June 18, 2021

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/M-20-900

Dear Mr. Seuffert:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

Petition of Minnesota Power for Approval of a Transmission Cost Recovery Rider.

The petition was filed on December 28, 2020 by:

Lori Hoyum
Regulatory Compliance Administrator
Minnesota Power
30 West Superior Street
Duluth, MN 55802.

The Department requests that Minnesota Power provide additional information in reply comments and is available to answer any questions that the Minnesota Public Utilities Commission may have in this matter.

Sincerely,

/s/ Stephen Collins
Financial Analyst
SC/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E015/M-20-900

I. INTRODUCTION

On December 28, 2020, Minnesota Power (MP or the Company) filed a petition requesting that the Minnesota Public Utilities Commission (Commission) approve the 2021 rate adjustment mechanism (Transmission Factor) for MP's Rider for Transmission Cost Recovery (TCR Rider, TCRR, Transmission Rider, or Rider), under Minnesota Statutes section 216B.16, subdivision 7b (the TCR Rider Statute). Specifically, MP requests approval to:

- Recover costs net of revenues of transmission facilities approved by the Commission under section 216B.243, or certified or deemed to be certified under section 216B.2425, or exempt from the requirements of section 216B.243;
- Recover charges incurred under a federally approved Midcontinent Independent System Operator (MISO) tariff for other transmission owners' regionally planned transmission facilities to be constructed that have been determined to benefit MP and the integrated transmission system; and new transmission facilities approved by the regulatory commission of the state in which the facilities are being constructed that MISO has determined to benefit Minnesota Power or the integrated transmission system; and
- Include all the MISO transmission resettlements for the Federal Energy Regulatory Commission (FERC) return on equity (ROE) changes in future Transmission Cost Recovery (TCR) filings following completion of the MISO process.

MP also requests that the 2021 Transmission Factor take effect the first of the month following Commission approval and no sooner than 90 days from the petition filing date. MP's petition contemplates that rates will come into effect no sooner than January 1, 2022.

II. TCR RIDER STATUTE

In 2005, the Minnesota Legislature enacted the TCR Rider Statute. The TCR Rider Statute states:

> Subd. 7b. **Transmission cost adjustment.**
>
> (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:

> (1) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or new transmission or distribution facilities that are certified as a priority project or deemed to be a priority transmission project under section 216B.2425;
> (2) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system; and
> (3) charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:

> (1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;
> (2) allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;
> (3) allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system;
>
> (4) allows the utility to recover costs associated with distribution planning required under section 216B.2425;

(5) allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under section 216B.2425;
(6) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;
(7) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;
(8) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;
(9) allocates project costs appropriately between wholesale and retail customers;
(10) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and
(11) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;
(2) a schedule for implementation of applicable projects;
(3) the utility's costs for these projects;
(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and
(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

III. HISTORY OF MP'S TCR RIDER

The instant petition is MP's eighth TCR petition. The Department provides a brief summary of the seven preceding petitions and corresponding Commission action below.

A. 07-965: FIRST TCR PETITION (2008 TRANSMISSION FACTOR)

On July 12, 2007, MP filed its first TCR petition, in Docket No. E015/M-07-965, requesting approval of its 2008 Transmission Factor.

On December 7, 2007, the Commission approved the petition. The Commission also stated that

> The Company shall maintain, and shall include with future filings for rate recovery, records sufficient to ascertain on a project basis that expenditures claimed by Minnesota Power are consistent with the guiding agreements between multiple owners of the project.
>
> The Company shall maintain expenditure, recovery, and tracker balance information on a project basis and shall supply such information with each annual renewal filing.

B. 08-1176: SECOND TCR PETITION (2009 TRANSMISSION FACTOR)

On September 30, 2008, MP filed its second TCR petition, in Docket No. E015/M-08-1176, requesting approval of its 2009 Transmission Factor.

On June 23, 2009, the Commission approved the petition with conditions, including:

> A. Minnesota Power shall provide supporting documentation to substantiate the actual Regional Expansion and Cost Benefit [RECB] charges incurred during the upcoming year as part of future Rider filings.
> B. Minnesota Power shall include in the rider any and all revenues received through the Regional Expansion and Cost Benefit process from this or other projects, as an offset to cost recovery.
> C. Minnesota Power shall justify any and all recovery of costs that are larger than originally estimated by the Company.

C. 10-799: THIRD TCR PETITION (2010 TRANSMISSION FACTOR)

On July 15, 2010, MP filed its third TCR petition, in Docket No. E015/M-10-799, requesting approval of its 2010 Transmission Factor.

On May 11, 2011, the Commission approved the petition with modifications. Notably, the Commission disallowed recovery of internal costs. In addition, the Commission stated that "Minnesota Power shall document actual RECB charges and revenues and include the information in future transmission cost recovery filings."

D. 11-695: FOURTH TCR PETITION (2011 TRANSMISSION FACTOR)

On June 29, 2011, MP filed its fourth TCR petition, in Docket No. E015/M-11-695, requesting approval of its 2011 Transmission Factor.

On November 12, 2013, the Commission approved the petition with modifications. Specifically, the Commission stated:

> The Company shall use a hybrid approach when accounting for net operating losses (NOLs) in its riders. That is, the NOL accumulated deferred income tax asset amount added to rate base each year should be based on the lower of the stand-alone and consolidated methods. The use of the consolidated method of tax calculation only applies to a rider with an NOL included in the calculation.
>
> The Company shall continue to exclude internal capitalized costs from recovery through its riders.
>
> …
>
> The Company shall continue to document actual charges and actual revenue offsets to its revenue requirements under the Regional Expansion Criteria Benefits cost-allocation process adopted by the Midcontinent Independent System Operator. The Company shall specifically identify such charges and offsets in all future Transmission Cost Recovery filings.

E. 14-337: FIFTH TCR PETITION (2014 TRANSMISSION FACTOR)

On April 24, 2014, MP filed its fifth TCR petition, in Docket No. E015/M-14-337, requesting approval of its 2014 Transmission Factor.

On February 23, 2015, the Commission approved the petition with modifications. Specifically, the Commission stated:

> 1. Minnesota Power's proposal to include NERC [North American Electric Reliability Corporation] Alert Projects in its 2014 TCR Rider is not approved.
>
> 2. The Commission approves Minnesota Power's proposal to include Multi-Value Projects (MVP) Auction Revenue Rights (ARR) revenues in the tracker and to reflect MVP ARR revenues in future filings and TCR factor calculations.

F. 15-472: SIXTH TCR PETITION (2015 TRANSMISSION FACTOR)

On May 22, 2015, MP filed its sixth TCR petition, in Docket No. E015/M-15-472, requesting approval of its 2015 Transmission Factor.

