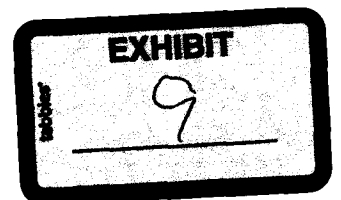


CapX2020 Group 1 Projects

MISO Cost Allocation Methodology

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Exhibit 9
Emineth & Associates Court Reporters

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Summary

This Appendix is provided in connection with Applicants' Application for an Advanced Determination of Prudence and addresses issues concerning ratepayer impact arising out of the CapX2020 Group 1 Projects (hereinafter referred to collectively as either "CapX2020 Group 1 Projects" or "Group 1 Projects" and each individually as Project).

In an effort to provide the North Dakota Public Service Commission ("Commission") with meaningful information regarding potential cost-allocation scenarios, Applicants have attempted to work through the Midwest Independent Transmission System Operator, Inc. ("MISO") cost allocation process pursuant to Attachment FF¹ of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). As will be discussed in this Appendix, there are various approaches to the allocation of transmission costs within the MISO Transmission System. Allocation of costs for those CapX2020 Group 1 Projects that are designated by MISO as "Baseline Reliability Projects" (the Fargo – Twin Cities 345 kV Project ("Fargo Project") and the Bemidji – Grand Rapids 230 kV Project ("Bemidji Project") and portions of La Crosse – Twin Cities 345 kV Project ("La Crosse Project")) is fairly straight forward. Cost allocation for the Brookings County – Twin Cities 345 kV Project ("Brookings Project") is likely to be more complex and will likely evolve over time.

In spite of these challenges and uncertainties, Applicants have attempted to estimate how costs of the CapX2020 Group 1 Projects will be allocated to the users of the MISO Transmission System, and in particular to Applicants. While the evolving rules and protocols make precise calculations difficult, some summary conclusions can be drawn. In the event that MISO develops cost allocation mechanisms that treat all four of the Group 1 Projects in a substantially similar fashion, the estimated cost to their respective North Dakota jurisdictional customers

¹ Attachment FF is sometimes referred to as "RECB," which stands for Regional Expansion and Criteria Benefits and was the name of the Midwest ISO stakeholder task force that developed the cost inclusion and allocation criteria.

for each Applicant will be the MISO charges on approximately \$40-60 million of investment for Xcel Energy and \$35-40 million of investment for Otter Tail.²

The following chart breaks this estimate down by Project:

	Xcel Energy	Otter Tail
Fargo Project*	\$13-16 million*	\$20-22 million*
Bemidji Project %	\$1-2 million%	\$5-7 million%
La Crosse Project+	\$9-11 million+	\$75,000+
Brookings Project^	\$22-27 million^	\$11-13 million^
Total investment attributable to ND	\$40-60 million	\$35-40 million
Approximate levelized revenue requirement per year in ND	\$9-10 million	\$7-7.5 million

*Assumes MISO cost allocation applicable to Baseline Reliability Projects applies.

% Assumes a combination of the MISO formula applicable to Baseline Reliability Projects and portion of Project designated non-MISO not subject to recovery of revenue requirements under the MISO Tariff.

+Assumes a combination of the MISO formula applicable to Baseline Reliability Projects and MISO Attachment O allocation for aspects of projects not eligible for cost sharing.

² As with any project that is still in the permitting stages, the final costs of the CapX2020 Group 1 Projects will not be known until they are completed. Applicants' submittal of costs estimated for this Application, pursuant to N.D.C.C. §49-05-16, and discussed herein are, therefore, estimates. These approximate totals are based on the estimated project costs in 2007 dollars and are subject to adjustment based on final route selection, timing of construction and the potential for unforeseen circumstances. Applicants will provide the Commission with updates on the costs and will advise the Commission of material changes in costs or material changes in MISO's treatment of the costs.

^Assumes MISO cost allocation applicable to Generator Interconnection Project applies. This assumption creates a high-cost “conservative” scenario for use in this proceeding. However, it is likely the Brookings Project’s costs will be allocated by some different (yet to be developed) methodology. As discussed below, MISO, Applicants and stakeholders are actively working to develop different allocation mechanisms for the Brookings Project.

