#62

DIRECT TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

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BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

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MINNESOTA POWER COMPANY

E015/GR-87-223

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1. INTRODUCTION AND QUALIFICATIONS

Q: Would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am President of PLC, Inc., 10 Post Office Square, Suite 950, Boston, Massachusetts.

1.1. Qualifications

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options.

As a Research Associate at Analysis and Inference, and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; and ratemaking for excess and/or uneconomical plant entering service. My resume is attached to this testimony as Exhibit PLC-1.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately forty times on utility issues before various agencies including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Sating Council, the Illinois Commerce Commission, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Pennsylvania Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear

Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you authored any publications on utility ratemaking issues?

A: Yes. I have authored a number of publications on rate design, cost allocations, power plant cost recovery, and other ratemaking issues. These publications are listed in my resume. Of particular relevance to the issues in this case are my papers "The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," and "Power Plant Phase-in Methodologies: Alternatives to Rate Shock."

1.2. The Purpose and Structure of this Testimony

Q: What is the purpose of your testimony?

A: I was asked by the Minnesota Department of Public Service (MDPS) to determine whether the Minnesota Power Company (MP) has excess generating capacity. I was also asked to determine, to the extent that there is excess capacity, to determine why that excess occurred, to identify the units which are (wholly or partially) excess, and to determine the costs imposed by that excess capacity. Thus, the issues addressed in the PLC Inc. study for the MDPS included:

What is excess capacity?

How much of MP's capacity is excess?

Why did that excess occur?

Could MP have taken steps to reduce its excess capacity?

With which plants is the excess associated?

Is the excess plant economically advantageous to ratepayers?

The report from that study is attached as Exhibit PLC-2.[1]

Q: How is your testimony structured?

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1. Exhibit PLC-4 contains some of the most important MP discovery responses upon which the study relied. Exhibit PLC-5 consists of some correspondence to and from MP, regarding the availability of MP capacity for sale to NSP and SMMPA, as an alternative to Sherco #3.

A: Section 2 summarizes the results of the PLC report on MP's excess capacity. Section 3 discusses the ratemaking policy issues which arise from MP's excess capacity situation, and provides the Commission with a range of ratemaking options.

2. EXCESS CAPACITY ON THE MP SYSTEM

2.1. Extent of Physical Excess

Q: How much of MP's capacity is excess in the 1987/88 time frame?

A: Approximately 440 MW is surplus over the 15% reserve margin at winter peak. A portion of the cost of 30 MW of this surplus will be borne by Large Power Contract customers as contract capacity in excess of projected peak. Another 30 MW will be used to repay diversity exchange power received in summer 1987.[2]

Q: What has MP's capacity situation been over the last decade?

A: In the late 1970s, MP maintained surpluses over the 15% reserve margin of 150-250 MW <u>including</u> capacity purchases and sales. For the first several years after Boswell #4 was completed, surpluses soared to the 500 to 800 MW level. Efforts were made to market this surplus, but the effect was limited to 50 MW or less in any given season. Since 1985, MP capacity has decreased by over 100 MW as 30% of Young reverted to its owner and a portion of Coyote was sold off. Peak load has remained depressed, however, with surplus <u>prior</u> to sales continuing to exceed 500 MW. MP has

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2. MP sold 425 MW of capacity in summer 1987, mostly at relatively low rates.

been able to reduce this somewhat by selling 50-150 MW in 1985-86.

The cost of some of MP's large surpluses in the 1980's have been borne by the Large Power Contract customers whose usage has been substantially below contract levels. In the 1981-1984 period when surpluses were greatest (due in large part to reduced operating levels at the taconites), Large Power Contract customers paid for up to 200 MW of unused capacity. Even with this adjustment, surplus capacity has generally ranged between 450 and 600 MW (prior to sales) since Boswell #4 was completed at the beginning of the decade.

Q: When is MP's surplus likely to end?

A: Based on MP's current forecast, capacity and demand will come into balance in 1992, when the second line at Lake Superior Paper comes on line and after the NSP sale is completed.

Q: Is any of MP's capacity in excess of the 15% reserve margin justified?

A: In general, it is reasonable to expect some excess at some times, due to the lumpiness of generation additions and the normal difficulties in precisely matching capacity to loads. Section 2.3 of Exhibit PLC-2 suggests that unacceptable excess be defined as capacity over a 25% reserve margin, or capacity not required in the next five years. MP has already had excesses well over 25% for the entire decade of the 1980s: reducing reserves to 15% for the next several years would still leave an average reserve margin substantially above 25% for the period since 1980. Similarly, most of the excess capacity in 1987 (or any other year since 1980) will not be required within a five-year planning horizon. More importantly, over 300 MW of the excess capacity created by the operation of Boswell #4 in 1980 and Coyote in 1981 would not be needed by MP for over a decade after the units' in-service dates.

In addition to considerations of reserves required for reliability and the additional reserves which will occur periodically, some excess may be justified by production cost savings. MP has not attempted to quantify this effect: at MP's level of reserves, only a very small part of the excess could be offset by production savings. Little, if any, of MP's excess has been economically justified.

2.2. Origin of the Excess

Q: How did MP end up with such large reserve margins?

A: MP committed several planning errors in the 1970s.

1. MP allowed itself to become excessively dependent on sales to the taconite industry, which represent an almost unique concentration of sales to a single industry for a major electric utility.

2. MP also ignored ample evidence that the Great Lakes steel industry's blast furnaces operations (on which taconite depended) were particularly risky, subject to a wide range of long-term problems.

3. MP's forecasting methodology depended heavily on the representations of customers, and potential customers, regarding load additions, and was therefore likely to be overstated in the long term.

4. MP failed to take any of a number of possible actions to moderate the effects of the taconite load uncertainties on its revenues, including diversification of supply to the taconites, diversification of MP's load additions, reduction of the taconite requirements for utility power supply, and merger of MP with a larger utility, particularly NSP.

Q: Would these errors have been avoidable, if MP's planning process had been designed in a prudent manner?

A: Yes. The errors, and the excess capacity which materialized in the early 1980s, were due primarily to imprudent actions on the part of MP management.

2.3. MP's Efforts to Sell Excess Capacity

Q: Did MP recognize that it had excess capacity in the early 1980s?

A: Yes. However, it took MP a long time to accept the fact that it would have excess capacity in the long term. It took MP even longer to acknowledge that long-term sales of excess capacity, which would eventually have to be replaced at higher annual costs, could be cost-justified by savings in the short term.

Q: When did MP recognize that it had excess capacity, over various lengths of time?

A: In 1978, MP first realized that it would have excess capacity after Boswell #4 was completed: MP offered 440 MW of capacity for sale in summer 1980. In 1979, MP offered capacity to SMMPA (Southern Minnesota Municipal Power Agency): 550 MW in summer 1985, with decreasing amounts available through summer 1985 and winter 1983. In the early 1980s, MP's load forecast dropped and actual load stagnated and then dropped. MP's was faced with an increasing amount of excess capacity, even though it was successful in selling small amounts of capacity. The time when capacity and demand would be balanced was moving further into the future.

It is important to point out that many of MP's power supply assessments were based on "pessimistic" assumptions such as no oil fired capacity and reserve margins higher than 15%. Utilizing these kind of pessimistic assumptions, MP informed the Minnesota Department of Energy, Planning and Development in 1982 that it did not have base load capacity for sale concurrent with Sherco #3's scheduled 1986 in-service date.

By 1984, MP believed that it was likely to have excess capacity until the late 1990s and possibly longer. In 1985, MP recognized that its excess capacity situation would be permanent unless substantial amounts of capacity were sold off.

Q: Why did MP require so long to accept the fact that the excess capacity would be a continuing problem?

A: A major part of the responsibility lies with MP's load forecasting process. MP's forecasts have dropped continuously since 1977, reducing predicted winter 1991 peak by over 1000 MW. Until 1982, the forecasts included large amounts of uncommitted load: MP's forecasts incorporated customer predictions of new or expanded industrial facilities. Until recently, MP was similarly dependent on industrial customers for predictions of operating levels of existing industrial customers. In particular, MP had not developed a familiarity with national steel markets that would allow it to independently forecast taconite production.

Q: Was MP willing to make long-term sales, once it realized that the capacity would not be required or cost-justified for a period of several years?

A: Until 1985, MP consistently used the date at which it might need capacity as the end point for any potential sale. Thus, in the 1978-1982 period, MP was willing to make a sale for several years hence. By 1984, MP was considering sales into the late 1990s and possibly slightly beyond. It has only been since 1985 that MP would consider sales longer than 15 years.

Q: Should MP have been willing to commit to long-term sales earlier?

A: Yes. MP's reluctance to commit to long-term sales was largely the result of a lack of any present-value analysis, and the absence of contingency planning.

Q: How did the lack of present-value analysis impede MP's ability to sell capacity in the long term?

A: A long term capacity sales typically results in savings in early years (when sale revenue exceeds increased production costs) and increased costs in later years (when production costs exceed sale revenue). A long term sale may be justified even if the increase in production costs over the life of the sale (in nominal dollars) is greater than sale revenue (again in nominal dollars): on a present-value basis, a dollar of savings in early years is worth more than a dollar of costs later on. Until very recently, MP does not seem to have evaluated capacity sales on a present-value basis, so it gave undue weight to increases in production costs in later years.

Q: How did the lack of contingency planning impede MP's ability to sell capacity in the long term?

A: MP is faced with very substantial uncertainty concerning future load levels, due in large part to the unsettled state of the taconite industry. Prior to 1985, MP basically limited its capacity supply options to existing capacity and construction of new coal capacity at a cost substantially higher than existing units. This limited view of supply planning enhanced the apparent desirability of retaining capacity as an insurance policy in case it is needed to meet future load growth.

In 1985, MP recognized that it had a much wider variety of supply options, such as cogeneration and wider use of Reserve and Erie generation. Recognition of these options, many of which could be added relatively quickly and cheaply, showed that it was no longer necessary to retain existing capacity to meet possible load growth.

Q: Should MP have recognized earlier that long-term sales of capacity were advantageous?

A: Yes. MP should have been prepared to offer for sale its share of Coyote and a large portion of Boswell #4 in the 1980-82 period.

Q: Was there a market for existing base load capacity in the early 1980s?

A: Yes. MAPP projected that the capacity situation would tighten later in the decade as load growth ended the short-term glut. Utilities were concerned about cost and availability of oil and environmental restrictions on coal. New capacity was forecast to be substantially more expensive than existing units. Interest rates were high. Relatively little new capacity was being planned.

At the beginning of the decade, NSP was planning to meet its load growth with Sherco #3, to be followed by Wisconsin and North Dakota coal plants.[3] NSP's forecast dropped in 1980 and it responded by selling off part of Sherco #3 and deferring other additions. NSP continued to move forward on Sherco #3, since it projected a need for additional capacity in the late 1980s. Also, NSP wanted to minimize use of its 1200 MW of oil fired units, approximately 20% of total capacity. Another 500 MW of NSP's capacity was pre-1955 coal units. So long as NSP's loads continued to grow steadily, NSP was interested in adding new capacity slightly ahead of need, to displace the older units.

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3. The Oliver County North Dakota plant was to be jointly owned with MP.

SMMPA was a joint owner of Sherco #3. The existing capacity of SMMPA's members was in small units, many of them oil-fired or very old. SMMPA had a strong interest in acquiring base load capacity. SMMPA was able to contract for purchases through winter 1985, after which it expected Sherco #3 to be on line.

At the end of 1982, Sherco #3 received its Certificate of Need for a January 1, 1988 in-service date. MP had indicated that it did not have capacity available that could serve as an alternative to Sherco #3: had it done so, Boswell #4, at or above book, would have been very competitive with the much more expensive Sherco #3.

Q: Was there a good market for capacity at the time MP decided to release significant amounts of Boswell capacity in the long term?

A: No. MP was willing to make long-term equity or participation sales (at prices close to book value) only after 1984.[4] MP's decision to release capacity was prompted, in large part, by the projection of long-term capacity surpluses in MAPP, which assured MP that it could buy back capacity at favorable rates if it should need to do so in the future. The same capacity surpluses reduced

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4. In 1984, MP did offer its 21 MW Coyote share to the joint owners at depreciated book if the sale could be concluded by the end of the year. A sale arrangement was not finalized until mid-1985.

the interest of other utilities in buying MP's capacity at book cost, let alone at a premium.

Q: Would prudent management have been able to sell MP's excess capacity in the early 1980s?

A: Yes. It should have been possible for MP to sell off Coyote and about 300 MW of Boswell #4 in the seller's market of the early 1980s. The sales would probably have gone off at book, or slightly higher.

2.4. The Cost of the Excess Capacity

Q: How much has MP's excess capacity cost the utility and its customers since 1980?

A: As computed in Table 5.3, Exhibit PLC-1, the cost is more than $450 million, with $45.9 million in 1987 and $411.4 million in 1980-1986. This cost includes an adjustment for payments by Large Power Contract customers for capacity in excess of actual use. This adjustment, which reduces the cost of excess capacity, is somewhat overstated: Large Power contract customers pay for capacity at average cost, which is lower than the cost of the excess capacity, i.e., Boswell #4 and Coyote.

MP has sought to reduce the cost of excess capacity by short-term sales of this excess to other utilities. As shown in Table 5.4, Exhibit PLC-1, revenue from these sales has totaled $7 million in 1987 and $21.1 million in 1980-86.[5] While these sales have not provided MP with full recovery of costs, they can be treated as a partial offset,

5. Revenue figures are computed on a power year rather than a calendar year basis. MAPP power years are divided into 2 seasons: summer (May 1-October 31) and winter (November 1-April 30). Thus 1987 revenues are for a May 1, 1987-April 30, 1988 period.

to the extent that the sales would not have been possible without excess capacity.[6]

Q: Would all of this cost have been avoided by prudent management?

A: Probably not. Some of the excess was due to short-term fluctuations in load, and it may have been economical to retain some of the excess. A conservative (i.e., possibly understated) estimate of the prudently avoidable costs, representing the complete avoidance of Coyote and a gradual sale of 300 MW of Boswell in the 1982-84 period, amount to about $184 million in 1980-86.

Q: What are the total cost and prudently avoidable cost of excess capacity in 1987?

A: The total cost is about $46 million and the prudently avoidable cost is about $35 million.

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6. MP is a winter peaking utility, while NSP and MAPP as a whole are summer peaking. Thus, MP may have capacity available for summer sales even if it has no excess capacity based on its higher winter peak. Over the last several years, MP winter peaks have exceeded summer peak by approximately 50 MW. Thus, even with no winter excess capacity, a portion of MP's sales to NSP in summers 1985, 1986, and 1987 could have possibly occurred. Whether such a sale would have actually been possible and profitable requires an examination of maintenance schedules and comparison of revenues and production costs.

   In recent years, MP has also been exploring seasonal diversity exchanges. These exchanges can be used to equalize seasonal capacity requirements and could reduce the amount of capacity MP must own to meet its peak load requirements. Such exchanges can free up winter capacity to permit year-round capacity sales.

Q: Have the short-term sales in the 1980-87 period reduced the burden of the excess capacity?

A: Yes, to some extent. The total sales revenues in the 1980-86 period were over $21 million, with another $7 million in 1987. The bulk of these sales would have been possible even if MP had made the prudent long-term sales discussed above, but the long-term sales might well have competed with the short-term sales.

2.5. The Effect of the NSP Sale on Excess Capacity and Excess Costs

Q: What effect will the NSP sale have on MP's excess capacity?

A: At the conclusion of the sale in 1991, MP's reserve margins are projected to be about 20%, bringing demand and supply roughly into balance. When the second line at Lake Superior Paper comes on line in winter 1992, projected reserve margin drops to 14%. The load forecast continues to grow slowly after 1992, increasing MP's need for capacity until MP recovers 102 MW of Young from NSP in 2008. This projection assumes that MP's current load forecast is an accurate representation of the future.

As MP recognizes, an additional contraction of the taconite industry is not unlikely, although it is also far from assured. MP's current (November 1986) base case forecast assumes that Minnesota taconite production will increase from 1986 output of 25.3 million tons, stabilizing at 32.6 million tons after 1989. The low scenario of the current forecast assumes taconite production will rise in the 1987 and 1988, and then fall, stabilizing at 24.2 million tons annually, slightly lower than 1986 output levels.

The difference between base forecast and low scenario taconite production translates into annual electrical use of about 1 million MWh and over 100 MW peak demand. This understates the total effect of taconite on MP load: the dependence of the economy in the service area on taconite means that reductions there will depress electric use by residential, commercial, and (possibly) other industrial customers. The low scenario predicts an essentially constant MP winter peak load of 1000 to 1040 MW from 1986 onward. This contrasts with the base forecast of 200 MW of winter peak load growth 1986-1996, and less than 100 MW in the following 15 years. With the low scenario, MP will continue to have over 100 MW of excess capacity after the NSP sale, with this excess growing to more than 200 MW when Young reverts to MP in 2008.

Q: Will the sale end the accumulation of excess costs which have been building up since MP's failure to sell Boswell #4 in the early 1980s?

A: No. The sale consists of 214 MW of Boswell (based on a 535 MW rating) and 102 MW of Young. Since Young is a less expensive plant, in terms of both carrying charges and fuel costs, the NSP sale will leave MP's ratepayers with annual costs on the order of $4-6 million higher than would have occurred under a sale of all Boswell #4 capacity.

Q: Does the gain on the sale of Boswell #4 above book cost offset the cost of the excess Boswell capacity in the 1980-88 period, and the higher continuing costs of MP's remaining Boswell share, as compared to Young?

A: No. The gain is much smaller than the excess costs in any one year, let alone the total 1980-88 loss.[7] The present value of the gain is roughly comparable to the difference in annual costs of Young and Boswell. Thus, the flow-through of the gain to the ratepayers (the "AFPO" credit) may be thought of as a small compensation to the ratepayers for the delay in the sale, or nearly full compensation for exchanging 102 MW of Young for Boswell #4 capacity.

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7. Actually, the excess capacity costs continue into 1991, when the final sale increment occurs.

3. RATEMAKING IMPLICATIONS AND RECOMMENDATIONS

3.1. Ratemaking Considerations

Q: What basic concepts might the Commission apply in determining the ratemaking effect of MP's excess capacity?

A: The two basic concepts which are relevant to the ratemaking treatment of excess capacity are (1) prudence and (2) used-and-useful. Each of these concepts has been relied upon by various regulators as the basis for disallowance of utility costs.

Q: How does the concept of prudence apply to ratemaking for excess capacity?

A: In general, utilities are only allowed to recover costs which were prudently incurred in the providing service to the public. Thus, if the excess capacity, or the costs resulting from the excess, resulted from events which the utility could not have predicted or mitigated, the prudence rule would lead to the conclusion that the ratepayers should absorb the additional costs. On the other hand, if the costs flow from actions (or failures to act) which would have been avoided by management acting on information it knew or should have known, the prudence rule would assign the excess costs to the shareholders.

The prudence rule is not controversial, and is widely accepted in principle. In the actual application of the rule, substantial disagreements usually arise regarding the standard of prudence to be applied and regarding the interpretation of the utility's actions.

