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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of Northern States Power Company for Authority to Establish Increased Rates for Electric Service in South Dakota)	Docket No. F-3382

INITIAL BRIEF OF

NORTHERN STATES POWER COMPANY

November 16, 1981

A-55

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I. INTRODUCTION.

A. The Requested Increase in Annual Revenues.

Northern States Power Company ("the Company") filed with the South Dakota Public Utilities Commission ("the Commission") on June 15, 1981, an application to change its electric rates for retail sales in the State of South Dakota to increase annual revenues by $6,184,000 or about 20.67%. The Company proposed that the increase be allocated to customer classes according to the indicated cost of service, subject to moderation. (NSP Ex. 1, p. 2). Without an increase in rates, the Company would earn in the test year only a 7.01% return on average rate base, or only a 5.88% return on common equity. (NSP Ex. 8, p. 3).

The increase in revenue requirement is a result of increases in virtually all of the costs of service, including cost of capital. There have been additions to the rate base, including new underground distribution facilities in South Dakota and the Manitoba Hydro interconnection. In addition, there are new costs caused by regulatory changes, many related to nuclear safety. (NSP Ex. 1, pp. 3-4). Despite these continuing cost increases, it appears that even with the requested rate increase, NSP's electric rates will have decreased over the 1976-1981 time period in real dollars. (NSP Ex. 3, p. 3).

The filed increase was based on a 1980 historical test year, as required by PUC Rules 20:10:13:44, adjusted for certain known and measurable changes. The filing also developed revenue requirements based upon forecast 1981 and

1982 test years, as permitted by PUC Rules 20:10:13:01(11). All three potential test years support at least the requested increase. In fact, had the 1981 Federal tax law changes been known at the time of filing, the filed revenue requirement would have been about $7 million instead of only $6,184,000 (Tr. 291).

B. Overall Staff Position.

The initial Staff recommendation favored at least a $3,056,000 increase. Corrections and refinements before and during the hearing changed the minimum Staff recommendation to $4,603,000. (Tr. pp. 11-13, 253-257, 518-520, 546-552, 562, NSP Ex. 13, Staff Ex. 25). The following tabulation represents NSP's understanding of the Staff minimum recommendation at the close of the hearing, using the minimum cost of equity recommendation throughout for sake of consistency:

ELECTRIC UTILITY - STATE OF SOUTH DAKOTA - DOCKET NO. F-3382
RECONCILIATION OF SDPUC STAFF'S
ORIGINAL POSITION TO THEIR FINAL POSITION

	Revenue Requirements (A)	Revenue Requirements (B)
1. Staff's original position on a rate base of $80,856,000 at 14.0% return on common with a hypothetical capital structure at 38.6% common	$	$ 3,056,000 (1)
Staff adjustments: (2)		
2. Fuel clause revenue decrease	$ 662,000	
3. Postage rate increase	$ 15,000	

ELECTRIC UTILITY - STATE OF SOUTH DAKOTA - DOCKET NO. F-3382
RECONCILIATION OF SDPUC STAFF'S
ORIGINAL POSITION TO THEIR FINAL POSITION

(Continued)

	Revenue Requirements (A)	(B)
4. Nuclear fuel plant related items allocated on an energy basis rather than demand	$ 139,000	
5. Bank service charges	$ 2,000	
6. Cash balances	$ 3,000	
7. Fuel stocks, 1980 year end quantity, August 1981 prices	$ 37,000	
8. Materials and supplies actual through August, 1981	$ 22,000	
9. Increase in rate base associated with use of gross of tax AFDC rate for 1980	$ 20,000	
10. Increases in book depreciation associated with use of gross of tax rate for AFDC in 1980	$ 6,000	
11. Recognize amortization of excess deferred taxes as a continuation of amortization begun in F-3353 and resultant increase in rate base due to decrease in deferred taxes	$ 35,000	
12. Recover 1/5 of recoverable repair allowance deduction disallowed by IRS 1975-1979	$ 239,000	
13. Less ITC associated with repair allowance	$ (13,000)	
14. Adjust accumulated deferred income taxes associated with disallowed repair allowance	$ (42,000)	

ELECTRIC UTILITY - STATE OF SOUTH DAKOTA - DOCKET NO. F-3382
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(Continued)	Revenue Requirements (A)	(B)
15. Working capital treatment of unrecovered portion of disallowed repair allowance	$ 109,000	
16. Interest expense recomputation (synchronization)	$ 113,000	
17. Use of gross of tax rate for AFDC for years 1976-1979	$ 58,000 (3)	
18. Application of AFDC to short term projects previously not receiving AFDC	$ 142,000 (3)	
19. Total of Staff adjustments		$ 1,547,000
20. Staff's position at hearings at a return on common equity of 14.0% with a hypothetical capital structure (38.6% common) on a rate base of $81,482,000		$ 4,603,000

(1) Per Faye Brown testimony less Towers' adjustment of $505,000 related to excess capacity.

(2) Per Staff Exhibit 25.

(3) Per Company Exhibit 13; Tr. pp. 549, 552, 562.

C. Issues for Decision.

The Company and Staff have agreed on many important matters, reflected in part by the relatively small (less than $1.6 million) difference in recommended results. There also appears to be substantial agreement on rate design. There are, nevertheless, several important issues being presented for Commission deliberation and decision.

The questions of prime importance relate to the cost of equity capital, the use of a hypothetical capital structure and a fictitious interest expense for income tax purposes, the equity return on plant capacity above the MAPP minimum reserve, and the proper estimate of nuclear plant decommissioning costs. There are also basic policy issues related to the use of income tax normalization and selection of a test year, including the application of the known and measurable changes standard. Additional matters at issue are the measurement of working capital requirements, treatment of Coordinating Agreement expenses, amortization parameters for the repair allowance and the excess deferred income taxes, donation and advertising expenses, and the level of a late payment charge.

As a result of circumstances surrounding the filing, the Company need not prevail on all of the issues in order to justify the entire requested increase. It should be kept in mind that with the entire increase in place, using flow through accounting, the Company only anticipates earning a return on equity in 1982 in South Dakota of about 11.5%. In a capsule, the issue of the case is should NSP have an opportunity to earn a return on equity of 11.5% or some lesser number?

II. <u>TEST YEAR SELECTION</u>.

A. <u>Level of Filing</u>.

In accordance with current Commission practices, the Company based its requested increase on 1980 book data adjusted extensively but conservatively for known and measurable changes. (NSP Ex. 8, pp. 10-12). With the additional adjustment for tax changes, the 1980 adjusted test year indicated a need for about a $7 million increase. The new rates which result from this case will probably take effect for service on and after December 15, 1981. A similar analysis of revenue requirements using the best available information about the cost of service during the 1982 period when the rates will be in effect, indicates that an increase of $10 million, not $7 million, is needed. (NSP Ex. 8, pp. 51-52, Tr. p. 291, 301). The almost $3 million difference is startling and dwarfs other contested issues in this case.

Although Company and Staff have suggested potential additional adjustments to the 1980 data to close the gap, we all must know by now that there is no way to "adjust" last year's results to look like next year's results. (Tr., pp. 284-285). If the permissible adjustments were expanded to allow a test year reflective of future conditions, a process would be employed that is essentially like the Company's existing planning and budgeting procedures. There is no way for the Commission to close this unconscionable revenue gap without major changes in test year selection and development. (NSP Ex. 8, p. 52).

B. Inadequacy of Historical Test Year and Adjustments.

It cannot be disputed that a test year should ideally reflect as accurately as possible the costs and revenues that will occur during the time period when the rates will be in effect. South Dakota is alone among the five jurisdictions which regulate NSP electric rates in attempting to reflect future conditions by looking backward to last year's results and making some adjustments. It has proven to be a clumsy and inadequate procedure. (NSP Ex. 1, p. 12).

The settlement of the 1980 NSP case, Docket No. F-3353, was designed according to the Staff, to provide an opportunity to earn about a 13% return on equity. The Company had made 19 adjustments to the 1979 historical year. Yet if the increase resulting from that case had been in effect for all of 1980, the Company would have earned only 7.41% on equity. (Ex. 8, p. 16). It is expected that the same rates will produce about a 6.24% return in 1981. (NSP Ex. 8, p. 51). The results of the last case confirm that a revenue gap caused by an unrealistic test year existed then as now.

Staff seems to recognize that at best a 1980 adjusted test year may possibly be reformed to reflect 1981 revenue requirements (Tr. pp. 402-404), although there is no confidence that even that has been accomplished. (Tr. p. 412). It is obvious that adjustments for known and measurable changes through the end of 1981 are not sufficient to reflect 1982 conditions. Although additional fudging such as year-end rate base and attrition allowance are possibilities, the result could not be confidently relied upon as indicative of 1982 conditions. (Tr. pp.

295-296). Past results and current forecasts establish the inadequacy of the historical test year as a basis for ratemaking in today's inflationary times. (Tr. p. 296; NSP Ex. 8, p. 16).

C. Desirability of Forecast Test Year.

The NSP budgeting process is elaborately and carefully undertaken to develop the best estimate of expense, investment and sales levels for the near future. (Tr. 259-268, 272-279). It has historically proved to be quite reliable in reflecting the near future (Tr. 289-291, NSP Ex. 8, p. 16). Although not perfect, the Company's budget is an undeniably superior estimator of future conditions than past results with some adjustments. (Tr. 284-285).

Budgets have been the basis of test years since 1975 for revenue determinations related to 97% of NSP's business. Forecast test years have been filed and audited in 18 rate cases. (NSP Ex. 8, p. 15). As a result of those cases, the Company has earned a return closer to, but still generally below, the allowed returns. (Tr. 266, 300; NSP Ex. 8, p. 16).

The budgets are primarily used in operating, planning and conducting Company business (NSP Ex. 8, p. 16), and for that reason represent the Company's best efforts. In addition, however, because of the importance of their continued use in ratemaking, the long-term credibility of the budgets is of great concern to NSP. (Tr. p. 274). Since any systematic errors would be detected as actual results become available, there is a self-policing aspect to the process. (Tr. 617-621). In addition, the Company has also agreed to implement procedures which would allow any overcollections to be returned to customers with comparable treatment for under-recovery. (NSP Ex. 11, p. 8; Tr. p. 266).

In this case, the 1982 forecast year is the best evidence of conditions that will exist when the rates take effect. (NSP Ex. 8, pp. 12 14, 52). As Mr. McIntyre stated, Tr. p. 280:

> "Generally the experience has been quite favorable in that the actual results track reasonably well with those which are projected. Also, generally speaking, the operating expenses that we have incurred have been greater than those budgeted, and the sales that we have budgeted have been somewhat greater than those we have actually experienced . . .. I would add that there is certainly with today's economy and the changeable conditions, the budget process has become more and more difficult to do correctly. However, it . . . is a better measure of what will happen this year and next year than trying to look backward and assume that 1980, for example, is the appropriate expense, construction and sales levels."

D. <u>Excuses for Continued Use of Historical Test Year</u>.

The Staff has gone to great effort to excuse itself from working with a test year which coincides the time period when the rates will be in effect. There is no argument that the historical test year is superior in principle (Tr. p. 617), and Staff agrees that a forecast year is theoretically correct. (Tr. p. 422). Instead Staff seems to dismiss a projected test year because it requires estimating and is supposedly difficult to audit, at least with current Staff resources.

The Company has consistently supported the proposition that the Commission and Staff should be provided the necessary resources to do the job. Forecasted test years are used by many jurisdictions which also have limited resources. (Tr. pp. 296-297). Their experience indicates that no extraordinary time and expense are involved in projected test year regulation. The Company has suggested ways to facilitate Staff's adaption to the process. (NSP Ex. 11, p. 37). The perennial revenue gap caused by historical test years can and must be closed. Mr. McIntyre testified (NSP Ex. 11, p. 37):

> "Under current procedures, the Commission's use of historical test years in order to save a few thousand dollars in staffing expenses, is working to deprive regulated industries of millions of dollars annually which they are entitled to recover."

As long as rates are set for the future we must all engage in a process of forecasting or estimating future conditions. Historical test years do not avoid the process, but instead yield estimates that are almost certainly wrong. Inspection of earned vs. allowed returns in this still bear this out. The Company has answered Staff's criticisms of the use of forecast data. (NSP Ex. 11, pp. 33-38):

1. There has been no serious criticism of NSP budget accuracy.

2. Cost/revenue relationships of the future are better reflected in a forecast test year than in an adjusted historical year.

3. The accuracy of a forecast year can be assessed as actual results occur, and correction made in the process. A similar evaluation of an adjusted historical year can never be made, except in terms of bottom-line result. (Tr. pp. 617-621).

4. No amount of hurry-up ratemaking will avoid serious revenue gaps caused by out-dated test years.

5. Accuracy in ratemaking, as in archery, is a dubious virtue when one is aiming at the wrong target. 1982 should be the target in this case.

The good experience that other jurisdictions have had using forecasted test years based on NSP budgets suggests that the same procedure would be successful in South Dakota as well. Mr. Towers volunteered that Staff could deal with a partially or fully forecast test year. (Tr. 406-408, 416). He supported 1975 as the test year in the first NSP rate case, F-3062, filed in mid-1975.

E. New Standards.

The Commission's filing rules were patterned after those of the FERC with certain exceptions. The FERC, for instance, has long required the use of future test years on all but the smallest rate cases. Many years of experience under the South Dakota rules, and recent changes in the FERC rules, could provide a basis for a review and tune-up of the filing rules. Part of that review could be a generic analysis of the test year issue. Nevertheless, there is no rule or law that prevents the Commission from using all of the data provided by the record, including the alternative forecast test years. (NSP Ex. 8, pp. 18-19). This forecast data shows that even with the entire requested increase in place, earnings almost certainly will be below the range of reasonableness in 1982.

Mr. McIntyre summarized the test year selection issue (NSP Ex. 11, p. 38):

> "The real question surrounding the propriety of test year selection is intent. If the intent of the Commission and Staff is to guarantee under-recovery of cost, the continued use of a historical test year is the answer. However, if the desire of the Commission and Staff is to properly measure the level of revenues, expenses, and rate base that will exist while authorized rates are in effect, then the use of a projected test year must be adopted as is used in all of NSP's other regulatory jurisdictions."