Cost Recovery and Allocations

A. Recovery of Capital Costs

As members of MISO, Applicants will recover their respective capital costs of each of the Group 1 Projects pursuant to the MISO Tariff (i.e., the segments of each Project that are eligible, under MISO Attachment FF, to receive cost-sharing, as discussed below). Those final eligible costs of ownership, pursuant to the final Ownership Agreements negotiated amongst the utilities participating in the CapX2020 Initiative (the “CapX2020 Utilities”), will be submitted by Applicants pursuant to MISO Attachment GG, the revenue requirements formula. For those segments of the Group 1 Projects without an eligible cost-sharing RECB designation, MISO will compute each MISO transmission owner’s MISO revenue requirements and transmission charges pursuant to Attachment O of the MISO Tariff. The non-MISO transmission owners will determine their own requirements and charges under their respective open access transmission tariffs.

It is expected that 100% of the Fargo and Brookings Projects will be part of the MISO Transmission System³ and subject to the cost allocation and cost recovery provisions of the MISO Tariff given that it is anticipated that all owners will be MISO

³ For purposes of this Appendix C, Transmission System is defined pursuant to the MISO Tariff as: “The transmission facilities owned or controlled by entities that have conveyed operational control to the Transmission Provider that are used to provide Transmission Service under Module B of this Tariff. The Transmission System includes facilities, the operational control of which has been transferred to the Transmission Provider subject to Commission approval under Section 203 of the Federal Power Act. In addition, the Transmission System includes other facilities booked to transmission accounts that are not controlled or operated by the Transmission Provider but are facilities that the Transmission Owners, by way of the Agency Agreement, have allowed the Transmission Provider to use in providing service under this Tariff. While not part of the Transmission System, service over Distribution Facilities is available through the execution of a Service Agreement pursuant to Schedule 11 of this Tariff. The term Transmission System shall include the Transmission System (Michigan).”

transmission-owning members. Approximately 80% of the La Crosse Project and 68.5% of the Bemidji Project will be part of the MISO Transmission System. Companies that are not transmission-owning members of MISO will own the remainder of these Projects and obtain cost recovery from their ratepayers. CapX2020 Utilities that are transmission-owning members of MISO will recover their respective share of each Group 1 Project from charges MISO imposes on the users of the MISO Transmission System, including Applicants.

Table 1, below, shows the expected ownership share of each of the Group 1 Projects. These values represent the ownership percentages if all participants were to elect to invest at maximum specified levels. Because final ownership proportions have not yet been agreed on, these allocations are subject to change.

Table 1

Expected Ownership Shares of CapX2020 Projects (%)

Transmission Owner	Twin Cities - Fargo 345 kV Project	Twin Cities - Brookings County 345 kV Project	Twin Cities - La Crosse 345 kV Project	Bemidji - Grand Rapids 230 kV Project
Central Minnesota Municipal Power Agency ("CMMPA")		2.2%		
Dairyland Power Cooperative ("DPC")			11.0%	
Great River Energy ("GRE")	25.0%	16.5%		13.0%
Minnesota Power ("MP")	14.7%			9.3%
Minkota Power Cooperative ("MPC")				31.5%
Missouri River Energy Services ("MRES")	11.0%	5.1%		
Otter Tail Power Company ("OTP")	13.2%	4.1%		20.0%
Rochester Public Utilities ("RPU")			9.0%	
Southern Minnesota Municipal Power Agency ("SMMPA")			13.0%	
WPPI Energy ("WPPI")			3.0%	
Xcel Energy	36.1%	72.1%	64.0%	26.2%
Total	100.0%	100.0%	100.0%	100.0%

B. MISO Cost Allocation

Most of the CapX2020 Utilities are transmission-owning members of MISO. As a general matter, MISO calculates a revenue requirement for the recovery of costs for the owners of the transmission facilities under the MISO Tariff and charges *users* of the MISO Transmission System in order to collect and remit to the MISO transmission *owners* their cost recovery on their transmission assets. Therefore, CapX2020 Utilities that are members of MISO will, in general, recover their capital costs for their ownership of the Group 1 Projects from MISO.