Q: What would be the implications of the prudence rule, as applied to MP's excess capacity situation?

A: MP's current and past excess capacity situations are primarily the result of MP's imprudence in planning for the taconite loads, and MP's imprudence in having inadequate planning processes and capabilities during the early 1980s. Thus, the prudence rule would suggest that shareholders be held responsible for all of the additional costs due to the excess.

Q: How does the concept of used-and-useful apply to ratemaking for excess capacity?

A: Used-and-useful has been applied in many forms in electric utility ratemaking. The general concept is that the ratepayers should only pay for plant (and for costs) which are reasonably necessary for the provision of service.

For example, when power plants under construction are cancelled, many regulatory commissions allow the utility to amortize the cost of the plant over a period of years, but do not allow a return on the unamortized balance; in many cases, the common equity portion of AFUDC is not recovered. Thus, shareholders assume the cost of the time value of money during the amortization period, and also often lose their deferred return on the funds they contributed to construction, while the shareholders pay the direct costs and the remainder of the AFUDC.

Used-and-useful has also been applied in situations closer to MP's current situation. The Massachusetts Department of Public Utilities has extended the cancelled-plant rules to cover the excess costs of new plants: i.e., a portion of the plant investment corresponding to the difference between the plant's costs and its benefits will be amortized (without return), rather than ratebased, and the equity AFUDC on that portion will not be recovered. This rule was applied in MDPU 85-270 to the share of Millstone Unit #3 owned by the Western Massachusetts Electric Company, despite a finding that the costs were prudently incurred.

The Pennsylvania PUC has similarly disallowed some costs related to prudent plant investments which resulted in excess capacity. For example, in the case of Pennsylvania Power and Light's Susquehanna plant, both units of which constituted excess capacity, the PUC removed from rate base a "slice of the system" (at the average cost/kilowatt) equal to the megawatt rating of Unit #1, and indefinitely disallowed any equity return on Unit #2.

The Kansas commission disallowed a large portion of the prudently incurred excess capacity costs of the Wolf

Creek nuclear plant. This action shifted all of the excess costs to the shareholders.[8]

Q: How would the used-and-useful concept apply to MP's excess capacity situation?

A: Used-and-useful is a much broader concept than prudence, and there is hence greater variation in the implementation of the concept. Depending on the approach taken, and the weight given to both past conditions and future conditions, used-and-useful could support any of several ratemaking adjustments, including the following:[9]

1. disallowance of return on the excess capacity in the rate year, based on the cost of the plants which created the excess, Boswell #4 and Coyote,

2. disallowance of return on the excess capacity in the rate year, based on the average cost of the MP's baseload capacity (all four Boswell units, Coyote, and perhaps Laskin and Young as well),

3. disallowance of return on the excess capacity in the rate year, based on the average cost of MP's capacity,

4. disallowance of any of the returns in (1) - (3), but with the excess adjusted to remove capacity sales in the rate year, capacity required within a set period (e.g., five years), a higher reserve margin, or with only portions of return disallowed,

5. disallowance of a fraction (perhaps 50%) of the total net costs due to the excess.

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8. For additional examples of used-and-useful and/or prudence treatments from earlier cases in Missouri, New York, Ohio, and Pennsylvania, see "Innovative Regulatory Approaches to Power Plant Productivity and Cost Allocation Issues," Lynn Danielson, Policy and Program, California Energy Commission, September 1981.

9. This list is not exhaustive.

Since the unnecessary capacity is so clearly due to the newest units, the first approach seems to be most appropriate in the case of MP.

3.2. Ratemaking Recommendations and Options

Q: What action would you recommend that the Commission take with regard to MP's excess capacity situation?

A: I believe that the Commission should take three actions. First, it should clearly describe the situation, MP's role, and the Commission's desire to avoid a repetition of the current situation. Second, the Commission should initiate a regular series of reports from MP on its efforts to bring loads and supply into balance, and to reduce costs. Third, a significant ratemaking disallowance should be imposed on MP in this proceeding.

Q: What points should the Commission make clear in the decision, regarding the excess capacity situation?

A: The Commission should clearly establish that:

1. the Commission considers MP to be fully responsible for the current situation,
2. MP's planning process and awareness of critical planning issues were woefully inadequate in the 1970s and early 1980s,
3. MP has refrained from cosmetic actions, such as the retirement of Winslow, Hibbard and Laskin, which might have reduced apparent excess capacity while further increasing costs to ratepayers,
4. MP has made significant improvements in its planning process, and now appears to be capable of managing its production system efficiently,
5. the Commission is more concerned about the level of costs produced by planning errors than by the level of physical capacity that results, and

6. the Commission intends that the costs of imprudent or careless planning will not be fully recoverable from ratepayers, in this case or in comparable future situations.

Q: What matters should MP be required to discuss in regular filings?

A: MP should regularly report to the Commission on its projected load and supply situation, future uncertainties in load and supply, MP's options if various uncertain events occur (e.g., Minnkota exercises a Young recapture option, or taconite production falls to 24 million tons), MP's efforts to monitor the likelihood of various outcomes, and its efforts to increase its flexibility and reduce costs. In short, MP should demonstrate that it is now performing the analyses it could not perform in the period 1975-85.

These reports should be tied into MP's forecasting process (the source of much of the uncertainty), and to the Conservation Improvement Program. Conservation and cogeneration may be valuable to MP in at least two distinct ways. First, by reducing MP's loads at a very low cost, conservation, and to a lesser extent cogeneration, may allow MP to sell off more of Boswell and further reduce total costs to ratepayers. Second, to the extent that MP can quantify the resource potential for conservation and cogeneration (as well as renewable energy and other small-increment, short lead-time power sources), it will be better positioned to release excess capacity in the event of a down-turn in demand, without worrying about the availability of resources if and when load growth resumes.

Q: What cost levels due to excess capacity should the Commission consider in this case?

A: A range of costs should be borne in mind in evaluating the costs of the excess. I will discuss these cost levels in descending order, noting differences between excess costs for used-and-useful purposes and imprudent costs, as applicable.

The Commission should consider the ratemaking for excess capacity in 1987 and beyond in light of the unnecessary increase in rates during the period 1980-86. This cost, in excess of $400 million,[10] is much larger than any disallowance which would be justified by the test-year costs.

The entire cost of excess capacity in 1987 is $45.9 million, as shown on Table 5.3 of Exhibit PLC-2. This calculation includes only fixed costs, on the assumption that the O&M costs of the excess capacity is offset by its fuel savings. This is the appropriate starting point for the Commission's determination of the cost in 1987 of MP's imprudence, and of the resulting excess capacity. It is also the starting point for determining the net cost (from whatever origin) which must be divided between the

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10. See Table 5.3, Exhibit PLC-1.

ratepayers and the shareholders, under any concept of used-and-useful.

Whether the Commission applies a prudence standard or a used-and-useful approach, the total cost of excess capacity is subject to certain adjustments. From a prudence viewpoint, not all of the excess capacity is necessarily attributable to the shareholders. It is entirely possible that better planning in the late 1970s would have allowed MP to avoid all of the current excess, but the wide range of potential options (none of which MP explored) makes it difficult to determine exactly how a prudent utility would have moderated the taconite-related risks, and thus how much excess MP would have today had it been prudent in the 1970s. Quantifying the excess capacity which MP could have avoided by sales in the early 1980s is much more tractable. Table 5.1 of Exhibit PLC-2 presents the cost of 310 MW of Boswell #4 capacity (based on a 535 MW rating), and Table 5.2 of Exhibit PLC-2 presents the cost of the remaining Coyote capacity. All of these costs should have been avoidable, had MP possessed an adequate planning process and been able to act promptly on sales efforts in the early 1980s. Thus, the imprudently incurred costs in 1987 are $34.9 million.

Both the $45.9 million in excess costs for used-and-useful purposes and the $34.9 million in imprudently incurred costs are potentially subject to adjustments for two offsetting factors: the revenues from off-system sales permitted by the excess capacity, and the AFPO (allowance for phase-out) credit from the gain on the sale of Boswell #4 above book value. The sales in 1987 produce about $7 million in demand revenue, and the AFPO credit in the test year is $10 million.

The AFPO credit need not be considered in either analysis. As demonstrated in Section 5 of Exhibit PLC-2, the AFPO is roughly comparable to the extra costs resulting from the substitution of 102 MW of Young capacity with the more expensive Boswell plant. The AFPO may also be thought of as some compensation to the ratepayers for the lengthy delay in the removal of excess Boswell #4 from rate base: rate payers would have been much better off if the sale had occurred at book in 1982, for example, than with the NSP sale in 1989-1991 at a premium above book.

The sales issue is more complicated. From the used-and-useful point of view, all $7 million reduces the cost of the excess capacity. However, the prudence-based estimate of $34.9 million in avoidable costs assumes that only 321 MW of the 409 MW excess in 1987 would have been avoided by a prudent sales effort in the early 1980s. This would have left 88 MW for short-term sales in 1987. This additional excess would have allowed the entire 75 MW sale to SMMPA ($5.1 million) and a small portion of the 350 MW sale to NSP: that portion would be worth about $0.1

million additional.[11] Thus, only a small part (somewhat less than $1.8 million) of the 1987 sales short-term revenues are attributable to the imprudent excess capacity.

These cost levels are displayed in Exhibit PLC-3. The net imprudent cost in 1987 is $33.1 million, while the total net cost due to excess capacity is $38.9 million.

Q: What cost disallowance is appropriate, based on these values?

A: Any of several disallowances would be justified, depending on whether the Commission is interested in imprudent costs or simply in excess costs, and on how strictly the Commission intends to interpret MP's traditional obligation to provide reliable service at the lowest possible cost.

I believe that the entire $33.1 million imprudence disallowance derived in Exhibit PLC-3 is objectively justified by the factual situation. However, if the Commission wishes to pursue the imprudence approach, but also wishes to treat MP more generously (such as by giving MP a further allowance for the "benefit of the doubt"), it could reduce the allowance in a couple of ways. One approach would be to reduce the target sales level, and treat less than 310 MW of Boswell's 1987 costs as

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11. Actually, the difference between the LP contract minimum and the LP loads would allow another 50 MW or so to be sold in 1987, even after the elimination of the imprudent capacity. Some of the revenues from such sales might flow back to the LP customers. In addition, the 1987 sales are summer sales, for which MP has more capacity available.

imprudent. Since the historical record strongly supports the feasibility of a 310 MW sale prior to the SMMPA/NSP commitment to a 1988 in-service date for Sherco #3, it would be preferable to find other ways to mitigate the effect of the prudence disallowance.

A more acceptable way to reduce the prudence disallowance would be to credit the excess capacity with a larger portion of the $7 million in 1987 short-term sales. Specifically, had MP sold a large portion of Boswell to SMMPA, the 75 MW short-term sale for 1987 might not have occurred. If the remaining 88 MW of excess capacity had served sales at the price of the NSP sale,[12] they would have earned only about $0.5 million, so $6.5 million ($4.7 more than in line 5 of Exhibit PLC-3) could be attributed to the imprudent capacity.

If the Commission is inclined to be very generous to MP, the AFPO could be attributed to both the imprudent capacity and to the total excess costs. Given both the past costs of the delay in the Boswell sale, and the future costs of the replacement of Young, I see little justification for treating the AFPO as reducing the cost of excess capacity; nonetheless, the effect <u>is</u> flowed through in the test year. This adjustment would bring the net

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12. The smaller size of the sale would probably allow for a higher price.

imprudent cost down to $18.4 million, and the total excess cost to $28.9 million.

In the event that the Commission reduces the test-year cost of excess capacity by the AFPO for ratemaking purposes, it should clearly state that it is giving MP a sizable favor, and should also state its intent to adjust rates following the Young sale to compensate ratepayers for the higher costs of Boswell power. I see no justification for a prudence disallowance of less than the $18.4 million level.

Q: How would the total excess cost estimate of $38.9 million (or $28.9 million, including the AFPO credit) be applied to a used-and-useful mechanism?

A: The $38.9 million in excess costs is equivalent to the cost of Coyote ($1.5 million) and the cost of 347 MW of Boswell ($37.4 million).[13] The $28.9 million is attributable to Coyote and 254 MW of Boswell. Mr. Lusti of the MDPS staff will present a detailed calculation of the rate effect of the return on MP's share of Coyote and of 254-347 MW of Boswell.

Q: What is your recommendation concerning a ratemaking disallowance for excess capacity in this proceeding?

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13. The computation is as follows: the ratio of Boswell #4 excess cost ($37.4 million) to Boswell #4 total 1987 fixed costs ($57.6 million as shown in Exhibit PLC-2, Table 5.1) multiplied by Boswell #4 total MW (535 MW).

A: I would recommend that the Commission reduce the level of rates which would otherwise be allowed by $33.1 million, based on my prudence analysis. More generous, but defensible, treatment under a prudence test would produce disallowances of $18.4 - $28.4 million. The result of the used-and-useful test are derived by Mr. Lusti.

Q: Does this conclude your testimony?

A: Yes.

EXHIBIT PLC-3: SUMMARY OF EXCESS CAPACITY COSTS ($ MILLION)

	Prudence Test Adjustment	Prudence Test Net Value	Used-and-Useful Test Adjustment	Used-and-Useful Test Net Value
1. 1980-86 Cost		$411.4		$411.4
1987 Costs:				
2. TOTAL		$45.9		$45.9
3. Lost 1980s Sales Opportunities		$34.9	Not Applicable	
4. AFPO, net of Young/ Boswell differential & Sale Delay	Nil	$34.9	Nil	$45.9
5. Short-term Sales (1987)	($1.8)	$33.1	($7.0)	$38.9
6. Additional Sales Attribution	($4.7)	$28.4	Not Applicable	
7. With AFPO	($10.0)	$18.4	($10.0)	$28.9

Note [4]: AFPO is $10 million in test year, but is offset by other costs as explained in text.
[5]: Sales which would not be feasible without excess.
[6]: Adjusts for competition between long-term & short-term sales.
[7]: This adjustment shown for informational purposes only. It is not recommended.

Exhibit PLC-2

REPORT ON

THE EXCESS CAPACITY SITUATION

OF MINNESOTA POWER:

MAGNITUDE, DURATION, AND ORIGIN

Prepared By PLC, Inc.
Paul Chernick
Ian Goodman

for

Minnesota Department of Public Service

July 20, 1987

Revised

August 12, 1987

REPORT ON

THE EXCESS CAPACITY SITUATION

OF MINNESOTA POWER:

MAGNITUDE, DURATION, AND ORIGIN

CONTENTS

1. INTRODUCTION

This report examines the current capacity situation of Minnesota Power Company (MP), and the origins of that situation. For the entire decade of the 1980s, MP has been supporting much more capacity than is required to meet its obligations to the Mid-Continent Area Power Pool (MAPP), and more than is economical. This situation is expected to prevail for the rest of the decade, and to end (or at least be substantially reduced) with the sale of more than 300 MW to Northern States Power (NSP) in the period 1989-1991. Most of this capacity came to be surplus to MP's needs because it was built to meet anticipated industrial load (particularly in the taconite industry), which either never materialized or which has since disappeared.

The second section of this report describes the current capacity situation, in the context of past and projected capacity reserves. The third section discusses the factors which resulted in the current excess capacity. The fourth section examines MP's efforts to reduce that excess, and the effectiveness of those efforts. The fifth section estimates the cost of MP's excess capacity.

Much of the information used in developing this report was taken from the responses of MP to discovery questions of the Department of Public Service (DPS) in this docket (E-015/GR-87-223). Such data is cited as "Response", followed by the number of the discovery question.

2. LOADS, CAPABILITY, AND EXCESS CAPACITY

2.1. MP's Capability

Table 2.1 lists MP's capacity resources from recent years, excluding short-term purchases. Early in this decade (1981-1984), when all of these resources were potentially available simultaneously, MP had total capability resources of about 1840 MW.[1] Table 2.1 also notes the dates that major changes in capability occurred.

Table 2.2 reproduces MP's load and capacity comparisons for 1975-1992, but with all available sources included.[2] The first section of Table 2.2 summarizes MP's potential capability for each year. The system capacity starts in 1975 with about 850 MW, and the important changes (in round numbers) are:

1. a 400 MW addition in 1977, from the contract purchase from the Young plant (located at Center ND, and sometimes called "Center") of the Square Butte Coop;
2. a 520 MW addition in 1980, with the commercial operation of Boswell #4;
3. a 120 MW reduction in 1984, as Square Butte exercised its rights to reclaim some of the Young capacity; and

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1. Since MP's actual load in that period was in the 900-1100 MW range, MP placed Laskin and Hibbard in cold reserve, and Erie shut down its plant. Nonetheless, all of these sources would have been available if they had been needed for planning purposes.

2. Various MP tabulations omit Erie, Hibbard, Laskin, and/or Winslow.

4. a 200 MW reduction in Boswell #4 capacity, phased in over the period 1989-1991, representing sales of a portion of the unit to NSP, to be accompanied by a 100 MW resale of Young capacity.

2.2. MP's Loads and Reserve Margin

Table 2.2 also lists MP's actual or projected system demands (in the lines labeled 1 and 2), and wholesale purchases and sales (in the lines labeled 3, 4, 8, and 9). Line 17 displays the reserve margin for each year.

Prior to 1975, MP's loads had been fairly stable, with winter peak remaining near 700 MW since 1972. In 1976 through 1978, load grew by a total of about 40%, due primarily to the addition of major taconite mines and processing facilities. In 1979 and 1980, load growth slowed to a crawl, followed by a steep decline in 1981 and 1982. Since 1982, loads have recovered somewhat, but they are not expected to return to the 1980 level until 1990.

The reserve margins reflect the patterns of capacity additions and load variations. MP maintained winter reserve margins of 21-46% from 1975 - 1979, in part through short-term purchases.[3] In 1980, reserves rose to 56% as Boswell #4 entered service, even with no short-term purchases. In 1981

3. MP generally over estimated peak load in the 1-2 years time frame. This may explain part of the high reserve margins in this period.

and 1982, falling load boosted reserves to 66% and 89%, respectively. Since 1983, load and sales of capacity have increased, over 120 MW of Young has reverted to its owner, and reserves have fallen somewhat.

2.3. Required and Desirable Reserve Margins

Two basic considerations determine the appropriate amount of generation capacity: reliability of service and economy of service. A certain amount of capacity is needed to provide service at any specified level of reliability. Additional capacity may be economically advantageous, as well.

2.3.1. Capacity Requirement for Reliability

A utility's capacity requirement for reliability purposes is generally expressed as a reserve requirement: the amount (or percentage) by which installed generating capability should exceed the peak demand. "Installed generating capability" refers to the demonstrated power production ability of the utility's plants, at the conditions of the peak load.

A number of factors influence the capacity requirement. For a power pool, or for a utility which is not part of a pool, factors which control required reserves include:

- the desired level of reliability;
- load shapes, including
  * the peak load level,
  * the number of hours with loads close to the peak and,
  * The extent of low-load seasons, in which maintenance can be performed;

- the forced outage rates of generating units;
- the maintenance requirements of generating units;
- the size of individual units compared to the size of the utility or pool;
- interconnections to neighboring utilities and pools, and the availability of emergency power from those neighbors; and
- interruptible loads, customer-owned generation, and other mitigation measures which reduce loads when needed.