III. INCOME TAX NORMALIZATION.

Another feature which NSP finds outstanding about South Dakota regulation is the continued requirement of flow through ratemaking. In this it is unique among the regulatory jurisdictions which set NSP rates. (NSP Ex. 8, pp. 23-24). Although NSP is a normalizing company for accounting and ratemaking, special accounting is required to track South Dakota ratemaking and is becoming more complex with time.

Staff continues to justify use of flow-through for the same reasons used by Mr. Towers when he originally introduced it to the Commission in the mid-1970's. Since that time, however, the flow-through advocates have lost ground nationally. Among the intervening events are:

1. The issuance of FERC Order No. 144 which answers and refutes at length every conceivable argument for the superiority of flow through. (NSP Ex. 8, pp. 25-28; NSP Ex. 11, p. 13).

2. Independent studies have found that over the long haul normalization results in lower total revenue requirements. (NSP Ex. 11, p. 14).

3. The postulate of a permanent tax savings under normalization has been shown to be incorrect. (NSP Ex. 8, p. 26; NSP Ex. 11, pp. 14-15).

4. The accounting profession continues to adhere to normalization as the proper reflection of a utility's financial position. (NSP Ex. 11, p. 16).

5. Recent tax law changes indicate a trend toward requiring normalization. (Tr. pp. 536-537).

The Company requests that the Commission begin the move toward normalization now by directing that future rate cases be filed on a normalized basis. (NSP Ex. 8, p. 28). Alternatively the Commission, on the strength of the recent FERC Order requiring normalization, may desire to initiate an investigation or rulemaking to allow careful consideration of the future use of tax normalization in this state. The current rate increase, of course, has been fully justified on a flow-through basis in accordance with past Commission practices.

IV. EXPENSES.

A. Tyrone-Related Expenses.

The Company's position regarding its payments toward the amortization of the Tyrone plant has not changed since the last NSP case. The Company continues to assert that as a matter of law it is entitled to recover as current expenses its payments under the Coordinating Agreement, including the Tyrone component. (NSP Ex. 1, pp. 9-10). This amounts to $455,872 in the test year. (NSP Ex. 8, pp. 34-37). The Company continues to question the Commission's ability and authority to defer consideration of the Tyrone issue until FERC action becomes final. (NSP Ex. 11, pp. 17-18). Judge Miller of the Circuit Court ruled on November 13, 1981, that the PUC did exceed its authority in deferring consideration of the Tyrone matter.

In this case Staff recommended additional deferral of consideration. The Company agrees with Staff that the peculiar status of the issue resulted in a record that does not address the issue at length. (Tr. p. 522). The Company believes that the proper disposition of the matter in this case is to follow the agreed terms in Article IV of the previous settlement agreement in Docket No. F-3353. Therefore, if the Commission desires to appeal the Circuit Court ruling and acquires a stay of the Court's order, the Tyrone expenses would continue to be excluded from rates subject to the carrying charge provisions. If the Commission decides not to appeal or does not acquire a stay of the Court's order, the settlement agreement provision which specifies that if a court reverses the deferral, the Tyrone expense shall be allowed in retail rates subject to refund, including carrying charges since November 23, 1980, should be followed. This provision states:

"If the Commission decides in favor of Staff's motion or its contentions and a reviewing court reverses the Commission Order, an additional $512,000 shall be allowed in NSP's retail rates, such allowance shall be subject to refund should the FERC ultimately order refunds or otherwise not approve the charge of such rates by NSP (Wisconsin) to NSP (Minnesota) and shall be subject to further refund to the extent the Commission has jurisdiction and subsequently disallows (or further defers) such charges."

B. Wisconsin Precertification Expenses.

The Wisconsin PSC and the FERC now require the NSP Wisconsin company to expense rather than capitalize certain precertification expenditures. (NSP Ex. 8, p. 38; Tr. 541). These expenses are required to be billed to NSP Minnesota through the Coordinating Agreement. (NSP Ex. 11, p. 17; Tr. 542). The Coordinating Agreement is a FERC rate schedule and the Minnesota company is legally required to pay the amount billed. (NSP Ex. 11, p. 17; Tr. p. 543). The South Dakota portion of this required expense is approximately $99,000 in the test year.

Staff has apparently recommended that these expenses be recovered from ratepayers, though the testimony is somewhat unclear. (Tr. pp. 543-544). Staff's scheme is to capitalize this portion of the Coordinating Agreement billings to some new account and then recover them someday as a particular Wisconsin plant is in service. If we were dealing with Minnesota company projects, the Staff position would be worthy of some consideration. When the precertification expense is a component of a federally-regulated rate, however, the Staff's suggestion is not a legal option. (NSP Ex. 11, p. 17).

The Rhode Island court, in Narragansett v. Burke, 381 A.2d 1358 (1977) cert. den., 435 U.S. 972 (1979), correctly determined that the reasonableness of the retail utility's claim for operating expenses which were based upon wholesale charges must be governed by the wholesale rates filed or fixed by FERC. The court stated 381 A.2d at 1362:

> "When the operating expense being investigated by the PUC is one incurred through a contract of the utility company with an affiliate, the burden is on the utility to establish the reasonableness of that expense. *** However, the Supreme Court has said that a reasonable rate is that rate filed with or fixed by the FPC. Montana Dakota Utility Co. v. Northwestern Public Service Co., 341 U.S. 246, 251, 71 S.Court 692, 695, 95 L.Ed. 912, 919 (1951). ***Thus the rate increase in the cost of electricity to Narragansett, filed and bonded by Nepco, constitutes an actual operating expense and must be so viewed by the PUC."

Narragansett, as a wholly owned subsidiary of New England Electric System, purchased electric power from New England Power Company, another wholly owned subsidiary of the same holding company. Narragansett requested the Rhode Island PUC to allow it to increase its rates under a purchase power cost adjustment provision, to reflect increases in the wholesale rate pursuant to a rate increase application filed with the FPC. The Rhode Island Commission determined that it could investigate the reasonableness of the costs underlying the new wholesale rate and could prevent Narragansett from passing those costs on to its retail customers if they were "strikingly" unreasonable. The Commission then disallowed Narragansett a portion of the increased purchase power costs. The Supreme Court of Rhode Island reversed, holding that the jurisdiction to determine the reasonableness of wholesale rates rests exclusively with the FPC and that the Rhode Island Commission must view the increase in the wholesale cost of electricity to Narragansett, pursuant to the filed and bonded interstate rate, as its actual operating expense. The Court stated (381 A.2d at 1363):

> "We conclude, therefore, that for the purpose of fixing intrastate rates, the PUC must treat Nepco's R-10 interstate rate filed with the FPC as a reasonable operating expense."

See also, United Gas Corporation v. Mississippi Public Service Commission, 127 So.2d 404 (Mi. 1961) and City of Chicago v. Illinois Commerce Commission, 150 N.E.2d 776, 13 Ill.2d 607 (Ill. 1958).

There is some similarity here to the issue of ultimate recovery of the Tyrone amortization component of Coordinating Agreement billings (Tr. p. 270) and, indeed, both are governed by the same law. It should be noted, however, that there is no pending FERC case regarding these precertification expenses. The $99,000 which is billed and paid will not change. It follows from this that the Commission by its own precedent should not defer consideration of the issue. The Staff's recommendation, however, in effect does defer determination of the recovery of these amounts in retail rates and subjects NSP to uncertainties like those complained of in the Tyrone appeal to the Circuit Court. Payment of a FERC rate is a current expense for accounting and ratemaking and its recovery cannot be pushed to some uncertain future time.

The legal obligation of the PUC to recognize the wholesale purchased power costs in retail rates would exist independent of preemption. Since the Company is legally bound (under exclusive federal law) to pay the FERC rates for wholesale transactions with NSP Wisconsin, the requirement that the PUC recognize and allow it as a legitimate expense for retail ratemaking flows from its own statutes and from the constitutional prohibition against taking of property without due process.

This conclusion is mandated by Montana-Dakota Utilities Company v. Northwestern Public Service Co., 341 U.S. 246 (1951). The Supreme Court held that a "reasonable" expense, in reference to a rate paid by one utility for electric service purchased from another utility, is not an abstraction which can be independently reviewed in any jurisdiction, but rather is established by the "concrete expression in dollars and cents" of the federal regulatory body (341 U.S. at 251):

> "We hold that the right to a reasonable rate is the right to the rate which the commission files or fixes, and that, except for review of the commission's orders, the courts can assume no right to a different one on a ground that, in its opinion, it is the only or the more reasonable one."

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> "We hold that the right to a reasonable rate is the right to the rate which the commission files or fixes, and that, except for review of the commission's orders, the courts can assume no right to a different one on a ground that, in its opinion, it is the only or the more reasonable one."

The dollars and cents paid under the Coordinating Agreement includes the $99,000.00 at issue here. The entire expense must be allowed as a test year expense.

C. Nuclear Plant Decommissioning.

The Company's development of an internal sinking fund for both nuclear fuel disposal costs and nuclear plant decommissioning costs has the support of the Staff (NSP Ex. 7, p. 8; Tr. p. 318) and makes NSP a leader in the industry in this arena. The method levelizes the cost of nuclear facilities over their useful life and is designed to treat both current and future customers as fairly as possible. Adoption of the method itself is attractive in that it decreases the burden on current customers.

Concurrently with the development of the internal sinking fund the Company conducted extensive engineering and economic analysis of the future nuclear plant decommissioning costs. (Staff Exhibits 8, 9, 10 and 11). These studies were used to provide the best possible estimates of the future costs of the decommissioning options. The cost estimates, along with other criteria, were used to select the most viable decommissioning option. The cost of the selected option was then used to develop the annual sinking fund amounts.

The merits of the sinking fund method, the decommissioning options and the cost estimates were the subject of an extensive certification hearing before the Minnesota PUC (NSP Ex. 7, pp. 5-8) which included participation by the Minnesota Staff and consumer groups. The total program presented in this South Dakota rate case was finally adopted by the MPUC on February 26, 1981. (Staff Ex. 12). The cost estimates will receive periodic future review.

The decommissioning cost estimates were developed by consultants with extensive experience and expertise. (NSP Ex. 7, pp. 7-8). They were performed using a minimum base plus contingency method, which is customary and appropriate for engineering estimates of single event costs. (NSP Ex. 7, pp. 9-10; Tr. p. 242). The best estimate of the future cost includes the cummulative effect of the variability of each task, which for these studies was a 25% total variability or contingency factor above the minimum base amount.

The Company's books must now be maintained in accordance with the MPUC certification order. It appears that unless some deviant result occurs in South Dakota, a uniform set of books for all jurisdictions will be achieved for these accounts. (NSP Ex. 7, pp. 2-9; Tr. pp. 328-329). Given the overall agreement on the sinking fund method, it would be a shame to destroy the efficiency of uniform accounting over one component of the cost estimate, particularly a component that can be reviewed in the future periodic certification proceedings.

Mr. Towers has suggested that the estimated decommissioning cost be reduced by 20% in this case (revenue impact in the test year is $142,000. Tr. p. 326) to "match the Company's actual estimate of decommissioning costs."

(Staff Ex. 15, p. 7). His assumptions and rationale are stated at pp. 11-12 of his testimony:

> "A 'contingency' allowance suggests that there is some uncertainty in the engineering cost estimates. But uncertainty indicates that the engineering estimates could be either too high or too low. In the absence of some persuasive evidence to the contrary to demonstrate that the detailed estimates prepared by NES are wholly or, on balance, understated by 25% it would be unreasonable, in my opinion, to assume that this is true."

In other words, at this point Mr. Towers was of the opinion that the best estimate of disposal cost, not one that was too high or too low should be used. (Tr. p. 317, l. 22).

Mr. Ewers testified at length based on his familiarity with nuclear projects engineering estimates and the NES studies that the base minimum amounts were not best estimates or expected values with a range of higher or lower possibilities. The evidence clearly establishes that Mr. Tower's assumption was simply not correct. He stated (Tr. pp. 213-214):

> "Q. If this Commission adopts Mr. Towers' adjustment in removing the 25 percent contingency that was in the engineering study, would that, in your opinion, amount to a deliberate understatement of your best estimate of the costs?
>
> A. In my opinion, yes.
>
> Q. Why is that?
>
> A. For the reasons outlined that the inflation rate assumed is very modest. Secondly, the decommissioning cost estimate, the base cost estimate, is very modest on the low side. In my experience, I have never seen a nuclear

> project . . . come in under the estimate. The variability has always been greater. People are more optimistic about the price and the cost of doing these operations. The variability ar evidenced by the estimate is all one sided. It is minus zero/plus 25%."

Mr. Towers was not acting improperly in raising the question since the fact that the base estimate was a low point, not a midpoint, was not known to him at the time (Tr. pp. 315-316, 318-320), and he has no personal experience with the development of engineering estimates (Tr. p. 314). The Company, however, has conclusively shown the error in his assumptions and satisfied the test set up by Mr. Towers in his prefiled testimony for the inclusion of the contingency factor in the total decommission cost used in this rate case. Without the contingency factor, the estimates are in fact understated.

Mr. Towers' change during the hearings to recommending a low-end estimate rather than a best estimate (Tr. 322-324), knowing that it would cause underrecovery of the costs (Tr. p. 325) is interesting, but not credible.

The goal of the procedure should be to use the best available estimate of future decommissioning costs (Tr. p. 317). Mr. Towers correctly recognized that the basis of the sinking fund method is that, "The decommissioning cost should be recovered from current ratepayers. Decommissioning is an inherent part of the plants and should be borne by the present ratepayers who are benefitting from these plants." (Staff Ex. 12, p. 4). A deliberate underestimation of decommissioning costs over the life of the plants will improperly shift a large cost burden to future customers who will receive no benefit from the plants. (Tr. pp. 247-249; 325-328). Staff agrees with the principle of current recovery based on best estimates, but violates the principle by clinging to a mistaken adjustment.

