Re Northern States Power Company

Docket No. E-002/GR-91-1

— PUR4th —

Minnesota Public Utilities Commission

November 27, 1991

ORDER, in a general rate case, authorizing an electric utility to increase its annual revenues by $53.460 million, incorporating an approved return on equity or 12.1%, and directing the utility to implement certain budget requirements in its next rate case filing. The order addresses issues relating to rate base, operating income, rate of return, rate design, conservation and load management, and economic development costs. The utility had sought to increase rates by approximately $98 million, an 8.1% increase over current rates. The utility also petitioned for interim rates of almost $72 million, a 5.9% increase.

APPEARENCES: Minnesota Department of Public Service (the Department), represented by Eric Swanson and Julia Anderson, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, MN 55101. Residential Utilities Division of the Office of the Attorney General (RUD-OAG), represented by Dennis Ahlers and Gary Cunningham, Special Assistant Attorneys General 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul MN 55101. City of St. Paul and the Board of Water Commissioners of the City of St. Paul, represented by Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, MN 55102. Suburban Rate Authority represented by David C. Roland and Glenn E. Purdue, Messerli & Kramer, 1500 Northland Plaza Building, 3800 West 80th street, Minnepolis, MN 55431. North Star Steel (NSS), represented by Garrett Stone and Peter Mattheis, Ritts, Brickfield & kaufman, Watergate 600 Building, Suite 915, Washington, D.C. 20037-2474. Minnesota Utility Investors (MUI), represented by Frank Pazlar, 405 Sibley Street, Suite 227, St. Paul, MN 55101. Metalcasters of Minnesota (Metalcasters), represented by John Knapp, Lloyd Grooms and David Cassidy, Winthrop & Weinstine, 3200 World Trade Center, St. Paul, MN 55101. Champion International (Champion), represented by Peggy Wells Dobbins, 915 Aduana

Avenue, Coral Gables, Florida 33146. Union Carbide Corporation, represented by William A. Chesnutt, McNees, Wallace & Nurick, 100 Pine Street, P.O. Box 1166, Harrisburg, PA 17108-1166. Minnesota Energy Consumers (MEC), represented by Byron Starns and James J. Bertrand, Leonard, Street and Deinard, 150 South Fifth Street, Suite 2300, Minneapolies, MN 55402.] Mankato Citizens Concerned with Preserving Environmental Quality (Manakato), represented by Rodney A. Wilson, Wilson Law Office, Suite 500, 701 Fourth Avenue South, Minneapolis, MN 55415. Minnesotans for an Energy Efficient Economy (ME3), represented by James W. Ladner, Jr., Robins, Kaplan, Miller & Ciresi, 1100 International Centre, 900 Second Avenue South, Minneapolis, MN 55402. Minnesota Senior Federation (Senior Federation), represented by Elmer Scott, 171 Iris Park Place, 1885 University Avenue West, St. Paul, MN 55104.

Before Peterson, chair, and Kitlinski, Knaak, McKanna, and Vick, commissioners.

BY THE COMMISSION:

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On January 28, 1991, Northern States Power Company (NSP or the Company) filed a petition under Minn. Stat. § 216B.16 (1990) for an increase in electric rates of $98,198,000, an 8.1% increase over current rates. The Company also filed a petition for interim rates in the amount of $71,904,000, a 5.9% increase.

On February 12, 1991, the Company made a supplementary filing containing summary schedules showing the rate base, income statement and revenue summary for the first year budget, and bridge schedules summarizing the regulatory adjustments made to the budget in arriving at the test year rate base and income statement.

On March 11, 1991, the Commission accepted the Company's filings, suspended the proposed rates, and ordered contested case proceedings under Minn. Stat. § 216B.16, subd. 1 (1990). The Office of Administrative Hearings assigned Administrative Law Judge Richard C. Luis to the case.

On March 15, 1991, the Administrative Law Judge (ALJ) held a Prehearing Conference.

On April 19, 1991, the ALJ issued a Prehearing Order granting petitions to intervene, establishing the hearing schedule and adopting procedural guidelines. On March 22, 1991, the Commission authorized collection of an additional $71,904,000 as interim rates, to be collected in the form of a 5.94% surcharge to retail rate schedules, beginning with bills for service rendered on or after March 29, 1991.

On May 13, 1991, NSP filed a Motion to Update, seeking to include in the record testimony supporting an additional $5,628,000 in revenue requirement. NSP explained that these adjustments were necessary because its original filing had inadvertently overstated an adjustment for advertising expenses and not included expenses for personal computer depreciation.

On May 22, 1991, the Department filed comments opposing the Company's motion.

On June 13, 1991, after conducting a Motion Conference, the ALJ issued an Order on Motion to Update Filing and Certification of Order granting NSP's Motion, allowing NSP to adjust its revenue increase request upward by $5,628,000, subject to the statutory cap holding the Company to a maximum increase of the amount for which it filed, $98,198,000. The ALJ also certified that Order to the Commission.

On June 26, 1991, the Commission issued its ORDER AFFIRMING DECISION OF ADMINISTRATIVE LAW JUDGE. On August 2, 1991, NSP, the RUD-OAG, MEC, and the Department filed a stipulation with the ALJ regarding deferred expenses. The stipulation lowered NSP's requested revenue deficiency by $3,257,900.

On August 20, 1991, NSP filed a Motion for Leave to Reopen the Record to Offer Late Filed Exhibit. The ALJ granted the motion, thereby reducing the Company's final requested revenue deficiency to $83,387,000.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

In his April 19, 1991 Prehearing Order, the ALJ granted petitions to intervene by the following parties:

Minnesota Department of Public Service (the Department), represented by Eric Swanson and Julia Anderson, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, MN 55101.

Residential Utilities Division of the Office of the Attorney General (RUD-OAG), represented by Dennis Ahlers and Gary Cunningham, Special Assistant Attorneys General 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul MN 55101.

City of St. Paul and the Board of Water Commissioners of the City of St. Paul, represented by Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, MN 55102.

Suburban Rate Authority represented by David C. Roland and Glenn E. Purdue, Messerli & Kramer, 1500 Northland Plaza Building, 3800 West 80th street, Minnepolis, MN 55431.

North Star Steel (NSS), represented by Garrett Stone and Peter Mattheis, Ritts, Brickfield &

kaufman, Watergate 600 Building, Suite 915, Washington, D.C. 20037-2474.

Minnesota Utility Investors (MUI), represented by Frank Pazlar, 405 Sibley Street, Suite 227, St. Paul, MN 55101.

Metalcasters of Minnesota (Metalcasters), represented by John Knapp, Lloyd Grooms and David Cassidy, Winthrop & Weinstine, 3200 World Trade Center, St. Paul, MN 55101.

Champion International (Champion), represented by Peggy Wells Dobbins, 915 Aduana Avenue, Coral Gables, Florida 33146.

Union Carbide Corporation, represented by William A. Chesnutt, McNees, Wallace & Nurick, 100 Pine Street, P.O. Box 1166, Harrisburg, PA 17108-1166.

Minnesota Energy Consumers (MEC), represented by Byron Starns and James J. Bertrand, Leonard, Street and Deinard, 150 South Fifth Street, Suite 2300, Minneapolies, MN 55402.]

Mankato Citizens Concerned with Preserving Environmental Quality (Manakato), represented by Rodney A. Wilson, Wilson Law Office, Suite 500, 701 Fourth Avenue South, Minneapolis, MN 55415.

Minnesotans for an Energy Efficient Economy (ME3), represented by James W. Ladner, Jr., Robins, Kaplan, Miller & Ciresi, 1100 International Centre, 900 Second Avenue South, Minneapolis, MN 55402.

Minnesota Senior Federation (Senior Federation), represented by Elmer Scott, 171 Iris Park Place, 1885 University Avenue West, St. Paul, MN 55104.

B. The Company

Northern States Power Company (NSP or the Company) was represented by David A. Lawrence and Michael Hanson, Northern States Power Company, 414 Nicollet Mall, Minneapolis, MN 55401 and Samuel L. Hanson, Briggs & Morgan, 2400 IDS Center, Minneapolis, MN 55402.

III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers. The dates and locations of these hearings are listed below.

May 22, 1991 Montevideo May 23, 1991 St. Cloud May 28, 1991 Minneapolis May 29, 1991 Coon Rapids May 30, 1991 St. Paul June 5, 1991 Winona June 10, 1991 North

Mankato

During the course of these seven hearings, 32 witnesses gave oral comments. NSP and the Department made presentations at each hearing and the RUD-OAG appeared at four locations.

At least one Commissioner attended each hearing except at Winona, due to a conflicting regional Commissioners' conference. Members of the public were allowed to file written comments through August 15, 1991.

Thirty members of the public contacted the Commission by telephone (11) or by letter (19) to comment on the proposed rate increase generally or with respect to one or more particular issues raised by the Company's proposal. Of the 19 letters, 11 writers opposed the rate increase generally and 8 commented critically regarding various aspects of the Company's proposal. Specific issues of concern included expenses for Pathfinder decommissioning and reduction of the Conservation Rate Break (CRB).

IV. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings on June 19-21, June 24-28, July 1-3 and July 8-10, 1991.

V. PROCEEDINGS BEFORE THE COMMISSION

The ALJ filed Part I of his report (revenue requirements) on September 30, 1991 and Part II if his report (rate design) on October 4, 1991. Upon review of the entire record of this proceeding, the Commission makes the following Findings of Fact, Conclusions of Law, and Order.

FINDINGS AND CONCLUSIONS

VI. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and .02 (1990). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1990).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1990) and Minn. Rules, Part 1400.0200 *et seg*.

VII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, Part 7830.4100, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of this Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3(1990), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd.4 (1990).

VIII. NORTHERN STATES POWER COMPANY

NSP is an investor-owned gas and electric utility incorporated in the state of Minnesota. It provides electric service in Minnesota to approximately 1,009,442 retail customers, approximately 877,465 of them residential. Its service area covers approximately 40,000 square miles and includes parts of Minnesota, Michigan, Wisconsin, North Dakota, and South Dakota. The Company's Minnesota service area is comprised roughly of the southern one-third of the state, and includes the Minneapolis-St. Paul metropolitan area. Most of the Company's electric revenues come from service to the metropolitan area.

This rate case involves only the Company's retail electric operations in the state of Minnesota.

IX. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1990) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719 (Minn. 1987). In the *Northern States Power* case the Court divided the ratemaking function of the Commission into guasi judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inference and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

X. MOTIONS

A. Department's Objection to NSP's Motion to Update

On May 13, 1991, NSP filed a Motion to Update Filing. Specifically, NSP sought to update the record to correct errors in its initial filing by adding administrative and general expenses and depreciation expenses that had not been included in its original filing. The ALJ granted NSP's motion over the objection of the Department but certified the matter to the Commission.

On June 26, 1991, the Commission issued its ORDER AFFIRMING DECISION OF ADMINISTRATIVE LAW JUDGE in this matter.

The Department renewed its objection to NSP's motion in its Exceptions to Part I of the Administrative Law Judge's Report. In its Exceptions, the Department argued that the Commission's Order improperly shifted the burden from the party seeking inclusion of late filed material to those objecting to the inclusion of such material.

The Commission's June 26, 1991 Order does not relieve NSP and other similarly situated parties from demonstrating good cause for reopening the record as the Department suggests. The party offering late filed information bears the burden of demonstrating that fairness and accuracy are served by admitting the new material. Other parties and the process itself cannot be prejudiced by the inclusion of the new material. The June 26 Order carefully examined the particular circumstances of this case and upheld the ALJ's decision to include this information in the record.

Regarding the Department's concern that the Order sets a precedent, the Order makes it plain that the burden of proof has not been shifted. At page 2 of its Order the Commission stated:

> The Commission appreciates the objecting parties' concerns about the obligation of utilities to present complete, coherent rate case filings. The Commission shares those concerns; it has enforced those obligations in the past and will continue to enforce them. Utility requests to correct, revise, update, or supplement rate case filings must be examined with care *on a case by case basis*. (Emphasis added.)

The goal of the rate case process is to arrive at just and reasonable rates. To do this, the Commission needs the most complete and reliable information available. None of the parties have claimed allowing these adjustments would make the record less accurate. None of the parties have claimed they would be prejudiced by having to examine the adjustments.

In such circumstances, the Commission remains disinclined to exclude useful information absent a showing that its inclusion raises problems of fairness or accuracy. The Commission will reject the Department's renewed objection. The record adjustments at issue will remain in the record.

B. Motion for Sanctions

On August 21, 1991, NSP filed a motion with the ALJ requesting leave to reopen the record to include a late filed exhibit. The Company explained that it had come to its attention that the Minnesota incentive compensation had been overstated by $1,973,701. NSP asked that this information be put in the record and that its revenue requirement be adjusted in that amount.

On August 27, 1991, MEC filed a Motion for Sanctions, requesting that the Commission exclude incentive compensation in its entirety from test year expenses. MEC argues that this sanction for failure to disclose accurate information was authorized under Rule 37.02(b) of the Minn. Rules of Civil Procedure.

NSP responded that Minn. R. Civ. P. 37.02(b) did not authorize dismissal of incentive compensation amounts from the record and was, moreover, inapplicable to contested case hearings. Finally, the Company argued that in any event sanctions would not be appropriate for unintended mistakes.

The ALJ denied MEC's Motion for Sanctions, reasoning that sanctions under Rule 37.02(b) were not available in connection with NSP's original filing, but only in connection with failures to respond to discovery. The ALJ did not certify this motion to the Commission for review.

Where an ALJ, as here, makes a recommendation to the agency rather than a binding decision, the agency may review the ALJ's disposition of those motions in its final Order. Minn. Rules, Part 1400.7600 provides in relevant part:

> Uncertified motions shall be made to and decided by the judge and considered by the agency in its consideration of the record as a whole subsequent to the filing of the judge's report.

This matter does not require the Commission to decide the scope of sanctions available to the ALJ and Commission. In this case, NSP's mistake was to not reflect the reduction to its budget from 4% to 2% for incentive compensation for bargaining employees. The Commission finds that this was a good faith, unintentional error. Moreover, NSP corrected the error promptly upon becoming aware of its impact upon the case. No party was prejudiced by this error. As such, it does not warrant the severe sanction sought here, exclusion from the record of information whose accuracy no one disputes. Accordingly, while not adopting the ALJ's rationale, the Commission affirms the ALJ's decision to deny MEC's Motion for Sanctions.

XI. TEST YEAR

NSP proposed that the 12-month period January 1, 1991 through December 31, 1991 be used as the test year in this proceeding. The Company used projected date to develop the proposed rate base and operating income for the test year. The Company also supplied 1989 historic data adjusted for known and measurable changes to corroborate the projected data. NSS urged that the Commission require NSP to file future rate requests based on historical test years.

The ALJ found that NSP's projected test year was appropriate and reliable for ratemaking purposes. The ALJ declined to recommend that the Commission require future filings based on a true historic test year adjusted for known and measurable changes. The record does not establish historic test years as superior to forecasted test years.

The Commission does not take the matter of future or historic test years lightly. The Commission expressed concern about future test years in the 85-558 Docket.[1(1)] In the 89-865 Docket[2(2)], the Commission discussed projected test years and the need for the ability to verify and substantiate the projected data. There must also be clear and substantial links with actual historical experience. In the 89-865 Docket, those links were too tenuous to set just and reasonable rates.

The Commission will accept NSP's proposed test year and will not require that future NSP rate cases be filed using historic test years. With the specific adjustments addressed later in this Order, the Commission will accept the proposed test year as reliable for rate purposes in this docket. NSP has made several adjustments to its budgeting process which improve its reliability. The Commission will order additional changes for future filings which should further improve the reliability. The Commission will not require that future filing be based on historical test years, but will continue to require that the Company provide adequate verification and substantiation of the projected data, and substantial linkage to actual historical data for its test year.

XII. RATE BASE

In its initial filing, NSP proposed a rate base of $2,235,528,000. The Company reduced this amount to $2,228,380,000 in its rebuttal position and to $2,228,148,000 in its reply brief. The Commission will use the originally filed amount as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues will be discussed below.

A. Capital Budget

The reliability of budget data submitted by an applicant to support its requested rate increase is a threshold issue in a rate case. The budgets supplying that data are the capital budget and the departmental operating expenses (DOE) budget. The Commission refused to approve NSP's previous request for a rate increase because it could not rely on the accuracy and predictive value of the capital and DOE budgets submitted by the Company. *In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-89-865, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (August 28, 1990).

Capital budgets attempt to establish what amount of fixed plant will be added to the rate base during the test year. As such, NSP's capital budget will be discussed in this section as a rate base issue. The DOE budget, on the other hand, projects the level of operating expenses in the test year and therefore will be discussed in Part XIII, the Income Statement section of this Order.

NSP's rate base is calculated as an average of the rate base balance at the beginning of the test year (January 1, 1991) and the rate base balance at the end of the test year (December 31, 1991). Because it lacked actual information beyond October 31, 1990 when it filed this rate case, NSP had to forecast capital expenditures for November and December to calculate a balance for the beginning of the test year. To get a balance for the end of the test year, of course, NSP had to project capital expenditures for all of 1991. These projected balances, then, are the basis for NSP's capital budget. It is the reliability of those projections that the Commission must now determine.

The Commission finds that NSP has eliminated significant deficiencies that prevented the Commission from accepting the capital budget provided in the previous rate case. In response to concerns raised in that case, NSP implemented numerous significant changes that improved the reliability of its projections. Among the changes that it implemented, the Company

1. adopted a new capital budgeting computer program that allows the Company to identify and trace reimbursables, better monitor deferred and canceled projects and track activity on specific improvement requisitions (IRs)[3](3);

2. proposed a budget based on first year rather than second year figures;

3. updated capital budget policies including provision for manual review before filing to verify exclusion of non utility items from the capital budget;

4. changed the corporate fund to contingency funds managed by each business unit and removed project funds from the capital budget;

5. adopted capital expenditure guidelines to manage costs at levels at or below the rate of inflation; and

6. provided extensive budget documentation to establish the link between the projected and historic expenses.

In addition, based on the Department's extensive review of IRs in key indication areas, the Commission finds no systemic problems with the capital budget that question its general reliability.

No party objected to the Company's capital budget. The Department and the ALJ recommended it as reliable. Due to the changes in NSP's capital Budget process and a specific review of key elements of the capital budget, the Commission finds that the Company's capital budget and supporting documentation provide an adequately reliable basis for establishing its test year rate base.

The Commission will require NSP to continue to improve the accessibility and usefulness of its capital budget filings in future rate cases[4](4) In the 89-865 Docket, serious concerns were raised regarding whether funds flowing from the contingency fund were actually expended for utility projects benefitting Minnesota customers. While NPS has made changes designed to improve accountability, the Commission continues to be concerned. Therefore, the Commission will require NSP to include with its next rate filing month-by-month accounting of all transactions in the contingent funds and a year-end summary report of project substitution within each contingent fund by project type and project benefit.

The Commission will also require the Company to include detailed Federal Energy Regulatory Commission (FERC) accounts. With this further change, NSP's future capital information will be more accessible to intervenors and more easily compared with that of other utilities and cross-checked with other reports such as FERC Form 1.[5](5)

B. Uncontested Rate Base Adjustments

1. October 1990 Plant Balance

As indicated earlier, NSP had actual figures through the end of October 1990 when it filed its rate case. To arrive at the rate base balance for January 1, 1990, then, NSP began with the actual plant balances and construction work in progress (CWIP) balances as of October 31, 1991.

Unfortunately, the beginning point for this calculation, the Company's end of October 1990 plant balances, was overstated in the Company's original filing due to a Company coding error. The Department detected the error which the Company acknowledged. The Commission will adjust for this error, reducing the rate base by $4,744,000 and increasing test year income by $194,000 for related depreciation and taxes.

2. IR 19-02785

In its original filing, NSP listed all the individual improvement requisitions (IRs) that together constituted its proposed addition to rate base. Among the IRs listed was IR 19-02785 in the amount of $5.514 million. In testimony submitted as part of the hearing before the ALJ, the Company submitted a list of "substitution" projects. This list is for projects that may be added if scheduled projects are canceled. IR 19-02785 also appeared on the substitution list.

The Department challenged the inclusion of IR 19-02785 in the rate base. The Department argued that the appearance of IR 19- 02785 on the substitution list indicated that this expenditure was not necessary to the provision of reliable service in 1991 and, hence, not properly a part of the test year rate base.

NSP explained that IR 19-02785 refers to a mandatory safety project to upgrade electric safeguards at Prairie Island in response to concerns of the Nuclear Regulatory Commission (NRC). The project began in 1990, will be completed in 1992, and totals in excess of $12 million. The amount listed for IR 19-02785 for the test year, $5.514 million, was the amount that the Company expected to expend toward completion of the project during the test year. Only the remaining portion of the project is on the substitution list. It other IRs are canceled during the test year, the Company may proceed with the expenditures now scheduled for 1992 and accelerate completion of the project. The Department accepted NSP's explanation and withdrew its objection.

Based on the Company's clarification, the Commission will accept the filed amount for this IR as part of the test year rate base.

3. Information Services (I/S) Chargeback

The Department noted that certain depreciation, maintenance, and programming costs for the mainframe computer appear in both the capital budget and the DOE budget. NSP explained that changes in its accounting procedures resulted in these items appearing as expenses. To avoid double counting these expenditures, the Department proposed and the Company agreed to remove these items from the capital budget.

The Commission finds that this disposition of the problem is appropriate. The capital budget will be adjusted accordingly, resulting in a net decrease the rate base of $1,324,000 and a net income increase of $11,000.

4. Purchasing Costs

The Department questioned whether NSP's budget data had double counted purchasing costs as the Company had done with respect to information service (I/S) chargebacks. NSP acknowledged that changed accounting procedures resulted in expensing purchasing costs in its 1991 filing, whereas formerly such expenses had been charged back to work orders and capitalized. NSP could not verify that these expenses had not been included in the 1991 capital budget.

Accordingly, the Company agreed that the rate base should be reduced by $1,649,000 and net income increased by $18,000. The Commission finds that this adjustment is appropriate.

C. Cash Working Capital

NSP included negative cash working capital of $66,437,000 in its original filing. The cash working capital was calculated using a lead lag study.

NSP supplied information identified as Staff Exhibit 145 at hearing. That exhibit shows that incorporating automatic payment processing into the lead lag study results in additional negative working capital of $477,000. The Commission will incorporate this adjustment in its determination. The adjusted cash working capital will more appropriately reflect the payment patterns expected to occur during the test year.

The Commission will adjust cash working capital by an additional negative $1,966,000 to reflect the effects of the Commission's income statement adjustments on cash working capital.

Consistent with prior Commission decisions, the Commission will also adjust cash working capital to reflect the effects of the rate increase granted in this proceeding and to adjust for the effects of interest synchronization on the Commission's adjusted rate base. These adjustments result in an additional negative cash working capital of $275,000. The Commission concludes that the appropriate test year cash working capital is a negative $69,155,000.

D. Rate Case Expense

In its original filing, NSP estimated rate case expenses for this docket in the amount of $823,000. No party has challenged this estimate. NSP proposed to amortize those expenses over a two year period, $411,000 in the 1991 test year and $412,000 in 1992. The Department agreed that a two year amortization period for these expenses was appropriate in light of the likelihood that NSP will file for another rate increase within two years.