For a utility which is part of a reliability power pool, as MP is a part of the Mid-Continent Area Power Pool (MAPP), the required reserve is determined by a two-step process. First, the pool's total requirements (either in megawatts or in percentage reserve) are determined, accounting for the factors discussed above. Second, the pool reserve requirement must be allocated to the member utilities.

MAPP suggests that its members maintain 15% reserves above their non-coincident peaks, which implies a reserve of about 23% above the coincident MAPP peak. In fact, MAPP recognizes that individual utilities will periodically have reserves of less than 15%, and declares that this is "not a major problem," so long as the pool as a whole has adequate reserves.[4]

This standard has been reviewed regularly to ensure that it is adequate for MAPP as a whole. A MAPP study dated October

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4. See p. 3-3, MAPP Coordinated Bulk Power Supply Programs, 4/1/86.

1980,[5] with essentially current data on unit sizes, and very recent data on forced outage rates, concluded that "the current fifteen percent reserve level is adequate to maintain present reliability for the next ten years." Even beyond the ten year period, the potential reliability problem concerning MAPP was the tendency for winter peak to rise relative to summer peak, constraining winter maintenance. Current forecasts show lower relative winter peaks through the 1990s than were projected in 1980 for the mid-1980s, so convergence of summer and winter loads should not be a serious problem in the foreseeable future. For current load shapes, 15% non-coincident summer peaks produce loss of load probabilities near one day in ten years, a standard reliability target in the industry. Actually, as the Reserve Requirements Study indicates, the calculated reliability level is less important than the fact that the projected reliability level is comparable to reliability levels in the 1970s, which were considered adequate.

It is therefore reasonable to treat all MP capacity above the required 15% MAPP reserve as excess capacity for reliability purposes. Reserves above that level are surplus for reliability purposes.

This does not imply that MP reserves above 15% of peak demand are not useful in providing electric service, for two

5. "MAPP Reserve Requirements Study, 1980-1994." An update is expected in 1989.

reasons. First, utilities can not always have exactly the right amount of generation capability: generation additions may be more economical in larger increments,[6] plants may be constructed faster or slower than expected, and load and supply situations are always uncertain. Therefore, reserves will be higher than desired at some times, and lower than desired at others. A certain level of inefficiency in matching supply to demand is unavoidable, as are a certain number of bad welds, broken tools, and other adverse events in any construction project. Hence, <u>some</u> deviations from a 15% reserve must be considered a normal part of the cost of providing service.

Second, reserves above 15% may be justified by economic considerations, as will be discussed in the next section. Considering the factors discussed above, the identification of generating capacity which is excess for reliability purposes should start with the 15% required reserve, and then add in an allowance for normal surplus capacity. That allowance might be a simple percentage of peak load, or it could be stated as the number of years until the capacity is needed.[7]

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6. This "economies of scale" consideration is becoming less important with new technologies, such as fuel cells, integrated gasification combined-cycle, and fluidized bed combustion, which are economical with small incremental additions. However, it was still an important issue at the time Boswell #4 was planned.

7. Both of these standards apply for limited periods of time. Utilities should not be encouraged to perpetually bring plant into service ahead of need.

There is no rigorous method for deriving such an allowance as a percentage of peak. Clearly, a margin of only 1% or 2% would not recognize the lumpy nature of capacity additions. Such a small allowance also would count as excess some capacity which would be needed almost immediately at the levels of load growth rates experienced in the 1970s.[8] An allowance of 15% or 20% above the MAPP requirement, on the other hand, would accept very large excess reserves, compared to the size of MP's system and compared to the size of its plants. Such a large excess would not be needed for several years at relatively high growth rates, and not for a decade or more at current projections.

Considering all these factors, an additional reserve allowance of 10% seems to be adequate, perhaps even excessive. This allowance is two thirds of the basic reserve requirement, and represents a few years of load growth at levels typical of the early 1970s. Applied to MP, 10% of peak is about 110 MW, equivalent to a significant fraction of the size of the typical capacity addition: from 21% of Boswell 4 to 38% of the current Square Butte purchase.

If the allowance is stated as the number of years until the capacity is needed it makes good sense to tie the excess capacity allowance to the planning and construction cycle. Since coal plants have generally been requiring no more than

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8. MP's winter peak grew at an average of 4.5% annually from 1971 through 1975, the period preceding the taconite boom.

five years to build,[9] it seems appropriate to treat as excess that capacity which would not be needed for five years into the future.

2.3.2. Economic Justifications for Additional Capacity

Capacity which is not needed for reliable service can be justified by several factors, each of which can result in ratepayers being better off paying for capacity which is excess from a reliability viewpoint. The most common factor is fuel cost: if units with low fuel cost are added to the system, and if those units allow for reduced usage of existing capacity with higher fuel costs, total costs may decrease. For example, Boswell #4 is dispatched after the hydro plants and Young, and before the other Boswell units, Laskin, and the oil/gas plants.

Additional capacity may also allow for reduced costs at other plants, through mothballing,[10] retirement, and even sale of assets. These savings are usually much lower than the costs of new capacity, but they may contribute to making excess capacity economical and useful.

Other economic factors may also contribute to the justification of higher reserves. For example, the remote

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9. For example, Boswell 3 construction took 37 months, and Boswell 4 took 46 months.

10. Boswell #4 reduced MP's cost somewhat in the early 1980s by allowing lower staffing levels at Laskin and Hibbard.

location of some units results in higher transmission losses than from local generation, and may periodically require the operation of peaking plants for reliability purposes. These considerations make some units (such as the converted Hibbard boilers, located in Duluth) slightly more valuable than they would be if plant location did not vary significantly, while making other units (such as Young and Coyote) less valuable.

Boswell #4, the unit which has accounted for most of MP's excess capacity, produces fairly small fuel savings, since it primarily displaces generation at the other Boswell units[11] and economy energy purchases. Coyote, fueled by less expensive lignite, must have yielded relatively large energy savings. MP has not attempted to quantify the fuel savings from its recent additions (Response 112).

MP's excess capacity, and in particular Boswell #4, have allowed MP to avoid some O&M costs at oil-fired units.[12] The savings were greatest at Hibbard, which was deactivated in Winter 1982. As Table 2.3 shows, O&M at Hibbard has been reduced by approximately $400,000 for 1982 and $1,000,000 annually for 1983-85, as compared to 1981 levels.[13] Not accrediting the oil capacity at Laskin from Winter 1983 through winter 1986 saved 10,000 - 20,000 gallons of oil for each test

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11. The full-load heat rates of Boswell 1 & 2 are only about 3% greater than those of Boswell #4, and the heat rates for Boswell 3 are actually lower than Boswell #4.

12. Response 140 discusses these savings.

13. MP's 1986 FERC Form does not provide data for Hibbard.

(or less than $17,000/year, assuming the 1981 price of $0.85/gallon, 20,000 gallons/test, and one test/year). Not accrediting Winslow in 1983-86 must also have saved some oil, but MP did not provide an estimate for this saving.

Boswell #4 has no significant locational advantages, compared to the rest of the MP system. Square Butte and Coyote are remote sources, at the end of a 463-mile DC line, with high transmission losses (over 10% at the current contract load) and obvious reliability implications.

MP has repeatedly asserted that a reserve of more than 15%, and more like 20%, would be economically advantageous due to its high load factor. The rationale for this assertion is MP's contention that total system costs are lower at higher reserve margins, since fuel and purchased power savings from the extra capacity exceed the fixed cost of the capacity. This is not an appropriate approach to setting reserve margins. In order to determine whether any increment of capacity in any particular plant is cost-effective, the specific costs and performance of **that** plant must be compared to its savings in fuel costs (which is determined by the nature of the remainder of the utility's system) and in avoided power purchases (which are determined by the power pool system and pricing rules). For example, if MP's system consisted entirely of the existing plants in its service territory, increasing its reserve margin from 15% to 20% by the addition of some Young capacity might well be justified. On the other hand, adding another 50 MW of Boswell #4 might not be justified.

However, MP could be correct that some of its excess capacity is economically justified by fuel savings.[14] In support of this position, MP offered two documents which discussed this subject (Response 801). Neither document strongly supports MP's conclusion.

The first discussion offered by MP was the testimony of Mr. Ostroski in FERC ER80-5.[15] That testimony simply asserts that MP's "high load factor, creating a need for energy beyond what can be continuously provided by MP&L generation, is the reason why MP&L's optimum reserve margin is sometimes higher than the 15% minimum required by [MAPP]" (page 3, lines 40-44). MP's high load factors certainly would tend to improve the economics of excess capacity, but that hardly establishes that a reserve of more than 15% is actually economically justified.

The second document is a memorandum from E. R. Norberg to K. L. Evens, dated 11/10/86, and entitled "MP Reserve Margin Based on Preliminary 1987 Forecast." This appears to be the first quantitative study MP conducted of optimal reserve

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14. There are really two separate ways of looking at cost-effectiveness. First, it is clear that at least a **small part** of the fixed cost of **every MW** of MP's excess coal capacity is offset by its fuel and purchased power savings, and by the value of short-term power sales. The second, and more difficult question, is whether the **entire cost** of **any MW** of MP's excess is covered by its value in energy cost savings.

15. Mr. Ostroski cites that testimony in his prefiled testimony in this docket.

margins.[16] The Norberg study indicates a vast improvement in MP's planning process, compared to its practice even a few years ago. However, this study does not address the question of how much capacity in Boswell #4 (or Coyote, or any other unit) was cost-effective at its original cost of $800/kW. Rather, it asks how much Boswell should be sold off at a MAPP short-term sales rate of $24 to $60/kW-year, or roughly a fifth to a half of the annual levelized cost of Boswell. Norberg asks the proper question for determining contract sales levels, but not for identifying excess capacity. Obviously, reducing the cost (in the study) of having or keeping capacity will make more capacity appear cost-effective. Hence, the reserve margin the Norberg memo is an absolute upper limit for planning purposes.

In addition, the Norberg memo indicates that even the short-term optimum is lower than 20% prior to the NSP sale. After the NSP sale, the short-term optimum rises to 23%, but a decrease in replacement costs of just 10% would drop the optimum to less than the 15% required for reliability purposes. Doubling the fixed costs of the capacity, to reflect its rate effect, would have at least as large an effect on the optimum reserve as would this 10% decrease in replacement power costs.

Hence, the available evidence indicates that none of MP's

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16. Norberg refers to a 1980-81 study for the rate cases before FERC and the PUC, but that "study" appears to be the conclusory language in Mr. Ostroski's testimony.

excess capacity is, or has been, fully justified by its replacement power savings.

2.4. Mitigation of MP's Excess Capacity by Large Power Contracts

MP provides service to the taconites and some paper mills under Large Power Contracts.[17] These contracts require customers to pay for a minimum level of capacity, whether this capacity is used or not. As a result, the actual peak demand figures in Table 2.2 do not fully reflect MP's revenues or the amount of capacity "required" by ratepayers. It could be asserted that the Large Power Contract customers have agreed to pay for a certain level of capacity, and that since MP is paid for the capacity, it is not really excess, as far as other customers are concerned.

Table 2.4 compares actual peak and contract minimum for each Large Power contract customer. Contract minimum is assumed as 90% of contract demand. It is our understanding that this is the basis of demand charges, prior to any ratchets based on actual usage. It should also be noted that Table 2.4 is based on the data in Response 148 on contract time periods and demand levels. In several cases, customers began to use

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17. Erie Taconite, which has its own generation, is served under a special power exchange agreement. Reserve Taconite was principally supplied by its own generation, supplemented by an MP Large Power Contract. The 6 other taconites have received all of their electric supply under MP Large Power Contracts. Two paper mills are also served under Large Power Contracts with an additional paper mill to begin receiving Large Power Contract service in the late 1980's.

sizable amounts of electricity prior to beginning of contract term indicated in Response 148. It is likely that these customers had reached agreements with MP for provision of service under other rate schedules or for some ramping up under the Large Power contract rates. In any event, all Large Power contracts were in operation by winter 1981, with all of the taconite contracts (except Reserve's small Silver Bay contract) in operation by summer 1979.

Table 2.4 indicates that actual peaks by individual customers are usually, but not always, lower than contract minimum. Prior to winter 1980, the differences were usually small. As the decline in the taconite industry reduced operating levels, actual peaks dropped substantially below contract minimums: the difference exceeded 100 MW for every season except one from winter 1981 to summer 1984. During 1982, the differences were almost 200 MW.

Table 2.5 uses Table 2.4 data on differences between actual peak and contract minimums for Large Contract customers to adjust the load and capacity data from Table 2.2.[18] The effect is to reduce the estimate of surplus capacity significantly. However, the amount of surplus at 15% reserves

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18. Table 2.5 does not reduce the Large Power loads from their contract levels to their lower contributions to coincident peak. Due to diversity, the LP load at peak is lower than the sum of billing demand. Thus, this analysis overstates the LP contract adjustment and understates the excess, even net of LP contracts.

is still in the 400-500 MW range for most of the period since Boswell #4 came on line.

The surplus figures in Tables 2.2, 2.4, and 2.5 include the effect of the capacity sales MP has made to mitigate its over-capacity. Table 2.6 recomputes the Table 2.5 data for the period since Boswell #4 came on line without any sales of capacity. Computed on this basis, the amount of surplus at 15% reserves has never been less than 400 MW since Boswell #4 came on line. In fact, surplus has dropped below 450 MW only twice: winter 1980, prior to completion of Coyote and with MP's highest peak demand ever; and winter 1987, based on MP's projected peak.

3. THE ORIGINS OF THE EXCESS CAPACITY

3.1. MP's Sales and Projected Growth Were Heavily Concentrated in the Taconite Industry

For many years, an unusually large share of MP's sales have been to industrial customers, and a very large percentage of those industrial sales have been to taconite mining and processing operations.[19] Table 3.1 lists MP's total sales, retail sales, industrial sales, and taconite sales for each year, 1974-86. Table 3.1 also shows that industrial sales amounted to 72%-81% of MP retail sales in various years, and 61% to 73% of total sales.[20] Sales to the taconites alone were always at least 46% of retail sales, and rose as high as 63%.

Similarly, MP projected in the 1970s that taconite would represent a substantial portion of its long-term load growth. For example, in the 1977 forecast, of the 924 MW of load growth projected between 1977 and 1986, 522 MW (or 56.5%) was direct sales to the taconites, and much of the base load growth must also have been taconite-related. Since the taconite customers were projected to operate at very high load factors, the

19. I will sometimes refer to these operations as "the taconites".

20. The latter percentages would have been still larger in the 1980s, except that MP's surplus capacity resulted in large off-system economy sales.

taconites' share of sales growth would be even higher than their share of peak load growth.

The extent of MP's concentration of sales to a single industry was highly unusual in early 1970s, and rose to an unprecedented level later on. Table 3.2 provides data comparable to Table 3.1, for a broad cross-section of electric utilities in 1976. For each utility, Table 3.2 lists the SIC group to which it sold the most energy, and the energy sales to that SIC.[21] The companies selected for inclusion in Table 3.2 were those which reported more than 40% of their retail sales as industrial: the large number of utilities excluded from this list are much less dependent on industrial sales than is MP. Where one utility subsidiary of a holding company was represented on the list, we added the other subsidiaries to the list, to complete the analysis from the perspective of the holding company. Very small utilities and those owned by their industrial customers (e.g., Upper Peninsula Generating Company, Tapaco) were also omitted.

As can be seen on page 2 of Table 3.2, very few utilities came close to MP's degree of concentration in industrial sales, and in sales to a single industry. The utilities are listed in order of decreasing ratio of Largest SIC sales to retail sales. Only Wheeling Electric approached MP's ratios of sales to a

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21. SIC group refers to the Standard Industrial Classification employed by the US Department of Commerce. Table 3.2 includes a sample Uniform Statistical Report, with a listing of SIC groups.

single industry both to total and to retail sales. Wheeling is part of the American Electric Power (AEP) group, which had 54% of its retail sales to industry, but no more than 22% to any one SIC group. In the mid-1970s, MP was more vulnerable to fluctuations (or inaccurate projections) in a single industry than was any other utility in the country, and was heading for greater concentration.[22]

The extraordinary concentration of sales to the taconites should have prompted MP to take extraordinary measures to protect its shareholders and other ratepayers from fluctuations in sales and from errors in projections. As we will see, MP's response to this situation was far from adequate.

3.2. The Taconite and Steel Industries Were Subject to Well-Known Risks

3.2.1. The steel industry in the 1970s

Even as the taconite mining firms were announcing expansion plans, and MP was gearing up to meet that expansion,

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22. The data in Table 3.2 is summary in nature, and may conceal some important details. For example, the taconite loads might have been classified by some utilities (if they had similar customers) as partially mining and partially processing, splitting a single industrial process into two SIC groups. On the other hand, the two-digit SIC groups listed in Table 3.2 are much broader categories than the taconites: a two-digit SIC is more diverse and more resistant to variability than the very specific taconite processing operations (which would all be in a single 4- or 5-digit SIC). For example, SIC 37 (transportation equipment) includes auto assembly plants and jet engine manufacturers.

the future of the US steel industry was in doubt. This was particularly true for the integrated Great Lakes producers which use the taconite mined in MP's service territory. Several major trends were acting to reduce the long-term demand for taconite:

1. America was using less of the things which require large amounts of steel. Heavy construction of infrastructure and industrial facilities, such as bridges and ports, had declined significantly from the post-war boom (Raddock, 1981, p. 123).
2. Cars, the largest single market for US steel manufacturers,[23] were using less steel. In response to consumer demand (and later to the Federal fuel efficiency standards), cars were getting smaller and lighter, using less material and substituting heavy steel with lighter aluminum and plastics.
3. More cars were being imported. In the 1970s the fuel efficiency, quality workmanship, and other advantages of foreign cars greatly increased their popularity, raising imports from 5% in 1965 to 18% in 1977 and to

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23. The 1981 MP Annual Report noted that the auto industry consumed roughly 20% of domestic steel production. With the domestic auto industry concentrated in the states bordering the Great Lakes, the auto market is especially important to the integrated Great Lakes steel mills which use Minnesota taconite.

29% in 1982.[24] (1985b p. 28) Cars made in Japan or Germany do not use Great Lakes steel.

4. More steel was being imported.[25] Faced with a global glut of steel-making capacity and slower world demand growth, especially in the later 1970s, nearly every developed nation (and several developing nations) were completing for a slice of the stagnant (but still large) US steel market. Many of these foreign producers were aided (at least arguably) by government subsidies, all of them had lower labor costs, and most had generally newer (more efficient) plants and lower production costs than did the integrated US producers.

5. The integrated Great Lakes mills, which turn raw ore into a variety of finished products, were losing market share (of the shrinking market left by falling demand and rising imports) to electric furnaces, which recycle scrap steel and are often sited in labor-efficient minimills located in the fast-growing South and West. Both the process and location of the minimills precluded use of Great Lakes taconite.

