

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Northern States Power Company
Electric
Rates**

Case No. PU-400-91-112

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

October 31, 1991

Appearances

Commissioners: Bruce Hagen, Leo M. Reinbold and Dale V. Sandstrom.

David A. Lawrence and Michael J. Hanson, Attorneys at Law, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, appearing for Northern States Power Company.

William W. Binek, Commerce Counsel, Public Service Commission, State Capitol, Bismarck, North Dakota 58505, appearing for the Public Service Commission Staff.

Myer R. Shark, Attorney at Law, 810 Black Building, 118 Broadway, P. O. Box 1616, Fargo, North Dakota 58107, appearing for the intervenor, Aggie Investments, GP, a commercial customer.

John M. Olson, Wheeler Wolf, Attorneys at Law, 116 North Fourth Street, P. O. Box 2056, Bismarck, North Dakota 58502, appearing for the intervenors, J. R. Simplot Company and RDO Foods Company, industrial customers.

Ilona A. Jeffcoat-Sacco, Commerce Counsel, Public Service Commission, State Capitol, Bismarck, North Dakota 58505, appearing for the Public Service Commission.

Jon Mielke, Public Service Commission, State Capitol, Bismarck, North Dakota 58505, as Hearing Examiner.

Preliminary Statement

On March 8, 1991, Northern States Power Company (NSP) filed an application with the Public Service Commission to increase electric service rates in North Dakota by \$6,604,000 annually. Of this amount, NSP requested that a \$4,800,000 increase become effective immediately as interim rate relief. NSP included its prefiled direct testimony and work papers in its application. On April 2, 1991, the Commission suspended NSP's increased electric rates.

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Also on April 2, 1991, the Commission issued an order denying interim rate relief stating that no actual emergency existed which demanded such an extraordinary remedy.

On April 16, 1991, the Commission issued a notice of hearing and public input sessions. The Commission set the technical hearing to begin on September 10, 1991, at 9:00 a.m. in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota, on the following issues:

1. What is the value of the applicant's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is the applicant's rate of return on its property, used and useful, for the service and convenience in North Dakota?
3. What is a just and reasonable rate of return on the applicant's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on the applicant's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are the applicant's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Other relevant information or proposals concerning the proceeding.

As a part of the hearing process, the Commission scheduled and noticed public input sessions. These were held as follows: 1) City Council Chambers at the City Hall, 2nd Floor, 515 Second Avenue Southwest, Minot, North Dakota, on June 12, 1991, at 7:00 p.m., 2) Civic Auditorium, Room 36A, Lower Level, 615 First Avenue North, Grand Forks, North Dakota, on June 13, 1991, at 11:30 a.m., 3) City Commission Chambers, City Hall, 2nd Floor, Fargo, North Dakota, on June 13, 1991, at 7:00 p.m.

Also on April 16, 1991, the Commission issued a procedural order establishing procedures and scheduling for certain matters, including interventions, prefiled testimony, witness lists, discovery, prehearing motions and prehearing conferences.

On April 18, 1991, NSP filed a motion for rehearing of its interim request. On May 1, 1991, Commission staff filed staff's response to NSP's motion. On May 21, 1991, the Commission issued an order denying the motion.

On June 14, 1991, at the Fargo public input session, Aggie Investments GP (Aggie), a commercial customer, filed a petition to intervene in this case. On June 25, 1991, the Commission granted Aggie's request for intervention. On June 28, 1991, J. R. Simplot Company (Simplot) filed a petition to intervene.

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Simplot also asked to conduct discovery. On July 2, 1991, the Commission granted Simplot's requests.

Also at the Fargo public input session on June 13, 1991, Aggie filed a motion to reschedule the technical hearing to Fargo, North Dakota, and a motion to coordinate hearings and decision (concerning coordination of the hearings in the instant case with that required by the Supreme Court's remand of Case No. 10,979 [PU-400-91-112]). On June 19, 1991, NSP filed a response to Aggie's motion to coordinate.

On July 30, 1991, the Commission issued an order denying Aggie's request to coordinate the hearings and denying Aggie's request to move the hearings to Fargo. However, the Commission did order that the technical hearing be moved from Bismarck, North Dakota, to Grand Forks, North Dakota, to begin on September 10, 1991, at 9:00 a.m. in the Baker Moot Courtroom, at the Law School, at the University of North Dakota. The Commission further ordered that an additional public input session be held on September 10, 1991, at 7:00 p.m. at the same location.

On August 7, 1991, the Commission staff submitted prefiled written testimony and exhibits of Commission consultant William J. Lang, CPA, St. Paul, Minnesota, and Commission Staff Engineer, Jerry Lein. On August 14, 1991, the Commission staff submitted prefiled written testimony of Commission consultants, Thomas Weiss, Senior Consulting Engineer, Baker G. Clay and Associates, 170 Jennifer Road, Suite 250, Annapolis, Maryland 21401, and Dr. Larry Dobesh, University of North Dakota, Grand Forks, North Dakota 58206.

On August 7, 1991, Simplot and RDO Foods Co., (RDO) filed a request for an extension of time to file prepared testimony and exhibits. Included in the motion was a notice of clarification stating that intervenor Simplot also represents the interests of RDO and that the omission of RDO when requesting intervention was an oversight. On August 14, 1991, Simplot filed direct testimony of J. Osgood, Vice President and General manager, RDO Foods Co., Grand Forks, North Dakota, Harley Leake, Purchasing Manager for the Grand Forks Plant, J. R. Simplot, 3630 Gateway Drive, Grand Forks, North Dakota 58203, David H. Hawk, Director, Energy Natural Resources, J. R. Simplot, 999 Main Street, Boise, Idaho 83702, and Don Reading, Consulting Economist, Ben Johnson Associates, Inc., 1234 Timberlane Road, Tallahassee, Florida 32312. In addition, the direct testimony of James Osgood was submitted on behalf of RDO.

On August 15, 1991, RDO, an industrial customer, filed a petition for intervention in this case. On August 20, 1991, the Commission issued an order denying Simplot's motion for extension of time and granting RDO's petition for intervention. The prepared direct testimony of James Osgood which was submitted on August 14, 1991, was filed on August 20, 1991, when RDO became a party to the proceeding.

On September 4, 1991, in response to staff's and intervenors' prefiled written testimony, NSP submitted prefiled written rebuttal testimony and schedules. NSP's prefiled direct testimony included that of James W. Sawyer,

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James M. Dalglish, Mark A. Hervey, Paul E. Pender, Steven V. Huso and Mark D. Thornsjo. NSP's prefiled rebuttal testimony included that of James M. Dalglish, Glenn B. Thorsen, Roy R. Hewitt, Mark A. Hervey, Ms. Betty L. Coleman, Stephen R. Foss, Paul E. Pender, Steven V. Huso and Mark D. Thornsjo.

On September 6, 1991, Aggie filed with the hearing examiner and served subpoenas duces tecum on Dr. Barry Payne, Director, Commission's Public Utility Division, Mike Diller, the Commission Chief Accountant, and Jerry Lein. On September 6, 1991, Commission staff filed a motion to quash subpoenas duces tecum and for a protective order prohibiting calling of witnesses. Also on September 6, 1991, Commission staff and Aggie filed prehearing briefs in the case. On September 9, 1991, NSP filed its prehearing brief.

On September 9, 1991, at 3:30 p.m. the hearing examiner convened a prehearing conference attended by all counsel. At the prehearing conference on September 9, 1991, the hearing examiner granted staff's motion to quash subpoenas duces tecum but deferred to the Commission a ruling on the motion for protective order prohibiting calling of witnesses.

On September 10, 11, 12 and 13, 1991, the technical hearing was held in the Baker Moot Courtroom at the University of North Dakota Law School in Grand Forks, North Dakota, and on September 10, 1991, a public input session was held as scheduled.

On September 24, 1991, Commission counsel filed with the hearing examiner copies of certain testimony and exhibits from Case No. PU-400-87-6 (10,979) and a copy of the NARUC cost allocation manual. During the hearing it was requested and agreed these documents be incorporated into the record.

During the hearing, at the conclusion of NSP's, Simplot's, RDO's and staff's cases, Aggie moved to dismiss. Aggie's written motion to this effect followed on September 30, 1991, together with a brief in support of the motion. On October 7, 1991, NSP filed a response to Aggie's motion. On October 11, 1991, Aggie filed a reply brief on the motion. On October 21, 1991, NSP filed a response to Aggie's reply brief.