The correctness of the decommissioning estimates will not be finally determined in this case, but are subject to periodic review by both this Commission and the MPUC for update and correction as new information becomes available. (NSP Ex., pp. 5, 11; Tr. pp. 214-215, 246-247). On the facts available to date, NSP's estimates of decommissioning costs are the best estimates available, and these include the 25% positive contingency.

NSP has developed a sophisticated procedure for a fair sharing of the future decommissioning costs based on conservative estimates, with a resulting overall decrease in current revenue requirements. It would be most unfair for this Commission to reward those efforts by guaranteeing an unfair sharing of those costs and gumming up the accounts by adopting Staff's mistaken low-end estimate.

D. Actual Income Tax Expense.

The 1980 adjusted test year filed by the Company includes an actual income tax expense derived using the actual interest available as a tax deduction. (NSP Ex. 8, pp. 49-50). Although there is no supporting testimony by either Ms. Brown or Dr. Wilson, Staff exhibits use a fictitious income tax expense based upon interest expense deductions which do not exist in the real world. This adjustment, in addition to being unsupported by credible testimony, makes no common sense.

Staff has consistently advocated the absolute fairness of flow through treatment of income taxes, stating that customers should pay actual income taxes, not some other amount. The Company has agreed that customers should pay actual taxes, but on a normalized basis for fairness between present and future customers. In this adjustment the Staff is suggesting that customers be relieved forever of their obligation to reimburse the Company for the actual income tax expense. (NSP Ex. 11, p. 23; Tr. pp. 554-555). Dr. Wilson can make whatever recommendation he wishes about the cost of capital. The Company has a right to recover an expense it is legally required to incur.

The result of allowing the adjustment would be to deprive the Company of a reasonable opportunity to earn the allowed overall rate of return on whatever real or imaginary basis it may be derived. (Tr. 557-562). The impropriety of this suggested exclusion of an actual tax expense is correctly analyzed by the Hawaii PUC in the decision Re Kauai Electric Division of Citizen's Utility Co., 30 PUR4th 299, 324 (Hawaii PUC 1979):

> "When this commission chooses to utilize a hypothetical capital structure as a tool for reaching a judgment concerning fair rate of return, it essentially is normalizing the capital structure so that the capital structure is not weighted too heavily to the 'senior cost of capital' or the equity component. The act of normalization reduces the

overall capital costs and decreases the revenue requirements. The county's proposal to increase the interest expense associated with the hypothetical debt component to reduce the amount of income taxes to be allowed cannot be allowed. The reason the county's proposal is not acceptable is because its proposal not only creates a fictitious income tax liability which reduces the income tax expense and revenue requirements but after the rates are placed into effect, it also reduces the income available for earning a fair return because the income tax liability is substantially higher than that allowed in the rates. In effect then, the rates are designed so that the company does not have an opportunity to earn a fair return. We conclude that the county's proposal is unreasonable and cannot be allowed. We further note that the courts have always declared such a procedure as that proposed by the county and adopted by the consumer advocate to be inappropriate whenever a commission has attempted to follow it. Re Diamond State Teleph. Co. (1954) 48 Del 317, 3 PUR3d 255, 103 A2d 304; (1954) 48 Del 497, 5 PUR3d 493, 107 A2d 786; (1955) 49 Del 203, 8 PUR3d 286, 113 A2d 437; (1959) 51 Del 525, 28 PUR3d 113, 149 A2d 324; General Teleph. Co. of Ohio v Ohio Pub. Utilities Commission (1963) 174 Ohio St 575, 49 PUR3d 264, 191 NE2d 341; Indiana Bell Teleph. Co. v Indiana Pub. Service Commission (Ind Cir Ct 1952) 93 PUR NS 480; (1955) 235 Ind 1, 11 PUR NS 209, 130 NE2d 467; General Teleph. Co. of Michigan v. Michigan Pub. Service Commission (1977) -- Mich App --, 21 PUR4th 563, 260 NW2d 874."

The suggested adjustment amounts to a $67,000 penalty which is illegal and improper. (Tr. pp. 561-562).

E. <u>Amortization of Deferrals in Excess of Prevailing 46% Rate</u>.

Most of the laws enacting liberalized depreciation for tax purposes require that the taxes payable relating to the timing differences between tax and book lives be deferred and flowed-back over the life of the investment generating the tax benefit. The deferrals are computed at the current tax rates in effect. For simplicity purposes and cost savings in record management, flowbacks are also computed at the current tax rates in effect by a procedure which the FERC audit staff has found to be adequate and fair.

Effective January 1, 1979 the Federal tax rate was lowered to 46% from 48%. Staff has proposed an adjustment in Staff Exhibit 23, pp. 10-11, to amortize over three years the difference in deferrals made at the Federal tax rate of 48%, and what they would have been if the tax rate had been 46%. The annual amount of that adjustment is $133,000.

Company and Staff agree on the basic issue that all tax deferrals will be flowed-back to the ratepayer. Staff and Company also agree that this adjustment is the second year of a three year amortization as proposed in F-3353. It is the time of the flowback which is in question. Staff proposes that a 2% increment be scraped off the top of all deferrals made prior to January 1, 1979, and flowed-back over three years. Company disagrees for two reasons:

First: The Company is currently operating with a procedure for flowing-back deferred taxes which in its opinion equitably treats ratepayer and Company alike. The FERC audit Staff initially took exception to Company's procedure. (NSP Ex. 11, p. 9). The audit staff withdrew its objections upon examining the procedure thoroughly.

FERC Order No. 144 addresses excess deferrals extensively. Pages 7 and 8 of NSP Ex. 11, quote from this source. In short, "any disparity between the actual tax effect in the year the timing difference originates and in the year the timing difference reverse is a normal and inherent part of the accounting process". Staff's proposal, at additional ratepayer expense, would cause a disruption of the normal accounting process which already guarantees that every deferred tax dollar will be flowed-back to ratepayers.

Second: If a three year write-down of accumulated deferred taxes results from a drop in the tax rate, what happens if the tax rate increases? The answer would be to inflate prior accumulated deferred taxes by imposing an amortization of the appropriate amount. As can be seen, either direction is an administrative headache and results in increased administrative costs.

To reiterate, in spite of tax rate changes the Company uses a procedure that guarantees the flowback of all deferred tax dollars.

F. Repair Allowance Amortization Period.

In recent negotiations, subsequent to an audit, the Internal Revenue Service disallowed $28.6 million in repair allowance tax deductions which the Company took in the years 1975-1979. The Company proposed a three year amortization of those disallowed deductions in NSP Exhibit 8, pp. 43-45. Company and Staff agree in principle on the issue that ratepayers should be responsible for reimbursing the Company for disallowed tax benefits which customers received in prior years. However, Staff has proposed recovery over five years versus Company's proposed three year recovery.

Part of Staff's adjustment was to determine the actual amount of repair allowance tax benefit flowed through to the customers. The Company does not object to that rationale. However, rates actually providing the tax benefit have been in effect approximately 3½ years since March 17, 1978 (Staff Exhibit 25, p. 4 of 5). Company's position is that recovery should be based on a comparable time frame. The Company and Staff agree as Ms. Brown states at Tr. p. 528, that benefits disallowed should be returned to the Company on the same basis they were accrued.

In addition, since Staff recommends three years for excess deferrals, the Company recommends three years for repair allowance. Going to the three year amortization would increase the revenue requirement by $159,000 over Staff's recommendation on the test year while reducing revenue requirements starting in December of 1984, instead of December of 1986.

G. Communications Expense.

The Company included in the test year expenses an amount for communication expenses actually incurred in 1980 which provided direct benefits to the ratepayers. (NSP Ex. 8, p. 32). The Staff supported the inclusion of these expenses above the line with the exception of $3,741 which relates to energy supply information. The information helps customers make decisions about the purchase and operation of appliances and equipment and informs them about the local energy supply situation as it relates to their fuel choices and consumption patterns. (NSP Ex. 11, p. 29). These communication efforts benefit customers and should not be excluded from the cost of service.

A utility has an obligation to maintain contact with the economic life of the area it serves, and advertising is a prime means for that contact. Pennsylvania PUC v. York Water Co., 78 PUR3d 113, 134 (Pa. PUC 1968). The test year advertising expense is not only related to beneficial communications, but it is reasonable in amount. The type and quantity of advertising is a matter to be decided by management. Such expenses should be scrutinized by the Commission but not reduced unless it clearly appears they are excessive, unwarranted or incurred in bad faith. New England Telephone and Telegraph Co. v. Dept. of Public Utilities, 275 N.E.2d 493, 517 (Mass. 1971); West Ohio Gas Co. v. PUC of Ohio, 294 U.S. 63, 72 (1935); Central Maine Power Co. v. PUC, 136 A2d 726 (Maine 1957); Petition of New England Tel. and Tel. Co., 66 A2d 135, 145 (Vt. 1949);

H. Donations.

The Company has requested recovery of $43,837 in test year donations to selected beneficiaries in the South Dakota service area. This is a reasonable amount, targeted to benefit the customers and community as a whole, and an appropriate expenditure for a corporate member of the South Dakota community. (NSP Ex. 8, pp. 32-33). These local organizations, such as the United Way, depend upon corporate as well as individual contributions, and a change in historical Commission practice will assist utilities in assisting the needs of these worthwhile organizations and their beneficiaries. (NSP Ex. 1, p. 10-11).

As Staff points out, these contributions are not absolutely essential to providing utility service to the area. The requests for donations could be turned down and life for most of us would go on. At a time when government agencies are under financial pressure to curtail social programs, however, it is important to encourage support of private agencies by both corporate and individual citizens. (NSP Ex. 11, pp. 27-28). The Commission can do this by beginning to allow regulated industries to recover some of their charitable donations through rates. (NSP Ex. 11, p. 28).

I. Responsive Adjustments.

1. Staff Testimony.

The revenue gap caused by the reliance on a 1980 test year to set rates for 1982 was addressed by Staff witnesses. In response to probing questions by the Commission, Mr. Towers ventured beyond the scope of his prepared testimony and discussed the possibility of closing the revenue gap through a more thorough process of historical test year adjustment for known and measurable changes. Although such a process is unlikely to close the gap entirely (Tr. p. 405), the Company listens carefully to suggestions on helping the situation.

In past cases involving NSP and other utilities, the Staff and Commission have been very strict in the application of the known and measurable change test. The result was that ground was given only grudgingly. For instance, an inflation adjustment of zero was often allowed when the applicant was unable to establish a realistic inflation factor with sufficient "certainty". (Tr. 567). In discussing on the record the need to reduce the revenue gap, the Company heard or sensed a new willingness on the part of the Staff and the Commission to make the historical test year approach work better.

It was stated that there is "no limitation on the number or the kinds of known and measurable changes that could be recognized" (Tr. p. 389), that changes occurring up to the implementation date of rates and beyond could be recognized in adjustments (Tr. p. 401), and that as we progress through 1981 additional changes can be recognized (Tr. p. 404). We were told that virtually all expense categories are candidates for adjustments, right down to pencils and rubber bands. (Tr. p. 398-400). Mr. Towers believed that with sufficient adjustment, the 1980 year could be made to look a lot like a 1981 forecast year. (Tr. pp. 390, 399). Mr. Rislov echoed the same aspiration. (Tr. pp. 626-627):

> "Q. As a general proposition you favor as comprehensive adjustments as possible within your parameters?
>
> A. As long as they can be reasonably measured under known

changes, I think, I see no reason why we can't accomodate those changes, if considered proper.

Q. Now, known and certain at what point in time in this case?

A. Well, we'd certainly like it to be known and certain before the Order has come out, but the Staff has accepted changes up through the hearing time. I mean it would be much nicer if all the adjustments were known and measurable when the case was filed, but in a lot of situations that just isn't the case, and we have accepted adjustments as late filed exhibits to rate hearings, rate cases."

To cap off the discussion, Staff emphasized that it was primarily the burden of the applicant to identify as many adjustments to make a historical test year as closely representative as possible of future conditions (Tr. pp. 397, 409) to minimize the revenue gap problem.

2. Company Response.

The Company must do all it can to reduce or eliminate chronic shortfalls in earned return. Perhaps for this case a very comprehensive adjustment process is a reasonable substitute for a forecast year given the conservative level of the requested rate increase. To meet the challenge presented by the oral Staff testimony the Company examined data already a part of the case which could be identified and recognized as necessary changes to the historical test year to simulate future conditions. We were concerned to find out if Staff's call for more comprehensive adjustments to reduce the revenue gap was a sincere new position or mere posturing. (Tr. pp. 628-631, 637).

Mr. McIntyre prepared NSP Exhibit 20 using data which had previously been introduced into evidence. (NSP Ex. 8, pp. 14, 18-19; Tr. pp. 637, 640, 643-646). He stated the reason for Exhibit 20 (Tr. p. 637):

> "I believe the Commission yesterday expressed an interest in determining if additional adjustments could be made which would allow the actual return earned to more closely approximate that which the Commission will eventually allow. The limited additional known and measurable changes which I've quantified are offered as possible adjustments in this case in response to the interest shown by the Commission and the Staff to have this data available to them."

The three adjustments quantified in NSP Exhibit 20 do not solve the revenue gap problem, but if adopted would constitute a sincere attempt by the Commission to ameliorate this chronic problem.

The Company is dismayed at Staff's objection to Commission consideration of the NSP Exhibit 20 adjustments coming as it does after a Staff challenge to the Company to suggest more adjustments to make the historical test year more current. A continuing objection casts doubt on Staff's expressed commitment to make the historical test year process work better, and the Company hopes the objection will be dropped. The quantification shown in NSP Exhibit 20 is precisely the information the Commission needs in order to begin closing the revenue gap within the historical test year process. The conditional acceptance of NSP Exhibit 20 and the related testimony should be made final.

