BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota	PUC Docket No. E015/GR-21-335 OAH Docket No. 5-2500-38008 **PETITION FOR RECONSIDERATION**

In the hopes of limiting issues in the appeal presently pending before the Minnesota Court of Appeals regarding the above-referenced general rate case proceeding, the Large Power Intervenors ("LPI")[1] are compelled to submit the following Petition for Reconsideration ("Petition") of the September 29, 2023, Order Approving Compliance Filing from the Minnesota Public Utilities Commission ("Commission") ("the Compliance Filing Order").[2] Via two overcollection factors and three different "final determinations" under Minn. Stat. § 216B.16, subd. 3(c), the Compliance Filing Order approved an interim-rate refund that is inconsistent with the plain language of state law and long-standing appellate precedent. LPI accordingly respectfully seeks correction of the Compliance Filing Order.

I. INTRODUCTION

On February 28, 2023, the Commission issued its Findings of Fact, Conclusions of Law, and Order in the above referenced dockets.[3] In response to LPI's position that any interim-rate

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1 An *ad hoc* consortium of large industrial end users of electric energy on Minnesota Power's (or the "Company") system, consisting for purposes of this filing of Blandin Paper Company; Boise White Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Cleveland-Cliffs Minorca Mine Inc.; Enbridge Energy, Limited Partnership; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Northern Foundry, LLC; Sappi Cloquet, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and USG Interiors, Inc.

2 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Order Approving Compliance Filing (September 29, 2023) (eDocket No. 20239-199257-01).

3 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions of Law, and Order (Feb. 28, 2023) (eDocket No. 20232-193486-01) ("Order").

refund "should be distributed to customers in the same proportion as was previously paid by that customer" and that all customers should "receive an interim rate refund in accordance with the interim rates paid, regardless of the potential for surcharges to one class and refunds to others,"[4] the Commission stated as follows in the Order:

> At the resolution of a rate case, the Commission typically directs the utility to file a compliance filing detailing, among other issues, how the utility proposes to handle any interim-rate refunds or surcharges that are necessary based on the Commission's final rates determination. The Commission sees no reason to deviate from past practice in this case; <u>LPI will have an opportunity to raise these arguments when the Commission considers Minnesota Power's compliance filing.</u> The Commission will therefore direct Minnesota Power to file an interim rate refund proposal addressing the refund issue as appropriate, based on the final revenue requirement and rates ordered in this case.[5]

On March 20, 2023, various parties submitted petitions for reconsideration and clarification, including Minnesota Power and LPI on the issue of interim rates. With respect to interim rates, Minnesota Power sought clarification on whether and how the interim-rate refund would be impacted by the Commission's treatment of certain test-year sales revenues,[6] and LPI sought clarification on what appeared during the evidentiary hearings to be undisputed—that non-residential customer classes would receive the full value of the difference between interim rates and final rates.[7] On May 15, 2023, the Commission issued its Order Denying Reconsideration and Granting, In Part, Requests for Clarification.[8] In the Reconsideration and Clarification Order, the Commission ordered as follows:

> Grant Minnesota Power's clarification request that ST Paper and

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4 Order at 77.

5 Order at 78 (emphasis added).

6 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Minnesota Power Petition for Reconsideration, at 24-26 (March 20, 2023) (eDocket No. 20233-194105-01).

7 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, LPI Petition for Reconsideration, at 16-18 (March 20, 2023) (eDocket No. 20233-194104-02).

8 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Order Denying Petitions for Reconsideration and Granting, In Part, Requests for Clarification (May 15, 2023) (eDocket No. 20235-195831-01) ("Reconsideration and Clarification Order").

> Cenovus sales should be regarded as a known and measurable change. The Company may exclude sales revenue not received from ST Paper and Cenovus during the period of interim rates; Minnesota Power shall file in a compliance filing its interim rate calculation, as described in the Company's clarification request, for final Commission approval.[9]

Because the May 15, 2023, Order was, as noted both in its title and explicitly in its content, an order resolving previously-filed petitions for reconsideration, LPI was precluded under Minn. R. 7829.3000, subp. 7, from filing a second petition for reconsideration and clarification on the issue of interim rates[10] and timely filed a petition for a *writ of certiorari* with the Minnesota Court of Appeals.[11] The petition sought review of orders issued by the Commission on various topics, including the issue of interim rates.[12] Furthermore, even at the time of the Reconsideration and Clarification Order, it was entirely unclear how the exclusion of sales revenue to these customers would be calculated, which is presumably why the Commission on February 28 and May 15, 2023, specifically directed that "LPI will have an opportunity to raise these arguments when the

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9 Reconsideration and Clarification Order at 4, para. 1.g. (emphasis added).

10 Minn. R. 7829.3000, subp. 7, provides that "[a] second petition for rehearing, amendment, vacation, reconsideration, or reargument of a commission decision or order by the same party or parties and upon the same grounds as a former petition that has been considered and denied, will not be entertained." Relevant here, Ordering Paragraph 2.e. of the Reconsideration and Clarification Order denied LPI's request for clarification via amendment, thereby precluding LPI from reiterating the same arguments and concerns by submitting a second petition for reconsideration.

11 LPI's appeal was assigned appellate file number A23-0867. LPI's appeal was consolidated with an appeal by Minnesota Power, assigned appellate file number A23-0871, which consolidated appeals (together, the "Consolidated Appeals") have since been stayed pending the Commission's decision on Minnesota Power's interim-rate refund. The Minnesota Court of Appeals' June 30, 2023, order consolidating and staying the appeals is attached to this Petition as Exhibit A. Depending on the results here, LPI may be in a position to streamline or withdraw its portion of the Consolidated Appeals.

12 As the Commission itself acknowledged in its June 27, 2023, Statement of the Case in LPI's appeal, "LPI petitioned for reconsideration of the [February 28, 2023] order, arguing that the Commission's revenue allocation decision (reflecting an even rate increase to all customers) was arbitrary and capricious and ignored the cost of service. LPI also sought clarification of the Commission's [December 30, 2021] Order Setting Interim Rates, raising concerns that Minnesota Power's forthcoming interim rate refund proposal could dilute the refund due to non-residential customers."

Commission considers Minnesota Power's compliance filing"[13] and that the calculations were subject to "final Commission approval."[14]

On June 14, 2023, Minnesota Power submitted its Compliance Filing, including its proposed interim-rate refund plan.[15] On June 20, 2023, the Commission issued a notice of comment period seeking party input on various issues regarding the Compliance Filing, including Minnesota Power's proposed Interim-Rate Refund Plan, and setting the initial and reply comment deadlines as July 17 and July 31, 2023, respectively.[16] In accordance with the Commission's February 28, 2023 Order deferring interim-rate refund concerns to the compliance-filing process,[17] the Notice specifically stated that one of the following topics was open for comment: "Is Minnesota Power's proposed Interim Rate Refund Plan in compliance with Commission Rules, Commission Orders, and Minnesota Statute."[18] In the hopes of limiting the issues subject to the Consolidated Appeals, LPI submitted a comment to explain how Minnesota Power's Interim-Rate Refund Plan was both inconsistent with state statute and longstanding caselaw, and a fundamentally unfair violation of LPI's due process rights, while also outlining what LPI believes were the necessary steps to modify the Interim-Rate Refund Plan to bring it in compliance with Minnesota law.[19]

On August 31, 2023, the Compliance Filing, including the Interim-Rate Refund Plan, came before the Commission for consideration.[20] On September 29, 2023, the Commission issued the Compliance Filing Order, concluding "The Commission concurs with the Company that its

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13 Order at 78.

14 Reconsideration and Clarification Order at 4, para. 1.g.

15 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Minnesota Power Compliance Filing (June 14, 2023) (eDocket No. 20236-196560-02) (generally, "the Compliance Filing," and with respect to interim rates, the "Interim-Rate Refund Plan").

16 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Notice of Comment Period (June 20, 2023) (eDocket No. 20236-196672-01) ("Notice").

17 Order at 78.

18 Notice.

19 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335. LPI Interim Rate Refund Comment (July 17, 2023) (eDocket No. 20237-197542-02) ("LPI Interim-Rate Refund Comment").

20 Compliance Filing Order at 2.

[interim rate refund] methodology is consistent with the law and Commission directives."[21] LPI respectfully disagrees with the Commission's conclusion. Specifically, LPI asserts that the Interim-Rate Refund Plan, as approved in the Compliance Filing Order, is inconsistent with state law and Commission precedent. To preserve its rights, LPI is therefore compelled to lodge this Petition.[22]

II. ANALYSIS

A. Introduction and Standard

"A petition for rehearing, amendment, vacation, reconsideration, or reargument must set forth specifically the grounds relied upon or errors claimed."[23] The Commission typically reviews petitions to determine whether they (1) raise new issues, (2) point to new and relevant evidence, (3) expose errors or ambiguities in the underlying order, or (4) otherwise persuades the Commission that it should rethink its previous order.[24] Here, LPI respectfully asserts that there are errors in in the Compliance Filing Order – the Compliance Filing Order is inconsistent with the plain language of state law and long-standing legal and Commission precedent. LPI's analysis, set forth below, has heretofore been unaddressed by the Commission.

B. Overview of Applicable Law on Interim-Rate Refunds

Minnesota law clearly and succinctly defines the interim-rate refund calculation. It specifically provides that "[i]f, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission *shall* order the utility to refund the excess amount collected under the interim rate schedule, including interest on it which shall be at the rate of interest determined by the commission."[25] In other words, state law

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21 Compliance Filing Order at 5.

22 *See* Minn. Stat. § 216B.27, subds. 1, 2, and 5; Minn. Stat. § 216B.52, subd. 1; and Minn. Stat. § 14.63.

23 Minn. R. 7829.3000, subp. 2.

24 *See, e.g.*, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, PUC Docket No. E-002/GR-13-868, Order Denying Petitions for Reconsideration, at 1 (July 13, 2015) (eDocket No. 20157-112358-01).

25 Minn. Stat. § 216B.16, subd. 3(c) (emphases added).

directs the Commission to compare two sets of rates, and only two sets of rates—interim rates and rates in the final determination, and to order the difference to be refunded — no more and no less.[26]

This point was made clear by the Minnesota Supreme Court in 1986. In *Application of Peoples Natural Gas Co.*, the Commission approved an interim-rate increase of $2,035,000 but ultimately approved a much smaller final rate increase in the amount of $276,000.[27] In that case, interim rates were assigned to all customers on a *pro rata* basis notwithstanding the utility's proposed allocation to the general service customers class (one of six classes of customers) of almost the entire revenue increase the utility was seeking. Ultimately, the Commission reduced the proposed rate increase and allocated the entire $276,000 increase to the general service customer class. Notwithstanding this decision, the Commission ordered payment of interim-rate refunds on the same *pro rata* basis as they had been collected.[28] A group of large industrial customers objected to and appealed the Commission's interim-rate refund decision arguing, *inter alia*, that because those customers were not allocated any share of the final rate increase, they should receive a full refund of interim rates they had paid, and not merely a *pro rata* share of the total interim-rate refund amount, as directed by the Commission.[29] The Minnesota Supreme Court disagreed with the large industrial customers, stating that the "statute mandates that the new rates and rate design shall be effective prospectively only" and concluding that "the only way the present statutory plan of utility rate regulation can be carried out consistently is to allocate interim rate increases among the consumer classes in accordance with the existing rate design … and to distribute any refunds due … in the same proportions as the interim rate increase was allocated."[30] The Minnesota Supreme Court summarized its holding as follows:

> The refund should be distributed ratably among the consumer classes in the same proportion as the contribution made by each class to the revenues produced by the interim rate increase. <u>In other</u>

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26 *See* Minn. Stat. § 645.16 ("When the words of a law in their application to an existing situation are clear and free from all ambiguity, the letter of the law shall not be disregarded under the pretext of pursuing the spirit."); *ILHC of Eagan, LLC v. Cnty. of Dakota*, 693 N.W.2d 412, 419 (Minn. 2005) (*citing* Minn. Stat. § 645.16) ("The touchstone for statutory interpretation is the plain meaning of a statute's language.").