On October 14, 1991, Commission staff filed its brief on incentive compensation. Also on October 14, intervenors Simplot and RDO filed proposed limited findings of fact, conclusions of law and order with the Commission. Also on October 14, 1991, NSP filed its brief on incentive compensation and its proposed findings of fact, conclusions of law and order. On October 15, 1991, Commission staff filed its proposed findings of fact, conclusions of law and order.

On October 16, 1991, Commission counsel requested two additional exhibits from Case No. PU-400-87-6 (10,979) be incorporated into the current case, which were inadvertently omitted from the September 24, 1991, filing. On October 24, 1991, Aggie filed a brief on NSP's rate application.

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We are concerned about the abuse of the public input process by NSP and Myer Shark. NSP has full opportunity to present its case. Its solicitation of witnesses to appear as if spontaneously at the public input hearings is inappropriate and deters members of the public at large from participating. The fact that the entities and individuals are dependent on NSP for significant funding makes its actions particularly cynical. It further illustrates how inappropriate it is to allow any ratepayer money to be used for those payments. We do not criticize those who appeared, rather we criticize NSP for the manipulation.

Shark's disruptions and tactics (including refusal to follow procedures and refusal to follow the hearing officer's directions) at the public input sessions we believe discourage members of the general public from participating.

In addition, some of the NSP witnesses were unresponsive. Non-responsiveness makes a mockery of the right to cross-examination. Witnesses should concisely answer questions asked. In the future, we will consider striking the testimony of non-responsive witnesses.

Motion to Deny

On Friday, September 13, 1991, at the close of the cases presented by all parties except Aggie, Aggie moved for an order "totally denying" NSP's application for increased rates. Aggie followed the oral motion with a written motion and brief filed September 30, 1991. Aggie gave four reasons for the motion: 1) that NSP has not met its burden of proving that its rate increase is just and reasonable under N.D.C.C. § 49-05-06, 2) that NSP has failed to comply with N.D.C.C. § 49-05-04, 3) that the Commission does not have power to approve a rate increase unless statutory requirements are fully complied with, and 4) that the Commission does not have the power or authority to waive compliance with the statutory requirements.

N.D.C.C. § 49-05-04 states:

Application for increase of rates-Information required.- Any public utility requesting an increase in its rates above the maximum approved or prescribed by the commission, shall furnish the commission:

1. The original cost of all its property.
2. The date of the acquisition of said property.
3. The amount of money invested in said property.
4. The amount of stock outstanding.
5. The amount of bonds outstanding against said property.
6. All books, papers, and memoranda of the utility showing the financial condition thereof.
7. Its total monthly salaries and wage expense for such time as the commission may request.

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8. An itemized statement of its expenditures.
9. The details of its profit and loss account.
10. All other books, papers, vouchers, and accounts which the said commission shall ask to have produced as evidence at the hearing.

N.D.C.C. § 49-05-06 states:

Hearing by commission on proposed change of rates. Whenever a notice or any schedule stating an individual or joint rate, classification, contract, practice, rule, or regulation, increasing or decreasing, or resulting in an increase or decrease in any rate, shall be filed with the commission, the commission may suspend by motion such rate, classification, contract, practice, rule, or regulation, but the period of suspension thereof shall not extend more than seven months for common carriers by rail and motor vehicle and for other public utilities beyond the time when it otherwise would go into effect. Upon complaint or upon its own initiative without complaint the commission may order a hearing, upon due notice, concerning the propriety of such rate, classification, contract, practice, rule, or regulation. On such hearing, the commission shall establish the rates, classifications, contracts, practices, rules, or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable. At any such hearing, the burden to show that the increased rate or proposed change of rate, classification, regulation, rule, or practice is just and reasonable shall be upon the public utility making application therefor. All such rates, classifications, contracts, practices, rules, or regulations not so suspended, on the expiration of thirty days from the time of filing the same with the commission, or of such lesser time as the commission may grant, shall go into effect and be the established and effective rates, classifications, contracts, practices, rules, and regulations, subject to the power of the commission, after a hearing had on its own motion or upon complaint, to alter or modify the same.

In its brief Aggie states that the motion rests mainly, but not exclusively, on noncompliance with subsections one, two, eight and nine of N.D.C.C. § 49-05-04.

NSP records its property on its books at its original purchase price as required by generally accepted accounting principles. The property is listed by Federal Energy Regulatory Commission category. Individual itemized units of property are not included. We believe N.D.C.C. § 49-05-04(1) does not require an itemized listing of each and every unit of a utility's property.

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Because NSP's property is identified at original book cost according to the FERC Uniform System of Accounts, the acquisition date of the property is unnecessary. As brought out by NSP in its response to Aggie's motion, even if it were possible for NSP to list the individual units of property and the dates each was purchased or installed, it would produce an enormous and unwieldy record. We agree with NSP that requiring such a massive listing would serve no useful purpose.

The amount of money invested in NSP's property is identified in NSP's filing (Exhibit NSP 7 Schedule 3). NSP has submitted an itemized statement of its expenditures in Exhibit NSP 5 Schedule 2 (operating expenses) and the work papers relating to operating expenses and capital expenses. As pointed out in NSP's response to Aggie, the FERC Uniform System of Accounts no longer contains a "Profit and Loss" account demoninated as such. However, in the income statement for NSP, which is a function of the test year revenue and expenses, is provided in Exhibit NSP 5 and the accompanying work papers.

We believe the filing requirements of N.D.C.C. §§ 49-05-04 and 49-05-06 have been met and there is no statutory filing deficiency in the rate application.

In its reply brief Aggie argues that information statutorily required of the company concerning the company's Wisconsin property was omitted from the filing. Aggie argues that the statute requires the submission of this information. NSP disagrees.

NSP-Wisconsin is a separate legal entity incorporated under the laws of the State of Wisconsin. NSP, the applicant in the instant case, owns the stock of NSP Wisconsin but does not own the property in Wisconsin. The North Dakota Public Service Commission has no jurisdiction over NSP-Wisconsin.

Under N.D.C.C. § 49-05-06 Aggie argues that NSP has not met its burden of proof and so the rate application should be summarily denied. The Commission believes NSP has made a prima facie case in its application. The Commission will, in this order, determine on an issue-by-issue basis if NSP's increased rates are fair and reasonable.

For the reasons stated, Aggie's motion is denied.

As a result of the hearing and having reviewed the record in this proceeding, the Commission makes the following:

Findings of Fact

Jurisdiction

1. NSP is an investor-owned utility company engaged in providing retail electric service to North Dakota customers and is subject to the jurisdiction

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of this Commission. The company's headquarters are located in Minneapolis, Minnesota.

Test Year

2. NSP's application is based upon a future test year ending December 31, 1991. Test year data and information in support of the application is based upon historical data. This approach is consistent with the Commission's past practice of setting rates for the future based upon an examination of a period when those rates will be in effect.

3. The Commission finds the company's use of the forecasted 1991 test year period reasonable.

Jurisdictional Demand Allocation Method

4. The average twelve month's coincident peaks (12CP) method for jurisdictional demand allocation to North Dakota was adopted by this Commission upon acceptance of a settlement offer after rehearing on NSP's last rate case, Case No. 10,979 (PU-400-87-6). The North Dakota Supreme Court ordered a remand of that case to the Commission for a hearing on the appropriateness of the settlement. (Supreme Court Nos. 900319 and 900327; Aggie Investments v. Public Service Commission and Northern States Power Company, 470 N.W.2d 805 (N.D. 1991)).

5. In Case No. 10,979 the Commission considered several other jurisdictional demand allocation methods including the single coincident peak method (1CP) recommended by Aggie, and the peak and average method (PA) recommended by Commission staff witness Albert Clark. All of the testimony and exhibits from the original hearing on Case No. 10,979 relating to jurisdictional demand allocation, as well as all the testimony and exhibits from the rehearing on Case No. 10,979, are a part of the record in the instant case.

6. The 1CP method focuses on the size of the single largest annual system peak. The Commission previously found that this method ignores the demand cost that off peak customers impose on the system. We continue to believe 1CP is inappropriate.