NSP further proposed to increase the rate base to allow a return on the unamortized balance. In calculating its proposed addition to rate base, NSP assumed that the entire $823,000 was spent by the first day of the test year and calculated the addition to rate base of $617,000.

The Department opposed adding any amount of rate case expenses to the rate base. If the Commission found it proper to add some portion of rate case expenses to the rate base, the Department argued that NSP's calculation overstated the amount. At a minimum, the Department recommended a rate base reduction of $372,000.

The ALJ recommended that none of these expenditures be added to the rate base but that the entire $823,000 be classified as test year expenses.

The Commission is reluctant to include the entire amount of rate case expenses in the test year. Counting these expenditures as test year expenses would allow NSP to continue to recover this same amount through rates in each subsequent year until the Company's next rate case is decided, thereby substantially overcollecting these expenses. As an alternative, the Commission has occasionally amortized rate case costs over a period of years representing the expected time until the next rate filing and added the unamortized balance to rate base.

Because the time of the Company's next rate filing may be as early as January 1992 but cannot be determined with any degree of certainty at this time, the Commission will give neither rate base nor test year expense treatment to these expenditures. Instead, the Commission will allow NSP to recover these one-time expenditures completely, but only once, by deducting this amount from the refund ordered in this matter.

Accordingly, test year net income will be increased by $245,000 and rate base reduced by $617,000. The refund of excess amounts collected under interim rates will be reduced by $823,000.

To evaluate the accuracy of NSP's estimate of rate case expenses, the Commission will require the Company to report its actual rate case expenditures 60 days after all administrative review of this Order has been exhausted.

E. The King Plant's Rotor

In 1988, NSP replaced a rotor, a major component of the steam turbine at its King generating station, at a cost of approximately $11 million dollars. According to established accounting procedure, the entire cost would normally have been charged to maintenance expense in 1988 because NSP's retirement unit of property is the turbine itself and not the rotor. However, NSP indicated that it planned to refurbish the replaced damaged rotor and keep it on hand as an emergency spare part. Pursuant to this plan, NSP proposed in its 1987 rate case and the Commission approved expensing (adding to test year expenses) the costs of removing the old rotor and capitalizing (adding to rate base) the costs of purchasing and installing the new rotor. No party objected to this treatment.

Following the close of the 1987 rate case, NSP found that once the turbine was modified to use the new rotor, the old rotor could not be used in the turbine as a spare part. The Company, therefore, decided to sell the old rotor instead of keeping it as a spare. This left the new rotor as the sole rotor available for this turbine. According to established accounting practice, this change altered the status of the rotor from capital expenditure to operating expense.

Rather than taking the entire expense at once in 1988, however, NSP proposed to amortize that expense over a five year period beginning January 1, 1988. Because the Company raised this proposal in a docket that was not a rate case, the Company did not request any ratemaking treatment for these expenses at that time. The Commission approved the Company's amortization plan. *In the Matter of the Petition on Northern States Power Company for Approval of a Specific Accounting Procedure for the Replacement Turbine Rotor at the A.S. King Generating Plant*, Docket No. E-002/M-88-923, ORDER (December 15, 1988).

For the current rate case, NSP included the annual yearly amortization amount, \$1,900,000, as a test year expense and requested rate base effect to the unamortized balance, \$1,720,00.

MEC opposed NSP's proposal. MEC recommended that the rotor expenses be excluded both from rate base and from test year expenses. MEC argued that the expenses at issue were past costs not incurred during the test year. According to MEC, then, NSP's proposal to include a portion of this expense in test year expenses is improper, an attempt to recover operating costs that are not representative of the 1991 test year.

MEC does not dispute that the Commission approved five year amortization of these costs in its December 15, 1988 Order, but denies that this Order did anything more than change the accounting treatment of these costs in its December 15, 1988 Order, but still remain expended in 1988 and despite the fact that the test year is the fourth year of the amortization approved by the Commission for these costs, no portion of these expenses can be included in the test year expenses.

The Commission's decision in the 88-923 Docket authorizing NSP to amortize these expenses over a five year period appropriately matched the costs of the rotor over time with the benefits received from that rotor. No party opposed the Commission's decision to authorize this amortization. As a result of this Order, an annual amortized amount of these costs occur during 1991, the test year.

The question that the Commission must decide in this rate case is whether the amount of the rotor repair costs allocated to 1991 pursuant to the approved amortization plan should be counted as test year expenses. Due to the approved amortization plan, there is no question that the annual amortized amount of these expenses "occurred" during the test year. As such they will be included as test year expenses if they were prudently incurred for the purpose of providing utility service to Minnesota customers.

No party has questioned the need for the repair or the prudencey of the repair costs and methods. The repair was necessary to continued production of electricity for Minnesota customers at the King plant. There is nothing in this record to suggest that ratepayers do not continue to benefit from this repair throughout the test year. Accordingly, NSP will be allowed to include in test year expenses the annual amortized amount of the Kings rotor expenses and to include the unamortized balance in rate base.

While the Commission accepted the King rotor amortization on its merits in the 88-923 Docket and is incorporating the results of that decision in this rate proceeding based on the unique facts of this case, proposals to defer costs from non-rate case periods to rate case period are not favored and will continue to receive careful scrutiny. See, e.g. Discussion of deferred costs in the 89-865 Docket Order, pp. 28-29.

F. Refuse Derived Fuel (RDF)

The Commission must decide whether NSP's Wilmarth and Red Wing generating plants are properly included in the Company's rate base and operating expense and whether the costs of electricity purchased by NSP from UPA's generating plant in Elk River are properly included as test year expenses.

NSP processes metropolitan solid waste (MSW) into fuel at its nonregulated RDF operations at Elk River and Newport. The fuel is then burned at the Red Wing and Wilmarth generating facilities. NSP also sells RDF to UPA. That fuel is burned in UPA's Elk River generating station; NSP purchases the power produced.

The Red Wing and Wilmarth units have been modified to accommodate the use of RDF. Plant investments in Red Wing Wilmarth are included in the regulated rate base, and operating costs are included in the test year income statement. The cost for power from UPA is also included as a test year cost. Mankato recommended that the Commission reduce rate base approximately $25.3 million to remove the Red Wing and Wilmarth units from the regulated rate base, exclude the related fuel cost of $3.8 million, exclude operating costs of $4.8 million, and include a cost for power at the current market price for the power purchased from the Red Wing and Wilmarth units. Mankato also recommended that the test year costs related to the power purchased from UPA be reduced by $858,000. Mankato further recommended additional investigation to determine the extent of any ratepayer subsidy of the RDF operation historically.

The Department and the RUD-OAG recommended that the Commission investigate this matter further in a separate docket. The RUD-OGA also recommended that the test year revenues be increased by $1.03 million to reflect cost savings which could be achieved independently of the RDF operations but are used to justify the RDF economics.

The ALJ rejected any financial adjustment for the test year, but recommended that the Commission investigate this matter further in a separate docket.

The Commission will adopt the ALJ's recommendation.

On August 15, 1985, the Commission issued its Advisory Opinion in Docket No. E-002/M-84-790. In that Opinion, the Commission questioned whether it was appropriate to include RDF processing facilities in regulated activities, but did advise that the burning of RDF in utility boilers could be considered "reasonably necessary to the efficient and reliable provision of utility service." The Commission advised that modification to existing generating plants to accommodate the burning of RDF may be appropriately included in rate base under certain conditions. They are: (1) that RDF be an economically priced fuel that provides generation at a cost competitive with other fuels; (2) that NSP is able to secure long term contracts for the purchase of RDF; and, (3) that the burning of RDF does not shorten plant life.

Mankato's arguments addressed whether these minimum conditions were met, specifically whether RDF is "an economically priced fuel that provides generation at a cost competitive with other fuels."

When the Commission last addressed this matter, in the 85-558 rate proceeding, the expected rate base investment in plant modifications was approximately $24, million. In that proceeding, there was much testimony assuring that ratepayers would be at least as well off through development of RDF capability as through generation using standard fuels.

In the current proceeding Mankato stated that the investment now exceeds $41 million, with the possibility of a need for more. Mankato said the capacity cost of Red Wing/Wilmarth is now greater than $172/kW, compared to $155/kW for comparable PURPA capacity. It referenced FERC Form 1 reports showing that the fuel costs at Wilmarth are approximately double that of Sherco, it introduced information showing that the cost of generation since conversion to RDF at Wilmarth averaged nearly $100/mWh greater than at Sherco, it cited internal NSP studies showing that ratepayers would save $30 million if Wilmarth were closed, and it stated that Wilmarth has operated at only 35 percent capacity since it was converted to RDF.

The Commission recognizes, however, that the Wilmarth unit was in process of conversion to RDF beginning in 1985, and has been restricted to generation at 50 percent capacity due to MPCA limitations. The Commission also recognizes that Wilmarth has recently been under further construction for addition of environmental protection devices. The Commission would not expect a unit under construction, and restricted to output at 50 percent of installed capacity, to perform at the same efficiency as NSP's largest and most recent coal-fired baseload plant.

None of this is necessarily relevant to a proceeding setting rates based on a standard test year, unless the test year is a simple reflection of the past. In this case, it is not. The capacity rate of the Wilmarth plant is set at 70 percent; unit costs should be correspondingly lower. Beyond this, record evidence indicates increases in incentive payments to the utility of approximately $2 million for the test year, improved fuel handling, enhanced fuel, and other operating adjustments which are likely to reduce the cost of generation.

With respect to the total investment and the investment per kW, the Commission notes that the rate base amount for the Red Wing and Wilmarth units is approximately $25, million, not $41 million. It would be inappropriate to simply add amounts expended between 1985 and the test year and compare the sum to the $25 million originally proposed in 1985, because that action ignores the time value of money. Comparison of expenditures must be based on the same time reference.

Mankato further argued that NSP was motivated to keep Wilmarth operating because it did not wish to pay the penalty for landfilling RDF. However, Mankato also argued that NSP was faced with the potential of not receiving sufficient MSW to operate Red Wing/Wilmarth at high capacity levels. While both of these arguments raise concerns, the Commission finds that there is an element of contradiction. There cannot be an excessive risk of landfilling RDF if there is insufficient RDF to operate the plant.

Regarding the contract to purchase power from UPA, Mankato argued that NSP originally offered to purchase the power at $77/kW/year for capacity and $13.75/mWh for energy. However, the RDF operation could not get the bid for Anoka's MSW at that price so NSP raised the price to ratepayers to $116/kW/year for capacity and $13.75/mWh for energy. Mankato argues that this allowed NSP's unregulated RDF operation to secure the bid, to earn substantial returns, and to allow the ratepayers to subsidize it. NSP argued that the ratepayers are actually enjoying a rate substantially below the PURPA rate.

RDF has advanced from the theoretical to the real. Projections and proposals have undergone changes required for actual implementation; contracts which then covered future actions are now being carried out. While the Commission established original conditions, management at NSP' regulated and unregulated operations have made many implementation decisions, including plant modifications and contract terms. The record in this case supports NSP's management decisions and demonstrates that the rate paid UPA for test year purchases is reasonable. The Commission will adopt the ALJ's recommendation and make no financial adjustment in this case.

At the same time, the Commission finds it appropriate to conduct further investigation into the RDF operations to determine the extent to which ratepayers benefit and to examine the propriety of NSP's activity with respect to RDF. Accordingly, in a separate Order the Commission will open an investigatory docket and direct the Department to begin an investigation. Parties to this rate case are encouraged to participate in the investigation.

G. Issues With Rate Base Effect Discussed in Income Statement Section

The following issues were discussed as income statement items in the income statement section of the order, but also affect rate base.

1. Conservation Cost Recovery

Adjustments made by the Commission for conservation costs increase the originally filed test year rate base $2,513,000.

2. Depreciation

Adjustments to depreciation expense to reflect the more recent depreciation schedules increase rate base $1,752,000.

3. Cogeneration Litigation

Adjustments excluding cogeneration litigation expense reduce rate base $262,000.

4. Nuclear Decommissioning

Adjustments made by the Commission incorporating the rate of return awarded in this proceeding into the nuclear decommissioning expense calculations decrease rate base $196,000.

H. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $2,228,283,000 as shown below (000's omitted):

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Utility Plant in Service	$4,761,823
Less: Reserve for Depreciation	2,115,273
Net Utility Plant in Service	$2,646,550
Construction Work in progress	153,086
Plant Held for Future Use	520
Accumulated Deferred Income Taxes	(611,461)
Working Capital	
Cast Working Capital	(69,155)
Materials and Suppliers	70,052
Fuel	29,438
Prepayments	5,731
Other	3,522
TOTAL AVERAGE RATE BASE	$2,228,283

XIII. OPERATING INCOME STATEMENT

The Commission will begin with NSP's originally filed net operating income. After adjusting the original amounts for the proprietary adjustments discussed later in this Order, the Commission will make its adjustments to beginning net income of $173,595,122. Individual income and expense adjustments will be disussed below.

A. DOE Budget

Background - NSP's Departmental Operating Expense (DOE) budgets represent the departmental operating and maintenance expense projections for the test year. The DOE budgets are developed by compiling the budget projections of each manager in over 200 departments. DOE budgets include such elements as production expense, transmission, distribution, customer accounts, and customer service.

Accurate and reliable DOE budgets are absolutely essential in the ratemaking process. Regulatory agencies must rely on departmental budget projections to assess the Company's revenue needs for the test year. In the 89-865 Docket the Commission refused to grant any increase in rates because the Commission found the Company's capital and DOE budgets were inadequate and unreliable. In the 89-865 Docket, the Commission noted that many of the budget items were insufficiently documented. The Company used "unorthodox" accounting methods and failed to present its budget at the FERC Uniform System of Accounts (USOA) subaccount level. The Commission also found that the Company improperly deferred a number of expenses into the test year. The Company displayed a "roller coaster" spending pattern and then asked the Commission to set rates above the highest level on the roller coaster. For all these reasons, the Commission found in the 89-865 Docket that it could not determine with reasonable certainty the amount of operating expense necessary to provide utility service. The Company failed to submit budgets which proved the necessity for a rate increase, and no rate increase was granted.

Between the time that NSP was refused a rate increase in the 89-865 Docket and the present rate case filing, NSP and the Department have worked together to ensure that NSP's budgets will conform to Commission requirements. NSP consulted the Department regarding proposed changes in budget methodology before they were implemented. The Department was apprised of changes as they were made. NSP and the Department had a basis for understanding the budget forecasts before they were submitted in the current docket.

The Commission must now determine whether NSP's present DOE budget is sufficiently reliable and verifiable to determine a reasonable level of rates.

Positions of the parties - After certain specific adjustments ware made to NSP's DOE budge, the Department recommended that the Commission accept the budget as reliable for setting rates in this proceeding. The Department also recommended that additional information be filed or available with future rate filings.

MEC recommended that the test year expenses be reduced by $26,923,000.

NSS recommended that the test year expenses be reduced by $33,818,500. NSS raised concerns about the absence of detailed FERC accounts.

The ALJ recommended that the Commission accept NSP's DOE budget as a reliable basis for setting rates. The ALJ did not recommend the MEC or NSS adjustments.

Changes since the 89-865 Docket - The Commission notes that NSP has made substantial efforts in this filing to address the many concerns detailed in the 89-865 Docket Order. Following are specific areas in which NSP has made specific improvements to its budget methods.

1. In response to concerns raised in the 89-865 Docket regarding the insufficient link of projected test year to historical data, NSP filed three volumes of budget documentation. within the budget documentation, NSP compared test year budgeted amounts with actual data for the year 1989. As part of the comparison, NSP attempted to note reasons for the more substantial changes. The record indicates that 1989 actual data was chosen as a base for comparison because it was the most recent actual data available at the time this rate case was filed. The record also suggests that 1989 was a year in which expenses were held at a minimum to avoid a rate filing. This indicates that the expenses in the present test year are being compared to a low point on the spending roller coaster.

2. NSP instructed its budgeters to hold increases to a certain level over the test year amounts approved in the 87-670 Docket (the 1988 test year). The level of increase would be at or below the rate of inflation as measured by the Consumer price Index (CPI).

3. The Company made approximately 40 volumes of budget documentation available to the intervening parties.

4. NSP responded to intervenors' concerns regarding costs deferred into the test year, as evidenced by the stipulation on deferred expenses discussed elsewhere in this Order.

5. In order to corroborate NSP's budgeted test year amounts, NSP included calculations adjusting the historic 1989 data for known and measurable changes. This information was intended to be corroborative and was not relied upon by the Company or the Commission as the basis for a final revenue requirement finding. The corroborative material shows a higher revenue requirement than that calculated using NSP's forecasting methods.

6. Finally, the record suggests that the Company has: improved its budgeting training guide; switched to using the first year budget as the test year; attempted to improve the tracking and reporting of costs at the Minnesota jurisdictional level; identified cost changes and reclassifications; tried to identify changes in accounting; and attempted to make the filing less complex.

Use of the CPI guideline - NSP used the CPI as a guideline for increases in the DOE budget from the test year amounts approved in the 87-670 Docket to this test year. MEC argued that the CPI guideline should be applied to the 1989 actual costs, not the 1988 test year. Accepting MEC's recommendation would result in making an across-the-board adjustment reducing the DOE budget by $26,923,000.

NSS argued that the Data Resources, Inc. (DRI) measure of cost increases specific to the utility industry should be used instead of the CPI guideline. Like MEC, NSS also recommended that the increase guideline be applied to the actual data for 1989 rather than the test year data from the 87-670 Docket. However, NSS would accept proposed labor costs but apply its adjustment to the non-labor portion of the DOE budget. Accepting NSS's recommendation would result in making an across-the-board adjustment reducing the DOE budget by $33,818,500.

The Commission will not accept the MEC or NSS adjustments. The Commission finds that there is no evidence in this record to show that the test year costs approved in the 87-670 Docket were unreasonable. Further, 1989 was an abnormally low-cost year. MEC and NSS did not weather-normalize the 1989 data before making adjustments.

Regardless of the guideline used, the Company must still show the reasonableness and necessity of individual expenditures. The Commission finds that it is necessary to review the specific content and costs included in operations and maintenance budget entries. This review process preserves flexibility, provides a reasonable procedure for parties to review for reasonableness, and assures ratepayers that rates are based on costs that are necessary in the provision of service.

Having reviewed the content and costs of the Company's DOE budget, the Commission finds that the Company used the CPI as a guideline, not as a rationale for across-the-board increases. The budget documentation contains evidence of costs that have increased more than the CPI and costs that have increased less than the CPI. The Commission finds that the CPI guideline was not applied by the Company for an inappropriate purpose, and does not justify an across-the-board adjustment to the DOE budget.

The Commission notes, however, that most of the parties expressed concern regarding the choice of the CPI as a means of comparing changes in utility costs. The Commission also shares this concern. The CPI is intended to evaluate cost changes in a "basket or goods" likely to be purchased by an average consumer. It does not focus on the "basket of goods" likely to be purchased by a major electric utility. The Commission finds that the DRI index addresses more closely the costs specific to an electric utility. The Commission will therefore require that the DRI index, or a comparable industry standard, be incorporated as a guideline by NSP in future rate cases. If there are deviations from the DRI or comparable industry guideline, NSP must provide explanations for the deviations.

Concerns raised by the parties - The Commission notes that MEC and NSS raised many concerns regarding the Company's budget process, yet agreed that the Company has made improvements since the 89-865 Docket. The Commission will comment on several concerns. First, the intervenors expressed concern that NSP had changed 1989 data. The Commission considers it necessary to do so. To use 1989 data without adjusting for the effects of the sale of the telephone operations would not be comparable to the test year, which did not have telephone operations as an allocation component. Next, the parties noted that NSP changed the basis for the test year budget to the actual year 1989. The Commission will not criticize the Company for attempting to make a better link between the test year and historical data.

MEC and NSS also expressed concern that NSP communicated its budget guidelines to its budgeters prior to commencement of budgeting, thus predetermining budget increases. The Commission is not disturbed by management's communication of a guideline, any deviation from which budgeters must explain. As noted in the 89-865 Docket, the Commission expects explanations of cost changes. Finally, the intervenors raised concerns that individual expenses were not shown as reasonable and necessary by the Company. The Commission finds sufficient the three volumes of documentation included with the filing, plus nearly 40 volumes of additional documentation made available to the parties. The specific costs that were raised as unreasonable or inappropriate for the test year are dealt with individually by this Commission elsewhere in this Order.

FERC subaccounts - The Commission agrees with NSS that the lack of summarization of the budget at the FERC subaccount level is a matter of concern. The Commission recognizes that NSP's budgeting system, which is not currently expressed at the FERC subaccount level, can develop substantial detail. The Commission also notes that the Department stated that adequate documentation review is not precluded by the absence of FERC subaccount level summaries. The Department has also stated, however, that the presence of FERC subaccounts can aid comparison of NSP's budget to historical performance, other utilities, and reports to regulatory agencies.

The record indicates that the absence of FERC subaccounts can hamper budget review by an intervenor experienced in utilities but inexperienced with NSP. One of the reasons this Commission adopted the FERC Uniform System of Accounts was to achieve a uniformity of accounting with other utilities. It makes little sense to require uniform accounting except when setting rates in a rate proceeding, a prime focus of the regulatory process. Further, the absence of FERC subaccounts complicates the comparison of the test year data with the actual results for the test year, which are reported according to FERC subaccounts, not in the budget format. For these reasons, the Commission will accept the DOE budgeting method submitted in this case but will require that NSP summarize all of its budgets by FERC subaccounts in future rate filings. If the Company cannot comply with this requirement, it shall show cause within 30 days of the date of this Order. Parties will be expected to comment on such a filing.

Future documentation requirements - Because the budget process is essential to the rate case process, the Commission will require NSP to implement the following budget requirements in its next rate case filing:

1. Besides budget documentation filed according to the above standards, make support documentation available at the time of filing future rate cases. This support documentation will be similar to the forty volumes in this rate case and may include workpapers and notes used in developing budgets The support documentation must be available for inspection by other parties upon request.

2. File translation reports linking cost element, cost activity, and project budgeting mechanisms on a common and consistent basis to ensure an accurate accounting for expenses contained in "default" cost elements like MS16;

3. File bridge schedules showing all adjustments used in moving from the unadjusted budget to the rate case numbers.

Conclusion - The Commission finds that NSP has made meaningful efforts to address budget inadequacies and has made substantial improvements to the process. The Commission finds that there are no systemic problems in the DOE methodologies which require across-the-board adjustments to the DOE budgets.

Based on the discussion in this section of the Order, the individual adjustments addressed elsewhere in this Order, and the future additional filing requirements, the Commission concludes that the Company's DOE budget is reliable for the purpose of determining just and reasonable rates in this proceeding.

B. Uncontested Income Elements

1. Interest Synchronization

NSP included an income tax deduction for interest expense of $81,802,000 in its original filing. The Company calculated the interest expense using the concept of interest synchronization, in which the rate base is multiplied by the weighted cost of debt. No party objected to this method. This treatment is consistent with prior Commission decisions affecting NSP, and will be incorporated here.

The Commission will adjust the interest deduction to $81,537,000 to incorporate the rate base adjustments made by the Commission, including the cash working capital effect of the increase awarded. This adjustment increases income tax expense and decreases test year net income by $107,400.

2. Sales Forecast

The Company filed a sales forecast for the projected test year. No party objected to this filing, and the ALJ recommended its acceptance. The Department's own sales forecast was actually lower than NSP's, and indication that NSP has not understated its test year sales.

