu for 0.001 second)

7.5.3 Transient High Voltage Violations

Under two disturbances listed in Table 7-6, voltage at buses listed in Table 7-6 exceeds 1.2 per unit for ¾ of a cycle (12 milliseconds) after faults are cleared. These transient high voltages have less than 0.01 per unit increase compared with those in the benchmark case, as shown in Table 7-6. These voltage violations are outside of the 0 to 10 Hz frequency bandwidth covered by transient stability simulation tools such as PSS®E, so these results are not reliable[1], and the voltage spikes are not categorized as constraints.

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

Table 7-6: Transient Voltages above 1.2 per unit

CEII Redacted

7.6 Network Upgrades Identified in Stability Analysis

No additional Network Upgrades are required in the stability analysis.

To mitigate the HVRT and LVRT violations identified in Table 7-5, the ICs and TOs are required to consult with manufacturers for actual turbine / inverter high voltage ride through (HVRT) or low voltage ride through (LVRT) capability and provide updated relay settings.

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

Section

8

MWEX Voltage Stability Study

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

The voltage stability analysis used 2023 summer shoulder cases to compare the Pre-DPP without Network Upgrades and the Post-DPP with the Base Case Network Upgrades. The MISO Base Case Network Upgrades are the following projects.

1. Construction of a Franklin – Morgan Valley 345 kV line;
2. Construction of a Franklin – Webster 345 kV line.

Both the Pre-DPP and Post-DPP + Base Case NUs cases contain the Network Upgrades required for the February 2016 and August 2016 West Area generation interconnection studies including the Cardinal – Hickory Creek MVP (Cardinal – Hill Valley – Hickory Creek 345 kV with a 345/138 kV transformer at Hill Valley, MTEP PrjID 3127).

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

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

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

	Real Power Flow (MW)							
	AHD-SLK[1]	MWEX				Margin to Nose[2]		
Case	N-0 Initial Condition	N-0 I.C.[3]	N-1 I.C.[3]	N-1 I.C. After Phase Shift[4]	N-1 Nose	(MW)	(%)	Notes
Pre-DPP without Base Case NUs	621.8	1513.5	721.5	698.9	800.0	101.1	12.6	Voltage Stable Sufficient Margin [5] Vnose > Vmin [6] (0.965 > 0.950)
Post-DPP with Base Case NU	647.8	1583.5	760.1	697.6	786.9	89.3	11.3	Voltage Stable Sufficient Margin [5] Vnose > Vmin (0.963 > 0.950)

Notes:

1. As described in the active MWEX Operating Guide, the AHD-SLK interface is a single element PTDF interface measured at the Minnesota Power 230 kV side of the Arrowhead 230 kV phase shifter.
2. Margin to Nose is defined as:
   a. "Margin to Nose (MW)" = "MWEX N-1 Nose" – "N-1 Initial Condition After Phase Shift"
   b. "Margin to Nose (%)" = "Margin to Nose (MW)" / "MWEX N-1 Nose"
3. Initial Condition flows were measured in the base cases with an intact system and the worst contingency plus operation of various control systems as needed with all transformer taps, switched shunts, and PARs locked.
4. Arrowhead PAR modeled as changing from neutral tap to a maximum of the 14th tap in the retard direction. Arrowhead PAR controls are presently set to stop tapping once flow through the PAR is less than 697 MW or 14 taps are reached.
   a. If the N-1 I.C. is less than 697 MW, then the N-1 I.C. After Phase Shift is listed as N/A because the PAR will not operate.
5. ATC Planning Criteria requires a 10% voltage stability margin.
6. ATC Planning Criteria requires Vnose < Vmin.
   a. In the Pre-DPP and Post-DPP cases the voltage is measured at the MP Arrowhead 230 kV bus. Per MP's Planning Criteria, the post-contingent minimum voltage is 0.95 p.u. at the MP Arrowhead 230 kV bus.

Section

9

Short Circuit Analysis

Siemens PTI and several transmission owning companies performed short circuit analysis for the DPP 2017 February West study cycle projects.

9.1 J441 Short Circuit Study

The J441 short circuit study was performed by SMMPA. The study found that fault current exceeds the interrupting capability of 161 kV circuit switchers at RPU's Northern Hills and IBM substations. It was determined that these equipment rating deficiencies pre-date the J441 generation addition. The study concludes that interconnection of the J441 project does not cause any short circuit constraints.

Study details can be found in Appendix J.1.

9.2 J570 Short Circuit Study

The J570 short circuit study was performed by MEC. The study results show that the 3PH fault current is 18,029 A (increased by 721 A) and the SLG fault current is 15,662 A (increased by 1,081 A) at the 345 kV interconnection substation. Based on the Transmission Owner's short circuit criteria, interconnection of the J570 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.2.

9.3 J718 Short Circuit Study

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

Study details can be found in Appendix J.3.

9.4 J721 Short Circuit Study

The J721 short circuit study was performed by OTP. The study results show that with the proposed projects additions, the fault currents are roughly 20.7 kA at the Big Stone South 230 kV bus, 13.1 kA at Big Stone South 345 kV bus, 12.9 kA at the Big Stone South 34.5 kV bus, and 21.5 kA at the Big Stone 230 kV bus. Based on the short circuit analysis performed, the fault current ratings of the Transmission Owner's equipment in the area are not exceeded and there are no upgrades required

Study details can be found in Appendix J.4.

9.5 J739 Short Circuit Study

The J739 short circuit study was performed by Siemens PTI. The study results show that in the study case, 3PH fault current is 11,984 Amps (increased by 840 Amps) and SLG fault current is 11,510 Amps (increased by 1489 Amps) at the Lyon County 345 kV bus. Based on the Transmission Owner’s short circuit criteria, interconnection of the J739 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.5.

9.6 J741 Short Circuit Study

The J741 short circuit study was performed by Siemens PTI. The study results show that in the study case, 3PH fault current is 1,978 Amps (increased by 646 Amps) and SLG fault current is 2,046 Amps (increased by 1059 Amps) at the J741 POI 115 kV bus. Based on the Transmission Owner’s short circuit criteria, interconnection of the J741 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.6.

9.7 J746 Short Circuit Study

The J746 short circuit study was performed by GRE. The study results show that none of the circuit breaker interrupting capabilities at McHenry, Stanton, Coal Creek, and other nearby substations will be exceeded after the addition of J746.

Study details can be found in Appendix J.7.

9.8 J748 Short Circuit Study

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

Study details can be found in Appendix J.8.

9.9 J767 Short Circuit Study

The J767 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J767. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.9.

9.10 J768 Short Circuit Study

The J768 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J768. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.10.

9.11 J777 Short Circuit Study

The J777 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J777. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.11.

9.12 J779 Short Circuit Study

The J779 short circuit study was performed by Siemens PTI. The study results show that in the study case, 3PH fault current is 3,976 Amps (increased by 658 Amps) and SLG fault current is 4,610 Amps (increased by 841 Amps) at the J779 POI 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J779 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.12.