7. The PA method uses the single annual system peak as a measure of peak responsibility to allocate the system excess demand to jurisdictions. The average demand of each jurisdiction is then added to the allocated excess demand to determine the jurisdictional demand allocation factors. This PA method represents one compromise between methods that merely recognize the seasonal peak or peaks and methods that give greater recognition to energy requirements of customers throughout the year. In its original decision in Case No. 10,979, the Commission found that the PA method of allocation offered reasonable recognition of a strong peak which consistently occurs in the summer

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and recognized that, because NSP's system is designed, built and operated to meet peak and average demand, there should be some recognition of average demand requirements. In that order the Commission found that the 12CP method proposed by NSP diluted the importance of NSP's high annual system peak, and would assign excessive capacity costs to North Dakota ratepayers even though the Minnesota jurisdiction requires substantially more capacity per unit of average monthly demand.

8. Upon adoption of a settlement offer after rehearing in Case No. 10,979, the Commission adopted the 12CP method. The evidence on rehearing, which is a part of the record in this case, included the testimony of NSP witnesses Caskey, who explained that NSP designs and operates its system to meet system demand on a monthly basis, and Treich, who testified that NSP's system characteristics, load factor, planning considerations, maintenance activities and the Manitoba Hydro diversity exchange support use of 12CP.

9. In this application NSP continued to use 12CP. NSP witness Huso testified that two important reasons for use of 12CP are to provide a uniform and consistent method between jurisdictions served to avoid either over-recovery or under-recovery of system costs, and that 12CP accounts for each jurisdiction's use of production facilities over the entire year. Other reasons advanced by Huso for use of 12CP include: 1) it is a widely accepted method; 2) it tracks substantial load trends but does not produce unreasonable shifts in revenue responsibility through time; 3) the resulting allocation factors can be easily verified and documented; 4) it has reasonable administrative costs and can be determined within necessary time constraints; and 5) it recognizes load management and conservation efforts.

10. Staff witness Weiss testified that NSP's use of 12CP is an acceptable method. Weiss also pointed out that NSP's membership in the Midcontinent Area Power Pool provides further justification for 12CP because every Midcontinent Area Power Pool jurisdiction continuously benefits from NSP's participation in the pool. Weiss testified that many jurisdictions use the 12CP method. On cross examination Weiss testified that not all integrated electric systems have characteristics which would call for the application of the 12CP method. He stated that the choice of allocation method would depend upon load pattern and the consistency of the load pattern over a long period of time.

11. On cross examination Weiss testified that, when using 12CP, it may be appropriate to give weighting, or greater emphasis, to a higher peak in a certain portion of the year. Weiss testified that weighting would be appropriate where there are perceptibly higher peaks in the load pattern. Weiss testified that the weighting for those peaks would be determined graphically and that it would be a judgment call. The extent of the weighting would depend on the size and extent of the high peaks relative to the smallest monthly peak. The smallest monthly peak would have a weighting of one and the other peaks would have a weighting of something greater than one. Weiss also testified that one could consider an average for the entire load curve and compute a weight for the peaks relative to that average.

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12. On cross examination Huso testified that the company has summer rates which are higher than winter rates to recognize that the NSP system is operated and planned to meet peaks in all 12 months of the year but that the company does focus on the summer months more than the others. In the instant case, the company is proposing a residential summer period rate of 6.01 cents per kilowatt-hour and a winter rate of 5.31 cents per kilowatt-hour. This is a rate differential of 13 percent. For residential time of day service, NSP is proposing a summer on-peak rate of 11.18 cents per kilowatt-hour and a winter on peak rate of 8.73 cents per kilowatt-hour. This is a rate differential of 28 percent. Huso stated that July and August are typically the highest demand months of the year.

13. Staff witness Weiss agreed that NSP's approach to the problem of high summer demand, by charging higher summer rates, could invite a weighting of the summer peak. Weiss had not investigated the figures related to the appropriate peak weighting for the jurisdictional demand allocation method.

14. In 1990, the smallest monthly peak demand for NSP Minnesota Company was 3,853,000 KW, the highest monthly peak during the winter months was 4,482,000 KW and the highest monthly peak during the summer months was 5,859,000 KW. Therefore in 1990, the highest winter peak demand was 1.16 times greater than the smallest monthly peak demand. In 1990 the highest summer peak demand was 1.52 times greater than the smallest monthly demand. The June 1990 peak of 5,641,000 KW was 1.44 times greater than the smallest monthly peak demand, the July 1990 peak of 5,859,000 KW was 1.52 times greater than the smallest monthly peak demand, the August 1990 peak of 5,483,000 KW was 1.42 times greater than the smallest monthly peak demand, and the September 1990 peak of 5,675,000 KW was 1.47 times greater than the smallest monthly peak demand. The Commission finds this load pattern justifies the weighting and greater emphasis on the summer peaks in the 12CP allocation method.

15. For the 1991 projected test year, the smallest monthly peak demand for NSP Minnesota Company is 3,917,106 KW, the highest monthly peak during the winter months is 4,627,958 KW and the highest monthly peak during the summer months is 5,972,364 KW. For 1991 projected, the highest winter peak demand is 1.18 times greater than the smallest monthly peak demand. The highest summer peak demand is 1.52 times greater than the smallest monthly demand. The June 1991 projected peak of 5,262,201 KW is 1.34 times greater than the smallest monthly peak demand, the July 1991 projected peak of 5,972,364 KW is 1.52 times greater than the smallest monthly peak demand, the August 1991 projected peak of 5,648,512 KW is 1.44 times greater than the smallest monthly peak demand, and the September 1991 projected peak of 4,685,834 KW is 1.19 times greater than the smallest monthly peak demand. The Commission believes this load pattern justifies the weighting and greater emphasis on the summer months' peaks in the 12CP allocation method.

16. The Commission finds that 1CP and PA are inappropriate methods of jurisdictional demand allocation for NSP. The Commission further finds that

an unweighted 12CP is also inappropriate. However, weighting the peaks in the 12CP method incorporates some of the desirable qualities of the PA method while retaining the desirable qualities of the 12CP method. We believe such weighting most fairly reflects NSP system load characteristics and most fairly allocates costs. For this case, the Commission finds it appropriate to weight each of the projected 1991 test year's 12 month's coincident peaks by comparing them to the smallest projected 1991 monthly peak of 3,917,106 KW in October. The smallest projected 1991 monthly peak will have a weighting of 1.0 and the other eleven monthly peaks will be divided by the smallest to produce weightings greater than 1.0.

17. This adjustment in jurisdictional demand allocation will affect many test year rate base and expense components and the company will have to use its computer model to determine the exact impact of the adjustment. Therefore, the finding of revenue deficiency in this case and other findings related to rate base and expenses will be approximated. We believe the adjustment in jurisdictional demand allocation will decrease test year revenue requirement by approximately \$650,000.

Average Rate Base

18. NSP presented evidence through witnesses Sawyer, Coleman and Hervey concerning its 1991 forecasted average rate base. Sawyer testified that 1991 forecasted average rate base dedicated to serve the State of North Dakota was \$143,697,000.

19. Staff witness Lang prefiled recommended adjustments to NSP's proposed rate base resulting in a recommended rate base of \$143,073,000.

Unamortized Rate Case Expenses

20. Lang recommended adjusting NSP's unamortized balance of rate case expenses at the beginning of the test year by \$65,000 to reflect the periodic occurrence of rate case expenses as the case proceeds through the process rather than showing the total estimated amount as a beginning balance. NSP witness Coleman agreed with Lang that rate case expenses are incurred periodically throughout the year and stated that for this rate case there were no rate case expenses incurred prior to 1991 and that consequently rate case expenses associated with this filing should not be included in the beginning balance. There was agreement that, assuming an order is issued by November, 1991, the average unamortized rate case expenses balance should be reduced by \$37,000. We find that the reasonable adjustment to average North Dakota rate base for the unamortized balance of rate case expenses is a reduction of approximately \$37,000.

Unamortized King Rotor Expenses

21. Lang recommended disallowance of NSP's test year rate base inclusion for the unamortized King rotor expenses. Lang's reasoning is that since NSP chose a deferred accounting treatment with 5-year amortization of the rotor cost to expense, it should not now be allowed to include the unamortized

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portion of the expense in rate base. Lang pointed out that use of deferred accounting can become a way to delay the recognition of operating expenses until the utility files a rate case. This results in out-of-period expenses being brought into a test year for recovery from ratepayers. While Lang recommended the exclusion of the unamortized King rotor expense balance in rate base, Lang did not dispute the inclusion of the King rotor amortization in test year expenses.