27 *In the Matter of the Petition of Peoples Natural Gas Co. for Authority to Increase Rates for Gas Utility Service in Minnesota*, 389 N.W.2d 903, 905 (Minn. 1986).

28 *Id.*

29 *Id.* at 906-07.

30 *Id.* at 908.

> words, the refund process simply places each consumer class in the position it would have occupied had the interim rate been so calculated that it produced revenues equal to or less than those authorized by the final determination.[31]

The Supreme Court further held that "during the … consideration of the utility's petition, the consumers maintain their relative position while paying higher interim rates…. Refunds of excess revenues generated by interim revenues are returned to the consumers in the same proportions."[32] In short, when an interim-rate refund is warranted, that calculation is simply the difference between the interim rates set and the rates set by the Commission in its final determination.

This approach, which the Supreme Court held was based on the plain-language reading of state law, was confirmed roughly three years later, when the Minnesota Court of Appeals addressed Minnesota Power's request to overturn the Commission's decision denying Minnesota Power's request to create a separate interim-rate test year from the final proposed test year, for purposes of modifying the interim-rate refund.[33] In that case, Minnesota Power filed two separate cost-of-service studies, both based on the same test year, with one allegedly supporting interim rates and the other allegedly supporting final rates.[34] The Court of Appeals summarized the proposal as follows:

> Minnesota Power requested that any refund of interim rates be calculated by reference to the separate interim cost-of-service study, and not the cost of service study for prospective general rates. In other words, Minnesota Power was requesting that the Commission make two final determinations based upon two separate cost studies: one final determination for interim rates and another final determination for prospective rates. This request was unprecedented; in the past, interim rate refunds have been determined by the difference between the interim rates allowed and

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31 *In the Matter of the Petition of Peoples Natural Gas Co. for Authority to Increase Rates for Gas Utility Service in Minnesota*, 389 N.W.2d at 908-09 (emphasis added).

32 *Id.* at 909. While this result was not satisfactory to the industrial customers initiating the appeal in *Application of Peoples Natural Gas Co.*, the Minnesota Supreme Court determined that this interim-rate-setting and refund process nonetheless met the "just and reasonable rate" standard in Minn. Stat. § 216B.03. *Id.* at 908.

33 *In re Minnesota Power & Light Co.*, 435 N.W. 2d 550 (Minn. Ct. App.), *pet. for rev. denied* (Minn. Apr. 19, 1989).

34 *Id.* at 553.

final prospective rates.[35]

Although it authorized an interim-rate *increase* of roughly $4.8 million, the Commission ultimately approved a final rate *decrease* of $8.3 million and directed that Minnesota Power issue an interim-rate refund for the difference between the $4.8 million interim-rate increase and $8.3 million final-rate decrease, resulting in lower rates for the interim period than had been authorized in Minnesota Power's previous rate case.[36] On appeal, Minnesota Power argued, *inter alia*, that the Commission erred by (i) effectively setting interim rates below previously authorized rates, (ii) refusing to accept Minnesota Power's separate proposed interim-rate test year and associated cost-of-service study,[37] and (iii) as an alternative to the first two, that the Commission should have at least made a downward adjustment to the interim-rate refund for certain cost changes during the interim-rate period.[38]

In rejecting Minnesota Power's first argument, the Court of Appeals applied the plain language of Minn. Stat. § 216B.16, subd. 3. The Court of Appeals stated "[w]e agree that the language of section 216B.16, subd. 3 is clear and confers upon the Commission the power to order the disputed refunds… By [the statutory language] the legislature has authorized the Commission to refund the amount by which interim rates collected exceed final rates authorized."[39] The Court of Appeals went on to conclude that this plain-language interpretation, even though it resulted in interim rates being less than previously-authorized rates, did not render the refunds unlawful.[40]

In rejecting Minnesota Power's second argument, the Court of Appeals examined the phrase "final determination" in Minn. Stat. § 216B.16, subd. 3, and whether, as Minnesota Power alleged, the phrase could include a "final determination" for both interim rates and final rates. The Court of Appeals concluded Minnesota Power's strained reading was incorrect. The court specifically held that "Minnesota Power's interpretation of this provision is strained. If the legislature had intended that the Commission make two separate 'final determinations,' we believe

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35 *In re Minnesota Power & Light Co.*, 435 N.W. 2d at 553 (emphasis added).
36 *Id*.
37 *Id*. at 554.
38 *Id*. at 557.
39 *Id*. at 555.
40 *Id*. at 555-56.

the legislature would have included such language in the statute. The court should not interpret a statute to include language which is clearly not there."[41]

In rejecting Minnesota Power's third argument, the Court of Appeals adopted the Commission's analysis and imposed the general rule that asymmetrical adjustments to the test year are inappropriate. The Court of Appeals quoted, and adopted, the Commission's analysis as follows:

> As a general rule, the Commission is reluctant to adjust revenue requirements to reflect changes, <u>certain or not</u>, unless there is a compelling need to do so. This is because the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical—some favoring the Company, others not. <u>Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process</u>. Anomalies are likely to exist in and beyond any test year. <u>In keeping with these general principles, the Commission has adjusted for changes in the past only when their certainty and magnitude would otherwise make the test year process unreliable</u>.[42]

The court agreed with the Commission that Minnesota Power's proposed adjustments regarding changes to capital structure, conservation improvement program expenditures, O&M associated with plant ownership, and property taxes should all be rejected on this basis, as well as on substantive grounds.[43] As the Court of Appeals noted in *Minnesota Power & Light*, "[t]he interim period has never been interpreted in the past as creating a substantive period for calculating rates. Rather, the purpose of the interim period is to prevent the 'potentially confiscatory effect of regulatory delay.'"[44]

People's Natural Gas and *Minnesota Power & Light* demonstrate that the interim-rate refund process can result in situations that, at first blush, appear to be unfair to the customer or the utility. But that unfairness, in and of itself, does not support change to the statutory process

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41 *In re Minnesota Power & Light Co.*, 435 N.W. 2d at 557 (*citing Comm'r of Rev. v. Richardson*, 302 N.W.2d 23, 26 (Minn. 1981)).

42 *Id*. at 558 (emphases added).

43 *Id*. at 558-59.

44 *Id*. at 556 (*quoting Henry v. Minn. Pub. Utils. Comm'n*, 392 N.W.2d 209, 2013 (Minn. 1986)).

unambiguously set out in Minn. Stat. § 216B.16, subd. 3. To the contrary, the interim-rate process is simply a blunt tool to protect utilities and customers during the interim-rate period. On the one hand, utilities are permitted to increase rates generally consistent with a statutory formula while refunds, when appropriate, are awarded to customers to protect them from overzealous utilities, consistent with another formula.

C. The Compliance Filing Order Violates Minnesota Law

In the Compliance Filing, Minnesota Power concedes that LPI's above legal analysis is correct. Specifically, Minnesota Power states as follows:

> In a typical rate case, an overcollection factor would be calculated based on interim rates collected over the interim rate period and final rates authorized by the Commission. This overcollection factor would then be applied to the interim rates paid by each customer to calculate the refund amount. This has been the recommended and approved method for calculating interim rate refunds in the Company's past several rate cases.[45]

Notably, this very same process was utilized by Minnesota Power, and approved by the Commission, in the Company's 2016 rate case (its most recent fully-litigated general rate case), during which the Commission approved test-year sales revenue figures that were dramatically different than those proposed by Minnesota Power.[46] In fact, one of the most significant issues in any Minnesota Power rate case is establishing a reasonable test-year sales forecast, which, to LPI's knowledge, has never before resulted in a deviation from the statutory interim-rate refund formula for Minnesota Power. In fact, and as explained above, when Minnesota Power previously proposed specific adjustments to the interim-rate refund based on adjustments to the test year used for setting final rates, the Commission rejected those adjustments, which rejection was affirmed on appeal.[47]

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45 Compliance Filing, Section 1, pg. 2 of 11.

46 In that case, the Commission approved annualizing revenues attributable to one customer that was only operational for nine months of the test year, resulting in a corresponding $1.8 million increase to Minnesota Power's test year revenue. *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact, Conclusions of Law, and Order, at 51 (March 12, 2018) (eDocket No. 20183-140963-01).

47 *In re Minnesota Power & Light Co.*, 435 N.W.2d 550.

Here, the Commission takes the exact opposite approach that it took in *Minnesota Power & Light* – the Commission approved adjustments to the test year used in setting final rates to reduce the interim-rate refund to all non-residential customers, but without any of the findings of fact required by *Minnesota Power & Light* that (i) the test-year process would be unreliable without the adjustments, (ii) only these two adjustments are required to render the test year reliable, and (iii) other changes in Minnesota Power's financial status during the test year will remain symmetrical.[48]

The clear violation of state law can be seen through a simple comparison of Minnesota Power's interim-rate refund approach adopted by the Commission and LPI's approach. In the Compliance Filing Order, the Commission concluded that "Minnesota Power correctly calculated revenues and corresponding refunds based on the *amount collected* during the interim rate period, consistent with the statute's requirement to do so."[49] This statement is demonstrably false for two reasons. First, the differences in approaches between what the Commission approved and what LPI suggested are based entirely on the differences in calculating the *overcollection factors* applied to actual interim rates collected, not, as the Commission states, differences in the amounts of interim rates Minnesota Power actually collected during the rate-case proceeding. Second, the Commission's justification for modifying the overcollection factors amounts to unlawful retroactive single-issue ratemaking.

1. The Compliance Filing Approved Unlawful Overcollection Factors, Diminishing the Interim-Rate Refund to Non-Residential Classes by over $7.7 Million

The table below outlines the two approaches for calculating the interim-rate refund owed to non-residential customers. In Step 1 for years 2022 and 2023, both approaches start (i) with the same total test-year interim-rate increase (lines a and j) and (ii) with the same test-year interim-rate increase without residential revenue included (lines b and k).[50]

48 *In re Minnesota Power & Light Co.*, 435 N.W. 2d at 558.

49 Compliance Filing Order at 6 (emphasis in original).

50 While the adjustment to remove test year sales revenue for the residential class is unique, Minnesota Power consented to this adjustment. Compliance Filing, Sect. 1, pg. 2 of 11 ("The Company agreed to … not factor in the undercollection [of sales revenue from the (continued . . .)

In Step 2 for years 2022 and 2023, both approaches also apply the overcollection factors to (i) the total test-year interim rates actually collected (lines f and o) and (ii) test-year interim rates actually collected from non-residential customers (lines g and p). As a result, both approaches necessarily exclude revenue that wasn't actually present – *i.e.*, both approaches "exclude sales revenue not received from ST Paper and Cenovus during the period of interim rates" as directed by the Commission.[51] The only difference in the two approaches, which flows through the calculation and results in significantly different refund amounts, is the assessment of the Commission-approved "rates in the final determination," as that phrase is used in Minn. Stat. § 216B.16, subd. 3(c) (red text in lines c and l).

(table on next page)

residential class] into its calculation of interim rate refunds for other customer classes. Therefore, the residential class is entirely backed out of all interim rate calculations."). No party disputed this adjustment. Therefore, any argument that this adjustment is inappropriate or unlawful has been waived.