3. Inflation Adjustment.

The Company included in its filing an inflation adjustment based on the weighted change in unit prices of expenses directly related to South Dakota operations. (NSP Ex. 8, pp. 38-39). Only one half or 50% of the calculated inflation amount was used to insure that the proposed adjustment would be very conservative and acceptable to the Staff (NSP Ex. 8, p. 39; Staff Ex. 23, pp. 16-17). Without the 50% factor, it is likely that the adjustment would not have been accepted by Staff. (Tr. pp. 567, 650). In Staff's view, using ½ of the expected increase in expenses results in approximating the end of 1980 conditions. (Tr. pp. 567-568).

As indicated by Mr. McIntyre, allowance of the remaining one-half of the quantified inflation would allow for inflation of only 3.86% in 1981 and an additional 3.86% in 1982. (Tr. pp. 650-651). Not even "Reaganomics" is expected to reduce inflation to this modest level. (Tr. pp. 650-651). More realistically, this additional adjustment of $280,000 (Tr. pp. 650-651; NSP Ex. 2, Sch. 1) would bring the test year expense levels up to a mid-1981 level, approximating those of a 1981 test year. At this level the expenses would still be conservative in light of the December 15, 1981 probable effective date for new rates. These are not expenses related to revenue production, and there are no offsetting sales increases. Recognition of the full inflation adjustment will help to close the revenue gap. Ignoring this adjustment will help continue the past pattern of earnings below allowed levels.

4. Wage Adjustment.

The Company's filing on the 1980 test year included an adjustment for January 1, 1981 wage increases based on December 31, 1980 employment levels (Tr. p. 651). The filing and other exhibits also contain the budgeted January 1, 1982 wage increases of 11%. (Staff Ex. 15; Tr. pp. 639-640, 655). Staff stated on the record that wage increases subsequent to the test year can be recognized in adjustments relatively easily (Tr. 405) and that the January 1, 1982 wage increase could be recognized without objection if known by the time of final decision. (Tr. p. 414). Mr. Towers also indicated by way of example that a wage increase occurring six months after new rates take effect could be recognized by including recovery of one-half of the wage increase in the rates. (Tr. p. 401).

The 11% wage increase, while not a final number at this time, is known more certainly than at the time of the filing (Tr. p. 653) and is the best estimate of the planned increase. (Tr. p. 652). It is, in fact, a conservative number considering the September 1, 1981 wage increase which has now occurred. As requested, the South Dakota portion of this September 1, 1981 increase was supplied for the record by Mr. McIntyre (Exhibit - EJM-5, Sch. 1) and is $50,000.

Schedule 2 of NSP Exhibit 2 was derived in the same way as earlier test year wage adjustments. (Tr. p. 653). It computes a wage adjustment using January 1, 1982 wages applied to end of 1980 employment levels. As a result, it does not account for any expansion of the work force or offsetting revenues created by new employees. (Tr. pp. 654-655). Use of this wage level is akin to using end of year rate base without the problem of matching end of year revenues. (Tr. pp. 653-654). This conservative wage adjustment totals $603,104.

The $50,000 increase in test year labor reflects only the September increase related to the annualized labor expenses for those employees on the Company's payroll as of December 31, 1980. (Line 3 of the late filed Exhibit _____(EJM-5), Schedule 1). Excluded from this amount is the additional labor expense resulting from promotions, additional employees, wage rate changes, etc. Recognition of these items on an annualized basis would increase test year labor by an additional $182,000. (Net of lines 5 and 6 of late filed Exhibit _____(EJM-5), Schedule 1).

These amounts reflect the actual wages and salaries in effect as of October 23, 1981 and require the further adjustment as developed on Schedule 2 of Exhibit 20 in order to accurately reflect the labor expense when the rates from this case will be in effect.

While it could be argued that a portion of the additional $182,000 should be interpreted to be "revenue producing", the weight of these actual labor expense dollars gives further support to the January 1 increase of 11 percent developed on Schedule 2 of Exhibit 20.

Also in support of the reasonable nature of the 11 percent January 1 increase is the current salary and benefit offer before the union of 10.3% for combined wage and benefit increase. Agreement between the union Bargaining Committee and the Company has been reached and it is expected that the union membership will approve the contract offer. This level will most certainly be the floor of any ultimate settlement of the contract and supports the use of the Company proposed adjustment. The increase included in the ultimate union settlement will also apply to all non-union employees.

In reviewing the potential adjustments to labor, the Company feels that it is essential that the September 1 increase of $50,000 be recognized, as well as the adjustment of $603,104 shown on Exhibit 20, Schedule 2. While the Company believes all or major portions of the additional $183,000 shown on late filed Exhibit _____ (EJM-5) are appropriate, it would forego that amount if the January 1, 1982 increase is recognized. Its recognition would help to close the revenue gap.

5. FICA Adjustment.

The Company submitted Schedule 3 of NSP Exhibit 20 as a corollary to Schedule 2. This schedule is intended to show the changes in FICA taxes on January 1, 1982. (Tr. pp. 653-654). Mr. McIntyre has revised Schedule

3 as originally provided to reflect those portions of increased FICA taxes which had already been recognized by Staff as well as a further increase in the FICA base from $31,800 to $32,400. As originally filed, the actual FICA taxes been used on line 6 rather than the "adjusted FICA taxes" as proposed by the Company and accepted by the Staff.

The adjustment is computed using the new statutory tax rate applied to the payroll including the Schedule 2 adjustment. The new rate and base are known with complete certainty. This adjustment is developed from the employee base as of December 31, 1980, and includes no amounts for additional employees or "revenue producing" increases.

The total adjustment per Revised Schedule 3 of Exhibit _____ is $34,280 rather than the $93,881 as previously indicated.

Theoretically, increased FICA tax would also be associated with the $182,000 further labor adjustment developed on Schedule 1 of late filed Company Exhibit, (EJM-5). However, because of the insignificant effect, the Company has not quantified it.

6. Conclusion.

These three adjustments total about $917,000. The additional data in NSP Ex. _____(EJM-5) supports further adjustment of from $50,000 to $182,000. These adjustments cannot by themselves make 1980 look like 1982, the year the rates will be in effect. They could, however, eliminate about 1/3 of the identified revenue gap and yield a revenue requirement quite similar to the unadjusted 1981 forecast year. They are the kinds of adjustments that Mr. Towers stated can and should be recognized in order to provide the Company with a more realistic opportunity to actually earn the allowed return. (Tr. pp. 409, 414). The Company views these adjustments as essential if the Commission is serious about using historical test year ratemaking to produce a fair and reasonable result.

V. RATE BASE.

A. Surplus Capacity.

1. Mr. Towers' Suggested Adjustment.

The planning, design and operation of an electrical generation system to produce economical, low cost power over a long period of time in this uncertain world requires the careful attention of experienced managers and engineers. The competence of the Company's personnel in performing this task is evidenced by generation costs being among the lowest in the region and its rates among the lowest in the state. As a general matter it would seem that the Commission should encourage NSP to continue its pursuit of the goal of low cost, reliable power supply.

Mr. Towers has no training or experience in this field. (Tr. p. 332). He has nevertheless been appearing in South Dakota and around the country offering opinions on the measurement of excess capacity. It is doubtful that he can speak as an expert on the subject. His analysis in this case is incompetent, incomplete and improper. If adopted it would penalize the Company for good management decisions and create incentives for management to pursue goals other than low cost and reliable power supply.

He suggests that any generation or other capacity in excess of the MAPP pool minimum reserve requirement is not needed and no equity return should be earned. He could not decide if a portion of all plants or a selected group of peaking plants should be branded "excess". Though trained in economics, he apparently gave no consideration to the complex cost considerations in adding and retiring capacity. His "analysis" consists entirely of the misuse of one solitary power pool requirement (Tr. p. 333), but resulted in the suggested large deduction from revenue requirements of up to $505,000.

2. <u>Existence of Excess Capacity</u>.

a) <u>Misuse of MAPP Reserve Requirement</u>.

MAPP requires each member to maintain at least a 15% reserve margin to ensure that no member will adversely affect the reliability of the entire region and other members. (NSP Ex. 2, p. 3; Tr. pp. 17-18). Each utility retains responsibility for evaluating its own system to determine the level and type of reserves for purposes of not just reliability, but also cost minimization and efficient operation. (NSP Ex. 2, p. 3; Tr. p. 26). Mr. Towers has latched onto the <u>minimum</u> MAPP reserve requirement and suggested its use as the <u>maximum</u> acceptable amount for ratemaking purposes. It is an insufficient and erroneous standard for ratemaking purposes.

As discussed below, there are compelling reasons which have led NSP to install generation in excess of the MAPP minimum. Even if lesser reserves were desirable, however, it is not realistic to expect a utility to have installed capacity precisely equal to the minimum. A utility cannot be held to such a standard of precision. An adjustment similar to that suggested by Mr. Towers was rejected by the Federal Power Commission in the decision Re Southern California Edison Co., 23 PUR4th 44, 52 (FPC 1977):

> "Because of the long lead time required for the construction of new generating capacity, Edison plans years in advance for the installation of the new capacity needed to maintain reliable service to its customers. Such planning is predicated on projections of anticipated customer demand during this future period as well as estimates of the capacity needed to provide service reliably to this projected demand. It is in the nature of things that projections of future circumstances are rarely precise. This is especially the case in the area of electric utility reliability where underestimations of needed reserves could spell disaster.
>
> In this proceeding, however, cities argue that the generating reserve margin experienced on Edison's system during the test period, being in excess of the company's planned goal, should result in an artificially limited rate base for ratemaking purposes which only reflects cost figures on the basis of an 18 per cent reserve margin, rather than at the actual 26.16 per cent reserve margin experienced. The impact of cities' exercise would be to reduce Edison's net allocated rate base by approximately $4 million . . . shifting the cost of maintaining the alleged "excess" of installed capacity to the company's investors without any return granted

thereon. There is little merit in cities' position. It has not been shown that Edison's historical planning was extravagant or imprudent, such as would necesarily have result in excess or unnecessary generating capacity being available at a time in the future. Even assuming arguendo that unneeded capacity was available on the Edison system during the test period, this fact proves nothing with respect to Edison's prudency in the planning and construction of additional capacity. Cities have failed to show that the company's production rate base and expenses are unreasonable for the reasons stated. Accordingly, the suggested reduction in rate base is rejected."

Mr. Towers' suggested standard is also unrealistic because capacity cannot be added efficiently in small increments. After a major plant is added, a utility is certain to have capacity above any minimum requirement. As stated by the Ohio PUC in its decision Re Cleveland Electric Illuminating Co., 38 PUR4th 498, 508 (Ohio PUC 1980):

> ". . . assuming an appropriate reserve criteria can be established, it must be recognized that in light of the extensive lead times involved in the construction of generating facilities and the variety of factors which can influence load growth, it is obviously unrealistic to assume that any utility would have the forecasting capability which would allow it to add capacity in the precise increments required to maintain the theoretically appropriate margin. The problem is intensified by the large size of the units being added today."

This was echoed by the Ohio Supreme Court in City of Cleveland v. PUC, 406 N.E.2d 1370, 1374 (1980):

> "Since utilities must anticipate load growth years in advance to maintain adequate capacity to ensure reliable service, it is unrealistic to expect a utility to have only the precise amount of capacity needed at a given time."

See also Re Tampa Electric Co., 92 PUR3d 398 (Fla. PSC 1971). Clearly the ratemaking criteria suggested by Mr. Towers cannot be met. Whatever the target reserve margin, it unavoidably will be exceeded from time to time. Mr. Towers recognizes this in principle (Tr. p. 351) but not in his adjustment computation.

b) Allowance for Management Discretion.

Mr. Towers stated that management should be given some latitude in installing capacity in excess of the 15% reserve (Tr. p. 367) and that it may be prudent to do so (Tr. p. 366). He refused to state how much latitude between 0 and 794 Mw would be proper because he had no basis for any number. (Tr. p. 367). His adjustment, again contrary to his testimony, allows no latitude.

There are circumstances where it is prudent to invest in more than a minimum amount of capacity and imprudent not to do so. The expansion of a utility system is a judgmental decision which management must make without being second-guessed by regulators and courts. Northwestern Bell Tel. Co. v. State, 216 NW2d 841, 851 (MN 1974); Minnesota v. Tri-State Tel. & Tel. Co., 284 NW 294, 307; 28 PUR NS 158 (MN 1939). The principle that capacity additions are primarily within the province of management is very well established. Re New York Telephone Company, 2 PUR 4th (NY PSC 1973); State of North Carolina v. General Telephone Co. of the Southeast, 92 PUR3d 209, 184 SE2d 526 (NC 1971); Latorenau v. Citizens Utility Company, 59 PUR3d 1, 209 A.2d 307 (Vt. 1965).

This matter is discussed in detail in the important decision Wisconsin Telephone Co. v. PSC, 30 PUR NS 65, 287 NW2d 122 (Wis. 1939). The commission had excluded 8% of the plant from rate base as excess capacity without any findings of imprudence. The Court stated, 30 PUR NS at pp. 111 and 114:

> ". . . it should be remembered that a public utility is required to furnish service when and as demanded by the public. It may not, as a private enterprise may do upon the basis of proper future advantages, choose a time for the enlargement of its plant. Being compelled to provide service when and as demanded it must have some latitude with respect to plant enlargement. We think some misconception is likely to arise by considering the rights of past ratepayers, and future ratepayers. The ratepayers are the public and it is the public which demands the service. The public does not change. It is a constant factor and one which the company must at all times take into consideration."
>
> ***
>
> "If the theory of the Commission is sound then rates are to be constructed on the basis of remanagement of the property in the light of experience and present conditions. We do not so understand the law even where confiscation rather than reasonable rate base is the issue. The company is entitled to have the matter of excess plant determined on the basis of the existing plant which is being valued. The Commission may not construct a hypothetical plant which would render an equivalent service or reconstruct in theory parts of the existing plant and on that basis hold that any provision in the existing plant over and above that found in the theoretical plant is excess plant, which seems to be substantially what was done in this case. This gives no effect to the broad discretion vested in the management. In making its determination in this case the Commission

> substituted the discretion of the witness for that of the managers of the property without in any way impeaching the discretion of the managers. It is much easier to point out past errors in management than it is to avoid future mistakes. A reasonable rate is one based on reason as applied to the property of the utility. While the company must bear the burden of an unreasonable extension of its plant and the risk that portions of it prudently acquired may become obsolete or not useful, it should not be penalized for failure exactly to anticipate future demands for service in a period of depression." (Emphasis added.)