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Section
10

Deliverability Study

10.1 Project Description

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

10.2 Introduction

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

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

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

10.3 Study Methodology

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

10.4 Determining the MW restriction

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

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

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

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

10.5 2023 Deliverability Study Result

10.5.1 J441

J441 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**170 MW (100%)**

10.5.2 J570

J570 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**150 MW (100%)**

10.5.3 J718

J718 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**49.98 MW (100%)**

10.5.4 J721

J721 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**200 MW (100%)**

10.5.5 J739

J739 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**200 MW (100%)**

10.5.6 J741

J741 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**29.84 MW (59.2%)**						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Wishek-Merricourt 230 kV	50.40	0.5614	No		J741; J746; J779	$3,133,654	$5,800,000

10.5.7 J746

J746 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	117 MW (58.5%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Wishek-Merricourt 230 kV	200.00	0.0888	No		J741; J746; J779	$1,966,940	$5,800,000

10.5.8 J748

J748 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	200 MW (100%)

10.5.9 J767

J767 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	12 MW (100%)

10.5.10 J768

J768 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	12 MW (100%)

10.5.11 J777

J777 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Iowa Falls Industrial-Farm Tap 69 kV	0.00	0.2014	No		J777	$10,000	$10,000
Iowa Falls Industrial 161-69 kV xfmr	0.00	0.3171	No		J777	$3,000,000	$3,000,000
Wall Lake-Wright 161 kV	60.66	0.2631	No		J777	$500,000	$500,000
Wright 161-69 kV xfmr	89.78	0.0634	No		J777	$1,750,000	$1,750,000
Iowa Falls Industrial-Wellsburg 161 kV	99.00	0.6812	No		J777	$2,200,000	$2,200,000

10.5.12 J779

J779 Deliverable (NRIS) Amount in 2023 case: (Conditional on ERIS and IC upgrades and case assumptions)	**29.84 MW (59.21%)**						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Wishek-Merricourt 230 kV	50.40	0.1253	No		J741; J746; J779	$699,407	$5,800,000

Section
11

Shared Network Upgrades Analysis

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

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations are listed in Table 11-1.

Table 11-1: Maximum MW Impact and SNU Cost Allocations

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
Oakes-Forman 230 kV	DPP-2015-AUG	J436	11.64	$300,000	$47,094
	DPP-2015-AUG	J437	11.64		$47,094
	Merricourt	G359R	40.43		$163,574
	DPP-2017-FEB	J741	10.44		$42,239
Oakes-Forman 230 kV	DPP-2016-FEB	J436	11.72	$950,000	$177,888
	Merricourt	G359R	40.43		$613,652
	DPP-2017-FEB	J741	10.44		$158,460
Oakes-Forman 230 kV	Merricourt	G359R	40.43	$112,750	$89,610
	DPP-2017-FEB	J741	10.44		$23,140
Oakes-Forman 230 kV	DPP-2016-AUG	J302	15.70	$19,900,000	$7,521,184
	DPP-2016-AUG	J503	15.40		$7,377,468
	DPP-2017-FEB	J741	10.44		$5,001,348
Oakes-Ellendale 230 kV	DPP-2015-AUG	J436	12.10	$700,000	$111,126
	DPP-2015-AUG	J436	12.10		$111,126
	Merricourt	G359R	41.36		$379,848
	DPP-2017-FEB	J741	10.66		$97,901
Oakes-Ellendale 230 kV	DPP-2016-FEB	J488	12.21	$1,650,000	$313,662
	Merricourt	G359R	41.36		$1,062,494
	DPP-2017-FEB	J741	10.66		$273,844

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
Oakes-Ellendale 230 kV	DPP-2016-AUG	J302	15.30	$20,500,000	$7,638,821
	DPP-2016-AUG	J503	15.10		$7,538,967
	DPP-2017-FEB	J741	10.66		$5,322,211
Johnson Jct-Morris 115 kV	DPP-2016-FEB	J493	2.83	$9,716,856	$1,374,248
	DPP-2016-FEB	J526	6.30		$3,059,280
	DPP-2017-FEB	J721	10.88		$5,283,328
Big Stone-Browns Valley 230 kV	DPP-2016-FEB	J488	8.97	$285,086	$48,277
	DPP-2016-FEB	J493	6.82		$36,705
	DPP-2016-FEB	J526	14.89		$80,138
	DPP-2017-FEB	J721	22.29		$119,965
Big Stone-Blair 230 kV	DPP-2016-FEB	J488	22.64	$150,183	$32,973
	DPP-2016-FEB	J493	7.63		$11,112
	DPP-2016-FEB	J526	19.47		$28,356
	DPP-2017-FEB	J721	53.38		$77,742
J302&503 POI-Heskett 230 kV	DPP-2016-AUG	J302	57.40	$9,000,000	$3,794,066
	DPP-2016-AUG	J503	56.20		$3,714,747
	DPP-2017-FEB	J741	22.56		$1,491,187
Hankinson-Wahpeton 230 kV	DPP-2015-AUG	J442	27.16	$400,000.00	$210,054
	DPP-2017-FEB	J721	24.56		$189,946
Johnson Jct-Ortonville 115 kV	DPP-2016-FEB	J493	2.83	$16,850,000.00	$2,383,083
	DPP-2016-FEB	J526	6.3		$5,305,097
	DPP-2017-FEB	J721	10.88		$9,161,819
Big Stone 230-115 kV xfmr	DPP-2016-FEB	J488	8.66	$3,250,000.00	$669,322
	DPP-2016-FEB	J493	4.39		$339,298
	DPP-2016-FEB	J526	10.01		$773,662
	DPP-2017-FEB	J721	18.99		$1,467,717
Hankinson-Wahpeton 230 kV	DPP-2016-FEB	J488	16.58	$1,050,000.00	$222,139
	DPP-2016-FEB	J493	9.27		$124,199
	DPP-2016-FEB	J460	7.84		$105,040
	DPP-2016-FEB	J526	20.12		$269,567
	DPP-2017-FEB	J721	24.56		$329,054

Section

12

Cost Allocation

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

12.1 Cost Assumptions for Network Upgrades

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

12.2 ERIS Network Upgrades Proposed for DPP West Area Projects

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

Table 12-1: Summary of ERIS Network Upgrades

Category of Network Upgrades	Cost ($)
Base Case Network Upgrades	$501,056,500
Network Upgrades Identified in MWEX Voltage Stability analysis	$0
Additional Thermal Network Upgrades Identified in MISO Steady-State Analysis	$71,210,800
Additional Reactive Power Network Upgrades for Voltage Constraints	$79,500,000
Network Upgrades Identified in Stability Analysis	$0
Network Upgrades Identified in Short Circuit Analysis	$0
Network Upgrades Identified in GRE LPC Analysis	$564,120,000
Network Upgrades Identified in OTP LPC Analysis	$0
Network Upgrades Identified in MDU LPC Analysis	$4,000,000
Network Upgrades Identified in DPC LPC Analysis	$4,510,000
Network Upgrades Identified in CIPCO AFS	$1,000,000
Network Upgrades Identified in MPC AFS	$500,000
Network Upgrades Identified in PJM AFS	$0
Network Upgrades Identified in SPP AFS	$795,889,208
Shared Network Upgrades	$29,039,901
Total	**$2,050,826,409**

ERIS network upgrades are listed below.

Table 12-2: Base Case Network Upgrades

NUs	Miles	Cost ($)
Webster-Franklin 345 kV	49.2	$117,000,000
Franklin-Morgan Valley 345 kV	138	$384,056,500
Total		**$501,056,500**

Table 12-3: Network Upgrades Required for MWEX Voltage Stability

NUs	Miles	Cost ($)
No additional NUs		

Table 12-4: Additional Thermal Network Upgrades in MISO Steady-State Analysis

Constraint	Owner	Mitigation	Cost ($)
J741 POI-Wishek 115 kV	MDU	Line clearance mitigation.	$475,000
Helena-Chub Lake 345 kV	XEL GRE	GRE: Add 2nd circuit to the Helena-Chub Lake 345 kV line. XEL: Add 345 kV breaker at Helena.	$31,500,000
Willmar-Granite Falls 230 kV	GRE WAPA	GRE: rebuild 17.75 miles of 230 kV line. $8,000,000 WMU: WMU portion of line is rated 296 MVA and is NOT limiting.	$8,000,000
Big Stone-Big Stone South 230 kV #1	OTP	Line will be required to be fully rebuilt with a larger conductor as well as replacement of terminal equipment at Big Stone.	$1,450,000
Big Stone-Big Stone South 230 kV #2	OTP	Line will be required to be fully rebuilt with a larger conductor.	$1,400,000
Big Stone-Blair 230 kV	OTP NWE	OTP: Line will be required to be fully rebuilt with a larger conductor. $12,750,000. NWE: Rebuild 18.17 miles of 230 kV to achieve a rating of 712.7 MVA. $15,485,800	$28,235,800
Hankinson-Forman 230 kV	OTP	Clearance mitigation required.	$50,000
Oakes-Forman 230 kV	OTP	Rating after DPP 2016 Aug NU is SN/SE = 684/684 MVA. Cost assigned to DPP 2017 Feb study projects is $0.	$0
Oakes-Ellendale 230 kV	OTP MDU	Rating after DPP 2016 Aug NU is SN/SE = 713/713 MVA. Cost assigned to DPP 2017 Feb study projects is $0.	$0
Wabaco-Rochester 161 kV	DPC	MTEP Appendix A project	$0