As noted above, in order to pay the *owners* of the transmission in the MISO footprint, MISO charges the *users* of the transmission facilities in the MISO footprint for their use of those transmission facilities. Thus, MISO CapX2020 Utilities, as users of transmission facilities in the MISO footprint, will pay a portion of those charges. It is these charges to use the transmission in the MISO footprint, including the CapX2020 Group 1 Projects, for which CapX2020 Utilities will incur costs and which will be recovered from the ultimate benefactors of this use, the CapX2020 Utilities' ratepayers.

1. MTEP Analysis

Each year, MISO reviews all of the transmission expansion plans proposed by the MISO transmission owners and independently determines those projects that are to be included in what is known as "Appendix A" of the Midwest Transmission Expansion Plan ("MTEP"). Appendix A projects are projects that have satisfied MISO's factors to be the preferred solution to an identified reliability, policy or other need, or to achieve an identified cost savings or other benefit and that have been approved by the MISO Board of Directors. The project justification process includes consideration of a variety of factors including urgency of need and comparison from amongst alternatives of operating performance, initial investment costs, robustness of the solution, longevity of the solution provided, and performance against other economic metrics. Projects in Appendix A may be generated from the Baseline Planning process, or from the Generator Interconnection or Transmission Service Request study processes. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

MISO's cost allocation process is outlined in Attachment FF, Section III of its Tariff. At the present time, MISO assigns costs based on four different categories.

Baseline Reliability Projects (“BRP”)

Generation Interconnection Projects (“GIP”)

Transmission Delivery Service Projects

Regionally Beneficial Projects (“RBP”)

The CapX2020 Group 1 Projects have been designated either as a BRP or GIP. Therefore, this discussion focuses on those two categories.

Baseline Reliability Projects are defined as projects that serve a documented need for baseline reliability, and are eligible for MTEP cost sharing if they: 1) have a total cost of \$5M or more; or 2) have a project cost below \$5M, but a total cost that is 5% or more of the transmission owners net plant as established according to Attachment O.

All costs for BRPs with a rated voltage of 100 kV through 344 kV are allocated to Transmission Customers in designated sub-regional pricing zones. The subregions and pricing zones are determined on a case-by-case basis using the Line Outage Distribution Factor methodology (LODF).⁴ MISO then models the LODF for each pricing zone for each new transmission facility. LODF is used because it is considered by MISO planners as a way to determine the added benefit of a new transmission facility to each of the pricing zones. Generally, pricing zones in close proximity to the proposed transmission facility have the greatest LODF cost allocation and those furthest away have little to no cost allocation from the LODF method thus this benefit assignment approach is defined as being sub-regional.

For BRPs of 345 kV or higher, the RECB criteria defines some of the benefit of the proposed transmission facility as being for system-wide reliability. Therefore a portion of the costs of the proposed facility (20%) is assigned to all pricing zones in MISO on what is known as a “postage stamp” basis. Postage stamp cost allocation spreads cost responsibility proportionally to the load in the pricing zones of MISO

⁴ LODF is an engineering calculation of the change of flows on the Transmission System created by the addition of a new transmission facility. MISO uses computer software to measure and model the LODF of all facilities within the MISO Transmission System for each new facility added to the system.

thus this benefit assignment approach is defined as being regional. The remaining 80% of the project costs are allocated sub-regionally to all Transmission Customers within designated pricing zones. As before, the sub-regions and pricing zones are determined on a case-by-case basis using the LODF process as previously described.

Under the current MISO Tariff, all upfront costs for GIPs are paid by the Interconnection Customer. For generation resources that are qualified as designated Network Resources of have a purchase power agreement of one year or more with a MISO Load, the Interconnection Customer may be repaid up to 50% of the costs of the GIP which is allocated among the pricing zones using the same methodology applicable to BRPs. The remaining 50% is directly assigned to the Interconnection Customer. The only exception is that all facilities classified as Transmission are considered for allocation purposes (i.e., cost allocation is not cut off at 100 kV).

If the initial screening criteria of RECB determines that the benefits of a proposed transmission facility is local in nature, then the assignment of costs for that facility is left to the local pricing zone of the owner of the facility. For example, a proposed transmission facility that serves a single customer on a radial line would be directly assigned for the benefit of that customer. Similarly, a proposed transmission facility that primarily benefits a local load center or even a load center that is not part of the MISO system would be assigned for the benefit of that local load center.