The North Carolina Supreme Court also spoke of the latitude which management must be allowed, North Carolina v. Mebane Home Telephone Co., 257 SE2d 623, 32 PUR4th 340, 350 (NC 1979):

> "A public utility is under a present duty to anticipate, within reason, demands to be made upon it for service in the near future. Substantial latitude must be allowed the directors of the utility in making the determination as to what plant is presently required to meet the service demand of the immediate future, since construction to meet such demand is time consuming and piecemeal construction programs are wasteful and not in the best interests of either the ratepayers or the stockholders."

c) Company Decisions on Reserve Capacity.

The Company has exercised its discretion in reserve levels in pursuit of the goal of low cost, reliable power supply. (Tr. 26). The standard used by the Company to determine the best reserve level involves consideration of types and sizes of existing facilities, fuel availability, individual plant reliability, plant locations on the transmission system, customer daily and seasonal load patterns, opportunities for new facilities with lower overall costs, and the possible loss of major facilities due to governmental action or other cause beyond management's control. (Tr. pp. 26-27, NSP Ex. 2, pp. 4-5). Company planners are in the best position to apply this complex standard (Tr. p. 47) and be judged by it.

Mr. Towers, however, has not applied this standard in suggesting his adjustment. He has instead misapplied the MAPP minimum. (Tr. p. 363). He states at Tr. pp. 365-366:

> "Q. Would you recommend that the planners at NSP adopt a standard more like what I think you are advocating here, which is to have on hand in any given year only the minimum reserve requirement required by MAPP as a qualification of MAPP membership, and look at absolutely nothing else as you have done in this case?
>
> A. No, I don't think that would be an adequate plan. I think there are <u>other considerations</u> that the Company has, and I think they have been stated by the Company in this case."

If Mr. Towers or the Commission is going to judge management's decisions on reserve in this case, it must apply the same <u>complete</u> standard that management is expected to apply, not some misleading short cut.

Based on all relevant considerations, Mr. Caskey testified as an expert that the current reserve level was proper. (NSP Ex. 2, p. 4). Speaking as a non-expert considering all relevant criteria, Mr. Towers testified (Tr. p. 362): "I have not made an independent determination of the company's requirement or the required reserve." If

Mr. Towers admits that the MAPP minimum is an incomplete standard for setting the proper reserve level, and makes no independent analysis of what reserve level is proper, then his testimony gives no assistance to the Commission in determining the proper reserve level. The Company testimony strongly stands alone.

A good discussion of reserve margins is found in an article by Peter Navarro in the June 18, 1981 "Public Utilities Fortnightly" at pp. 25-30. He concludes as an economist that traditional reserve margins must be considered a lower bound below which no utility would want to go for reliability reasons, but above which they may want to go for economic reasons, particularly to avoid using oil fired generation. That is what NSP has done and hopes to continue.

In summary, applying a complete test to determine if NSP has "excess" capacity under today's circumstances, there is simply no answer provided by Mr. Towers. As discussed below, NSP has shown its capacity level to be reasonable and proper.

3. <u>Reasons for Maintaining Today's Capacity Reserves</u>.

a) <u>History</u>.

NSP installed its oil fired generation primarily in the late 1960's and early 1970's for reserve and peaking capacity. Such units had very low capital costs and, at the time, reasonably low operating costs. The world events which have driven up the cost of oil were not foreseeable at that time. (NSP Ex. 2, p. 5). There is no question about the prudence of the decisions to install that capacity. (Tr. p. 48; Staff Ex. 15, p. 17).

Since that time the cost of oil has increased faster than other fuels. NSP has responded by constructing non-oil facilities to minimize the use of expensive oil. This consists primarily of the two Sherco units and the Manitoba Hydro interconnection. (NSP Ex. 2, p. 5). These more recent additions have also been prudent in that they have been fully used and have kept the total cost of generation on the system low. (NSP Ex. 2, p. 5; Tr. p. 61). The Company is continuing its efforts to install additional base load facilities to avoid increases in the use of expensive oil. (Tr. p. 42).

b) Value of Reserve of Oil Fired Capacity.

There can be no question of the wisdom of keeping the Company's most efficient units on line, since they are the most reliable and lowest cost power generators. (NSP Ex. 2, p. 5). One may inquire into the wisdom of maintaining the oil fired reserves given their relatively high operating costs and position in the order of dispatch. Just as in the case of capacity additions, the analysis of whether or not a plant should be retired involves many factors. See Re Detroit Edison Co., 35 PUR4th 429 (Mich. PSC 1980).

Retention of the oil capacity enhances system reliability. (Tr. p. 352). For example, in case of an unplanned outage of base load facilities, oil fired capacity can be started quickly to take up the load. (Tr. pp. 28, 31). If there are supply problems for other fuels, the oil capacity would be available. In case of transmission outages, the dispersed oil units can keep a section of the service area energized until repairs are made. (Tr. pp. 22, 28). Oil capacity is well suited for serving narrow peaks that may occur on the system. (Tr. p. 65). There is an uncertainty at this time about the future of NSP's older coal units (Tr. p. 34) and its nuclear units. (NSP Ex. 2, p. 5). The oil units provide relative cheap insurance against the possibility of power shortages from whatever cause. (NSP Ex. 2, p. 4; Tr. p. 50). The Company monitors the costs and benefits of these units on an ongoing basis (Tr. pp. 32-33) and has judged that the units as a general matter should be retained.

Mr. Towers agrees that the question of retiring any particular unit involves its costs and benefits (Tr. p. 361) and the Company is willing to be judged by that standard. Mr. Towers, however, has performed no such analysis at all and has no opinion on whether or not particular units be kept in service. The Company's evidence here, as in the issue of proper reserve margin, stands alone unopposed by any credible testimony.

4. <u>Used and Useful</u>.

Mr. Towers testified that a "used and useful" test is usually applied to determine whether or not a plant should be included in rate base. (Tr. p. 375). He alleged that because NSP reserves exceeded the MAPP minimum, some portion of the capacity was not "fully used and useful". (Staff Ex. 15, p. 8). His allegation contains two fundamental errors. The first is the idea that for rate purposes a plant fully dedicated to service of customers may be partially used and useful. This is discussed in the next section. The second is that a reserve in excess of 15% by itself means some plant is not used and useful. This is simply not true.

During cross, Mr. Towers discussed the used and useful standard. He agreed a plant may be a standby facility and be used and useful even though on a peak day or in an entire year it is not used for generation. (Tr. p. 376). He specifically did not analyze the issue of excess capacity by applying the used and useful test to existing plants, but used the MAPP minimum as an admittedly inadequate shortcut to that determination. (Tr. p. 377). He was sure that Manitoba Hydro was used and useful, but had no answer regarding other base load plant. (Tr. pp. 378-379). Mr. Towers has not evaluated whether the oil fired plants are used and useful either. There is no credible Staff testimony to establish that any of NSP's plants are not used and useful.

Speaking of the oil fired capacity, Mr. McIntyre stated (NSP Ex. 11, pp. 4-5):

> "They are still 'used and useful' (as that term has been traditionally applied in ratemaking) from an economic and engineering view in providing peaking and insurance capacity as indicated by Company witness Caskey. These oil fired

plants were prudently built, as were the intensively utilized base load plants which caused their displacement. Therefore, it is only equitable for these to remain in the rate base earning a full return on the invested dollars."

See City of Torrington v. Torrington Electric Light Co., 13 PUR NS 24 (Conn. PUC 1936); Re Wisconsin Michigan Power Co., 33 PUR3d 515 (Wis. PSC 1960). Mr. Caskey's testimony establishes that the peaking units are very useful and beneficial to the system, and that if their costs begin to exceed their benefits, they are typically not retained. (Tr. pp. 21-25, 30-34, 65). As for the base and intermediate plants, there is no question that they are intensively used and very useful to the NSP system. The evidence establishes that essentially all of the present plant capacity is used and useful. Yet Mr. Towers' suggested adjustment presumes that a portion of all plants or else a large number of oil fired plants (most of which were used to serve customers in the test year) are not used and useful. Such an adjustment does not reflect reality.

The Ohio Supreme Court established in its decision Consumers' Counsel v. PUC, 391 NE2d 311, 313 (Ohio 1979):

"[W]hether property is used and useful in providing service to the customer of a utility is a question which of necessity must be resolved on the basis of a case by case analysis. That status cannot be determined through the application of a rigid formula, but should be ascertained by the trier of facts in light of all the circumstances."

Mr. Towers not only has suggested using a rigid formula, but has suggested one that yields the wrong answer in this case.

5. Exclusion of a Portion of All Capacity.

Mr. Towers' first alternative, to exclude an equity return percentage of all capacity, is perhaps a result of haste in his preparation. In other appearances he took the time to identify specific plants that could be identified as excess. For instance, in the case Pennsylvania PUC v. Philadelphia Electric Co., 31 PUR4th 15, 25 (Pa. PUC 1978) we find that:

> "Mr. Towers chose to eliminate from rate base these older plants which are already highly depreciated and generally of lower original cost, rather than the newer and more efficient nuclear plants, as the plants representing excess capacity."

Although his suggestions were rejected in that case, the point is that he should have at least attempted a similar plant identification in this case. Since this was not done, Mr. Caskey identified the less efficient plants on the NSP system in a manner akin to that previously used by Mr. Towers.

The original $505,000 adjustment would deprive NSP from an equity return on 12% of its investment in all its coal, nuclear, oil, gas and hydro capacity. (Staff Ex. 15, p. 18; Tr. pp. 334, 367). Even if it were established that NSP maintained too much capacity, this kind of across the board slicing of all plants is a conceptually incorrect and unfair method for adjusting revenue requirements. In addition to depriving the Company of a return on investments that are clearly used and useful by any analysis, it fails to recognize the impact on operating costs of the elimination of 12% of all capacity. (Tr. p. 29). If Mr. Towers wants to eliminate 12% of the capacity of each plant on paper, he cannot ignore the corresponding impact on paper on the cost of generation. Since the Company would have to replace coal, hydro and nuclear base load with oil under this scenario, the impact on operating cost would be quite large. For instance, the 1981 fuel cost per Kwh for oil is 5.5¢, compared to 1.19¢ for coal and for hydro. (Tr. p. 353). Stated differently, it is unfair for customers to receive the low cost reliable power from the newer base load capacity while not paying a full return to the owners.

Mr. Towers tells NSP to make itself whole by selling the excess capacity to other utilities. The record evidence establishes that such sales cannot occur and the Company cannot recover the cost of its investment elsewhere. Mr. McIntyre has already accounted for <u>all</u> sales to other utilities as offsets to revenue requirements. (NSP Ex. 11, p. 5). In theory NSP could sell more (or less) than these amounts (Tr. p. 346) but in reality it is only remotely possible. Most sales to other utilities do not involve demand charges which could cover the foregone equity return. (Tr. p. 346). Other MAPP utilities are not currently in the market for firm energy sales. (Tr. p. 348). Mr. Towers agreed that his theory is at odds with reality. (Tr. p. 348):

> "Q. Is it likely that the company can sell very much of its

capacity and recover demand charges from other pool members?

A. It seems unlikely to me.

Q. Do you have any other potential buyers in mind for us?

A. No, I do not.

Q. Do you have any idea where we should start looking?

A. No, I don't."

Since base load facilities are intensively used to meet retail loads at the lowest cost, any new sales would have to be made from the oil capacity. Regarding such sales Mr. Towers testified (Tr. pp. 353-354):

"Q. What does that per Kwh cost of fuel alone indicate to you about the possibility of making sales to other utilities right now, particularly sales that would include a demand charge?

A. Out of the oil fired equipment that you have identified as the excess capacity, I would think that there is no chance. Virtually no chance to sell that capacity."

The only conclusion that can be drawn from this evidence is that the Company has already accounted for all revenues that will be received from capacity sales. This means that any excess capacity adjustment will deprive shareholders of a return on their investment in generating facilities.

It may be inviting to slice from rate base any capacity above some magic number. The idea was proposed and rejected years ago. In the decision City of Detroit v. Detroit Edison Company, P.U.R. 1933E (Mich. PUC 1933), rate case intervenors requested that rate base or rate of return should be reduced by excluding unused capacity caused by a reduction in demand. The Michigan Commission rejected that approach and stated, P.U.R. 1933E 201:

> "This theory sounds very fascinating and apparently offers a means of solving all of the problems of ratemaking. The many hundreds of pages of record devoted to an exposition of this theory, however, fall short of convincing us that it has all of the merits its proponents claim for it. In the first place, it is admitted on the record that all of the property of the company has been actually used by it in serving the public. It is further admitted in the record that the investment was prudently made and was necessary when made. The fact that today a substantial reduction in the demands made by its customers has decreased the percentage of use of plant capacity cannot change the admitted fact that all of the investment was needed when it was made and that at the time the company was clearly entitled to earn upon all of the property."

In the case <u>Laclede Gas Light Company v. Public Service</u> Commission of Missouri, 6 P.U.R. (n.s.) 10, 8 F. Supp. 806 (W.D. Mo. 1934). The Missouri Commission had applied a percentage reduction to the utility's rate base on the theory that if the use of property declines by 4.9% then 4.9% of the property is no longer used and useful in providing service. The company successfully sought an injunction in Federal Court to restrain the application of the rate reduction order. The Court held that the theory was unsound and adopted the language used by a dissenting commissioner, 6 P.U.R. (n.s.) 13:

". . . the theory is utterly illogical, . . . by reason of its being applied generally, that it, to each and every item making up the total of the plant. The production plant is being reduced 4.9 per cent, as are the holders, mains, services, meters, and general equipment. Much of this equipment must necessarily remain of the same size, irrespective of the extent of use, if they are used at all. . . . Furthermore, the application of this theory seems to us to be illogical in view of the fact that the cost per unit does not vary in the same ratio as does capacity. . . . For the foregoing and other reasons, we believe that the application of the horizontal percent reduction in the rate base, because of the decline in these times of consumption, is wholly inadmissible and indefensible in the present case."