51 Reconsideration and Clarification Order at 4, para. 1.g.

Table 1.[52]

2022	Interim Rate Refund	Public Utilities Commission/MP	LPI
Step 1	*Calculating the Overcollection Factor*		
a	TY Interim Rate Increase	$87,323,708	$87,323,708
b	TY Interim Rate Increase w/o Resi.	$71,393,484	$71,393,484
c	Final Approved TY w/o Resi.	$54,917,913	$48,278,951
d	Non-Resi Overcollection Amount (b-c)	$16,475,571	$23,114,533
e	Non-Resi Overcollection Factor (d/b)	23.0771%	32.3763%
Step 2	*Applying the Overcollection Factor*		
f	TY Interim Rates Collected	$85,517,202	$85,517,202
g	TY Interim Rates Collected w/o Resi.	$77,600,762	$77,600,762
h	Non Resi Overcollection Factor (e)	23.0771%	32.3763%
i	Non-Resi Overcollection Amount Before Interest (h*g)	$17,908,033	$25,124,217
2023	**Interim Rate Refund**	**Public Utilities Commission/MP**	**LPI**
Step 1	*Calculating the Overcollection Factor*		
j	TY Interim Rate Increase	$87,323,708	$87,323,708
k	TY Interim Rate Increase w/o Resi.	$71,393,484	$71,393,484
l	Final Approved TY w/o Resi.	$49,627,398	$48,278,951
m	Non-Resi Overcollection Amount (k-l)	$21,766,086	$23,114,533
n	Non-Resi Overcollection Factor (m/k)	30.4875%	32.3763%
Step 2	*Applying the Overcollection Factor*		
o	TY Interim Rates Collected	$29,867,559	$29,867,559
p	TY Interim Rates Collected w/o Resi.	$26,835,975	$26,835,975
q	Non Resi Overcollection Factor (n)	30.4875%	32.3763%
r	Non-Resi Overcollection Amount Before Interest (q*r)	$8,181,617	$8,688,482
s	**TOTAL (i+r)**	$26,089,650	$33,812,699

Consistent with the plain language of Minn. Stat. § 216B.16, subd. 3(c), and *Minnesota Power & Light*, LPI utilizes the information contained in Schedule 11 of Minnesota Power's compliance filing to arrive at the actual Commission-approved rates in its final determinations. Schedule 11 shows that the Commission's total final approved test-year rate increase is $58,789,261.[53] Subtracting from that amount the final approved test-year rate increase for residential customers ($10,510,310) results in the Commission-approved rate increase for non-residential customers in the final determination to be $48,278,951.[54] As is evident in Table 1

52 *See* Compliance Filing, Sect. 1, pg. 5-6 of 11; LPI Interim-Rate Refund Comment, pg. 10.

53 Compliance Filing, Sched. 11, pg. 2 of 8.

54 As Commission Staff has noted, assuming LPI's legal analysis is correct, LPI's calculations are accurate. *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16- (continued . . .)

above, LPI uses this figure as required by statute (i.e., the "final determination" in Minn. Stat. § 216B.16, subd. 3(c)) for calculating the interim-rate refund in both years 2022 and 2023.

In a manner totally at odds with the plain language of Minn. Stat. § 216B.16, subd. 3(c), and *Minnesota Power & Light*, the Commission approved Minnesota Power's proposed changes to the $58,789,261 amount, the intent of which was to reduce the overcollection-factor percentage and the result of which is a windfall to Minnesota Power. The Commission approved Minnesota Power's change to the overcollection factor not once, but twice – the overcollection factor was adjusted for both the years 2022 and 2023.[55] In other words, the Commission approved three separate "final determinations" for purposes of calculating the interim-rate refund due non-residential customers – two different final interim-rate determinations and one rate determination to set final rates prospectively. This, the Commission cannot do. Again, "[i]f the legislature had intended that the Commission make two[56] separate 'final determinations,' … the legislature would have included such language in the statute."[57]

The economic impact to non-residential customer classes of the unlawful deviation from the statutory formula for interim-rate refunds is dramatic. The overcollection factors calculated by Minnesota Power for non-residential customer classes for the years 2022 and 2023 are 23.0771% and 30.4875%, respectively.[58] Correcting for Minnesota Power's unlawful deviation from the statutory interim-rate refund methodology, LPI respectfully asserts the proper overcollection factor for both 2022 and 2023 is 32.3763% (again, a calculation Commission Staff has confirmed[59]). Applying LPI's overcollection factor, the appropriate interim-rate refund due non-residential customer classes is $33,812,699, before interest. The Commission's overcollection factors result in a total interim-rate refund of $26,089,650, before interest,

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664, Staff Briefing Papers (corrected), at 15 (August 31, 2023) (eDocket No. 20238-198554-01).

55 Compliance Filing, Sched. 1, pg. 2 of 11.

56 Or, as in this instance, three.

57 *In re Minnesota Power & Light Co.*, 435 N.W. 2d at 557.

58 Compliance Filing, Section 1, pg. 5-6 of 11.

59 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Staff Briefing Papers (corrected), at 15 (August 31, 2023) (eDocket No. 20238-198554-01) ("Staff replicated [LPI's] calculations and believes they are accurate.").

representing a difference of more than $7.7 million (before interest). LPI recognizes there may be differences in final implementation. Nonetheless, LPI respectfully requests the Commission to correct its approval of Minnesota Power's two overcollection factors (23.0771% for 2022 and 30.4875% for 2023) and to direct Minnesota Power to utilize LPI's single overcollection factor of 32.3763% as set forth in Table 1 above, in accordance with state law.

2. The Compliance Filing Order Amounts to Inappropriate Retroactive Single-Issue Ratemaking

The retroactive removal of ST Paper and Cenovus sales revenue from the Commission-approved test-year, and the corresponding retroactive increase in Minnesota Power's revenue requirements during the interim-rate period, thereby resulting in a decrease in the interim-rate refund owed to all non-residential customers, flies in the face of longstanding regulatory precedent. To be sure, the Compliance Filing Order ignores that the test year itself is a snapshot in time, designed to be a reasonable representation of costs and revenues for the purposes of establishing rates prospectively. If it is proper to retroactively look to actual sales of two individual customers during the year 2022 (or the lack thereof), then it follows that the Commission would also need to incorporate actual sales to all customer classes during the year 2022 for setting rates, which would also presumably impact the approved revenue requirement and the interim-rate refund. But that too would be incomplete, because actual costs and expenses for the year 2022 undoubtedly differ from those approved in this rate case. For example, the Commission-approved 2022 test-year sales in megawatt hours (MWh) for the residential class is 946,536 MWh.[60] But Minnesota Power's actual sales to the residential class in the year 2022 were 1,063,695 MWh.[61] This sales deviation, along with others, presumably impacts various fuel, plant, and O&M costs, which are undoubtedly part of countless deviations from the Commission-approved 2022 test-year. To single out one wholesale customer and one retail customer for purposes of a retroactive analysis of Minnesota Power's alleged revenues during the rate-case proceeding ignores all of these variations, some of which increased Minnesota Power's revenues and some of which decreased Minnesota Power's

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[60] Compliance Filing, Sched. 11 pg. 2 of 8.

[61] *See e.g., In the Matter of Minnesota Power's Petition for Approval of the Annual Automatic Adjustment Charges for the Period of January 2022 through December 2022*, Docket No. E-015/AA-21-312, Commission Staff Briefing Papers at pg. 4 of 18, Table 2 (June 21, 2023) (eDocket No. [20236-196725-01]) (copy at Exhibit B).

revenues. Therefore, the Commission's attempt at precision erroneously fails to account for the myriad other moving parts in establishing the revenue requirement in this rate case, runs contrary to the entire interim-rate construct, and runs counter to the Commission's own principle that it "does not treat test year changes in isolation from one another."[62] *See also In re Minnesota Power & Light Co.*, 435 N.W.2d at 558 (quoting the Commission's own consistent precedent that "[a]s a general rule, the Commission is reluctant to adjust revenue requirements to reflect changes, *certain or not*, …" (emphasis added)).

III. CONCLUSION

From the utility's perspective, interim rates are an imprecise but critical tool to protect against the regulatory lag associated with a rate-case filing. From customers' perspective, critical protection is provided via a straightforward refund process prescribed by Minnesota law. Namely, the difference between interim rates as determined at the outset of a rate case and final rates set by the Commission at the end of a rate case. This clear and unambiguous process ensures customer classes are placed in the same position they would have been in had interim rates been set equal to final rates. The Commission's attempt at precision, here benefiting Minnesota Power to the tune of millions of dollars, finds no support under the historic statutory construct, Commission precedent, or the record. Accordingly, LPI respectfully urges the Commission to correct the Compliance Filing Order to be consistent with Table 1 above, rendering it consistent with the historic statutory construct, Commission precedent, the record, *and* Minnesota law.

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[62] *In re Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Auth. to Change its Schedule of Rates for Retail Elec. Serv. in the State of Minn.*, Docket No. E-015/GR-87-223, Order after Reconsideration and Rehearing, at 3-4 (May 16, 1988) (eDocket No. 92066) (copy at Exhibit C).

Dated: October 19, 2023

Respectfully submitted,

STOEL RIVES LLP

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ATTORNEYS FOR
THE LARGE POWER INTERVENORS

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STATE OF MINNESOTA

IN COURT OF APPEALS

In the Matter of the Application
by Minnesota Power for Authority
to Increase Rates for Electric Service
in Minnesota.

O R D E R
A23-0867
A23-0871

BASED ON THE FILE, RECORD, AND PROCEEDINGS, AND BECAUSE:

1. On June 14, 2023, relator Large Power Intervenors (LPI) filed a petition for a writ of certiorari, seeking review of orders issued by respondent Minnesota Public Utilities Commission (the commission) that, inter alia, set interim and final rates to be charged for electricity by respondent Minnesota Power. The clerk of the appellate courts issued a writ of certiorari and assigned appellate file number A23-0867 to LPI's appeal.

2. Also on June 14, 2023, relator Minnesota Power filed a petition for a writ of certiorari, seeking review of orders issued by the commission in the same docket. The clerk of the appellate courts issued a writ of certiorari and assigned file number A23-0871 to Minnesota Power's appeal.

3. Together with its petition for a writ of certiorari, LPI filed a motion to stay appeal A23-0867 pending the commission's "resolution of outstanding issues concerning non-residential customers' entitlement to an interim-rate refund pursuant to Minn. Stat. § 216B.16, subd. 3." LPI asserts that the resolution of these issues may moot and will finalize its arguments on appeal regarding the interim and final rates.

4. On June 22, 2023, Minnesota Power filed a motion to consolidate its appeal with LPI's appeal and a response to LPI's motion to stay. Minnesota Power states that it does not oppose staying the appeals for up to three months, during which time it anticipates that the commission would resolve the outstanding issues.

5. Also on June 22, 2023, the commission filed motions to consolidate the two appeals and a response to LPI's motion to stay. The commission states that it does not oppose staying the two appeals.

6. On June 27, 2023, LPI filed a response to the motions to consolidate, stating that it does not object to consolidation.

7. Related appeals may be consolidated by this court's order on its own motion or upon motion of a party. Minn. R. Civ. App. P. 103.02, subd. 3. Because these appeals involve the same parties and related issues, consolidation is warranted in the interest of judicial economy.

8. This court has inherent authority to stay an appeal in the interest of judicial economy. *See Landis v. N. Am. Co.*, 299 U.S. 248, 254 (1936) (observing that "the power to stay proceedings is incidental to the power inherent in every court to control the disposition of the causes on its docket with economy of time and effort for itself, for counsel, and for litigants"). Staying the consolidated appeals to allow resolution of outstanding issues before the commission will promote judicial economy.

IT IS HEREBY ORDERED:

1. Appeals A23-0867 and A23-0871 are consolidated.

2. Processing of the consolidated appeals is stayed pending further order of this court.

3. By August 1, 2023, and by the 1st of each month thereafter, LPI's counsel shall e-file and e-serve a status letter with this court, addressing the status of the proceedings on the outstanding issues and the expected remaining duration of the stay.

4. In the event the outstanding issues are not timely resolved, any party may move for an order dissolving the stay.

Dated: June 30, 2023

BY THE COURT

Susan L. Segal
Chief Judge

EXHIBIT B

MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	June 29, 2023		Agenda Item 4*
Company	Minnesota Power		
Docket No.	**E-015/AA-21-312**		
	In the Matter of Power's Petition for Approval of the Annual Automatic Adjustment Charges for the Period of January 2022 through December 2022		
Issues	Should Minnesota Power's 2022 Annual Fuel and Purchased Energy Charge Rider true-up be approved?		
Staff	Eric Willette	eric.r.willette@state.mn.us	651-201-2193

✓ **Relevant Documents**	**Date**
Minnesota Power – True-up Report (Public and Trade Secret)	March 1, 2023
Department of Commerce - Comments (Public and Trade Secret)	April 14, 2023
Large Power Intervenors – Comments	April 17, 2023
Minnesota Power – Reply Comments (Public and Trade Secret)	May 11, 2023
Large Power Intervenors - Reply Comments	May 22, 2023
Department of Commerce – Letter	May 31, 2023

I. Statement of the Issue

Should Minnesota Power's 2022 Annual Fuel and Purchased Energy Charge Rider true-up be approved?