2. Revenue Requirement and Cost Allocation

For the costs for existing transmission or new transmission that is not eligible for cost sharing, the affected transmission owner will generally incorporate the costs of those facilities in its rate base as calculated pursuant to Attachment O of the MISO Tariff. As described below, portions of the La Crosse Project are not eligible for cost sharing under the MISO Tariff; thus those costs are included into the transmission owners' (including Applicant Xcel Energy) MISO rate base calculated pursuant to Attachment O.

MTEP projects that qualify for cost sharing are reported through MISO Attachment GG revenue requirement and rates calculations. The Attachment GG information is used for tracking costs and in-service dates of approved MTEP cost shared projects and for distributing the revenues associated with such charges. Schedule 26 of the MISO Tariff provides the rate recovery mechanism by which the MISO collects the Attachment GG revenue requirements. If a new transmission

facility qualifies for MISO cost sharing (pursuant to Attachment FF of the MISO Tariff and as described above), the revenue requirements are determined through Attachment GG of the Tariff and the subsequent recovery of those revenue requirements are assessed under Schedule 26 of the MISO Tariff.

C. Cost Allocations and Ratepayer Impacts of the Group 1 Projects

The Fargo Project and the MISO portion of the Bemidji Project have been designated as BRPs in the 2006 and 2008 MTEPs. The segment of the La Crosse Project from North Rochester to La Crosse has also been designated as a BRP in the 2008 MTEP. The Hampton Corner to North Rochester 345 kV segment of the La Crosse Project and both 161 kV circuits of the La Crosse Project were screened as local facilities under the RECB criteria because the primary benefit of these facilities are for the load of two non-MISO CapX2020 Utilities (Dairyland Power Cooperative (“DPC”) and Rochester Public Utilities (“RPU”)). Similarly, a portion (31.5%) of the Bemidji Project is assigned to a non-MISO CapX2020 Utilities (Minnkota Power Cooperative). Thus, that portion is not treated as a BRP by MISO. Finally for the Brookings Project, MISO has stated that this line is primarily a GIP under RECB (no near term BRP benefit and no RBP benefit). MISO is still working through the specific cost allocation of the Brookings Project costs attributable to the generators that require the Brookings Project for their interconnection.

In summary each of the CapX2020 Group 1 Projects have been designated for cost responsibility as follows under the RECB criteria:

Fargo Project – All of the cost responsibility assigned as a BRP with 20% through postage stamp to all MISO pricing zones and 80% through the LODF method.

Bemidji Project – 68.5% of the cost responsibility assigned as a BRP through the LODF method (as applicable to 100 kV through 344 kV projects) and 31.5% of the cost of the project that non-MISO transmission owner Minnkota Power Cooperative will incur are not assigned to any MISO members.

La Crosse Project – All of the cost of the Hampton to North Rochester portion of this project along with the 161 kV lines from North Rochester into the Rochester area are assigned locally to the owners of this segment of the line. This approach is defined as “Market Participant Funding” for non-BRP facilities. Further, the cost of the project that non-MISO transmission owners DPC and RPU will incur are not assigned to any MISO members. Finally, the cost of the

remaining portion of the project is assigned as a BRP with 20% through postage stamp to all MISO pricing zones and 80% through the LODF method.

Brookings Project – 100% of the cost responsibility initially assigned to the generators that require the project for their interconnection (yet to be finalized). Any further cost responsibility assignment has not been finalized and will be discussed later in this document.

A more detailed discussion of the cost allocation results for each of these projects is contained in the following discussion.

1. The Fargo Project

The entire length of the Fargo Project has been designated as a Baseline Reliability Project in the 2008 MTEP. As a 345 kV Baseline Reliability Project, 20% of the costs for use of the Fargo Projects will be allocated to all pricing zones as a postage stamp rate. The remaining 80% of the costs of the Fargo Project will be allocated to pricing zones based on the LODF allocation method. Table 2 shows the estimated cost of the Fargo Project to each MISO pricing zone that contain CapX2020 Utilities load (after both the Postage Stamp and LODF allocations) based on the budgeted costs for the Project.