In more recent settings the idea of a partial exclusion of a generating plant has also been explored. A plant is either used and useful and includable in rate base or it is not. A plant cannot be partially used and useful. Kansas Gas & Electric Co. v. State Corp. Comm., 544 P.2d 1396 (Kan. 1976).

A series of decisions in Ohio thoroughly reject the kind of slicing adjustment at issue here. In the case Re Dayton Power Co., 21 PUR4th 376 (Ohio PUC 1977) various parties advocated exclusion of a percentage of rate base above various minimum reserve possibilities. The Commission applied a used and useful test stating at p. 383:

"The Commission is of the opinion that a quite significant consideration in judging the usefulness of a generating unit is whether or not its availability will reduce the company's overall cost of service and thereby the rates paid by the electric consumer. If such a

> unit does serve to reduce the net cost of providing electric service, the property should be considered useful absent other overriding or compelling considerations. When capacity greater than that necessary to meet peak needs plus an adequate reserve (a "physical" excess capacity) is shown to exist, attention must be given to the net effect of such capacity upon the company's total costs before it can be judged whether a facility is useful. Certainly, this commission should not construe the used and useful provision so as to frustrate construction of a generating plant mix which would lower, or reduce the rate of increase in, electric rates. The commission cannot agree that the existence of capacity in excess of peak needs plus an adequate reserve is sufficient, in itself, to establish that a portion of the generating facilities is not useful . . .".

See also Re Monogahela Power Co., 21 PUR4th 540 (Ohio PUC 1977) which also rejected an elimination of capacity above a 20% reserve. The Ohio Supreme Court ratified the cost-benefit approach taken to determinations of whether or not to include a unit in rate base. City of Cleveland v. PUC of Ohio, 400 NE2d 1370 (Ohio 1980). The Ohio PUC again discussed the issue in Re Cleveland Electric Illuminating Co., 38 PUR4th 494, 507-508 (Ohio PUC 1980):

> "Claiming, without a shred of evidence as to why the figure should be accepted, that a 20 percent reserve margin is appropriate, intervenors propose a rate base deduction, never quantified, to exclude capacity in excess of this amount on the theory that such property is not used and useful. The short answer here would be to simply point out that there is nothing in the record, save for intervenors' base assertions, that would support these objections. However, the commission will once

again set out the considerations which must be taken into account in dealing with this question.

The so-called "excess capacity" issue has been before the commission time and time again in recent years in cases involving almost all major electric companies subject to our jurisdiction. (Citations omitted.) One fact has emerged from these cases, as it has from the record in the instant proceedings, is that it is most inappropriate to measure the reasonableness of existing capacity levels by a simple comparison to some assumed ideal reserve margin. <u>Reserve requirements are company specific, and what is reasonable for one electric utility may not be reasonable for another depending on factors such as unit sizes and generation mix</u>. Next, assuming appropriate reserve criteria can be established, it must be recognized that in light of the extensive lead times involved in the construction of generating facilities and the variety of factors which can influence load growth, it is obviously unrealistic to assume that any utility would have the forecasting capability which would allow it to add capacity in the precise increments required to maintain the theoretically appropriate margin. This problem is intensified by the large size of the units being added today. Thus, the relevant inquiry is not whether the reserve at any pont in time matches some optimum margin, but whether, given all those factors which can influence construction and load growth, the company can be fairly said to have acted imprudently in its capacity planning. . . .

Finally, there is the conceptual problem which attends a capacity adjustment based on the theory that a portion of a company's production capacity is not used and useful. All applicant's generating stations, although they may have been downrated or off line from time to time, were in service meeting customer demand pursuant to principles of economic dispatch during the test period. Thus, each unit, standing alone, clearly would meet the used and useful requirement. A percentage adjustment to system capacity ignores the reality that such capacity is comprised of individual units which represent actual, substantial dollar investments committed to assure that adequate service can be maintained. As the commission stated in the Columbus and Southern decision cited, infra: "Hindsight is always perfect, and before the commission will consider denying a return on property actually used in providing service something more need be shown than that the company's foresight was not." Intervenors' objections are, hereby, overruled." (Emphasis added).

6. Exclusion of Peaker Units.

It has been shown that there is no excess capacity on the NSP system and that all units, including oil fired units, are used and useful. Nevertheless, to show which plants would be excluded if there were 794 Mw of excess capacity, Mr. Caskey and Mr. McIntyre identified the certain oil capacity and the related equity return. (NSP Ex. 2, p. 6; NSP Ex. 10, Sch. 2; NSP Ex. 11, pp. 4-6). This would be an adjustment of $175,000 rather than $505,000, since the book investment per Kw is much less on these units than on newer base load plants.

Mr. Towers, who has engaged in a similar selection process in other cases, supported the analysis (Tr. p. 335):

> "I believe that the selection that the company made of specific units represents, call it a reasoned attempt to identify where the excess is."

Even here though, Mr. Towers recognized that much of that identified capacity was operated in the test year. (Tr. pp. 335, 355). If any adjustment for excess capacity is made in this case, it cannot include the removal of a percentage of all plants from rate base. It would have to be made up of specific units which are determined to be no longer used and useful.

7. Effects of Excess Capacity Adjustment.

The Company desires to pursue its goal of low cost and reliable electric supply. Additions of the Sherco units and the Manitoba Hydro interconnection were consistent with goal (NSP Ex. 2, p. 5) and have produced substantial savings to customers (Tr. pp. 58-59). In particular Manitoba Hydro, which substitutes for approximately 500 Mw of base load generation (Tr. p. 68) and utilizes a renewable resource, involves capacity costs similar to a peaker with running costs lower than a coal plant. (Tr. p. 342).

Mr. Towers takes no exception to management decisions regarding deferrals or abandonments of planned generating units. (Tr. p. 340). Regarding Manitoba Hydro, he agrees that it was a prudent addition. (Tr. p. 351). In fact he states (Tr. pp. 343-344):

> "Q. If NSP management had been presented as they were with that opportunity [to build the line]. and they turned it down, would that have perhaps called into question their prudence?

> A. I have not, as I indicated, I have not made a comprehensive economic analysis of that transaction, but of the cost figures that you have cited and that I am aware of, it seems the opportunity should not have been missed."

About 2/3 of the alleged excess capacity is caused by the recent Manitoba Hydro addition. (Tr. p. 342). The suggested adjustment punishes the Company for making the addition while allowing all the associated savings to be enjoyed by customers. (Tr. pp. 344-345). Stated differently, had management not gone forward with the project, the resulting higher generation costs could be attacked as imprudent expenses.

The Ohio PUC recognized in the case Re Dayton Power & Light Co., supra, 21 PUR4th, p. 383:

> "Certainly this commission should not construe the used and useful provision so as to frustrate construction of a generating plant mix which would lower, or reduce the rate increase in electric rates."

If regulation signals management that it should not expect a return on capacity investments in excess of some minimum reserves, management would be justified, perhaps required, to pursue a new goal. Corporate directors and officers in their fiduciary capacity cannot invest funds where there is no expectation of a reasonable return. The new goal would be to keep the reserve from year to year as close as possible to the minimum, regardless of the overall economic impact, regardless of the costs and benefits. Projects like Manitoba Hydro would not be built, nor would efficiently sized generating plants. Minimizing the cost of power would no longer be the goal. For NSP, the use of oil generation would increase markedly. Such regulation would be sadly shortsighted. Pursuit of a minimum reserve requirement is not a proper procedure for certificate of need proceedings, good rate regulation, or good utility management.

8. Conclusion.

The record in this case established that no excess capacity adjustment is proper. It shows:

1) The MAPP minimum is not a reasonable maximum allowable reserve.

2) It is not economical or practical to always have total capacity very near a minimum level.

3) Management must be given latitude to determine the best reserve level for the system.

4) Reserve determinations are made on the basis of all relevant engineering and economic considerations.

5) Current reserve capacity is reasonable in amount, valuable to the system and should be maintained.

6) All base load and intermediate capacity is used and useful. All oil fired capacity also passes the used and useful test, even those units that were not needed for emergency generation in the test year.

7) It is illogical and unfair to exclude a percentage of all plants from rate base, particularly while ignoring the higher operating costs which would be

incurred if base load units were not fully available.

8) NSP management has prudently and successfully pursued its goal of low cost reliable power. The Company is encouraged to pursue a less efficient goal if it cannot anticipate earning a full return on new capacity which would lower overall power costs.

9) An adjustment for excess capacity would punish the Company for installing the new Manitoba Hydro line while allowing customers to reap substantial rewards.

10) Exclusion from rate base of investment which is used and useful is illegal and should not be attempted.

B. Working Capital

NSP and Staff disagree on the method for calculating cash working capital to be included in the rate base. Some general and historical review of cash working capital methodology might be helpful to a better understanding of the dispute.

Cash working capital calculations have long received attention in regulation and various methods have been in and out of favor. There is no disagreement with respect to the objective of the calculation -- to determine what amount of cash investors have necessarily supplied to the utility to allow it to carry on its day-to-day operation. The difficulty comes not so much in determining the amount of cash working capital required, but rather in separating that amount supplied by investors (and thus entitled to be included in the rate base) and that amount supplied by creditors (for which the investor is not entitled to any return).

Years ago regulation began utilizing an accounting approach for measuring cash working capital called a lead/lag study. This study makes a comparison between the delay from date of service to receipt of revenues from customers and the delay from date incurred to payment of company obligations to creditors. Such lead/lag studies are highly complex, are subject to varied interpretations and are prime topics for litigation. Accordingly, some regulators have made an effort to adopt a simplified formula which was intended to produce approximately the same result of a lead/lag study, but with far less detail and effort.

The most common formula came to be known as the "FPC formula" adopted by the Federal Power Commission. In its early form it allowed the approximation of cash working capital requirements by taking 45 days of average expenses. In places where property taxes became a significant item, the FPC formula was adjusted to provide for a deduction against cash working capital requirements for the average amount of accrued taxes since the utility recovered for the taxes in rates, but was not obliged to pay to the taxing authority until after a significant delay. The experience under use of these formulas was to obtain a positive cash working capital requirement, though the offset for accrued taxes reduced it more and more as time passed.

Because of the imprecision of the formula approach and the changing economic impacts, some regulatory bodies returned to the lead/lag study. There is no single form of lead/lag study. They may vary substantially in breadth and depth from one to another.

NSP's filed case for cash working capital is based upon a comprehensive and detailed lead/lag study which was intended to account, as precisely as possible, for all items of non-investor supplied capital. That study is summarized by Mr. McIntyre in NSP Ex. 9, Schedule 31. This schedule lists the 16 components which make up NSP's cost of service; applies a revenue "lead" of 43.24 days from service to receipt of payment; and offsets those revenue lead days by expense lag days from incurrence to payment of each company expense. The determination of the revenue lead days, as applied to each of the 16 cost of service components, establishes the requirement for cash working capital and the determination of the expense lag days for each of those components identifies the extent to which each requirement is satisfied by funds provided by non-investors. In fact, as Schedule 31 shows, NSP is not claiming a positive cash working capital requirement, but instead has reduced the rate base by negative cash working capital of $569,200, the excess of funds supplied by non-investors above the requirement.

The dispute between NSP and Staff in the calculation of cash working capital requirements centers around three items which can be seen from page 1 of Staff Ex. 29, the exhibits supplied by Staff witness Robert Knadle. That page is analogous to McIntyre's Schedule 31 but produces a negative cash working capital requirement of $1,372,000, more than twice that proposed by NSP. The three differences are (1) the shorter revenue lead[1] days used by witness Knadle of 39.6 as compared to NSP's 43.2 days; (2) the

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1. The witnesses evidently use the terms lead and lag interchangeably, McIntyre speaking of a revenue lead and expense lag and Knadle speaking of a revenue lag and expense lead. For consistency, we will use McIntyre's designation.

use by Staff of a hypothetical long term debt interest; and (3) the elimination by Staff of the revenue lead connected with the recovery by the Company of the cost of common equity. The Staff's difference in the calculation of the revenue lead days was supported by witness Knadle, the basis for the Staff's calculation of long term debt interest was supplied by witness Brown and the Staff's elimination of the revenue lead days for common equity was supported by witness Rislov. (Tr. 584 et seq.)

1. Shorter Revenue Lead Days: The Delayed Payment Rule

Witness Knadle testified that he reduced the revenue lead from NSP's 43.24 days to 39.6 days based upon the delayed payment rule proposed for South Dakota, which would provide for the collection of a penalty on any electric bill unpaid after the 20th day from date of billing (Tr. 585-6). Mr. Knadle was not assuming, as fact, that everyone would pay before the 20 day cut-off, but he did assume that the 1% penalty charge which he proposed would fully compensate the Company for any customer who did not pay within the 20 days. Since this compensation is to be treated by the Company as a below-the-line item, and thus would not affect the revenue requirement, Knadle believed that it would offset the Company's need to obtain rate base treatment for any cash working capital requirement resulting from delays longer than 20 days (Tr. 586-8). By using 20 days from the date of billing as the maximum for customer payment, the total lead time from the date of service to the date of payment is reduced to 39.6 days (Tr. 588).

The Company disagrees with Mr. Knadle's adjustment to the revenue lead days for several reasons. First, as Mr. Knadle evidently agrees, the Company does not believe that the late payment rule represents such a known and measurable charge as should be recognized in the calculation of rate base for this case.[2] Second, the Company contends that the late payment charge of 1% proposed bv Mr. Knadle is inappropriate and that a one-time 4% penalty, such as described in the testimony of NSP witness Dupay, is the minimum amount necessary in order for the late payment provision to actually provide an incentive for the customer to make payment within 20 days of billing (NSP Ex. 16, pp 5-6).