II. Background

On March 1, 2023, Minnesota Power (MP, Company) filed its 2022 Annual True-Up of its Fuel and Purchased Energy Charge (Petition) seeking recovery of $13.3 million. MP proposed a 12-month recovery period beginning the first month following Commission approval.

On April 14, 2023, the Minnesota Department of Commerce, Division of Energy Resources (Department, DOC) filed comments recommending approval of Minnesota Power's Petition.

On April 17, 2023, Large Power Intervenors (LPI) filed comments requesting updated rate information, if/how baseload generation decisions exposed MP to market at a greater degree, if/how the short/long term action plans MP recent integrated resource plan (Docket No. 21-33) impacted market exposure in 2022 or will impact market exposure in 2023 and beyond, if/how MP's existing demand response programs mitigate exposure, whether MP is exploring economic demand response or other customers options to help further mitigate market exposure going forward, and a detailed analysis explaining why/how FCA costs are increasing at dramatic pace MP's significantly lower reliance upon fossil-based fuel generation.

On May 11, 2023, Minnesota Power filed reply comments agreeing with the Departments recommendations and provided LPI's requested information.

On May 22, 2023, Large Power Intervenors filed response comments recommending the Commission reject Minnesota Power's requested $13.3 million FCA true-up and order MP to explore rate mitigation strategies.

On May 31, 2023, The Department filed a letter reiterating approval of MP's FCA true-up.

III. Parties' Comments

A. Minnesota Power - True-Up Filing

1. Background

On December 2, 2021, the Commission approved Minnesota Power's January 2022 through December 2022 Forecasted Rates for its Rider for Fuel and Purchased Energy Charge (Fuel Adjustment Clause, FAC, FCA).

On June 30, 2022, Minnesota Power submitted a proposal to adjust rates by $36.0 million due to higher than forecasted market pricing and associated impacts on congestion costs between generation and load. After a 30-day notice period and no objection to the rate adjustment, Minnesota Power increased the approved monthly fuel cost rates for August through December 2022 by $36.0 million.

2. 2022 FCA Forecast to Actuals

Minnesota Power's 2022 actual sales were 8,962,240 MWh and actual fuel costs were $285.9 million. During 2022 Minnesota Power under collected fuel costs by $13.3 million and proposed to recover that amount over a 12-month period beginning the first of the month following Commission approval.

3. Fuel Costs

Table 1 compares 2022 forecasted total sales, total cost of fuel and average cost of fuel to actuals

Table 1 Fuel Cost Summary

2022 Forecasted Fuel	2022 Adjusted Forecast	2022 Actual	Difference
Company's Generating Stations	$87,497,496	$130,269,082	$42,771,585
Purchased Energy	$210,911,146	$262,867,849	$51,956,703
MISO Charges	$18,239,651	$59,750,884	$41,511,234
MISO Schedules 16, 17 & 24	($107,186)	($406,916)	($299,730)
Fuel Cost Recovered through Inter System Sales	$88,073,950	$167,749,176	$79,675,226
Costs Related to Solar	$-	$83	$83
Time of Generation and Solar Energy Adjustment	$384,405	$440,270	$55,864
Forecasted Cost of Fuel	$229,065,935		
Significant Events Filing	$36,052,884		
Total Cost of Fuel	$265,118,819	$285,985,742	$20,866,923
Total Fuel Clause Sales (MWh)	8,763.90	8,962.30	198.4
Average Cost of Fuel	$30.25	$31.91	$1.66

4. Sales

As shown in Table 2, mainly due to increased Large Power Taconite sales, actual sales were 198,378 MWhs, or 2%, higher than forecasted. Additionally, due to increased MISO market sales Inter System sales were 832,716 MWhs higher than forecast. However, Inter System sales are removed from the Total Sales as they are non-FAC MWhs. Minnesota Power used the RTSim production cost model to determine the volume and cost of MISO market sales used in the forecast. Actuals are looked at hourly so there will be hours where Minnesota Power is a net purchaser which creates market purchases and sales in a month.

Table 2 – Sales Comparison (MWh)

2022 Sales	Forecasted Sales	Actual Sales	Difference
Total Sales of Electricity	**11,917,313**	**12,948,280**	**1,030,966**
Residential	1,033,882	1,063,695	29,813
Commercial	1,188,275	1,181,292	-6,983
Large Power Taconite	3,925,163	4,297,541	372,378
Large Power Paper and Pulp	485,003	490,030	5,027
Large Power Pipeline	316,335	305,030	-11,305
Other Miscellaneous	332,806	341,716	8,910
Municipals	1,498,638	1,299,049	(199,589)
Inter System Sales	3,137,211	3,969,927	832,716
Less: Inter System Sales	**3,137,211**	**3,969,927**	**832,716**
Customer Intersystem Sales	872,711	820,924	(51,787)
Market Sales	2,260,131	3,140,614	880,483
Station Service	4,369	8,390	4,021
Sales due to Retail and Resale Loss of Load	0	0	0
Less: Solar Generation & Purchases	**16,240**	**16,112**	**(128.00)**
Total Fuel Clause Sales	**8,763,862**	**8,962,240**	**198,378**

Minnesota Power provided the following information regarding 2022 actual sales when compared to forecast:[1]

- Residential sales were within 2% of the 2022 forecast.
- Commercial sales were 1% less than forecasted.
- Large Power Taconites were 9% more than forecasted. Taconite customers were above forecasted production levels in 2022.
- Large Paper and Pulp were 1% more than forecasted.
- Large Power Pipelines were 4% lower than forecasted due to lower loads.
- Other Misc. were 3% more than forecasted.
- Municipals were 13% lower than forecasted due to the new NEMMPA contracts. In addition, effective September 1, 2022, Hibbing Public Utilities is no longer a municipal customer of Minnesota Power.
- Intersystem Sales were about 832,000 MWhs above forecasted.

[1] Minnesota Power Petition at Attachment 2, pg. 24.

5. Generation[2]

Higher energy production at Minnesota Power's thermal generation fleet as well as the Hibbard Renewable Energy Center was due to being called upon by MISO more frequently because of higher market prices than forecasted. Additionally, when Minnesota Power submitted its forecast in May 2021, the Company did not anticipate Boswell Unit 3 would be dispatched most of the year because it had transitioned to economic dispatch in July 2021. The increased generation at the Company's Laskin facility was due to MISO dispatching the units for reliability purposes.

Minnesota Power provided the following information regarding 2022 generation costs when compared to forecast:[3]

- Boswell total costs were 29% above forecast because sales were higher than forecast. Also, Minnesota Power saw actual market prices come in significantly higher than forecast which increased Boswell 3 and 4's output. With Boswell 3 being economic and market prices being high, Boswell 3 was cleared by MISO more often than expected which increased their generation by 67% compared to forecast.
- Higher market prices also resulted in Hibbard being called on and running more than forecasted. Minnesota Power forecasted and ran Hibbard for all 12 months but actual generation was 115% above forecast. Hibbard's $/MWh was 122% above forecast due to a significant rise in biomass fuels costs throughout 2022 due to higher production costs related to diesel, labor, and inflation.
- The higher market prices contributed to higher than forecasted generation at Laskin. Minnesota Power forecasted Laskin to run 4 months but it ran 10 months which increased its generation 500% compared to forecast. Also, 2022 natural gas prices were 66% higher than 2021 which resulted in a higher $/MWh.
- Wind generation was 0.21% below forecast with Bison being 1% below forecast but Tac Ridge being 29% above forecast. Wind generation owned by Minnesota Power has a $0 Fuel Cost so this increased generation helped reduce FCA Costs.
- Hydro generation was 11% lower than forecast due to a drier spring and fall. In the spring, low snowfall totals from the previous winter led to a lower than forecast runoff. In the fall, drier conditions led to low flows which lowered the Hydro generation in September and October 2022. Hydro generation owned by Minnesota Power has a $0 Fuel Cost.

6. Purchase Costs

Minnesota Power provided the following information regarding 2022 purchase costs when compared to forecast that shows the main drivers of purchase cost increases:[4]

[2] Trade Secret Table 3 in Minnesota Power's Petition summarizes MP's production, by plant.

[3] Minnesota Power Petition at Attachment 2, pgs. 24-25.

[4] Minnesota Power Petition at Attachment 2, pgs. 25-27.

- Manitoba Hydro’s 133 MW contract has a variable energy piece based on energy market (133 Purchase Power Agreement) and, throughout 2022, Minnesota Power procured higher than forecast energy from Manitoba Hydro at a slightly higher cost.
- With higher than forecast market prices, Minnesota Power increased company generation to offset market purchases which lowered the MWhs purchased from market. Market per MWh purchase prices were 141% above forecast due to higher that forecast MISO Market prices.
- Minnkota Power Station Service costs were higher than forecasted. The forecast was based on prior year monthly average.
- Purchase to serve Non-Firm Retail Customer are forecasted at $0, so this section is a placeholder when the forecast is made. Purchases to cover this Non-Firm Retail Customer were contracted with different counter parties and are included in the purchase by counterparty.
- Counter Party Purchases were not known or under contract at the time of the forecast filing but were procured during times when Minnesota Power was short and needed to purchase energy to cover load. This can happen when generation is lower than expected, load is high, or Minnesota Power has generating units off for outage.
- The other purchases section includes all customer owned generation purchases that are not forecasted.
- Oliver 1 costs were 4% lower than forecast due to credits received on the Oliver 1 invoices that were not forecasted and lowered the $/MWh.
- Oliver 2 costs were 3% more than forecast due to more generation than forecasted at Oliver 2. There were credits received on the Oliver 2 invoices that were not forecasted which lowered the $/MWh but, with the higher generation, total costs at Oliver 2 were higher than forecast.
- Wing River generation and costs were 42% lower than forecasted. Wing River was slightly below forecast almost every month and did have an outage in January and February 2022.
- Nobles generation was 8% higher than forecast and its $/MWh was slightly higher than forecast. Minnesota Power saw strong winds in southern MN throughout 2022 which increased Nobles generation. The slightly higher $/MWh was due to compensated curtailments which are not forecasted.
- When the forecast was prepared, there was no purchase to serve municipal solar energy as this was a contract that was signed after the forecast was filed. The contract to serve municipal solar energy started in April 2022. The offsetting sales are in the Inter-System-Customer Sales section.
- Square Butte generation was higher than forecast and its fuel costs were slightly lower than forecast which reduced its overall costs.

7. Inter-System Sales

Minnesota Power provided the following information regarding inter-system sales when compared to forecast:[5]

- IPS and RFPS MWhs were higher than forecasted. The increased $/MWh was due to higher than forecasted market prices.
- Economy and Non-Firm MWhs were lower than forecast due to Silver Bay Power- North Shore Mining being idle from April - December. The increased $/MWh was due to higher than forecasted market prices.
- Since it is usually small, Excess Energy is not forecasted. With higher than forecasted loads, MP saw more excess energy.
- Since it is usually small, Incremental and Price Recall are not forecasted. With higher than forecasted loads, MP saw more Incremental and Price Recall energy.
- Oconto loads were higher than forecasted.
- NEMMPA Incremental: Starting January 1, 2022, all Minnesota Power municipal customers except for SWL&P, Nashwauk, and Hibbing Public Utilities. This was not known at the time the forecast was prepared.
- Municipal Solar Energy: When the forecast was prepared, there was no solar energy sale to a municipal customer as this was a contract that was signed after the forecast was filed. The contract to serve municipal solar energy started in April 2022.
- Hibbing Public Utilities: In April 2022, Hibbing Public Utilities signed a Purchase Power Agreement with Minnesota Power. Part of this new contract includes a long-term firm sale. Effective September 1, 2022, Hibbing Public Utilities is no longer a municipal customer of Minnesota Power. This was not known at the time the forecast was prepared. Minnesota Power's on May 11, 2022 compliance filing in Docket No. E015/M-21-28, discloses the pertinent details of this bilateral contract.
- Asset Based Sales (Non-MISO): Since load was higher, more Minnesota Power generation was used to serve load and not available to serve Asset Based Sales thus creating less Asset Based sales and more Liquidation sales.
- Since Minnkota Power Liquidation which is based on Butte Square Butte's generation, increase the MWhs and lower costs of the Minnkota Power Liquidation which is based on the output and costs of Square Butte.
- Minnesota Power uses the RTSim production cost model to determine the volume and cost for MISO market sales. When excess energy is available and it's economical, the model will sell the excess energy into the MISO market. With the increase in purchase and generation, MP saw increased MISO Market sales.
- Oliver County I's forecast assumptions were based on the previous year's average and 2022 actuals were slightly higher.
- Oliver County II's forecast assumptions were based on the previous year's average and 2022 actuals were slightly lower.
- WPPI station service is calculated when Boswell 4 is offline. Boswell 4 was offline 62 more days than forecast and costs are based off on DA LMPs and with higher market prices higher WPPI station service costs were higher than forecast.