Constraint	Owner	Mitigation	Cost ($)
Wabaco-DPC_MN 161 kV	DPC	Increase rating of Alma-Wabaco 161 from 291 MVA to 303 MVA.	$100,000

Table 12-5: Additional Reactive Power NUs Required for Voltage Constraints

Network Upgrades	Owner	Cost ($)
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	OTP	$2,000,000
additional 1x150 MVAR switched cap bank at Franklin 345 kV (1)	MEC	$4,000,000
200 MVAR SVC at Montezuma 345 kV (635730)	MEC	$60,000,000
1x150 MVAR switched cap bank at Tiffin 345 kV (636420)	MEC	$4,000,000
1x50 MVAR switched cap bank at Salem 161 kV (631061)	ITCM	$3,000,000
3x50 MVAR switched cap bank at Buffalo 345 kV (620358)	OTP	$5,000,000
additional 1x30 MVAR switched cap bank at HUC-McLeod 230 kV (619940)	MRES	$1,500,000

Table 12-6: Network Upgrades Required for Transient Stability

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

Table 12-7: Network Upgrades in Short Circuit Analysis

Constraint	Owner	Mitigation	Cost ($)
No additional NUs			$0

Table 12-8: GRE Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Voltage collapse under CUDC bipole contingencies and voltage constraints under other contingencies	GRE MPC MDU	Build Center-Ellendale 345 kV line	$406,750,000
Voltage collapse under CUDC bipole contingencies and voltage constraints under other contingencies	XEL	2nd 1×75 MVAR MSC at Bison 345 kV (601067)	$4,000,000
Transient instability and voltage collapse under CUDC bipole disturbance	OTP	150 MVAR SVC at Jamestown 345 kV (620369)	$24,370,000
Transient instability and voltage collapse under CUDC bipole disturbance	MPC	200 MVAR SVC at Winger 230 kV (657758)	$25,000,000

Constraint	Owner	Mitigation	Cost ($)
Transient instability and voltage collapse under CUDC bipole disturbance	GRE	200 MVAR SVC at River Road 345 kV (615664) [1]	$50,000,000 [1]
Transient instability and voltage collapse under CUDC bipole disturbance	MPC	200 MVAR SVC at Prairie 345 kV (657946)	$50,000,000
Transient instability and voltage collapse under CUDC bipole disturbance	XEL	3rd 1×75 MVAR MSC at Bison 345 kV (601067) (total of 3×75 MVAR)	$4,000,000

Note 1: This cost is subject to be updated.

Table 12-9: OTP Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
No additional NUs			

Table 12-10: MDU Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
J302&503 POI-Heskett 230 kV	MDU	Line rebuild	$2,500,000
System instability and local voltage collapse	MDU	Additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	$1,500,000

Table 12-11: DPC Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Harmony-Harmony Municipal 69 kV	DPC	Relay Load Limit issues, relay setting changes	$10,000
Lime Springs Tap-Cherry Grove 69 kV	DPC	Rebuild 5.5 miles of line with 636 ACSR	$2,100,000
Lime Springs Tap-Granger 69 kV	DPC	Rebuild 6.5 miles of line with 636 ACSR	$2,400,000

Table 12-12: CIPCO Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Prarie Creek-Square D 115 kV	CIPCO ITCM	CIPCO: No mitigation needed.	$0
Hazleton-Dundee 161 kV	CIPCO ITCM	CIPCO: Upgrade Dundee terminal to 3000 Amps ITCM: CIPCO LPC. $0	$500,000
Liberty-Hickory Crk 161 kV	CIPCO ITCM	CIPCO: Upgrade Liberty terminal to 3000 Amps. ITCM: CIPCO LPC	$500,000

Table 12-13: MPC Affected System Network Upgrades

Constraint	Mitigation	Cost
Bison 345 kV voltage	3x60 Mvar shunt capacitors at Maple River 230 kV substation, or 3x50 Mvar shunt capacitors at Buffalo 345 kV substation, or 9x15 Mvar shunt capacitors at Buffalo 115 kV substation.	$3,000,000 [1]
Sweetwater-Langdon 115 kV line	Clearance mitigation required.	$500,000

Note 1: MISO ERIS analysis requires installation of a 3x50 MVAR shunt capacitor at the Buffalo 345 kV substation. This MPC ASA NU is not required if the MISO Reactive Power NU moves forward.

Table 12-14: PJM Affected System Network Upgrades

Constraint	Owner	Mitigation	Total Cost ($)
No additional cost			$0

Table 12-15: SPP Affected System Network Upgrades

Mitigation Required	Upgrade Cost
Cooper - Stranger Creek 345 kV circuit 1 Rebuild of Cooper - St. Joseph 345kV circuit 1 Rebuild of Cooper - Fairport - St. Joseph 345kV circuit 1 Dekalb & Nemaha county 345kV substations Additional COOPER_S mitigation as determined in Facility Study	$625,292,807
Rebuild Bismark - Hilken 230kV circuit 1	$22,290,721
Rebuild Bismark - Hilken 230kV circuit 2	$22,290,721
Rebuild Tekamah - S1226 161 kV circuit 1	$19,431,803
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936
Rebuild Raun - Tekamah 161 kV circuit 1	$34,534,047
Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173

Table 12-16: Shared Network Upgrades

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
Oakes-Forman 230 kV	DPP-2016-FEB	J436	11.72	$950,000	$177,888
	Merricourt	G359R	40.43		$613,652
	DPP-2017-FEB	J741	10.44	$950,000	$158,460
Oakes-Forman 230 kV	Merricourt	G359R	40.43	$112,750	$89,610
	DPP-2017-FEB	J741	10.44		$23,140
Oakes-Forman 230 kV	DPP-2016-AUG	J302	15.70	$19,900,000	$7,521,184
	DPP-2016-AUG	J503	15.40		$7,377,468
	DPP-2017-FEB	J741	10.44		$5,001,348
Oakes-Ellendale 230 kV	DPP-2015-AUG	J436	12.10	$700,000	$111,126

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
	DPP-2015-AUG	J436	12.10		$111,126
	Merricourt	G359R	41.36		$379,848
	DPP-2017-FEB	J741	10.66		$97,901
Oakes-Ellendale 230 kV	DPP-2016-FEB	J488	12.21	$1,650,000	$313,662
	Merricourt	G359R	41.36		$1,062,494
	DPP-2017-FEB	J741	10.66		$273,844
Oakes-Ellendale 230 kV	DPP-2016-AUG	J302	15.30	$20,500,000	$7,638,821
	DPP-2016-AUG	J503	15.10		$7,538,967
	DPP-2017-FEB	J741	10.66		$5,322,211
Johnson Jct-Morris 115 kV	DPP-2016-FEB	J493	2.83	$9,716,856	$1,374,248
	DPP-2016-FEB	J526	6.30		$3,059,280
	DPP-2017-FEB	J721	10.88		$5,283,328
Big Stone-Browns Valley 230 kV	DPP-2016-FEB	J488	8.97	$285,086	$48,277
	DPP-2016-FEB	J493	6.82		$36,705
	DPP-2016-FEB	J526	14.89		$80,138
	DPP-2017-FEB	J721	22.29		$119,965
Big Stone-Blair 230 kV	DPP-2016-FEB	J488	22.64	$150,183	$32,973
	DPP-2016-FEB	J493	7.63		$11,112
	DPP-2016-FEB	J526	19.47		$28,356
	DPP-2017-FEB	J721	53.38		$77,742
J302&503 POI-Heskett 230 kV	DPP-2016-AUG	J302	57.40	$9,000,000	$3,794,066
	DPP-2016-AUG	J503	56.20		$3,714,747
	DPP-2017-FEB	J741	22.56		$1,491,187
Hankinson-Wahpeton 230 kV	DPP-2015-AUG	J442	27.16	$400,000.00	$210,054
	DPP-2017-FEB	J721	24.56		$189,946
Johnson Jct-Ortonville 115 kV	DPP-2016-FEB	J493	2.83	$16,850,000.00	$2,383,083
	DPP-2016-FEB	J526	6.3		$5,305,097
	DPP-2017-FEB	J721	10.88		$9,161,819
Big Stone 230-115 kV xfmr	DPP-2016-FEB	J488	8.66	$3,250,000.00	$669,322
	DPP-2016-FEB	J493	4.39		$339,298
	DPP-2016-FEB	J526	10.01		$773,662