On February 3, 2016, the Commission approved the petition with modifications. Specifically, the Commission stated:

> Minnesota Power proposed to recover a revenue requirement of \$30,703,479 through the TCR rider, which includes an outstanding tracker balance of \$13,026,312, and \$14,375,026 for the following projects:[1]
>
> - ID# 102853 Peqout Lakes 115/34 kV Sub
> - ID #103752 115kV Pine Rv to Peq Lks
> - ID #103862 Badoura - Peq Lks 142L/147L Fiber
> - ID #103434 CAPX: 345kV Fargo to St. Cloud Phase 3
> - ID #105019 CAPX: 345kV Fargo to St. Cloud Phase 1
> - ID #103319 CAPX: 230kV Boswell to Bemidji
> - ID #105147 CAPX: 345kV Fargo to St. Cloud Phase 2
> - ID #106233 CAPX: 345kV Fargo to St. Cloud - ND Portion
> - ID #104975 CAPX: Boswell 230kV Sub - Add 230kV Exit
> - ID #104959 Savanna 115/15kV Sub
> - ID #105148 Savanna 115/15 Sub, Cloquet-Blackberry Line 9 tap
> - ID #105149 115kV Floodwood-Savanna Line #151
> - ID #105900 #39 Line Reconfiguration
> - ID# 105973 Zemple 230/115/23 kV Substation
> - ID #106052 115kV Line #153
> - ID #107264 230kV Boswell to Zemple Line #82
> - ID #107303 230kV Zemple to Cass Lk Line #904
> - ID #106905 115kV Line No. 28 Tap Removal
> - ID #106909 Deer River Substation Removal
>
> [1] The remaining \$3,302,141 is the sum of MISO Regional Expansion and Cost Benefit charges and credits for amounts recovered by other means.
>
> The Department objected to TCR rider recovery for two of the listed projects—the Deer River and 39 Line projects …
>
> …
>
> 1. Excluding the Deer River and 39 Line projects, Minnesota Power's Transmission Cost Recovery Rider petition is approved.
>
> 2. The Company shall use the jurisdictional demand allocators approved in the Company's last retail rate case and shall use the same allocators in future TCR Rider filings.

G. 16-664: MOST RECENT RATE CASE

On November 2, 2016, MP filed a general rate case (GRC) petition in Docket No. E015/GR-16-664. The GRC petition stated that MP anticipated incurring two TCR-eligible projects in the future: the Great

Northern Transmission Line (GNTL) and a 115 kilovolt (kV) transmission line and associated facilities in the Motley area (referred to internally by Minnesota as the Dog Lake project).[1]

The GRC petition also proposed that, other than MISO Regional Expansion and Cost Benefit (RECB) revenue and expenses and a Multi Value Projects (MVP) credit (ARR revenues), all transmission projects currently (at the time) recovered in the TCR Rider would be rolled into base rates. MP also stated that it would address Dog Lake and the GNTL in future TCR Rider dockets.[2]

On March 12, 2018, the Commission approved MP's rate case petition with modifications.

H. 19-440: SEVENTH TCR PETITION (2019 TRANSMISSION FACTOR)

On July 9, 2019, MP filed its seventh TCR petition, in Docket No. E015/M-19-440, requesting approval of its 2019 Transmission Factor. Consistent with MP's stated intent in the 16-664 docket, the petition requested approval to recover revenue requirements associated with the Dog Lake project, the GNTL, net RECB revenue or expenses, and a MVP project credit (ARR revenues).

On December 3, 2020, the Commission issued its Order Approving Transmission Cost Recovery, Clarifying Prior Order, and Requiring Filings (2019 TCRR Order) approving the petition with additional requirements. Specifically, the 2019 TCRR Order states:

> 1. The Commission approves Minnesota Power's petition as updated in Minnesota Power's supplemental reply comments dated February 24, 2020.
>
> 2. The Commission clarifies that the 28.3% limit in rider recovery in its June 30, 2015 order was intended to apply to the capital costs over the entire life of the Great Northern Transmission Line project and not the Construction-Work-In-Progress balance prior to the Great Northern Transmission Line project's in-service date.
>
> 3. Minnesota Power shall include in this proceeding the net credits it receives from MISO under Schedule 9 for Dog Lake and Great Northern Transmission Line.
>
> 4. Minnesota Power shall file a copy of FERC's audit report regarding Minnesota Power's transmission formula rates in this proceeding when it becomes available.

[1] Minke Direct filed November 2, 2016 in E015/GR-16-664, page 11.
[2] Minke Direct, page 12.

> 5. Minnesota Power shall include any refunds that it receives for 2016–2019 return on equity reductions in future Transmission Cost Recovery Rider filings.
>
> 6. Minnesota Power shall file compliance tariffs reflecting the modifications adopted in this order.
>
> 7. Minnesota Power shall file in their Transmission Cost Recovery Factor filing, annually, descriptions of all potentially eligible projects that they will seek recovery for in the future, and the impacts those projects will have on the Transmission Cost Recovery factor.

On December 10, 2020, MP made a compliance filing with the following tariff:

> Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.
>
> The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$1.51 per kilowatt-month [kW] for all Billing Demand kW and 0.167¢ per kW-hours [kWh] for all kWh
All other applicable Retail Rate Customers	0.318¢ per kWh for all kWh

MP's petition in the instant docket states that the 2019 Transmission Factor was to be applied to customer bills on January 1, 2021, the first day of the first full month following the issuance of the 2019 TCRR Order.

IV. DEPARTMENT ANALYSIS

MP proposes to update the TCRR tariff by modifying the transmission factor as follows. As can be seen, MP's proposed increase would approximately double the transmission factor.

Table 1: MP's Proposed Tariff Update[3]

	Approved 2019 Transmission Factor	Proposed 2021 Transmission Factor
Large Power Customer Demand Charge	$1.51 per kW-month	$3.56 per kW-month
Large Power Customer Energy Charge	0.167¢ per kWh	0.363¢ per kWh
All other applicable Retail Rate Customers	0.318¢ per kWh	0.742¢ per kWh

MP estimates that the updated transmission factor would increase total bills by 3.8% for Residential customers, 3.8% for General Service customers, 5.0% for Large Light & Power Customers, 7.0% for Large Power customers, and 2.3% for Lighting customers.

The Company's proposed tariff update is based on projected year-end tracker balance for 2020 (calculated using forecasted recoveries and MP's estimated 2020 revenue requirements) and 2021 revenue requirements,[4] as shown below.

Table 2: MP's Proposed Revenue Requirements and Billing Units

	Large Power	All Other Classes	Total Minnesota Jurisdiction
Revenue Requirements (annual)			
Projected Year-End 2020 Tracker Balance	$24,561,297	$11,400,780	$35,962,077
Proposed 2021 Revenue Requirements	$17,011,889	$10,570,821	$27,582,710
Total 2021 Factor Revenue Requirements	$41,573,186	$21,971,601	$63,544,787
Billing Units			
kW-month	545,563	n/a	n/a
kWh (annual)	5,035,842,978	2,959,275,000	n/a

Based on the information provided in MP's petition, a little more than half of MP's revenue requirement is due to the net costs of the GNTL and a little less than half is net RECB expenses. Dog Lake only accounts for about 1%.