22. NSP witness Coleman testified that it is common rate-making practice to levelize the impact of large non-recurring expense items such as the King rotor expense. NSP contends that the King rotor replacement was a prudent business expenditure made for the benefit of the ratepayers, and therefore it should be recovered by inclusion in the rate base. Coleman stated that the Commission allowed the King rotor expenditures in the last NSP rate case (Case No. 10,979 [PU-400-91-112]), but acknowledged that it was not made an issue in that case.

23. Simplot's witness Reading recommended that the unamortized portion of King rotor expenses be charged to North Dakota customers over a 10-year period.

24. We agree with Lang and find it reasonable to continue amortization of the King rotor and that the amortization should continue without inclusion of the unamortized portion in rate base. The resulting adjustment to average North Dakota rate base is a reduction of approximately \$122,000.

Unamortized Cogeneration Litigation Expenses

25. Lang recommended that the Commission disallow the inclusion of unamortized cogeneration litigation expenses in rate base because: 1) the amount is in dispute; 2) NSP chose to dispute an unambiguous contract; 3) the shareholders should bear the loss because NSP's management was in error in causing the cost to be incurred; and 4) NSP is using deferred accounting to delay recognition of the expenses until the year of a general rate case. NSP witness Hervey claimed the contract NSP chose to dispute was not unambiguous and that NSP genuinely believed in its interpretation of the contract. Hervey argued that disallowing the unamortized litigation costs from rate base would constitute a disincentive for NSP to pursue actions it believes are in the ratepayers' interest. Hervey acknowledged that NSP knew the liability existed on June 15, 1990.

26. We agree with Lang and find that the unamortized portion of the expenses should not be included in the 1991 test year rate base. The resulting adjustment to average North Dakota ratebase is a reduction of approximately \$18,000.

Depreciation Study

27. NSP witness Hervey testified that there is a major change in the test year depreciation based on the extension of nuclear plant remaining lives to coincide with the Nuclear Regulatory Commission license termination date. NSP proposed that the effect of its remaining life depreciation study

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be incorporated into the 1991 test year. This would result in a decrease in annual depreciation accruals of \$410,000 for the North Dakota jurisdiction. Lang agreed with NSP's proposal. We find NSP's proposal is reasonable and the resulting impact to average North Dakota rate base is an increase of approximately \$123,000.

Plant Balances - October, 1990

28. Lang recommended that an adjustment be made to average rate base for the October, 1990, plant balances because actual October 31, 1990, plant balances were overstated. NSP witness Coleman acknowledged that October, 1990, plant balances in the functional plant-in-service system were overstated as a result of coding errors within the system, and that an adjustment is needed to reduce the plant balances to an accurate starting point. Coleman accepted Lang's jurisdictional adjustments. We find these adjustments reasonable and the resulting adjustment 1991 to average North Dakota ratebase is a reduction of approximately \$314,000.

Beginning Construction Work-In-Progress

29. Lang recommended an adjustment to reduce the test year construction work-in-progress by \$52,000 which was the amount represented by the Savers Switch Program which is a part of NSP's demand side management efforts but will not be available to North Dakota customers until 1992. NSP witness Coleman acknowledged that the allocation was inadvertently made to North Dakota and agreed with Lang's adjustment. We agree. The resulting adjustment to average North Dakota ratebase is a reduction of approximately \$52,000.

Information Services Chargebacks

30. Lang recommended an adjustment for information services chargebacks because of an accounting change implemented by NSP on January 1, 1991, which resulted in expensing information services costs. Coleman acknowledged that for the 1991 budget process, information services chargebacks were included as an expense component of the department operating expenses budget. NSP accepted Lang's reduction of \$46,000 for the North Dakota jurisdictional rate base. We find that the recommended adjustment to remove the chargebacks from the budgeted capital accounts and reflect the expense correctly under the new accounting policy effective January 1, 1991 is reasonable. The resulting adjustment to average North Dakota ratebase is a reduction of approximately \$46,000.

Purchasing Costs

31. NSP implemented a change in accounting procedures to expense Purchasing Costs rather than capitalize these costs, similar to Information Services Chargebacks. Staff witness Lang recommended a reduction to the test year average rate base of \$57,000. Again, NSP acknowledged the double counting of these costs in its filing. We find that Lang's adjustment is fair and reasonable.

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Cash Working Capital - O&M Expenses

32. NSP's original filing included a lead/lag study to estimate its cash working capital requirements. Staff witness Lang did not dispute the method or the calculations as filed by NSP. As a result of adjustments applicable to test year operating expenses, the working capital component of rate base must be adjusted. The amount of this adjustment is a reduction of approximately \$24,000 to average North Dakota rate base.

Demand-Side Management Programs

33. NSP included \$645,000 in the test year for demand-side management expenditures. NSP witness Thornsjo stated that NSP's goal is to manage demand and energy use growth so new electric generating capacity is deferred and use of existing facilities is maximized. NSP has set an aggressive goal of achieving 1,000 megawatts of cumulative peak impact and related capacity deferrals by 1995. NSP proposed that the Commission allow rate base treatment with a return on the unamortized rate base amount at five percent above the rate of return on equity. NSP also proposed to include a "tracker account" and a carrying charge. Lang recommended that the Commission disallow NSP's proposed deferred accounting and amortization in test year demand-side management expenditures for the reason that demand-side management expenditures should be recovered the same way other operating expenses are recovered from ratepayers. Lang contended that the forecasted test year is supposed to represent the company's best estimate of what it expects costs will be, including demand-side management programs. NSP contended that the equity return on demand-side management investments should carry a five percentage point premium above the cost of equity for other investments because of the disincentive associated with demand-side management investments. The disincentive to NSP is that demand-side management investments cause customers to conserve energy resulting in lost revenues to the company.

34. Staff witness Dobesh applauded NSP's aggressive action to promote demand-side management, but expressed concern with NSP's proposals for the tracker mechanism and the premium for demand-side management investment. Dobesh pointed out that if a tracker mechanism is approved without careful oversight into what is allowed into the account, there would be an incentive for the company to label as many expenses as possible as demand-side management expenses. Dobesh argued that the five percentage point premium on ROE for demand-side management investment would create a further incentive for the company to label as demand-side management investments all projects remotely related to demand-side management.

35. Dobesh recommended rejection of NSP's tracker and rate basing proposals for demand-side management because NSP's plan would be administratively costly and would provide perverse incentives for efficiency. Dobesh pointed out, however, that his testimony should not be taken as an endorsement of the current method of expensing demand-side management costs, and although he

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does not believe NSP's proposals are appropriate, he does believe the company has raised important questions that deserve study. Dobesh recommends that the Commission notice a generic hearing on demand-side management.

36. We agree with Lang and Dobesh that NSP's tracker and rate basing proposals for demand-side management should be rejected and require that demand-side management expenditures be expensed.

37. The Commission finds the approximate average North Dakota rate base for the 1991 test year to be approximately \$143,150,000 as shown on Attachment A.

Rate of Return

38. Staff witness Dobesh and NSP witness Pender testified on appropriate cost rates for debt, preferred equity and common equity as well as an appropriate test-year capital structure. Combining the component costs of capital with capital structure gives the weighted average cost of capital for NSP's North Dakota operations.

39. NSP's proposed capital structure for the 1991 test year is 41.98 percent long-term debt, 42 percent short-term debt, 9.85 percent preferred, and 47.75 percent common. Dobesh agrees that NSP's proposed 1991 capital structure is reasonable. We agree.

40. Both NSP and Dobesh agreed that the cost of long-term debt for the company is 8.650 percent, the cost of short-term debt is 7.780 percent and the cost of preferred is 6.130 percent. We agree.

41. The cost of common equity was disputed. Dobesh testified that the market cost of equity is between 11.3 percent and 11.9 percent. Dobesh recommended a point estimate of 11.80 percent, given the company's good performance in keeping its debt and preferred costs low. Pender testified that the cost of common equity is 12.75 percent. In its application, NSP employed a cost of common equity of 12.75 percent to determine its weighted average cost of capital.

42. Both Dobesh and Pender employed the Discounted Cash Flow (DCF) method to determine the company's cost of common equity. The DCF method, as a means to determine the cost of common equity, is strongly supported in both the professional literature and rate-of-return decisions of the federal and state regulatory agencies.

43. In addition to the DCF method, Pender employed an equity risk premium and a capital asset pricing analysis to support his cost of equity recommendation. This Commission, like many regulatory agencies, has in past cases adopted the DCF method when determining the market cost of equity. We reject the equity risk premium and capital asset pricing analysis approaches in determining cost of common equity. We find Dobesh's method appropriate and reasonable.