Table 2

**Allocation of Fargo Project Costs
to Midwest ISO Pricing Zones (million \$)**

Midwest ISO Pricing Zone	Twin Cities - Fargo 345 kV Project
ALTW (ITCM)	\$6.9
American Transmission Co.	\$17.6
GRE	\$17.8
MP	\$54.3
Northern States Power Co.	\$298.9
OTP	\$94.4
SMPA	\$0.3
All Other MISO Pricing Zones	\$86.1
Total	\$576.2

Pricing Zones Containing CapX Members	\$490.1
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Non-CapX Members Pricing Zones	\$86.1
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The next step in the process of allocating costs is to allocate these charges to the load in each pricing zone. These last charge assignments are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing

zone. Table 3 provides estimates of charges that CapX2020 Utilities will incur on a pricing zone basis for the Fargo Project.

Table 3

Allocation of Fargo Charges to Owners for CapX2020 Projects (\$1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Twin Cities - Fargo 345 kV Project
GRE	ALTW (ITCM)	\$213
	GRE	\$15,793
	MP	\$4,889
	NSP	\$25,404
	OTP	\$10,190
MP	MP	\$47,863
Xcel Energy	ALTW (ITCM)	\$14
	GRE	\$1,209
	MP	\$54
	NSP	\$261,808
	OTP	\$26,041
OTP	OTP	\$48,214
SMMPA	ALTW (ITCM)	\$69
	GRE	\$783
	NSP	\$4,782
	SMMPA	\$334
CMMPA	ALTW (ITCM)	\$62
	NSP	\$1,793
DPC	ATC	\$53
	NSP	\$5,081
MRES	ALTW (ITCM)	\$117
	NSP	\$5,081
	OTP	\$9,907
WPPI	ATC	\$1,055
	NSP	\$1,793
Total		\$472,600

Non-CapX Member Pricing Zones	\$86,083
Non-CapX Members in CapX Member Pricing Zones	\$17,517

Total Project Costs	\$576,200
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Therefore, some Project costs will be recovered through MISO charges paid by all MISO transmission owners through the postage stamp rate and the remainder will be recovered from MISO customers that more directly benefit from the Project as determined by MISO's LODF methodology.

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have an approximate cost responsibility of \$289,126,000 for the Fargo Project and that Otter Tail will have an approximate cost responsibility of \$48,214,000 for the Fargo Project. Of those MISO charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers. 41.3% of those charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Fargo project to their respective North Dakota jurisdictional customers for each Applicant, as represented in the MISO charges each Applicant will incur, is the MISO revenue requirements on approximately \$13,357,621 of investment for Xcel Energy and approximately \$19,864,168 of investment for Otter Tail.

2. The Bemidji Project

The Bemidji Project was designated as a Baseline Reliability Project in the 2006 MTEP. As a Baseline Reliability Project less than 345 kV, all of the CapX2020 Utilities who are MISO members' share of the Bemidji Project (68.5% of the costs of the Bemidji Project) will be allocated on a pricing zone basis to those pricing zones that benefit from the Bemidji Project based on MISO's LODF calculation (sub-regional basis). Table 4 shows the estimated charges on a pricing zone basis for the Bemidji Project.

Table 4

**Allocation of Bemidji Project Costs
to Midwest ISO Pricing Zones (million \$)**

Midwest ISO Pricing Zone	Bemidji - Grand Rapids 230 kV Project
ALTW (ITCM)	\$0.4
American Transmission Co.	\$3.6
GRE	\$1.5
MP	\$21.0
Northern States Power Co.	\$26.7
OTP	\$29.0
Total	\$82.2

The remaining 31.5% of the Bemidji Project is expected to be owned by Minnkota Power Cooperative, which is not a transmission owning member of MISO. The costs to Minnkota of owning its respective portion of the Bemidji Project will be recovered by its ratepayers.

As noted above, the charges allocated to each pricing zone are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing zone. Table 5 provides estimates of charges that Applicants will incur on a pricing zone basis for the Bemidji Project.