[5] Minnesota Power Petition at Attachment 2, pgs. 27-29.

- Wing River was offline in January and February 2022 and there was station service which was not forecasted.
- MISO Costs recovered through Customer Sales is part of their fuel cost and is reflected in the average cost price in the “Inter-System Sales-Customer Sales” section. Higher than forecast MISO Costs recovered thru Market Sales were due to higher than forecast Market MISO sales.
- The Asset Based Margin Credit were 458% higher than forecast. This increase in the credit is mainly due to higher than forecasted MISO market prices which increased the sales price for Asset Bases Sales. This increase in sales price increased the margins back to customers. Also, with the signed NEMMPA and Hibbing Public Utilities contracts some of the sales margins flow to the customers in the “Asset Based Margins” section.

8. MISO Costs

Minnesota Power provided the following information regarding 2022 MISO Costs when compared to forecast:[6]

- Day Ahead/Real Time Asset, Non-Asset, Excessive, and Non-Excessive Energy: Asset Energy is reflected in MISO market purchases and sales; therefore, Minnesota Power did not include amounts in its forecast.
- Day Ahead (DA)/Real Time (RT)Losses and Congestion are Minnesota Power’s repurchased energy costs. When the forecast is prepared, all of the repurchased energy costs are reflected in Day Ahead Loss category. Actual costs are split out between DA Losses, RT Losses, DA Congestion, and RT Congestion.
- Day Ahead Financial Bilateral Transaction Congestion, Auction Revenue Rights Transaction Amount, Financial Transmission Rights Annual Transaction Amount, and Financial Transmission Rights Hourly Allocation are charges that are based on market prices. Minnesota Power saw a difference in prices between forecast and actuals which caused a difference in these various charges.
- The Real Time Revenue Sufficiency Guarantee Make Whole Payment difference is mainly since some of Minnesota Power’s generating units, for reliability purposes, were called on more than forecasted. This resulted in more Real Time Revenue Sufficiency Guarantee Make Whole Payments to Minnesota Power.

9. True-Up Proposal

Minnesota Power proposed a 2022 FCA True-up of $13.3 million to be collected over a 12-month period beginning the first of the month following Commission approval.

B. Department of Commerce – Comments

The Department reviewed Minnesota Power’s Petition to determine (1) whether the Company’s actual 2022 energy costs were reasonable and prudent, (2) correctly calculated the

[6] Minnesota Power Petition at Attachment 3, pg. 2.

2022 true-up for its FPE rates, and (3) whether the Petition complies with the reporting requirements set forth in the applicable Minnesota Rules and Commission Orders.

1. Prudency and Reasonableness of Minnesota Power's Actual 2022 Fuel/Purchased Power Costs

As shown in Table 3, the Department noted that Minnesota Power's relevant MWh sales were 2% higher than forecasted, total system actual fuel/purchased power costs recoverable through the FCA were 8% higher than forecasted and average fuel and purchased power costs, per MWh, were 5.5% higher than forecasted.

Table 3 – Comparison of Select Forecasted to Actual Data for Minnesota Power's Fuel Clause Adjustment True-Up

Data Description	Actual	Forecast	Percentage Difference
MWh Sales Subject to FCA	8,763,862.00	8,962,240.00	2.26%
Total Cost of Fuel/Purchased Power	$265,118,819	$285,985,742	7.87%
Average Fuel/Purchased Power Cost Per MWh	$30.25	$31.91	5.49%

Table 4 breaks into several major categories of cost and offsetting credit/revenue components of Minnesota Power's actual and forecasted fuel/purchased power costs recoverable through the FCA. The higher energy market prices combined with higher sales caused higher generation and purchased power costs. Also, MISO charges were significantly greater than forecasted - $59.8 million actual compared to $18.2 million forecasted or 227.6% higher.

Table 4 - Minnesota Power's Actual and Forecasted Total Company 2022 Fuel/Purchased Power Costs and Offsetting Credits/Revenues by Major Category

Fuel/Purchased Power Cost, Credit, or Revenue Category	2022 Forecast	2022 Actual	Percentage Difference
Plant Generation Costs	$87,497,496	$130,269,082	48.88%
Purchased Power Costs	$210,911,146	$262,867,849	24.63%
MISO Charges	$18,239,651	$59,750,884	227.59%
MISO Schedule 16, 17 & 24	($107,186)	($406,916)	-279.64%
Fuel Cost Recovered through Inter System Sales	$88,073,950	$167,749,176	90.46%
Costs Related to Solar	-	$83	n/a
Time of Generation and Solar Energy Adjustment	$384,405	$440,270	14.53%
Significant Events Filing	$36,052,884	-	n/a
Total Costs, Net Credits and Revenue	$265,118,819	$285,985,742	7.87%
Total Fuel Clause Sales (MWh)	8,763.9	8,962.3	2.26%
Average Cost of Fuel	$30.25	$31.91	5.49%

The Department noted that, due to increased Large Power Taconite sales, MP's customer sales increased 198,378 MWhs, or 2%, over forecast.

Based on Minnesota Power's experience, the Department concluded it is reasonable that the Company's actual fuel/purchased costs recoverable through FCA were more than forecasted. The Department noted that most of the reasons for increased fuel costs, including higher gas and energy market prices as well as higher MISO charges, were mostly beyond Minnesota Power's control, although continued costs controls and efficiency are important to keep fuel costs reasonable. The Department recommended the Commission find MN Power's actual 2022 fuel/purchased power costs recoverable through FCA be found to be reasonable.

2. Minnesota Power's 2022 Fuel Clause Adjustment True-up

In its Petition, Minnesota Power requested recovery of $13.3 million in FCA under attributed to under collected 2022 fuel costs, with recovery over a 12-month period effective the first of the month following Commission approval. Table 5 summarizes the actual amount to be recovered.

Table 5 – 2022 Over/(Under) Collection Credit

	Actual
2022 Actual Collections from Customers	$231,771,476
Less: Actual Costs and Actual Sales	$245,039,378
Net 2022 FCA True-up Amount	($13,267,902)

The Department concluded Minnesota Power correctly calculated its FCA/FPE $13.3 million under-collection and considered the Company's proposal to collect the amount over the 12-month period beginning the first month following Commission approval to be reasonable.

3. Compliance with Reporting Requirements

The Department verified that the Petition included the information required by the following:

- Minnesota Rules 7825.2800 - 7825.2840, as revised on pages 3 - 4 and approved in Point 1 of the Commission's June 12, 2019 Order.
- Annual FCA true-up general reporting guidelines, as outlined on page 7 and approved in Point 5 of the Commission's June 12, 2019 Order.
- Annual FCA true-up reporting compliance matrix specific to Minnesota Power, as shown in Attachment 1 of the March 1, 2019 joint comments and approved in Point 7 of the Commission's June 12, 2019 Order.

The Department concluded that Minnesota Power's Petition complies with the applicable reporting requirements and recommended that the Commission approve the Petition's compliance reporting portions.

4. Maintenance Expenses of Generation Plants and Correlation to Incremental Forced Outage Costs

In its February 6, 2008 Order,[7] the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case. This requirement stems from the drastic increase in Investor-Owned Utilities' (IOUs) outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have otherwise produced, usually through wholesale market purchases. The cost of those market purchases flows directly to ratepayers through the FCA. The high outage costs incurred by investor-owned utilities in FYE06 and FYE07 raised the question of whether plants were being maintained appropriately to prevent forced outages and whether IOUs were spending as much on plant maintenance as they were charging their customers in base rates. The Commission agreed with the Department and the Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work."

The Department reviewed Minnesota Power's approved and actual Minnesota jurisdiction generation maintenance expenses for 2022 and, since actual generation maintenance expenses exceeded amounts approved in rates, found them to be reasonable. The Department will continue to monitor Minnesota Power's generation maintenance expenses in future filings, to ensure underspending on generation maintenance expenses does not result in increased outage costs passed on to the ratepayers through the FPE.

5. Conclusion and Recommendations

Based on its review, the Department concluded (1) MN Power's actual fuel/purchased power costs for 2022 were reasonable and prudent, (2) MN Power correctly calculated its 2022 FCA/FPE Rider under collection of $13,267,902, and (3) MN Power's Petition complies with the applicable reporting requirements, subject to the Department's review of MP's generation maintenance expenses in the Company's Reply Comments. Therefore, the Department recommended the following:

- Find MN Power's actual 2022 fuel/purchased power costs recoverable through the FCA/FPE rider were reasonable and prudent for 2022.
- Find MN Power correctly calculated its 2022 FCA/FPE Rider under-collection of $13,267,902.

[7] ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING FURTHER FILINGS, AND AMENDING ORDER OF DECEMBER 20, 2006 ON PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE, In the Matter of the Review of the 2005 AAA of Charges for all Electric Utilities, Docket No. E-999/AA-06-1208 (February 6, 2008) p. 9, ordering paragraph 18

- Allow MN Power to collect $13,267,902 in the 12-month period following approval by the Commission.
- Approve the compliance reporting portions of Minnesota Power's Petition.

C. Large Power Intervenors – Comments

Large Power Intervenors stated increasing FCA rates represented one aspect of an overall troubling trajectory of rates and bills on Minnesota Power's system. LPI noted that during the 2011-2012 timeframe, fuel and purchased energy costs averaged between $19-$20 per MWh, which shows customers' fuel and purchased energy costs alone have increased by 60% over the last 10 years. The magnitude of this increase appears counterintuitive considering Minnesota Power's decreased reliance on fossil fuel. Therefore, LPI requested additional information from Minnesota Power in reply comments.

LPI argued that FCA rates and other increases are driving industrial customers' rates and bill upward. As shown in Table 6, based on Minnesota Power's response to LPI Information Request No. 5000, Large Power customers' average rate in 2022 was $94.90 per MWh. Rates at this level are well above customers' expectations and certainly raise concerns about Minnesota Power's duty to have just and reasonable rates that comply with explicit state energy policy. Additionally, LPI requested Minnesota Power provide additional level of detail, showing how each item contributed to the total number.

Table 6. Rate Impacts of Preferred Plan Relative to Actual and Projected Average Rates

Rate Class Impact	2021	2022	2023	2024
Large Power (average rate, cents/kWh)	8.04	9.49	9.605	9.605
Increase (cents/kWh)	-0.002	0.055	0.035	0.041
Increase (%)	-0.02%	0.58%	0.36%	0.43%
Average Impact ($ / month)	-$1,140	$32,828	$20,752	$24,674

Large Power Intervenors also requested Minnesota Power provide additional information pertaining to increased market pricing in 2022 and beyond, by supplementing the record with the following information:

- If/how decisions to move baseload generation to seasonal/economic dispatch have exposed the Minnesota Power to the market to a greater degree.
- If/how the short- and long-term action plans in the Minnesota Power's recent integrated resource plan (PUC Docket No. 21-33) impacted market exposure in 2022 or will impact market exposure in 2023 and beyond.
- If/how the Minnesota Power's existing demand response programs mitigate market exposure.
- Whether the Minnesota Power is exploring economic demand response or other customer options to help further mitigate market exposure going forward.
- A detailed analysis explaining why/how FCA costs are increasing at a dramatic pace despite the Minnesota Power's significantly lower reliance upon fossil-based fuel generation.

D. Minnesota Power – Reply Comments

In response to the Department and LPI's requests for additional information MP provided the following.