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24. These figures exclude net imports from Canada, which took a few more percent of the market in the 1970s and 1980s.

25. Net imports rose from a few percent in the early 1960s to 15% in 1968, averaged in the low teens through the 1970s, and climbed to 25% by 1984.

Table 3.3 displays some important indicators of the health of the US steel industry and the Minnesota taconite industry in the 1970s and 1980s. The US has been using less steel, more of it has been imported, and the decline in taconite production has been much steeper than the corresponding decrease in steel consumption or production.

The demand for taconite was thus subject to the effects of imports (both of steel and of products), national economic performance, the value of the dollar, prevailing interest rates, tax policy, specific demand for steel-using equipment and consumer goods, and the steel intensity of the goods which were demanded. These vulnerabilities were apparent long before the steep decline of the US steel industry, and of taconite production, in the early 1980s.

As early as 1974, in an environment of "No pessimism, but a certain amount of uneasiness," the secretary-general of the International Iron and Steel Institute told his members:

> I am less confident about the current outlook today than in any of the [seven] earlier years. There are just too many uncertainties that we as an industry have no control over that have to be resolved, [including inflation and capital shortages] . . .
>
> [T]here is reason to believe that sufficient new capacity will be built to meet expected growth and demand -- if the money can be found to finance it. (Modic 1974)

By the next year, the financial problem was very clearly discussed in **Industry Week** (5/19/75):

> US steelmakers have been arguing for years that they won't be able to raise the capital required to expand

and modernize production capacity and, at the same time, meet tightening anti-pollution requirements.

Now they have a comprehensive study . . . to support their argument. . .

Arthur D. Little (ADL) . . . concluded that the steel industry will have to spend as much as $14 billion annually through 1983 to meet air and water pollution control regulations now on the books. That averages out to more than $1.5 billion annually . . .

By comparison, the industry's average annual capital outlay in the years 1968 through 1972 was $1.7 billion for all purposes.

If ADL's estimates are reasonably accurate, the items included will consume a good deal more capital than the industry can possibly hope to raise.

[The American Iron & Steel Institute] observed that "the maximum level of funds available to the industry appears to be in the range of $3.3 to $4 billion annually" [compared to the $5.4 billion requirement estimated by ADL]. But [the AISI] estimate assumes "favorable government policies, optimum market conditions, and improvement in the long-term debt market" -- an unlikely combination of circumstances. (In the peak years of 1973-74, the industry's net internal cash flow averaged only $2.8 billion.)

Edgar B. Speer, chairman, US Steel, termed the capital formation problem "extremely serious."

The impact of pollution control costs will fall heaviest on smaller, marginally profitable plants . . . A number of plants, that altogether employ a total of more than 90,000 people, are "potentially vulnerable" to shutdowns . . .

In what was generally perceived to be a normal cycle after the 1973-74 boom, 1975 was a very bad year for steel producers. The combination of depressed earnings and series of complaints with government further threatened the industry's investment prospects:

William Verity, Armco chairman, said: "The impact of such a no-profit situation in our steel business depresses our

> outlook for additional job-creating investment in steel. . . [S]hort-sighted government meddling with pricing policy and inaction on an energy policy have so muddled the short-range outlook that prudent management dictates a moratorium on any new expansion in steelmaking capacity." (**Industry Week** 10/27/75)

Sales picked up in 1976, but worries about capital availability continued:

> [T]he White Houses's Council on Wage and Price Stability . . . engaged a consultant, Paul Marshall, a professor at Harvard Business School, to prepare [a study of steel industry prices and capacity needs.] . . . The industry's record on internally generated funds . . . indicates, he says, that these will not be sufficient to meet the capital spending required . . .
>
> National's [chairman] Mr. Stinson also said that planned expansions would be subject to delays "if we continue unable to recover in 1976 the cost increase of 1974." (**Industry Week** 5/3/76)

Edward Leach, Bethlehem Steel's Vice President, Mining discussed how problems with capital availability and imports affected Minnesota taconite:

> "[T]he main problem . . . is capital - Money to expand an ailing but vital industry in the nation's economy." . . .
>
> Competition . . . is a major factor in determining the impact of imports on current and future domestic iron ore production. . .
>
> It is immediately obvious that the various substantial steel plants along our seaboards cannot use Lake Superior ore and stay in business . . . This reliance on foreign ores must continue . . .
>
> I hardly need to point out that the major marketplace for Lake Superior ore is made up of the industrial area around the Lower Lake Ports . . .
>
> Canadian ores, including those from Labrador and eastern Quebec moving via the St. Lawrence waterway, are real competitors at the Lower Lake Ports. Other foreign ores are very competitive indeed with Lake Superior ore that might go to the western Pennsylvania district. . . [W]ith

respect to the Lake Superior ores versus their foreign competitors we must face the fact that the bulk of Minnesota's and Michigan's future production must come from low grade, hard, costly to mine raw material, and that 3 tons of this world's hardest rock must be ground to a powder and fused into a pellet, a product which, though high in quality, is no better than its competitors from Canada, Brazil, and elsewhere. Some of those competitors enjoy important advantages in transportation and, in certain cases, taxes and financing charges can be largely ignored when it comes to determining their market price.

. . . While it is usual to look critically at the impact of Canadian and foreign ore imports on the production of Lake Superior ores, it seems that we seldom consider the impact of foreign steel brought into this same market area. The fact is that the Lower Lake Ports are the single largest market area for foreign steel. During 1974, 4,229,000 tons of foreign steel . . . along the Great Lakes. The Pacific Coast, whose steel market is seriously invaded by Japan, was not far behind . . .

It startles me . . . perhaps because I have always thought of this central industrial area as a locked in territory of our domestic steel industry. It obviously is not. We miners should be thinking of those 4,000,000 tons as the equivalent of over 6,400,000 tons of iron ore.

The American Iron and Steel Institute takes the position that the United States reliance on imports of iron ore will continue to grow . . .

AISI further points out that our country's reliance on foreign iron ores has increased from 7.4% in 1951 to about 37.2% in 1974. . .

You know that we are in the midst of a steel industry recession. And I have tried to point out the role and impact of foreign imports in all of this picture. . .

Those foreign automobiles don't have a pound of Minnesota iron in them! (Leach 1976)[26]

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26. Leach's comments were made in January 1976 in an address to the 49th Annual Meeting Minnesota Section, A.I.M.E. MP relied upon the proceedings of these annual meetings as source of information on the taconite and steel industries (Response 146). In fact, MP's Vice President Walter Olson presented a paper at the 1976 conference, "MP&L - Meeting Taconite's Electrical Energy Challenge."

Leach also discussed the steel industry's efforts to compete by modernizing and cutting costs and by seeking government relief on taxes and imports. He noted the large investments being made in the taconite industry and was hopeful about the future demand for steel and iron ore. Nonetheless, Leach was clear that the taconite and steel industry were confronted with serious problems and that the future was in no way certain.

By 1977, the integrated US steel industry had clearly entered a period of crisis, experiencing a wide variety of problems, including

rising fixed costs,
aging plants,
governmental pressure for price restraint,
decreasing profits,
increasing foreign competition,
worker layoffs,
production cutbacks,
costly environmental regulations,
and rising labor costs.

Some of these conditions were short-run, while others were structural, and basically did not improve during the rest of the 1970s and into the 1980s.

The language which steel industry executives and economists used to describe the condition of the industry gives some sense of the extent of the problems. Time (9/19/77) quoted the Executive Vice President of Republic Steel, E. Bradley Jones, as saying that "Basically, it gets down to whether the U.S. steel industry is going to survive." *Time* agreed that "the steelmakers' troubles are real and severe," and noted that "the industry's principal troubles are longer-range." Among Time's concerns:

- Argus Research Corporation had predicted that "the industry will reduce its production capacity by as much as 20% over the next five years, as it closes more and more marginal mills."
- "[I]mports from Europe and Japan are rushing in at prices 10% to 15% below those charged by American mills. Imports . . . now account for more than 15% of US usage. Argus predicts a 25% share within a year or 18 months."
- Merrill Lynch "concludes that it costs a Japanese mill $241, or $84 less than a US mill, to turn out a ton of finished steel."

Another observer in the business press found the steel industry "at a crossroads" (Thompson 1977). Even in a booming market, some firms were contracting capacity, with employee layoffs, plant closings, and postponed expansions. "More and more steel industry authorities are voicing the opinion that while growth in demand for steel will continue, the industry overall is likely to continue shrinking." A study by Putnam, Hayes and Bartlett for the American Iron & Steel Institute concluded that imports would capture 30% of the domestic market by 1980, under "present conditions." The solutions sought by the steel companies included government action to restrain imports, relax environmental regulations, and reduce steelmakers tax burdens. The industry was not investing enough to replace retired capacity, let alone meet any increases in demand.[27]

Lewis W. Foy, Chairman of Bethlehem Steel, put a slightly better face on the situation: "So the picture isn't all black, I'm convinced we're going to come out of this - though it's going to be a tough battle. . . Sometimes crises produce good results." (**US News World Report** 11/21/77) Foy, like other industry leaders, acknowledged the severity of steel's problems with environmental regulation, imports, and taxes, but expected government to solve the industry's problems. It was obvious from this sort of discussion that steel was in for a rough ride; it was less certain how that ride would end.

A recovery for the steel companies did not necessarily mean continued demand for Great Lakes iron ore, since the companies could increase their profitability with less production and/or more electric furnaces and geographically dispersed plants. Lee G. Weeks, Treasurer of Armco, acknowledged that "Our major capital expenditures in steel are

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27. Thompson also quoted Richard S. Bari of Argus Research as suggesting that steel management would carry out "de facto liquidation" of the industry. The liquidation could be even more severe for taconite demand than for the industry as a whole, since much of the capacity served by Great Lakes ore was particularly vulnerable to retirement.

behind us, at least until we can make a reasonable return on investment."[28]

Despite sales growth, 1977 was such a bad year for steel company profits that observers assumed "1978 can only be better" (Thompson 1978). Thompson noted government promises of assistance with import restrictions, tax breaks, and even government loans or grants, but

> Yet major questions remain. Does all of this mean that steel industry's critical need to generate capital for modernization? And what are the implications of solutions that bring added government involvement?
>
> Still, the outlook has to be judged brighter for an industry which in 1977 lost 5 million tons of capacity and some 20,000 jobs from . . . shocking facility closings . . . and bankruptcy.

Even the specter of nationalization of the steel industry was raised.

Forbes (1/9/78) thought that "Horrendous was the only word for the facts" about the steel industry.

> A business that sick either goes down the drain -- or it presents investors with one of the great turnaround opportunities of all time. The US steel industry is not going down the drain. It is the foundation of the US industrial economy. Says Chairman Lewis Foy of Bethlehem: "If you're going to have a healthy economy in this country, you need a healthy steel industry to support it."
>
> The plain fact is that steel has nowhere to go but up.

The **Forbes** prescription for industry recovery (from the viewpoint of stockholders, rather than suppliers) included

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28. "The Gleam is Gone From Steelmen's Eyes", **Business Week**, 4/25/77.

government assistance and further retirements of existing capacity. "The reduction of old-plant capacity means that break-even points will fall and margins rise. Many of the surviving plants will be located in the right places -- South, Middle West, West -- to be closer to customers." Even so, "[p]lenty of problems remain," including continued shutdowns, layoff costs, and imports.

David M. Roderick, President US Steel, acknowledged that the structural changes were permanent "... it seems doubtful to me that we (the US) will again become net exporters. . . there has been [a world steel] surplus for the last twenty years with the exception of 1973-1974."[29]

With much stronger orders than in 1978, 1979 offered some hope for expansion in the steel industry, "But major steelmakers still see the industry as walking a tightrope. . . Steel executives are neither satisfied with the 1978 earnings nor convinced that the import problem has been solved." (Thompson 1979a)

U.S. Steel's David Roderick "is far from cheered" by a tripling of first half profits, compared to the recovery year of 1978, because "... the domestic industry is going to continue to shrink." Roderick was counting on increases in demand in the 1980s, but that prediction was conditioned on "proper investment incentives from government," i.e., tax incentives. As direct government aid to steel became less

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29. "Embattled Steel," **Challenge**, May-June 1978.

likely, the industry came to hope more for indirect assistance. In the meantime, US Steel could reduce its "capacity by an additional 10% over the next few years. . . Roderick will also steer his company away from steel, devoting a greater portion of capital to nonsteel lines [with] greater hopes for profit growth." Meanwhile, Kidder Peabody warned that US Steel must triple its capital spending on its steel facilities to $2 billion annually, or "it will rot away. We have a time bomb that sooner or later is going to explode."

"Few experts expect the U.S. steel industry to wither away -- but there seems little doubt that it is in serious trouble. Rising labor costs, cheaply produced foreign steel and huge expenditures to meet environmental standards continue to erode profits even as the industry needs billions of dollars to upgrade antiquated mills. . . For all the current woes, the industry's problems seem almost certain to grow worse in the months ahead. . . [T]he economy -- and the industry -- may be headed for a deep recession. Unless something is done to improve industry's fundamentals, steel's performance in the subsequent economic recovery may be equally disheartening." ("Blues for Big Steel," **Newsweek**, 12/10/79)

Thompson (1979b) asked the rhetorical question "Is a continuing period of contraction, rather than expansion, in the cards for the US steel industry?" He pointed out that the question had remained open since the "disastrous 1977" experience, and despite two years of attempted governmental intervention. Even accelerated tax depreciation was not expected to be sufficient to turn the industry around. Eugene Frank, Vice President and steel economist of M. Waddell & Towne, foresaw further contraction. After retirements and environmental restrictions, the remaining cokemaking capacity would only support operation at 85% of existing steel-making capacity.[30]

The concerns about sales in the late 1970s were realized in 1980. Under the headline "Steelmakers gird for a bad slump," **Newsweek** (5/19/80) quoted a major steel company executive as saying, "In just the past week, business has simply fallen off the cliff."[26] (May 1980) There was some hope that low inventories would shorten the recession, but "the bad signs can not be denied."

1981 did not start out much better. "If orders don't increase in April or May, what looks like a slow start for 1981 could rapidly turn into a first-class debacle." (**Newsweek** 1/12/81) "Despite strong evidence to the contrary, steel executives keep hoping for an increase of 10% or more in domestic auto sales this year, and they are praying for a rebound in sales of trucks . . . But with the average car using half a ton less steel than in 1975, the industry realizes that it faces a permanently shrunken auto market. . . [M]any steel producers are even now hacking back their already truncated

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30. Since no coke is used in electric furnaces, the remaining capacity would support less than 85% of the blast furnace capacity which was taconite's potential market.

capital spending programs -- they simply do not have the cash to fund them."

A review of the 1979-80 steel industry recession (Raddock 1981) concluded that the US industry might be able to capture most of the domestic market, if it could pursue more modernization and moderate wage increases. The market for the integrated inland steel producers would probably continue to contract, and much demand may go to minimills (expanding rapidly in the South and West) and to specialty producers.

US Steel's William Roesch presented a similar picture:

> "I have often remarked that steel . . . in this country . . . is essentially a "no-growth" industry . . . with consumption expected to grow at about a 2 percent average annual rate over the next decade. . . A key element is, of course, how much of the market will be served by domestic producers . . . and how much by imports. . .
>
> The mid-50's saw the entry into the marketplace of the first mini-mills. They began by producing second quality products . . . using small furnaces of 5 to 10 tons charging weight . . . an annual capacity ranging between 10,000 and 40,000 tons a year . . . and serving small regional markets. . .
>
> Now . . . we're seeing integrated mini-mills. Furnaces with charging weight of over 150 tons are not uncommon. A few new ones are up to 350 tons. Capacity of many so-called mini-mills is now 200,000 to 250,000 tons a year. Some have a capacity of 500,000 to 1 million tons a year.
>
> For 1979, the American Iron and Steel Institute reported that 25 percent of raw steel production in the U.S. was by electric furnace. (Roesch 1981)

The slump continued into 1982. **Business Week** (1/11/82) started the year with predictions of paltry gains in sales, permanent shrinkage in the auto market, further plant closings, tough labor problems in the effort to control wage rates, difficulty controlling imports, and a permanent concession of 17 to 20 million tons of sales to imports. The industry entered 1982 "at a near-depression market level."

In July, Paul C. Harmon of Armco said that the outlook for steel was "lousy" (**Business Week** 7/5/82). Steel companies were cutting dividends, slashing capital spending budgets, selling assets, cutting salaries and benefits, and encouraging early retirements, to (in Roderick's words) "conserve cash, ensure its core strength, and remain a competitive and stable force in the labor market." Terms like "strength" and "stable" were relative, in this context. And the problems were expected to continue:

> Meanwhile, steelmaking facilities continue to shut down. . . . The betting among steel experts now is that the present economic recession will speed an inevitable contraction of the US industry. And they would not be surprised is, at this time next year, US steel producers will have permanently abandoned 10% of their present . . . steelmaking capacity.

Industry Week (11/1/82) reported that a conference of financial and economic analysts agreed that there would be more mill closings and bankruptcies.

3.2.2. The additional risks of taconite

Even if the steel industry recovered, and even if the recovery included some of the Great Lakes basic oxygen furnaces which use iron ore as an input, Minnesota taconite was not the only potential supplier for that ore. Taconite operations also exist in Michigan, Quebec, and Ontario; imports of iron ore (which are more common in other parts of the country) are also possible in the Great Lakes. Thus, MP's taconite load depended on a large number of risky factors:

1. the extent of steel sales,
2. the level of imports,
3. the geographical distribution of US steel production,
4. the technology used in that production,
5. the strength of the dollar (which affects imports of ore, steel, and finished products like cars),
6. interest rates and government tax policies (which affect both steel company investments and the use of steel by other sectors),
7. the competitiveness of Minnesota mines with those in other areas, and
8. the competitiveness of MP-served mines with those having their own generation (Erie and Reserve).

MP now recognizes the high degree of risk and uncertainty inherent in its dependence on the taconite industry. The testimony of Joe Pace on behalf of MP in the current docket (pages 21-22) describes the combination of factors that makes MP's situation so unusual. A major portion of MP's load is in a single industry (Minnesota taconite) that has one market (the Great Lakes steel industry). Minnesota taconite must compete with other sources of supply. The Great Lakes steel industry is cyclical and subject to several forms of competition. MP's concentration of sales to the highly uncertain taconites results in a very large potential variations in MP load. Unfortunately, MP did not understand that it was assuming these risks during the expansion of the taconite industry in the 1970s.

3.3. MP's Forecasting Methodology Was Prone to Overestimation

MP's load forecasts were consistently incorrect in the 1970s. This fact is responsible for a large portion of MP's subsequent excess capacity. Figure 3.1 displays representative forecasts from 1977 (the highest forecast ever) to 1986. As can be seen in that figure, the load levels projected in 1977 and 1979, even for the next winter, have never been attained.[31]

MP's forecasting methodology in the 1970s contained some serious problems, which biased the forecasts towards overestimates of load growth. Possibly the most serious of these was the inclusion in the forecasts of non-committed Large Power loads, for which no contracts had been signed. MP relied on these forecasts in making commitments to generating capacity to serve industrial customers who had not even provided MP the limited protection afforded by the demand contracts. These forecasts also helped MP convince itself that it would quickly grow into any excess capacity which might be created from large additions, forecasting errors, or contract cancellations. This mistake undoubtedly contributed to MP's decision to accept the planned overcapacity represented by Boswell #4, its delay in selling off its excess capacity, and its willingness to rely on the demand contracts for protection. Table 3.4 displays, for

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31. This is also true for the 1978 forecast.

each forecast year 1974-81, the non-committed LP contract load included in the forecast.[32] The worst year for this particular form of overoptimism was 1977, when MP was projecting 465 MW of uncommitted load just ten years in the future.