From 2019 to 2020, MP's requested annual revenue requirements are roughly consistent at around $30 million each year. For context, the Commission's March 12, 2018 Order approving MP's most recent rate case cited total Minnesota revenue requirements of $825 million (Order Point 1).

[3] Petition, Exhibit A-1.
[4] Petition, page 42.

Table 3: MP's Requested TCRR Revenue Requirements

	Instant Petition						2019 Petition	
	2021		2020		2019		2019	
	$	% of Total	$	% of Total	$	% of Total	$	% of Total
MN Jurisdiction Total	**27,582,710**	**100.00%**	**31,073,883**	**100.00%**	**31,189,465**	**100.00%**	**28,384,191**	**100.00%**
Dog Lake Project	**318,729**	**1.16%**	**325,903**	**1.05%**	**340,194**	**1.09%**	**356,433**	**1.26%**
ID #108005 Dog Lake Substation Expansion	219,231	0.79%	224,237	0.72%	232,496	0.75%	243,856	0.9%
ID #108035 115kV Dog Lake - Badoura Line #40	3,122	0.01%	3,180	0.01%	3,625	0.01%	3,757	0.0%
ID #108547 Dog Lake Expansion - Line #24	31,277	0.11%	31,968	0.10%	32,982	0.11%	34,547	0.1%
ID #108550 Dog Lake Expansion - Line #155	49,704	0.18%	50,862	0.16%	55,219	0.18%	57,838	0.2%
ID #108985 Baxter 534 FDR Underbuild 115kV	15,395	0.06%	15,657	0.05%	15,872	0.05%	16,434	0.1%
					-			
GNTL	**44,872,114**	**162.68%**	**34,998,652**	**112.63%**	**17,722,702**	**56.82%**	**17,652,189**	**62.19%**
ID #105471 Great Northern Transmission Line	39,210,828	142.16%	29,781,272	95.84%	14,881,436	47.71%	14,672,351	51.69%
ID #107621 Iron Range Substation	3,005,101	10.89%	3,166,910	10.19%	2,013,485	6.46%	2,036,688	7.18%
ID #107623 Series Comp Station	1,579,308	5.73%	1,390,515	4.47%	656,893	2.11%	686,192	2.42%
ID #107626 Blackberry Substation Modifications	46,776	0.17%	24,309	0.08%	1,550	0.00%	8,282	0.03%
ID #107627 Arrowhead Substation Modifications	11,437	0.04%	6,930	0.02%	1,285	0.00%	3,049	0.01%
ID #107628 Forbes Substation Modifications	11,266	0.04%	7,984	0.03%	1,168	0.00%	3,659	0.01%
ID #107629 Hilltop Substation Modifications	9,202	0.03%	6,150	0.02%	990	0.00%	3,049	0.01%
ID #110418 Black River Regen	44,612	0.16%	45,741	0.15%	21,399	0.07%	26,017	0.09%
ID #110435 GNTL Togo Regen	30,007	0.11%	30,566	0.10%	12,774	0.04%	16,965	0.06%
ID #110738 GNTL Salol Radio Project	1,746	0.01%	1,809	0.01%	1,878	0.01%	1,876	0.01%
ID #110742 GNTL Williams Radio Project	1,457	0.01%	1,510	0.00%	1,565	0.01%	1,566	0.01%
ID #110743 Baudette Radio Project	1,799	0.01%	1,865	0.01%	1,932	0.01%	1,934	0.01%
ID #110744 GNTL Fairland Radio Project	1,638	0.01%	1,698	0.01%	1,761	0.01%	1,761	0.01%
ID #110745 GNTL Margie Radio Project	2,565	0.01%	2,658	0.01%	2,757	0.01%	2,756	0.01%
ID #110747 GNTL Effie Radio Project	3,178	0.01%	3,293	0.01%	3,416	0.01%	3,416	0.01%
ID #110748 GNTL Marcell Radio Project	1,316	0.00%	1,364	0.00%	1,414	0.00%	1,414	0.00%
ID #110751 GNTL Shannon Radio Project	1,021	0.00%	1,058	0.00%	1,097	0.00%	1,097	0.00%
ID #110753 GNTL Blackberry Radio Project	554	0.00%	574	0.00%	594	0.00%	595	0.00%
ID #110760 GNTL 115 kV Line 9 Mod	8,218	0.03%	8,964	0.03%	3,633	0.01%	7,883	0.03%
ID #110761 GNTL 230 kV Line 93	34,252	0.12%	37,019	0.12%	20,571	0.07%	27,399	0.10%
ID #110764 GNTL 230 kV Line 98	68,403	0.25%	99,136	0.32%	41,261	0.13%	67,422	0.24%
ID #110766 GNTL 230 kV Line 105	26,634	0.10%	29,078	0.09%	15,832	0.05%	21,867	0.08%
ID #110767 GNTL 230 kV Line 106	63,618	0.23%	69,486	0.22%	33,660	0.11%	51,862	0.18%
ID #111173 GNTL Fairland MW Site – MTEP 3831	95	0.00%	171	0.00%	75	0.00%	940	0.00%
ID #111174 GNTL Salol MW Radio – MTEP 3831	2,547	0.01%	3,081	0.01%	276	0.00%	2,148	0.01%
ID #112139 Iron Range Storage Building	*704,535*	*2.55%*	*275,511*	*0.89%*	-	0.00%	-	*0.00%*
Manitoba Hydro	**(27,851,047)**	**-100.97%**	**(17,270,765)**	**-55.58%**	**-**	**0.00%**	**-**	**0.00%**
6690271 Manitoba Ltd Payments	*(9,411,938)*	*-34.12%*	*(5,888,633)*	*-18.95%*	-	0.00%	-	*0.00%*
MH Must Take Fee (133 MW)	*(18,439,109)*	*-66.85%*	*(11,382,132)*	*-36.63%*	-	0.00%	-	*0.00%*
Net RECB Expenses	**10,682,773**	**38.73%**	**14,298,817**	**46.02%**	**13,875,505**	**44.49%**	**10,466,128**	**36.87%**
Other Offsets	**(439,859)**	**-1.59%**	**(1,278,724)**	**-4.12%**	**(748,936)**	**-2.40%**	**(90,559)**	**-0.32%**
Base Rates Revenue Credit (Dog Lake and GNTL)	*(47,303)*	*-0.17%*	*(46,898)*	*-0.15%*	*(34,875)*	*-0.11%*	-	*0.00%*
Dog Lake Base Rate Revenue Credit	*incl. above*	*incl. above*	*incl. above*	*incl. above*	*incl. above*	*incl. above*	*(4,880)*	*-0.02%*
MVP Project Credit	(49,628)	-0.18%	(60,724)	-0.20%	(63,864)	-0.20%	(85,679)	-0.30%
Schedule 9 Dog Lake Revenue Credit	*(14,784)*	*-0.05%*	*(18,565)*	*-0.06%*	*(12,869)*	*-0.04%*	-	*0.00%*
Schedule 9 GNTL Revenue Credit	*(328,144)*	*-1.19%*	*(1,152,537)*	*-3.71%*	*(637,328)*	*-2.04%*	-	*0.00%*

The Department reviews MP's proposed revenue requirements below.