1. Department of Commerce Request to Update Maintenance Expenses

As the Department's request, Minnesota Power provided the approved generation maintenance expense from most recent rate,[8] as well as the 2022 actual Minnesota Jurisdiction generation maintenance. Minnesota Power also updated its Attachment 10, which includes the generation maintenance expense information requested. MP noted that the data shown under the Commission Decision column in the updated attachment is not considered final approved until after all compliance filings have been submitted in the rate case.

2. LPI Information Request 5000 Update

LPI requested that Minnesota Power update the LPI IR 5000 with 2022 actuals, updated 2023 information and, current 2024 forecasts inclusive of base rates, riders, and FCA charges. The updated information is shown below in Table 7.

Table 7. Rate Impacts of Preferred Plan Relative to Actual and Projected Average Rates Updated[9]

Rate Class Impact	2021	2022	2023	2024
Large Power (average rate, cents/kWh)	7.78	9.13	10.07	10.45
Increase (cents/kWh)	-0.002	0.055	0.035	0.041
Increase (%)	-0.02%	0.58%	0.36%	0.43%
Average Impact ($ / month)	-$1,140	$32,828	$20,752	$24,674

[8] Docket No. E-015/GR-21-335.

[9] Notes: 2021 and 2022 actual average rates are based on FERC Form 1 actual revenue and usage, average monthly actual FPE and rider billing factors, and adjustment to align CPA factor in base rates with actual billing factor. 2023 average base rates are prorated assuming Interim Rates continue through 7/31/2023 and Final Rates are implemented on 8/1/2023. Interim Rates are based on 12/23/21 Interim Rate Compliance Schedule 1 and Final Rates are based on draft Final Compliance Schedule E-1. Other 2023 rates include actual 2023 updated FPE factors with 2021 true-up, CPA adjustment assuming the new rate is implemented on 7/1/2023 as filed, the 2022 RRR factors effective 2/1/2023, the 2023 TCR factors effective 1/1/2023, and the 2023 SRRR factors effective 8/1/2023. Monthly rider rates are averaged. 2024 average base rates are based on draft Final Compliance Filing Schedule E-1. All other billing factors noted above as being in-place by 12/31/2023 are continued through 12/31/2024.

3. Economic Dispatch

At LPI's request, Minnesota Power provided insight on baseload generation and economic dispatch. In 2021, Minnesota Power successfully transitioned Boswell Unit 3 to economic dispatch. During 2022, Boswell Unit 3 was consistently dispatched by MISO, due to the strong energy markets. Currently with the transition there has not been a significant increased market exposure; however, as market prices begin to soften and are closer to the dispatch price for Boswell Unit 3, the Company could experience periods of time where MISO does not dispatch the unit and therefore, could have increased exposure to the market.

4. Impacts from Integrated Resource Plan ("IRP")

In response to LPI's request, Minnesota Power provided additional information on if/how the short and long-term action plans approved in Minnesota Power's recent IRP impacted market exposure in 2022 or will impact market exposure in 2023 and beyond. Specifically, the Company stated:

> *Minnesota Power's transition away from fossil fuel generation has been done carefully and thoughtfully to ensure a reasonable cost power supply and reliability is maintained for our 7x24 customers. The short-term action plan in Minnesota Power's IRP approved by the Commission did not include any actions that impacted market exposure in 2022. Going forward, Minnesota Power has developed, and the Commission approved, a diverse generation portfolio to decarbonize the company's power supply that includes Power Purchase Agreements ("PPA") and owned wind, hydro (including dispatchable), dispatchable gas generation, biomass, and solar that results in a low-cost portfolio for customers. With Minnesota Power's diverse renewable portfolio, it helps maintain a more consistent production of renewables, and when renewables are unavailable Minnesota Power has a dispatchable generation portfolio and demand response that can be used to fill the gaps. We will continue to keep reliability and market exposure in the forefront as* we continue to transform.

5. Existing Demand Response Programs

At LPI's request, Minnesota Power provided additional information on how Minnesota Power's existing demand response programs mitigate market exposure. Minnesota Power stated it has the following demand response programs that are used to mitigate market exposure.

- Dual Fuel is an interruptible discount rate designed primarily for electric heating, which requires a separate meter that can be controlled by Minnesota Power. In exchange for a discounted rate, customers must agree to be interrupted (through a meter that can be interrupted by Minnesota Power), which typically occurs when demand on the electric system is high. Dual Fuel load is interrupted to reduce or mitigate exposure to market purchases from MISO when market costs are high.

- Incremental Production Service (IPS) – Incremental energy procured by Large Power Customers for service above the IPS threshold established in the Electric Service Agreement. This product also offered the Company a curtailable product in times of high system loads or during concerns of system volatility. Duration and frequency of curtailments are at the sole discretion of the Company and require a 10-minute notice.
- Released Energy and Voluntary Energy Buyback – Voluntary Customer products that reduce energy requirements during times when Minnesota Power is purchasing energy to meet firm energy requirements, thereby enabling the avoidance of higher-cost energy purchases.

6. Exploring Economic Demand Response or Other Customer Products

In response to LPI's inquiry regarding whether Minnesota Power was exploring economic demand response or other customer options to help further mitigate market exposure going forward. Minnesota Power noted that in its most recent IRP proceeding the Company proposed, and was subsequently ordered, to work collaboratively with customers to pursue up to 50 MW of additional long-term demand response by 2030 to address future resource adequacy changes. Minnesota Power stated that it continues to work with its customers to implement new longer-term demand response products to maximize this valuable resource for the region. This would also include exploring economic demand response criteria and options. Lastly, Minnesota Power noted that it continually evaluates additional demand response programs through its IRPs, including air conditioning and electric hot water heater cycling programs.

7. Detailed Analysis of Why FCA Costs are Increasing

In response to LPI's request for an analysis explaining why FCA costs are increasing at a dramatic pace despite the Company's significant lower reliance upon fossil-based fuel generation, Minnesota Power stated:

> Minnesota Power stated transition away from fossil fuel generation has been done carefully and thoughtfully to ensure a reasonable cost power supply and reliability is maintained for Minnesota Power 7x24 customers. MP's power supply decisions are prudently vetted by the Commission and stakeholders through the IRP process every couple of years. The IRP evaluation takes into consideration Minnesota renewable and carbon reduction goals, environmental cost impacts to residents, rate impacts to customers, and the reliability of the system. Minnesota Power has been executing a well thought out plan to decarbonize our power supply that includes continuing to operate our most efficient coal generation resources (i.e. Boswell Units 3and 4) to provide low-cost power to customers throughout the transition, a diverse renewable portfolio of wind, solar, and hydro that is a mix of owned resources and PPAs, a dispatchable fleet of gas and biomass fired generation, utilization of the MISO market when economical, and efficient use of customer demand response. Minnesota Power's decarbonization plan

maintains a consistent production capability where renewables provide low-cost power, and when renewables are unavailable Minnesota Power has a dispatchable generation portfolio and demand response that can be used to economically fill the gaps.

E. Large Power Intervenors – Reply Comments

1. Commission Should Reject 2022 FCA True-Up Request

LPI noted that increasing FCA costs are placing unreasonable strains on customers. In 2022, the Minnesota Power's initially forecasted total cost of fuel was $229,065,935 (subsequently increased by $36 million and potentially increasing by $13.3 million more). In 2023 and 2024 the Company's forecasts increased to $265,752,178 and $263,625,304, respectively. These costs are, undoubtedly, contributing to increasing projected rates for customers, which are trending upwards at an alarming rate applying Company projections. In the span of only a few months, Minnesota Power's 2023 and 2024 Large Power customer projections are now approximately $100.66/MWh and $104.53/MWh, respectively.[10] As a result, LPI recommended that MP's true-up request be denied.

2. The Commission Should Order Exploration of Rate Mitigation Strategies

Large Power Intervenors recommended the Commission also order Minnesota Power to explore further rate mitigation options to provide customers with additional opportunities to control rapidly increasing electricity costs. LPI argued that Minnesota Power acknowledged that it "continually evaluates additional demand response," and that it has been ordered to pursue more demand response options. Given the current trajectory of customers' rates (described above), the need to facilitate these proposals is urgent, and LPI believes that stakeholder conversations and workshops should begin as soon as possible. LPI noted that the Commission has previously ordered the Company to work with customers on rate design issues, and LPI urged the Commission to direct a similar process here.[11]

F. Department of Commerce – Reply Comments

The Department reviewed the Company's approved and actual Minnesota jurisdiction generation maintenance expenses for 2022 provided in MP's reply comments and found them reasonable.

[10] MP Reply Comment at Updated Table 2(b).

[11] See In the Matter of Minnesota Power's Compliance Report on Rate Design for Large Power Customers, PUC Docket No. E-015/M-21-61.

IV. Staff Comments

Staff has reviewed and verified Minnesota Power's calculations and concurs with the Company and the Department's recommendation that Minnesota Power's Petition be approved.

Staff notes that LPI's recommendation that Minnesota Power explore rate mitigation possibilities does not include a timeline recommendation. Therefore, if the Commission is persuaded by LPI's recommendation, Staff will add a compliance date to the decision alternative related to this issue.

V. Decision Alternatives

Petition

1. Accept and approve Minnesota Power's 2022 Annual Fuel and Purchased Energy Charge Rider true-up compliance filing. (MP, DOC)

True-Up Amount

2. Authorize Minnesota Power to recover its 2022 under-collection of $13,267,902. (MP, DOC)

3. Do not authorize Minnesota Power to recover its 2022 under collection. (LPI)

Timing of True-up

4. Allow Minnesota Power to recover the 2022 under-collection over a 12-month period starting the 1st of the next month after the Commission issues its written order. (MP, DOC)

Rate Mitigation

5. Order Minnesota Power to work with stakeholders to explore rate mitigation strategies and file a progress report by January 15, 2024. (LPI, amended by Staff)

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Barbara Beerhalter	Chair
Cynthia A. Kitlinski	Commissioner
Norma McKanna	Commissioner
Robert J. O'Keefe	Commissioner
Darrel L. Peterson	Commissioner

In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota

ISSUE DATE: May 16, 1988

DOCKET NO. E-015/GR-87-223

ORDER AFTER RECONSIDERATION AND REHEARING

PROCEDURAL HISTORY

On March 1, 1988 the Commission issued its FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER in the above-captioned general rate case. Under Minn. Stat. Section 216B.27 (1986) parties to the case had 20 days from the date of the Order to seek reconsideration or rehearing.

The following parties filed timely petitions for rehearing:

Minnesota Power (MP or the Company);

The Department of Public Service (DPS or the Department);

Eveleth Taconite Company and Eveleth Expansion Company, d/b/a/ Eveleth Mines (Eveleth);

Joint Intervenors Designated in the Original Order and Herein as Inland Group

Inland Steel Mining Company (Inland)
National Steel Pellet Company (National)
USX Corporation (USX)
Pickands Mather & Company, also known as Hibbing Taconite Company (Hibbing)

On March 21, 1988 the Commission issued its ORDER GRANTING PETITIONS FOR REHEARING AND VARYING TIME FOR REPLIES. In that Order the Commission granted all petitions for reconsideration or rehearing filed on or before March 21 and varied the Rules of Practice and Procedure to establish a uniform filing deadline for replies to these petitions.

Upon review and consideration of all the pleadings, briefs, and evidence submitted herein, the Commission finds it appropriate to reconsider its decisions on the following issues: litigation expenses associated with the FERC audit; budget line items captioned "vegetation control," "interest and dividends," "American Bank Note Company," "financial communications," and "financial mailing lists;" excess demand revenues; and the allocation of the shortfall in revenues among retail rate classes.

The Commission declines to reconsider and affirms its March 1 Order as to all other issues.

FINDINGS AND CONCLUSIONS

Two Revenue Deficiencies

The Commission rejected the Company's request that it determine a separate revenue deficiency for the interim rates period, in large part because doing so would have amounted to deciding two separate rate cases in the course of one proceeding. For the two deficiencies the Company offered different cost of service studies and proposed different rate bases, income statements, capital structures, and overall rates of return. The Company identified approximately 15 items it believed required adjustment.