Mr. Knadle agreed that the late payment charge "should be to encourage the customer to make the payment on a timely basis" (Tr. 590); that he did not know how significant the 1% charge would be on reducing the number of late paying customers (Tr. 590); that the 1% charge is more in the nature of

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2. At Transcript 588 the following question and answer were given:

Q: "Do you consider, Mr. Knadle, that the assumption which you just described of 20 day maximum is a known and measurable charge as the result of the late payment penalty that you are proposing?"

A: "I don't think you can find the approximate value for that, no."

a finance charge for unpaid electric bills (Tr. 592); and that NSP's 4% one-time charge would provide a greater incentive for prompt payment by those who had the ability to pay (Tr. 592).

If the Commission adopts Ms. Dupay's recommended late payment charge, then the cash working capital calculation should be based upon the Company's 43.2 revenue lead days. If the Commission adopts Mr. Knadle's 1% late payment charge, then Mr. Knadle's cash working capital calculation is appropriate so long as all revenues received from late payment penalties are considered below-the-line and not credited against revenue requirement.

2. Long Term Debt Interest

Mr. Knadle took his test year interest expense number ($3,342,000) from Ms. Brown's calculation in Staff Ex. 24, Schedule 6. Ms. Brown's calculation has two errors which overstate interest expense, and thus produce an excessive negative cash working capital requirement in Mr. Knadle's study. First, Ms. Brown used a hypothetical debt ratio (artifically set above actual) supplied by Mr. Wilson. Second, as Schedule 6, Staff Ex. 24, reveals, the calculation includes interest on construction work in progress. Since CWIP is not in rate base, South Dakota ratepayers do not provide funds for CWIP and thus, clearly, a working capital should not be reduced on account of them.

Mr. Rislov generally agreed with the facts set forth above but had doubts about the conclusion (Tr. pp. 613-4).

His concern was whether the Company was able to book AFDC on CWIP before actually paying the interest expense (Tr. 614-5). Under the Uniform System of Accounts, however, a utility cannot book AFDC prior to the time the money is actually expended.

3. Delayed Recovery of Common Equity Costs

Staff witness Rislov proposed adjustment to the lead/lag study to eliminate any recognition of the delay in recovery of the cost of common equity. In Staff Ex. 30, he stated two basic reasons for his criticism: that inclusion improperly implies that the amount of the return can be accurately measured and that there is no fund requirement for common equity (p. 10). Rislov stated that there is no guarantee NSP will earn any specific return and, further, that NSP has the offsetting use of funds recovered for common equity until it pays dividends to the equity investor (pp. 10 and 11).

With regard to Mr. Rislov's concern that the return on equity cannot be accurately measured, it is clear that the Commission will, in its order in this case, establish an allowed rate of return. It logically follows that the Commission can and should approve a cash working capital requirement based upon the use of the "allowed" rate of return in calculating the delay in recovery of the common equity cost. Mr. Rislov agreed that this can be done (Tr. 612). NSP witness McIntyre established that it should be done. In fact, similar use of the "allowed" return is necessarily utilized for other aspects of the lead/lag study, such as the calculation of additional income taxes (NSP Ex. 10, p. 32).

Mr. McIntyre further countered Mr. Rislov's claim that the return on common equity is a customer provided source of funds until a dividend is actually paid. Since the equity shareholder is the owner of the company's earnings, he stated that the "appropriate and logical time of the transference of proprietary rights from the customer to the shareholder is when the earnings are recorded on the books and the records of the company" (NSP Ex. 10, p. 32). Since the shareholder is the owner of the earnings from that time, the retention of those earnings by the Company, for use to satisfy cash working capital requirements until the payment of dividends, is based upon the forebearance of the investor and, therefore, the funds are provided by the investor (NSP Ex. 10, p. 32). As Mr. McIntyre points out, if a 100% of earnings dividend were paid out immediately when recorded, the utility would have a working capital requirement that would have to be provided by some other source and the fact that investors allow the use of the funds by the Company amounts to the provision of those funds (NSP Ex. 10, p. 32).

The subject can be approached another way, as was done in the discussion with Mr. Rislov on cross-examination. Mr. Rislov agreed that the 16 items, including common equity, contained in Mr. McIntyre's lead/lag study did represent all of the components in the cost of service for a utility (Tr. 607). He further agreed that the revenue requirement to be set in regulation must, by law and regulatory practice, produce a revenue requirement that recovers the cost of service, including an appropriate amount for each of these 16 items (Tr. 607-8). Since the rate tariffs are constructed to recover that revenue requirement, it is divided into various rates for the customers. As a result, every monthly bill rendered to a customer charges that customer's proportionate share of the cost of each of the 16 components. Thus, every bill charges that customer's proportionate share of the cost of common equity (Tr. 608). Mr. Rislov admitted that the Company does experience a delay (whether measured by Knadle's 39.6 days or McIntyre's 43.2 days) in the recovery from each customer of that customer's proportionate share of common equity requirement (Tr. 610).

Since the delay in recovery was clearly identifed and since the lead/lag study was otherwise comprehensive and eliminated all other possible sources of non-investor funds, the Staff is clearly in error in eliminating the cost of common equity from the lead/lag study. Alternatively, to be consistent the Staff would also have to eliminate the other capital cost recovery items which, like common equity, are recorded below the line. Those are the delayed recovery of debt interest and preferred dividends. The three items (debt, preferred and common) produce a negative cash working capital requirement, since the positive requirement resulting from the delay in receipt of common is offset by the funds available from non-investors for payment of interest and preferred dividends. The Staff should not be permitted to pick and choose, eliminating the only item which provides a positive working capital requirement. The appropriate result is to either include all three capital items or to eliminate all three.

VI. COST OF CAPITAL

Determination of the cost of capital involves the combined issues of the appropriate capital structure and the proper cost to be allowed for each component of the capital structure. NSP requested an overall rate of return of 11.07% based upon the following capital structure and cost rates (NSP Ex. 4, Schedule 6):

Capital Employed	($ 000's)	Percent of Total	Cost(%)	Weighted Average
Long-Term Debt	1,022,003	49.18	8.11	3.99
Preferred Equity	220,755	10.62	6.14	.65
Common Equity	835,298	40.20	16.00	6.43
TOTAL CAPITAL	2,078,056	100.00		11.07

Staff proposed a composite cost of capital of 10.16%, based on the following "adjusted capital structure and cost rates (Staff Ex. 18, JWW-1 and TR. 439):

	($ 000's)	Capital Ratio	Cost Rate	Weighted Cost
Long-Term Debt	1,022,003	50.3	8.1	4.07
Preferred Stock	224,229	11.1	6.2	.69
Common Equity	781,923	38.6	14.0	5.40
TOTAL	2,028,155	100.0%		
Composite Cost of Capital				10.16%

As can be seen, three major adjustments were proposed by Staff: (1) reduction of the common equity portion of capital structure,

(2) increase of the preferred stock portion of capital structure and (3) reduction of the cost rate for common equity.

A. Capital Structure

NSP's recommended capital structure was based upon the actual long-term debt and preferred stock as of December 31, 1980, adjusted for expected changes in 1981, and the thirteen month average common stock from December, 1979 through December, 1980 (NSP Ex. 4, Sch. 6; NSP Ex. 5, p. 16). NSP did not update the common equity portion to year-end 1981 and, as a result, NSP's capital structure is conservative. The 1981 retained earnings would have increased the common equity dollars by at least $40 million (according to witness Wilson, at Tr. 441), this would have increased the equity ratio and the overall rate of return would have gone up 18 basis points.

As a result of this conservative capital structure, NSP's common equity ratio at 40.20%, which is below the Company's ratio for the past few years, is approximately equal to the common equity ceiling imposed upon NSP by the Minnesota PUC in a gas rate case in 1979 and is well below the 42.2% common equity ratio approved by the Minnesota PUC in its 1980 electric case. Staff criticized the use of a thirteen monthly average for common equity, arguing that since NSP was purchasing common shares, the averaging method overstates the equity at year end 1980. As noted above, this aspect of the calculation is more than offset by NSP's nonrecognition of the retained earnings for 1981, which would have increased the common equity ratio (NSP Ex. 5, p. 16).

The first adjustment proposed by Staff was a hypothetical add-back to preferred stock of amounts previously redeemed by the Company in 1980 and 1981. Staff argued (Staff Ex. 17, pp. 65-6):

> "During 1980, NSP purchased 42,969 shares of its $10.36 preferred stock. The sinking fund requirement for this series is 12,500 to 25,000 shares, and NSP's cost of capital is minimized as this 10-plus percent capital replaces more expensive common equity capital. *** The preferred stock balance used in my calculations excludes the extraordinary and unnecessary retirements of the 10.36 preferred stock capital by NSP and restates the amount as if maximum sinking fund retirements were made in 1980 and 1981. Mr. Kolkmann's proposed balance reflects larger retirements of this issue, and thus his preferred stock ratio is lower than that used in my calculations."

By adding back retired preferred stock, the preferred stock ratio is increased and, since it is the lowest cost component, the overall rate of return is decreased. This adjustment is in error.

NSP witness Kolkmann demonstrated that the retirement of the preferred stock was neither extraordinary or unnecessary. The repurchase cost averaged $99.99 per share, which was $1.20 per share less than the specified $101.10 redemption price (NSP Ex. 5, p. 17). Thus, early redemption at a discount produced a savings that benefited ratepayers. Mr. Kolkmann established that the preferred shares were replaced by debt and thus there "has been a saving because more expensive preferred dividend payments have been replaced with interest payments." (NSP Ex. 5, p. 17). Staff agreed that long-term debt capital is less

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Staff attempted to relate the redemption of preferred stock with common equity costs by arguing that NSP should have redeemed higher cost equity instead of preferred. This argument is erroneous. First, NSP had already redeemed equity to the extent of $37 million. Second, and more important on this issue, there is no reason that the redemption of preferred by itself would have prevented additional redemptions of common. The two questions are completely separate and not a valid basis for analysis. The question regarding redemption of common will be covered separately below.

Staff then made a series of adjustments to the common equity balance which significantly reduced the equity ratio. Those adjustments can be summarized as follows (taken from work papers supplied by witness Wilson to the Company, Tr. 440 et seq.):

Outstanding shares 12/31/80	$824,874,000
1981 Retirements	(37,000,000)
1981 Retained Earnings	80,000,000
Subtotal	$867,874,000
Less Non-utilities	(6,350,000)
Tyrone 12/31/80	(47,601,000)
Tyrone 1981	(32,000,000)
TOTAL	$781,923,000

Each of the four reductions shown above was in error. If the common equity were to be correctly adjusted to December 31, 1981, even with a lower amount of retained earings (see Tr. 441) the result would be an increase rather than a decrease.

1. <u>1981 Retirements</u>

Staff witness Wilson noted that NSP had retired a portion of its common equity capital in 1980, which had reduced the common equity ratio (Staff Ex. 17, p. 67). From this he made the incorrect assumption that "the return should be set on the expectation that further reductions will be made." Staff agreed that the Company had not actually made any purchases of its shares on the market as of the date of the hearing, October, 1981 (Tr. 444). In fact, the adjustment was not based upon any real expectation that the Company would actually retire the stock, but rather upon the hypothetical calculation of the impact which would occur if the Company did retire the stock (Tr. 445-448). While the explanation of this adjustment was difficult to pin down, it evidently was related in part to the repurchase of preferred stock (the incorrect argument that the Company could either redeem preferred stock or common stock and made the wrong choice) and in part to the view that the common equity ratio of the Company was too high (Tr. 445-446).

As indicated earlier, NSP's proposed equity ratio was slightly over 40%, well below the ratio approved by the Minnesota PUC of 42.23% (Tr. 452). NSP's proposed equity ratio is not unreasonable or out of line with the industry.

Witness Wilson's discussion of the so-called "industry average common equity ratio" gives a very misleading impression that a 36% equity ratio is a proper financial goal for a company such as NSP. As Mr. Kolkmann stated (NSP Ex. 5, p. 16):

> "Currently, over 30% of companies rated AA by both Moody's and S&P have equity ratios of over 40% when you exclude short-term debt as NSP did in its filing this year. The trend is toward a stronger equity position. Standard & Poor's, in its rating analysis of NSP in March, 1981, indicated that criteria for a AA rating include a common equity ratio in excess of 42%."

Thus, the need for NSP to repurchase shares no longer exists -- in fact, it has become inappropriate. Consideration must also be given to the new federal income tax laws concerning dividend reinvestment plans. Witness Wilson explained that the first $750 of dividend reinvestment is exempt from income taxes and twice that amount is allowed for a married couple (Tr. 453). He agreed that the intent of the law was to improve the attractiveness of utility stock (Tr. 454). He further agreed that in order to be eligible for the tax benefits under the law, "the law did require the issuance of <u>new stock</u> in order to receive the benefit, and I think NSP's plan is inconsistent with that, to begin with" (Tr. 457). He then acknowledged that NSP had petitioned the Minnesota PUC for permission to issue <u>new common shares</u> in its dividend reinvestment program, so as to qualify for the favorable tax treatment (Tr. 460). The ratepayers would clearly be benefited by NSP's eligibility for dividend reinvestment tax exemption. If it does not become eligible, because it continues to repurchase its shares, then ratepayers will lose because the relative attractiveness of its stock, as compared to other electric utilities, will actually decline, with costs of equity going up.

Since NSP's equity ratio has already declined substantially from previous levels through the purchases made in 1980, NSP would urge that the Commission not hypothetically reduce its equity ratio even further.

2. <u>Non-Utility Property and Tyrone</u>

The remaining adjustments made by Staff to the equity ratio were evidently attempts to match certain rate base exclusions. The items producing the adjustment are not included in NSP's South Dakota rate base and no return is sought on them. Witness Wilson incorrectly concluded from this that a parallel adjustment should be made to the equity component of capital. This conclusion is erroneous for the several reasons discussed below.