A. GNTL

1. Project Eligibility

The Commission approved adding the GNTL to the TCRR in last year's TCRR docket. TCRR statute "terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates." Since costs have not been fully recovered and have also not been added to base rates, the Department concludes that the GNTL is still eligible for TCRR recovery.

2. Cost Recovery Background

MP owns 100% of the GNTL. However, given the project was built to facilitate the exchange of energy between Manitoba Hydro (MH) and MP, MP and MH have a cost-sharing arrangement.

Specifically, MP is only required to pay 46% of the GNTL capital costs and 51% of GNTL operation and maintenance (O&M) costs. Payments from Manitoba Hydro (the "6690271 Manitoba Ltd Payments" cited in MP's petition) cover the remaining 54% of capital costs and 49% of O&M costs.

In addition, MP receives a monthly "Must Take Fee" from Manitoba Hydro as part of a 133 megawatt power purchase agreement (PPA) between the two entities. The Must Take Fee is designed to cover 17.7% of capital costs and 17.7% of O&M costs.[5] Therefore, MP's ultimate responsibility is 28.3% (46% - 17.7%) of capital costs and 33% (51% - 17.7%) of O&M costs. MH is required to make the monthly payments during the contract term of the PPA, which is the 20-year period beginning when the GNTL is placed into service.

In summary, MH contributes to the GNTL costs in three ways.

1) MH paid MP a Non-Shareholder Contribution to Capital (NSCC) for 54% of the GNTL. This payment is reflection in a corresponding reduction in the plant-in-service balances reflected in the revenue requirement calculations for each component of the GNTL.
2) MH pays MP a Must Take Fee each month, as described above, which is calculated to contribute 17.7% of the GNTL's capital costs and 17.7% of O&M. The 2020 and 2021 revenue requirements for Must Take Fees are shown in the line labeled "MH Must Take Fee (133 MW)" on page 3 of Exhibit B-1. These payments began in 2020 after the GNTL began service.
3) MH pays MP for the 49% of O&M and property taxes not covered by MP's 33.3% ratepayer contribution and the 17.7% Must Take Fee contribution (49% = 1 – 33.% - 17.7%). The total 2020 and 2021 revenue requirements for these estimated contract payments for ongoing O&M and property taxes attributable to MH are shown in the line labeled "6690271 Manitoba Ltd Payments" on page 3 of Exhibit B-1. These payments also began in 2020 after the GNTL began service.

---

[5] The details of the Must Take Fee calculation are provided in the PPA. See MP's November 6, 2014 TRADE SECRET petition in Docket No. E015/M-14-960, Exhibit A, section 2.6.

Corresponding to MP's cost sharing arrangement with MH, the Commission's June 30, 2015 Order (Docket No. E-015/CN-12-1163) authorizing a CN for the GNTL set forth the following cost recovery conditions:

- Limit Minnesota Power's recovery in riders to an amount equal to 28.3 percent of the total capital costs of the Project or $201 million (in 2013 dollars), whichever is less,
- Allow Minnesota Power to request recovery of any excess costs only in a rate case where the costs will be subject to full prudence review,
- Put Minnesota Power on notice that it will have the burden of demonstrating the prudence of any additional costs and show why it would be reasonable to recover the additional costs from ratepayers given the representations made in this proceeding, and
- Require Minnesota Power to obtain prior approval from the Commission if it proposes to charge ratepayers for operation and maintenance costs greater than 33 percent of the project's total operation and maintenance costs at any time in the future.

GNTL began service on June 1, 2020, with the final component placed into service in July 2020. Prior to the in-service date, MP began acquiring property for the route in April 2016 after receiving the route permit. Based on Table 1 of the instant petition, material procurement began in late 2016 and construction started at the beginning of 2017.

3. *Summary of GNTL Revenue Requirements*

As shown in Table 4 and Exhibit B-1 (page 3) of the petition, MP proposes GNTL revenue requirements of $17,021,067 in 2021 and $17,727,887 in 2020. The 2021 revenue requirements consist of $44,872,114 in quasi-gross[6] GNTL revenue requirements, minus $9,411,938 of MH contributions for 49% of ongoing operating costs, and minus $18,439,109 in MH must-take fee payments, which as noted above accounts for 17.7% of the GNTL's capital and ongoing costs. The 2020 revenue requirements consist of $34,998,652 in quasi-gross GNTL revenue requirements, minus $5,888,633 for MH's 49% ongoing cost contribution and $11,382,132 for must-take fees.

MP provides detail for the Exhibit B-1 gross GNTL revenue requirements (MP's payment net of MH's NSCC) in Exhibit B-3. The Department confirmed that Exhibit B-3 matched Exhibit B-1.

4. *Plant In Service*

MP's total estimated capital costs for the GNTL were $663,752,601. According to page 2 of Exhibit B-9 to the petition, MP estimates that this amount is equivalent $587,282,915 in 2013 dollars. This recovery amount includes the Iron Range Material Storage Building and the "certain other Non-Manitoba Ltd. Charges." 28.3% of this amount is $166,201,065 in 2013 dollars, which is less than $201 million. Therefore, adding on the 17.7% of capital costs recovered through the Must Take Fee, MP's capital cost recovery is limited to 46.0% of the total $663,752,601 of capital costs, which equals $305,326,196.

---

[6] This amount is "quasi-gross" because it reflects plant-in-service net of MH's NSCC.

To check whether MP was complying with the $305,326,196 limit on capital cost recovery, the Department added up the total plant-in-service balances for each sub-project (ID#) in the GNTL as shown in Exhibit B-3 of the petition. The total Dec'21 ending plant-in-service balances was $303,365,645, which is less than the $305,326,196. The Department therefore concludes that MP has complied with the capital cost limits in the GNTL CN Order.

5. O&M and Property Taxes

Regarding O&M payments, the petition states:

> Operations and maintenance ("O&M") expenses for GNTL maintenance totaling about $483,000 are included in the 2021 budget. These costs include estimates for line inspections and maintenance, vegetation management, software patches at the Warroad location, utilities (electric, gas, and portable outhouses at remote sites), and snow plowing at the substations. This O&M cost is paid entirely by Minnesota Power, but the Company is reimbursed for a set level of O&M per the contract with Manitoba Ltd., and such O&M payments are passed along to Minnesota Power customers.