MP moderated its reliance on uncommitted load somewhat in 1980, by omitting loads which it believed had less than a 50% chance of coming onto the system. Only in 1982 did MP exclude the uncommitted loads altogether.

MP apparently required that the LP customers sign the original demand contracts, to accommodate loads projected for the late 1970s, as a precondition to building Boswell #4. This would seem to indicate an understanding on MP's part that the promises and projections of a potential (or potentially expanded) industrial customer are not highly reliable. Yet MP used such promises in several important decisions.

A second problem, overlapping with (but somewhat broader than) the inclusion of uncommitted load, was a general willingness of MP to rely on customer representations and projections for planning purposes. Until the early 1980s, MP relied almost exclusively on its industrial and commercial customers (both Large Power and smaller customers) for information on future load levels. There are several reasons not to rely on this sort of information, including:

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32. Given the dependency of the local economy on the large industrial customers, a large portion of the projected growth in base load must also have depended on the uncommitted loads.

1. Business owners and managers are prone to optimism and enthusiasm about their businesses (and indeed, they often must be optimistic, in order to survive the tensions and reversals of life in business). Especially when they are not betting their own money (or even the money of their employers), they are apt to see as rosy a future as possible for the enterprises under their control, and hence for themselves.

2. The incentives for customers are highly asymmetric, when preparing forecasts for their utilities. If the customer underforecasts, the utility may not be ready to provide service. The shortage may arise with transmission and distribution facilities to serve smaller customers; with larger customers, such as the taconites, an individual customer's growth could outstrip generation resources. Those outcomes could be inconvenient or expensive for the customer. If the customer overforecasts, it usually costs the customer nothing, and may provide a better level of service, such as a bigger, more reliable transformer, redundant transmission service, or even lower rates.[33] Even if the overestimation results in

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33. The taconites have received relief from some of the provisions of their demand contracts, due in part to MP's excess capacity situation, to which their own erroneous projections contributed.

overcapacity and higher rates, the effects are spread over many customers: if the potential customer does not come onto the system, it bears none of the extra costs.

3. Customers may well believe that they will get better service if they are perceived as important, growing customers, than if they are stagnant or shrinking loads. If it costs the customer nothing to impress a utility representative, and it might be of some use in resolving a billing dispute or in service restoration, the customer might as well be highly optimistic about potential growth. This problem is exacerbated if the utility representative is a sales rep, who has an obvious interest in bringing tales of great prospects back to his superiors.

4. For the taconites, and for some other customers (e.g., supermarkets, housing developers), the plans projected by various customers may well compete with one another. Each steel company might have plans for enough new taconite capacity to meet the entire projected growth in national demand: obviously, some of those facilities would be cancelled or lie idle. A simple poll of the customers' plans might well yield a total projection greater than the underlying demand could support.

A third, and relatively smaller problem, was that MP apparently did not recognize until 1980 that the LP contract loads would not all be coincident with the system peak. Not every LP customer would use its contract load in every year, and even those which did were unlikely to all be at full load at the time of seasonal peak. Thus, including the LP contract loads without diversity would tend to overstate demand.[34]

Fourth, and finally, MP remained highly optimistic on levels of taconite production, despite growing concern that the traditional blast-furnace steel operations were not competitive. The forecast documents in the 1970s show little evidence of the anxiety in the steel industry. The 1980 forecast, which clearly recognized the risk of stagnation or decline, chose to accept a fairly optimistic projection of taconite demand for the base-case forecast.[35] The 1980 forecast also introduced the concept of high- and low-growth sensitivity cases in the forecasts. The 1981 forecast described projections for the industry as "bleak" to "moderate", but continued to rely on recovery of the existing facilities and still included uncommitted loads.

Mr. Harmon's description of MP's current forecast methodology (e.g., his testimony in Docket E002-E015/PA-86-722,

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34. This factor may account for much of MP's short-run forecasting error.

35. Since MP was still relying on customer projections, it is not clear how important this external check was.

pages 14-16) describes many of the actions which it should have taken in the 1970s:

- detailed analysis of demographic and economic assumptions,
- increased use of econometric modelling,
- use of outside information sources . . . to supplement and verify information provided directly by customers,
- greater conservatism in estimating Mesabi range taconite production, and
- looking beyond taconite capacities to the condition and prospects to those US steel mills where Minnesota taconite can compete with international ore sources.

Thus, MP now recognizes some of the fundamental considerations which it omitted from its load forecasting in the 1970s and early 1980s.

3.4. MP Failed to Adequately Control Its Risks

As we have seen, MP's dependence on sales to the taconite industry was a highly unusual, and perhaps unique situation for an electric utility. This fact in itself should have been sufficient reason for MP to take extraordinary measures to mitigate the risk of demand fluctuations in one very narrow industrial segment. In the environment surrounding the U.S. steel industry in general, the Great Lakes steel industry in particular, and thus the taconite industry, even greater caution was warranted.

To its credit, MP clearly recognized that its situation was unusual, and that some special action was required to protect MP's shareholders and other ratepayers. The special action which MP took was to place the large power customers on ten-year demand contracts with five-year cancellation notice provisions.[36]

In some situations, the demand contract would be very useful to MP. For example, the steel industry (and thus the mining industries which serve it) is known to be highly cyclical: steel demand is determined by levels of general economic activity, by the rate of investment in major equipment and construction projects (including military programs), by the

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36. This group was primarily composed of the taconites, but also included a few forest products firms.

rate of production of domestic automobiles, and so on. In a steel industry slump lasting a year or two, the demand contracts would maintain MP's revenue levels: the taconites would continue to pay their demand bills, even if they were not using much energy. When steel demand resumed, the activity at the taconite mills would also pick up.

The demand contract would also be helpful in the event that certain kinds of permanent retrenchments affected the steel industry. If demand for taconite declined uniformly across companies,[37] causing the companies to give notice that they would be reducing their demand contracts, MP would have five years to sell off or grow into the excess.

However, the demand contracts would provide little protection under other circumstances, especially those involving secular, rather than cyclical, downturns in taconite demands. Some of the potential problems included:

1. The contract provided for only five year's notice: if MP were supporting a large amount of new, expensive capacity when the taconites gave notice, it could be left with large amounts of excess costs to absorb (or distribute to other ratepayers) when the notice period ended.

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37. Recall that the taconite mines are generally owned by specific steel companies. Whether a mine decreased or suspended operation could therefore depend as much on the competitiveness of its parent company as on the relative economics of the taconite operation. In the 1980s, a more open market developed.

2. Five years is enough time to adjust capacity if small increments are being added to a steadily growing system, or if there is a good market for wholesale power sales. The five-year notice provision would not be of much help if:

   a. notice were given about the time a very large capacity addition (say, 30-40% of peak load) entered service,

   b. all the taconites reduced their loads at the same time, and the MP system load essentially ceased to grow, or even fell, and/or

   c. the taconite recession coincided with a general capacity surplus in the region.

3. The contracts would not be much comfort to MP if the recession in the steel industry were severe or persistent enough that the taconite mills were closed and their owners declared bankruptcy.[38]

4. In the event of a severe downturn, MP might have a choice of enforcing the demand contracts and forcing the shutdown and bankruptcy of one or more of the taconites,[39] or of accepting a modification of the

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38. One of the ironies in MP's relationship with its taconite customers is that the $2 billion the steel companies invested in taconite production (much of which proved to be surplus) in the 1970s drained the industry's increasingly scarce financial resources. The failure to invest adequately in modernization is widely credited as one of the major factors contributing to US industry's loss of competitiveness. Thus, the "successful" expansion of the taconite industry in the 1970s contributed to the wave of shutdowns and bankruptcies in the 1980s.

39. Any reduction in taconite output under these circumstances would also have implications for residential and commercial loads, and for the overall economy of MP's

contracts. MP's bargaining position in these circumstances could be very limited.[40]

5. If an LP customer gave notice, it would have five years to sign a new demand contract.[41] In the meantime, MP would have to decide whether to plan capacity to meet the load covered by the notice contract, running the risk of excess capacity, or to plan to meet system loads without this LP customer, running the risk of being unable to serve the additional load.

To summarize, the demand contracts provide considerable protection against small, short-term, or isolated reductions in the loads of basically healthy LP customers, and against reductions in LP load which coincide with growing demand on MP's system or in the region as a whole. They provide little protection against long-term, severe, simultaneous downturns, especially when growth rates on the MP system and in the region

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service territory.

40. Table 2.4 illustrates that the Large Power contract customers were only willing to pay for large amounts of unused capacity for a few years. After that point, customer pressure resulted in renegotiations, which have reduced the contract demand levels to bring them more in line with actual use.

41. In times of tight capacity, the customer might be worried that it would not allowed to sign a new contract, and would be forced off the system. In periods of excess capacity, the customer would run little risk of that sort.

are low and reserve margins are high. Unfortunately, all of these latter conditions have occurred in recent years.

Indeed, MP does not appear to have been very concerned about the conditions for which the contracts are of little value. MP appeared to believe in the 1970s that significant long-term contraction in the Great Lakes steel industry was unlikely, and that excess capacity would always be a readily marketed asset, rather than a liability.

As a result, MP failed to pursue several options which could have mitigated the subsequent problems, including:

1. sharing the risk (and rewards) of taconite sales with other utilities,
2. diversifying power supply and reducing the lumpiness of capacity additions through joint ownership arrangements,
3. reducing the size of the taconite loads through conservation, cogeneration, and other on-site generation,
4. transferring more of the risk to the taconites by requiring them to meet a portion of the requirements through joint ownership of utility-sponsored power plants, or
5. merging with another utility.

Risk sharing. The basic problem with the taconites, from MP's point of view, was that this one very narrow industrial group represented such a large portion of MP's sales and loads. MP was a small utility with a large load in a single industry, as demonstrated in Tables 3.1 and 3.2. However, while MP's taconite load was large enough to be significant for most utilities, that load assumed crucial importance only because MP is a small utility. Table 3.5 displays the ratios of MP's 1986 taconite sales to the energy requirements of five utility systems: MP, NSP, MP plus NSP, the Minnesota-Wisconsin subregion of MAPP, and MAPP as a whole.[42] There are no taconite-processing facilities in any of these systems, other than those in MP's service territory.[43] While the sales to the taconites are 47% of MP's energy requirements, they are only 9% of the combined MP/NSP load, 6% of the Minnesota-Wisconsin requirements, or 3% of MAPP's requirements. Compared to the figures on concentration of sales to a single industry, given in Table 3.2, only the MP ratios in Table 3.5 are remarkable. Shared among any significant fraction of MAPP participants, the variability and uncertainty in the taconite loads would have been a minor problem.

Sharing the risk among a larger group of utilities could have been accomplished in a number of ways. MP could have limited the amount of load it would serve at any location,

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42. Note that the energy requirements of the taconites are slightly higher than the sales to them, since some losses and in-house utility energy usage is attributable to the taconites.

43. Other steel-related industrial sales do not appear to be very important for the larger systems, either.

alerted other utilities to the opportunity to serve loads in MP's service territory, offered to provide brokerage services to match selling utilities with buying industrials, and provided wheeling and administrative services (e.g., meter reading, billing). The arrangements between the taconites, MP and other utilities could have specified that MP would provide all electric service up to some limit (say, 20 MW), with another seller providing power above that level,[44] or the sellers could split the actual load at any time in proportion to their contracted obligations.

The taconites and the non-MP sellers might prefer to negotiate individual contracts, or they could pool power supply (possibly including MP's commitment to the taconites) and load. The pooling might be accomplished through a distinct corporate entity,[45] or simply a contractual agreement which would determine how taconite load would be added up and allocated to the participants. The utility could provide its power supply from its own sources, or the consortium could collaborate in construction of plants especially for this purpose.[46] Regardless of the mechanism by which the loads were

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44. This approach would provide MP with the most stable load level, since it would be providing the most nearly constant baseload power supply to the customer.

45. It is not unusual for utilities to create corporations to facilitate joint ventures. For example, the Vermont utilities (both public and private) have established just such a corporate umbrella for their purchases from third parties.

46. Boswell #4 could have been such a plant.

distributed, MP would have been in much better shape planning to meet (say) 20% of the taconite load than 100%.

Diversifying supply. MP's risks could also have been reduced considerably by spreading its construction program over a larger number of power plants. Part of MP's supply planning problem has been the large size of the units it has added to its capacity. Adding 408 MW from Young in 1977 created a couple hundred MW excess, despite sharp reductions in short-term purchases. Load growth was rapidly eroding this surplus in the late 1970s, when the addition of Boswell #4 in 1980 pushed the surplus past 450 MW, even without short-term purchases. As demonstrated in Figure 3.2, MP had anticipated as early as 1974 that Boswell #4 would be largely surplus when it entered service. Had load growth continued at the 1976-78 levels, MP would have grown into Boswell in a few years. Since loads fell, and are not projected to reach the 1980 peak again until 1990, Coyote and much of Boswell #4 have been surplus ever since it entered operation.

Had MP been adding 100-200 MW shares in a number of plants,[47] it would have avoided the predictable surpluses, which would have been (and were) exacerbated by any unpredicted surpluses. MP would also have avoided the possibility of

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47. In addition to Boswell #4, MP might have shared in Sherco #3 and #4, as well as units in Iowa, North Dakota, Nebraska and perhaps Wisconsin. As long as additions in various subregions were well balanced, net power flows and transmission requirements would not be greatly affected by the ownership of specific units.

scrambling for power immediately prior to the in-service date of a very major power-supply addition, since additions would be smoother and more frequent. With a broader variety of joint owners, it should have been easier to rearrange ownership of units under construction to reflect changing load conditions. Since MP was reluctant to sell completed plant for original cost, a steady stream of plants under construction would have increased its planning flexibility. Units still under construction can also be delayed or canceled, avoiding significant costs which are fixed if the same capacity is in one larger, earlier addition. If four 100 MW additions are in the pipeline, it is easier to delay or cancel some of them than to reschedule a portion of a large unit.

Reduction of taconite load. The taconite operation posed a challenge to MP, not because their output, or investment, or employment was large, but because they directly used (or expected to use) large amounts of electrical energy, which was to be provided by MP. The taconite loads on the MP system could have been reduced in several ways. First, the total electric usage could have been reduced by conservation measures, particularly increases in the efficiency of the motors used in transporting, crushing, grinding, and handling the ore, pellets, and tailings. MP acknowledges that there was considerable room for efficiency improvements, at least some of which the taconites have undertaken in recent years (Response 138).

Second, the taconites could produce some of their own electricity through cogeneration. The largest cogeneration opportunity would result from the large heat loads required to bake and dry the finished pellets at 2400 degrees F. Given the high process temperature, cogeneration might have been most attractive as a bottoming cycle, using the heated air leaving the kilns. Reserve Mining actually has a cogeneration system at its Silver Bay plant (Response 138): we have not been able to determine the technology utilized.

Third, the taconites could have produced some of their electricity requirements at generating plants at their own facilities. Erie has enough capacity to provide all of its own power, and Reserve was also able to serve most of its own load.[48] At the Floodwood certification proceedings, Eveleth, Hibbing, and Inland indicated varying levels of willingness to consider building their own capacity, if necessary. Since the demands (including reserves) of some of the mills approached the scale of utility power plant units, the inefficiencies could be fairly small.

Fourth, the concept of the taconites owning their own generation could be improved on substantially by encouraging them to be joint ownership participants in utility-sponsored power plants.[49] This approach would capture the perceived

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48. As noted above, it is not clear how much of the Reserve generating capacity was cogeneration.

49. Where cogeneration was feasible, on-site generation was probably still preferable to joint ownership.

economies of scale from larger units and the experience of utilities in building and operating power plants, while still transferring the risk of generation ownership to the taconites.

The direct ownership approach was clearly feasible for the Minnesota taconites, since it was the solution utilized by the major Michigan taconite facilities. Cleveland Cliffs, the operator of the two largest Michigan mines (Empire and Tilden), owns 93% of Upper Peninsula Generating Company (UPG), which supplies power to the mines. UPG's plant consists of nine coal-fired units, three of which were added in the late 1970s. The total plant capacity is about 590 MW: since none of the units are larger than 80 MW, the UPG model could have been followed by the Minnesota taconites either by ownership of units at the plant site (as Erie and Reserve did),[50] or more efficiently through participation in utility-run plants.

Table 3.6 approaches the feasibility issue in another way. That Table calculates the late 1970s investment per kW of contract load attributable to that investment, for each taconite facility for which we have sufficient information.[51] The investment per kW ranges from $1,875 to $3,570, with an average of $2,810. Compared to this level of investment, the

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50. Since both Empire and Erie are low cost producers (Marcus, et al., 1987), taconite producers are apparently not disadvantaged by ownership of their own generation. Tilden is a high-cost plant because it uses non-magnetic ore, and Reserve has high fixed costs from its 1980 renovations.

51. Reserve and Erie have their own generation (so we have limited information on their load levels) and Butler added no capacity in the late 1970s.

roughly $800/kW represented by an ownership share in Boswell #4 would have been significant, but not overwhelming. The cost of Boswell was less than half the range in the direct investment costs.

Merger: The risk-sharing discussed in the first point could have been accomplished quite efficiently by the merger of MP with a larger utility. The obvious candidate for such a merger would be NSP, which is larger than MP, has a very different mix of loads, is geographically close to MP's service territories, and deals with the same state commissions.

4. MINNESOTA POWER'S DELAYS IN DISPOSING OF THE EXCESS

4.1. MP Missed Out on Valuable Sales Opportunities

MP's efforts to market excess capacity and energy can be divided into four time periods since the mid-1970s. In the 1975-1978 period, MP believed that it was facing the prospect of serious capacity shortages, so its orientation was capacity purchases rather than sales. From 1978 through 1983, MP believed that surplus capacity would persist for several years after the completion of Boswell #4. Thus, it sought to make short term rather than long term sales. In 1984, MP decided that reductions in taconite demand were permanent and that it should sell off a portion of its generating capacity. However, MP's efforts to reduce capacity were constrained by a very limited evaluation of potential power supply options. Since 1985, MP has adopted a much more flexible approach to supply planning. MP has now concluded arrangements that are expected to eliminate (and will at least substantially reduce) the large amounts of surplus capacity which have persisted since 1980.

MP has engaged in a wide variety of efforts to market its surplus capacity and energy over the last decade. This section will review these efforts in some detail to document why they have not been more successful in relieving MP and its ratepayers from the burden of excess capacity. The following review relies upon the testimony of Mr. Ostroski and MP discovery responses in the current docket, as well as material from previous regulatory proceedings where MP's sales efforts have also been discussed at length.