The Commission finds the Company's sales forecast reasonable and appropriate. The Commission will accept this portion of the filing.

3. Depreciation

At the time of filing its proposed rate case depreciation expenses, NSP had not yet submitted its 1991 remaining-life depreciation study for Commission approval. The 1991 depreciation filing has since been submitted and approved by the Commission under Docket No. E-002/D-91-300. At the time of its original filing the Company proposed that the 1991 depreciation figures, if approved, be incorporated into rate case expenses. The result would be a decrease in expenses of $5,823,000.

All parties who commented on this adjustment and the ALJ agreed that it is appropriate. The Commission finds that factoring the Company's 1991 depreciation schedule into test year expenses will result in an accurate picture of depreciation expenses. The Commission will accept this adjustment, which will increase rate base by $1,752,000 and increase net income by $2,995,000.

4. AFUDC

NSP included $9,064,000 in test year income as Allowance for Funds Used During Construction (AFUDC). This figure was initially contested by the Department. Later, when the Department agreed to the inclusion of IR 19-02785 in rate base, the Department dropped its recommendation of the related adjustment to AFUDC. No other party objected to the AFUDC income item as filed.

The Commission accepts NSP's inclusion of AFUDC as filed.

5. Graystone

NSP proposed that its investment in the Graystone nuclear fuel enrichment project be considered non-regulated activity. No party opposed this treatment of the investment. The Commission notes for the record that Graystone is not included in the regulated activities. Transactions between Graystone and the regulated entity shall be subject to review to ensure proper accounting and allocation of costs.

6. Nuclear Regulatory Commission Fees

In April of 1991, the Nuclear Regulatory Commission (NRC) reduced its estimated fees charged to NSP by $1.277 million. NSP proposed that its original filed test year expenses be reduced by $1.277 million to reflect the fee reduction. No party opposed this proposal. The Commission finds NSP's proposed expense reduction reasonable and appropriate. This adjustment increases test year net income by $644,000.

C. Pathfinder Atomic Power Plant

Background - NSP included in its rate case filing $2,918,000 in test year expenses stemming from the decommissioning of the Pathfinder Atomic Power Plant (Pathfinder). Although NSP originally estimated total decommissioning costs of $16.8 million, the Company did not seek rate base treatment of the unamortized balance. During the course of this proceeding, NSP reduced the test year expense by $746,000 to reflect a revised estimated total cost of $12.5 million.

Pathfinder, located near Sioux Falls, South Dakota, was built by Allis-Chalmers for NSP. Although a final construction permit for Pathfinder was issued by the Atomic Energy Commission (AEC) on May 12, 1960, an operating license was not granted by the AEC until March, 1964. Delays in licensing and subsequent startup delays were due to repeated failures of plant equipment. The Pathfinder plant did not achieve 100 percent power until September 12, 1967. After approximately one hour of 100 percent operation, the plant was shut down completely due to equipment failure, never to resume operations as a nuclear facility.

Faced with the failure of Pathfinder as a nuclear generating facility, NSP eventually converted the Pathfinder plant to a gas fired boiler. The nuclear components of the plant were put into SAFSTOR, a means of nuclear containment then allowed by the AEC, and the remainder of the plant continued to operate as a nonnuclear facility.

In 1988, the NRC (the successor to the AEC) promulgated rules requiring the eventual decommissioning of facilities in SAFSTOR condition to levels permitting unrestricted use. NSP began the decommissioning of Pathfinder's nuclear components in 1989. On September 21, 1989, the Commission issued an Order granting NSP deferred accounting of the decommissioning costs, with a five year amortization schedule to begin January 1, 1990.[6(6)] In its Order, the Commission specifically deferred consideration of ratemaking treatment of the decommissioning costs until a subsequent proceeding. In the present rate case, the Company has asked the Commission to take up the ratemaking issues of decommissioning.

Positions of the parties - NSP advanced several arguments for inclusion of Pathfinder decommissioning expenses in its rate case. The Company stated that its proposal of including in expense the annual amortization, but excluding the unamortized balance from rate base, amounted to a proper sharing of costs between shareholders and ratepayers.

The Company also argued that this is the optimal time to decommission the plant. According to the Company, the previous containment process was prudent at the time it took place, just as complete nuclear decommissioning is prudent under today's regulations. NSP noted that no party alleged that decommissioning was imprudent.

NSP argued that construction of the Pathfinder plant had been a benefit to NSP ratepayers, for which ratepayers should share the cost. The Company reasoned that nuclear generating technology and nuclear plant decommissioning techniques learned form the Pathfinder experience would benefit NSP ratepayers through application in other nuclear facilities.

The Department, the RUD-OGA, MEC and the ALJ agreed that Pathfinder decommissioning costs should be totally excluded from the rate case. The intervenors and the ALJ reasoned that Pathfinder had been of virtually no benefit to NSP ratepayers. Throughout its life as a nuclear generating plant, pathfinder generated no significant amount of power for ratepayer use. The technology used in the pathfinder plant was inapplicable to NSP's other two nuclear facilities, because these plants use significantly different technology. The Department and the RUD-OAG argued that decommissioning methods learned in the Pathfinder experience were also inapplicable and of no benefit to ratepayers.

Commission analysis - The Commission finds that NSP has failed to meet the statutory standard for inclusion of decommissioning costs in rate case expenses. Minn. Stat. § 216B.16 (1990) lists factors to be considered by the Commission in determining just and reasonable rates. The statute states that the Commission must allow a utility sufficient revenue to meet the costs of providing service, "including adequate provision for depreciation of its utility property used and useful in rendering service to the public." (Emphasis supplied). The used and useful standard is reasonably applied to expenses as well as rate base items. The Company has failed to prove that the Pathfinder nuclear generating plant was ever used and useful to Minnesota ratepayers, whether during its development, its one hour of 100% operation, or during its decommissioning process. NSP has made no showing of benefit to Minnesota ratepayers from the pathfinder nuclear plant; ratepayers should not pay for the costs of its decommissioning.

Even if Pathfinder technology had been found used and useful, the Commission finds that inclusion of Pathfinder costs in rate case expenses would violate a basic idea of decommissioning recovery through rates. The Commission and other utility regulatory bodies allow gradual recovery of decommissioning expenses so that present ratepayers, who benefit from the facility, share in the future expense of its decommissioning. In the Pathfinder case, the nuclear facility has been shut down for twenty-four years. It would be violative of a basic tenet of decommissioning recovery to require present NSP ratepayers to pay for the decommissioning of the long-defunct facility.

The Commission notes that NSP ratepayers were not part of the decision process at any time during the ill-fated history of the Pathfinder nuclear facility. It was NSP management, not ratepayers, who chose to construct Pathfinder, pursued Pathfinder's construction despite repeated problems, accepted delivery of a defective plant, settled with the plant builders for $3 million in 1969, and chose the SAFSTOR method over total decommissioning in 1970 when estimates for complete decommissioning ranged from $1.5 million to $2.7 million. Shareholders, not ratepayers, should absorb the cost of NSP's long line of bad decisions regarding Pathfinder.

NSP argued that disallowing Pathfinder decommissioning costs would mean that the Commission is discouraging future innovation and research. The record indicates, however, that NSP viewed Pathfinder more as a demonstration project than as a research project. (Department Exhibit 162, VCC-45,46). Even if Pathfinder were considered a true research project, such projects are subject to a review of prudence. NSP has failed to prove that the project was undertaken or pursued in a prudent fashion.

The Commission finds that all expenses stemming from the decommissioning of the

Pathfinder nuclear facility must be disallowed. This adjustment increases test year net income by $1,441,000.

D. Cogeneration Litigation Expenses

On January 3, 1987, NSP and Biosyn Chemical Corporation (Biosyn) entered into a contract under which NSP would purchase cogenerated capacity and energy from Biosyn. Oxbow, a developer of independent power projects, later formed the Rosemount Cogeneration Joint Venture (the Joint Venture) with Biosyn. On July 19, 1988, the Joint Venture, Biosyn and Oxbow petitioned the Commission to resolve contractual disputes which had arisen between NSP and Biosyn. After a contested case hearing took place, the Commission issued an Order[7(7)] construing the Contract between NSP and Biosyn, granting the Joint Venture's petition and awarding the Joint Venture attorneys' fees. The attorneys' fees were awarded pursuant to Minn. Stat. ¿Sc 216B.164, subd. 5 (1990), which states in part:

> The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees, except that the qualifying facility will be required to pay the costs, disbursements, and attorneys' fees of the utility only if the commission finds that the claims of the qualifying in the dispute have been made in bad faith, or are a sham, or frivolous.

The amount of attorneys' fees to be paid to the Joint Venture by NSP is the subject of further contested proceedings between the parties. Because the exact amount has not yet been determined by the Commission, NSP proposed inclusion in the rate case of one half of the amount claimed by the Joint Venture. Since the Joint Venture claimed legal expenses of $805, 371.25, NSP proposed that one half of that sum be amortized over two years. The Company included first year test year expenses of $175,000, with rate base treatment of $262,000 representing the unamortized balance.

The Company also included in test year expenses the litigation fees for its defense against antitrust and RICO actions brought against NSP by the Joint Venture. The claimed legal fees were in the amount of $304,954.

The Company argued that cogeneration litigation expenses should be included in the ratemaking process because they arise in the normal course of utility business. NSP noted that it is required by law to pay the cogeneration litigation expenses if the cogenerator prevails in the dispute. The Company also argued that both cogeneration legal actions arose from an attempt by NSP to lower its costs, an attempt which would have benefitted ratepayers if the Company had prevailed.

The Department and the RUD-OAG opposed inclusion of any cogeneration litigation expenses in the rate case. Both agencies argued that these expenses did not arise in the normal course of utility operations. Had NSP chosen to go forward with its contract with the Joint Venture as originally contemplated by the parties, the legal expenses would not have arisen. According to the Department and the RUD-OAG, NSP ratepayers should not have to pay for this management decision. MEC argued for the total exclusion of cogeneration litigation expenses. MEC reasoned that the payment of legal fees constituted a penalty which NSP must pay because the Joint Venture prevailed. The ALJ recommended that the Joint venture's legal fees be recoverable in years as a normal cost of utility business, but that the antitrust and RICO defense fees be excluded because NSP has not met its burden of proof as to their merits.

The Commission finds that the payment of cogeneration litigation fees by a utility under Minn. § 216B.164, subd. 5 (1990) dose not constitute a penalty to be paid the cogenerator. Rather, it reflects the legislative intent of giving "the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public." Minn. Stat. § 216B.164, subd. 1 (1990). It would be against this legislative intent to allow utilities to pass onto ratepayers the cost of cogeneration. The statutory awarding of attorneys' fees in cogeneration matters was designed to foster fairness between utilities and independent cogenerators. Requiring ratepayers to pay for these litigation costs would provide utilities with almost limitless litigation resources and would undermine the encouragement of cogeneration. Such a policy would encourage litigation against cogenerators, who often have limited means to engage in dispute resolution.

Antitrust and RICO defense fees are of different nature from statutorily awarded cogeneration litigation costs. In previous Order[8](8), the Minnesota Public Service Commission (the PSC, predecessor to present Minnesota Public Utilities Commission) found that antitrust defense costs should not be recovered in rates. The PSC found that such costs were not directly related to the costs of utility service. The PSC also concluded that antitrust defense fees constitute a defense of property, which is the responsibility of the property owners (shareholders) rather than of ratepayers.

The Commission finds that neither the cogeneration litigation fees nor the antitrust and RICO defense fees were normal costs of utility business within the ratemaking sense. Engaging in these actions was a corporate decision whose costs should not be shared by ratepayers. The Commission will totally exclude expenses of NSP's cogeneration and antitrust/RICO litigation. This will result in a reduction to rate base of $262,000 and an increase to net income of $285,971.

E. Conservation

1. Conservation Cost Recovery

NSP requested in its filing that the budget determined in the Commissioner of Public Service's final decision on NSP's Conservation Improvement Program (CIP) be used to determine the Company's Conservation Cost Recovery Charge (CCRC). No party opposed that request.

On August 13, 1991, the Commissioner issued her final decision in Docket No. E-002/M-90-360. The Commissioner approved a 1991 CIP budget for NSP of $16,509,671. Since the August 13 decision, the Commissioner has approved two additional projects for implementation in 1991 with budgets totaling $1,45,500.

The Commission finds that it is appropriate to use $17,963,171, the entire amount of approved CIP expenditures to date, in the calculation of the CCRC. The use of the most accurate budget in calculating the CCRC will result in more timely recovery of conservation costs for NSP and a lesser burden on ratepayers when the CIP Tracker Account is trued up in future rate proceedings.

On March 19, 1991 the Commission approved a Demand-Side Management (DSM) Financial Incentive for NSP in Docket No. E-002/M-90-1159.[9(9)] The incentive allows NSP to amortize its direct impact projects over five years and earn its allowed rate of return, plus a five percent bonus return on equity, on the unamortized balance. Research,development and administrative expenses will continue to be expensed in the year incurred. The Company will also be permitted to recover 50% of lost margins due to interruptible sales in excess of test year levels.

The DSM Financial Incentive results in additional tracking requirements over the traditional method of expensing CIP costs. The Commission finds that NSP should track the following items in its tracker: Conservation Cost Recovery through the CCRC; research, development and administrative expenses; the amortization of direct impact conservation; the unamortized balance in the Conservation Rate Base; the allowed return on the Conservation Rate Base; the bonus return on equity; and the allowed lost revenues due to interruptible sales over test year levels.

The Commission finds that the CCRC should be calculated using the above elements, with the exception of the bonus return on equity and the lost revenues due to interruptible sales over test year levels. The DSM financial incentive is still subject to some refinements as the utility complies with he Commission's March 19, 1991 Order to link the incentive with its performance in implementing cost-effective conservation program. The bonus will be determined by the Commission based on its decisions on NSP's compliance filing in the 90-1159 Docket and NSP's actual performance in implementing its 1991 CIP. Therefore, it is currently not known what level of bonus may be earned by the Company in the financial incentive. Once the bonus is determined, NSP may track the bonus and seek recovery in the next rate proceeding.

Lost revenues will not be included in the calculation of the CCRC because NSP has figured all of its anticipated load management sales into the test year forecast, If NSP's interruptible sales exceed he test year forecast, NSP may track the lost revenues for recovery in the next rate proceeding.

The Commission finds that NSP will have direct impact conservation expenditures of $14,461,720 and research, development and administrative expenditures of $3,501,451 for 1991. Using the financial incentive mechanism based on the items allowed for recover in the CCRC, NSP's CCRC will be set to recover revenues of $6,888,895. Projected KWH sales for the test year are 23,730,911,000. The Commission finds that the appropriate CCRC is $0.0002903.

In its original filing, NSP included $13,636,499 as test year conservation expense and

$931,000 in rate base.In incorporating the increased amounts approved by the Commissioner and the financial incentive mechanism, the Commission will decrease test year expense by $7,242,704, increasing net income by $4,311,582, and increase rate base by $2,513,000.

The Commission finds that it is necessary to continue monitoring the Company's CIP tracker account on an annual basis. Annual monitoring under the financial incentive will allow the Commission to determine the appropriate bonus return on equity earned by the Company and the appropriate amount of lost revenues recoverable due to interruptible sales. The Commission will require NSP to submit a tracker report on March 1 of each year detailing the activity in all of the tracker elements and demonstrating the appropriate bonus return and lost revenue recovery.

2. CIP Tracker Balance

NSP requested recovery of two amounts in the CIP Tracker account to true-up the account as of December 31, 1990. The first amount of $2,993,282 is the undisputed portion of the tracker balance which represents expenditures over recoveries dating from January 1, 1988. No party has objected to the recovery of these amounts.

The Commission finds that NSP should recover the full undisputed tracker balance $2,993,282. Allowance of these amounts is consistent with Minn. Stat. § 216B.241 (1990) and with Minn Stat. § 216B.16, subd. 6b (1990), which states as follows:

> All investments and expenses of a public utility ... incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments and expenses were directly made or incurred by the utility in furnishing utility service.

Recovery of the full undisputed tracker balance is also consistent with Minn. Stat. § 216B.03 (1990, which requires the Commission to set rates to encourage energy conservation.

The second amount of $1,242,581 represents the disputed portion of the CIP tracker, plus associated carrying charges, which was excluded by the Commission without prejudice in its May 31, 1889 ORDER DISALLOWING CERTAIN AMOUNTS IN TRACKER ACCOUNT in Docket E-002/CI-88-684. In that Order, the Commission disallowed certain expenditures for inclusion in the CIP tracker account because they were incurred either before or without specific Commission approval. At issue in this case is whether NSP should be allowed to recover the following amounts, plus associated carrying costs of $40,667:

[Graphic(s) below may extend beyond size of screen or contain distortions.]

General and Administrative Costs	$543,195
Residential Audit Services Promotion	374,826
Lost Revenues On C&I Audits	239,847
DSM Potentials Study	44,046

NSP asserted that these costs should be recovered because they were incurred to support valid ad fully approved CIP programs and were in the public interest. NSP acknowledge that CIP expenditures incurred before Commission approval of program are at risk if the Commission does not approve the program; NSP believes that those amounts should be recoverable once a program is approved. The Company maintained that it must retain some flexibility in its programs to respond to the market. It also noted that since the Commission investigation disallowing these amounts, it has worked with the Commission and Department to improve communication and timely approval of its filings.

The Department Stated that NSP's explanations for the disputed expenditures are reasonable and the expenditures should be recovered. The ALJ recommended recovery of these amounts.

The commission finds that all of the disputed amounts are recoverable with the exception of General and Administrative costs of $543,195, plus associated carrying charges. The Commission agrees with the Department and he Company that NSP has improved its efforts to receive timely approval of new projects and project changes, and that some misunderstandings may have occurred between the Company and the Commission regarding approval of projects and budgets. The Commission finds that NSP may recover $658,719, plus associated carrying charges of $22,288, for the disputed tracker amounts related to the Residential Audit Services Project, the C&I Audit Services project and the CIP DSM potentials Study.

The Commission will not allow recovery of General and Administrative Expenses of $543,195, plus associated carrying charges of $18,379. In the Company's 1987 general rate case in Docket No. E-002/GR-87-670, the Commission disallowed $843,400 of General and Administrative costs which were incurred from October 1, 1985 to December 31, 1987. In disallowing these amounts, the Commission stated:

> The Commission accepts the DPS recommendation to disallow the recovery of $843,000 in General Administrative and Regulatory (A&R) expenses for the October 1, 1985 - December 31, 1987 CIP period. The total cost of CIP programs is an important factor in determining the overall cost-effectiveness of CIP; therefore the Commission must be presented with all expenses at the time of each CIP filing. The Commission finds that NSP has never before presented these administrative costs for approval.

In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in Minnesota, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, August 23, 1988, page 31.

NSP witness Mr. James Gamble stated that the $543,195 at issue here is the money which accrued to the A&R account between January 1, 1988 and August, 1988, when the above Order was issued and the account was closed. The Commission finds that the $543,195 remaining in the account represents the same type of expense disallowed in the last rate proceeding and will disallow it here for the same reasons. NSP first received approval for a CIP General and

Administrative Account in its 1989 CIP filing. G&A costs incurred apart from specific project costs prior to January 1, 1989 never received Commission approval nor the necessary scrutiny to determine their impact on the cost-effectiveness of NSP's CIP.

In summary, the Commission finds that NSP may recover a total of $3,674,289 in the CIP tracker account, including $2,993,282 in undisputed expenses and the allowed portion of $681,007 in disputed expenses. The Company, the Department and the ALJ all recommended that the final approved amount left in the account should be surcharged to any interim rate refund. The Commission agrees with this procedure and finds that the final approved amount of $3,674,289 should be recovered through a reduction in the interim rate refund.

3. Demand-Side Demonstration Initiative Project

Minnesotans for an Energy-Efficient Economy (ME3) argued that there is untapped energy conservation potential in Minnesota and that NSP should be required to improve its current annual energy savings of 0.3% per year. ME3 recommended that the Commission require NSP to spend at least 2.5% of its gross operating revenues on energy conservation. ME3 further recommended that the Company be required to implement a Demand-Side Demonstration Initiative Project. The purpose of the project would be to demonstrate the achievable demand-side resource potential in NSP's service territories. ME3 recommended that the project be overseen by a panel consisting of representatives from NSP, the Commission, the Department, ME3 and an independent outside organization. The panel would select vendors to carry out a variety of energy efficiency programs across all sectors and end-uses in the service area.

ME3 believes that a large-scale demonstration would be helpful to determine achievable conservation potential in Minnesota. It would remove market barriers to conservation such as inadequate funding, lack of motivation, undeveloped infrastructure and ineffective marketing strategies.

ME3 recommended that the Commission deny NSP's request for a rate increase unless NSP is required to reduce the demand for energy in its service territory by two percent per year, to implement the Demand-Side Demonstration Initiative, and to use the societal cost test to evaluate conservation programs.

NSP argued that the Demand-Side Initiative proposed by ME3 had significant problems. The creation of a panel to make DSM decisions for NSP would be an abrogation of regulatory authority and responsibility assigned to the Department and the Commission in Chapter 216B. ME3 also failed to demonstrate that the project, which would cost ratepayers between $50 and $100 million dollars, would be cost-effective. NSP concluded that the merits of ME3's proposal would be best addressed in the CIP process.

The Department concurred with NSP. It stated that ME3's proposal would provide actual conservation improvements. The authority for approving CIP programs lies with the Commissioner of Public Service. The Department stated that ME3 could file its proposal with the Department under Minnesota Rules, part 7690.1400.

The ALJ found that ME3's proposals are not appropriate for consideration in this process, but would be appropriate for consideration as part of the CIP process. He found that it would be inappropriate to deny NSP's increase because of non-compliance with ME3's proposals.

The Commission finds that NSP's general rate case is not the appropriate initial forum to consider the Demand-Side Demonstration Initiative or ME3's other requests. The Commission and the Department currently have orderly processes in place to consider appropriate long-term goals for conservation (the Commission's Resource Planning Process, Minn. Rules, parts 7843.0100 to 7843.0600) and short-term conservation project implementation (the CIP process, Minn. Rules, parts 7690.0100 to 7690.1500). These processes serve better than a general rate case process, where issues are numerous and time is limited, as the initial forum to focus on the facts which are relevant to the determination of demand-side policy for NSP or Minnesota in general.

It is possible that demand-side issues determined in other proceedings may require future development, consideration or ratemaking treatment in a general rate proceeding. The Commission finds, however, that ME3's concerns would better be addressed initially in the processes described above, both of which are ongoing proceedings which encourage public involvement. Therefore, the Commission will deny ME3's requests to require NSP to reduce the demand for energy in its service territory by two percent per year, to implement the Demand-Side Demonstration Initiative, and to use to societal cost test to evaluate conservation programs.

F. Burlington Northern Coal Transportation

NSP contracts with Burlington Northern Railroad (BN) for coal transportation services. Under the NSP/BN coal transport agreement, last amended in 1987, the railroad charges a decreasing unit cost per ton. This means that the higher the volume of coal transported, the lower the transport costs.

NSP transports coal for its utility plant use and also transports coal for the University of Minnesota (U of M) for a fee. Since 1987, NSP has been recording revenues and costs of its U of M coal transportation below the line, that is, as nonoperating revenue and expenses. NSP excluded expenses and revenues from its U of M contract in the current rate case filing.