44. We accept Dobesh's range based on his studies. Dobesh's recommendation of what we should allow within this range of reasonableness is his opinion on a matter of Commission policy and judgment, and as such is entitled to no particular weight. However, we find Dobesh's recommendation of 11.8 percent reasonable and therefore allow a cost of equity of 11.8 percent.

45. We find the company's required rate of return on rate base is 9.90 percent as shown on Attachment B.

Operating Expenses

46. NSP witness Hervey presented testimony in the company's prefiled application reflecting total operating expenses in the State of North Dakota for the 1991 test year of \$85,109,000. Staff witness Lang prefiled proposed adjustments resulting in a projected test year total operating expense level of \$83,877,000.

Depreciation Study

47. NSP witness Hervey and staff witness Lang agreed that the results of a new remaining plant life study performed by NSP should be incorporated into this case. This adjustment results in a decrease in annual depreciation accruals of \$410,000 for the North Dakota jurisdiction. The Commission finds it just and reasonable to incorporate the results of the new remaining plant life study in this case and to reflect the results of that study in rates.

Nuclear Regulatory Commission Fees

48. NSP witness Hervey testified that a major change has occurred in payment of Nuclear Regulatory Commission fees since NSP's last rate case. In the past, user fees were set to recover 45 percent of the Nuclear Regulatory Commission's budget, but federal legislation which was passed in December, 1990, resulted in Nuclear Regulatory Commission user fees being set at the 100 percent level. NSP estimated those fees to be \$10,000,000. Lang recommended an adjustment to the user fees based upon an internal NSP memo dated May 8, 1991, which indicated a revised calculation of \$8,530,000. Hervey testified that NSP has recalculated 1991 Nuclear Regulatory Commission fees based on the final fee structure and that \$8,771,000 is the correct total company amount. Lang agreed with NSP's final figure. We agree, and find the North Dakota Nuclear Regulatory Commission expense should be decreased by approximately \$75,000.

Incentive Program Expense

49. NSP has initiated a Performance Incentive Pay Plan for eligible employees. For the 1991 test year, NSP included \$15.3 million dollars on a total company

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basis with North Dakota's jurisdictional amount being \$934,000. In rebuttal testimony, Hervey testified that the 1991 budget for incentive compensation was overstated for union employees because the union employees incentive compensation target in the budget was four percent of base pay and the final union agreement called for target incentive compensation at two percent of base pay. The adjustment to correct that difference is a decrease of approximately \$138,000 for the North Dakota jurisdiction. We agree with the adjustment.

50. Lang recommended that the Commission disallow fifty percent of the North Dakota jurisdictional portion of the incentive compensation expense because, although ratepayers benefit from greater operation efficiencies, benefits also accrue to the employee through additional compensation and to the stockholder through increased earnings per share. Lang does not recommend that NSP discontinue its incentive compensation program, but expressed concern that amounts of incentive payments as a percentage of total administrative and general expenses and as a percentage of labor and related expenses appears high. Lang presented no evidence to substantiate the claim that the incentive payments are excessive.

51. NSP witness Hewitt testified that incentive compensation is not additional compensation but is simply a portion of the total compensation package. Hewitt argued that achievement of the goals results in operating efficiencies that directly benefit the ratepayers. Hewitt further testified that such plans are common in the industry, directly benefit the ratepayers and are appropriate for recovery in rates.

52. The reasonableness of total compensation is always an appropriate issue. The evidence presented does not support a finding that total compensation is excessive. A thorough study of management and other total compensation would be appropriate in the next rate proceeding.

53. We agree that the incentive compensation program should be continued, and find no evidence to determine that the total compensation package is excessive. We find there should be no adjustment to 1991 North Dakota test year expenses relative to the incentive compensation program.

Charitable Contributions

54. NSP included charitable contributions in the amount of \$60,000 in the test year operating and maintenance expenses. NSP witnesses Dalglish and Hervey defended the charitable contributions as representing a normal business expense. In addition they stated that the \$60,000 figure represents one-half of the total amount of test year contributions to charitable organizations in North Dakota. Lang recommended that all charitable contributions be excluded for rate making purposes because they are not necessary operating expenses of a public utility and have no direct impact on the company's operating efficiency or quality of utility service.

55. Dalglish testified that charitable contributions be included in the expenses of NSP and flowed through in the utility rates. On cross examination,

Dalglish agreed that NSP ratepayers have no choice to purchase electric power from someone other than NSP and therefore cannot choose whether or not to buy the product if they disagree with NSP's choice of charitable contributions. The only choice the customers have is to move to another spatial location outside of NSP's service territory.

56. We find that inclusion of charitable contributions as an operating expense forces an involuntary contribution to those organizations by the ratepayer. The Commission has consistently disallowed charitable contributions in previous rate cases, and charitable contributions should be excluded in this case. We find the 1991 test year North Dakota expense should be decreased by approximately \$60,000 to exclude charitable contributions.

Pathfinder Decommissioning Costs

57. NSP requested amortization of expenses associated with decommissioning of the Pathfinder Nuclear Plant located near Sioux Falls, South Dakota. NSP witness Hervey testified that Pathfinder amortization began January 1, 1990, and therefore current rates do not include Pathfinder amortization. NSP proposed treatment similar to that granted by the South Dakota Public Utilities Commission which approved a 5 year amortization of decommissioning costs with no rate base inclusion.

58. The Pathfinder Nuclear Plant was an experimental reactor built in the early 1960's. The plant was operated by NSP from 1964 through 1967 as a commercial operation on an intermittent basis. During that time, Pathfinder generated electricity approximately five to twenty-five percent of the time. On cross examination, NSP witness Hervey testified that during its life Pathfinder operated at full generating capacity less than one day. NSP witness Hewitt could not quantify the number of hours Pathfinder operated at full capacity. At the end of 1967 a decision was made to discontinue operations, and between 1968 and 1971 the nuclear portions of the plant were placed in safe storage.

59. The Pathfinder Plant was a joint research and development project involving the Atomic Energy Commission and ten investor owned utility companies. The joint venture was known as the Central Utilities Power Associates (CUPA).

60. NSP supported its request for recovery of decommissioning costs with the claim that experience gained in design, construction, operation and maintenance of the systems at the Pathfinder Plant was directly applicable to the successful construction and operation of the Monticello and Prairie Island Nuclear Plants.

61. Commission consultant Lang recommended disallowance of NSP's recovery of decommissioning costs from current ratepayers. Lang pointed out that NSP, in a letter to shareholders dated October 24, 1968, stated that the reactor was

shut down because of significant mechanical failures involving components of the nuclear reactors and that the Pathfinder reactor had not fulfilled NSP's expectations that the manufacturer would provide the company with an operable power plant. Lang also challenged NSP's claims that valuable training was gained by employees which now benefits current operations of Prairie Island and Monticello. Lang referenced an NSP memorandum dated April 30, 1968, which indicated NSP's concerns about using Pathfinder as a training facility for its Monticello and Prairie Island personnel. Lang also pointed out that NSP is inconsistent in its request for decommissioning costs for the Pathfinder Plant in comparison for its request concerning the Prairie Island and Monticello reactors, because NSP's argument concerning Prairie Island and Monticello was that ratepayers using the power from those plants should be responsible for the cost of decommissioning. Lang points that recouping from current ratepayers the expense of decommissioning a nuclear plant abandoned over more than twenty years ago violates the fundamental rate making principle of matching expenses with associated services.

62. Reading, who testified on behalf of Simplot, disagreed with NSP's logic concerning having today's ratepayers pay for costs associated with a project used over twenty years ago and suggested an alternate recommendation amortizing the costs over a ten year period with no return on the unamortized balance.

63. We agree with Lang that NSP has failed to show that Pathfinder provided benefits to NSP ratepayers. The Pathfinder Nuclear Plant failed to produce electricity on any consistent basis or for any significant time on the NSP system, and Pathfinder failed to operate sufficiently as a training facility or to provide any valuable experience for NSP's Prairie Island and Monticello Plant employees. We also find it inappropriate to include in the 1991 test year for North Dakota, expenses related to a plant investment that was abandoned 24 years ago. We find that the 1991 North Dakota test year expense should be reduced by approximately \$205,000 to eliminate Pathfinder decommissioning expenses.