MP provides the monthly O&M and property tax expenses for the GNTL sub-projects in Exhibit B-3 on pages 16-93. These O&M and property tax expenses are the total amount since MH's contributions to O&M and property taxes are reflected separately.

The Department requests that MP provide, in reply comments, detailed calculations for the monthly requested GNTL property taxes and O&M as shown in Exhibit B-3 for each project ID#, and a clear explanation for why the total monthly amount of property taxes and O&M for each project ID# is reasonable and consistent with paragraph (d) of the TCR Statute:

> Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, **the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers [emphasis added]**

6. MP 100% Cost Allocation Proposals

Despite the language in the GNTL Order, the instant petition proposes to allocate 100% of costs to MP ratepayers for certain GNTL costs:

> There are two categories of GNTL project costs that are wholly Minnesota Power's responsibility with no Manitoba Ltd. ownership. These are: (1) the Iron Range Material Storage Building; and (2) certain other Non-Manitoba

> Ltd. Charges that were incurred by and for the benefit of only Minnesota Power.

a.) *Iron Range Material Storage Building*

Regarding the Iron Range Material Storage Building,[7] the instant petition states:

> The Iron Range Material Storage Building was constructed to store capital spares for the GNTL 500kV transmission line as well as the Iron Range 500kV substation. These assets are being held for future use when and if there is an interruption of service at either of those two locations. Further, the Iron Range Material Storage Building was stocked with specialized tooling and equipment to work on the transmission line should an event occur. Since Minnesota Power does not support other lines of this size, it was important to ensure that Minnesota Power, as Maintenance Provider, has the tools and equipment needed to bring the line back into service in the occurrence of an event. The location of the storage building is in an area where Minnesota Power previously did not have a service center or other location to perform maintenance activities or store equipment and materials. The storage building was not included in the original project scope and was added when it was determined that the existing storage facilities would not be sufficient to store required spares for the assets. Minnesota Power is reimbursed for these costs as part of the set level of O&M paid by Manitoba Ltd. per the Operations and Maintenance Agreement.[22] The O&M payments are passed along to Minnesota Power customers.
>
> [22] The O&M fee is discussed in more detail on page 27 [the Department notes that MP appears to be referring to page 29].

The GNTL CN Order is clear that cost recovery must be limited to 28.3% of the total capital costs (or, if less, $201 million in 2013 dollars) and 33% of O&M costs and that MP can only request recovery of excess costs in a rate case. Therefore, **the Department recommends that the Commission limit TCRR recovery of the Iron Range Material Storage Building to 28.3% of total capital costs and 33% of total O&M costs. The Department also requests that MP provide in reply comments additional information to demonstrate whether the Iron Range Material Storage building was least-cost relative to other alternatives considered.** Per the GNTL Order, MP can request 100% recovery of the Iron Range Material Storage Building in their next rate case.

In addition, the instant petition states:

> Now that the GNTL is in service, there are some minor changes to how the actual accounting and billing for Minnesota Power and Manitoba Ltd. is

[7] To the Department's understanding, this building was not included in the original GNTL plan and cost estimates. In other words, MP's is requesting recovery of this building for the first time in this docket.

> handled compared to what was anticipated for budget purposes. These changes reduced the 2018 year-end tracker balance that was previously provided in the 2019 TCR Factor Filing (Docket No. E-015/M-19-440) by $72,098, which is shown as a credit to customers in Exhibit B-1, page 2, in the category "Update to GNTL Internal Costs." At the inception and throughout the construction phase of the project, the Company allocated all of the 54 percent contribution from Manitoba Ltd to the 500 kV transmission line project (Project ID #105471). The 500 kV transmission line project was set up with CIAC from Manitoba Ltd. from a budgeting perspective, but set higher than 54 percent (closer to 60 percent) to compensate for the projects not receiving CIAC which resulted in the overall 46/54 percent split being maintained. After the projects went into service, 54 percent of the contribution from Manitoba Ltd. was transferred from the 500 kV transmission line project to each ancillary project that went into service. However, during the course of the project it was decided by the GNTL Construction Manager and the GNTL Management Committee that costs for **the Iron Range Material Storage Building (Project ID #112139)** and one small work order on the 500 kV transmission line project would both have 100 percent Minnesota Power cost responsibility, as described above in section IV.C.1. As a result, all capital projects now have 46 percent of internal costs backed out of the capital costs, **except Project ID #112139 has 100 percent backed out, and the 500 kV transmission line project, Project ID #105471, has 46.19 percent backed out. This adjustment is reflected in the current filing calculations and the impact to the 2018 year-end tracker balance is shown in Exhibit B-1, page 2.** [emphasis added]

Given the Department's above recommendation that the Commission only allow recovery of the 28.3% of the capital costs and 33% of the total O&M costs for the Iron Range Material Storage Building (Project ID #112139), for consistency **the Department recommends that MP back out the same amount of internal costs as other projects.**

b.) "Certain Other Non-Manitoba Ltd. Charges"

Regarding the "certain other Non-Manitoba Ltd. Charges," MP has stated they consist of the following:

- Legal-related costs of approximately $1.0 million, including attorney time to negotiate, develop and review the project agreements and amendments, as well as to secure the necessary state and federal (FERC) approvals for required permits costs and similar,
- GNTL Management Committee-related costs of approximately $0.8 million, including labor, travel, meeting room/facility rental, and meals when necessary, for in-person meetings with Manitoba Ltd. for the purpose of reviewing the project's progress, third-party engineering, and making decisions on various project components,

- Approximately $0.1 million of other costs, including employee recognition costs and project safety recognition awards, GNTL office set up, and administrative and general costs.

As noted above, the Commission has prohibited MP from recovering internal costs in the TCR Rider. The test year for base rates already includes a representative amount for costs such as a legal, travel, meals, etc. MP has not demonstrated that the "certain other Non-Manitoba Ltd. Charges" are not internal costs that are already recovered in base rates. Therefore, **the Department recommends that the Commission reject recovery of the approximately $1.9 million of "certain other Non-Manitoba Ltd. Charges."**

If the Commissions allows recovery of any "certain other Non-Manitoba Ltd. Charges," then, **per the GNTL CN Order, the Department recommends that the Commission limit cost recovery to 28.3% of capital costs and 33% of O&M costs.**

B. DOG LAKE

1. Background Information

On March 19, 2015, Great River Energy (GRE) and MP filed a petition in Docket Nos. ET2,E015/CN-14-853 and ET2,E015/TL-15-204 requesting that the Commission grant a CN and issue a route permit to construct 15.5 to 16.5 miles of new overhead 115 kilovolt (kV) transmission line in Morrison, Cass and Todd counties, Minnesota (Dog Lake Petition). The instant petition refers to this project as "Dog Lake." Specifically, GRE and MP proposed to:

- Construct a new single circuit 115 kV transmission line between the existing Minnesota Power "24 Line" transmission line and the new Crow Wing Power (CWP) Fish Trap Lake Substation. Some segments of the transmission line will carry distribution line underbuild,
- Convert the existing 34.5 kV Motley Substation to 115 kV service and add a three-way switch.
- Construct the new CWP Fish Trap Lake Substation to serve the new Minnesota Pipe Line Company (MPL) Fish Trap pump station,
- Add breakers to the existing Minnesota Power Dog Lake Substation using a more reliable ring bus design and construct a one-half mile transmission line between the substation and the "24 Line" 115 kV transmission line, and
- Install a three-way switch to allow for the construction of a future CWP Shamineau Substation.