NSP reasoned that revenues from its U of M coal transportation services should be excluded because ratepayers have benefitted sufficiently from the volume discounts for utility coal transportation. According to NSP, the contract with the U of M allows NSP to reach the discount level for its own coal more quickly each year than it would be able to do it it were only hauling coal for its own use. NSP stated that ratepayers have benefitted from the discounts by $300,000 to $500,000 per year in the year 1988 through 1990.

NSP proposed a two-part test for below the line treatment of net revenue: such treatment is appropriate if the activity is not necessary for utility service and competition for the activity exists or is reasonably probable. NSP argued that coal transportation for the U of M is not necessary for the provision of electric service. NSP also argued that competition for U of M coal transport exists from other haulers, rendering monopoly oversight unnecessary. The ALJ was persuaded by the Company's arguments.

The Department advocated including net revenues from U of M coal transport in rate case treatment. The Department argued that the Company should follow the FERC's recommended above the line accounting treatment. The Department also argued that NSP had incurred no additional risk in entering into the U of M transport contract and its shareholder should therefore not be rewarded.

The Commission finds that there is a sufficient nexus between the activity of transporting U of M coal and utility activity to allow inclusion in rate case revenues. Several factors are relevant to this conclusion. NSP is hauling the same coal from the same mines for use by its utility plants and the U of M. NSP would most likely not be involved in coal transport without the need for coal for its own operations. Volume discounts are achieved by pooling tonnage for utility and U or M use. Ratepayers are paying through rates for the costs of hauling NSP coal, which in turn benefits the U of M enterprise through discounts. NSP ratepayers should receive the benefits of the U of M contract.

The Commission does not here address or adopt the second part of NSP's two-part test, available competition. The Commission does note, however, that competition for NSP's coal service to the U of M is in one important sense probably nonexistent. NSP's actual service to the U of M is not the mechanical transporting of coal, but the providing of a contract for a quantity of coal at a volume discount. There is no record of any competitor who could provide the U of M with a discounted contract by pooling the U of M's coal needs with the competitor's immense quantity of transported coal.

Because the record is unclear, the Commission makes no finding regarding the risk or lack of risk in the U of M contract. The Commission also notes that FERC accounting methods are enlightening but are not controlling on the Commission.

G. Nuclear Fuel Exchanges

NSP engages in nuclear fuel transactions such as borrow/sell and buy/replace simultaneous transactions, swap/exchange transactions, and brokerage services. Until 1988, the Company engaged in nuclear fuel transaction solely to obtain fuel for its nuclear facilities at Monticello and Prairie Island. Since 1988, NSP has entered into various fuel exchange and brokerage agreements which have involved fuel not intended for its own use. Since at least 1990, NSP has recorded revenues and expenses from these transactions below the line. In its present rate case filing, NSP excluded net revenues from these enterprises from rate case treatment.

NSP advanced the same arguments for exclusion of these revenues as it used for the coal transportation issue. NSP reasoned that its two-part test leads to exclusion of nuclear fuel exchange revenues from the rate case: nuclear fuel brokerage services are not necessary for utility service, and competition for this activity is available. The ALJ agreed with NSP's reasoning and recommended below the line treatment of the nuclear fuel exchange activity.

The Department opposed below the line treatment of NSP's transactions regarding nuclear fuel for other parties' use. The Department argued that the FERC had recommended above the line treatment for this type of activity. The Department also reasoned that NSP entered into this business for the purpose of obtaining fuel for its own plants. NSP ratepayers have borne any risks and startup costs that may have been involved in entering into this enterprises; NSP ratepayers should share in revenues flowing from the activity.

The Commission finds that all revenues from NSP's nuclear fuel transactions must be included in the rate case. There is a sufficient nexus between the nuclear fuel transactions NSP engages in for its own use and those transactions by which NSP brokers fuel for others' use. Several factors are relevant to this conclusion. Knowledge, expertise and even the key employee of NSP's internal brokerage enterprise have passed to NSP's external brokerage business. The Commission finds that it is appropriate that NSP ratepayers should share in the benefits of all of NSP's nuclear fuel transactions.

The Commission does not here specifically address or adopt the second part of NSP's two-part test, available competition. The Commission does note, however, that evidence of true competition is lacking. It is only reasonable to infer that NSP, as a utility with approximately 1,000,000 customers, wields sufficient market power to gain favorable terms in its nuclear fuel brokerage contracts. Only a similarly situated entity could provide competition for NSP. There is no evidence in the record of such an entity.

H. Miscellaneous Social/Meeting Expenses

In its investigation of NSP's rate case filing, the Department conducted a thorough investigation of each line item of NSP's DOE budget. For certain line items, the Department reviewed each cost element which made up the line item, and each expense within each cost element.

NSP's DOE line 16 is entitled "Non-Labor, Other Expenses." Two cost elements within DOE line 16 are MS16, "Miscellaneous Other Expenses," and SOCL, "Social Employee/Other Expenses." The Department disputed certain expenses within these two cost elements.

The Department recommended exclusion of certain items totaling $321,626 from MS16. These items were described in such terms as "misc.," "meeting related expenses," and "other misc. materials based on historical average." The Department pointed out that labeling an expenses item as "misc." within the cost element "Miscellaneous Other Expenses," which in turn comes under the heading of "Non-Labor, Other Expenses," provides the reviewing body with little guidance regarding the nature of or necessity for the expense.

The Department also recommended exclusion of $254,622 from cost element "SOCL-Social Employee/Other Expenses" under DOE line 16. The Department argued that these expenses were inadequately described or justified. The Department also stated that NSP had included a significant amount of social expenses under other budget headings. Because $254,622 of the expenses under cost element "SOCL" were excessive and vague, the Department recommended their exclusion.

The Company argued that meeting and social expenses are a normal and necessary part of doing business. NSP argued that it is not possible to describe minutely every expense in a large utility operation, and that the term "misc." is sometimes a valid description. The Company defended its social expenses as a means of promoting employee morale and teamwork.

The Commission agrees with the ALJ that company accountability and auditability are the key issues here. While meeting and social expenses are indeed part of an appropriate DOE budget, they must be open to meaningful review in order to be included as rate case expenses.

The Commission must examine each expense proposed by a utility and determine if it is an appropriate element of just and reasonable rates. Only in this way are utility ratepayers adequately protected from possible utility overrecovery. In this case, NSP has failed to meet its burden of showing that its meeting and social expenses were necessary and appropriate for the conduct of utility business. The Commission finds that $576,248 must be excluded from meeting and social expenses in the rate case, which will increase net income by $343,040.

I. Economic Development

NSP included $431,187 in test year expenses for five separate economic development projects engaged in during the test year. The Company argued that these expenses were justified because the economic health of the community is reflected in the financial performance of the utility, which in turn is reflected in rates. The Company further argued that a poll of its ratepayers indicated their approval of NSP's economic development expenditures. The Company stated that its economic development expenditures were reasonable compared to those of other utilities, and that Minn. Stat. § 216B.16, subd. 13 (1990) allows these expenses in rates.

NSP submitted a cost-benefit analysis of the economic development programs. The Company's analysis indicated that benefits to ratepayers from the economic development programs outweighed their costs. The Department submitted its own cost-benefit analysis, which the Department claimed more accurately reflected relative costs and benefits. The Department insisted that long-term marginal capacity costs must be included as an essential part of the cost-benefit analysis. NSP argued that marginal capacity costs should be excluded because the Company's economic development focus is on business retention rather than business growth. Even if capacity costs should be included, NSP argued that they should not be factored in until a new plant is necessary, years from now.

The ALJ agreed with the Department, the RUD-OAG and MEC, who recommended exclusion of NSP's economic development costs from rate case expenses. The intervenors argued that there is an insufficient nexus between economic development expenses and the provision of efficient and reliable electric service. The Department and the RUD-OAG also stated that the

Company had failed to produce sufficient hard, measurable data to justify the expenditures. The RUD-OAG recommended that if the Commission did not totally exclude the expenditures, the Commission should reduce them by one half.

In its analysis of NSP's proposed economic development expenditures, the Commission must look to the recently enacted Minn. Stat. § 216B.16, subd. 13 (1991), which states:

> ECONOMIC AND COMMUNITY DEVELOPMENT. The commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development.

The Commission notes that the new legislation simply states that the Commission may allow recovery of economic development expenses. The statute is not a directive to the Commission requiring inclusion of such expenses. The Commission must still examine each proposed expense to determine if it is reasonable, related to utility service, and an appropriate component of just and reasonable rates.

The new statute does indicate the legislative intent of facilitating economic development programs. The Commission recognizes the values of a strong economy to all the public, including NSP ratepayers. Allowing corporation to assume part of the responsibility of promoting a healthy economy is sound public policy.

In rate case public hearings, representatives of area development partnerships with NSP testified in support of NSP's community development programs. Witness emphasized NSP's role in promoting business retention in economically stagnant areas. The Commission finds that NSP has met its burden of showing the value of its economic development programs. Ratepayers do benefit from a healthy economic climate in which a broad spectrum of ratepayers from every rate class are able to share the costs of electric service.

The Commission is not persuaded by the Department's argument that NSP's proposed expenses must be disallowed because NSP has failed to produce sufficient hard data supporting their inclusion. As noted previously, any link between economic development expenditures and benefits to ratepayers will of necessity be indirect. Economic development expenditures are reflected on the economy, which is reflected on the utility's financial picture, which is in turn reflected on rates. The indirect impact of these costs means they are not easily translated into hard data analysis. The Commission has looked instead to the testimony of those involved in the community development projects for proof that these expenditures should be part of rate case expenses.

The Commission has also found the Company's cost-benefit analysis of its economic development programs useful in this case. Because NSP's economic development programs are focused on business retention, marginal capacity costs are not here an essential part of the analysis. Business retention programs are not likely to produce an increased strain on capacity.

The Commission agrees with RUD-OAG's second line argument, that 50% of the Company's economic development expenses should be recovered in rates. The Company has stated that its programs will help the economy of the community, and a healthy economy will eventually increase NSP's sales. The economic development costs will thus benefit NSP's shareholders through increased profits and will benefit NSP's ratepayers through additional future sales and delayed rate increases. It is logical that economic development costs should be shared by the utility shareholders and ratepayers through a 50% recovery in rates.

The Commission approves inclusion of 505 of NSP's proposed economic development costs of $431,187 in test year expenses. This increase test year net income by $128,343.

J. Marketing Programs

NSP has offered a number of electric marketing programs throughout the test year. The programs include floodlighting, dual fuel, commercial cooking, snow melting, electrical thermal storage, electric work vehicles, greenhouse lighting, infrared heating, security lighting, supplemental space heating and cable heating. These programs offer customers alternative energy services. Many of them are designed to sell additional electricity off-peak in order to smooth out NSP's load curve and spread fixed costs over more sales. NSP proposed inclusion of $262,605 for its electric marketing programs in rate case expenses.

Based upon a cost-benefit analysis, the Department recommended excluding $109,400 for three programs which failed the analysis. The programs were electric cooking, snow melting, and infrared heating programs. The Department and NSP differed in their cost-benefit analyses in the same way as they had in their economic development arguments. The Department included long term marginal capacity costs in its analysis while NSP did not. The RUD-OAG and ALJ agreed that the expenses should be excluded, based upon the Department's cost-benefit analysis.

The Commission finds that it is sound public policy to look to a cost-benefit analysis in the case of marketing programs, which will almost certainly result in future increases to NSP's load and potential acceleration of new capacity. The Commission has therefore in this case looked closely at the Department's cost-benefit analysis, which holds the Company responsible for the marginal capacity costs created by the marketing programs. The Commission is persuaded by the Department's cost-benefit analysis that $109,400 should be excluded from test year expenses for the three programs which fail the analysis. This increase net income by $65,126. The Commission will so order.

K. Advantage Service

NSP offers Advantage Service, a nonregulated appliance maintenance program, to its customers. Advantage Service shares some parts of the regulated NSP operation, including mailing lists, the regulated billing system, and referrals from NSP's utility representatives. The RUD-OAG raised questions regarding the treatment of this cross-use.

NSP provides mailing lists to Advantage Service. The RUD-OAG argued that Advantage Service should pay a competitive rate for the use of the mailing lists. Because no mailing was actually contemplated for the test year, the RUD-OAG did not propose a rate case adjustment for this issue.

Advantage Service pays the NSP regulated entity the incremental cost associated with the use of NSP's billing services. The RUD-OAG argued that Advantage Service should in addition pay a return on this asset so that ratepayers are fairly compensated for its use. The RUD-OAG did not ask for an adjustment in the present rate case because the amount adjusted would be minute. The ALJ supported the RUD-OAG's recommendation.

NSP's nonregulated maintenance service receives the benefit of referrals from NSP's regulated service representatives. Although NSP does not allocate the costs of any service representative's time to Advantage Service, NSP has stated that its customer business office personnel spend about two hours per month on referrals to Advantage Service. The RUD-OAG argued that in future rate cases Advantage Service should compensate NSP electric utility for the referral time.

The Commission agrees with the RUD-OAG's proposals. No adjustments will be made in this area in the current rate case because there is insufficient justification in the present record and any amount to be awarded would be very small. The Commission, however, will require NSP's Advantage Service in the future to compensate NSP properly for the use of NSP's electric utility assets, including a return on utility assets. Advantage Service must adopt these compensation principles from this point on, and reflect proper compensation in its future rate case filings.

Finally, the RUD-OAG recommended that NSP's customers should be notified of their option to be dropped from NSP's mailing lists. The RUD-OAG suggested that the notice be included in a future billing insert. The Commission finds this recommendation appropriate and will adopt it as a requirement.

L. Nuclear Decommissioning

NSP's nuclear decommissioning costs and end-of-life nuclear fuel costs are reviewed every three years by the Commission. Following the last triennial review, the Commission issued an Order[10(10)] dated February 25, 1991, in which it approved the Company's nuclear decommissioning cost studies, funding mechanisms, earnings assumptions, and inflation assumptions. The nuclear decommissioning methods approved in the February 25, 1991 Order were applied by NSP in the present rate case. NSP included in its revenue requirement approximately $17.6 million for decommissioning nuclear plants and approximately $1.6 million for end-of-life nuclear fuel.

Nuclear decommissioning funds are collected by NSP throughout the projected life of the plant. During the period they are held by the Company, they are invested partly in internal funding and partly in external funding. Funds held in internal funding earn a rate of return based upon the Company's last approved rate case filing. Funds in the external funds are held by Mellon Bank of Pittsburgh as trustee and managed by Delaware Investment Advisers (DIA). In its rate case filing, NSP estimated an after-tax and after-administration return on tax-qualified external funds of 5,5%.

MEC argued that NSP had chosen an unwise investment strategy which had worked to the detriment of NSP's ratepayers. MEC stated that NSP could have earned a return two percentage points higher if it had chosen 20-years bonds instead of the seven-to-ten year debt instruments which were chosen. MEC advocated reducing NSP's revenue requirement by $4,200,000 to reflect the Company's lost investment opportunity. MEC also urged the Commission to require NSP to submit its DIA investment management contract to the Commission for a review of prudence.

The Commission agrees with the ALJ that NSP's nuclear decommissioning cost projections and proposed recovery procedures are appropriate and consistent with the Commission's February 25, 1991 decommissioning Order. The Commission's opinion of NSP's investment strategies remains unchanged from its February 25, 1991 Order, in which the Commission stated:

> The Commission agrees with the Department and the Company that investing in intermediate term securities is a sound investment strategy meriting Commission approval. Although it is true that some long term investments would currently earn higher returns, it is not clear that this would be true thorughout the 20 years that ratepayer funds would remain invested. Financial conditions change significantly over the course of 20 years. The intermediate terms favored by the Company would allow the funds manager to shift funds between investment vehicles to earn the highest return consistent with favorable tax treatment and ratepayer security. Furthermore, investing in intermediate term securities would make ratepayer funds more accessible if early decommissioning should become necessary.
>
> The Commission concludes that the flexibility provided by intermediate term securities is more valuable than the possibility of higher current returns offered by long term securities. The Commission will therefore approve the Company's proposal to invest decommissioning funds in intermediate term securities.

The Commission will adjust the test year cost to reflect the 10.04 percent rate of return awarded in this case. This will ensure that the internal fund earns a return based on the rate of return authorized for NSP. Without this adjustment, NSP would be paying the internal fund a rate of return greater than its own authorized rate return. No party opposed the concept of this adjustment. This adjustment reduces rate base by $196,000 and reduces net income by $334,000.

Finally, the Commission rejects MEC's proposal to submit the Company's DIA contract for immediate review of prudence. The prudence of the Company's nuclear decommissioning investment strategies will be subject to review during the Company's next triennial decommissioning filing.

M. Unbilled Revenue

The term "unbilled revenues" refers to revenues a company has earned between the most recent meter reading date and the end of the month. Utility companies bill customers on a cyclical basis throughout the month based on meter readings. The electricity usage from each customer's meter reading date to the end of the month remains unbilled until the meter is read and the bill prepared the following month. Unbilled revenues can be a ratemaking issue because, while the utility incurs electricity costs in the month service is provided, a portion of the utility's revenues from the sale of that electricity to its retail customers is not billed until the month after service. A company's test year may overstate its revenue deficiency if it reflects all electricity costs but not the proper level of related revenues.

There are two main ways of approaching unbilled revenues for utility ratemaking purposes. In one method, unbilled revenues are not included in the test year. At the beginning of the test year, revenues are recorded for meters read in the early days of the test year which reflect services rendered at the end of the previous year. Conversely, with respect to the last days of the test year, no revenue is recorded for services rendered but not yet billed through meter reading. This method results in a revenue year which in effect falls from approximately December 15 of the previous year to December 15 of the test year. Based upon the logic of this approach, NSP did not include unbilled revenues in its rate case filing.

In another method, the utility estimates revenue that it has earned but did not bill for during the test year and includes that amount as test year unbilled revenue. The utility excludes the amount that it had earned but did not bill for in the month immediately prior to the test year. Test year costs and revenues are calculated from January 1 in the test year through December 31. The Commission approved this method of including unbilled revenues in Midwest Gas' last general rate case.[11(11)]

The RUD-OAG raised two main objections to NSP's proposed exclusion of unbilled revenues. The RUD-OAG argued that test year unbilled revenues should be included because greater revenue is usually left unbilled at the end of each December than is left unbilled in the approximately last two weeks of the prior year.[12(12)] The latter, pre-test year amount is included in test year revenues under NSP's method while the former amount is not This disparity works against the interests of ratepayers. The RUD-OAG also argued that including test year unbilled revenues results in a proper matchup of test year revenues and test year costs, which are recorded in the month of their occurrence.

Using this reasoning, the RUD-OAG compared test year end-of-the-year unbilled revenues amounting to $57,031,874 with beginning-of-the-year unbilled revenues of $55,570,231. The RUD-OAG proposed that the difference, $1,461,643, be included as 1991 test year unbilled revenues. The ALJ agreed with the RUD-OAG's position on this issue.

The RUD-OAG raised a second objection to NSP's approach to unbilled revenues. The RUD-OAG argued that NSP had accrued $55,570,231 in pre-test year unbilled revenues at the beginning of the test year, and that this amount should be recognized as test year income. The RUD-OAG proposed a ten year amortization of this sum, resulting in a test year revenue increase of approximately 45.6 million. According to the RUD-OAG, this sum should be included in test year revenues, along with the test year revenue increase of approximately $1.4 million. The ALJ disagreed with the RUD-OAG's proposal regarding the accrued pre-test year unbilled revenues.

NSP countered that its approach to unbilled revenues is consistent with general accounting principles. The Company argued that its method provide an accurate matchup of revenues to costs, based upon meter readings and not upon estimates. NSP stated that any reexamination of pre-test year unbilled revenues would amount to retroactive ratemaking, and any such treatment could only be approached through a generic proceeding. The Commission agrees with the ALJ's position in these matters. It is appropriate to include test year unbilled revenues in rate case revenues. This method results in a proper matchup of test year costs and revenues. Without it, NSP would receive credit for expenses through the end of the test year but ratepayers would be credited with revenues from the end of the previous year instead of from the end of the test year. This matchup is improper and all too often works to ratepayers' detriment. Inclusion of test year unbilled revenues is consistent with the Commission's treatment of this issue in the Midwest rate case. The Commission finds that $1,461,643 in unbilled revenues should be included in test year revenue. This adjustment increases net income by $870,117.

The Commission also agrees with the ALJ's recommendation regarding the RUD-OAG's proposed inclusion of an amortized portion of accrued unbilled revenues. Unbilled pre-test year revenues should not be included in test year revenues, because to do so would be to match twelve months' costs with more than twelve months' revenues. Amortization of these revenues would not change the fact that they are improperly included in test year revenues. The Commission finds that pre-test year accrued unbilled revenues should not be included in test year revenues.

N. Chippewa Land Sales

Introduction - For purpose of this subsection, NSP's Minnesota utility enterprise will be referred to as NSP-M. NSP's wholly owned subsidiary, which is located in Wisconsin and provides electric and gas service in Wisconsin and Michigan, will be referred to as NSP-W.

NSP-W and NSP-W are two separate public utilities and their wholesale transactions are separately regulated by the FERC. Because NSP-W and NSP-W are interconnected and exchange power, their interchanges are regulated by the FERC. The FERC has approved a formal Interchange Agreement between the two entities, which governs the rates and the terms and conditions applicable to their exchanges of power.

History - In 1920, NSP purchased approximately 8,500 acres of land around the Chippewa Flowage near Hayward, Wisconsin. The land, which was purchased for less than $5 per acre, was held as part of NSP's original federal license requirement. The land was leased by NSP-W to its subsidiary, Chippewa and Flambeau Improvement Company (CFIC). NSP-W in turn paid toll charges to CFIC for use of the water in the Chippewa Flowage for the generation of electricity.

In 1984, the federal license requirement which necessitated holding the Wisconsin land was lifted. In 1988 and 1989, NSP-W sold the land to the federal government and the State of Wisconsin. NSP-W realized a before-tax gain of approximately $8.6 million on the sales and an after-tax net gain of $5,588,117. NSP claimed the gain for its shareholders and did not include the effects of the gain in its rate case filing.

Positions of the parties - The RUD-OAG urged the Commission to require NSP to recognize the gain for ratepayers. The RUD-OAG recommended that the after-tax gain of $5,588,117 be allocated to the Minnesota jurisdiction and amortized over three years, with rate base treatment of the unamortized balance. This would decrease rate base by $3,426,000 and increase test year net income by $1,371,000. NSS supported the RUD-OAG's position.

The RUD-OAG argued that the land had been recorded by NSP-W in FERC Account 104, Utility Plant Leased to Others, and was therefore utility property. In fairness, ratepayers should share in the gains from utility property, as NSP suggests ratepayers should share in losses such as King Roter and Pathfinder. The RUD-OAG noted that Minn. Stat. § 216B.16, subd. 6 (1990) does not preclude the inclusion of nondepreciable property such as land in rate base. The RUD-OAG argued that Minnesota ratepayers had supported the Chippewa land asset through rates: tollage charges paid to the CFIC by NSP-W had been reflected in Minnesota rates because of the utilities' power interchange agreements.

NSP protested the inclusion of the land sale gain in the rate case. NSP argued that the gains had been realized in 1988 and 1989, not in the rate case test year. The Company stated that there had been no return of the investment by NSP ratepayers because land is a nondepreciable asset. If any return on the investment by Minnesota ratepayers had taken place, the amount was too insignificant to determine ownership of the asset.