Organization Dues

64. NSP included organization dues of \$162,000 for the North Dakota jurisdiction in its test year operating expenses. Lang recommended an adjustment to test year expenses for organization dues which resulted in a reduction of \$57,000. The organization dues making up the proposed reduction are a combination of individual memberships, allocated amounts from Minnesota organizations, telephone associations, tuition and fees, and unidentified organizations in North Dakota. Lang recommended disallowance of membership or organization dues that do not contribute to providing reliable electric services to customers in North Dakota. NSP witness Dalglish provided testimony to support inclusion of \$29,000 of local dues that Lang excluded, and NSP witness Hervey accepts the elimination of \$9,000 of organizational dues but testified that the remaining \$48,000 be included in rates.

65. We find that \$24,000 of organization dues allocated to North Dakota should be excluded from the revised request of \$152,000. This adjustment reflects a one-half disallowance of disputed costs between Lang and NSP witnesses. The resulting test year expense for organization dues is approximately \$128,000 or \$34,000 less than NSP's prefiled testimony.

Cogeneration Litigation Expenses

66. In this order the Commission determined that unamortized cogeneration litigation expenses should be excluded from 1991 North Dakota test year average rate base. For the same reasons cited for that exclusion, we agree with Lang's adjustment to the 1991 North Dakota test year to exclude cogeneration litigation expense. The resulting decrease in 1991 North Dakota test year expenses is approximately \$14,000.

Allocation of Receipt Processing Costs

67. NSP witness Hervey testified that NSP-North Dakota began handling receipts processing locally in Fargo, North Dakota in May of 1991. Previously all bill payments by mail were centrally processed in Minneapolis. At the time this case was filed, the North Dakota cost of service included a full year allocation of the Cash and Banking Department which centrally performed receipts processing. The correction of this allocation results in a decrease in customer accounting expense for North Dakota of \$40,000. The Commission finds it just and reasonable to reflect this adjustment in rates.

Other Adjustments

68. Lang recommended adjustment to the test year income statement related to adjustments made to the rate base for Information System Chargebacks, purchasing costs, and plant balances - October, 1990, related expenses. These adjustments are consistent with adjustments made to rate base, and NSP witnesses agreed to the adjustments. We agree.

Electric Departmental Operating Expenses

69. Commission consultant Dobesh examined NSP's projected 1991 electric department operating expenses. Dobesh concluded that the 5.88 percent growth in departmental operating expenses for the test period was unreasonable and should be reduced. Dobesh estimated a reasonable growth in departmental operating expenses per megawatt hour would be four percent which is a figure representative of recent economy-wide inflation. NSP witness Foss agreed with Dobesh's recommendation. Witnesses for both NSP and staff agreed that information system chargebacks and purchasing costs changes should be adjusted to reflect reductions in the capital budget and the departmental operating expense budgets in accordance with the changes in the accounting treatment for information system chargebacks and purchasing cost changes. We agree and decrease the 1991 North Dakota test year electric departmental operating expense by approximately \$231,000.

Rate Base Income Taxes

70. The Commission's decision to authorize a lower rate base than requested by NSP results in a smaller interest deduction for tax purposes. Accordingly, we find that income tax expense should be increased by approximately \$7,000 to reflect the impact of the rate base adjustments..

71. The Commission finds the average North Dakota return earned for the 1991 test year to be approximately \$11,500,000 as shown on Attachment C.

NSP's Revenue Requirements

72. NSP claimed in its application that its revenue deficiency for the test year was \$6,604,000. In rebuttal testimony NSP witness Hervey testified that the revenue deficiency after reflecting adjustments testified to by NSP witnesses was \$5,872,000 or a decrease of \$732,000 from the original filed amount.

73. Staff witness Lang calculated the revenue deficiency for the test year to be \$3,941,000 using the overall rate of return of 9.902 percent recommended by Dobesh.

74. Due to the Commission's modified jurisdictional allocation in this case and the refusal of intervenors to waive procedural barriers to securing the necessary data on a timely basis we are unable to provide the exact revenue deficiency. However, we find the approximate revenue deficiency for the 1991 North Dakota test year to be approximately \$3,705,000 as shown on Attachment D.

Rate Design

75. NSP witness Huso sponsored the NSP North Dakota embedded class cost of service study which was used as a guide in developing the proposed class revenue responsibilities and rate designs.

76. We believe that both fully-distributed embedded class cost of service studies and long run incremental studies may provide useful guidance in designing rates. However, we will continue to use our own judgment considering the evidence, arguments and public policy in a particular case as to an appropriate rate design. We will avoid mechanical application of the results of any given cost study.

77. Staff witness Weiss testified that NSP's cost classification and allocation follows generally accepted principles and practices based upon the principles established by the National Association of Regulatory Utility Commissioners (NARUC) in 1973 as the NARUC Electric Utility Cost Allocation Manual.

78. Weiss disagreed with NSP's technique used in classifying system production costs between peaking and base load. Weiss also recommended a

change in the allocation of cash working capital to reflect a more cost positive allocation. Based on its policy to use class cost of service studies only as a guide in designing rates, the Commission finds no need to decide these two issues for this case.

79. NSP witness Huso stated that the company's primary electric rate design objectives are to develop rates which will:

1. yield total revenues necessary to recover the test year operating cost, including a reasonable return on NSP North Dakota investment and facilities used to provide service,
2. to reflect the resource cost of the service provided, and where appropriate, reflect market value of the service provided,
3. provide the flexibility and price structure and the flexibility and service conditions which are necessary to allow NSP North Dakota electric service to remain competitive in the energy market, and
4. be understood and accepted by customers, maintain reasonable rate continuity and revenue stability, and be administratively practical.

80. NSP contends that its rate design proposals reflect the company's objective of moving revenues derived from each customer class in a direction which will ultimately result in each class paying the commission-authorized overall rate of return.

81. Based on the revenue deficiency originally filed in its application, an overall increase of 7.9 percent, NSP proposed to increase revenue from the residential class by 9.1 percent, increase the revenue from the commercial/industrial class by 7.0 percent, increase the revenue from the sales to public authorities by 17.0 percent and decrease the revenue from the street and area lighting customer class by 0.2 percent.

82. Staff witness Weiss generally agreed with NSP's objective to adopt a rate design which tends to move customer class revenues in a direction which will ultimately result in each class paying the Commission-authorized rate of return. Weiss pointed out, however, that economic conditions and public policy may signal the need to set rates at levels other than costs.

83. In the event the Commission were to find a revenue deficiency for NSP at a level different from that proposed by the company or that proposed by Lang, Weiss recommended that the Commission constrain the residential class revenue requirement to approximately the level recommended by Lang and assess any excess to the other classes according to Company witness Huso's rate design.

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84. Simplot's witness Reading stated that he agreed with many of the tenants underlying NSP's rate design proposal, but he does not believe that they have been reflected in the company's proposed distribution in a consistent and logical manner. He also believes the proposal imposes excessive increases on the commercial/industrial as well as the public authority rate classes. Reading stressed that large commercial and large industrial customers have relatively elastic demand for electric service, and consequently, if the price of alternate sources of energy fall relative to the price of electricity charged by NSP, the large customer will opt for the less costly alternative.

85. Reading recommended that residential and other class rates be increased to the level required to cover costs. However, Reading recommended that increases to any customer class be restricted to 1.5 times the average overall rate increase. Also, Reading recommended that no customer class receive a rate reduction.

86. Osgood, testifying on behalf of RDO, expressed the concern of his company, being a small industrial start-up company, as it relates to the proposed electric rate increase. He asked that any rate increase be fair with all costs fully allocated to the appropriate class of service.

87. The Commission finds that the residential class and the commercial/industrial class should be assigned equal percentage increases. The Commission agrees with Reading that no customer class should receive a reduction and therefore the revenue from the street/area lighting class should not be reduced. The Commission also finds that the percentage increase to public authorities class should not exceed 1.5 times the average overall percent revenue increase.

88. NSP proposes to increase the monthly customer charge for the residential class from \$4.00 to \$5.00.

89. Weiss recommended that the increase in customer charge for the residential class be rejected leaving the minimum monthly charge at the level of \$4.00 to continue to make service available to as broad a residential customer base as possible. Weiss recommended that the difference between the \$4.00 minimum monthly charge and the customer related cost for a residential customer continue to be recovered in the initial energy rate block. We agree that the residential minimum monthly charge should remain at \$4.00 and that the remaining customer related cost continue to be recovered in the initial energy block of the dual-block rate structure.