Table 5

Allocation of Bemidji Charges to Owners for CapX2020 Projects (\$1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Bemidji - Grand Rapids 230 kV Project
GRE	ALTW (ITCM)	\$11
	GRE	\$1,339
	MP	\$1,889
	NSP	\$2,266
	OTP	\$3,130
MP	MP	\$18,475
Xcel Energy	ALTW (ITCM)	\$1
	GRE	\$103
	MP	\$21
	NSP	\$23,350
	OTP	\$7,988
OTP	OTP	\$14,798
SMMPA	ALTW (ITCM)	\$4
	GRE	\$66
	NSP	\$426
	SMMPA	\$0
CMMPA	ALTW (ITCM)	\$3
	NSP	\$160
DPC	ATC	\$11
	NSP	\$453
MRES	ALTW (ITCM)	\$6
	NSP	\$169
	OTP	\$3,043
WPPI	ATC	\$219
	NSP	\$160
Total		\$78,090

**Table 5
(continued)**

Allocation of Bemidji Charges to Owners for CapX2020 Projects (\$1000)

Non-CapX Member Pricing Zones		\$64
Non-CapX Members in CapX Member Pricing Zones		\$4,046
Non MISO Owners		
	MPC	\$37,800
Total Non BRP		\$37,800
Total Project Costs		\$120,000

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have a cost responsibility for \$31,500,000 of investment for the Bemidji Project and that Otter Tail will have a cost responsibility for \$14,800,000 of investment for the Bemidji Project. Of those charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers. 41.3% of those charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Bemidji Project to their respective North Dakota jurisdiction for each Applicant, as represented by the MISO charges each Applicant will incur, is the MISO revenue requirement on approximately \$1,454,000 of investment for Xcel Energy and approximately \$6,112,000 of investment for Otter Tail.

3. The La Crosse Project

As mentioned above, it is expected that 80% of the La Crosse Project will be owned by CapX2020 Utilities who are transmission owning members of MISO. The

other 20% will be owned by RPU (9%) and DPC (11%). The non-MISO 20% of the La Crosse Project will be recovered by RPU and DPC from their ratepayers.

The 345 kV segment of the La Crosse Project from North Rochester to North La Crosse has been designated as a Baseline Reliability Project in the 2008 MTEP. Therefore, the costs for this segment will be allocated similarly to the costs of the Fargo Project. Twenty percent of the costs for use of this segment of the La Crosse Projects will be allocated to all pricing zones as a postage stamp rate. The remaining 80% of the costs of this segment of the La Crosse Project will be allocated to pricing zones based on the LODF allocation method.

The Hampton Corner to North Rochester 345 kV segment of the La Crosse Project and both 161 kV circuits of the La Crosse Project were not designated as a RECB Project. Therefore, the transmission charges for this segment will be determined based on the MISO Attachment O formula and incorporated into the applicable pricing zone rate in proportion to each MISO transmission owning member's ownership share.

Table 6 shows the estimated cost of the La Crosse Project to each MISO pricing zone based on the budgeted costs for the Project and anticipated ownership shares.

Table 6

**Allocation of La Crosse Project Costs
to Midwest ISO Pricing Zones (million \$)**

Midwest ISO Pricing Zone	Twin Cities - La Crosse 345 kV Project
ALTW (ITCM)	\$25.1
American Transmission Co.	\$36.8
GRE	\$3.7
MP	\$3.9
Northern States Power Co.	\$135.0
OTP	\$0.4
SMPA	\$18.1
All Other MISO Pricing Zones	\$30.1
Total	\$253.0

Pricing Zones Containing CapX Members	\$222.9
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Non-CapX Members Pricing Zones	\$30.1
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As noted above, the charges allocated to each pricing zone are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing zone. Table 7 provides estimates of charges that Applicants will incur on a pricing zone basis for the La Crosse Project.

Table 7

Allocation of La Crosse Charges to Owners for CapX2020 Projects (\$1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Twin Cities - La Crosse 345 kV Project
GRE	ALTW (ITCM)	\$777
	GRE	\$3,287
	MP	\$348
	NSP	\$11,472
	OTP	\$39
MP	MP	\$3,398
Xcel Energy	ALTW (ITCM)	\$50
	GRE	\$252
	MP	\$4
	NSP	\$118,092
	OTP	\$100
OTP	OTP	\$185
SMMPA	ALTW (ITCM)	\$251
	GRE	\$163
	NSP	\$2,159
	SMMPA	\$18,146
CMPA	ALTW (ITCM)	\$226
	NSP	\$810
DPC	ATC	\$110
	NSP	\$2,294
MRES	ALTW (ITCM)	\$426
	NSP	\$135
	OTP	\$38
WPPI	ATC	\$2,208
	NSP	\$810
Total		\$165,781