Commission analysis - After carefully examining the facts in this case, the Commission finds that the link between the Chippewa land sale gains and Minnesota ratepayers is too tenuous to support inclusion in the rate case.

There is little in the record to show either a return of the investment or a return on the investment by Minnesota ratepayers. The fact that NSP-W placed the land in FERC Account 104, Utility Plant Leased to others, does not of itself mean that the asset was included in Wisconsin utility rate base. There is nothing in the record to prove that there was rate base treatment or a return of the investment. The record is also insufficient to prove that Minnesota ratepayers paid a return on the asset. The RUD-OAG points to a statement by NSP regarding the effect the CFIC tollage charges may have had on Minnesota ratepayers. This speculative statement, unsupported by any other evidence, does not persuade the Commission that Minnesota ratepayers have paid a return on the land investment.

The record does not show a burden on Minnesota ratepayers from the Wisconsin land asset which would support inclusion of the gain from sales in the rate case. As stated previously, the land was not in rate base and there is no evidence of return of or a return on the investment. There is no evidence that other costs associated with the land, such as maintenance, were directly included in regulated operations.

There is also no showing that Minnesota ratepayers shared with utility shareholders a risk of loss associated with the asset. NSP testified that even if the land had been sold at a loss, it would not have asked ratepayers to make up the loss.

The Commission is unpersuaded by the RUD-OAG's argument that fairness requires a ratepayer sharing in gains if the utility seeks ratepayer sharing of losses on other items. While this fairness argument is appealing, it cannot change the nature of the asset itself. An analysis of the relationship between ratepayers and assets is necessary to determine rate treatment. An abbreviated, shorthand analysis, whether a fairness or accounting analysis alone, will not suffice.

The fact that Minn. Stat. § 216B.16, subd. 6 (1990) does not preclude rate base treatment of land does not of itself mean that land must at all times be included in rate base.

The Commission finds nothing in this particular set of facts to support inclusion of the gain from land sale in rate base. The Commission will not require an adjustment to NSP's rate base or income to reflect the gains from Chippewa land sales.

O. Cost Savings

Intervenors identified two areas of savings which they claimed had been implemented by NSP but not reflected in the rate case. They proposed reductions in expenses to reflect these savings.

Transco - NSP's transmission services operation is known as Transco. NSP commissioned a costs savings analysis, known as the Transco Study, to evaluate operations of the Transco department. The Study identified two main sources of potential savings: reduced labor costs of $4.7 million and increased efficiency of $2 million. NSP did not expect the total potential Transco savings of $6.7 million to be achieved in the test year because a number of operational changes would have to be put into place first.

MEC argued that NSP's test year expenses should be reduced by $5,319,000, the Minnesota jurisdictional amount of the total savings identified in the Transco study. MEC felt that NSP's proposed filing did not reflect the Transco cost reductions.

NSP opposed any expense adjustment for the Transco study. NSP stated that its filing already reflected a reduction in Transco labor costs of $5.7 million, based upon principles of the Transco study. A further $400,000 in Transco labor costs would be implemented in 1992. NSP stated that it had taken advantage of all possible test year Transco savings, and those savings had been reflected in its filing.

The RUD-OAG recommended that NSP's expenses should be reduced by $400,000 to reflect the $400,000 Transco labor savings which would be implemented in 1992. The RUD-OAG argued that these savings, though not part of the test year, should be included as known and measurable changes.

The Commission agrees with the ALJ, who recommended that no adjustment to NSP's filing should be made for Transco savings. The Commission finds that NSP has made serious efforts to reduce Transco labor costs and increase production efficiency. These efforts have been reflected in the Company's budget for this rate case. MEC's proposed reduction would be improper because it would reduce NSP's expenses for an item already taken into account. The RUD-OAG's adjustment is also inappropriate because it would reflect savings which will not occur until after the test year. The Commission will not adjust NSP's expenses to reflect additional Transco savings.

Maple Grove inventory - In an August 1990 staff meeting, NSP employees discussed the possibility of a $10 million reduction in plant inventory at the Maple Grove facility. After reviewing minutes of the NSP staff meeting, MEC urged the Commission to reduce NSP's rate base by $8,724,546 to reflect the test year reduction in inventory levels.

NSP representatives testified that it staff members had only been discussing a possible reduction of general generating plant inventory over a five year period, not specifically a Maple Grove inventory reduction. In fact, no part of the inventory reduction mentioned in the August, 1990 meeting was accomplished in the test year.

NSP stated that it had already accounted for a %6.6 million inventory reduction in its rate case filing, although that reduction was never achieved in the test year. NSP argued that a further inventory reduction as proposed by MEC would work as a detriment rather than a benefit to ratepayers. Such a dramatic reduction in plant inventory would render its generating plants vulnerable to expensive forced shutdowns.

The Commission agrees with the ALJ that no further adjustment should be made for inventory reductions. The Company's filings show that it has prudently reduced inventory without reaching dangerously low levels. It would not be in ratepayers' best interests to force NSP to lower inventory further. The Commission will not require an adjustment.

P. Deferred Costs

Following the denial of its requested rate increase in the 89-865 Order, NSP set a goal of reducing "controllable operating expenditures" by $50 million. The Company actually achieved expense reductions of approximately $38 million in 1990. NSP's cost reductions raised concerns among intervenors that the Company was deferring costs into the 1991 test year DOE budget.

The Department submitted information requests regarding Company costs. In its responses to information requests, NSP identified certain 1990 expense reductions which resulted in costs carried over into 1991. After analyzing NSP's responses, the Department, the RUD-OAG and MEC identified certain other 1990 expense reductions which may have increased the test year budget. NSP, the Department, the RUD-OAG and MEC agreed to enter into a Stipulation on Deferred Expenses (the Stipulation), which eliminated deferred costs, reducing test year expenses by $3,257,900. The Stipulation was signed by the parties on August 2, 1991.

NSS did not join the stipulation, arguing that the adjustment for deferred items should be at least $11.4 million.

The ALJ admitted the Stipulation into the record. The ALJ stated that the Stipulation provided the kind of accurate, detailed information on carry-over expenses which the Commission had been seeking in the 89-865 Docket.

The Commission finds that the Stipulation is reasonable and is sufficiently supported by the record. The parties to the Stipulation made substantive efforts to analyze costs. A rational and systematic review of the Company's costs was provided by the parties as part of the Stipulation. The Commission will accept the parties' Stipulation.

The Commission is not persuaded by the arguments of NSS. NSS provided no analysis of the many individual components of its proposed reduction. The mere fact that a utility achieved a cost reduction does not mean that the cost was carried over into the following year. The Commission will not accept the proposed adjustment of NSS.

The Commission will reduce test year expense by $3,257,900, increasing test year net income by $1,939,428.

Q. Cyprus Minerals Purchased Power Costs

NSP included in its test year expenses $2,226,000 in costs of purchasing power from Cyprus Minerals (Cyprus) under a PURPA agreement. Although no power purchases contract had been formalized between the parties at the time of NSP's rate case filing, letters of intent were signed by NSP and Cyprus on June 6, 1991. The agreement indicated that power purchases would begin on July 1, 1991.

MEC urged the Commission to remove the Cyprus power costs from rate case expenses because no contract had been signed and these costs were therefore speculative.

The Commission finds that MEC's point is moot. A formal power purchase contract was signed by the parties and approved by the Commission under Docket No. E-002/CG-91-524. On October 17, 1991, parties were apprised of the contract approval. No party chose to address the effects of the contract approval. Pursuant to the contract, NSP has been buying power from Cyprus. The Commission accepts NSP's test year expenses of $2,226,000 for Cyprus power purchases.

R. Revenue Credits

WPP1 - NSP and Wisconsin Public Power, Inc. (WPPI) entered into a contractual agreement under which NSP wheels power from Minnesota Power to WPPI. Under this contract, NSP began wheeling firm power on November 1, 1991. NSP included in its rate case expected firm revenues of $236,284 per month for November and December 1991. NSP projected nonfirm revenues from WPPI of $480,000, consisting of $45,000 per month through October and $15,000 for November and December, 1991.

MEC argued that NSP's two months of firm wheeling revenue should be projected for the entire test year since the contract would continue through 1992 and beyond. If the Commission accepted MEC's recommendation, NSP's jurisdictional revenues would increase by $1,762,868. The ALJ rejected MEC's recommendation.

The Commission disagrees with the position advocated by MEC. One of the very basic tenets of ratemaking is the necessity of matching proper test year revenue and costs. In this case, costs for the test year 1991 have been included in the rate case. It would be improper to match these costs with known revenue changes which will occur after the test year. In a 1988 Order[13(13)], the Commission stated its reasons for disallowing a test year adjustment for post-test year changes:

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.

The Commission will not require annualization of NSP's two months of firm wheeling revenue.

FERC generic transportation tariff - NSP has filed with the FERC a generic tariff for the provision of wheeling services. Although the generic tariff is currently in effect, the record did not indicate that any customer had as yet attempted to avail itself of the tariff. The record did not indicate that any revenue had been obtained from the FERC tariff, now was there evidence of any upcoming use of the tariff.

MEC argued that an unspecified adjustment should be made to test year revenues to reflect the generic wheeling tariff. The Commission disagrees. It would be inappropriate to adjust test year revenues to reflect hypothetical revenue from a generic tariff which the record indicated had never been utilized. No such adjustment will be made.

S. Advertising, PC Depreciation

As noted previously in this Order, NSP filed a Motion to Update Filing on May 13, 1991. NSP wished to include certain administrative and general expenses and depreciation expenses which it had recently discovered. The Commission has granted NSP's motion and allowed these adjustments to be admitted into the record. As a result, test year net income will be reduced by $1,104,000 for late-filed advertising expenses and by $2,247,000 for late-filed PC depreciation expenses.

T. Incentive Compensation

NSP has an extensive incentive compensation plan in place. The program applies to all levels within the Company, including 19 officers, 119 middle level managers, 3,237 nonbargaining exempt employees and 2,895 bargaining employees. NSP originally included in expenses

$13,300,000 in Minnesota jurisdiction test year incentive compensation payments plus $1,434,000 in Pension Make-Up expenses.[14](14)

On August 21, 1991, NSP filed a Motion for Leave to Reopen the Record to Offer Late Filed Exhibit. The Company stated that it had discovered that the Minnesota jurisdictional incentive compensation had been overstated by $1,973,701. As stated previously in this Order, the Commission denied MEC's motion for sanctions against NSP for failure to disclose accurate information.

MEC's primary recommendation was the exclusion of all costs associated with incentive compensation. NSS indicated possible support for this position. MEC stated that the programs conflict with ratepayer interest and that test year expense levels are speculative.

The Department, the RUD-OAG and the ALJ agreed that test year costs should be reduced by the $1,973,701 mentioned in NSP's motion. They felt that the record should be adjusted to reflect NSP's late-discovered error.

NSP advanced a number of arguments to support the inclusion of incentive compensation costs. The Commission is not persuaded by the Company's reasoning.

NSP argued that the incentive compensation plan is necessary to attract and retain qualified employees. The record fails to support that assertion. Record evidence fails to show that NSP has substantial employee turnover or difficulty in filing vacant positions. The record does show that NSP's salaries are comparable to or better than similar utilities.

The Company argued that base salaries would have risen more without the incentive programs. According to NSP, the introduction of a "pay-at-risk" philosophy into NSP's compensation program benefitted ratepayers by holding down salary increases. The Commission finds, however, that the record does not support this premise. The record shows that nearly 99 percent of available incentive compensation has been awarded over recent years. Salaries have clearly remained at the level they would have attained without the incentive program.

NSP stated that ratepayers are benefitted by its incentive compensation program through the establishment of certain nonfinancial goals. The Company cited improved safety, customer satisfaction, and productivity. NSP failed, however, to quantify these benefits as part of its rate case filing. Further, even if these benefits were quantified, the Commission considers these goals as normal duties of employees that would be required in the provision of utility service. Ratepayers should not be required to pay an incentive for such expected service.

NSP argued that incentive program expenses should be included because its program is tied to the goal of maintaining competitive rates. According to this theory, the program will cause NSP employees to strive for greater efficiency and productivity; ratepayers will thus reap a benefit. As proof of this argument, NSP compared its rates favorably with a selected group of electric utilities.

The Commission finds that the link between NSP's rates and its incentive compensation program is too tenuous to support inclusion of these costs. Rates must always reflect a utility's prudent costs in providing safe and adequate service to its ratepayers. Individual operating characteristics of various utilities render rate comparisons difficult. Linking these rates to performance compensation programs makes meaningful comparisons impossible. The Commission will not accept NSP's argument linking favorable rates with its incentive compensation program.

Finally, the Commission notes that a threshold earnings per share of $2,75 must be met before any incentive compensation is paid under the program to any NSP employee. The Commission finds that this component of the Company's incentive program is unreasonable and unacceptable.

Because compensation is linked to Company earnings per share, employees may be motivated to gauge their actions by immediate Company earnings rather than overall Company benefit. NSP's incentive compensation program may motivate employees towards decisions bringing immediate profit, regardless of the long-term consequences.

Although NSP's incentive plan incorporates some individual performance goals, an employee who meets those goals will still be denied compensation if the Company's earnings per share threshold is not reached. It would be unreasonable and unfair to deny an employee the compensation he or she may have personally earned because the utility's earnings per share reached $2.74 rather than the required $2.75. This hypothetical would hold true under NSP's plan, even though the Company's failure to reach targeted earnings had nothing to do with the employee's performance.

The Commission concludes that NSP's incentive compensation program is an improper effort by the Company to pass the risk of operations from shareholders to ratepayers and employees. This program is an attempt to maximize shareholders benefit at the expense of ratepayers. The Commission will exclude all test year incentive compensation costs. As a result of this adjustment, expenses will decrease by $14,447,200 and net income will increase by $8,600,418.

U. Issues With Income Statement Effects Discussed in the Rate Base Section of this Order.

The following issues were discussed in the rate base Section of this order but also affect the income statement.

1. October 1990 Plant Balance

Adjustment accepted by the Commission to correct the beginning balances increase net income $194,000.

2. Information Services Chargebacks

Adjustments accepted by the Commission increase net income $11,000

3. Purchasing Costs

Adjustments accepted by the Commission increase net income $18,000.

4. Rate Case Expense

Adjustments accepted by the Commission increase net income $245,000.

V. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is $191,895,000 as shown below (000's omitted):

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Operating Revenues:	
Retail Electric Revenues	$1,207,725
Late Payment Revenues	3,412
Miscellaneous Service Revenues	2,598
Total Minnesota Retail Revenues	$1,213,735
Other Operating Revenues	157,953
Gross Earnings Taxes	18,049
Total Operating Revenues	$1,389,737
Operating Expenses:	
Production	$ 589,688
Transmission	28,029
Distribution	77,173
Customer Accounts	32,488
Customer Information	7,912
Administrative and General	99,033
Depreciation and Amortization	163,515
Taxes:	
Real Estate and Property	119,626
Gross Earnings	18,049
State and Federal Income	67,819
Deferred Income	10,068
Net Investment Tax Credit	(6,494)
Total Operating Expenses	$1,206,906
Operating Income Before AFUDC	$ 182.831
AFUDC	9.064
Operating Income With AFUDC	$ 191,895

XIV. RATE OF RETURN

A. Introduction

The overall rate of return represents the percentage the utility is authorized to earn on its Minnesota jurisdictional rate base. The overall rate of return is determined by the capital structure, which is the relative mix of debt and equity financing most of the rate base, and the costs of these sources of capital. The Commission will first address the capital structure, then the costs of debt and preferred stock and the cost of equity. Finally, the Commission will put these factors together to derive the authorized overall rate of return on rate base.

Five parties submitted rate of return testimony in this proceeding. Mr. Paul E. Pender testified for NSP, Dr. Luther C. Thompson for the Department, Dr. Matityahu Marcus for RUD-OAG, Mr. J. Bertram Solomon for NSS and Mr. Derick Dahlen for MEC.

B. Capital Structure

1. Summery of the Parties' Positions

NSP proposed a capital structure consisting of 41.98% long-term debt, 0.42% short-term debt, 9.85% preferred stock and 47.75% common equity as shown below:

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Capital Employed	Amount *(Thousands)*	*Percent*
Long Term Debt	$1,280,919	41.98
Short Term Debt	12,833	0.42
Total Debt	$1,293,752	42.40
Preferred Equity	$ 300,509	9.85
Common Equity	1,457,002	47.75
Total Capital	$3,051,263	100.00

The percentages are based on the forecast capitalization for the test year ending December 31, 1991.

The Department and RUD-OAG witnesses used the Company's proposed capital structure for calculating their recommended overall rates of return. Dr. Thompson stated that the determination of the actual capital structure was a prerogative of company management, but for regulatory purposes it is the Commission which must decide what capital structure is fair and reasonable in determining the overall allowed rate of return on rate base. Dr. Thompson asserted that the Company's proposed equity ratio showed a trend similar to the equity ratios for comparable companies. He recommended that the Commission monitor NSP's rising equity ratio and put NSP on notice that equity ratios beyond the average ratios of companies of comparable risk may not be allowed for regulatory purposes in future cases. NSS witness Solomon stated that the Company did not sustain its burden of demonstrating the reasonableness of a 47.75% equity ratio. Mr. Solomon cited NSP's 1985 general rate case, Docket E-002/GR-85-558, in which the Commission stated that the common equity ratio should not exceed 45%. Mr. Solomon claimed that a 47.75% equity ratio would cost ratepayers approximately $7.2 million more than a 45% capital structure. He asserted that the Company presented no evidence that the benefits of an increased equity ratio outweigh the costs. He further claimed that there was no evidence that a 45% equity ratio would reduce NSP's bond rating below AA, nor was there evidence that a AA rating was necessary for adequate provision of service. Mr. Solomon recommended that the Commission restrict NSP's common equity ratio to the 45% level.

NSP argued that Mr. Solomon failed to presented evidence on a reasonable capital structure for NSP. The Company asserted that NSS simply lectured the Commission on how to apply its own precedent, without regard for recent trends in the industry toward larger equity components. NSP supported the use of its actual capital structure for ratemaking purposes in order to maintain the company's financial integrity and AA bond rating. It claimed that its proposed common equity ratio of 47.75% was comparable to that of other AA rated utilities, and that higher electric utility business risks have made it necessary for utilities to increase equity ratios in order to decrease financial risks.

2. Recommendation of the ALJ

The ALJ found that NSP's proposed capital structure, which included a common equity ratio of 47.75%, was reasonable. He found that NSP's approach is a compromise between using the current capital structure and the forecasted capital structure, and that the common equity ratio is in line with that of comparable utilities. The ALJ also noted that NSP is not planning any power plant construction during the period anticipated to be covered by these rates. The increasing equity ratio therefore recognizes the financing trends faced by the Company during the immediate past and future horizon of rates proposed in this case.

3. Commission Findings and Conclusions

The Commission is charged with determining the most reasonable capital structure for NSP for ratemaking purposes. In making this determination, the Commission finds that the relative proportions of the various forms of capital employed by the Company must be reviewed to ensure that ratepayers are not being required to pay an unnecessarily high cost of Capital. Because common equity is typically the highest cost capital, the equity ratio is of particular concern. Use of too much common equity in the capital structure could cause an excessive cost of capital.

The Commission also recognizes that the cost of any of the forms of capital is a function of the perceived risk of that form. All other things being equal, the higher the percentage of common equity financing, the lower the risk in each forms of capital. More common equity implies a greater likelihood that earnings will be sufficient to pay the fixed-cost obligations of interest on debt and dividends on preferred stock. In turn, the greater the equity ratio, the less those fixed-cost obligations will cause earnings available for dividends and retained earnings to fluctuate as the company experiences fluctuating sales.

The Commission must, therefore, be satisfied that the Company has established a capital structure that properly balances the needs. of ratepayers for economy and the needs of investors for safety. If the Commission finds that the Company has not achieved a reasonable balance, causing the ratepayers to pay an unreasonably high cost of capital, the Commission will adjust the capital structure for ratemaking purposes to put it within a reasonable range.

NSP has the burden of establishing by competent evidence that the capital structure it purposes is reasonable. Minn. Stat. 216B.16 subd. 4 (1990). Similarly, parties who propose alternative capital structures must support their proposals by competent evidence. To carry out its statutory duty to determine the most reasonable capital structure for ratemaking purposes, the Commission must consider all the proposals and evidence in the record.

NSP has made several arguments in support of its proposed capital structure which have been rejected previously by this Commission. In the 85-558 Docket, the Commission found that citing the Standard and Poors debt ratio objective does not support the reasonableness of NSP's proposed capital structure. The Commission found that rating agencies use a broad array of criteria to assign bond ratings. not merely debt ratios.

The Commission has, however, supported the use of equity ratios of comparable utilities as a check on the reasonableness of a utility's proposed capital structure. Mr. Pender, Dr. Thompson and Dr. Marcus all submitted evidence regarding average comparable group equity ratios ranging from 45.9 (Dr. Marcus' total comparable group) to 48.1 percent (Dr. Thompson's combination utility group and Mr. Pender's AA rated comparable group) to 49.7% (Dr. Marcus' AA rated comparable group). The Commission finds that NSP's equity ratio of 47.75% is contained within this range. It is reasonable for use in the ratemaking capital structure because it is comparable to that of utilities in the same range of risk as NSP.

The Commission rejects NSS's premise that the Company has not sustained its burden of proof in justifying an equity ratio higher than 45%. NSP has offered competent evidence, corroborated by comparable group analyses by the Department and RUD-OAG, which demonstrates that an increased equity ratio is justified for this test year. NSS witness Mr. Solomon offered no evidence to the contrary in this proceeding. The Commission has not absolutely restricted NSP or any other utility to a 45%- equity ratio. It has merely notified the Company that it will employ a hypothetical capital structure for ratemaking purposes unless it is clearly shown by competent evidence in the record that NSP's projected equity levels are reasonable.

In adopting NSP's actual capital structure for this test year, the Commission is not specifically the use of a utility's financial goals, nor is it advocating the use of a utility's actual capital structure for ratemaking as appropriate in all cases. The Commission continues to reserve its authority to examine a utility 's capital structure and adjust it for ratemaking purposes where deemed necessary. NSP will be required to justify its proposed capital structure in future rate proceedings, and this Commission may adjust that capital structure if it finds that the Company's equity ratio is unreasonable for ratemaking purposes.

C. Costs of Long-and Short-term Debt and Preferred Stock

In its original filing, NSP proposed a test year cost of long-term debt of 8.65%, short-term debt of 7.78%, and preferred stock of 6.d13%. No party challenged the Company's proposed costs of debt and preferred stock. The ALJ found these costs to be reasonable in determining NSP's overall rate of return.

The Commission accepts the costs of long-term debt of 8.65%, short -term debt of 7.78%, and preferred stock of 6.13%. The Commission concludes that these costs reasonably reflect the costs expected to prevail for NSP during the test year.

D. Rate of Return on Common Equity

1. Legal guidelines for Commission Decision-Making.

In reaching a decision on the appropriate cost of common equity, the Commission, as an administrative agency, must act both within the scope of its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide these general guidelines for Commission rate of return decisions:

a. The allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties;

b. The return should be sufficient to enable the utility to maintain its financial integrity; and

c. The return should be sufficient to attract new capital on reasonable terms.