90. Simplot witness Leake testified that his company is served by NSP under a peak-controlled time-of-day service. He estimated that the 7.1 percent increase proposed by NSP would cost his company approximately \$87,000 based on 1990-1991 usage, and that if expansion occurred, that figure could rise to \$120,000. He stated that future expansion plans would be directed toward bringing the production facility into balance, and while that would make the plant more efficient, it would preclude the ability to shut down lines for

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load shedding. This could result in his company's loss of eligibility for the peak-controlled time-of-day service. Leake also stated that opportunities currently under evaluation by his company include alternate electric suppliers, cogeneration, and alternate sites.

91. Simplot witness Hawk recommended that the commercial/industrial class be separated into two classes. His reasoning was that there are significant differences between commercial and industrial users. Such differences include the cost to serve a large load, load factor, ability to shed load, and the customer's potential for temperature sensitivity. He also pointed out that the industrial customer offers a more revenue stable load and has a more profound potential to cogenerate.

92. Reading recommended separating the commercial/industrial customer class into two customer classes. He further recommended that the Commission order NSP to work with the large industrial customers and the Commission staff to develop a proposal for separating the large industrial customers from the commercial and industrial class, and that the proposal be presented to the Commission for approval in a separate proceeding.

93. We find that NSP should work with large industrial customers and study the recommendation to separate the large industrial customers from the commercial/industrial class. The results of the study should be presented to the Commission for review.

Competitive Electric Rates

94. NSP proposed design of its electric rate to include a competitive service rider which would provide flexibility as well as price structure and service conditions which are necessary to allow NSP to remain competitive in the energy market.

95. Staff witness Lein testified that the Commission previously addressed the issue of flexible electric rates in Case No. PU-401-90-14, an application by Otter Tail Power Company, and Case No. PU-399-89-170, an application by Montana-Dakota Utilities Co. Lein pointed out that the Commission denied both of the applications, but made suggestions for changes that would make the proposed tariffs acceptable.

96. Lein recommended that the Commission reject NSP's proposed competitive service rider tariff because it is not limited to economical development applications and could be used in any competitive situation, including explosive territorial disputes with neighboring cooperatives. Lein suggested that NSP be encouraged to refile an economic development tariff consistent with the guidelines suggested by the Commission in Case Nos. PU-401-90-14 and PU-399-90-170.

97. We find that NSP's proposed competitive service rider should be rejected because it does not conform to the guidelines in Case Nos. PU-401-90-14 and PU-399-90-170 and because it may constitute unreasonable discrimination.

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98. We find the remainder of NSP's rate design proposal to be reasonable and that NSP should implement its rate design proposals to the extent possible given the constraints in this order.

From the foregoing findings of fact, the Commission now makes its:

Conclusions of Law

1. The Public Service Commission has jurisdiction of this proceeding.
2. The projected 1991 test year is appropriate for this case.
3. The existing level of NSP's rates is inadequate to produce a reasonable rate of return on the company's electric property, used and useful, for the service and convenience of the public in North Dakota.
4. NSP is entitled to a rate level adequate to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.
5. The rate levels and rate design filed by NSP in its application are unreasonable and should be disapproved.
6. The rate levels and rate design found reasonable and approved in the Findings of Fact and Order will provide NSP an opportunity to earn an adequate rate of return on its electric property, used and useful, for the service and convenience of the public in North Dakota.

From the foregoing Findings of Fact and Conclusions of Law, the Commission issues its:

Order

The Commission orders:


1. The tariff filed by NSP on March 8, 1991, with its application for increased electric rates is unreasonable and is disapproved.
2. NSP shall file rate base, expense, working capital and revenue deficiency summaries similar to those provided as Attachments A, B, and C to its Proposed Findings of Fact, Conclusions of Law and Order. These summaries should show the 1991 North Dakota test year revenue deficiency in accordance with our decision in this case.
3. NSP shall file for Commission approval rate schedules in accordance with the rate design, rate base and rate of return found reasonable in our decision in this case that will yield additional annualized revenues over current rate levels not in excess of the revenue deficiency determined in accordance with our decision in this case.

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4. NSP shall file rate schedules effective for service rendered on or after November 8, 1991.
5. NSP shall file rate schedules for Commission approval at least three working days prior to their effective date.
6. The motion filed by Aggie is denied.

PUBLIC SERVICE COMMISSION

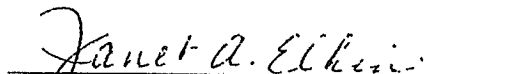


Bruce Hagen, President

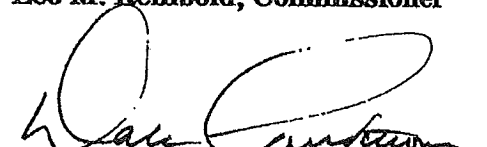
ATTEST:



Leo M. Reinbold, Commissioner



Janet A. Elkin, Executive Secretary



Dale V. Sandstrom, Commissioner

Northern States Power Company - ELECTRIC
 Case No. PU-400-91-112
 Average Rate Base Statement
 (000's Omitted)

Attachment A
 Page 1

Line	Description	TYE 1991		
		Company Filing	Adj.s	Order
1	Plant in Service	\$331,647	(\$481)	\$331,166
2	Less: Accumulated Depreciation	148,583	(215)	148,368
3	Net Plant in Service	\$183,064	(\$266)	\$182,798
4	Materials and Supplies	4,837	0	4,837
5	Fuel Stocks	2,080	0	2,080
6	Prepayments	393	0	393
7	Unamortized Expenses	349	(256)	93
8	Other Working Capital	(221)	0	(221)
9	Cash Working Capital	(3,386)	(24)	(3,410)
10	Accumulated Deferred Income Taxes	(43,419)	(1)	(43,420)
11	Total Average Rate Base	\$143,697	(\$547)	\$143,150

Northern States Power Company - ELECTRIC
Case No. PU-400-91-112
Rate Base Adjustments
(000's Omitted)

Attachment A
Page 2

Line	Description	(A) Deprec. Study Reduction	(B) October Plant Balances	(C) Info. Service Chg/Backs	(D) Pur. Costs	(E) CWIP Saver Switch	(F) Unamort. Rate Case Expense	(G) Unamort. King Rotor Expense	(H) Unamort. Cogen. Litigation	(I) O&M Exp. Adj.'s Impact	(J) Total
PLANT INVESTMENT											
1	Production		(\$3)	(\$30)	(\$31)						(\$64)
2	Transmission		2	(5)							(3)
3	Distribution		(323)	(11)	(28)						(362)
4	General		(5)	(1)							(6)
5	Common		7	(1)							6
6	Plant Held for Future Use										0
7	Construction Work in Progress						(52)				(52)
8	TBT Investment										0
9	Total Plant Investment		(\$322)	(\$48)	(\$59)	(\$52)					(\$481)
RESERVE FOR DEPRECIATION											
10	Production	(\$205)		(\$1)	(\$1)						(\$207)
11	Transmission										0
12	Distribution		(6)	(1)	(1)						(8)
13	General										0
14	Common										0
15	Total Reserve for Depreciation	(\$205)	(\$6)	(\$2)	(\$2)						(215)
16	ACCUMULATED DEFERRED INCOME TAXES	(\$82)	\$2					\$79			(1)
WORKING CAPITAL											
17	Cash Working Capital										0
18	Materials & Supplies									(\$24)	(\$24)
19	Fuel on Hand										0
20	Prepayments										0
21	Unamortized King Rotor Expense							(201)			(201)
22	Unamortized Rate Case Expense						(37)				(37)
23	Unamortized Cogen. Litigation Expense								(18)		(18)
24	Unamortized CIV Expense										0
25	Other Working Capital										0
26	Total Working Capital						(\$37)	(\$201)	(\$18)	(\$24)	(\$280)
27	TOTAL AVERAGE RATE BASE IMPACT	\$123	(\$314)	(\$46)	(\$57)	(\$52)	(\$37)	(\$122)	(\$18)	(\$24)	(\$547)

Case No. PU-12-813
 EXHIBIT A - Part 4
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Northern States Power Company - ELECTRIC
 Case No. PU-100-91-112
 Cash Working Capital
 (000's Omitted)

