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 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, 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

Mary Ellen Hennen
Executive Secretary

(S E A L)