**Table 7
(continued)**

Allocation of La Crosse Charges to Owners for CapX2020 Projects (\$1000)

Non-CapX Member Pricing Zones	\$30,141
Non-CapX Members in CapX Member Pricing Zones	\$57,128

Non MISO Owners		
	DPC	\$47,157
	RPU	\$38,583
Non-BRP		
	SMMPA	\$14,610
	WPPI	\$3,372
	Xcel Energy	\$71,928
Total Costs Not Assigned through BRP		\$175,650

Total Project Costs	\$428,700
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Therefore some Project costs will be recovered through MISO charges paid by all MISO transmission owners through the postage stamp rate. The remainder will be

recovered by MISO members who serve load in affected pricing zones as determined by MISO's LODF methodology and as incorporated into each owner's MISO pricing zone pursuant to Attachment O methodologies.

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have a cost responsibility for \$190,426,000 of investment for the La Crosse Project and that Otter Tail will have a cost responsibility for \$185,000 of investment. Of those charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers and 41.3% of the charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the La Crosse Project to their respective North Dakota jurisdictional customers for each Applicant, as represented by the MISO charges each Applicant will incur, is the MISO revenue requirements on approximately \$8,797,681 of investment for Xcel Energy and approximately of investment \$76,220 for Otter Tail.

4. The Brookings Project

In MTEP 2008, MISO determined that the Brookings Project is considered a GIP. As stated above, GIPs are those additions to the MISO transmission system necessary for the interconnection of new or the upgrading of existing generation ("Network Upgrades").⁵ This decision is currently being discussed and analyzed and, as described below, MISO is in the process of a public stakeholder process designed to determine whether and how the Tariff might be changed to address stakeholder concerns over this designation.

The MISO cost allocation process for GIP facilities requires the affected generators to pay 100% of the cost of such facilities and allows for up to 50% of the initial assignment of cost responsibility to be passed back to the CapX2020 Utilities who are MISO transmission owners depending on the ultimate use of the generation.

⁵ In the case of the Brookings Project, MISO has identified a group of nineteen generators under study for interconnection to the MISO system consisting of 1,300 MW of generating capacity. These studies have identified the Brookings Project as a necessary Network Upgrade for the reliable interconnection of the proposed generation projects. Specifically, these nineteen generators have a measurable contribution to system overloading if the Brookings Project is not built. Therefore, MISO's starting position for allocation of the generation portion of the costs of the Brookings Project should be assigned to the generators making up the 1,300 MW of capacity studied.

This designation creates a number of difficult complications in the case of the Brookings Project:

The generators who will actually use the Brookings Project are currently unknown.

Even those 19 generators identified by MISO do not have signed interconnection agreements or power purchase agreements.

It is too early to specify how much of the potential 50% cost of the Brookings Project will actually be passed back to the CapX2020 Utilities who are MISO transmission owners under the MISO Tariff.

The timing of the construction of the transmission as compared to the timing of the completion of the generation does not fit well under the Tariff.

The Tariff requirement that generation projects fund 100% the Brookings Project is problematic since such generator projects do not yet exist and are not available to provide such funding.⁶

In light of all of these issues, Applicants and others have raised concerns with MISO on the need to address this situation in some fashion in order to provide an allocation mechanism that is workable. In light of those concerns, there are several activities going on within MISO and/or in the MISO area that could affect the ultimate cost assignment methodology for the Brookings Project. MISO has convened a public stakeholder process to develop potential proposals for Tariff revisions. And MISO has reconvened its RECB task force to address possible solutions.⁷

⁶ The GIP Cost Allocation process is based on the premise that interconnection facilities are built in response to approved interconnection requests for which the generator has a signed interconnection agreement and generation commitment. In the case of the Brookings project, this sequence could be backwards where completion of the transmission facilities may precede the completion of the generation.