First, adjustment solely to the common equity portion only is based upon the erroneous assumption that the equity investor was the sole source of funds for investment in non-utility property or for the proposed Tyrone project. Witness Wilson was forced to agree that no one could determine the source of funds for these particular items since they simply "came out of the Company's treasury." (Tr. 460-1). Specifically, the Tyrone funds came from the "corporate pool" and could not be traced to any particular stock issue, preferred stock offering or other component of capitalization (Tr. 464). His assignment of all of the Tyrone costs to the equity component was based, therefore, solely upon the abstract notion that "all up front investment in new production facility" is the "role of risk capital." (Tr. 464).

Evidence to the contrary of witness Wilson's assumption was provided by a number of items. For one, the May, 1975 prospectus for $80 million of first mortgage bonds indicates that the proceeds will be added to the general funds of the Company and be used to pay borrowing incurred in connection with construction (Tr. 467). The Tyrone Energy Park is included in the list of construction items (Tr. 468 and NSP Ex. 19). Further, for the purpose of computing the capitalized return on construction investment, the assumption made as to source of construction funds is exactly opposite to Wilson's assumption; that is, AFDC is calculated on the basis of a composite of all sources of capital and, in fact, short-term debt is considered to go in first, then long-term debt and equity last (Tr. 465-6). Under the circumstances, the advice given by NSP witness Kolkmann should be followed (SNP Ex. 5, p. 18):

> "If non-utility investments [or Tyrone investments] are to be excluded from the capital structure, the deductions should be made proportionately from debt, preferred stock and common equity, since the investments came from all these sources of funds. Dr. Wilson's method improperly reduced the aggregate return on NSP's capital structure."

Even if equity could fairly be identified as the only source of funds for non-utility payments or Tyrone, Staff's adjustment would still be substantially in error. For one thing, the reduction in equity for both the $47 million and the $32 million is erroneous double counting. Since the total loss being amortized for Tyrone began at $75 million (the final figure will be closer to $67 million) and since the amortization began in March of 1979 on a five year basis, over two years amortization have already been charged against shareholders. If an adjustment to equity were proposed (which we oppose) the adjustment should certainly be no greater than the unamortized balance (about $43 million). The shareholder has already absorbed the rest (unless, South Dakota ratepayers are ultimately required to compensate for the amortization; in which case Staff's adjustment to equity should be eliminated completely). Further, even the unamortized balance would be too high because the ratepayer has already been given the benefit by flow through of the tax savings due to the amortization. Thus, the appropriate figure is really the net of deferred taxes unamortized balance of $24.9 million (Tr. 498).

B. Return on Common Equity

The Company's request for a 16% rate of return on common equity was amply supported by the studies presented by witness Kolkmann.

Mr. Kolkmann presented four separate studies to provide a comprehensive consideration of the issue. He analyzed the dcf formula in depth, presented a "standard dcf analysis (Method I) and made alternative presentations which more completely and accurately reflected the mathmetical principles underlying dcf (Method II). He also analyzed the market price to book value ratio (Method III) and made a comparison of NSP's return with that of other companies (Method IV).

Mr. Kolkmann concluded that the use of the dcf formula in regulation had very serious shortcomings in the translation of the philosophical concept to an abstract and oversimplified mathmetical formula (NSP Ex. 3, p. 8). Certain restrictive assumptions have been followed, such as the assumption that the cost of equity is constant for an infinite number of time periods in the future (NSP Ex. 3, p. 8). Mr. Kolkmann suggested that the standard dcf formula be used in a manner more consistent with the basic theory and, because of its shortcomings, that it not be the only method relied upon (NSP Ex. 3, p. 9).

Under Method I, Mr. Kolkmann conducted a regression analysis which related historic yields to general financial and economic parameters and then utilized forecasts of these financial and economic parameters to forecast the expected yield (NSP Ex. 3, pp. 11-12). This procedure was designed to overcome the usual undue reliance, by dcf practitioners, upon historical data as the basis for determining the investors' expectations for the future. NSP's historical dividend yield has been volatile and is influenced by both unfavorable and favorable economic conditions (NSP Ex. 3, p. 11). Mr. Kolkmann's procedure produced an estimated yield for the test year of 10.8 (NSP Ex. 3, p. 13). His calculation of growth was based upon a review of historic growth in dividends, earnings and book value. He indicated that growth in book value was more stable and relied upon it to estimate the value of growth at 4.2% (NSP Ex. 4, Sch. 13, pp. 2 and 5). This produced a barebones cost of equity of 15.0% (with continuous compounding and discounting) and 15.5% (with discrete compounding and discounting) (NSP Ex. 3, p. 16).

Method II separates the return into two components, the real rate of interest including a risk premium and the impact due to inflation (NSP Ex. 3, p. 15). This process allowed him to use a real rate of interest including premium for risk which was constant and also to consider the impact of taxation. Further, it does not require any assumptions as to the growth rate of dividends and of the value of the return 50 years from the present (NSP Ex. 3, p. 15). By use of this method Mr. Kolkmann determined that the barebones cost of equity would be 15.1% (NSP Ex. 3, p. 15).

Mr. Kolkmann then demonstrated, for Methods I and II, the need to consider underwriting expenses and market pressure in determining the reasonable rate of return required by regulation (NSP Ex. 3, p. 16). He did an analysis of public utility common stock offerings in 1979 and 1980 and found a selling cost of about 4% (NSP Ex. 3, p. 16). He found market pressure on NSP offerings in the range of 5 to 6% (NSP Ex. 3, p. 16). He therefore recommended that the dividend yield term in the dcf analysis be increased by 9 to 10% which, under Methods I and II, brought the return on common equity to a range of 16.1 to 16.6 (NSP Ex. 3, p. 16).

Mr. Kolkmann's Method III was a market price to book value analysis which attempted to measure the impact of various factors on the market price to book value ratio of NSP (NSP Ex. 3, p. 17). The analysis was able to account for 98.5% of the quarterly variation in the market to book ratio over a 20 year period for 1960 through 1979 (NSP Ex. 4, Sch. 15, p. 2). Based upon this analysis, he determined that a 16% return is necessary for NSP to achieve a market to book ratio of 1 (NSP Ex. 4, Sch. 15, p. 3).

Finally, Method IV involved a comparison of NSP's return with companies whose rank, as to return on equity and market to book ratio, was similar to NSP's rank for 1974 and 1975 when its market to book ratio was near 1. The 1979 returns on equity for this group of companies averaged 16.35% (NSP Ex. 3, p. 18).

period to 7% in June and returned to 11.6% in October (NSP Ex. 5, p. 2). The money supply was sharply increased during Wilson's selected period producing a pronounced but short-lived drop in interest rates and yields on AA utility bonds to their lowest level (NSP Ex. 5, p. 2). Since October, 1980 (the end of witness Wilson's selected time period) the Federal Reserve has returned to its tight money policy and interest rates have risen sharply (p. 2). The Chairman of the Federal Reserve Board has reiterated its intent to stay with the tight money policy (p. 3).

If witness Wilson were to have used data from the entire twelve months of 1980, a more balanced view of financial conditions would have resulted and a better estimate of the dividend yield term would have been provided. The average 1980 dividend yields published in Value Line Investment Survey for the 93 electric utilities examined by witness Wilson was 11.8% (NSP Ex. 5, p. 3).

With respect to the growth rate, witness Wilson's estimates are unrealistically low. Various investment advisory services, with a wide circulation, publish estimates of dividend growth, earnings growth and book value growth greatly exceeding those obtained by witness Wilson (NSP Ex. 5, p. 4). The average expected dividend growth among the 93 companies is 5% (NSP Ex. 5, p. 5). When combined with an appropriate dividend yield, this growth would produce a dcf estimate of the cost of common equity of 16.8% (NSP Ex. 5, p. 5).

In addition to conceptual problems and inappropriate period selection, basic errors appeared in witness Wilson's data. On Table B-8, the seven year growth rate calculation in book value per share for NSP was incorrectly shown at 2.23%, when the true calculation based on the simple average of 3.67% and on a logarithmic regression was 3.89% (NSP Ex. 5, p. 5).

Witness Kolkmann performed an analysis to determine whether Wilson's selected comparable companies were truly comparable in terms of business and financial risk. His method relied on similarities in stock price movement as a basis for identifying those comparable companies (NSP Ex. 5, p. 6). This was accomplished by a regression analysis using data for 88 utilities for a ten year period beginning April, 1971, eliminating that portion of stock price movement attributable to movements in the stock market as a whole and determining that portion of the movement in stock price attributable to company specific factors. By regressing these company specific price movements against each other, stocks with the highest correlation were combined into clusters and the process continued until companies that exhibited the most similar correlations to NSP were selected. Twenty-three such companies were presented by witness Kolkmann, with dividend yields for 1980 averaging 11.76% and weighted average growth rates, based upon the highest statistical reliability, averaging 3.61%, for a barebones cost of equity of 15.37% (pp. 8 and 9).

Based on all the evidence, the recommendation by Staff of 14 to 14.5% is clearly inadequate. This level is well below the current yield required for long-term debt rated AA. It is based upon the bias of the analyst in selecting an unreasonable time frame in order to produce an unreasonably low number. The Company's study is far more realistic and comprehensive and should be followed.

C. Fuel Clause.

After some discussion in prefiled testimony, the Company and Staff agreed that the fuel adjustment clause should be modified to include a true-up for over and underrecoveries and a carrying charge for delay in recovery. (NSP Ex. 16, pp. 2-5; Staff Ex. 30, pp. 7-9; Tr. pp. 604-605, 615-617). Mr. Rislov and Miss Dupay have begun work on the design of the necessary modifications with an eye toward implementation on December 15, 1981. It is hoped that final language will be available at the time of the order at the end of this case. If the modifications are accomplished, the Company believes the fuel clause will be a truly superior mechanism to track the cost of generation through the rates.

D. Other Rate Design Changes.

The Company proposed many rate design changes which in general follow past Commission orders and trends in rate design, and move rates closer to cost. (NSP Ex. 1, p. 11; NSP Ex. 14, pp. 3-20; NSP Ex. 16, pp. 8-9). It would be wasteful to list the many components of the rate design program described in Miss Dupay's testimony and exhibits. The Company's proposed rate design is reasonable, fair to all customers and consistent with Commission precedent. It was unopposed by the Staff and should be adopted in its entirety.

VII. RATE DESIGN

A. Late Payment Charge

Prior to this filing, only large commercial and industrial customers were subject to a late payment charge. The Company recommends the institution of a late payment charge for all customers. It proposes that the late payment charge be established at "4% on current months billing" (NSP Ex. 14, p. 20). The express purpose for the Company's recommendation is "to induce prompt payment of utility bills" (NSP Ex. 14, p. 20).

In the Company's view the late payment charge must be sufficiently high to realistically induce prompt payment. If effective to reduce the number of customers who do not pay their bills within 30 days, it would also reduce the 30 day account receivables and reduce the annual cost of money to the Company (NSP Ex. 14, p. 21). A successful late payment charge would also reduce the number of customers who go delinquent 60 days or more and thus reduce the cost of subsequent credit action (NSP Ex. 14, p. 21). Comparison between the residential customers' payments, without the late payment charge, and large commercial and industrial customers, who are currently charged for late payments, give strong evidence of the effectiveness of a sufficiently high late payment charge. Accounts receivable in 1980 for residential customers were 17% of the total revenues collected from that class while accounts receivable for customers which include the large commercial and industrial customers represented only

2.7% of the total revenues received from that class (NSP Ex. 14, p. 21).

As discussed earlier in connection with the working capital requirement, Staff witness Knadle also proposed a late payment charge, but at a significantly reduced level of 1% of the outstanding balance (Tr. 591). While he agreed that the purpose of the charge "should be to encourage the customer to make the payment on a timely basis" (Tr. 590), he was unable to state that his 1% charge could reasonably be expected to produce the desired effect (Tr. 590). In essence, his position was that the 1% charge should be implemented on a trial basis and data would thereafter be obtained to measure its effect (Tr. 590).

The Staff recommendation is simply not tailored to the objectives of the late payment charge. As Mr. Knadle agreed, it is more in the nature of a finance charge for unpaid electric bills since it applies to the unpaid balance for however long outstanding, whereas the Company's 4% charge represents a one-time charge in the month of the billing (Tr. 592). The Company's response to the Staff's recommendation was summarized by witness Dupay as follows (NSP Ex. 16, pp. 5-6):

> "I also do not agree that the primary purpose of the late payment charge should be a finance charge, rather the primary purpose should be an inducement to pay bills promptly, and thereby hold down collection costs."

When collection costs are examined, it becomes clear that the 1% late payment charge is limited to covering only those costs associated with extending credit to customers, which represent about 25% of the credit activity costs and requires other ratepayers, who are paying on time, to pick up the remaining costs (NSP Ex. 16, p. 7). As shown in NSP Ex. 15, Sch. 8, p. 2, the total amount of credit activity costs for 1980 were $96,900.00. NSP Ex. 17, Sch. 3 clearly demonstrates that the 4% charge is necessary in order to fully recover credit costs from the customers who are not paying their bills on time.

Finally, Mr. Knadle's recommendation implies that the 1% charge will fully compensate the Company for costs not recognized in the working capital calculation, which determines cash working capital based on the assumption that all customers will pay within 20 days from date of billing. This 1% charge amounts to only a 12% annual interest rate, which is far less than the costs experienced in 1980 and well below the current prime interest rate (NSP Ex. 16, p. 7). There clearly should be some direct relationship between what the Company charges customers for the use of its money and the interest rate used by the Company in making refunds for any rates collected under bond, which has historically been equal to the prime interest rate plus 2% (NSP Ex. 16, p. 7).

For these reasons, we propose that the Company's late payment charge be approved.

Dated this 16th day of November, 1981.

NORTHERN STATES POWER COMPANY

By ______________________
David A. Lawrence
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-6648

And ______________________
Samuel L. Hanson (SLH)
Briggs and Morgan
2452 IDS Center
Minneapolis, MN 55402