In its request for reconsideration, MP narrowed its focus and asked only that the Commission take into account four "known changes" resulting in higher costs for the interim period than for the period on which final rates were based. The areas in which the known changes were said to have taken place were capital structure, the Coyote transfer, historical CIP costs, and property taxes. The Company argued that the adjustments proposed for these changes would be similar to adjustments the Commission has made in past rate cases for single known changes. The adjustments proposed by MP would result in a $2,658,384 increase in the final interim revenue requirement.

The Department agreed that the four adjustments proposed would be appropriate. The OAG interpreted Minn. Stat. Section 216B.16, subd. 3 (1986) to require the retroactive application of the final revenue requirement to the interim period. The Inland Group objected to what it viewed as manipulation of the test year to protect MP from the consequences of its own actions in selecting the test year it did.

The Commission will not make the requested adjustments for two reasons. First, isolating the four items targeted for adjustment on reconsideration is inconsistent with established Commission practice and policy. There is no evidence in the record which would support an adjustment for the four items in isolation of the many differences identified by MP throughout this proceeding. Second, the Commission has already rejected the substantive basis for making two of the four adjustments proposed. Each reason will be discussed in turn.

First of all, adjusting the interim revenue requirement to reflect the four items viewed in isolation from the rest of the filing is inconsistent with the arguments maintained by MP throughout this proceeding. MP supplied arguments and schedules throughout this proceeding which maintained its request for a separate revenue deficiency for final interim rates and for final prospective rates. The differences between the final interim rate request and the prospective rate request involved approximately 15 separate issues as listed by MP in its June 9, 1987 communication and as discussed in MP Exhibit 101. For the first time, in its request for reconsideration, MP narrows the focus to four separate items which it claims cannot lawfully be used to reduce rates for the interim period. As a general rule, the Commission is reluctant to adjust revenue requirements to reflect changes, certain or not, unless there is a compelling need to do so. This is because the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical -- some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year.

In keeping with these general principles, the Commission has adjusted for changes in the past only when their certainty and magnitude would otherwise make the test year process unreliable. In a related process, the Commission has also required companies to combine their Tax Reform Act filings with general rate case filings in the interests of administrative efficiency and to protect the interests of ratepayers. This has resulted in many of the adjustments cited in the Company's petition for reconsideration.

The four changes identified by the Company in its petition do not merit adjustment as exceptions to the general rule set forth above. They do not fall outside the bounds of changes assumed to counterbalance one another over the course of the test year. It appears, for example, that the sums represented by these four items would be offset by the National and Butler revenue adjustments reflected in final rates, or any of the 15 items initially identified by MP throughout this proceeding. Including the National and Butler revenues of approximately $2.8 million could result in a lower revenue requirement for the interim rate period than for the prospective rate period. This scenario is just one illustration of the reasons the Commission does not treat test year changes in isolation from one another.

Furthermore, as noted above, the Commission has rejected the substantive basis for two of the four changes for which the Company advocated adjustments. The Commission rejected the capital structure proposed for the interim rate period and disallowed the inclusion of historical CIP costs in other sections of the March 1 Order. Eliminating those two items virtually eliminates the claimed $2,658,384 difference in the revenue requirement for the interim rate period.

Finally, the Commission rejects the Company's argument that failing to make the four adjustments advocated results in incorporating events occurring after the test year. On the contrary, each of the four events at issue is expected to occur during the test year, with the exception of historical CIP expenses, which were incurred prior to the test year.

For these reasons, in addition to those set forth in its March 1 Order, the Commission declines to reconsider the two revenue deficiency issue.

FERC Audit

In its March 1 Order, the Commission deferred action on certain litigation expenses included in the Company's fuel adjustment clause pending final decision in a proceeding before the Federal Energy Regulatory Commission (FERC). The Order required the Company to make a compliance filing within 45 days of FERC's final decision in the matter. In its petition for reconsideration, MP pointed out that the matter is now before the U. S. Court of Appeals and requested that the Commission clarify its Order to require that the compliance filing be made within 45 days of that court's decision.

The Commission finds that it would be inefficient to commence a separate proceeding based on the FERC decision when that decision might be modified on appeal. The Commission will clarify its March 1 Order as the Company requests.

Vegetation Control

In its March 1 Order, the Commission reduced test year vegetation control expense by $496,459 for the Company as a whole. The reduction was based on a Commission finding that the test year expense for this item was higher than normal because vegetation control had been curtailed in 1986 as an economy measure. Test year expenses therefore included amounts which would normally have appeared in the 1986 expenditures. This conclusion was based in part on a comparison between actual 1986 expenditures and projected test year expenditures.

The Company requested reconsideration on this issue on two grounds: (a) the amount claimed represented what the Company will actually spend during the test year, and (b) $549,000 in actual 1986 expenditures had been overlooked because it appeared in an account which had been discontinued in the test year budget.

The Commission reaffirms its decision that some adjustment to test year vegetation control expense is warranted because test year expenses have been inflated by the inclusion of expenses which normally would have appeared in the 1986 expenditures. Superwood Exhibit 111 clearly supports the contention that 1986 budget restrictions caused scheduled vegetation control work to be delayed until 1987.

The Commission agrees with the Company, however, that the amount of the adjustment was overstated in the March 1 Order and that $549,000 in total company transmission vegetation control expenses were overlooked in calculating the permissible amount for vegetation control. This occurred largely because the vegetation control issue was first raised at the briefing stage, making factual development of the issue difficult. The Commission is now convinced that an additional $549,000 in total company expenses should have been included in the amounts averaged to obtain the amount allowed for vegetation control, and the Commission will order its inclusion on reconsideration.

This adjustment increases jurisdictional test year expense by $163,810, resulting in a decrease in test year net operating income of $97,844 from the March 1 Order.

<u>Interest and Dividends</u>

The Commission excluded the entire amount included in test year expense for the preparation and mailing of 1099s. MP requested reconsideration and allocation of the expenses between utility and non-utility operations. The DPS supported the Company.

MP clarified this issue in its petition for reconsideration. The Commission finds that MP must provide this information to its shareholders under the requirements of the Internal Revenue Service. Furthermore, this kind of communication may fall within the provisions of Minn. Stat. Section 216B.16, subd. 8 (1986), which requires allowance of expenses incurred by the utility to disseminate information about corporate affairs to its owners.

Since these costs are related proportionately to MP's utility and non-utility activities, the Commission will allow recovery of these expenses after allocating 35.8% to non-utility operations. This adjustment increases jurisdictional test year expense by $7,614 and decreases net operating income by $4,548 from the March 1 Order.

American Bank Note Company

The Commission excluded the entire amount of expenses for printing stock certificates as a shareholder expense. MP requested reconsideration and allocation between utility and non-utility operations. The DPS supported the Company's request.

Upon reconsideration, the Commission will allocate this expense. The Commission finds that although no stock offerings are in progress, MP must issue new stock certificates as a result of daily trading of its stock. This is an integral part of MP's financing through public ownership. The expense should be allocated between utility and non-utility operations, since the expense is applicable to both.

This adjustment increases jurisdictional test year expense by $5,747 after allocating 35.8% to non-utility activities and decreases net operating income by $3,433 from the March 1 Order.

Financial Communications

The Commission excluded the entire cost of financial communications to the investment community as a shareholder expense. MP requested reconsideration and allocation.

After reviewing the record in this case, the Commission finds that communications with the investment community also benefit ratepayers. They promote financing flexibility by maintaining a pool of informed investors. This expense will therefore be allowed and allocated between utility and non-utility operations.

The Commission is aware of the possibility that expenses of this nature may on occasion actually be advertising not allowable under Minn. Stat. Section 216B.16, subd. 8. Expenses of this nature will therefore be carefully reviewed on a case by case basis.

This adjustment increases jurisdictional test year expense by $19,539 and decreases net operating income by $11,671 from the March 1 Order.

Financial Mailing Lists

The Commission excluded all of the expenses related to mailing information to the financial community. The Company requested reconsideration and allocation.

On reconsideration, the Commission finds that, like the financial communications discussed above, these costs are incurred to keep the financial community and owners informed. They are necessary to MP's financing and produce benefits to ratepayers by increasing financing flexibility. As discussed in the financial communications section above, however, it is necessary to review such costs on a case by case basis to ensure that they are not in fact advertising costs.

The Commission will allow the financial mailing list expenses after allocating 35.8% of the cost to non-utility activities. This adjustment increases jurisdictional test year expense by $10,252 and decreases net operating income by $6,123 from the March 1 Order.

Eveleth Revenues

As discussed in the excess demand revenues section of this Order, Eveleth buy-down revenues were recalculated based on the revised LP demand rate estimate. This adjustment increases test year revenues by $50,465, and increases net operating income by $30,143 from the March 1 Order.

Interest Synchronization and Cash Working Capital Effects

The cash working capital effects of the income statement changes, interest synchronization, and the change in the amount of the decrease results in a positive change of $10,802 from the March 1 Order.

The combined effect of interest synchronization and the effects on income taxes resulting from the decrease is a $206 reduction in state and federal income tax expense, with a corresponding increase in test year net income from the March 1 Order.

Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year after reconsideration is $543,202,866, as shown below.

Utility Plant in Service	$939,761,794
Less: Accumulated Depreciation	(267,059,740)
Net Utility Plant in Service	$672,702,054
Construction Work in Progress	$ 16,202,859
Accumulated Deferred Income Taxes	(145,561,985)
Customer Advances	(685,176)
Customer Deposits	(343,751)
Miscellaneous Deferred Items	589,060
Working Capital:	
Cash Working Capital	$(20,120,382)
Materials and Supplies	2,579,023
Fuel Inventory	17,231,169
Prepayments	609,995
TOTAL RATE BASE	$543,202,866

Operating Income Statement Summary

Based upon the above findings, the Commission concludes that the appropriate operating income after reconsideration for the test year is $55,772,282 as shown below.

Operating Revenues:	
Sales of Electricity by Rate Class	$285,142,803
Other Electric Revenues	37,323,107
Other Revenues	12,442,547
Total Operating Revenues	$334,908,457
Operating Expenses:	
Operations and Maintenance	$200,818,240
Depreciation	28,934,373
Amortization	444,032
Taxes Other Than Income	34,173,140
State Income Tax	3,176,877
Federal Income Tax	9,995,013
Provision for Deferred Tax (net)	4,009,405
Investment Tax Credit	(1,860,286)
Total Operating Expenses	$279,690,794
Operating Income Before AFUDC	$ 55,217,663
AFUDC	554,619
NET OPERATING INCOME	$ 55,772,282

Revenue Deficiency (Surplus)

The above Commission findings and conclusions after reconsideration result in a Minnesota jurisdictional gross revenue surplus of $8,342,232 determined as shown below.

Rate Base	$543,202,866
Rate of Return	9.35%
Required Operating Income	50,789,468
Test Year Net Operating Income	55,772,282
Operating Income Deficiency (Surplus)	(4,982,814)
Revenue Conversion Factor	1.674201
Revenue Deficiency (Surplus)	$ (8,342,232)

After reconsideration, the Commission finds revenues from the sales of electricity by rate class of $285,142,803, other electric revenues of $37,323,107, and other revenues of $12,442,547 for total test year operating revenues of $334,908,457 under present rates. Subtracting $8,342,232 from $334,908,457 results in total authorized Minnesota operating revenues of $326,566,225. As discussed elsewhere in this Order, authorized revenues from the sales of electricity by rate class are decreased to $279,437,100, other electric revenues are decreased to $34,686,578, and other revenues remain at $12,442,547.

Excess Demand Revenues

1. Hibbing and Inland Excess Demand Revenues

The Company sought reconsideration of the Commission's calculation of projected revenues from excess demand sales to two Large Power (LP) customers, Inland and Hibbing. Those revenue projections were based on present rates. Since the March 1 Order placed excess demand sales in other electric revenues, lowered base rates for LP customers, and established a $5 per kW discount for excess demand sales, the Company alleged it simply could not collect the revenues projected in the Order. The Company advocated recalculating projected revenues from these customers using the final LP demand rate established in this rate case.

The DPS indicated that the Commission adopted the correct billing units for Hibbing and Inland but that the Commission should correct an error in the computation of excess demand revenues. Specifically, the DPS indicated that the Commission properly used present rates in the calculation but did not make an adjustment to reflect its adoption of the excess demand discount. According to the DPS, this would place MP in a position of potential underrecovery of its authorized revenue requirement.