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
	DPP-2017-FEB	J721	18.99		$1,467,717
Hankinson-Wahpeton 230 kV	DPP-2016-FEB	J488	16.58	$1,050,000.00	$222,139
	DPP-2016-FEB	J493	9.27		$124,199
	DPP-2016-FEB	J460	7.84		$105,040
	DPP-2016-FEB	J526	20.12		$269,567
	DPP-2017-FEB	J721	24.56		$329,054

12.3 Cost Allocation Methodology

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

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

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

12.4 Cost Allocation

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

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

For each thermal constraint, the maximum MW contribution (increasing flow) from each generating facility is calculated. MW contribution from one generating facility is set as zero if the MW contribution is less than 1 MW, or the constraint is not categorized as MISO ERIS constraint or affected system constraint for that specific generating facility.

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

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

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

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

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

Assuming all generating facilities in the DPP 2017 February West Area group advance, a summary of the costs for total NUs (NUs for ERIS, NRIS, and Interconnection Facilities) allocated to each generating facility is listed in Table 12-17.

Table 12-17: Summary of Total NU Costs Allocated to Each Generation Project

Project	Max Output (MW)	Total Cost of NU per Project ($)	$/MW	Share %
J441	170	$120,467,706	$708,634	5.72%
J570	150	$407,782,215	$2,718,548	19.37%
J718	49.98	$15,867,010	$317,467	0.75%
J721	200	$167,690,230	$838,451	7.96%
J739	200	$120,447,117	$602,236	5.72%
J741	50.4	$101,433,492	$2,012,569	4.82%
J746	200	$506,571,726	$2,532,859	24.06%
J748	200	$179,368,656	$896,843	8.52%
J767	12	$51,174,912	$4,264,576	2.43%
J768	12	$37,164,828	$3,097,069	1.77%
J777	99	$234,516,589	$2,368,854	11.14%
J779	50.4	$162,879,154	$3,231,729	7.74%
Total/Average	**1393.8**	**$2,105,363,635**	**$1,965,820**	**100.00%**

Appendix

A

Model Development for Steady-State and Stability Analysis

A.1 DPP 2017 February Generation Projects

Table A-1: DPP 2017 February West Area Projects

MISO Project #	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J441	MN	Dodge	SMMPA	Byron 345 kV	170	Wind	NRIS
J570	MO	Atchison	MEC	Cooper-Atchison 345 kV	150	Wind	NRIS
J718	MN	Fillmore	DPC	Cherry Grove 69 kV	49.98	Solar	NRIS
J721	SD	Codington, Deuel	OTP	Big Stone South 345 kV	200	Wind	NRIS
J739	MN	Lyon	Xcel	Lyon County 345 kV	200	Wind	NRIS
J741	ND	Emmons, Logan	MDU	Wishek-Linton 115 kV	50.4	Wind	NRIS
J746	ND	McHenry, McLean, Ward	GRE	Stanton-McHenry 230 kV	200	Wind	NRIS
J748	IA	Plymouth	MEC	O'Brien-Raun 345 kV	200	Wind	NRIS
J767	IA	Hancock	ITCM	Lime Creek 161 kV	12	Wind	NRIS
J768	IA	Story	ITCM	Story Co 161 kV	12	Wind	NRIS
J777	IA	Franklin	ITCM	Whispering Willow 161 kV	99	Wind	NRIS
J779	ND	Emmons, Logan	MDU	Bismarck-Linton 115 kV	50.4	Wind	NRIS

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

MISO Project #	Turbine / Inverter	Generator Reactive Power Capability (power factor)
J441	8 GE 2.3 MW, 60 GE 2.5 MW	± 0.90
J570	65 Vestas V120 2.2MW & 7 Vestas V110 2MW	± 0.95 for 2.0 MW ± 0.95 for 2.2 MW
J718	17 TMEIC 3200 kW	± 0.91
J721	43 GE 2.3 MW, 44 GE 2.3 MW	± 0.90
J739	100 Vestas V110 2.0 MW	± 0.95
J741	21 GE 2.4 MW	± 0.90
J746	104 Vestas V110 2.0 MW	± 0.95
J748	80 GE 2.5 MW	± 0.9
J767	100 GE 1.62 MW	± 0.9
J768	100 GE 1.62 MW	± 0.9

MISO Project #	Turbine / Inverter	Generator Reactive Power Capability (power factor)
J777	5 GE 2.3 MW & 35 GE 2.5 MW	GE 2.3 MW: ± 0.9 GE 2.5 MW: ± 0.9
J779	21 GE 2.4 MW	± 0.90

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

MISO Project #	Generator Modeling	Collector System Modeling	Shunt Compensation
J441	One 170 MW unit	R=0.0057 pu X=0.0099 pu B=0.0476 pu	2×12 MVAR capacitor bank on 34.5 kV system
J570	One 150 MW unit	R=0.00524 pu X=0.00497 pu B=0.06015 pu	3×13.5 MVAR capacitor bank on 34.5kV system
J718	One 49.98 MW unit	R=0.01142 X=0.00880 B=0.00648	6x0.6 MVAR capacitor bank on 34.5kV system
J721	One 98.8 MW unit and one 101.2 MW unit	Circuit #1: R=0.0073934 pu X=0.0111741 pu B=0.0292 pu Circuit #2: R=0.0073934 pu X=0.0111741 pu B=0.0292 pu	14 MVAR capacitor bank on each of the two 34.5 kV collector system
J739	Two 100 MW units	Circuit #1: R=0.026793 pu X=0.030726 pu B=0.08797 pu Circuit #2: R=0.026793 pu X=0.030726 pu B=0.08797 pu	16 MVAR capacitor bank on each of the two 34.5 kV collector system
J741	One 50.4 MW unit	R=0.0145348 pu X=0.0225163 pu B=0.0 pu	6 MVAR capacitor bank on 34.5 kV system
J746	One 200 MW unit	R=0.00216 pu X=0.00217 pu B=0.02365 pu	3x8 MVAR capacitor bank on 34.5kV system

MISO Project #	Generator Modeling	Collector System Modeling	Shunt Compensation
J748	Two 100 MW units	Circuit #1: R=0.0145 pu X=0.0147 pu B=0.0689 pu Circuit #2: R=0.0145 pu X=0.0147 pu B=0.0689 pu	1x12 MVAR capacitor bank on 34.5kV system
J767	One 162 MW unit	R=0.00698 pu X=0.01227 pu B=0.0 pu	2×36 MVAR and 2×54 MVAR at 161 kV substation (already modeled at Bus 631220)
J768	One 162 MW unit	R=0.00698 pu X=0.01227 pu B=0.0 pu	None
J777	One 11.5 MW unit and one 87.5 MW unit	R=0.007409 pu X=0.0495 pu B=0.07312 pu	5 MVAR capacitor bank on 34.5kV system
J779	One 50.4 MW unit	R=0.014538 pu X=0.0225 pu B=0.02543 pu	6 MVAR capacitor bank on 34.5kV system