Regarding ownership, the Dog Lake Petition stated:

> Minnesota Power will continue to own the Dog Lake Substation and the proposed half-mile of new 115 kV transmission line from the substation to the existing "24 Line" transmission line (to be renamed the "155 Line" transmission line upon project completion). Great River Energy will own the 3-way tap switch interconnecting the new 115 kV transmission line to Minnesota Powers "24 Line" transmission line, approximately 15 to 16 miles of new 115 kV transmission line, and the three-way tap switch for

> the future Shamineau Substation. Crow Wing Power will continue to own the existing Motley Substation (proposed to be converted to 115 kV service) and the proposed new Fish Trap Lake Substation.

The petition in ET2,015/CN-14-853 stated that MP and GRE anticipated starting construction in fall 2016 and energizing the line in summer 2017.

On March 23, 2016, the Commission issued an order granting the CN and issuing the route permit.

The project began construction late in 2016 and was energized around August 31, 2017.[8]

Regarding project costs, the Dog Lake Petition stated (on page 4-14, Table 4-4) that Minnesota Power's share of the total project costs were estimated at $3,930,000 in 2014 dollars, consisting of $1,140,000 for transmission line, $2,680,000 for the Dog Lake substation, $100,000 for distribution, and $10,000 for communications.

The instant petition refers to the $3,930,000 in 2014 dollars amount as a cap on project costs. The Department agrees.[9]

Project costs in nominal dollars totaled $4,176,251. As shown on page 1 of Exhibit B-9 in the instant petition, MP estimates this amount is equivalent to $3,944,121 in 2014 dollars, or $14,121 over the cap. However, MP states that petition only requests TCRR recovery of the capped amount, which MP estimates is equivalent to $4,160,541 nominal dollars.

2. *Department Analysis*

a.) Project Eligibility

The Commission approved adding Dog Lake to the TCRR in last year's TCRR docket. TCRR statute "terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates." Since costs have not been fully recovered and have also not been added to base rates, the Department concludes that Dog Lake is still eligible for TCRR recovery.

---

[8] Based on page 22 of MP's petition and https://www.transmissionhub.com/articles/2017/08/great-river-energy-construction-of-the-motley-area-115-kv-project-completed.html.

[9] For example, see the Commission's April 7, 2010 Order regarding Xcel Energy's TCRR filing in Docket No. E002/M-09-1048, which stated:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

See also the Commission's March 10, 2014 Order in Docket No. E015/M-13-103.

b.) Plant-in-Service and O&M & Property Taxes

Based on Exhibit B-3, the total plant-in-service (before accumulated depreciation) of Dog Lake is $3,357,384.[10] The Department concludes that MP's requested capex recovery appears to be consistent with the limits described above.

MP's Dog Lake revenue requirements do not include any O&M expenses.

For property taxes, **the Department requests that MP provide an explanation and calculations for the requested property tax amounts in Exhibit B-3, pages 1-15**.

C. NET RECB EXPENSES OR REVENUES (MISO SCHEDULES 26, 26A, 37, 38)

During the 2008 Minnesota Legislative Session, Minn. Stat. 216B.16, subd. 7(b)(2) was amended to allow utilities providing transmission service to recover "the charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by MISO to benefit the utility, as provided for under a federally approved tariff," upon Commission approval. The Statute further requires any recovery to "be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

MISO's regionally planned transmission projects are also referred to as Regional Expansion and Cost Benefit, or RECB, projects.[11] RECB charges and revenues are primarily reflected under MISO Schedules 26/26A. MISO Schedule 26 includes regionally shared projects such as Market Efficiency Projects and Generation Interconnection Projects. MISO Schedule 26A includes projects that have been deemed to be Multi-Value Projects (MVPs).

In addition to MISO Schedules 26/26A, utilities also receive revenues related to regionally-shared projects under MISO Schedules 37 and 38. MISO Schedule 37 revenues represent a utility's share of contributions MISO receives from American Transmission Systems, Inc., which left MISO on June 1, 2011 to integrate with PJM. Likewise, MISO Schedule 38 revenues represent a utility's share of payments from Duke-Ohio and Duke-Kentucky, which left MISO on December 31, 2011, but have an ongoing obligation to pay for MISO projects due to their previous membership.

As noted above, the Commission's June 23, 2009 Order in Docket No. E015/M-08-1176 (MP's second TCRR petition) stated:

---

[10] Sum of the December 2021 plant-in-service balances for each of the Dog Lake components shown in Exhibit B-3: Dog Lake substation Expansion (2,343,666), 115kV Dog Lake – Badoura Line #40 (27,339), Dog Lake Expansion – Line #24 (323,417), Dog Lake Expansion – Line #155 (542,108), and Baxter 534 FDR Underbuild 115 kV (120,853).

[11] GNTL and Dog Lake are not RECB projects.

> A. Minnesota Power shall provide supporting documentation to substantiate the actual Regional Expansion and Cost Benefit charges incurred during the upcoming year as part of future Rider filings.
> B. Minnesota Power shall include in the rider any and all revenues received through the Regional Expansion and Cost Benefit process from this or other projects, as an offset to cost recovery.

Similarly, the Commission's May 11, 2011 Order in Docket No. E015/M-10-799 (MP's third TCRR petition) stated that "Minnesota Power shall document actual RECB charges and revenues and include the information in future transmission cost recovery filings."

As also noted above, consistent with the Commission's June 23, 2009 Order and per MP's petition in its most recent completed rate case (Docket No. E015/GR-16-664), MP continues to recover RECB revenue and expenses (the above referenced MISO schedules) in the TCRR instead of base rates.

The instant petition provides documentation of actual RECB revenues and charges as Exhibit C-1. Pages 2-3 of Exhibit C-1 show total RECB <u>revenue</u> over the 21 months ending August 31, 2020 (December 1, 2018 to August 31, 2020) of $33.4 million which equates to $19.1 million on average per year. MP also provided an email from MISO confirming these revenue distributions (Exhibit C-1, pages 1 and 4-5). Pages 6-7 of Exhibit B-3 show total RECB <u>charges</u> over the 20 months ending August 31, 2020 (January 1, 2019 to August 31, 2020) of $30.9 million for Schedule 26, equivalent to $18.6 million on average per year, and $27.6 million for Schedule 26A, equivalent to $16.6 million on average per year. MP also provided an email from MISO confirming these billings (Exhibit C-1, page 9).