4.1.1. 1975-1978: Capacity Purchases to Meet a Perceived Shortage

To explain the substantial excess capacity that developed when Boswell #4 was completed, it is useful to go back to the inception of the project in 1974-77. Based on its 1975 forecast, MP believed it would be facing large capacity deficits in 1980 without Boswell #4. Meanwhile, MP was very concerned that construction on that unit would be delayed by the permitting process. As insurance against potential delays, MP contracted for 100 MW of summer 1980 capacity from NSP and 64 MW from Dairyland Power. MP believed that it was fortunate to purchase additional capacity since in 1976 MAPP was forecasting only 204 MW of surplus (over the 15% reserve margin) for summer 1980. MP also sought 2 LWAs (Limited Work Authorizations) to expedite construction at Boswell.

Even in the 1974-77 period, while MP was scrambling to deal with a perceived capacity shortage, signs of a surplus began to appear. For example, between the 9/16/76 and 4/19/77 MP forecasts, the predicted winter 1980 peak decreased almost 200 MW.[52] In each year, MP overestimated the following year's

52. Predictions of winter 1986 peak continued to increase until the 7/20/77 forecast, and then these also began a steep decline.

peaks. As a result MP supported capacity substantially in excess of 15% or even 25% reserves throughout the late 1970s (Table 2.2). MP had been very effective in adding capacity to meet very rapid projected load growth, ensuring substantial excess if these projections were not realized.

4.1.2. 1978-1983: Short Term Sales of a "Short Term" Surplus

In 1978, MP began attempts to market the surplus power that would result from the completion of Boswell #4. Semi-annually, all MAPP utilities submit a 48-month surplus and deficit survey in which they can indicate seasonal surpluses (or deficiencies) they are willing to sell (or fill with purchases). On the August 1978 survey, MP offered to sell 440 MW for summer 1980. MP also made telephone calls to MAIN and SWPP[53] utilities. Some indicated slight interest, but the cost of wheeling over long distances was prohibitive.

In 1979, MP intensified its sales efforts. 440 MW of capacity for summer 1980 was again offered on the February 1979 MAPP survey although the offer was reduced to 355 MW on the August survey. In June, letters were sent to 11 MAPP utilities projecting a summer 1980 deficit. The letters indicated capacity was available for summer 1980 and in decreasing

53. MAIN (Mid-America Interpool Network) and SWPP (Southwest Power Pool) are power pools serving, respectively, Illinois, Eastern Wisconsin, and Eastern Missouri; and Western Missouri, Kansas, Arkansas, Oklahoma, Louisiana and portions of Mississippi, Texas, and New Mexico.

amounts over the next 4 years. In May, MP offered capacity and energy to SMMPA (Southern Minnesota Municipal Power Agency) under MAPP Schedule B, Participation Power. MP offered summer capacity starting in 1980 at 550 MW, decreasing to 1985 (40 MW), and winter capacity starting at 200 MW in 1980, decreasing to 100 MW by 1983. Lesser amounts of power were available on a firm basis.

MP was successful in overcoming the obstacles that it feared would prevent Boswell #4 from being available for summer 1980. The unit entered commercial service on April 28, 1980. Unfortunately, the taconite industry was entering a severe slump, creating a much higher level of excess capacity than MP had expected. MP's sales efforts to market this excess yielded very limited success. MAPP allocated MP for 1 MW of a 6 MW winter 1980 purchase by Montana-Dakota Utilities.[54] MP negotiated a 20 MW sale to Otter Tail Power for winter 1980.

MP's difficulty in marketing capacity was not surprising in light of the conditions in MAPP. Mr. Ostroski's Rebuttal Testimony in FERC Docket No. ER80-5 (submitted in August 1980) describes how the predicted surplus in MAPP had increased from 1979 to 1980. He goes on to say:

> With the indicated large surplus available in the Pool, it would be extremely imprudent for any member utility to make commitments any earlier than is

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54. During 1980, MP continued to indicate capacity for sale on the semi-annual MAPP surveys as it had since August, 1978. MP has continued to offer capacity in this manner throughout the 1980-1987 period.

absolutely necessary. Recent load forecasts have been volatile and have shown significant downward pressures. Since there is a large surplus and all indications point to softening of forecasted demand, each utility in the pool has incentive to wait as long as possible before committing to any power purchase. The current MAPP system surplus and deficit tabulation . . . shows significant surpluses on the pool until the summer period of 1988. These surpluses would indicate that MP&L will have significant difficulty in selling surplus capacity to neighboring utilities. . . With so much surplus on the pool, however, it is a buyers' market. (Page 11)

In 1981, MP did succeed in selling 10-50 MW of Boswell #4 capacity to Lake Superior District Power[55] for the winter 1981 to summer 1986 period. The demand rate was $5329/MW-month, substantially below Boswell's carrying costs. Mr. Sandbulte discussed the pricing of the short term sales that MP has made in the 1981-87 period in his Docket No. E002-E015/PA-86-722 testimony:

These sales, while helpful, have not been on a full return basis. Rather, these sales represent an opportunity to partially recover total costs of owning and operating portions of Minnesota Power's capacity, as opposed to having this capacity remain idle during the pool periods involved. (Page 9)

MP also negotiated with NEMMPA (Northeast MN Municipal Power Agency) which offered to buy 15% of Boswell #4 at depreciated book value. NEMMPA member utilities had been MP wholesale customers. MP offered to sell at a price based on depreciated replacement cost.[56] These negotiations became an

55. Lake Superior Water District was later merged into NSP.

56. From the materials we have examined to date, it is not clear how MP was determined its "replacement cost." Since these were negotiations for a January 1982 sale of a plant

issue in Docket No. E-015/GR-81-250. MP's concerns can be summarized as follows:

1. Capacity sold at less than depreciated replacement would have to replaced with higher-cost facilities at some later date.

2. If a precedent of selling capacity at depreciated replacement were established, MP would have to sell capacity at this price to other customers, notably the taconites.

3. The Commission should not interfere in negotiations.

The Commission declined to order MP to sell capacity to NEMMPA and no sale was ever concluded with MP.

Although it is difficult to comment definitively without detailed knowledge of the negotiations, it would appear that MP missed a valuable sales opportunity with NEMMPA. Certainly, it is advantageous to sell capacity at the highest possible price. However, MP was facing excess capacity for the remainder of the decade, capacity it would have to attempt to sell in the face of a pool-wide surplus. MP's reluctance to make long-term capacity sales consigned it to a short-term power market where it was difficult, if not impossible, to sell on a full return

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with a 1980 in-service date, the distinction should be minor. Indeed, MP indicates that the replacement date was assumed to be the date of the sale. MP somehow derived a $993/kW replacement cost for a plant which cost $800/kW 1.5 years earlier, for a depreciated markup of 993/(800-800*1.5/30) - 1 = 31%. The Handy-Whitman North-Central steam plant inflation index increased only 12.4% from the July 1980 to January 1982 (or 14.4%, extrapolating back to April 1980), so it is not clear how MP's replacement cost was derived. On the other hand, even this large markup represented only about a year or two of Boswell fixed costs, so it is not clear why MP was willing to be stuck with the excess capacity rather than sell at book.

basis. The likelihood that the taconites, facing excess capacity and serious financial problems in the steel industry, would be anxious to buy generating capacity was probably small. In any event, such a sale might have been very advantageous to MP, since it would have shifted some risks (and some of its most expensive capacity) away from MP.

In early 1982, MP believed that it had limited excess capacity in the late 1980s. This evaluation was soon to come into question as the downturn in the taconite industry became a depression. MP kwh sales to ultimate customers were reduced by almost a quarter from 1981 to 1982. MP long term forecasts had been falling continuously since 1977, as expansion in the taconite industry was delayed and eliminated. Now a series of events was beginning that would severely reduce the capacity and utilization of the existing taconite industry.

Three of the taconites gave notice of contract cancellation, the 5 year termination provision required by the Large Power Contracts under which they receive MP services.[57] MP responded by offering a 5% reduction in billing demand in exchange for 1 year extensions to the contracts and recision of any contract cancellation notice. MP included a major

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57. Erie, with its own generation, is served under a special power exchange agreement. Reserve was principally supplied by its own generation supplemented by an MP Large Power Contract. The 6 other taconites received all of their electric supply under Large Power Contracts. Two paper mills are also served under Large Power Contracts with an additional paper mill to begin receiving Large Power Contract service in the late 1980s.

sweetener: $3.7 million in refunds.[58] In 1983, MP's offer was accepted by two of the taconites which had given notice of cancellation. Four other taconites and one paper mill also accepted. Butler Taconite chose not to rescind its cancellation notice, and Boise Cascade chose not to extend its contract.

The contract cancellation notices and revisions were a clear signal of the weakness and uncertainty surrounding the taconites, both short and long term. The prospect that MP's excess capacity situation would be cured by load growth was fading. Instead, MP faced the very serious risk that the excess would grow and persist. However, MP still lacked a sophisticated planning process and analysis tools that would allow it to take meaningful steps to remedy its long term problems. MP's continuing resistance to selling off capacity long term is clearly illustrated below.

During 1982, the Minnesota Department of Energy, Planning and Development conducted hearings on a Recertification of Need for the 800 MW Sherco #3 unit. NSP was the lead participant with a 59% share (571 MW). SMMPA and UMMPA (United Minnesota Municipal Power Agency) were joint owners with respective shares of 38% (300 MW) and 4% (28 MW). Sherco #3, which had

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58. When power use by MP's Large Power Contract customers decreased in 1982, MP's other customers benefitted from the availability of lower cost power. These refunds were designed to channel this benefit back to the Large Power Contract customers. In addition to the refund provisions, US Steel and National Steel were allowed to reduce contract demand during their one year renewal.

earlier received a Certificate of Need in 1976 for a 1981 on-line date, was proposed for a May 1, 1986 in-service date.

The availability of capacity in other units as an alternative to Sherco #3 was a major issue in the proceeding. MP was asked to indicate if Boswell or any other capacity were available. Mr. Ostroski responded in April 1982 that base load capacity was unavailable concurrent with the proposed Sherco #3 in-service date of May 1, 1986. This statement was based on a computation of reserves excluding oil fired capacity and the Erie exchange, and using a 20% reserve margin. Had the computation included all MP capacity and a 15% reserve margin, or taken a less bullish view of the taconite industry, some capacity would have been available in the 1986-90 period. Furthermore, MP stated that the basis for any capacity sale price must be depreciated replacement cost. MP noted that it had recently rejected purchase offers from two other regional power suppliers, for 50 and 75 MW respectively, because they were unwilling to pay replacement cost.[59]

At the end of 1982, Sherco #3 received an Amended Certificate of Need with the in-service date delayed to January 1, 1988. Construction has proceeded more rapidly than planned and the unit is now scheduled on-line in late 1987.

Sherco #3 represents another lost opportunity for MP, a particularly important one. Sales within MAPP may be helpful

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59. The offer for 75 MW would appear to have been from NEMMPA. The identity of the 50 MW offer is uncertain.

SMMPA's situation also presented an opportunity for MP. The existing generating capacity of SMMPA's members consisted of very small units, many of them oil fired or relatively old. Thus, SMMPA had a strong interest in promptly obtaining low cost base load capacity. After the Sherco #3 on-line date was deferred, SMMPA was left with a gap in power supply, due to termination of existing purchase contracts after winter 1985. SMMPA then negotiated with MP for a purchase of Boswell #4 capacity in summers 1986 and 1987 (75 MW) and winter 1986 (50 MW). The demand rate was $9,163/MW-month in summer 1986, increasing to $11,397 in summer 1987. Fuel costs included a 10% adder. The resulting total cost to SMMPA (based on a 65% load factor) were estimated at 37.82 mills/kwh increasing to 43.92 mills/kwh. The contract was signed in 1983.

The preceding discussion indicates very strongly that a ready-made market for MP excess capacity existed within Minnesota. NSP had already deferred Sherco #3 by five years. The Department of Energy, Planning and Development ordered another two year delay. With Sherco #3 costing over $1200/kw, an MP offer of Boswell #4 ownership at depreciated book, or even substantially above, should have been very competitive.

In November 1982, E. R. Norberg analyzed the effect of a potential 150 MW sale of Boswell #4 on MP production costs (Response 169, Attachment 1). The load scenarios used were both substantially lower than MP's then-current forecasts. Case 1 assumed total Minnesota taconite production would level in allowing individual utilities to optimize their power supplies. However, they do not generally have any effect on the overall surplus of capacity in the pool. Sherco #3 is one of the few large units planned for the late 1980s in MAPP. Had MP been more realistic in its evaluation of its supply and demand, it might have been possible to delay Sherco. In early 1982, the amount of capacity offered for sale by MP might have been relatively small, say 100 MW.[60] Even this amount of capacity could have delayed Sherco #3 for a year. Then as conditions in the taconite industry worsened and Large Power Contracts were renegotiated, MP could have expanded its sale offer to 300 MW. The important point is that if MP had become involved in the Sherco #3 planning process, construction could have been delayed while long term capacity needs became clearer.

The situation that has come to pass is backward and illogical: NSP added a new unit (Sherco #3) to meet load growth in the 1980s (leaving Boswell as excess for essentially the entire decade) and then purchased capacity from older units (Boswell #4 and Young) to meet load growth in the 1990s. Boswell #4, as an existing and surplus unit, could have allowed NSP to defer the construction of Sherco #3, reducing excess reserves at both MP and NSP, and increasing the planning flexibility for both utilities.

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60. Better MP planning would have permitted a larger sale, as would an option for MP participation in the delayed Sherco #3.

off at 40 million tons, with MP-served production of 32.5 million tons. This scenario, which seems to match the low scenario of MP's February 1983 forecast document, results in peak load remaining basically constant around 1150-1175 MW. Case 2 assumed another 25% reduction in taconite load from Case 1: total Minnesota production at 32 million tons, with MP-served at 24.5 million tons. Peak load remained relatively constant at 1000-1030 MW.

Energy which could not be served by MP generation was assumed to be supplied by MAPP purchases priced to reflect an expected increasing reliance on oil. The only changes in capacity (other than the Boswell sale) were reduction in Young by 122 MW on January 1, 1985, 41 MW in November 1989, and 45 MW in November 1994.[61] Table 4.1 reproduces MP's results.[62] In Case 2 (the lower of the two load scenarios), the increase in production costs is slight throughout the 1984-2003 study period. In Case 1, the differential grows moderately, reaching about $20 million annually by the turn of the century.

The November 1982 Norberg report neither specifies the purpose of the study, nor does it state any conclusion as to the desirability of a 150 MW Boswell sale. It does seem clear

61. The Square Butte Coop by contract was to recapture 30% of Young on January 1, 1985. The Coop has the option to recapture up to an additional 21% on 5 years notice.

62. Table 4.1 shows the results from Norberg's Tables 1 and 2. Norberg also evaluated the two load scenarios with a later Square Butte option (all 86 MW in November 1994). The effect is to slightly reduce production costs.

that no change in MP's resistance to long term capacity sales occurred at this time. The November 1982 analysis by Norberg is interesting mainly in what it implies about MP's planning process. It appears from this study that, even if MP had been able to accurately forecast taconite sales and total load, it still would have been resistant to selling capacity. The Case 1 load scenario is not very different from MP's current (November 1986) forecast: the Case 1 scenario is higher until 1992, and the November 1986 forecast is higher in later years. The Case 2 scenario of total MP demand is similar to the low scenario of the November 1986 forecast. The Case 2 scenario forecast of taconite production and demand for MP electricity is only slightly below that of the November 1986 base case forecast.[63]

The effect of the Boswell #4 sale on production costs is quite small when considered on a Net Present Value (NPV) basis. At the 12% discount rate MP uses currently,[64] the sale cost only $43.9 million in higher production costs. The 1982 Norberg study does not state a sale price or avoided carrying costs, but the projections would have been comparable to the

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63. Regardless of how accurate the Case 1 and 2 scenarios have proven to be, it is unclear how much further consideration MP gave them. The Case 1 scenario was used in the December 1982 analysis of the sale of capacity to SMMPA in 1986-87. (Response 169, Attachment 2)

64. In 1982, higher interest rates might have caused MP to use a higher discount rate, which would have further reduced the importance of increases in production costs far into the future.

current estimates of Boswell carrying costs given in Response 121.[65] The Boswell non-fuel costs in Response 121 are equivalent to $22.5 million for a 150 MW share in 1984, falling to $9.3 million by 1995. The first two or three years of the proposed sale would save enough in non-fuel costs to cover the entire value of the additional fuel costs for the 20 years modeled. If MP had included the time value of money in evaluating the sale decision, the "low load" case represented by the Norberg study would have indicated that the sale was cost-effective (at least for the low-load case). The fact that the study reached no such conclusion indicates how limited was MP's planning perspective.

MP's short term sales efforts continued in 1983. In May, MP agreed to supply NSP with up to 200,000 MWH of energy to cover extended nuclear outages. No capacity was nce it was nearby and, unlike most of MAPP utilities, was expecting significant load growth that would require additional capacity after Sherco #3. Dairyland Power was projecting capacity deficits beginning around 1990 and was concerned that Wisconsin acid rain legislation would affect future operations at its generating plants. Montana-Dakota Utilities, a joint owner in the Coyote unit, was also contacted.

Based on a March 1984 analysis (Response 123), MP decided to offer a 200 MW Boswell #4 sale until the mid-1990s. A 200

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65. Finance charges were higher in 1982 than they are currently, so a 1982 estimate of carrying costs would have been somewhat higher.

MW sale until 2003 was viewed as risky due to the potential cost of replacing this capacity. Replacement cost was based on new coal capacity at Floodwood or Oliver County, ND, costing $1500-1550/kw. MP believed this replacement cost might be higher than projected revenue from the sale of Boswell #4. MP did not believe purchases from other MAPP utilities could be counted on since the pool-wide surplus was projected to end around 1990.

MP evaluated reserves under various options. The most "optimistic" case concerning the potential capacity sale included the following assumptions:

1. MP existing capacity including oil units, plus 50 MW of upratings in 1990, minus 10% Square Butte options in 1995 and 1999, and not including any Erie interchange capacity.
2. MP February 1984 load forecast minus 50 MW taconite reduction.

Under this most "optimistic" case, 15% reserves were maintained with a 200 MW sale until the second Square Butte option was exercised in 1999. Reserves with a 200 MW sale dropped below 15% earlier with the other considerably more pessimistic cases considered.

In April 1984, MP offered 100-200 MW of Boswell #4 capacity to NSP at a price of $15,500/MW-month, for a 10-15 year period beginning in the late 1980s. NSP responded that it preferred a longer term sale.