See *Bluefield Water Works and Improvement Co. v. P.S.C.*, 262 U.S. 679 (1923), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). No particular method or approach for determining rate of return was mandated by those cases, but the necessity of a fair and reasonable rate of return was clearly stated:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. *Bluefield Water Works*, 262 U.S. at 690.

The Minnesota Supreme Court has also provided some legal guidelines for Commission decision-making. In *Minnesota Power & Light Company v. Minnesota Public Service Commission*, 302 N.W. 2d 5 (1980), the Court said:

> ... The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function; and (2) the allocation of rates among classes of utility customers, which is a quasi-legislative function.
>
> ... we now hold that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.

302 N.W.2d at 9. In conducting its evaluation of the Commission's decision, the Court explained:

> ... A reviewing court cannot intelligently pass judgement on the PSC's determination unless it knows the factual basis underlying the PSC's determination. Judicial deference to the agency's expertise is not a substitute for an analysis which enables the court to understand the PSC's ruling. Henceforth, we deem it necessary that the PSC set forth factual support for its conclusion. The PSC must state the facts it relies on with a reasonable degree of specificity to provide an adequate basis for judicial review. We do not require great detail but too little will not suffice.

302 N.W. 2d at 12.

In order to provide the factual basis for its decision required by the Court, the Commission will review the testimony of each of the parties on rate of return on common equity, and the objections raised thereto by other parties. The Commission will also review the recommendations of the ALJ. Finally, the Commission will draw its conclusions from the parties testimony and determine the proper rate of return.

2. Summary of the Parties' Positions

NSP - NSP witness Paul Pender looked at three different models to derive the appropriate return on equity (ROE) for NSP. Using a discounted cash flow (DCF) model, Mr. Pender estimated NSP's required ROE to be 13.51%. Using a risk premium model, he estimated the ROE at 14.23%. Using a Capital Asset Pricing Model (CAPM), Mr. Pender arrived at a required ROE of 14.07%. The Company's official position is that the Commission should grant NSP an ROE of 12.75%.

NSP believes that the DCF model is limited in its ability to accurately estimate required ROE for companies, and that the results are sensitive to the historical time period relied upon by investors in estimating future growth rates. NSP argued that the Commission should consider all the evidence in determining ROE, including its use of the Risk Premium model and the CAPM.

Mr. Pender used a standard DCF analysis to estimate the required ROE for NSP. He used the average of the monthly high and low stock prices and dividends paid for the last one and two years to calculate the dividend yield, adjusted to account for the increase in dividends for the first year. At the time the case was filed, Mr. Pender calculated the dividend yield to be 6.61%. The growth rate was estimated by averaging ten-year (1979-89) historical growth rates in dividends, book value and earnings per share. Mr. Pender used ten years to account for a wide range of economic and financial conditions. He estimated the growth rate to be 6.90%. The result of his DCF analysis yielded an ROE of 13.51%.

NSP also performed a comparable-group DCF analysis. For its comparable group, NSP selected a group of 23 AA-rated utilities. Mr. Pender calculated a comparable group dividend yield of 7.26% and a growth rate of 5.41%, for an ROE of 12.67%.

The intervenors argued that although their more recent data produced a higher dividend yield, Mr. Pender's growth rate was so inflated as to render his DCF analysis useless to determine the required cost of equity for NSP. The RUD-OAG argued that investors do not rely exclusively on ten-year data; they also consider shorter periods such as five-year historic periods in determining growth expectations. The RUD-OAG noted that Mr. Pender has testified in previous cases (Dockets E-001/GR-85-558 and E-002/GR-87-670) using five-year trends as well as ten-year trends. NSP also reports its five-year trends to analysts.

The RUD-OAG further argued that Mr. Pender used the incorrect ten-year period for estimating growth rates. The RUD-OAG asserted that using the most recent ten-year period of 1980-1990 would have produced a mechanical average rate of 6.21%, while averaging five-year data with ten-year data ending 1990 yields a growth rate of 4.8%.

NSP contended that the RUD-OAG's criticism of Mr. Pender's analysis demonstrates the inherent subjectivity involved in calculating growth rates using the DCF model. NSP did not place reliance on five-year trends because such trends indicate declining earnings which NSP does not anticipate will continue into the future.

Mr. Pender presented his risk premium analysis by calculating the average premium for stocks of the comparable group (23 AA-rated utilities) over those utilities' first mortgage bonds. He calculated a risk premium of 4.64% over an average yield of 9.59% on first mortgage bonds for an ROE determination of 14.23%.

In general, the intervenors argued that the risk premium determination was unreliable due to its volatility and uncertainty. RUD-OAG witness Marcus testified that by using a fifteen year period rather than the nineteen year one, Mr. Pender's model would yield a result of 15.98%. The RUD-OAG also argued that the Commission has consistently rejected the risk premium analysis.

NSP argued that the use of the nineteen year period encompassed a range of complete market cycles and, if anything, produced a conservative estimate of risk premium. It cited two cases in

Iowa in which the Iowa Utilities Board used the risk premium model to determine the appropriate rate of return.

NSP witness Mr. Pender also used the CAPM to estimate NSP's ROE The CAPM estimates a company's cost of equity by "measuring" its response to systematic risk. The CAPM is applied by calculating a risk premium for the market over a risk free rate and multiplying it by the Company's beta (a statistic which measures the company's systematic risk relative to the market) to arrive at a company-specific risk premium. This risk premium is then added to the risk free rate to arrive at the required ROE. The beta is estimated by several services, such as Value Line and Compustat.

Mr. Pender determined the market risk premium using a study by Ibbotson and Sinquefield which covers a time period of 1926 to 1988. The equity market risk premium in the study is 7.4%. Using the Value Line beta for NSP of 0.75 and a risk-free rate of 8.52% (the average of one and two year T-bond yields), Mr. Pender estimated the CAPM ROE for NSP of 14.07%. The CAPM ROE for his comparable group, using an average beta of 0.65, was 13.33%.

Intervenors argued that the CAPM is similar to a risk premium method and a great deal of subjectivity exists in estimating the beta. The Department pointed out that by using the Compustat beta of 0.453 for NSP rather than the Value Line beta, the CAPM ROE would be 11.87%.

NSP replied that *all* methods of estimating ROE are subjective, including the DCF method. NSP believes that the DCF should not be used in isolation and that the Commission has an obligation to consider all of the evidence on ROE, including its results for the risk premium model and the CAPM. NSP cited a recent Wisconsin decision in which CAPM was used as a partial basis for setting ROE.

Mr. Pender, using the three models above, calculated a range of ROE for NSP from 13.51% (his DCF result) to 14.23% (his risk premium result). For the comparable group, he calculated a range of 12.67% (DCF) to 14.23% (risk premium). He recommended a return of 12.75% to fully reflect his expectations of a general economic downturn. To corroborate his studies, Mr. Pender cited 1990 return on equity decisions ranging from 12.00% to 15.76%, and averaging 12.77%. NSP-Wisconsin was allowed a 12.75% ROE in its most recent rate case, which set rates for a 1991 test year. California, which sets ROE annually for its utilities, established ROEs for 1991 ranging from 12.85% to 13.05%.

NSP argued that returns allowed in other jurisdictions are relevant because NSP must compete nationally with other utilities for equity capital. NSP's ROE must be considered competitive with others or its ability to finance maintenance and construction would be impaired.

The Department claimed that Mr. Pender's own recommendation of 12.75% discounted the reliability of any of his model estimates. Intervenors pointed out that other jurisdictions were irrelevant to NSP's specific cost of capital, and that 1990 determinations did not contain current information.

Department of Public Service- Department Witness Thompson recommended a 12.10% ROE. He relied on a DCF analysis of NSP data and of a comparable group of utilities.

Dr. Thompson took the average of the 20 day yield (as of April 18, 1991), the fourth quarter 1990 yield, the one-year annual yield and the two-year annual yield to derive a dividend yield range of 6.75% to 7.0%. He used 6.85% as a reasonable estimate of dividend yield. In determining growth rate, Dr. Thompson looked at 5 and 10 year growth rates on book value per share (BPS), dividends per share (DPS), and earnings per share (EPS) as well as log linear rates. He concluded that an appropriate range of growth rates would be 3.5% to 7.0%. He concluded that the midpoint of that range, or 5.25%, was the appropriate growth rate. Therefore, he estimated the cost of equity for NSP at 12.10%.

To test his analysis, Dr. Thompson performed a comparable group DCF analysis on 12 electric utilities with similar betas and Price Stability Indices. He used both an electric group and a combination gas/electric group. Applying the same method as in his NSP analysis, he determined an ROE range for the combination group from 10.8 to 11.2% and for the electric group from 12.4 to 12.6%.

NSP criticized Dr. Thompson for failing to adjust his dividend yield for first year dividend growth. NSP also argued that Dr. Thompson disregarded higher historical growth data in developing his range and that he gave equal weight to historical data and analysts projections. NSP believes projections should be given little weight because it is not known how forecasts are made. The Company believes the Commission should find its own growth rate through analysis of objective data rather than relying on unknown formulas and assumptions of analysts.

NSP also noted that Dr. Thompson's analysis demonstrated the wide range of possible values obtained using a DCF analysis. The low to the high point in Dr. Thompson's range represents $66 million in revenue requirements when applied to NSP's rate base. NSP argued that parties rely on DCF because it produces a low result, not because it is less subjective than other models.

The Department argued that the DCF method is the most basic and fair methodology to estimate ROE. The Minnesota Public Utilities Commission has consistently used DCF in making its determinations of appropriate rates of return for Minnesota. Dr. Thompson pointed out that his growth range excluded both high and low values.

The Department believes that the goal of regulation is met when rates are set at the lowest level which allows the utility to earn a return sufficient to meet legal standards.

Office of the Attorney General - RUD-OAG witness Marcus recommended an ROE of 11.7%. He relied on a DCF analysis of NSP data, using a DCF study on comparable utilities as a check.

Dr. Marcus estimated NSP's dividend yield at 7.1% by taking an average of 12 monthly dividend yields from May, 1990 to April, 1991 and adjusting it forward to reflect the increase in the dividend during the first year. He derived a growth rate of 4.5% (from a range of 3.3% to 5.6%) by looking at 5 and 10 year dividend growth, estimated growth from retained earnings, and analysts' growth forecast from the Institutional Brokers Estimate System (IBES). Dr. Marcus testified that, since NSP has recently achieved its target dividend payout ratio of 65 to 70 percent of earnings, dividend growth is more likely to match earnings growth than exceed it in the future. Adding the 7.1% dividend yield and the 4.5% growth rate produced an ROE of 11.6% for NSP.

For his comparison group, Dr. Marcus used the twenty-nine largest electric utilities (ranked by revenues) on the New York Stock exchange, after excluding nuclear-constructing utilities and those utilities which have reduced or eliminated dividends. Applying the same methodology as in his DCF analysis of NSP, he found a dividend yield of 7.7% and a growth rate of 4.0%, for an average cost of equity of 11.7% for the comparison group. Dr. Marcus reasoned that, since there is very little difference between the results for NSP and the comparable group, NSP's ROE could be reasonably estimated at 11.7%.

NSP noted that Dr. Marcus, like other intervenors, relied exclusively on the DCF method for NSP and comparable groups, without regard for other methods and checks. NSP noted that although Dr. Marcus stated that analysts' predictions are too low, he used those predictions to form the low end of his growth range. NSP argued that the retained earnings model is very subjective and should not be relied on. NSP demonstrated that a simple average of five and ten year growth in book value and dividends, using Dr. Marcus' data and yield, would produce a growth rate of 5.67% and an ROE of 12.77%.

The RUD-OAG replied that NSP simply objects to Dr. Marcus' using too much relevant data. Analysts' forecasts are widely available to investors and should not be completely ignored. The RUD-OAG also argued that Dr. Marcus' approach, which is to apply expert judgment to the circumstances surrounding his data, was more appropriate than mechanical manipulation of the data. Dr. Marcus thoroughly explained why investors may or may not rely on certain types of data in formulating his growth recommendation.

North Star Steel - NSS witness J. Bertram Solomon recommended an ROE of 11.0%. He relied on a DCF analysis of NSP data. He did not use a comparable group analysis.

Mr. Solomon used a six-month average dividend yield ending April, 1991 to derive a dividend yield of 6.93%. He adjusted the yield forward to account for the first year's growth in dividends. Based on his range of growth estimates, this produces a dividend yield of 7.06% to 7.1%. After looking at ten-year historical growth rates in dividends, earnings and book value per share, estimated growth from retained earnings and analysts' forecasts, Mr. Solomon estimated a range of growth rates from 3.70% to 4.79%. His resulting estimate for NSP's ROE ranged from 10.76% to 11.89%. Mr. Solomon also added a flotation cost adjustment of 0.08% to reflect the cost of future issuance of common equity for a range of 10.84% to 11.97%. He selected 11.0%, a number near the low end of the range, to give more weight to analysts' forecasts and the recent downward trend in NSP's growth rates for book value, dividends and earnings per share.

NSP criticized Mr. Solomon's analysis because it placed too great a weight on analysts' forecasts and assumed very low numbers for the application of the retained earnings model. NSP suggested that by using Mr. Solomon's historical data, the growth rate could be estimated at 5.45% for an ROE of 12.47%. Eliminating volatile earnings per share numbers would produce an ROE of 13.32%.

NSS replied that the analysts' forecasts are supported by NSP's own projections to increase dividends by 10 cents each year for the next five years. This would correspond to an initial growth rate of 4.4%, declining to 4% by the fifth year.

Minnesota Energy Consumers - MEC witness Dahlen did not provide a comprehensive ROE analysis on NSP data. He did, however, recommend that the Commission use the FERC benchmark rate for NSP's ROE. MEC argued that the benchmark rate contains the best available information because it utilizes a DCF approach, reflects recent financial markets, and is established through a more comprehensive process than an individual rate case. Mr. Dahlen contended that applying the FERC benchmark rate to NSP was fair because, due to the lower risk of NSP, it would be justifiable to offer them a lower return than an industry average such as the benchmark. At the time Mr. Dahlen filed his testimony, the FERC benchmark was 12.02%.

NSP noted that the Commission is free to take judicial notice of the FERC benchmark rate regardless of whether it was in testimony. NSP pointed out that even the FERC does not automatically adopt the benchmark rate, and that it could be used by the Commission as an advisory reference point on the industry. However, NSP argued that relying on it exclusively would be an abrogation of the Commission's duty to set the appropriate rate of return for NSP.

3. Recommendation of the ALJ

The ALJ found that the appropriate test year return on equity for NSP was 11.9%. He arrived at this number by balancing the testimony of the intervenors' witnesses Dr. Thompson, Dr. Marcus and Mr. Solomon. He stated that NSP failed to sustain its burden of proof that its cost of equity was 12.75%.

The ALJ found that the DCF method was the best available method for calculating investors' required return on equity for NSP. He determined that the appropriate dividend yield was 7.1%, which equaled Dr. Marcus' dividend yield and approximated Mr. Solomon's estimated yield and Dr. Thompson's one-year dividend yield. The ALJ found an appropriate growth rate of 4.8%, which was also a balance of the recommendations of the three intervenors who submitted ROE calculations. The ALJ gave Mr. Solomon's recommendation less weight than the other witnesses because of his reliance on analysts' forecasts which were discounted by Dr. Marcus, and because of his reliance on the low end of the growth range.

The ALJ agreed with the intervenors that the goal of regulation is met when rates are set at the lowest level consistent with the opportunity to earn a return sufficient to meet the *Hope* and *Bluefield* standards. He rejected NSP's analyses, stating that the DCF growth rate was overstated due to reliance on the less current 1979-89 period. The risk premium data has been consistently rejected by the Commission and the data in this case demonstrated volatile fluctuations in return from year to year. He also found that the CAPM was unreliable due to the potential variability in beta estimates.

The ALJ rejected NSP's use of bond ratings to select risk-comparable companies, stating that bond rating alone is not an appropriate measure of investment risks for common shareholders. He endorsed the comparable-group DCF analyses performed by Drs. Marcus and Thompson as a reasonable verification of results obtained on NSP-specific data.

In Part II of his report, the ALJ clarified his growth rate analysis. He found that he had inadvertently stated that Dr. Marcus' growth recommendation was 4.6% when it was actually

4.5%. Applying the ALJ's weighting formula from part I, the growth rate would have been 4.75%. The ALJ has, however, determined not to change his recommendation of a 4.8% growth rate due to the subjective nature of growth rate determination, the insignificance of the difference, and the fact that 4.8% accords less weight to Mr. Solomon's recommendation, which the ALJ views as biased toward a low ROE.

4. Commission Findings and Conclusions

The Commission finds that the appropriate return on equity for NSP in the test year is 12.1%. In making that determination, the Commission fully adopts the testimony of Department witness Dr. Luther Thompson.

The Commission agrees with the ALJ that the DCF method is appropriate for determining the cost of equity for NSP. The DCF method is firmly grounded in modern financial theory, and has been relied on by the Department, RUD-OAG, and NSS in this proceeding and by this Commission in nearly every case decided since 1978. The Commission finds it is reasonable to place primary weight on a direct DCF analysis of data for NSP since NSP is actively traded in the market and its price, dividends and past performance are directly observable.

The cost of common equity cannot be directly observed in the marketplace but can be inferred from market data with the application of reasoned judgment. The DCF method seeks to estimate the return expected by investors by using the current dividend yield plus the expected growth in dividends.

After careful evaluation of the record in this case, the Commission concludes that Dr. Thompson's analysis provides the most reasonable balance of long- and short-term market data and expert judgment in determining the appropriate ROE for NSP. Dr. Thompson looked at both shorter (20 day and three month) and longer (one and two year) periods in calculating the dividend yield and estimated a yield of 6.85%. The Commission finds that this dividend yield appropriately recognizes and captures expected trends in the dividend yield during the anticipated regulatory period.

While the current dividend yield is fairly easily observed in the market, the determination of the appropriate growth rate is much more subjective. The Commission must determine the rate at which investors expect NSP dividends to grow in the future. In applying the DCF method, it is reasonable to assume that investors place some weight on past growth trends in determining future expectations. The analysis of historical data must be tempered, however, with the consideration of current and expected economic trends.

Dr. Thompson's range of growth rates appropriately captures most of the data available to investors for determining growth expectations. His use of five- and ten-year historic data strikes an appropriate balance between recent trends and long-term stability. The use of analysts' forecasts also captures a broad base of expert opinion on future growth rate trends.

Dr. Thompson selected the midpoint of his growth range, 5.25%, as a fair and reasonable estimate of expected growth for NSP. This growth rate is the highest submitted by an intervening party and was presented by Dr. Thompson as a "generous" growth estimate. The Commission finds that 5.25% is an appropriate estimate of growth. Unlike the data used by Dr. Marcus and Mr. Solomon, the growth data used by Dr. Thompson does not include data from the year 1990, when NSP's 1989 general rate increase request was denied in its entirety. The Commission recognizes that the rate case denial may have caused some results in the Company's financial performance for 1990 which investors would not expect to continue into the future. Therefore, it is appropriate to accord 1990 data less weight in this proceeding. The use of 5.25% also accords less weight to anlaysts' forecasts, which are at the low end of the growth range. The Commission agrees with the ALJ that analysts' forecasts should be given less consideration because the decline predicted by analysts for NSP bears little relationship to predictions for the electric industry as a whole.

Combining the 6.85% dividend yield with the 5.25% expected growth rate, the Commission finds that the cost of equity for NSP is 12.10%. The 12.10% is based on substantial evidence in the record and will allow NSP the opportunity to attract capital on reasonable terms and maintain its financial integrity.

The Commission finds that NSP has not sustained its burden of proof in demonstrating that the appropriate cost of equity for NSP is 12.75%. NSP's request is not reasonably linked to any of the methodologies purported to support it. Mr. Pender performed three different analyses, the DCF with a result of 13.51%, the risk premium model with the result of 14.23%, and the CAPM with a result of 14.07%. He also based his recommendation on returns allowed in other jurisdictions and a forecast of a general economic downturn. The Commission finds that Mr. Pender's analysis lacks the clarity and reliability of Dr. Thompson's analysis.

The Commission rejects NSP's exclusive reliance on ten-year historic growth rates in estimating the future growth rate in its application of the DCF model. The ten-year period includes an early period of rapidly increasing returns which investors would not reasonably expect to occur in today's market. Investors also have other data available to assist them in forming their growth expectations, including more recent five-year historic rates and analyst projections of future growth. As noted above, Dr. Thompson's growth analysis accords the appropriate weight to the various data used by investors.

The Commission also rejects NSP's reliance on the risk premium and CAPM models in this case. The Commission has long considered the risk premium model unreliable for use as an estimator of return due to the potential volatility of the results from this method; this record confirms that volatility. If the time period used to calculate the risk premium were shortened by four years, the risk premium would yield a required return of 15.98%, an increase of 175 basis points over NSP's result.

The CAPM suffers from many of the flaws of the risk premium analysis as well as the subjectivity involved in determining the statistic beta. NSP used a Value Line beta of 0.75. At least two other services which publish betas (Standard and Poors and Compustat) provided estimates for NSP which would produce much lower CAPM returns. The Commission finds that the CAPM is not reliable as a primary indicator of return on equity.

The Commission also finds that there is insufficient evidence in the record to support the use of returns awarded to other utilities in other jurisdictions as a check on the return allowed NSP. NSP offered no evidence as to the comparability of the affected utilities to NSP, nor did it offer evidence as to the comparability of other rate jurisdictions to Minnesota. Furthermore, 1990 rate decisions were made based on data for time periods which are likely different from the time periods employed in this 1991 rate case.

The reasonableness of the 12.10% rate of return on common equity for NSP can be confirmed by the comparable group analysis performed by Dr. Thompson. This analysis finds a cost of equity for an electric utility comparable group of 12.4% to 12.6% and for a combination utility group of 10.8% to 11.0%. The finding of a 12.10% ROE is also confirmed by the FERC benchmark rate of 12.02% which was in force at the time intervenor direct testimony was filed. The Commission has not directly adopted MEC's position that the FERC benchmark return should be used as a cap on NSP's allowed return. However, the Commission finds that the FERC benchmark return, which is based on a broad sample of electric utilities, can provide a check on the return found for a specific utility. The 12.02% FERC benchmark rate in force during the test period confirms the reasonableness of the Commission's finding of 12.10% for NSP.

E. Overall Rate of Return

Based upon the Commission's findings and conclusions on return on equity, cost of debt and preferred stock, and capital structure herein, the Commission finds the overall rate of return for NSP in the test year to be 10.04%, calculated as follows:

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Capital Employed	*Percent*	*Cost*	*Weighted Cost*
Long-term Debt	41.98%	8.65%	3.63%
Short-term Debt	0.42	7.78	0.03
Preferred Stock	9.85	6.13	0.60
Common Equity	47.75%	12.10	5.78%
Total	100.00%		10.04%

F. Gross Revenue Deficiency

The above Commission findings and conclusions result in Minnesota jurisdictional gross revenue deficiency for the test year of $53,460,000 as shown below (000's omitted):

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Rate Base	$2,228,283
Rate of Return	10.04%
Required Operating Income	$ 223,720

Test Year Net Operating Income	191,895
Operating Income Deficiency	$ 31,825
Revenue Conversion Factor	1.679825
Gross Revenue Deficiency	$ 53,460

In the test year income statement, the Commission found that the Minnesota retail revenue at present rates is $1,213,735,000. Adding the gross revenue deficiency of $53,460,000 to this amount results in total authorized revenue from Minnesota retail customers of $1,267,195,000.