The Department requests that MP provide, in reply comments, an exhibit or other information connecting the information in Exhibit B-1 with the revenue and charges provided in Exhibit C-1.

The Department also requests that MP provide, in reply comments, a full linkage and explanation between the requested RECB revenue requirements as shown in Exhibit B-5, and the revenues and charges confirmed by MISO in Exhibit C-1. For example, page 2 of Exhibit C-1 shows Schedule 26 revenue of $1,824,063 for the January 2019 financial period. In contrast, Exhibit B-5 shows January 2019 Schedule 26 revenue of $1,649,486.

In addition, to ensure rates accurately reflect costs to the extent possible, **the Department recommends that the Commission require that MP incorporate updated actual net RECB expenses before implementing an updated transmission factor.**

D. ARR REVENUES

As described in the petition, MISO Auction Revenue Rights (ARR) revenues are a MP's entitlement to a share of revenue generated in annual Financial Transmission Rights (FTR) auctions. MP states that its firm historical usage of MISO's transmission system determines its share and, depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge.

MP's proposed revenue requirements include ARR revenues for the MVP projects that MP is not an owner of but is allocated a portion of the costs as a MISO member. Specifically, MP states that it credits the MVP ARR revenues that it receives to retail customers in the TCR tracker.

MP projects the 2021 Minnesota jurisdictional credit to be about $49,628, as shown in Table 4 and Exhibit B-1, page 3 of its petition ("MVP Project Credit").

The Department requests that MP provide documentation for the ARR credits.

E. NON-RECB REVENUES AND EXPENSES (SCHEDULE 9 CREDITS)

The Department notes that the bulk of Minnesota regulated electric utilities' transmission assets over 100 kilovolts are considered to be non-RECB projects for MISO purposes and are included in the utilities' base rates rather than a transmission rider. As such, any wholesale transmission revenues and expenses associated with these facilities are generally reflected in base rates. However, if the non-RECB projects have not been moved to base rates, which is the case for Dog Lake and GNTL, these revenues and expenses must be incorporated in the TCRR.

Similar to RECB charges that are reflected in MISO Schedules 26/26A, these non-RECB charges are reflected in MISO Schedule 9 revenues for the party that owns the transmission assets and in MISO Schedule 9 expenses for any party that uses the transmission assets (including the owner of the assets). Correspondingly, Order Point 3 of the 2019 TCRR Order requires that MP include the net credits it receives from MISO under Schedule 9 for Dog Lake and the GNTL. These net credits reflect the difference between what the utility pays MISO for using its own non-RECB transmission asset and what the utility receives from MISO for other utilities' use of the asset.[12] MP estimates the total Schedule 9 credits for Dog Lake and the GNTL to be $342,928 for 2021 (Table 4 of petition). This total amount corresponds to the $14,784 credit cited for Dog Lake and $328,144 credit cited for the GNTL, as shown in Exhibit B-1.

The Department requests that MP provide documentation of all Schedule 9 credits it has received for any year.

F. BASE RATE REVENUE CREDITS FOR GTNL AND DOG LAKE

[12] For example, if FERC determined that annual revenue requirements for a specific non-RECB project totaled $100 and MP were the owner, the $100 would be allocated and charged to all utilities located in MP's transmission pricing zone, based on their respective loads in that zone. If MP makes up approximately 80 percent of the load in its own transmission pricing zone, MP would be required to pay MISO $80 in Schedule 9 expenses (paying MISO for MP's use of its own facilities). The remaining $20 in MISO Schedule 9 expenses would be paid by the other utilities with load in MP's transmission pricing zone to reflect their reliance on MP's facilities. MISO would then pay MP the entire $100 in MISO Schedule 9 revenues for its ownership of the project. The difference between what MP pays and receives for its ownership of the non-RECB project is the $20 net credit. (Sometimes the net credit is presented in percentage terms. In this example, the net credit would equal 20 percent of the revenue requirements.)

MP's proposed revenue requirements include base rate revenue credits for both Dog Lake and the GNTL. As described in the petition, MP include these credits because:

> When a project has retirements of equipment that customers are paying for in base rates, a base rate revenue credit associated with retired plant is needed at the time the Transmission Projects go into service and is credited to customers until the project is incorporated into base rates. Minnesota Power's 2019 TCR Factor filing did not include $420,588 of retired Original Installed Cost ("OIC") that was not recorded for the project until after the 2019 TCR Factor filing was submitted. Minnesota Power has now added the credit to the TCR Tracker effective back to the in-service date as shown in Exhibit B-6, page 1. Please note that because this credit goes back to September of 2017, the 2018 year-end tracker balance shown in Minnesota Power's 2019 TCR Factor filing has been amended as shown in Exhibit B-1, page 2.
>
> …
>
> The components of the revenue requirement will include an after-tax return on investment, current and deferred income taxes, interest expense, depreciation expense, property taxes and other incremental O&M expenses related to the Transmission Projects. Similarly when equipment is retired, a base rate revenue credit is calculated using the same components, and a monthly revenue credit is applied beginning with the month the project goes into service and remains until the project is incorporated into base rates.

MP provides detail on the base rate revenue credit calculations in Exhibit B-6. **The Department requests that MP provide, in reply comments, an explanation connecting these calculations to the total amounts shown in Exhibits B-1 and B-2.**

G. COST ALLOCATION & RATE DESIGN

MP's proposed cost allocation and rate design are the same as those currently employed. The Department does not object to this proposal.

H. RATE OF RETURN

The TCRR Statute states in part:

> Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:
>
> allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest. … [and]

> provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

The 2019 Transmission Factor currently in place in the TCRR uses the authorized rate of return (ROR) approved in MP's 2016 rate case (Docket No. E015/GR-16-664). MP's petition, as described on pages 36 and 38, proposes to continue using the rate of return from the 2016 rate case for the updated (2021) Transmission Factor. Page 3 of MP's Exhibit B-7 shows MP's proposed rate of return for calculating the 2021 Transmission Factor, which the Department also provides in the table below:

Table 4: MP's Proposed Rate of Return
(ROR Approved in 2016 Rate Case[13])

	Weight	Component Cost	Weighted Cost
Long-Term Debt	46.189%	4.517%	2.086%
Common Equity	53.811%	9.250%	4.978%
Total			7.064%

On November 1, 2019, MP filed a rate case in Docket No. E015/GR-19-442 in which the Company proposed updating the cost of long-term debt to 4.4723% based on its estimate of the embedded cost for a 2020 test year, while maintain the same capital structure.[14] The Company then withdrew that rate case.

The Department requests that MP provide, in reply comments, its estimate of the Company's embedded cost of debt and capital structure for 2021.