In October 1984, MP analyzed two NSP purchase proposals for Boswell #4: 100 MW from 1987 through the life of the plant and 200 MW from 1993 to 2004. The cover letter from J. M. Weaver and the attached report by Eric Norberg (Response 169, Attachment 4) detail the rationale behind MP's continuing resistance to long term capacity sales. MP remained unwilling to sell off capacity which might have been needed sometime in the future:

> The NSP 100MW purchase proposal is favorable with an early (1987) starting date. MP has capacity to consider a 100MW sale until the mid-to-late 1990's; however, a sale for the life of Boswell #4 will require MP to replace the capacity in the 2000 time frame with costly new capacity. If a lower forecast materializes or the Square Butte options are delayed, MP's replacement requirement will be delayed and the negative impact for serving future customers will be reduced. This future replacement necessity essentially requires the penalty of serving customers with a new unit or purchase instead of the substantially lower Boswell #4 unit costs.

NSP proposed demand revenue of about $14,500/MW-month for the 100 MW sale. MP comments "by the year 2000 additional energy costs are higher than expected demand revenue. This reinforces that Boswell #4 low energy cost is valuable to MP and supports seeking a shorter sale and higher (as proposed by MP) demand revenue."[66]

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66. MP hopes that NSP will agree to a shorter sale term <u>and</u> a higher price. Given market conditions, a shorter sale term would probably result in a lower sale price.

Nowhere in its consideration of NSP's proposal does MP appear to employ a Net Present Value analysis. MP seems unable to compare a dollar of savings in 1987 to a dollar of costs in 2001. The fact that the crossover (when increasing annual energy costs first exceed sales revenue) does not occur for 13 years is an indication that, on a Present Value basis, short-term sales revenues may outweigh any potential increase in future production costs.

The material in Response 169, Attachment 4 does not include yearly production cost estimates with and without the sale. Thus, we are unable to perform a Present Value analysis directly on MP production cost data, as we did in Table 4.1. In Table 4.2, we have estimated incremental production costs, using the MP data from Table 4.1 for 1987-2003 and then escalating at 7.5% out to 2020.[67] The Table 4.1 estimates are based on a low load forecast (Case 1) and a 150 MW Boswell #4 sale. They are reasonably similar to MP's March 1984 estimate of incremental cost to serve MP load due to a 100 MW Boswell #4 sale.[68] (Response 123, Attachment 1, Page 22)

Table 4.2 indicates that the proposed 100 MW NSP sale was

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67. The 2002 figure from Table 4.1 was selected as the basis for the escalation since it was higher than the 2003 figure. The analysis was run out to 2020 when Boswell #4 would be 40 years old. The 7.5% escalation rate was that used for coal in MP's November 1982 analysis. (Response 169, Attachment 1)

68. The March 1984 estimates have not been used directly in Table 4.2, since they appear in graphical form only.

profitable to MP.[69] NSP and MP conducted serious negotiations in 1984, but MP's refusal to sell capacity beyond the mid-1990s was a stumbling block. If MP had been able to correctly evaluate the economic consequences of NSP's proposal, it seems quite likely that a sale could have been concluded.[70]

In April 1984, MP made offers of Boswell #4 capacity to Dairyland and Montana-Dakota. These offers were substantially similar to the offer to NSP made in April 1984: $15,000/MW-month for 100 MW, 1989-1998. By November, Dairyland was no longer interested, due to decreased load forecasts and reduced concern over emissions requirements. In May 1984, similar offers of Boswell #4 were made by letter to all MAPP utilities: $15,500/MW-month for 200 MW, 1987-1996.[71]

In 1984, MP management did decide to <u>permanently</u> dispose of a portion of its owned generating capacity.[72] As MP's

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69. Table 4.2 includes only revenue from Boswell #4 demand charges. NSP's proposed payments for Boswell O&M and Administration would add over a $1 million in annual revenue with the O&M charges escalating over time. Thus the net revenue estimate is understated. The utilities had not agreed on the adjustment for losses, which would affect net revenues.

70. MP also rejected NSP's proposal for a 200 MW sale 1993 to 2004, but for reasons that appear to be sound. It appears that NSP would have been willing to make a more attractive offer had MP been willing to offer 200 MW on a longer term basis.

71. In May, just before these letters were sent, MP repeated its May 1983 offer to all MAPP utilities: Boswell #4 at $2000/MW-month and 110% incremental production cost <u>or</u> $500/MW-month and 150% incremental production cost.

72. Sandbulte Testimony, NSP Sale Docket, page 9.

newest and most expensive generation, Coyote was selected. In early 1984, MP informed Coyote's joint owners, Otter Tail, Minnkota, and Montana-Dakota, of MP's intentions. MP's entire Coyote share was offered by letter to each joint owner in May 1984. In a noted departure from its previous position, MP stated that the sale could occur at depreciated book cost _if_ a sale could be concluded in 1984. Otter Tail and Minnkota were not interested, but serious negotiations ensued with Montana-Dakota. A sale arrangement was finalized in mid-1985. The price of $1200/kw was substantially above depreciated book with capacity transferred in two 25% increments in 1985 and 1986 and the remainder in 1988.[73]

In 1984, MP also began discussions with several Wisconsin utilities concerning WISMINTOBA, a plan to buy power from Manitoba hydro on the Nelson River. A large DC line was to be constructed from Manitoba through Northeast Minnesota to Wisconsin using existing transmission rights of way. MP suggested that the portion of the line from Minnesota to Wisconsin could be constructed to permit sales of Boswell #4 capacity until the late 1990s, when the Canadian hydro would become available.

4.1.3. 1985-1987: Flexible Power Supply Planning and Successful Efforts to Match Load and Capacity

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73. The reported gain of $7 million indicates a depreciated book cost of $800-$850/kw.

In 1985, MP finally moved decisively to balance long term power supply and demand. As numerous events made it increasingly clear that excess capacity and low load growth could persist far into the future, MP developed a more flexible approach to supply planning. Such an approach was necessary to deal with the highly uncertain environment that confronted MP. MP's long term capacity needs were difficult to project since it was very uncertain how much taconite capacity would be retained and how much this capacity would operate. Prior to 1985, MP's tendency was to hold on to capacity that was excess today but might be needed sometime in the future. In 1985, MP acknowledged that capacity should be balanced with the level of demand anticipated in the short term. MP also realized that it had a number of options for meeting any future need for capacity.

By 1985, it had become clear that the taconite industry had to contract to survive. Butler Taconite closed permanently in June.[74] Other taconites pressed for modifications in their Large Power Contracts since it was clear they would no longer need as much capacity as they had contracted for. In July 1985, MP offered to reduce pre-1983 contract demand by 3% for

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74. Butler had issued a 5 year cancellation notice on September 17, 1982. Thus its service agreement did not terminate until September 17, 1987. Butler claimed not to be bound to this agreement and MP initiated legal action to recover lost revenue for the remaining contract term. MP and Butler reached agreement on these outstanding claims in April 1986.

each year of extension in contract term agreed to, up to a maximum of 18%. Other changes included reducing the cancellation notice requirement from 5 to 4 years and allowing usage up to 120% of contract demand without subsequent demand ratchet. Three taconites and one paper mill accepted, with a resulting decrease in Large Power class contract demand of 79 MW.

With projections of future power needs shrinking, MP now believed that it could sell off capacity long term. Negotiations with NSP continued. In July 1985, MP submitted an offer for an ownership share in Boswell #4 at about twice book value. Transmission was included but Anthony Benkusky's testimony for NSP in the NSP sale docket indicates that NSP did not believe the offer was economical compared with its alternatives.

MP then sweetened the pot with power from Young. As will be discussed later, this was a significant attraction for NSP. In July 1985, MP evaluated a 307 MW capacity sale to NSP consisting of 40% of Boswell #4 and 24.5% of Young transferred in three equal increments on January 1, 1989, 1990, and 1991. MP concluded that such a sale might result in capacity deficits by the late 1990s, if the base forecast proved accurate. These deficits would be small and could be met economically with a variety of supply options. (Response 126; see section 4.2.2 <u>infra</u> for a more detailed description). Even with the sale, substantial excess capacity would persist into the next century

(272 MW in 2005) based on the July 1985 demand forecast low case.

While negotiations with NSP moved forward, MP concluded its arrangement to sell off its share in Coyote. MP continued other efforts to sell short and long term capacity. A meeting was held in January 1985 with the Wisconsin utilities on the WISMINTOBA project. Various concerns were expressed, including the preference of the Wisconsin PSC for conservation. In a March letter to each of the Wisconsin utilities, MP offered 200 MW of Boswell #4 until perhaps 2003-2005 at $15,500/MW-month. Interest in WISMINTOBA then faded as the Wisconsin utilities' forecasts dropped and their need for power in the late 1980s disappeared.

Nebraska utilities were also considering Canadian purchases from the MANDAN project. A transmission line would be constructed Manitoba-North Dakota-Nebraska which would also permit seasonal power exchanges. MP met with the Nebraska utilities in April 1985 to propose a connection with MP's transmission line to the Young plant. The North Dakota-Nebraska segment of the transmission line would be built initially to allow sales from MP to Nebraska. The remainder of the line and sales with Canada would come later. MP followed up with a letter to the Nebraska Public Power District offering 200 MW of Boswell #4 from the late 1980s to 2000 at $15,500/MW-month. Shortly afterwards, the Nebraska forecast dropped, eliminating interest in capacity purchases. The MANDAN project was also subsequently cancelled.

In March letters, MP again solicited all MP utilities for Schedule A sales of 100 MW of Boswell #4 at $3500/MW-month and 110% incremental production cost. NSP was the only utility that responded. A 100 MW summer 1985 sale of Laskin and Boswell at $1000/MW-month was negotiated.

In March MP responded to an inquiry by WPPI (Wisconsin Public Power) concerning 10 MW of participation power for summer and winter 1985. MP offered Boswell #4 at $3500/MW-month and 110% incremental. Subsequently, MP and WPPI agreed to an interruptible energy-only sale of 10-20 MW with price negotiated by dispatchers at time of potential sale.

In January 1986, MP and NSP reached a Memo of Understanding for a capacity sale much like that evaluated in July 1985. 40% of Boswell #4 and 24.5% of Young were transferred in three equal increments on May 1, 1989, 1990, and 1991. The price for Boswell was about $700/kw, which translates into a $31 million premium over depreciated book of approximately $550/kw. The Young portion of the deal was a transfer of a portion of MP's entitlement, to be recaptured by MP in 2008. NSP also was to pay $32.9 million for value of transmission leaseholds relating to the two plants. In late 1986, MP and NSP submitted their agreement for regulatory approval.

It may be deceptive to examine the Boswell #4 sale above book without considering the effect of the Young transfer. In his NSP sale docket testimony, Anthony Benkusky emphasizes the key role of Young in the negotiation between NSP and MP:

> Center # 2 is among the lowest production cost fossil fuel generators in the United States. This energy would provide a significant savings to NSP.
>
> With the addition of the low-cost system capacity and energy purchase the combined purchase package became more attractive. It should be emphasized that this is a total package deal. (Page 9)

Thus, the "profit" MP earns on the Boswell #4 sale is offset (from the ratepayers point of view) by the fact that MP is left with 102 MW less of Young, a much less expensive plant. Table 4.3 demonstrates the difference in cost between Young and Boswell #4. Due to the different operation of the two units,[75] Table 4.3 evaluates cost both on a per-kilowatt basis and on a per-megawatthour basis. For the kilowatt analysis, Young is treated as a 292 MW unit, and Boswell as 535 MW. For the MWH analysis, Young is assumed to have a 70% capacity factor (MP's assumption for maximum capacity factor, and consistent with the 69.4% achieved or planned for 1985-88), while Boswell #4 is evaluated at 66.5% (the 1985-88 actual/projected). By each of these measures, a unit of power is more expensive from Boswell than from Young. The annual cost of substituting Boswell for the 102 MW portion of Young which will be ultimately sold to

75. Young has a lower maximum capacity factor than Boswell (70% vs. 85%), due to boiler problems, but it is dispatched up to the maximum level. With its higher fuel costs, Boswell is not dispatched as much as Young.

NSP ranges from $3.8 to $6.0 million in the 1992-1995 period, depending on the measure and year. Clearly, there is a considerable cost to ratepayers from having ended up with 102 MW of Boswell instead of Young.

Table 4.3 also compares the present value of these extra cost streams to the present value of the AFPO. The cost differences are extrapolated out to 2007 (when Young is reclaimed) at the average of the 1992-1995 period.[76] The present values of the AFPO and of the cost differences are very close: the AFPO roughly compensates ratepayers for the replacement of a portion of Young with Boswell #4. From NSP's point of view, the transaction is very close to receiving roughly 316 MW of Boswell #4 at book cost.

While moving forward on completing the NSP sale which will eliminate (or at least substantially reduce) its excess capacity, MP has continued to make short term sales at less than full return. MP sold NSP 35 MW of firm power for summer 1985 at $1000/MW-month. In October, MP agreed to sell NSP 350 MW of Boswell #3 for summer 1987 at $870/MW.

In June 1986, MP informed all MAPP utilities that 84 MW had been released by a Large Power Contract customer for resale. The power had been released for a portion of the summer, but MP was willing to consider long term sales as well as various pricing structures. Later in June, MP indicated

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76. This is obviously a rough approximation. It may be favorable to Boswell, since more of that plant's costs are fuel costs, subject to escalation.

that an additional 19 MW had become available for the next 5 years. MP again indicated it was flexible as to duration and pricing of sales. In December 1986, MP responded to an inquiry by the Geneva municipal concerning power purchases beginning in December 1987. MP offered participation power from any of the Boswell units for November 1987 into the early 1990s at "a competitive demand charge" to be negotiated.

In January 1987, MP offered all MAPP utilities short term capacity and/or energy from the Boswell units for winter 1987 through the early 1990s. MP also indicated an interest in seasonal diversity exchanges to cover projected winter deficits beginning in the early 1990s. In January, MP offered Boswell capacity to FERMI National Accelerator Lab in Illinois. In March, MP responded to a WPPI request, offering 5 and/or 15 MW of Boswell #4. Summer and winter 1989, price would be $2000/MW-month and 110% of incremental operating costs, with price increasing to $3000/MW-month the following year. Extension of the sale term was possible, contingent on capacity availability.

In March, MP responded to an inquiry by Iowa Electric Light and Power. MP indicated that Boswell, or any other units, were available for Schedule A or B sale. Capacity was offered only through 1990, with the amount available dropping from over 300 MW in 1987-1988 to 58 MW in winter 1990. MP did express an interest in diversity exchanges in the early to mid-1990s. In April, MP informed IEL&P up stating that potential changes in mining load could make 100 MW of capacity available long term. Equity sale of Boswell #4 was offered, with long term participation sale as an alternative.

In February 1987, MP concluded two seasonal diversity agreements. Manitoba Hydro will provide 50 MW of capacity (up to 50% capacity factor unless mutually agreed upon) for summer 1987 at $15.50/MW-month. MP will return 50 MW in winter 1989 at 110% of Boswell incremental cost. Otter Tail will provide 30 MW Firm Power summer 1987 at 110% Otter Tail incremental cost. MP will return 30 MW Firm Power winter 1987 at 110% incremental cost.[77]

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77. Note that these diversity agreements reverse MP's usual pattern of buying in the winter and returning the power in the summer.

4.2. MP Was Not Prepared to Deal with Changing Conditions

Without extensive interviews with MP staff and review of MP documents going back into the 1960s, it is not possible to formulate a definitive explanation of the process which resulted in MP's failure to dispose of its excess capacity in a more timely fashion. However, three particularly important factors can be identified from the materials we have reviewed:

1. MP seems to have experienced great difficulty in redirecting its attention from accommodating the growth spurt in the 1970s to mitigating the excess capacity in the 1980s.
2. Especially considering the risks it had assumed in taking on the taconite loads, MP had a very limited planning perspective in the 1970s and early 1908s.
3. Until recently, MP lacked a formal mechanism for trading off short-run costs and long-run benefits (or vice versa).

While most of these problems appear to have been substantially alleviated in the last couple of years, they contributed substantially to MP's problems in the early 1980s.

4.2.1. Fixation on meeting growth

In about 1974, MP planning came to be dominated by the need to meet the massive increases in mining load which occurred in 1976-78, and another round of additions which were planned for the late 1970s and early 1980s, but which never materialized. MP planning appears to have remained fixated on meeting a wave of future large power additions, until 1982, when the uncommitted large power loads were finally dropped from the load forecast.

MP was gearing up for a massive expansion in the late 1970s, in a period in which the pool was not projecting substantial surpluses. Having decided to take on the increased taconite loads, and having committed to providing firm power on specific dates, MP was understandably nervous about meeting that commitment.

MP's scramble for power in the last few seasons prior to the in-service date of Boswell #4 was somewhat excessive. MP had substantial excess capacity for the entire period after Young reached full power. Still, MP did not suffer greatly from its planning priorities in the 1970s: the lights stayed on, growth continued, additional load growth was planned, and the service territory was doing very well. Perhaps these factors explain why the late-1970s excesses did not cause MP to become more cautious in avoiding surplus capacity. As we have discussed above, MP continued to be very reluctant to sell off capacity until 1985.

Overall, MP must have seen itself as having survived a difficult trial, and having succeeded. The company had taken a significant risk with the late-1970s load growth, and it had done very well. MP was preparing in the late 1970s for a similar trial in the 1980s, with a new wave of expansion and a major new plant (Floodwood/Fine Lakes). While the date of that subsequent trial receded into the future, MP took a long time to redirect its attention from dealing with rapid growth and capacity deficiencies, to dealing with stagnant (or even falling) loads and capacity surpluses.

4.2.2. Lack of planning

MP's contemporaneous studies of capacity planning decisions in the late 1970s, and its recent retrospective discussions of those decisions, indicate serious deficiencies in MP's planning process. Perhaps the most serious problem involves a lack of flexibility. Section 3.4 discussed the wide range of options which MP did not pursue in the 1970s, as an alternative to becoming extremely dependent on the taconite industry. MP's planning in the early 1980s showed a similar rigidity.

For example, once it became clear that NSP was actually planning to build Sherco #3, MP had an excellent opportunity to arrange a capacity-sharing arrangement. MP's excess Boswell capacity, spread over the larger MP-NSP system, would represent a much smaller burden in the 1980s, and would provide greater opportunities for fuel cost reduction.[78] An NSP share in Boswell would pay off later in the 1980s, by allowing for the

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78. SMMPA would also have to be included in the capacity-sharing agreements.

deferral of Sherco #3 until the combined systems required it.[79] MP rigidly refused to give up any Boswell capacity long-term, until after its best sales opportunities had disappeared.

MP also shows no signs of having developed a contingency planning process until July 1985. At that point, in a memo authored by E. R. Norberg (Response 126, Attachment #1), MP recognized that a large number of capacity sources were available on fairly short notice if a successful long-term capacity sale and subsequent load growth required an incremental addition in the 1990s. These included:

capacity upgrades at existing units,

small hydro additions which would almost pay for themselves in fuel savings,

cogeneration,

150 MW of extra capacity at Erie and Reserve <u>even if the taconite facilities were in operation</u>, and 350 MW if they were shut down, and

a 100 MW boiler addition at Young.

Many of the power sources noted in 1985 must have been available for some time.[80] In March 1984, MP believed that

79. In the early 1980s, Boswell #4 would have been a very attractive alternative to the much more expensive Sherco #3. Having waited until Boswell could no longer defer Sherco, MP was forced to include some less expensive Young capacity to secure an agreement with NSP.