XV. RATE DESIGN

A. Class Cost of Service Study

1. General Methodology

The Company presented a fully-allocated, stratified, embedded class cost of service study (CCOSS). NSP's stratified cost methodology classifies the fixed costs of baseload plants that are in excess of the costs for a peaking plant as energy-related. NSP argued that a significant portion of fixed production costs are energy-related, because they were incurred in order to acquire the less expensive energy which baseload plants provide. NSP argued that its embedded class cost of service study provides an appropriate benchmark for evaluating proposed class revenue requirements and is consistent with studies approved by the Commission in the last four NSP electric rate cases.

Champion urged rejection of the NSP cost study methodology. Champion contended that the quantity of energy consumed and the rate at which it is consumed are the two important factors when pricing electricity. NSP's stratification method does not reflect NSP's system planning, is too simple to adequately recognize that electricity is taken at various rates, minimizes the demand-related costs in the classification process and encourages a poor system load factor.

Champion offered two alternative embedded cost studies. The first study used a strict fixed and variable cost method to classify costs and used a single summer peak to allocate fixed costs to classes. The second study used the Capital Fuel Substitution method which classified all fuel costs above those incurred in the generation of energy from the most efficient baseload unit as capacity costs.

The Department and the RUD-OAG supported NSP's stratified CCOSS approach, although they did not agree with every detail of the study. They recommended rejection of Champion's cost studies.

The ALJ stated that the embedded class cost of service study proposed by NSP is reasonable, accurately reflects the economics of power production, and is consistent with established Commission precedent. The ALJ rejected Champion's fixed/variable method of classifying production plant costs and Champion's alternative cost study based on Capital Fuel Substitution methodology.

The Commission agrees with the ALJ and finds that NSP's stratified class cost of service study methodology is appropriate. Contrary to the assertions of Champion, NSP's approach properly recognizes the energy-related nature of certain generation costs. A significant portion of the fixed costs of more expensive baseload plants was incurred to produce the less expensive energy needed to meet average demand. The Commission has encouraged this approach and found it reasonable in all NSP electric rate cases since 1977.

Champion's proposed cost studies do not reflect cost causation and are therefore not adopted. Neither the fixed/variable nor the capital fuel substitution methods recognize the dual role of baseload plants for providing both energy and capacity.

The Commission believes that refinements to the way certain specific costs were classified or allocated in the NSP study are reasonable, as discussed below.

2. Allocation of Winter Peaking Costs to Interruptible Customers

The Company allocated winter peaking plant costs to the interruptible subclass in its CCOSS, based on the characteristics of Peak-Controlled customers. Peak-Controlled customers can be interrupted only at a peak or for a system emergency. Because NSP is a summer peaking utility, these customers have not been interrupted in the winter. NSP argued that Peak-Controlled customers do not contribute capacity to the system during the winter, receive essentially firm service and, therefore, should be allocated winter peaking capacity costs. In contrast, Energy-Controlled customers can expect to be interrupted during both summer and winter periods when NSP must burn oil or purchase an equivalent-priced fuel, as well as for system emergencies and at peak times.

The Department stated that NSP appropriately allocated winter capacity costs to peak-controlled customers because these customers do not contribute capacity in the winter through interruption. The Department argued that the key issue is whether the Company's system planners can count on these loads being off-line when they estimate the amount of marketable capacity and suggested that the evidence shows Peak-Controlled customers are treated as firm customers in the winter.

The Metalcasters and NSS contended that it is inappropriate to allocate winter peaking plant costs to the interruptible class. These parties stated that while NSP may choose not to interrupt Peak-Controlled customers during the winter period, the Company still has the right to do so. Thus NSP does not need to consider interruptible load in the planning to meet system load. NSS argued that the allocation of winter peaking costs to interruptible customers ignores the interruptible class's contribution to NSP's diversity exchange agreements which allow NSP to minimize peaking capacity in both summer and winter.

Since peak-controlled customers are virtually never interrupted during the winter, the ALJ believed it appropriate to treat winter interruptible loads as being essentially firm for costing purposes.

The Commission finds that it is inappropriate to allocate winter peaking costs to the interruptible subclass. The fact that NSP has the right to interrupt Peak-Controlled customers in the winter allows the Company to exclude these loads when planning winter peaking capacity needs and provides a benefit to the system. Interruptible customers by their nature do not cause peaking costs to be incurred, although they may benefit from their incurrence under some circumstances. This benefit can be taken into account when setting a reasonable interruptible discount and pricing interruptible service, but does not justify improper cost assignment in the class cost of service study.

3. Allocation of Conservation, Load Management and Economic Development Costs

The Department recommended modifications to NSP's CCOSS with respect to the classification of conservation expenses, load management capital costs and economic development expenses. NSP classified these costs as 50 percent demand-related and 50 percent energy-related. The Department contended that these costs should instead be classified based on a more detailed analysis of the reasons the costs are incurred. The Department recommended that conservation costs be classified as 55.6 percent capacity-related and 44.4 percent energy-related, that load management capital costs be classified as 97.5 percent capacity-related and 2.5 percent energy-related, and that economic development expenses be classified as 59.3 percent capacity-related and 40.7 percent energy-related.

The ALJ agreed with the Department's proposed modifications

The Commission finds the Department's approach to be reasonable. It is preferable to classify costs based on the reason they are incurred because a more reasonable allocation of costs to customer classes results. The Commission notes that the modifications would cause little change in the CCOSS results in this case since the level of the costs involved is relatively small. In future cases, NSP will be required to classify conservation, load management, and economic development costs based on the principles set out by the Department.

4. Distribution Cost Classification

Utility distribution plant is installed to extend service to customers and to meet their peak demand requirements. Because this distribution plant serves two purposes, total distribution costs are classified as both customer and demand-related. Imputing a minimum distribution system is a common method for deriving this breakdown. If utilities were concerned with only extending service to customers and meeting their minimum requirements, they would install the smallest possible distribution system. The cost of installing this theoretical minimum system is then classified as customer-related, while remaining distribution costs are classified as demand-related.

The Department recommended that NSP be ordered to study its method of classifying and allocating distribution costs, to evaluate the need for adjustments and to present the results of the study with its next rate case filing. The RUD-OAG supported the Department recommendation, as did the ALJ.

The Commission finds that it is reasonable to adopt the Department recommendation, because NSP's current method of classifying distribution costs may not recognize certain load-carrying capabilities of the minimum distribution system. Therefore, the Commission will direct NSP to study its method of classifying and allocating distribution costs to provide more accurate cost information in the future. NSP will be required to present the results of the study in it next rate case filing, along with any appropriate adjustments to its cost study.

B. Class Revenue Responsibilities

NSP's CCOSS indicated that major classes were paying rates that were very close to cost. Based on this study, NSP proposed an across the board increase to major customer classes. Specifically, NSP proposed to apply the overall increase of 8.1 percent to residential and commercial/industrial customers, an 8.3 percent increase to sales to public authorities, and a 2.3 percent increase to lighting customers.

The Department and RUD-OAG recommended that the Commission accept NSP's proposed apportionment of revenue responsibilities.

Champion recommended that the residential class receive a greater than average increase, with a correspondingly lower increase to the commercial and industrial customer group based on the results of its fixed/variable cost study. Champion also made allocation recommendations based on its capital fuel substitution study.

The ALJ found NSP's proposed class revenue allocations to be just and reasonable.

The Commission finds that the revenue allocation to major classes proposed by NSP is reasonable, when adjusted proportionately for the lower revenue requirement ordered herein. This class revenue allocation is consistent with the results of NSP's class cost of service study adopted by the Commission and will provide continuity with past rate levels for major customer classes.

The Commission will discuss the relative increases for General Service and interruptible customers in Section D, Interruptible Rates, of this Order.

C. Residential Rates

1. Conservation Rate Break (CRB)

The Company proposed to reduce the conservation rate break credit from $3.50 to $2.50 for customers who use 300 kWh or less per month and from $1.75 to $1.25 for customers who use between 301 to 400 kWh per month. NSP would continue to phase-out the CRB in future rate cases. The Company argued that the CRB is not cost effective, that no significant conservation is achieved by customers who qualify for it and that there is a low level of customer awareness of the CRB. NSP contended that whether a customer receives the credit or not depends more upon lifestyle and demographics than actual efforts to conserve energy.

The Department supported the Company's proposal to reduce the conservation rate break. The Department argued that the CRB is fundamentally unfair because it transfers wealth among residential customers and is a flawed rate design because it sends improper price signals to customers. Also, the Department argued that the CRB fails to accomplish its major goal of promoting cost-effective conservation, as low electric use, not conservation, determines whether a customer qualifies for the credit.

The RUD-OAG opposed reducing the CRB credit. The RUD-OAG contended that the Company did not meet its burden of proving that the credit is not effective for promoting conservation or income transfer. The RUD-OAG stated that low energy lifestyles should be rewarded and that this was a part of the Commission's intent when the CRB was created. The RUD-OAG argued that NSP ignores one of the purposes for the establishment of the CRB which was to lower bills for essential uses of electricity, i.e. a lifeline rate. The RUD-OAG recommended that the Commission require a study involving the Company and outside parties to more appropriately evaluate the effectiveness of the CRB.

The ALJ agreed with the arguments of the RUD-OAG. He also contended that there would be a dramatic rate increase for low-use and low-income customers if NSP's proposal were adopted.

The proposal to reduce the conservation rate break poses a dilemma for the Commission. The Commission is committed to the promotion of cost-effective conservation and with the provision of basic electric service at low cost. Unfortunately, the Commission must agree with the Company and the Department that the CRB, as it is presently structured, is not a cost-effective method of promoting conservation and does not provide particularly effective aid to low income customers.

When the conservation rate break was developed and adopted by the Commission in 1978, NSP offered few conservation programs to residential customers. Since that time, however, a wide array of conservation programs have been developed for residential customer, including home energy audits, appliance rebates, and educational programs. The Commission believes continued development of cost-effective conservation programs aimed at the residential class will be more effective at promoting energy conservation and efficiency than continuing the CRB at its present level. The Commission also encourages exploration of alternative rate designs that would more effectively promote conservation in future cases.

The Commission recognizes the shortcomings of the CRB as a vehicle for providing affordable electricity to low-income customers. However, the Commission is reluctant to permit full elimination of the CRB in the future without a thorough examination of options for more effectively meeting this goal. The Company will be directed to provide a thorough discussion of alternatives for addressing low income energy needs in its next rate case filing. Other special circumstances, such as medical needs, should also be addressed. The Department, and other interested parties, are strongly encouraged to do likewise.

Based on the above, the Commission will adopt NSP's proposal to reduce the CRB in this proceeding. The Commission finds that the reduction will not unduly impact customers who currently receive the credit, because the dollar amount of the change is relatively low and the revenue increase to the residential class ordered herein is lower than under NSP's original filing.

2. Electric Space-heating Rate

NSP proposed to increase the current winter end-step differential of approximately 0.2 cents per kWh to 1 cent per kWh for all kWh in excess of 1,000 kWh per month. However, this end-step would apply to electric space heating customers only. The Company argued that there are cost considerations which support the end-step differential and also that the lack of a differential would cause severe billing impacts on space heating customers.

The Department and the RUD-OAG proposed the creation of a separate space heating rate. This proposed rate: 1) has flat energy charges in winter and summer, with the summer rate the same as under the standard residential rate, 2) has customer charges of $5.00 for overhead service and $7.00 for underground service and 3) requires that customers who receive service under the rate use electricity as the primary source for space heating. The Department and the RUD-OAG argued that flat rates send appropriate price signals to customers, more accurately reflect the costs of providing service and moderate any billing impacts for space heating customers through a reduced energy charge.

These parties recommended that the Commission require the Company to file a plan indicating how customer reliance on electric space heating can be verified and how new customers on the rate, who have no alternative heating source, can be identified.

The Senior Federation supported the agencies' proposal because it removes a conservation disincentive by removing declining block rates and moderates the billing impact of removing the end-step differential through a reduced energy charge.

The ALJ found it reasonable for the Commission to eliminate declining block rates because such rates send improper price signals to ratepayers. Also, flat rates better reflect NSP's incremental costs. The ALJ agreed with the arguments of the Department and RUD-OAG in support of their proposal.

The Commission notes that both the NSP and state agency proposals attempt to better reflect costs while giving some relief to electric space-heating customers. The Commission prefers the Department/RUD-OAG proposal to establish a separate space-heating rate. The separate rate will eliminate the winter end-step in the current rate. The resulting flat rate will send better price signals to customers. A separate space-heating rate may also allow more effective monitoring and evaluation.

For the reasons stated above the Commission finds that the Department and RUD-OAG proposal for a separate space heating rate is reasonable. The Company shall be required, as part of its compliance filing in this case, to file a plan indicating how it will identify customers who qualify for this rate.

3. Inverted Rate Structure

The Senior Federation proposed an inverted rate structure, in which successive blocks of increased kWh usage are priced at successively higher prices. According to the Senior Federation, such a rate would make customers contribute revenues in proportion to their contribution to peak demands, provide conservation incentives, and reduce peak demands. The Senior Federation submitted load curve data which it claimed provided cost support for its proposed rate structure.

NSP and the Department argued that flat rates better reflect the costs customers impose on the system. In addition, they argued that the Senior Federation's proposal does not take into account when a customer uses electricity, only how much a customer consumes. These parties contended that the load data submitted by the Senior Federation showed that flat rates, not inverted rates, were cost-justified.

The ALJ agreed with NSP and the Department, finding that the record supports the continuation of flat rates because flat rates more accurately reflect the cost of providing service.

The Commission finds that the inverted rate structure proposed by the Senior Federation is not supported by the record. The load data presented by the Senior Federation shows that all sizes of residential customers tend to use electricity similarly during the day; higher use customers do not seem to consume a disproportionate amount of their electricity on-peak when compared to smaller customers. Not surprisingly, the Senior Federation data indicates that customers who use more energy also tend to have higher demands. However, they also pay higher bills. The Commission finds that flat residential rates reasonably account for increased costs related to increased use.

4. Customer and Energy Charges

The Company proposed to maintain the standard residential customer charges at their current levels and to increase energy charges by 9.6 percent for winter, 14.2 percent for winter-excess and 8.2 percent for summer.

The Commission finds that the Company's approach is based on the results of its CCOSS and is reasonable, when adjusted to recognize the lower revenue requirement granted and the separate space heating rate adopted herein.

5. Residential Time of Day Rate

This rate was developed to be compatible with the standard residential rate. The Company proposed to reduce the customer charge from $9.50 to $9.00 with an average increase in the energy charge of 9.16 percent. No party contested the proposed residential TOD rate. The ALJ found that the specific changes to the residential TOD rate proposed by NSP should be adopted.

The Commission finds that NSP's proposal for residential time of day service reflects the results of its CCOSS and is reasonable. The energy rate must be adjusted to reflect the lower revenue requirement and to be compatible with the standard residential rate discussed above.

D. Interruptible Rates

NSP offers two types of interruptible rates: Peak-Controlled (both standard and time-of-day) and Energy-Controlled. Peak-Controlled customers can be interrupted only when approaching system peak or for a system emergency. Energy-Controlled customers may be interrupted when NSP must burn oil or purchase equivalent-priced energy, as well as at times of peak and system emergency. Under existing rates, Peak-Controlled customers receive a $2.91 per kW demand charge discount (44%) and Energy-controlled customers receive a $3.10 demand charge discount (47%) compared to the General Service rate.

NSP proposed to continue the same dollar amount of the interruptible demand discount. The proposed changes in the basic customer, demand and energy charges reflect the same changes proposed for the corresponding firm General Service rates. Thus, while for the commercial/industrial group NSP's proposed increase is 8.1 percent, Peak-Controlled customers would see an increase of 10.9 percent and the Energy-Controlled group would receive a 11.1 percent increase.

NSP contended the pricing of interruptible service should be based in part on value of service concepts. The Company argued that interruptible service is not primarily a utility service, but rather a source of supply. NSP asserted that current demand discounts attract a sufficient number of interruptible customers at this time and will continue to do so.

The Department supported NSP's proposed interruptible rates and pricing concepts. The Department recommended not raising interruptible discounts before it is clear more interruptible supply is needed. The Department suggested that the Commission order NSP to file a report exploring different interruptible options, such as establishing a priority schedule with respect to interruption of different customer groups and that interested parties be allowed to comment on NSP's filing.

NSS, Champion and the Metalcasters all opposed NSP's interruptible rate proposal and value of service pricing concept. They argued that at a minimum, the same percentage interruptible demand discount must be maintained to preserve the value of the discount. These parties contended that a cost-based discount would be significantly greater.

The Metalcasters contended that the costs of complying with interruptible tariffs has increased, at the same time NSP is proposing to reduce the value of the discount. The Metalcasters also argued that interruptible customers are receiving only a small part of the benefit they provide to the NSP system.

Champion argued that under the value of service or any other costing standard, NSP's interruptible demand discount is not commensurate with the benefit which the interruptible class is providing NSP in available capacity at peak and emergency periods.

NSS proposed to increase the interruptible discount to $5.12 as a reasonable movement toward the long-run marginal cost avoided by each KW of interruptible demand. Using the marginal cost of a combustion turbine plus the marginal peaking cost of transmission capacity, NSS estimated that a full cost-based discount or credit would be $9.66 per KW per month.

NSS developed a new rate for interruptible service entitled Large Interruptible/Energy-Controlled Service (LIS/EC). NSS argued that the LIS/EC rate's terms and conditions incorporate the best aspects of NSP's interruptible rates with additional considerations to increase flexibility and insure that NSP obtains the maximum benefit from its interruptible program. Some of the terms of this rate would include: 1) a minimum requirement of 5 MW of load, 2) a 10 minute advance notice by NSP, 3) a minimum 5 year contract, 4) limiting interruptions to periods when system capacity is impaired, NSP's system reliability is endangered or when costs of operation exceed a specified measure and 5) limiting interruptions to 150 hours per year, 8 hours per day, and 25 interruptions per year.

The ALJ found that it is not discriminatory to use value of service pricing rather than cost of service to set the discount. He stated that it is reasonable for NSP to price its interruptible discount just high enough to attract customers to meet its supply needs. The ALJ found that it is reasonable to continue NSP's current interruptible discount levels during the test year and to reject NSS's LIS/EC interruptible tariff. He stated it was reasonable to order NSP to file a report that explores different interruptible options.

The Commission finds that the current demand discount percentages should be maintained in this proceeding. Maintaining the percentage relationship preserves the value of the discount to current interruptible customers. NSP's proposal, on the other hand, would result in disproportionate increases for these customers because demand charges would increase while the dollar amount of the discount would remain the same.

The Commission is not convinced that a significant increase in the interruptible discount is reasonable at this time, but would like this issue to be addressed in the future. The Commission is also interested in exploring alternative interruptible rate designs, but is not convinced that NSS's proposed rate is reasonable to adopt at this time.

Therefore, the Commission finds that it is just and reasonable to maintain the 44 percent demand charge discount for Peak-Controlled Service and the 47 percent discount for Energy-Controlled Service in this proceeding. NSP shall make the necessary adjustments to keep these rates consistent with the corresponding General Service schedules and the lower revenue requirement.

A number of parties proposed further study of interruptible rates. The Commission will order NSP to study various interruptible rate design and pricing options, and file a report in its next rate case or by June 1, 1992, whichever comes first. At a minimum, the study should address effects of different advance notice provisions, initial contract periods and cancellation provisions, frequency and duration of interruptions, size of interruptible load, priority of interruptions, and penalties for failure to interrupt. NSP should also provide a discussion of the interruptible potential on its system and what is the optimal level of interruptible load based on its DSM goals. The Commission encourages NSP to seek input from other interested parties.

In addition, the record indicates that NSP includes limits on the number of hours of interruption, and perhaps other similar conditions, in current interruptible contracts with its customers. The Commission is concerned about the potential for unequal treatment of customers under such a policy, since some customers may receive more favorable interruption terms than others who are paying the same rates. As part of the above study, the Commission directs NSP to report on what types of provisions it has in existing contracts and whether the provisions are reasonable.

E. General Service Rates

1. Standard General Service Rate

NSP proposed several changes to its General Service rate. First, voltage discounts would be updated to reflect current costs. Second, a split service provision would be added to allow customers to place their thermal storage equipment on a TOD rate and leave the remainder of the service on the standard rate. Third, the billing demand limiter would be revised to take effect at a 10 percent load factor rather than 7 percent load factor. Both the demand and energy charges would be increased with a larger increase coming in the energy charge in order to equalize the rate of return earned from both the small and large members of this class. A small reduction in the customer charge was also proposed for the same reason.

MEC contended that NSP's rate design for General Service customers is inappropriate because the proposed demand charge is less than the demand cost shown in NSP's CCOSS. This underpricing of demand penalizes high load factor customers and will not stimulate enough demand conservation to be consistent with the Company's demand-side management goals. MEC proposed that any increase in the General Service rate be applied to the demand charge, leaving energy rates at present levels. In addition, the Commission should require NSP to communicate that future increases in rates will be made in the demand charge and that customers should begin to manage the demand they place on NSP's system.

Champion argued that by emphasizing energy charges compared to demand charges NSP is sending a signal to its customers to reduce load factor and to disregard peak demand imposition. These signals conflict with NSP's demand-side management program goals. Champion proposed to equalize the revenue increases derived from the demand and energy charges, increase the seasonal demand charge from $2.25 to $2.50 per kW and create a tariff block for the first 50 kW of demand. The charge for this block would be $0.16 per kW less than that for all firm demand in excess of 50 kW.

The Department recommended that General Service customers with usage of 500 kW or more be required to take service under time-of-day rates. (A more detailed discussion of the Department's proposal can be found in the following section).

The ALJ found that it is reasonable to recognize that a major portion of plant costs is related to providing energy and therefore, it is unreasonable to adopt the positions of MEC and Champion. The ALJ noted that to increase demand charges by too much or too quickly sends an improper price signal to customers, leading to uneconomic investments in equipment or production processes.

The Commission finds NSP's proposal for General Service rates to be reasonable. The Commission supports the split service option to allow greater flexibility for customers while providing benefits to the NSP system. NSP's proposals provide a proper balance of energy and demand charge increases. Increasing demand charges significantly, as proposed by MEC and Champion, could send improper price signals by setting energy charges below economic cost, and could thus promote uneconomic energy use.

2. General Service Time-of-Day

No structural changes to the Large General Service time-of-day rate were proposed by NSP. The metering charge would increase from $6 to $7. The on-peak demand charge would equal the standard rate demand charge, and the off-peak demand charge would recover distribution costs only. The energy charges were de-averaged based on marginal cost considerations. The split service and billing demand limiter features proposed for the Large General Service class would also apply.

The Department recommended that time-of-day rates be required for all large General

Service customers whose demand exceeds 500 kW per month. These proposed rates would be similar to NSP's current voluntary TOD rates for firm General Service customers.

The Department claimed that requiring TOD rates was fair and reflected cost causation. Under the current system, customers who use more during off-peak periods subsidize customers who consume during peak periods. TOD rates could also provide an incentive for customers to conserve energy on-peak or to shift load to lower cost off-peak periods. The Department recommended that the transition to TOD rates be implemented over a nine month period to allow customers to weigh their options to minimize their energy costs.