I. FERC ROE REFUNDS

On November 21, 2019, in Docket No. EL14-12, FERC issued Opinion No. 569, approving a lower return on equity (ROE) of 9.88 percent for formula transmission rates with an effective date of September 28, 2016, and requiring refunds. Specifically, FERC ordered:

> (B) MISO TOs' [transmission owners'] base ROE is set at 9.88 percent with a total or maximum ROE including incentives not to exceed 12.24 percent, effective as of September 28, 2016, as discussed in the body of this order.
>
> (C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2019), within thirty (30) days of the date of this order, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the

[13] March 12, 2018 Order in Docket No. E015/GR-16-664, page 61.
[14] Cutshall Direct filed November 1, 2019 in Docket No. E015/GR-19-442, page 39.

> period from September 28, 2016 to the date of this order, as discussed in the body of this order.
>
> (D) MISO and MISO TOs are directed to file a refund report detailing the principal amounts plus interest paid to each of their customers within forty-five (45) days of the date of this order.

On May 21, 2020, in the same docket, FERC issued Opinion No. 569-A, in part granting and in part denying a rehearing of Opinion No. 569. Specifically, FERC ordered:

> (B) MISO TOs' base ROE is set at 10.02% with a total or maximum ROE including incentives not to exceed 12.62%, effective as of September 28, 2016, as discussed in the body of this order.
>
> (C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2019), by December 23, 2020, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 to the date of this order, as discussed in the body of this order.
>
> (D) MISO and MISO TOs are directed to file a refund report a detailing the principal amounts plus interest paid to each of their customers by December 23, 2020.

FERC's now chair (appointed January 21, 2021), Richard Glick, provided an opinion dissenting in part, arguing that FERC was unduly "fiddling" with its ROE methodology.

On November 19, 2020, in the same docket, FERC issued Opinion No. 569-B, modifying and setting aside in part Opinion No. 569-A. Specifically, FERC ordered:

> (B) MISO TOs' base ROE is set at 10.02% with a total or maximum ROE including incentives not to exceed 12.62%, effective as of September 28, 2016, as discussed in the body of this order.
>
> (C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2020), by September 23, 2021, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 to the date of this order, as discussed in the body of this order.
>
> (D) MISO and MISO TOs are directed to file a refund report detailing the principal amounts plus interest paid to each of their customers by September 23, 2021.

Current FERC Chair Richard Glick again dissented in part. Of note, Chair Glick stated that: "If the Commission is going to purport to rely entirely on financial models to evaluate and set ROEs, it has to take those models at face value without second-guessing them when it does not like the results."

At this time, it is not clear to the Department whether FERC will continue "fiddling" with its ROE methodology and updating its ROE refund policy.

The 2019 TCRR Order requires that MP "include any refunds that it receives for 2016–2019 return on equity reductions in future Transmission Cost Recovery Rider filings." MP's petition addresses this requirement as follows:

> … MISO transmission resettlements occurring as a result of the FERC ROE changes are ongoing. Only a portion of the required transmission resettlements for the latest FERC ROE change orders have been completed by MISO. Therefore, Minnesota Power proposes to include all the MISO transmission resettlements for the FERC ROE changes in future TCR Rider filings following completion of the MISO process. In the meantime, in November 2019, Minnesota Power set up an account to reserve for the net estimated amount of the MISO transmission resettlements but has not yet been reflecting these amounts in the TCR factor calculations. When the MISO process is complete, the Company will include the actual net transmission resettlements received in the TCR Rider.

The Department requests that MP provide, in reply comments, resettlements to date, an estimation of how including them would affect the rider, and when MP expects the resettlements (MISO process) to be complete. The Department also requests that MP explain whether MP could include an estimated resettlement amount for 2021 and then adjust to actuals in future TCRR filings.

J. PRORATED ACCUMULATED DEFERRED INCOME TAXES & IMPLEMENTATION DATE

Due to accelerated tax depreciation, the federal income-statement taxes used to calculate MP's revenue requirements exceed the actual federal income taxes that MP pays. To account for this difference, MP's rate base is reduced by the accumulated difference between the amount of federal income taxes that MP charges to its customers and the amount the Company actually pays, referred to as Accumulated Deferred Income Taxes (ADIT), resulting in a reduction in customers' rates. In recent years, the Internal Revenue Service has required that, if rates are implemented prior to the end of a test period, the amount by which ADIT reduces rate base must be prorated (reduced) in calculating rates. Prorating ADIT increases customers' rates compared to normal ADIT. For example, if the test year is 2020 and rates are implemented on November 1, 2020, then 10 months of ADIT is removed from rate base, instead of the full 12 months, resulting in higher rates for the two months' worth of ADIT proration.

One way to avoid the issue of ADIT proration is to implement rates after the end of the test period. MP's petition uses a 2021 test year. Therefore, MP contemplates implementing rates after 2021.[15] As stated in the petition:

> Under Internal Revenue Code Section 167, rate-regulated utilities that utilize accelerated tax depreciation are required to use a normalization method of accounting. If a future test year, or a part historical and part future test year are utilized when determining the reserve for deferred taxes for the reduction of rate base, then a specific pro rata calculation must be utilized to avoid a normalization violation. In this TCR current cost recovery filing, the Company is utilizing a 2021 test year. The Company is estimating that rates under this 2021 Transmission Factor will take effect after December 1, 2021. This results in 2021 being a historical year and therefore no pro rata calculation is required for this TCR current cost recovery filing.

Given MP's contemplated implementation date, **the Department recommends that the Commission require MP to implement its updated transmission factor effective January 1, 2022 or the first day of the month following the Commission's Order in this docket, whichever is later, thereby eliminating the need to prorate ADIT.**

K. POTENTIALLY ELIGIBLE PROJECTS

Order Point 7 of the 2019 TCRR Order states:

> 7. Minnesota Power shall file in their Transmission Cost Recovery Factor filing, annually, descriptions of all potentially eligible projects that they will seek recovery for in the future, and the impacts those projects will have on the Transmission Cost Recovery factor.

The Department requests that MP, in reply comments, provide this description or point to where the description is provided in the petition.

L. OTHER REQUIREMENTS

Paragraph (c) of the TCR Rider Statute requires that utility TCRR petitions provide

1. a description of and context for the facilities included for recovery;
2. a schedule for implementation of applicable projects;
3. the utility's costs for these projects;
4. a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

---

[15] In addition, as noted in the introduction to these comments, MP requests that the 2021 Transmission Factor take effect the first of the month following Commission approval and no sooner than 90 days from the petition filing date.

5. calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

The Department confirmed that MP's petition provided this information.

V. RECOMMENDATION

The Department requests that MP provide additional information in the Company's reply comments. The Department will provide final recommendations to the Commission after reviewing the additional information.

/ar

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E015/M-20-900

Dated this 18th day of June 2021

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-900_M-20-900
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-900_M-20-900
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_20-900_M-20-900
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	OFF_SL_20-900_M-20-900
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-900_M-20-900
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-900_M-20-900