Table A-4: DPP 2017 February Central Area Projects

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J708	IN	Posey	Vectren	AB Brown 138 kV sub	847	CC	NRIS
J734	IL	Ford	Ameren	Gibson City South 138 kV sub	57.1	CT	NRIS Only
J740	IN	Jasper, Pulaski	NIPS	Reynolds 345 kV sub	200	Wind	NRIS
J753	KY	Breckinridge	BREC	Hardinsburg 161 kV sub	100	Solar	NRIS
J754	IN	Montgomery	DEI	Cayuga-Nucor 345kV	303.6	Wind	NRIS
J756	IL	Logan	Ameren	Fogarty-Mason City West 138 kV	202.4	Wind	NRIS
J757	IL	Morgan, Sangamon	Ameren	Meredosia-Austin 345 kV	303.6	Wind	NRIS
J759	IN	Spencer	HE	Troy 161 kV sub	70	Solar	NRIS
J762	KY	Meade	BREC	Meade 161 kV sub	200	Solar	NRIS
J783	IN	Spencer	Vectren	Grandview 69 kV sub	70	Solar	NRIS

Table A-5: DPP 2017 February Michigan Area Projects

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

Table A-6: DPP 2017 February ATC Area Projects

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

MISO Project Num	State	County	Trans. Owner	Point Of Interconnection	Max Output	Fuel Type	Service Type
J704	MI	Baraga	ATC	M38 138 kV sub	54.9	CT	NRIS
J760	WI	Rock	ATC	Townline 345 kV sub	30	CC	NRIS

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

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

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

Constraint	Owner	Mitigation
Bondurant-Montezuma 345 kV	MEC	Structure Replacements. $600,000. New rating is 1,189 MVA.
Blair-Granite Falls 230 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.
Watertown 345-230-13.8 kV xfmr	WAPA	NU is not required unless it is identified as constraint in affected system study.
Watertown-Appledorn 230 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.
Harmony-Cresco 69 kV	DPC	Rebuild line with 477 ACSR
2×75 Mvar switched cap bank at Killdeer 345 kV (631199)	ITCM	2×75 Mvar switched cap bank at Killdeer 345 kV (631199)
2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)	ITCM	2×75 Mvar switched cap bank at Hickory Creek 345 kV (631191)
2x150 Mvar switched cap bank at Hills 345 kV (636400)	MEC	2x150 Mvar switched cap bank at Hills 345 kV (636400)
1×50 Mvar switched cap bank at McLeod 230 kV (619940)	MRES	1×50 Mvar switched cap bank at McLeod 230 kV (619940)
J302&J503 POI-Heskett 230 kV	MDU	Line rebuild
Merricourt-Ellendale 230 kV	MDU	Rebuild Line with high temp. conductor New Rating: 440 MVA
Oakes-Ellendale 230 kV	OTP MDU	MDU: MDU owns the Ellendale Terminal. It is rated for 776 MVA OTP: Complete rebuild of the 24 mile line: $20.5 M. Not applicable for MDU LPC
Zackary 345/161 kV transformer	Ameren	Add Second 560 MVA 345/161 kV transformer
Adair-Zackary 161 kV	Ameren	Add second 161 kV line between Adair and Zachary
Adair 161 kV bus tie 2-3	Ameren	Bus tie to be upgraded to 2000 A as part of the Zachary-Ottumwa MVP project
Novelty 161 -69 kV xfmr	AECI	Replace with 84 MVA.
South River-Emerson 161 kV	AECI	Upgrade 600 A disconnect switches at South River.

A.3 Model Review Comments

Table A-8: Model Review Comments

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

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

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

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

Company	Python/ Idev File Name	2023 SH	2023 SPK	2023 Stability
MISO	Aug16-NU.py	x	x	x
MISO	SPP_Study_Voltage_Solutions.py	x	x	x
J718	J718.py	x	x	x
SPTI	Killdeer_SWS.py	x	x	x
OTP	Feb17DPP2ModelReview_OTP_4-23-19.idv	x	x	x
DPC	DPC_Comment.py	x	x	x
SPTI	RMV_GEN-2015-087.py	x	x	x
J441	J441.py	x	x	x
MDU	MDU_Updates-DPP_2017_Feb_West_Ph2_ALL_Models_v2.idv	x	x	x
SPTI	POSTROC_fic_SWS.py	x		x
SPTI	St_Joe_250_SVC.py	x		x
SPTI	Webster-Franklin-Morgan.py	x	x	x
SPTI	RMV_fic_SVC_Franklin.py			x
J718	J718_r2.py	x	x	x
MPC	Ashtabula_GE_WECC_Generic_20MAR18.dyr			x
MPC	Langdon_GE_WECC_Generic_20MAR18.dyr			x
J718	J718.dyr			x
OTP	2023SSH-MISO18-OTP-Load-Model.dyr			x
OTP	OTP_generator_dynamics_models_23-Apr-2019.dyr			x
OTP	OTP_PRC-024_models_22-Mar-2019.dyr			x
OTP	OTP_switched_shunt_models_21-Mar-2019.dyr			x
OTP	OTP_UVLS+UFLS_models_26-Mar-2019.dyr			x

A.4 MISO Classic as the Study Sink

Table A-9: MISO Classic as the Study Sink

Area #	Area Name
207	HE
208	DEI
210	SIGE
216	IPL
217	NIPS
218	METC
219	ITC
295	WEC
296	MIUP
314	BREC
333	CWLD
356	AMMO
357	AMIL
360	CWLP
361	SIPC

Area #	Area Name
600	Xcel
608	MP
613	SMMPA
615	GRE
620	OTP
627	ALTW
633	MPW
635	MEC
661	MDU
663	BEPC-MISO
680	DPC
694	ALTE
696	WPS
697	MGE
698	UPPC

A.5 PJM Market as PJM Projects Sink

Table A-10: PJM Market as PJM Projects Sink

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

A.6 SPP Market as SPP Projects Sink

Table A-11: SPP Market as SPP Projects Sink

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

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

A.7 Contingency Files used in Steady-State Analysis

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

Contingency File Name	Description	2023
Automatic single element contingencies	Single element outages at buses 69 kV and above in the study region	x
CC Bipole Events.con	Specified category P1, P7 contingencies in GRE Coal Creek	x
CIPCO DPP-2017-FEB-P6.con	Specified category P6 contingencies in CIPCO	x
MEC-DPP2017FEB West Ph1 2023 Cat P1 04.17.2019.con	Specified category P1 contingencies in MEC	x
MEC-DPP2017FEB West Ph1 2023 Cat P2 04.17.2019.con	Specified category P2 contingencies in MEC	x
MEC-DPP2017FEB West Ph1 2023 Cat P5 04.17.2019.con	Specified category P5 contingencies in MEC	x
MEC-DPP2017FEB West Ph1 2023 Cat P7 04.17.2019.con	Specified category P7 contingencies in MEC	x
OTP_P1_22-October-2018.con	Specified category P1 contingencies in OTP	x
OTP_P2_22-October-2018.con	Specified category P2 contingencies in OTP	x
OTP_P5_19-June-2018.con	Specified category P5 contingencies in OTP	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_ATC_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in ATC	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_ATC_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in ATC	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_West_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in West	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_West_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in West	x
MISO18_2023_SUM_TA_P1_P2_P4_P5_IL-MO_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in IL, MO	x
MISO18_2023_SUM_TA_P2_P4_P5_P7_IL-MO_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in IL, MO	x

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Appendix

B

Model Data

B.1 Power Flow Model Data

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B.2 Dynamic Model Data

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B.3 2023 Slider Diagrams

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Appendix

C

Reactive Power Requirement Analysis Results (FERC Order 827)