NSP opposed the Department's mandatory TOD rate proposal because current voluntary TOD rates have been effective, the benefits of the mandatory program may not be immediate or certain and customers required to move to TOD rates may not be receptive. Also, NSP estimated that a mandatory program would involve additional metering costs of approximately $47,000 per year and up-front administrative costs of about $315,000.

The Metalcasters opposed the Department's mandatory TOD rates because they believe it is an ineffective tool for decreasing peak load. The Metalcasters indicated that only a limited number of customers have signed up between 1987 and 1991 for NSP's voluntary TOD rates and that those customers have only effected a 14 megawatt reduction to system peak. In addition, the mandatory TOD rates will reach only 650 customers. The Metalcasters argued that these numbers suggest a very limited potential to further reduce system peak. The Metalcasters argued that the Department's proposal violates the principle that rates should provide a reasonable continuity with past and future rates and should prevent an inordinate and immediate impact on existing and future customers.

The ALJ concluded that the potential for a more equitable distribution of cost sharing within the commercial and industrial class through the imposition of mandatory TOD rates outweighs the billing impacts on the customers who are being subsidized, administrative inconveniences and the problems with customer acceptance. The ALJ was persuaded that the split service option could produce positive benefits and should be adopted if mandatory TOD rates are not adopted.

The Commission finds it is not reasonable to require time-of-day rates for large General Service customers at this time. Such rates could have a serious negative impact on existing companies who cannot shift load due to the nature of their business, with little potential for off-setting benefit to NSP. Also, the Commission is concerned that the administrative and materials costs of implementing this proposal would be excessive. The Commission finds that NSP's General Service time-of-day rate proposals should be adopted, with rate levels adjusted for the lower revenue requirement.

F. Competitive Electric Rates

The Company proposed a rate schedule entitled Competitive Service Rider (CSR). The CSR is applicable to commercial and industrial customers of 500 kW or more and where effective competition exists. The rider develops a framework which NSP would use to negotiate rates with individual customers. The application of the rate schedule requires the development of a specific rate for each customer and the approval of the Commission.

Regular service provisions would still apply under the CSR, but the demand and energy charges would be negotiated. The upper limitations on the rate level are the charges contained in the regular applicable service schedule. The minimum level is determined by the Company's short run marginal cost plus an incremental margin of 0.2 cents per kW.

The Department recommended two modifications to the Company's proposed CSR. The first modification was to make the language of the CSR explicitly state that the annual minimum charge was set to recover the distribution costs. The second modification was to require the Company to provide an energy audit to customers receiving service under the CSR.

The Administrative Law Judge agreed with the Department's adjustments.

The Commission finds the Company's proposed competitive electric rate schedule is consistent with Minn. Stat. § 216B. 162 (1990). The new rate will allow the Company flexibility where competitive conditions exist. The Commission agrees with the Department's first proposed modification. Since the purpose of the minimum charge is to recover distribution costs, the language in the CSR should be modified to explicitly state that fact.

Regarding the Department's second proposed modification, although the statute expressly authorizes the Commission to require the Company to provide energy audits, the Commission will not do so in this case. In many instances, customers may have recently received such an audit. Instead, the Commission will require the Company in its petition for approval of the customer rate to 1) verify that it has fully informed applicants of the availability of such audits, and 2) if no audit is performed for a customer, to explain why not.

G. Lighting Rates

1. Maintenance of Customer-owned Street Lights

The Company proposed to include a new provision called the Major Roadway Maintenance Surcharge to cover the higher costs associated with the additional personnel and equipment necessary to safely conduct maintenance operations along major roadways.

The Department recommended that the Commission reject NSP's proposal for a Maintenance Surcharge as unnecessary regulation of a competitive service. In its May 29, 1989 ORDER APPROVING TARIFF in Docket No. E-002/M-88-677, the Commission determined that repair and maintenance of customer-owned street lighting was a competitive service but did not deregulate the service at that time.

The Department recommended that the Commission now deregulate all maintenance service for customer-owned equipment and allow electric contractors to compete with NSP to provide the service. The Department suggested that the Company propose reasonable standards for contractors if NSP felt such standards to be necessary.

The Department's proposal is reasonable and the Commission will deregulate maintenance services for customer-owned street lighting in this Order. The Commission previously determined that this is a competitive service. Continued regulation is inconsistent with the fact that customers can obtain such services from other electrical contractors.

Accordingly, NSP's proposed Major Roadway Maintenance Surcharge will be denied. In addition, because the financial effect of deregulation of this maintenance service is negligible no adjustment to NSP's revenue requirement is warranted in this proceeding.

To implement this decision, the Commission will require NSP to file its proposed accounting and allocation procedures for removing this service from regulated operations within 60 days of this Order. Further, the Company may propose reasonable standards which contractors may be required to meet in providing these services. Any such proposals should be filed within 60 days of this Order. The Company's lighting rate schedules are to be modified as necessary to reflect this decision.

2. Other Lighting Service Issues

NSP proposed to increase the revenue responsibility of the street and area lighting class by 2.3 percent overall. NSP performed a specific cost analysis to apply the increase to various components of lighting service. The Commission finds NSP's proposals reasonable when adjusted for the lower revenue requirement and the deregulation of maintenance of customer-owned equipment and will approve them.

The Company also proposed to rename its lighting service from "Company-Owned Equipment" to "Leased Equipment". No party opposed NSP's proposals. The Commission will approve this uncontested proposal.

H. Three Period Time of Day Rate

NSP indicated in its initial filing that it was looking at developing a multi-period rate which would accurately reflect time-varying cost of service. The Company was not proposing the adoption of a three-period TOD rate in this filing but was soliciting comment from interested parties.

The Department of Public Service expressed its concern that the use of multiple or complex periods might be confusing and that introducing a shoulder period may lead to peak chasing. As an alternative the Department recommended refining the hours of peak periods. The Department later stated its opinion that given the lack of response to the Company's solicitation for comments, there is no need to change the current design of peak and off-peak periods.

The Board of Water Commissioners of the City of St. Paul supported the proposal for a three-period TOD rate and would like to see one adopted by the Commission as soon as is practicable. The City intervened and supported this position in *NSP* 89-865. The City maintained an interest in such a rate, but believed it would be unnecessary to intervene in this proceeding, because they expected NSP to propose a three-period rate for adoption. Also, the City indicated it was not able to afford to intervene again in the rate case process.

The Commission is sympathetic to the position of St. Paul. A three period time of day rate could allow municipal pumping customers, and potentially others, to reduce their electric bill while providing a benefit to the NSP system. The Commission believes that the Company has sufficient data and expertise to design a rate with multi-period peak hours. The Commission will order NSP to design and file a multi-period time of day rate in its next rate case, or by June 1, 1992, which ever comes first. At a minimum, the rate should be applicable to the Municipal Pumping class; NSP may propose a rate of wider applicability if appropriate.

I. Other Rate Schedules

1. Standby Service Rider

NSP proposed to reduce the customer charge for the standby service rider rate from $37.00 to $26.00 and to increase the demand charge per month per kW of contracted capacity by 7.6 percent for secondary voltage service and 4.1 percent for transmission transformed voltage service.

The Company indicated that it had complied with the Commission's Order in the 87-670 Docket and included the costs of demand-metered secondary voltage customers and higher voltage customers into the analysis to determine the generation and transmission cost portion of standby service. The Company also examined the merits of using plant availability factors rather than the reserve margin to determine this component of standby rates. The Company chose to continue using the reserve margin method.

No party opposed the Company's proposal.

The Commission acknowledges NSP's compliance with the Order in the 87-670 Docket. The Commission finds the Company's proposed changes to the customer charge and demand charge for the standby service rider rate to be reasonable for the reasons stated by NSP, when adjusted for the lower revenue requirement. The Company's proposal for standby service will be adopted.

2. Energy-Controlled Service (Non-Demand Metered)

NSP proposed no changes to the design of the energy-controlled service rate. The Company proposed to increase the customer charge from $2.50 to $2.75 and to increase the energy charge by 10.3 percent.

No party to this case expressed any opposition to the proposed increases. The ALJ found the adjustments to the customer and energy charges should be adopted.

The Commission finds the Company's proposal for the energy-controlled (non-demand metered) rate to reflect the results of its CCOSS and to be reasonable for adoption, when adjusted for the lower revenue requirement.

3. Limited Off-Peak Service

NSP proposed no changes to the design of the limited off-peak service rate. The Company proposed to increase the customer charges for service under this schedule by approximately. 10 percent and to increase the monthly minimum charge by 16.7 percent and 10 percent for the single phase and three phase customers respectively. Finally, the Company proposed an increase in the energy charge of 10.4 percent for secondary voltage and 11.2 percent for primary voltage.

No party objected to the Company's proposal. The ALJ recommended the Company's proposal should be adopted.

The Commission finds the proposed changes to the limited off-peak service rate schedule to reflect the results of NSP's CCOSS and to be reasonable for adoption, when adjusted for the lower revenue requirement.

4. Small General Service-Standard and TOD

NSP proposed no design changes in the small general service rate. The customer charge remains at $6.60 while the proposed energy charges increase by 9.6 percent for winter and 8.3 percent for summer.

The small general service time-of-day rate was developed to be compatible with the standard rate. The proposed customer charge would be reduced by 2.1 percent to $11.60. The on-peak winter and summer energy charge would increase by 11.9 and 10.1 percent respectively and the off-peak energy charge would increase by 6.2 percent.

No party opposed the Company's proposed rate for the small general service standard or time of day rate. The ALJ found that NSP's proposed rates were unopposed and are appropriate for adoption.

The Commission agrees with the ALJ that the Company's proposals for the small general service rates are appropriate for adoption, when adjusted for the lower revenue requirement.

5. Municipal Pumping and Small Municipal Pumping Rates

The Company proposed to increase the municipal pumping service rate in order to maintain the current relationship to the corresponding general service rate. NSP proposed to increase its small municipal pumping energy charge by 21 percent for winter and 17 percent for summer. NSP argued that the above average increase for this rate schedule is needed to maintain its existing relationship to the corresponding small general service rate.

NSP's proposals were uncontested by any party to this case. The ALJ found the proposal to be just and reasonable.

The Commission finds that the Company's proposals for municipal pumping services should be adopted in this proceeding. The Company's proposal is consistent with the results of the CCOSS, when adjusted for the lower revenue requirement. However, the Commission finds that NSP should make a specific proposal for adoption of a three part time-of-day rate in its next rate case filing as discussed above.

6. Nicollet Mall Service, Fire and Civil Defense Service, Direct Current Service

The Nicollet Mall service rate is used primarily during the winter season to melt snow on the Nicollet Mall. NSP proposed to cancel this rate schedule and move the customers to the Small General Service schedule. This movement results in a 15.7 percent increase.

The fire and civil defense siren service use is generally off-peak and is unmetered. NSP proposed an increase of 7.2 percent to the monthly minimum charge and a 7.6 percent increase to the rate per month per horse power of connected capacity.

The direct current service is closed to new customers. The loads being served on this rate are direct current motors used in elevators in some older buildings. NSP proposed to increase the rates for this service by the same amount as those for the general service rate.

No party opposed the Company's proposal for these rate schedules. The ALJ found NSP's proposed changes to these rate schedules to be just and reasonable and recommended their adoption.

The Commission finds the changes for these rate schedules proposed by NSP to be reasonable, when adjusted for the lower revenue requirement.

7. Excess Energy-St. Anthony Falls Lock and Dam

The Company proposed to increase the excess energy-St. Anthony Falls Lock and Dam rate to bring it in line with the corresponding standard General Service rate. It proposed to increase the demand charge from $3.00 to $4.70 per kW with an increase in the energy charge of 10.1 percent.

No party opposed the Company's proposed rates for this rate schedule. The ALJ found that the Company's proposed rate should be adopted.

The Commission finds it appropriate to increase the rate to correspond with the standard general service rate as adjusted for the lower revenue requirement.

J. Miscellaneous Charges and Provisions

1. Service Connection Charges

NSP proposed to divide its current $10.00 service connection charge into three separate services: processing, service reconnection and service relock. The proposed service processing charge would remain at $10 and would cover the costs of setting up new customer accounts. Service reconnection would be a separate charge of $25 for re-establishing service that has been cut off for customers who have failed to pay their bills. The proposed service relock charge is $100 and would cover the costs when customers tamper with locks which the Company has placed on meters that have been disconnected for non-payment.

The Department agreed to the Company's proposal to split its present service connection charge into three services and to set the processing charge at $10. However, the Department argued that the proposed charges for service reconnection and service relock are not in the public interest. The Department recommended that the proposal be tempered by setting the charges at $15 and $50 for the service reconnection and service relock respectively.

The ALJ found the Department's recommended charges for service reconnection and service relock to be reasonable. The ALJ also stated that the Department's recommended charge of $50 for service relock was high enough to reflect the intended penalty involved.

The Commission finds that the Company's proposals to split its service connection charge into three separate services and to set the service processing charge at $10 is reasonable. The Commission agrees with the Department that a reasonable level for the reconnection charge is $15. The Company's proposed charge of $25 may contribute to another cycle of non-payment of bills. The Commission views the relock issue with the utmost seriousness. Customer tampering with Company equipment is a violation of the law as well as a safety hazard and an infringement on the Company's right to disconnect service for non-payment. The Commission finds the Company's proposed charge of $100 for service relock to be just and reasonable.

2. Trouble Call Charge

Trouble call charges apply when the Company dispatches a service-person to a customer's trouble call. If the trouble is with the customer's equipment and the customer asks the NSP employee to repair or adjust the faulty equipment, the charges apply.

NSP proposed to increase the trouble call charges by an average of 43 percent during business hours and 44 percent for all other hours. The Company argued that the proposed increases for trouble call charges are designed to reflect the costs associated with providing this service.

The ALJ believed it was reasonable to adopt the Company's proposed adjustments.

The Commission finds that NSP's proposed charges are reasonable and will approve them. The Company's proposals maintain a close relationship between the charges to customers and the cost of providing the trouble call service.

3. Excess Footage Charge

NSP usually constructs a customer's service at no charge to the customer. Excess footage charges apply when the length and costs of a customer's service is greater than normal.

NSP proposed to increase the excess footage charges by an average increase of 60 percent. The Company argued that the proposed increase is based on the marginal material and installation expenses incurred for such extensions.

The ALJ stated it is appropriate to adopt the Company's proposed adjustments.

The Commission agrees with the position of the Administrative Law Judge and adopts NSP's proposed changes to the excess footage charge. The percentage increase for this service is significant, but the Commission finds it is reasonable to reflect cost and to minimize the subsidization of customers needing longer than normal service extensions by other ratepayers.

4. Automatic Protective Lighting - Special Extension Charges

The special extension charges are similar to the excess footage charges discussed above. These charges recover the extra or unusual costs associated with providing protective lighting services to a small number of customers who request extra facilities.

NSP proposed a substantial percentage increase for services offered under automatic protective lighting. The Company argued that the changes are proposed to bring the charges for this service closer to cost.

The ALJ stated that it was reasonable to adopt the proposed adjustments of the Company.

The Commission finds that the proposed increases are just and reasonable. The changes reflect cost and insure that customers requesting unusual services from the Company are not subsidized by other ratepayers.

5. Account History Charges

The Company is proposing to increase the account history charge from 50 cents to $1 in order to reflect the higher costs.

The Commission finds the proposed increases to be just and reasonable and supported by the cost information in the record.

6. Returned Check Charge

The Company proposes to increase the return check charge from $10 to $15. NSP argues that the proposed charge better reflects the current cost of $18.

The Commission finds the proposed increase to be just and reasonable and supported by cost data in the record.

7. Business Interruptions

NSP proposed to revise the language in Section 6.3 of the General Rules and Regulations to clarify the language in the business interruptions provision. The revision makes clear that the annual minimum demand charge will be prorated and the demand ratchet suspended in the case of an interruption outside the customer's control.

The ALJ found the proposed change to be reasonable and recommended adoption.

The Commission finds the proposed changes to section 6.3 of the General Rules and

Regulations: Business Interruptions to be appropriate for adoption because they clarify the application of this regulation.

ORDER

1. Northern States Power Company (NSP or the Company) is entitled to increased annual revenues of $53,460,000 to produce total annual operating revenues of $1,267,195,000 from Minnesota retail customers for annual periods beginning March 29, 1991.

2. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all other parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein. The Company shall include proposed customer notices explaining the final rates. Parties shall have 15 days to comment on the compliance filing.

3. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposed plan for refunding to all customers with interest the revenue collected during the interim rate period in excess of the amount authorized herein minus the adjustments authorized in this Order, i.e. $823,000, the amount of the Company's rate case expenses, and $3,674,289, the amount in the CIP tracker account. Following the filing of this plan, the parties shall have 15 days to comment.

4. Within 60 days after all administrative review of this Order has been exhausted, the Company shall file with the Commission, and serve upon all parties, detailed rate case expense documentation. This filing shall include copies of invoices from outside witnesses, counsel, and all other persons, agencies, or businesses to whom rate case expenses were paid. All such documentation shall be identified with the corresponding rate case expense projections in this filing in order to permit comparison.

5. The Company shall incorporate the DRI index, or a comparable industry standard, as a guideline in future rate cases.

6. The Company shall implement the following budget requirements in its next rate case filing:

a. Besides budget documentation filed according to the standards of this Order, the Company shall at the time of filing make support documentation available for inspection by other parties upon request. Such documentation should include workpapers and notes used in developing budgets;

b. The Company shall file translation reports linking cost element, cost activity, and project budgeting mechanisms on a common and consistent basis to ensure a proper audit trail;

c. The Company shall file bridge schedules showing all adjustments used in moving from the unadjusted budget to the rate case numbers;

d. The Company shall provide summaries of all of its applicable budgets by FERC subaccounts. If the Company cannot comply with this requirement it shall show cause within 30 days of the date of this Order;

e. The Company shall include month-by-month accounting of all transactions in the contingent funds;

f. The Company shall provide a year-end summary report of project substitution within each contingent fund by project type and subject benefit.

7. On or before March 1 of each year, the Company shall file a CIP tracker report detailing the activity in all of the tracker elements and proposing the appropriate bonus return on equity and lost revenue recovery.

8. Within 30 days of the date of this Order, and on an annual basis thereafter, the Company shall file with the Commission a proposed notice apprising the Company's customers of their option to be dropped from the Company's mailing lists. The notice shall be included in the next possible Company billing insert following Commission approval of the proposed notice.

9. The Company shall adopt compensation principles set out in the body of this Order, including the following requirements:

a. Advantage Service shall pay a return on the use of NSP's billing services asset.

b. Advantage Service shall compensate the Company for its personnel's referral time.

c. Advantage Service shall pay the Company a competitive rate for use of its mailing lists. The above compensation principles must be reflected in future rate case filings.

10. In future rate case filings, NSP shall classify conservation, load management, and economic development costs as capacity-related or energy-related based on a detailed analysis of the reasons the costs are incurred.

11. In its next rate case filing, NSP shall study its method of classifying and allocating distribution costs to provide more accurate cost information and shall present the results of the study, along with any appropriate adjustments in its cost study.

12. In its next rate case filing, NSP shall provide a thorough discussion of alternatives for addressing the energy needs of low income people and the energy needs of customers with other special circumstances such as medical needs.

13. As part of the filing made pursuant to Ordering Paragraph 2, NSP shall file a plan indicating how it will identify customers who qualify for the newly approved Electric Space-Heating Rate.

14. As part of its next rate case filing or by June 1, 1992, whichever comes first, NSP shall study various interruptible rate design and pricing options and shall file a report as described in

the text of this Order.

15. In petitions to the Commission for approval of Competitive Service Rider (CSR) rates, NSP shall

a. verify that it fully informed the applicant for the Competitive Service Rider (CSR) that NSP would conduct a free energy audit of the applicant's place of business in conjunction with the applicant's consideration of CSR; and

b. if no audit is performed for a customer, explain why not.

16. NSP's maintenance service for customer-owned equipment is deregulated herewith.

Within 60 days of this Order, NSP shall file its proposed accounting and allocation procedures for removing this service from regulated operations.

Any proposals that the Company may wish to file regarding standards for customer-owned equipment maintenance contractors shall be filed within 60 days of this Order.

17. With its next rate case or by June 1, 1992, whichever comes first, NSP shall design and file a multi-period time of day rate. At a minimum, the rate shall be applicable to the Municipal Pumping class; NSP may propose a rate of wider applicability if appropriate.

18. This Order shall become effective immediately.

FOOTNOTES

[1]*NSP*, E-001/85-558, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (June 2, 1986) at p. 9.

[2]*NSP*, E-001/89-865, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (August 28, 1990), pp. 32-35.

[3]The term "improvement requisition" (IR) refers to a form the Company uses to formalize and document project authorization requests.

[4]Improvements that will be required in the other primary budget, the DOE budget, are set forth below at page 25 of this Order.

[5]See more extensive discussion of this subject on page 24 of this Order.

[6]*In the Matter of the Petition of Northern States Power for Approval of a Specific Accounting Procedure for Nuclear Decommissioning Costs of the Pathfinder Atomic Power Plant*, Docket No. E-002/M-89-120, ORDER ACCEPTING AND ADOPTING SETTLEMENT AGREEMENT (September 21, 1989).

[7]*In the Matter of the Petition of Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation, and Oxbow Power Corporation for an Order Resolving a Dispute with Northern States Power*, Docket No. E-002/CG/CG-88-491,*PORDER GRANTING PETITION, CONSTRUING CONTRACT, AND REQUIRING PAYMENT OF COSTS AND ATTORNEYS' FEES (May 11, 1989). ATTORNEYS FEES (May 11,*

[8]*In Re Northwestern Bell Telephone Company*, Docket No. P-421/GR-79-388 (April 4, 1980).

[9]*In the matter of the Proposal of Northern States Power Company's Electric Utility for a Demand-Side Management Incentive Mechanism*, ORDER APPROVING PROPOSAL AND REQUIRING FURTHER FILINGS (March 19, 1991).

[10]*In the matter of the Petition of Northern States Power Company for Depreciation Certification for Expected Decommissioning Costs for the Monticello and Prairie Island Nuclear Steam Generating Facilities*, Docket No. E-002/D-90-184, ORDER DETERMINING DECOMMISSIONING COSTS, APPROVING COST RECOVERY PROCEDURES, AND ESTABLISHING FUTURE FILING REQUIREMENTS (February 25, 1991).

[11]*In the Matter of the Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change Its Schedule of Gas Rates for Retail for Retail Customers within the State of Minnesota*, Docket No. G-010/GR-90-678, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (July 12, 1991).

[12]The yearly rise in revenue is due to increased electric usage, increasing customer base and periodic rate increase.

[13]*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 oj Minnesota*, Docket No. E-015/GR-87-223, ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988), at 3.

[14]In considering this proposed amount, the Commission has noted that $1,434,000 represents the Pension Make-Up amount stated on a total company basis. For purposes of this Order, the Commission will make an adjustment to the proposed Pension Make- Up amount, reducing it to $1,147,200. This amount approximates the Minnesota jurisdictional amount of Pension Make-Up expenses. The total proposed incentive compensation amount under Consideration is thus $14,447,200 ($13,300,000 in incentive Compensation payments and $1,147,200 in Pension Make-Up expenses).

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Endnotes

1 (Popup)

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