Eveleth and the Inland Group also agreed in argument before the Commission that the March 1 Order would cause MP to have a revenue shortfall.

The Commission, in examining this issue very carefully, finds that the March 1 Order would place MP in a position of not being able to collect authorized revenues. The basic problem is that the Order would not allow MP to design rates to recover revenues lost through the rate design decisions to (a) lower the LP demand rate and (b) allow a discount for excess demand sales to LP customers. The Commission finds, based upon the representations of the parties, that the levels of excess demand sales assumed in the Order could not be increased substantially in the near future. In fact, excess demand sales could drop below the assumed levels if the excess demand discount were not available. As a result, the revenue shortfall alleged by the Company almost surely would occur unless a remedy is adopted by the Commission. The Commission will correct this rate design problem by increasing the class revenue responsibilities by $2,636,529. This dollar figure is the product of three factors: the excess demand units; the difference between the present LP tail-block demand rate and the revised estimate of the discounted excess demand rate; and the jurisdictional allocation factor used in the March 1 Order.

2. Effects of Other Adjustments

There are a number of other revenue and rate adjustments which must be made on reconsideration. Most of the modifications to the March 1 Order made in this Order have revenue and rate consequences. Also, Eveleth and the Company have negotiated a new Electric Service Agreement providing for a buy-down payment recognizing the difference between the old and new contract demand levels. This payment is based on the final rates approved in this rate case and will therefore have to be adjusted from the $2,899,800 estimated in the March 1 Order to $2,956,185.

3. Overall Effect of Adjustments

Taken together, the modifications to the original order made on reconsideration result in a net revenue adjustment from the Company's filed levels of $7,789,073, rather than the $7,738,608 given on page 31 of the March 1 Order, and a new revenue surplus of $8,342,232.

The resulting revenue responsibilities of the rate classes total $279,437,100, rather than the $276,642,727 indicated in the March 1 Order.

4. Allocation of Additional Revenue Requirement Among Rate Classes

The remaining question is how the additional revenue which must be collected as a result of the decisions in this Order should be allocated among the customer rate classes.

Most of the need for additional revenue results from the Commission's acceptance of the LP excess demand discount. At first glance, then, assigning the additional revenue responsibility to the LP class is an attractive option. The record, however, supports the argument of the parties that promoting excess demand sales to LP customers benefits all customer classes. Excess demand sales provide a contribution to fixed costs which would otherwise have to be made by other customers; they foster economic growth in the service area; and they help reduce surplus capacity on the system. It was for these reasons that the Commission initially adopted the excess demand discount. Assigning total revenue responsibility to the LP class would be unfair and counterproductive.

Since the benefits of excess demand sales accrue to all classes, the Commission concludes that the cost of the discount should be borne by all classes. Accordingly, the Commission will permit MP to recover the additional necessary revenues through a uniform 1.0101% increase in the class revenue responsibilities established in the March 1 Order. The new revenue responsibilities will be as follows:

Class	Revenue Responsibility
Residential	$ 40,614,100
General Service	28,791,900
Large Light & Power	35,434,200
Large Power	169,861,900
Municipal Pumping	2,386,500
Lighting	2,348,500
Total Sales by Rate Class	$ 279,437,100
Other Electric Revenues	34,686,578
Other Revenues	12,442,547
Total Operating Revenues	$ 326,566,225

5. Excess Demand and the May 1989 Investigation

The excess demand discussion above and that in the March 1 Order illustrate that the excess demand discount poses problems in a ratemaking context. Therefore, the Commission believes that the treatment of excess demand revenues and the associated discount should be reexamined in the May 1989 investigation to be conducted as a result of the transfer of capacity to Northern States Power Company in In the Matter of Minnesota Power & Light Company's Sale and Northern States Power Company's Purchase of Forty Percent Undivided Ownership Share in the Boswell Steam Electric Generating Station Unit No. 4 Facilities, Docket No. E-002, 015/PA-86-722 (June 23, 1987). Specifically, the Commission will order the parties to consider the cost of service implications of excess demand and the effectiveness of various levels of the excess demand discount in spurring additional production by customers in the LP class.

Class Rate Structures

The March 1 Order contemplated no changes in the existing rate levels or rate structures for the Residential, General Service, Large Light and Power, and Municipal Pumping classes. However, the changes in retail class revenue requirements discussed above will now require small changes in the rates for these classes. Also, the reductions in class revenue responsibilities for the LP and the Lighting classes are now somewhat different from those stated in the March 1 Order. Parties did not address the issue of class rate structure changes in their petitions for reconsideration.

Except as specifically modified by this Order, all class rate structure and other rate design decisions in the March 1 Order are unchanged.

1. Residential

Since the approximately $406,100 increase to be collected from the Residential class is relatively small, the Commission does not believe that major changes in the existing Residential rate structure which could substantially increase rates for some customers would be reasonable at this time. However, a small movement toward a more appropriate Residential rate structure can be accomplished without undue impact on particular customer groups. The Commission finds that the most reasonable way to collect the increase from the standard Residential rate schedule is by increasing the tail block of the energy charge. The increase for seasonal Residential rates will be collected through the flat energy charge.

Placing the increase on the tail-block energy charge of the standard Residential schedules results in an increase of less than 0.2¢, or 4%, in this portion of the rate. The Commission finds this change will move toward a flattening of the rate blocks without having a major impact on space heating or other large-use Residential customers. Lower-use customers will experience no increase in their rates. This decision reasonably balances the concerns expressed by the OAG and the Seniors regarding low-use and low-income Residential consumers and MP's concerns regarding the impact on higher-use customers.

2. General Service

The Commission finds it reasonable to collect the approximately $287,900 increase from the General Service class through small increases in all components of the rate, changing the customer and demand charges slightly more than energy charges. This is the method proposed by MP and endorsed by the DPS and the ALJ in the rate case to bring these charges closer to cost.

3. Large Light and Power

The Commission finds it reasonable to collect the approximately $354,300 increase for the Large Light and Power class by increasing the customer charge by $10, with the balance collected from small increases in energy and demand charges. This is similar to the methods proposed by MP and the DPS and reflects cost considerations. However, the customer charge increase is less than the $20 and $25 amounts proposed by MP and the DPS, respectively, reflecting the much smaller percentage increase to this class than contemplated by these parties in the rate case.

4. Large Power

Retail rates for the LP class are reduced by approximately $6,301,000 over present rates; additional reductions will be experienced by LP customers taking consumption under the excess demand discount. The Commission reaffirms the basic rate structure from its March 1 Order for this class, which included increasing the first demand block by 10% over present rates and applying the decrease to the tail-block demand. The Commission estimates that this will result in a tail-block demand charge of approximately $16.01 per kW.

5. Municipal Pumping

The Commission finds it reasonable to collect the approximately $23,900 increase from the Municipal Pumping class through an increase in the customer charge and smaller increases in demand and energy charges. This is essentially the method recommended by the DPS in its rate case testimony to make the rate structure better reflect cost. The Commission agreed with the DPS that the record does not support phasing out this rate, and that more information should be provided in future rate filings on this issue.

6. Lighting

The Commission reaffirms the rate structure decisions in its March 1 Order for this class. The Lighting rate schedules are to be reduced by approximately $476,500, applying the same general approach proposed by MP and supported by the DPS.

ORDER

The Order Paragraphs in the Findings of Fact, Conclusions of Law, and Order of the Minnesota Public Utilities Commission, issued March 1, 1988, as revised by the decisions herein, are restated as follows:

1. Minnesota Power shall decrease the gross annual utility operating revenues by $8,342,232 to produce annual gross Minnesota utility operating revenues of $326,566,225. Authorized revenues from the sale of electricity by rate class are decreased to $279,437,100, authorized other electric revenues are decreased to $34,686,578, and other revenues remain at $12,442,547.

2. Within 30 days of the issue date of this Order, Minnesota Power shall file with the Commission for its review and approval a schedule of revised rates, charges, and tariffs, with supporting documentation and calculations, based on the revenue requirement authorized herein, including:

   a. an increase of 1.0101% over present rate levels for the Residential, General Service, Municipal Pumping, and Large Light & Power classes, with the rate structure changes approved herein;

   b. a reduction of approximately $476,500 for the Lighting class with the rate design changes discussed herein;

   c. a reduction of approximately $6,301,000 for the Large Power class with the rate structure changes discussed herein, including a 10% increase in the demand charge for the first 10,000 kW and a decreased demand charge for all additional kW;

   d. the addition of a Large Power excess demand discount rate;

e. mandatory weekly billing for taconite-producing Large Power customers, with optional weekly billing for non-taconite Large Power customers;

f. inclusion of ten-year initial term contracts and four-year cancellation notice provisions in the Large Power rate schedule, with a provision for waiver;

g. the addition of a Large Power non-contract rate;

h. a policy for crediting off-system sales under the best efforts obligation.

3. Within 30 days of the issue date of the Order, the Company shall file with the Commission for its review and approval a proposed plan for refunding to all customers the revenue collected during the interim rates period in excess of the revenue requirement authorized herein, as discussed in Section XIV of the March 1 Order.

4. Minnesota Power shall serve on all parties to this proceeding copies of the filings required in Ordering Paragraphs 2 and 3 above. Parties shall have 15 days to comment on these filings.

5. Within 30 days of the issue date of this Order, Minnesota Power shall file with the parties and serve on the Commission, with its revised rates and charges, a revised base cost of fuel and supporting schedules, incorporating the changes made herein. Minnesota Power shall also file a fuel clause adjustment establishing the proper adjustment to be in effect at the time final rates become effective. Parties shall have 15 days to comment on these filings. The DPS shall review these filings in the same manner as any other automatic adjustment filings submitted to them.

6. As discussed herein, Minnesota Power has satisfied the intent of the Commission's rules relating to rate adjustments due to the Tax Reform Act of 1986. Further filings shall not be required under Minn. Rules, parts 7827.0100 to 7827.0600.

7. On or before January 1, 1989, Minnesota Power shall file with the Commission, and serve on all parties, a conservation cost recovery report of activities for the 15 months ending September 30, 1988. The report shall contain a summary of the following items: (1) the revenues collected under the conservation cost recovery charge, (2) an itemization by program cost of the conservation expenses incurred by Minnesota Power for the Commission-approved CIP costs, and federally-required program costs which Minnesota Power placed in the conservation cost tracker account, and (3) separate itemization of item (1) and (2) for the three-month period

ending September 30, 1987. The same report is required annually thereafter except subsequent reports will cover the 12-month period ending the preceding September 30 and item (3) will not be required.

8. Within 45 days following the issuance of the U.S. Court of Appeal's decision in the matter of the FERC ruling in Docket No. FA-84-15-000, regarding litigation expenses included in the fuel adjustment clause, Minnesota Power shall file with the Commission, and serve on all parties, its compliance filing. Such compliance filing shall include copies of the FERC and U.S. Court of Appeal's decisions, full detail of the costs at issue, and Minnesota Power's testimony stating its position on the matter before the Commission. Parties shall have 30 days from the date of the compliance filing to make comments to the Commission.

9. Within two years of the issuance of this Order, Minnesota Power shall file with the Commission, and serve on all parties, its updated proposal for the treatment of post-shipment mine closing costs which addresses the concerns described herein. Minnesota Power shall maintain detailed records sufficient to identify the amount of post-shipment mine closing costs collected through rates accumulated in the sinking fund, including interest at the after-tax cost of capital determined in this proceeding.

10. On or before March 1, 1989, Minnesota Power shall file with the Commission, and serve on all parties, the detailed rate case expense documentation as discussed herein.

11. As part of the investigation for May 1989 ordered in <u>In the Matter of Minnesota Power & Light Company's Sale and Northern States Power Company's Purchase of Forty Percent Undivided Ownership Share in the Boswell Steam Electric Generating Station Unit No. 4 Facilities</u>, Docket No. E-002, 015/PA-86-722, Minnesota Power and other interested parties shall consider the cost of service implications of the excess demand discount and consider the effectiveness of various levels of the excess demand discount in spurring additional production by Large Power customers.

12. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

MEHennen

Mary Ellen Hennen
Executive Secretary

(S E A L)