Table C-1. Reactive Power Requirements Analysis Results

Project #	HV Side Bus #	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Lagging Power Factor at HV Side	Meet Lagging Power Factor Req.?	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Leading Power Factor at HV Side	Meet Leading Power Factor Req.?	Turbine Inherent Power Factor	Shunt Compensation
J441	84410	166.7	69.1	0.9238	Yes	165.7	-114.7	0.8222	Yes	GE 2.3 MW: ± 0.90 GE 2.5 MW: ± 0.90	2×12 MVAR capacitor bank on 34.5 kV system
J570	85700	146.7	48.7	0.9491	Yes	146.3	-85.6	0.8631	Yes	Vestas V110 2 MW: ± 0.95 Vestas V120 2.2 MW: ± 0.95	3×13.5 MVAR capacitor bank on 34.5kV system
J718	87180	49.4	19.0	0.9333	Yes	49.2	-32.1	0.8375	Yes	± 0.91	6x0.6 MVAR capacitor bank on 34.5kV system
J721	620417	196.1	89.7	0.9094	Yes	195.3	-139.8	0.8131	Yes	± 0.90	14 MVAR capacitor bank on each of the two 34.5 kV collector system
J739	87390	192.2	66.0	0.9458	Yes	191.4	-100.0	0.8863	Yes	± 0.95	16 MVAR capacitor bank on each of the two 34.5 kV collector system
J741	87410	49.4	20.4	0.9243	Yes	49.2	-36.7	0.8016	Yes	± 0.90	6 MVAR capacitor bank on 34.5 kV system
J746	87460	196.8	45.4	0.9744	No	196.1	-125.7	0.8419	Yes	± 0.95	3x8 MVAR capacitor bank on 34.5kV system
J748	87486	194.4	76.0	0.9314	Yes	193.8	-133.6	0.8233	Yes	± 0.90	1x12 MVAR capacitor bank on 34.5kV system
J767 & G735	631220	339.4	143.8	0.9208	Yes	337.6	-126.9	0.9361	Yes	± 0.90	2×36 Mvar and 2×54 Mvar at 161 kV substation (already modeled at Bus 631220)
J768	631184	158.1	40.3	0.9690	No	157.2	-127.0	0.7779	Yes	± 0.9	None
J777	87770	97.7	33.4	0.9462	Yes	97.4	-73.2	0.7994	Yes	GE 2.3 MW: ± 0.90 GE 2.5 MW: ± 0.90	5 MvVAR capacitor bank on 34.5kV system
J779	87790	49.4	21.9	0.9142	Yes	49.4	-31.1	0.8463	Yes	± 0.90	6 MvVAR capacitor bank on 34.5kV system

Appendix

D

2023 Summer Peak Contingency Analysis Results

D.1 2023 Summer Peak (SPK) Constraints

Table D-1: 2023 SPK System Intact Thermal Constraints

Table D-2: 2023 SPK System Intact Voltage Constraints

Table D-3: 2023 SPK Category P1 Thermal Constraints

Table D-4: 2023 SPK Category P1 Voltage Constraints

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

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

Table D-7: 2023 SPK Non-Converged Contingencies

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

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Appendix
E

2023 Summer Shoulder Contingency Analysis Results

E.1 Thermal Constraints Identified in Stage-1 Contingency Analysis with Fictitious SVCs

Table E-1: 2023 SH System Intact Thermal Constraints in Stage-1 ACCC

Table E-2: 2023 SH Category P1 Thermal Constraints in Stage-1 ACCC

Table E-3: 2023 SH Category P2-P7 Thermal Constraints in Stage-1 ACCC

Table E-4: 2023 SH Non-Converged Contingencies in Stage-1 ACCC

Table E-5: 2023 SH Non-Converged Contingencies DCCC Results in Stage-1 ACCC

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E.2 Base Case Network Upgrades Justification Results

E.2.1 Project Justification Details in Iowa Area

Table E-6: Project Evaluation Details in Iowa Area

Transmission NUs	Miles	Project Benefits	Facilities with Loading Relief (MVA)	Facilities with Adverse Impact (MVA)	Potential Overloaded Facilities by New NU (MVA)
Webster-Franklin 345 kV	49.2	1) New lines carry significant flows: Webster-Franklin (884 MVA), Franklin-Morgan Valley (631 MVA) 2) Eliminate required SVC at Franklin 345 kV 3) Provide an outlet from Iowa to Illinois, which will improve voltages in Iowa and help mitigation of MWEX voltage stability	St. Joseph-Cooper 345 kV: -81 Helena-Chub Lake 345 kV: -112 Plaza-Marshalltown 161 kV: -63 Plaza-Timber Creek 161 kV: -63 Wellsburg-Iowa Falls Industrial 161 kV: -61 Wellsburg-Marshalltown 161 kV: -57 Lime Creek 161 kV bus tie: -115 Emery-Lime Creek 161 kV #2: -103 Killdeer 345-161 kV xfmr: -292 Timber Crk-Marshalltown 161 kV: -55 Adams-Beaver Crk 161 kV: -33 Hazleton-Mitchell Co 345 kV: -342 Barton-Lime Creek 161 kV: -64 Bondurant-Montezuma 345 kV: -193 Union Tap-Butler 161 kV: -121 Ackley-Franklin 161 kV: -121 Ackley-Butler 161 kV: -121	The following facilities have small amount of loading increase: Split Rock-White 345 kV: 31	MVA Loading increase: Hazleton-Hickory Crk 345 kV: 94 Hazleton-Blackhawk 345 kV Morgan Valley-Tiffin 345 kV: 327 Hills-Tiffin 345 kV: 294 Hills-Sub 92 345 kV: 114 Hills-Sub T HSK 345 kV: 111
Franklin-Morgan Valley 345 kV	138				

E.3 Constraints Identified in Stage-2 Contingency Analysis with Base Case NUs

Table E-7: Stage-2 System Intact Thermal Constraints

Table E-8: Stage-2 System Intact Voltage Constraints

Table E-9: Stage-2 Category P1 Thermal Constraints

Table E-10: Stage-2 Category P1 Voltage Constraints

Table E-11: Stage-2 Category P2-P7 Thermal Constraints

Table E-12: Stage-2 Category P2-P7 Voltage Constraints

Table E-13: Stage-2 Non-Converged Category P1-P7 Contingencies

Table E-14: Stage-2 Non-Converged Category P2-P7 Contingencies DCCC Results

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Appendix

F

Local Planning Criteria Analysis Results

F.1 GRE Local Planning Criteria Analysis Results

Below is the GRE local planning criteria analysis report.

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F.2 OTP LPC Analysis

Below is the OTP local planning criteria analysis report.

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F.3 MDU LPC Analysis

Below is the MDU local planning criteria analysis report.

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F.4 DPC LPC Analysis

Below is the DPC local planning criteria analysis report.

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Appendix

G

Affected System Contingency Analysis Results

G.1 CIPCO Affected System Analysis Results

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

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

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G.2 MPC Affected System Analysis Results

Below is the Affected System Analysis report provided by MPC.

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G.3 PJM Affected System Study Results

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

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G.4 SPP Affected System Study Results

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

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Appendix

H

Transient Stability Results

H.1 2023 Summer Shoulder Stability Results Summary

Stability simulation was performed in the 2023 summer shoulder Phase 2 case with Base Case Network Upgrades and Reactive Power Network Upgrades identified in the MISO steady state analysis.

Stability study results are summarized in Table H-1.