Attachment A
 Page 3

Line	Description	(A) T.Y. Expenses As Filed	(B) Adj.s	(C) T.Y. Expenses As Adj.	(D) Exp./ Day As Filed	(E) Exp./ Day As Adj.	(F) Expense Lag Days	(G) Excess Rev. Lead Days(41.75)	(H) Net Rev. Lag \$'s As Filed	(I) Net Rev. Lag \$'s As Adj.	(J) CWC Adj.
1	Coal Fuel	\$16,730	\$0	\$16,730	\$45.84	\$45.84	21.9	19.85	\$910	\$910	\$0
2	Gas Fuel	435	0	435	\$1.19	\$1.19	38.4	3.35	4	4	0
3	Oil Fuel	40	0	40	\$0.11	\$0.11	18.9	22.85	3	3	0
4	Nuclear Disposal	702	0	702	\$1.92	\$1.92	75.6	-33.85	(65)	(65)	0
5	Purchased Power	9,700	0	9,700	\$26.58	\$26.58	33.7	8.05	214	214	0
6	Labor & Related Expenses	19,555	(301)	19,254	\$53.58	\$52.75	8.9	32.85	1,760	1,733	(27)
7	All Other Expenses	17,136	(496)	16,640	\$46.95	\$45.59	40.3	1.45	68	66	(2)
8	Property Taxes	7,054	(12)	7,042	\$19.33	\$19.29	358.4	-316.65	(6,120)	(6,109)	10
9	General Taxes	1,194	0	1,194	\$3.27	\$3.27	42.2	-0.45	(1)	(1)	0
10	Federal Income Taxes	3,208	231	3,439	\$8.79	\$9.42	52.4	-10.65	(94)	(100)	(7)
11	State Income Taxes	730	52	782	\$2.00	\$2.14	34.1	7.65	15	16	1
12	Employee Withholdings	5,342	0	5,342	\$14.64	\$14.64	5.5	-5.50	(80)	(80)	0
13	Totals								(\$3,387)	(\$3,411)	(\$24)

Northern States Power Company - ELECTRIC
 Case No. PU-400-91-112
 Cost of Capital
 (000's Omitted)

Attachment B

Line	Description	Capital Structure	Cost	Weighted Cost

Company Filing - TYE 1991:				

1	Debt	42.40%	8.63%	3.66%
2	Preferred Equity	9.85%	6.13%	0.60%
3	Common Equity	47.75%	12.75%	6.09%
4	Total	100.00%		10.35%

Commission Order - TYE 1991:				

5	Debt	42.40%	8.63%	3.66%
6	Preferred Equity	9.85%	6.13%	0.60%
7	Common Equity	47.75%	11.80%	5.63%
8	Total	100.00%		9.90%

Northern States Power Company - ELECTRIC
 Case No. PU-400-91-112
 Income Statement
 (000's Omitted)

Attachment C
 Page 1

TYE 1991				
Line	Description	Company Filing	Adj.s	Order
Operating Revenues:				
1	Residential	\$36,201	\$0	\$36,201
2	Commercial & Industrial	44,735	(123)	44,612
3	Other Operating Revenues	15,002	0	15,002
4	Total Operating Revenues	\$95,938	(\$123)	\$95,815
Operating Expenses:				
5	Production Expenses	\$41,850	(\$187)	\$41,663
6	Transmission Expenses	1,973	(7)	1,966
7	Distribution Expenses	4,684	(32)	4,652
8	Customer Accounting Expenses	3,066	(21)	3,045
9	Customer Service and Info. Expenses	849	0	849
10	Sales Expenses	22	(12)	10
11	Administration and General Expenses	8,626	(333)	8,293
12	Pathfinder Amortization	205	(205)	0
13	Depreciation Expense	11,868	(427)	11,441
14	General Taxes	8,249	(12)	8,237
15	Total Operating Expenses	\$81,392	(\$1,236)	\$80,156
16	Net Operating Income Before Income Taxes	\$14,546	\$1,113	\$15,659
17	Income Tax Expense	3,717	442	4,159
18	Net Regulated Earnings	\$10,829	\$671	\$11,500

Northern States Power Company - ELECTRIC
Case No. PU-400-91-112
Income Statement Adjustments
(000's Omitted)

Attachment C
Page 2

Line	Description	(A) Depr. Study	(B) October Plant Balances	(C) I/S Charge- backs	(D) Purch. Costs	(E) Receipts Proc.	(F) NRC Fees	(G) Incentive Compens. Program
OPERATING REVENUES								
1	Retail Revenues							
2	Other Operating Revenues	(59)	(1)	(1)	(1)		(12)	
3	Gross Earnings Tax							
4	Total Operating Revenues	----- (\$59)	----- (\$1)	----- (\$1)	----- (\$1)	\$0	----- (\$12)	\$0
OPERATING EXPENSES								
5	Production							
6	Transmission							
7	Distribution							
8	Customer Accounting							
9	Customer Information							
10	Sales							
11	Administrative & General							
12	Economic Development O&M Expense					(40)		(138)
13	Pathfinder O&M Expense							
14	Subtotal	----- \$0	----- \$0	----- \$0	----- \$0	----- (\$40)	----- (\$75)	----- (\$138)
Taxes:								
15	Real Estate & Personal Property							
16	Gross Earnings							
17	Federal & State Income Taxes	(23)	12	2	2	15	24	53
18	Deferred Income Taxes	163	(5)					
19	Investment Tax Credit Net							
20	Subtotal	----- \$140	----- (\$5)	----- \$2	----- \$2	----- \$15	----- \$24	----- \$53
21	Provision for Depreciation	----- (\$410)	----- (\$10)	----- (\$3)	----- (\$4)			
22	Total Operating Expenses	----- (\$270)	----- (\$15)	----- (\$1)	----- (\$2)	----- (\$25)	----- (\$51)	----- (\$85)
23	NET OPERATING INCOME	----- \$211	----- \$14	----- \$0	----- \$1	----- \$25	----- \$39	----- \$85

Northern States Power Company - ELECTRIC
Case No. PU-400-91-112
Income Statement Adjustments - CONTINUED
(000's Omitted)

Attachment C
Page 3

Line	Description	(H) Charit. Donations	(I) Path. Decomm.	(J) Organ. Dues	(K) Cogen. Litig. Expense	(L) D.O.E. Expenses	(M) Impact of R.B. Adj.s	(N) Total
OPERATING REVENUES								
1	Retail Revenues							\$0
2	Other Operating Revenues							(123)
3	Gross Earnings Tax		(31)			(18)		0
4	Total Operating Revenues	\$0	(\$31)	\$0	\$0	(\$18)	\$0	(\$123)
OPERATING EXPENSES								
5	Production					(\$112)		(\$187)
6	Transmission					(7)		(7)
7	Distribution					(32)		(32)
8	Customer Accounting					(21)		(21)
9	Customer Information					(12)		(12)
10	Sales					(47)		(333)
11	Administrative & General	(60)		(34)	(14)			0
12	Economic Development O&M Expense							(205)
13	Pathfinder O&M Expense		(205)					0
14	Subtotal	(\$60)	(\$205)	(\$34)	(\$14)	(\$231)	\$0	(\$797)
Taxes:								
15	Real Estate & Personal Property							(\$12)
16	Gross Earnings							0
17	Federal & State Income Taxes	23	67	13	5	82	7	284
18	Deferred Income Taxes							158
19	Investment Tax Credit Net							0
20	Subtotal	\$23	\$67	\$13	\$5	\$82	\$7	\$430
21	Provision for Depreciation							(\$427)
22	Total Operating Expenses	(\$37)	(\$138)	(\$21)	(\$9)	(\$149)	\$7	(\$794)
23	NET OPERATING INCOME	\$37	\$107	\$21	\$9	\$131	(\$7)	\$671

Northern States Power Company - ELECTRIC
 Case No. PU-400-91-112
 Revenue Deficiency
 (000's Omitted)

Attachment D

Line	Description	TYE 1991		
		Company Filing	Adj.s	Order
1	Rate Base	\$143,697	(\$547)	\$143,150
2	ROR Required	10.35%	-0.45%	9.90%
3	Return Required	\$14,874		\$14,168
4	Return Earned	10,829	\$671	11,500
5	Return Excess (Deficiency)	(\$4,045)		(\$2,668)
6	Combined State & Fed. Income Tax Factor	1.632387		1.632387
7	Sub-total	(\$6,603)		(\$4,355)
8	Estimated Impact of Weighted 12CP			650
9	Estimated Revenue (Deficiency) Excess			(\$3,705)