⁷ On another front that affects the Brookings Project, the Upper Midwest Transmission Design Initiative (“UMTDI”) is evaluating the transmission needs, including cost allocation issues, for a five state region including CapX2020 Group 1 Project states. Initial expectations of this group are that the Brookings Project is a foundational transmission facility required in order to achieve any of the increased transmission supply capability objectives of the group. Thus there is analysis underway to determine if it is appropriate for the Brookings project to be included in the cost allocation treatment that may come out of the UMTDI work efforts.

As a result of the RECB task force process, MISO submitted to FERC a proposal to modify the cost allocation methodology contained in its Tariff for the costs associated with generators interconnection to its Transmission System on July 9, 2009. In its filing, MISO proposed changing the 50%/50% cost share for the costs of Network Upgrades by allocating 90% of the costs of Network Upgrade facilities in a voltage class of 345 kV or higher to the generators and 10% of the costs to the users of the MISO Transmission System. The costs of the 10% of the Network Upgrades allocated to users of the MISO Transmission System would be allocated on a postage stamp basis to all MISO pricing zones. The outcome of this process may result in changes to the way the costs for the Brookings Project will be allocated to Applicants and other MISO members. These changes could result in substantially lower impacts to all of our ratepayers. Applicants will keep the Commission informed on this process and of the impact any revised Tariff procedure may have on this proceeding.

Since MISO's current position is that the Brookings Project is to be treated as a GIP, for purposes of this filing, Applicants have provided the calculation of the cost allocation under that category. Table 8 shows the estimated investment costs for the CapX2020 Utilities responsible for the Brookings Project.

Table 8

Investment Costs of Brookings Project Owners for CapX2020 Projects (\$1000)

Transmission Owner	Twin Cities - Brookings County 345 kV Project
CMMPA	\$15,346
GRE	\$115,088
MRES	\$35,572
OTP	\$28,598
Xcel Energy	\$502,898
Total	\$697,500

As shown in Table 4 above, it is expected that Xcel Energy will have an initial cost responsibility of approximately \$502,898,000 for the Brookings Project and that Otter Tail will have an initial cost responsibility of approximately \$28,598,000 for the Brookings Project. Of those charges to Xcel Energy, revenue requirements for 4.62% of that investment will be allocated to Xcel Energy's North Dakota jurisdictional customers. Revenue requirements for 41.3% of those investments by Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Brookings Project, as represented by MISO charges to be paid by each Applicant, to their respective North Dakota jurisdictional customers for each Applicant is the MISO revenue requirements on approximately \$23,233,888 of investment for Xcel Energy and approximately \$11,810,974 for Otter Tail.

As noted above, under the current MISO Tariff, these costs are to be initially funded by the affected generators, subject to refund of up to 50% depending upon the circumstances. But currently the generators are not in place to utilize and pay for these transmission improvements. The MISO Tariff does not resolve how funding is to be treated in such a circumstance and this issue creates a significant difficulty in developing and constructing transmission facilities for use by future generation. Until that and other issues relating to cost allocation have been resolved, it is unclear how these costs will be absorbed or recovered. For example, if the CapX2020 Utilities choose to move forward with the Brookings Project without generators, the utilities

would potentially need to fund the transmission improvements and would need to recover these costs from their retail customers until costs are re-assigned under the MISO Tariff. This is among the issues being considered by MISO.

Applicants would like to emphasize that these complex issues of cost responsibility are being discussed with stakeholders with the objective of reaching a workable solution by the end of the year. Many possible outcomes exist and stakeholders have many divergent points of view on the situation. Since the outcome is not yet known, we have simply allocated the jurisdictional portion of applicants' investment to North Dakota, without any adjustments, as an estimate of impact in the North Dakota. This provides the Commission with a potential worst case scenario for consideration.

5. Total Impact of CapX2020 Projects

For all of the CapX2020 Projects, the estimated cost to their respective North Dakota jurisdiction for each Applicant will be the MISO charges on approximately \$47 million of investment for Xcel Energy and approximately \$37 million of investment for Otter Tail. This ultimate cost responsibility represents an approximate annual levelized North Dakota jurisdictional revenue requirement of \$9.5 million per year for Xcel Energy and \$7.5 million for Otter Tail. However, Applicants will expend the costs of the CapX2020 Group 1 Projects over time through the final costs expected to be made in 2015.