Table H-1: 2023 Summer Shoulder Phase 2 Stability Analysis Results Summary

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H.2 2023 Summer Shoulder Stability Plots

Plots of stability simulations for 2023 summer shoulder Phase 2 study case are in separate files which are listed below:

AppendixH2_2023SH_DPP 2017Feb-West_Ph2_Study_Plots.zip

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Appendix
I

MWEX Voltage Study

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

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Appendix

J

Short Circuit Analysis

J.1 J441 Short Circuit Study

J.2 J570 Short Circuit Study

J.3 J718 Short Circuit Study

J.4 J721 Short Circuit Study

J.5 J739 Short Circuit Study

J.6 J741 Short Circuit Study

J.7 J746 Short Circuit Study

J.8 J748 Short Circuit Study

J.9 J767 Short Circuit Study

J.10 J768 Short Circuit Study

J.11 J777 Short Circuit Study

J.12 J779 Short Circuit Study

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Appendix

K

2023 Cost Allocation Results

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

Table K-1: Distribution Factor and MW Contribution on Constraints for Webster-Franklin-Morgan Valley 345 kV Base Case NU Cost Allocation

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

Table K-3: Distribution Factor and MW Contribution on MISO Voltage Constraints for MISO Reactive Power NU Cost Allocation

Table K-4: Distribution Factor and MW Contribution on GRE LPC Voltage Constraints for GRE LPC Reactive Power NU Cost Allocation

Table K-5: Distribution Factor and MW Contribution on MDU LPC Voltage Constraints for MDU LPC Reactive Power NU Cost Allocation

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K.2 Cost Allocation Details

Table K-6: Network Upgrades Cost Allocation in 2023

Legalectric, Inc.

Carol Overland **Attorney at Law, MN #254617**

Energy Consultant—Transmission, Power Plants, Nuclear Waste

overland@legalectric.org

1110 West Avenue
Red Wing, Minnesota 55066
612.227.8638

August 14, 2019

Dan Wolf
Executive Secretary
Public Utilities Commission
121 – 7th Place East, Suite 350
St. Paul, MN 55101

eFiled and eServed

RE: Dodge County Wind request for Suspension and Withdrawal
Suspension: PUC Dockets IP-6981/CN-17-306; IP-6981/WS-17- 307
Withdraw: PUC Docket IP-6981/TL-17-308

Dear Mr. Wolf:

Attached please find MISO DPP 2017 February West Area Phase 2 Study, released July 19, 2019.

I'm sending this comment as an individual, and not in the course of representation of any party. Moments ago, I received notice of the applicant's request to suspend the CoN and wind site permit proceedings, and its request to withdraw the application for transmission for the project (Docket IP-6981/TL-17-308).

Mindful of my prior comments regarding the size and type of transmission requested, that it's oversized and radial, and mindful of Commissioner Schuerger's comments at the most recent Commission meeting regarding the appropriateness of the 345kV transmission proposed, I believe the record should include the MISO study triggering the applicants' August 9, 2019 withdrawal of its MISO queue position J441 and today's requests for suspension and withdrawal. Thus, it's attached for your review and consideration.

Please let me know if you have any questions or require anything further.

Very truly yours,

Carol A. Overland
Attorney at Law

Table K-6: Network Upgrades Cost Allocation in 2023

Monitored Element	English Name	Cost	J441	J570	J718	J721	J739	J741	J746	J748	J767	J768	J777	J779	Upgrade for
Webster-Franklin-Morgan Valley 345 kV	Webster-Franklin-Morgan Valley 345 kV	$501,056,500	$83,439,491	$58,038,260	$0	$21,610,679	$20,432,410	$5,378,954	$20,810,409	$32,725,910	$23,546,718	$31,993,067	$197,658,739	$5,421,863	Base Case NU Webster-Franklin-Morgan Valley 345 kV
87414 J741POI 115 661095 WISHEK 7 115 1	J741 POI-Wishek 115 kV	$475,000	$0	$0	$0	$0	$0	$475,000	$0	$0	$0	$0	$0	$0	MISO SH
541199 ST JOE 3 345 640139 COOPER 3 345 1	St. Joseph-Cooper 345 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601006 SPLT RK3 345 652537 WHITE 3 345 1	Split Rock-White 345 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601050 HELENA 3 345 615649 GRE-CHUBLAK3 345 1	Helena-Chub Lake 345 kV	$31,500,000	$0	$0	$0	$0	$31,500,000	$0	$0	$0	$0	$0	$0	$0	MISO SH
619975 GRE-WILLMAR4 230 652550 GRANITF4 230 1	Wilmarth-Granite Falls 230 kV	$8,000,000	$0	$0	$0	$0	$8,000,000	$0	$0	$0	$0	$0	$0	$0	MISO SH
620314 BIGSTON4 230 620322 BSSOUTH4 230 1	Big Stone-Big Stone South 230 kV #1	$1,450,000	$0	$0	$0	$1,450,000	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620314 BIGSTON4 230 620322 BSSOUTH4 230 2	Big Stone-Big Stone South 230 kV #2	$1,400,000	$0	$0	$0	$1,400,000	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620314 BIGSTON4 230 655465 BLAIR-ER4 230 1	Big Stone-Blair 230 kV	$28,235,800	$0	$0	$0	$28,235,800	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620327 HANKSON4 230 620363 FORMAN 4 230 1	Hankinson-Forman 230 kV	$50,000	$0	$0	$0	$0	$0	$50,000	$0	$0	$0	$0	$0	$0	MISO SH
620362 OAKES 4 230 620363 FORMAN 4 230 1	Oakes-Forman 230 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620362 OAKES 4 230 661098 ELLENDLMVP4 230 1	Oakes-Ellendale 230 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631047 LIME CK L1 5 161 631160 LIME CK L2 5 161 Z	Lime Creek 161 kV bus tie	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
681532 WABACO 5 161 681537 ROCHSTR5 161 1	Wabaco-Rochester 161 kV	$11,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
Wabaco-Alma 161 kV	Wabaco-Alma 161 kV	$100,000	$100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	2×25 MVAR switched cap bank at Wahpeton 230 kV (620329)	$2,000,000	$0	$8,267	$0	$1,563,880	$105,401	$288,521	$0	$19,568	$0	$0	$0	$14,363	MISO Reactive Power
additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	additional 1×150 MVAR switched cap bank at Franklin 345 kV (1)	$4,000,000	$0	$395,147	$0	$649,193	$645,742	$151,491	$558,530	$1,113,608	$91,307	$16,381	$233,187	$145,415	MISO Reactive Power
200 MVAR SVC at Montezuma 345 kV (635730)	200 MVAR SVC at Montezuma 345 kV (635730)	$60,000,000	$0	$18,660,866	$0	$7,139,758	$5,661,802	$1,808,539	$6,951,870	$13,903,739	$55,124	$1,312,053	$2,624,638	$1,881,612	MISO Reactive Power
1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	1×150 MVAR switched cap bank at Tiffin 345 kV (636420)	$4,000,000	$631,187	$170,020	$96,294	$567,341	$600,628	$136,810	$526,376	$607,723	$58,587	$30,469	$442,262	$132,304	MISO Reactive Power
1×50 MVAR switched cap bank at Salem 161 kV (631061)	1×50 MVAR switched cap bank at Salem 161 kV (631061)	$3,000,000	$653,412	$31,195	$49,838	$441,950	$480,770	$107,286	$418,061	$383,933	$41,682	$4,863	$283,487	$103,524	MISO Reactive Power
3×50 MVAR switched cap bank at Buffalo 345 kV (620358)	3×50 MVAR switched cap bank at Buffalo 345 kV (620358)	$5,000,000	$0	$0	$0	$0	$0	$429,931	$3,795,586	$0	$0	$0	$0	$774,484	MISO Reactive Power
1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	1×30 MVAR switched cap bank at Huc-McLeod 230 kV (619940)	$1,500,000	$0	$29,841	$0	$475,242	$621,971	$75,548	$194,951	$47,723	$0	$0	$0	$54,724	MISO Reactive Power
680026 HARMNY 69.0 680475 HAR MUNI 69.0 1	Harmony-Harmony Municipal 69 kV	$10,000	$0	$0	$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	DPC LPC
680177 LIME TP 69.0 680413 CHERRY_8 69.0 1	Lime Springs Tap-Cherry Grove 69 kV	$2,100,000	$0	$0	$2,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	DPC LPC
680177 LIME TP 69.0 680419 GRANGER 69.0 1	Lime Springs Tap-Granger 69 kV	$2,400,000	$0	$0	$2,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	DPC LPC
631017 PRAR CK7 115 631032 SQUARED7 115 1	Prarie Creek-Square D 115 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	CIPCO AFS
631051 HAZLTON L2 5 161 631101 DUNDEE 5 161 1	Hazleton-Dundee 161 kV	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500,000	$0	CIPCO AFS
631100 LIBERTY5 161 631159 HCKRYCK5 161 1	Liberty-Hickory Crk 161 kV	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500,000	$0	CIPCO AFS
83021 J302&503 POI 230 661042 HESKETT4 230 1	J302&503 POI-Heskett 230 kV	$2,500,000	$0	$0	$0	$0	$0	$2,500,000	$0	$0	$0	$0	$0	$0	MDU LPC
additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	additional 1×50 MVAR fast switched capacitors at Ellendale 230 kV (661098)	$1,500,000	$0	$0	$0	$0	$0	$910,166	$419,106	$0	$0	$0	$0	$170,728	MDU LPC
GRE LPC Voltage NU	GRE LPC Voltage NU	$564,120,000	$0	$13,490,609	$0	$12,949,076	$0	$51,407,509	$387,184,067	$10,725,690	$0	$199,818	$0	$88,163,229	GRE LPC
Oakes-Forman 230 kV (SNU, 2015 Aug)	Oakes-Forman 230 kV (SNU, 2015 Aug)	$300,000	$0	$0	$0	$0	$0	$42,239	$0	$0	$0	$0	$0	$0	SNU
Oakes-Forman 230 kV (SNU, 2016 Feb)	Oakes-Forman 230 kV (SNU, 2016 Feb)	$950,000	$0	$0	$0	$0	$0	$158,460	$0	$0	$0	$0	$0	$0	SNU
Oakes-Forman 230 kV (SNU, Merricourt)	Oakes-Forman 230 kV (SNU, Merricourt)	$112,750	$0	$0	$0	$0	$0	$23,140	$0	$0	$0	$0	$0	$0	SNU
Oakes-Forman 230 kV (SNU, DPP 2016 Aug)	Oakes-Forman 230 kV (SNU, DPP 2016 Aug)	$19,900,000	$0	$0	$0	$0	$0	$5,001,348	$0	$0	$0	$0	$0	$0	SNU
Oakes-Ellendale 230 kV (SNU, 2015 Aug)	Oakes-Ellendale 230 kV (SNU, 2015 Aug)	$700,000	$0	$0	$0	$0	$0	$97,901	$0	$0	$0	$0	$0	$0	SNU
Oakes-Ellendale 230 kV (SNU, 2016 Feb)	Oakes-Ellendale 230 kV (SNU, 2016 Feb)	$1,650,000	$0	$0	$0	$0	$0	$273,844	$0	$0	$0	$0	$0	$0	SNU
Oakes-Ellendale 230 kV (SNU, 2016Aug)	Oakes-Ellendale 230 kV (SNU, 2016Aug)	$20,500,000	$0	$0	$0	$0	$0	$5,322,211	$0	$0	$0	$0	$0	$0	SNU
Johnson Jct-Morris 115 kV (SNU)	Johnson Jct-Morris 115 kV (SNU)	$9,716,856	$0	$0	$0	$5,283,328	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Big Stone-Browns Valley 230 kV (SNU)	Big Stone-Browns Valley 230 kV (SNU)	$285,086	$0	$0	$0	$119,965	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Big Stone-Blair 230 kV (SNU)	Big Stone-Blair 230 kV (SNU)	$150,183	$0	$0	$0	$77,742	$0	$0	$0	$0	$0	$0	$0	$0	SNU
J302&503 POI-Heskett 230 kV (SNU)	J302&503 POI-Heskett 230 kV (SNU)	$9,000,000	$0	$0	$0	$0	$0	$1,491,187	$0	$0	$0	$0	$0	$0	SNU
Hankinson-Wahpeton 230 kV (SNU, 2015Aug)	Hankinson-Wahpeton 230 kV (SNU, 2015Aug)	$400,000	$0	$0	$0	$189,946	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Hankinson-Wahpeton 230 kV (SNU, 2016Feb)	Hankinson-Wahpeton 230 kV (SNU, 2016Feb)	$1,050,000	$0	$0	$0	$329,054	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Johnson Jct-Ortonville 115 kV (SNU)	Johnson Jct-Ortonville 115 kV (SNU)	$16,850,000	$0	$0	$0	$9,161,819	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Big Stone 230-115-13.8 kV xfmr (SNU)	Big Stone 230-115-13.8 kV xfmr (SNU)	$3,250,000	$0	$0	$0	$1,467,717	$0	$0	$0	$0	$0	$0	$0	$0	SNU
Wishek-Merricourt 230 kV (NRIS)	Wishek-Merricourt 230 kV (NRIS)	$5,800,000	$0	$0	$0	$0	$0	$3,133,654	$1,966,940	$0	$0	$0	$0	$699,407	NRIS
Iowa Falls Industrial-Farm Tap 69 kV (NRIS)	Iowa Falls Industrial-Farm Tap 69 kV (NRIS)	$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000	$0	NRIS
Iowa Falls Industrial 161-69 kV xfmr (NRIS)	Iowa Falls Industrial 161-69 kV xfmr (NRIS)	$3,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000	$0	NRIS
Wall Lake-Wright 161 kV (NRIS)	Wall Lake-Wright 161 kV (NRIS)	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500,000	$0	NRIS
Wright 161-69 kV xfmr (NRIS)	Wright 161-69 kV xfmr (NRIS)	$1,750,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,750,000	$0	NRIS
Iowa Falls Industrial-Wellsburg 161 kV (NRIS)	Iowa Falls Industrial-Wellsburg 161 kV (NRIS)	$2,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,200,000	$0	NRIS
Sweetwater-Langdon 115 kV line	Sweetwater-Langdon 115 kV line	$500,000	$0	$0	$0	$0	$0	$0	$500,000	$0	$0	$0	$0	$0	MPC AFS
Upgrade related to Cooper	Upgrade related to Cooper	$625,292,807	$33,991,390	$304,458,010	$9,910,878	$47,660,105	$46,944,033	$12,381,657	$48,651,589	$53,374,911	$27,381,494	$3,608,177	$24,389,277	$12,541,286	SPP AFS
Rebuild Bismark - Hilken 230kV circuit 1	Rebuild Bismark - Hilken 230kV circuit 1	$22,290,721	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,290,721	SPP AFS
Rebuild Bismark - Hilken 230kV circuit 2	Rebuild Bismark - Hilken 230kV circuit 2	$22,290,721	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,290,721	SPP AFS
Rebuild Tekamah - S1226 161 kV circuit 1	Rebuild Tekamah - S1226 161 kV circuit 1	$19,431,803	$0	$0	$0	$0	$0	$0	$0	$19,431,803	$0	$0	$0	$0	SPP AFS
Rebuild Sioux Falls - Pahoja 230 kV circuit 1	Rebuild Sioux Falls - Pahoja 230 kV circuit 1	$21,430,936	$0	$0	$0	$7,737,888	$4,254,361	$2,000,946	$7,437,741	$0	$0	$0	$0	$0	SPP AFS
Rebuild Raun - Tekamah 161 kV circuit 1	Rebuild Raun - Tekamah 161 kV circuit 1	$34,534,047	$0	$0	$0	$0	$0	$0	$0	$34,534,047	$0	$0	$0	$0	SPP AFS
Rebuild Mingo - Setab 345 kV circuit 1	Rebuild Mingo - Setab 345 kV circuit 1	$50,618,173	$0	$0	$0	$18,179,747	$0	$5,287,149	$21,456,502	$0	$0	$0	$0	$5,694,775	SPP AFS
Total Cost Per Project for Actual NRIS Elections for each Project	**Total Cost Per Project for Actual NRIS Elections for each Project**	**$2,064,086,409**	**$118,815,480**	**$395,282,215**	**$14,567,010**	**$166,690,230**	**$119,247,117**	**$98,933,492**	**$500,871,726**	**$166,868,656**	**$51,174,912**	**$37,164,828**	**$234,091,589**	**$160,379,154**	

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