80. Even the 1985 study did not discuss some commonly-cited capacity options with short lead times, such as the addition of combustion turbines at the gas/oil plants (Hibbard 1&2, Winslow, and Laskin's topping boilers), for eventual repowering of the existing units as combined-cycle plants. Another example would be the installation of small cogeneration units at commercial and institutional facilities. Perhaps the most attractive

replacement capacity would cost $1500/kW in 1988: by 1987, this estimate had been scaled down to $1342/kW in 1996, or about $1000/kW in 1988 dollars, assuming 5% inflation.

MP's lack of a comprehensive planning framework seems to have seriously limited the company's ability to make decisions which reduced its capability in the long term.[81] Without a good grasp of future risks and alternatives, MP appears to have rejected an opportunity to sell off 15% of Boswell #4 at cost in 1981, based on (if we are to believe the arguments of MP's witnesses in E015/GR-81-250) the concern that others (specifically NEMMPA and perhaps somehow the taconites) would profit excessively from the transaction. Since MP could not commit itself to selling a piece of Boswell at cost in 1981, it has been stuck with the excess capacity ever since.

Similarly, MP was always reluctant to sell excess capacity if, at the point MP was projecting need, the pool was not projecting a substantial surplus. Of course, with the falling load forecasts of the 1980s, the date at which MAPP projects deficiencies has receded considerably. As the shortage date moves out beyond the construction period for new capacity,

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option is a contingency conservation program, composed of investments which are not currently attractive, but which would be less expensive than a new base-load unit. These omissions are not serious at this time, given the likely lead time until MP will again require a capacity addition, but they should be corrected in time to allow MP to accommodate future developments in loads and costs.

81. MP showed little difficulty in committing itself to short-term sales or to additional purchases of any length.

projected shortages become meaningless. If the shortages are not eliminated by falling load forecasts, small utility-owned plants, independent power producers, or out-of-region purchases, some group of utilities will eventually build additional capacity. Hence, MAPP's projected shortage dates were almost worst cases, and MP was willing to sell capacity long-term only when MAPP faced a near certainty of surpluses for over a decade into the future.

4.2.3. Inability to balance short-term versus long-term interests

Strangely enough, MP does not appear to have produced a net present value (NPV) analysis of Boswell sales until 1987.[82] This may help to explain why MP consistently had difficulty deciding whether or not to sell off excess capacity, which would reduce costs in the short term but increase them at some point in the future. As late as 1984, MP was not even willing to sell off capacity which it did not expect to need until a decade later (Responses 123 and 169-Attachment 4).

The analysis of these decisions is not easy to follow, and the decision rules MP used are far from clear. However, it appears that MP simply avoided choices which could have major costs later, regardless of the short-term savings. The lack of

82. A 1984 study (Response 169, Attachment 4, Appendix 3) mentions a present value analysis, but no such analysis was attached.

NPV perspective, or any formal mechanism for trading off short-term and long-term costs, appears to have been a major obstacle to the earlier sale of Boswell capacity.

5. THE COST OF MINNESOTA POWER'S EXCESS CAPACITY

Having established the magnitude of MP's physical excess capacity, and having placed that excess in its historical context, it is now necessary to determine the costs of the excess capacity. In measuring those costs, it is appropriate to focus on Boswell #4 and Coyote. These are the newest and most expensive units, whose addition to MP's power supply resulted in this decade's excess capacity. Had MP improved its load forecasting, developed a more flexible planning process, and arranged to supply less of the taconite loads in the late 1970s, it would be left with a smaller portion of Boswell #4 and no Coyote. If MP had sold off Coyote and a portion of Boswell #4 in the early 1980s, there would be no excess today, and the difference in costs would be determined by the cost of those plants.

Table 5.1 shows that Boswell #4 has cost ratepayers almost \$500 million in fixed charges from 1980 to 1986 and another \$57 million in 1987. To reflect the fuel savings produced by Boswell #4, Table 5.1 omits Boswell's O&M costs. Table 5.2 presents similar data for Coyote. Fixed charges from 1981-1986 total \$20.4 million. 1987 fixed charges have been reduced to only \$1.5 million since MP has already sold off half of its share, with the other half to be transferred in 1988.

Table 5.3 estimates the total cost of excess capacity in the 1980-1987 period. The surplus capacity estimate from Table 2.6 has been allocated first to Coyote, with the remainder assigned to Boswell #4. Total fixed costs attributable to excess capacity total $411 million from 1980 to 1986, with another $46 million in 1987.

The cost of excess capacity in Table 5.3 is a rough estimate, for several reasons. First, it neglects factors which reduced (or will reduce) the cost of the excess capacity:

a. The excess capacity has allowed for additional off-system sales. Table 5.4 tabulates these revenues. The revenues have been (and are still) much smaller than the cost of the excess capacity.

b. The AFPO from the Boswell sale will reduce rates by $10 million in 1987.

c. The Coyote sale went off above book: we assume that some of this gain went to the ratepayers.

d. We have assumed that the fuel savings from Coyote and Boswell were just enough to cover their O&M. This is likely to be a very close approximation for Boswell, but Coyote may have produced slightly greater savings.

e. MP may not have passed along all of its excess costs to customers, since it refrained from filing for rate relief for so long, and the reduced costs due to a sale would not have immediately flowed through, either.

Second, we did not adjust for some factors which increase the cost of the excess:

f. Some of the sales revenue were refunded to the taconites (and perhaps to other Large Power contract customers, as well), on the grounds that it was their capacity which was being sold. Thus, not all the contract demand ended up as revenue to MP.

g. The unused portion of the Large Power contracts (like most other retail rates) were priced at average capacity cost, not at the higher costs of the excess capacity.

h. We neglected the diversity among Large Power customers, and between LP customers and the system peak. As a result, the MP load for which the Large Power customers were paying was lower (by 5-10%) than the figures computed in Table 2.4 and reproduced in Table 2.5.

Table 5.3 is an estimate of the total cost of excess capacity. The issue of what portion of this cost was avoidable must be considered separately. Table 5.1 shows that if MP had sold off 300 MW of Boswell #4, 1987 fixed charges would be reduced by $33 million. Assuming the sales had taken place in three 100 MW increments at the end of 1981, 1982, and 1983, fixed charges prior to 1987 would have been reduced by $163 million. We believe that the 300 MW sale in the 1981-83 time frame would have been a very reasonable target, had MP had a better planning function in the late 1970s and early 1980s. With this hypothetical 300 MW sale virtually all of the capacity sales shown in Table 5.4 could have still been made.

MP's entire ownership in Coyote can be considered excess capacity.

6. CONCLUSIONS

MP assumed very large and unnecessary risks in the 1970s, in taking on a very large load from a single, very narrow industry. Given the magnitude of the risk it had taken on, MP should have maintained a comprehensive planning process in the late 1970s, which could have warned the company of the problems in the steel industry, identified markets for excess capacity and sources of replacement capacity (in the event that sales picked up again), and generally prepared MP to act rapidly if problems developed. MP did not have such a capability. Forecasts in the 1970s (and early 1980s) were unnecessarily vulnerable to overestimation.

In the 1980s, when things started to go bad, MP took years to develop the contingency planning, present-value analysis, and reasonable independent forecasting capability which it needed to justify a major capacity sale. As a result, most of Boswell #4 is excess to MP's needs, by any reasonable standard, and has been since the time it entered service. This excess, which MP expects will persist until the NSP sale is completed in 1991, is largely due to MP's lack of preparedness, in addition to simple bad luck and some bad judgement calls.

It is entirely possible that the taconite industry will contract further, and that MP will find that still more of its capacity is surplus. At this point, MP seems to have developed the tools and perspectives necessary to make reasonable decisions regarding capacity sales.

To date, MP's excess capacity has cost more than $400 million in the 1980-86 period, and will cost another $46 million in 1987. A gradual, moderate sell-down of capacity (including 310 MW of Boswell) in the early 1980s, to levels which will not be needed before the 1990s, would have saved $184 million in 1980-86 and $35 million in 1987. Sales revenues would offset some $21 million of the excess costs in 1980-86, and another $7 million in 1987, but virtually none of the costs avoidable through the moderate sell-down, since adequate excess existed for those sales even after the moderate sell-down. The AFPO credits from MP's gain in selling Boswell #4 to NSP above book value will roughly compensate MP's ratepayers for the loss of the Young capacity.

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TABLE 2.1: MP CAPACITY RESOURCES

Resource	Maximum Capability	COD	Fuel	Notes
Laskin 1 and 2	110	Pre 1973		Accreditation reduced to 82 MW from Winter 1983 to Winter 1986.
Boswell 1 and 2	138	Pre 1973		
Boswell 3	350	7/73		
Boswell 4	517	4/80		Rerated to 535 MW in Summer 1987; 214 MW sold in stages from 1989 to 1991.
Coyote	21.05	5/81		Sold in stages from 9/85 to 5/88.
Milton R Young	408	5/77		30% reclaimed by owner in 1/85; up to 20% more can be reclaimed on 5 year notice. 102 MW sold in stages from 1989 through 1991; to be reclaimed by MP in Summer 2008.
Hibbard 3 and 4	75	Pre 1973		Shut down since 1982. Restart scheduled in 1991 at 50 MW in Summer, 46 MW in Winter.
Hibbard 1 and 2	50	Pre 1973		Shut down since 1982. Restart scheduled in 1991.
Winslow	25	Pre 1973		Owned by MP subsidiary. Not accredited Winter 1983 to Winter 1986.
Hydro	115			22 MW added from 1976 to 1987.
Erie Interchange	40	1956		Interchange with customer generation; emergency kwh repaid with kwh, non-emergency kwh @ split savings.

Source: Discovery Responses #111, 121, 132, 139, and 140.

	75S	75W	76S	76W	77S	77W	78S	78W	79S
Hydro Subtotal	94	93	106	105	106	105	106	105	108
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	0	0	0	0	0	0	0	0	0
Coyote	0	0	0	0	0	0	0	0	0
Milton R Young	0	0	0	0	340	408	408	408	408
Hibbard 3 and 4	75	75	75	75	75	75	75	75	75
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	882	881	894	893	1234	1301	1302	1301	1304
(1) Seasonal System Demand	688	748	794	903	955	1011	1014	1117	1116
(2) Annual System Demand	691	748	794	903	955	1011	1014	1117	1117
(3) Firm Purchases	0	0	85	275	100	125	100	100	0
(4) Firm Sales	0	0	0	0	0	0	20	0	0
(5) Seasonal Adjusted Net Demand	688	748	709	628	855	886	934	1017	1116
(6) Annual Adjusted Net Demand	691	748	709	628	855	886	934	1017	1117
(7) Net Generating Capability	882	881	894	893	1234	1301	1302	1301	1304
(8) Total Participation Purchases	68	76	94	74	0	0	40	70	200
(9) Total Participation Sales	65	50	50	50	50	50	50	50	50
(10) Adjusted Net Capability	885	907	938	917	1184	1251	1292	1321	1454
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	104	112	106	94	128	133	140	153	168
(12) Total Firm Capacity Obligation	792	860	815	722	983	1019	1074	1170	1284
(13) Surplus or Deficit Capacity	93	47	123	195	201	232	218	151	170
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	173	187	177	157	214	222	234	254	279
(15) Total Firm Capacity Allowance	861	935	886	785	1069	1108	1168	1271	1395
(16) Surplus or Deficit Capacity	24	-28	52	132	115	143	124	50	59
(17) Actual Reserve Margin	28%	21%	32%	46%	38%	41%	38%	30%	30%

Notes: [1] Data for 1975 through Summer 1986 from Response to Question 141, Attachment 1. Data for Winter 1986 from Testimony of G. B. Ostroski, Docket #E002-E015/PA-86-722. Data for 1987 and after from Testimony of G. B. Ostroski, Docket # E-015/GR-87-223.

[2] Formula in Lines 11 and 14 was changed to the reserve margin multiplied by Line 6.

[3] The following changes were made to MP reported capabilities: Laskin was changed to 110 MW from Winter 1983 through Winter 1986; Hibbard 3&4 was changed to 75 MW from Winter 1982 through Summer 1987, and 50 MW in Summer and 46 MW in Winter thereafter; Hibbard 1&2 was changed to 50 MW from Winter 1982 through Summer 1991; Winslow was changed to 25 MW from Winter 1983 to Winter 1986; Erie was added as 40 MW Generating Capacity from Summer 1975 through Winter 1986 & deleted as 40 MW Participation Purchase Summer 1975 through Winter 1982; and Young sale beginning Summer 1989 was noted as reduction in Generating Capacity instead of Participation Sale.

	79W	80S	80W	81S	81W	82S	82W	83S	83W
Hydro Subtotal	107	109	108	109	108	109	109	110	109
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	0	517	517	517	517	517	517	517	517
Coyote	0	0	0	21	21	21	21	21	21
Milton R Young	408	408	408	408	408	408	408	408	408
Hibbard 3 and 4	75	75	75	75	75	75	75	75	75
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	1303	1822	1821	1843	1842	1843	1843	1844	1843
(1) Seasonal System Demand	1144	1041	1156	1092	1080	955	898	1018	1076
(2) Annual System Demand	1144	1041	1156	1156	1092	955	955	1018	1076
(3) Firm Purchases	200	100	0	0	0	0	0	0	0
(4) Firm Sales	0	0	1	0	0	0	0	0	0
(5) Seasonal Adjusted Net Demand	944	941	1157	1092	1080	955	898	1018	1076
(6) Annual Adjusted Net Demand	944	941	1157	1156	1092	955	955	1018	1076
(7) Net Generating Capability	1303	1822	1821	1843	1842	1843	1843	1844	1843
(8) Total Participation Purchases	90	64	0	0	0	0	0	0	0
(9) Total Participation Sales	50	50	20	10	30	10	40	20	40
(10) Adjusted Net Capability	1343	1836	1801	1833	1812	1833	1803	1824	1803
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	142	141	174	173	164	143	143	153	161
(12) Total Firm Capacity Obligation	1086	1082	1331	1265	1244	1098	1041	1171	1237
(13) Surplus or Deficit Capacity	257	754	471	568	568	735	762	653	566
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	236	235	289	289	273	239	239	255	269
(15) Total Firm Capacity Allowance	1180	1176	1446	1381	1353	1194	1137	1273	1345
(16) Surplus or Deficit Capacity	163	660	355	452	459	640	666	552	458
(17) Actual Reserve Margin	42%	95%	56%	59%	66%	92%	89%	79%	68%

	84S	84W	85S	85W	86S	86W	87S	87W	88S
Hydro Subtotal	110	109	110	109	110	109	110	115	116
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	517	517	517	517	517	517	535	535	535
Coyote	21	21	16	16	11	11	11	11	0
Milton R Young	408	286	286	293	293	293	293	293	293
Hibbard 3 and 4	75	75	75	75	75	75	75	46	50
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712	1707
(1) Seasonal System Demand	1035	1096	1031	1018	968	1057	1004	1104	1049
(2) Annual System Demand	1076	1096	1096	1031	1018	1057	1057	1104	1104
(3) Firm Purchases	0	0	0	0	0	0	80	0	0
(4) Firm Sales	0	0	0	0	35	0	0	30	0
(5) Seasonal Adjusted Net Demand	1035	1096	1031	1018	1003	1057	924	1134	1049
(6) Annual Adjusted Net Demand	1076	1096	1096	1031	1053	1057	977	1134	1104
(7) Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712	1707
(8) Total Participation Purchases	0	0	0	0	0	0	0	0	0
(9) Total Participation Sales	40	50	130	50	115	100	425	0	0
(10) Adjusted Net Capability	1804	1671	1587	1673	1603	1617	1311	1712	1707
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	161	164	164	155	158	159	147	170	166
(12) Total Firm Capacity Obligation	1196	1260	1195	1173	1161	1216	1071	1304	1215
(13) Surplus or Deficit Capacity	608	410	391	500	442	402	241	408	492
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	269	274	274	258	263	264	244	284	276
(15) Total Firm Capacity Allowance	1304	1370	1305	1276	1266	1321	1168	1418	1325
(16) Surplus or Deficit Capacity	500	301	282	397	337	296	143	295	382
(17) Actual Reserve Margin	68%	52%	45%	62%	52%	53%	34%	51%	55%

	88W	89S	89W	90S	90W	91S	91W	92S	92W
Hydro Subtotal	115	116	115	116	115	116	115	116	115
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	535	464	464	392	392	321	321	321	321
Coyote	0	0	0	0	0	0	0	0	0
Milton R Young	293	259	259	225	225	191	191	191	191
Hibbard 3 and 4	46	50	46	50	46	50	46	50	31
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	1702	1601	1596	1496	1491	1391	1386	1391	1371
(1) Seasonal System Demand	1130	1074	1150	1093	1162	1104	1157	1099	1207
(2) Annual System Demand	1130	1130	1150	1150	1162	1162	1157	1157	1207
(3) Firm Purchases	0	0	0	0	0	0	0	0	0
(4) Firm Sales	0	0	50	0	0	0	0	0	0
(5) Seasonal Adjusted Net Demand	1130	1074	1200	1093	1162	1104	1157	1099	1207
(6) Annual Adjusted Net Demand	1130	1130	1200	1150	1162	1162	1157	1157	1207
(7) Net Generating Capability	1702	1601	1596	1496	1491	1391	1386	1391	1371
(8) Total Participation Purchases	0	0	0	0	0	0	0	0	0
(9) Total Participation Sales	0	0	0	0	0	0	0	0	0
(10) Adjusted Net Capability	1702	1601	1596	1496	1491	1391	1386	1391	1371
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	170	170	180	173	174	174	174	174	181
(12) Total Firm Capacity Obligation	1300	1244	1380	1266	1336	1278	1331	1273	1388
(13) Surplus or Deficit Capacity	402	358	216	231	155	112	55	118	-17
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	283	283	300	288	291	291	289	289	302
(15) Total Firm Capacity Allowance	1413	1357	1500	1381	1453	1395	1446	1388	1509
(16) Surplus or Deficit Capacity	289	245	96	116	38	-4	-61	2	-138
(17) Actual Reserve Margin	51%	42%	33%	30%	28%	20%	20%	20%	14%

TABLE 2.3: NON-FUEL O&M FOR HIBBARD

	Non-Fuel O&M --[1]--	Savings From 1981 --[2]--
1980	1,357,794	-
1981	1,042,924	-
1982	608,824	434,100
1983	29,462	1,013,462
1984	30,545	1,012,379

Notes: [1] From FERC Form #1, p. 432 for 1980, p.403 for 1981-1984.
[2] Difference between year value and 1981 value.

TABLE 2.4: LARGE POWER CONTRACT CUSTOMERS: ACTUAL PEAK & CONTRACT MINIMUM: 1975 - 1987

ACTUAL/ESTIMATED PEAK	75S	75W	76S	76W	77S	77W	78S	78W	79S
RESERVE TAC/SILVER BAY									
BUTLER TACONITE	[*]	[*]	[*]	42.6	49.1	48.0	47.7	43.8	37.3
EVELETH TACONITE	[*]	[*]	[*]	[*]	[*]	[*]	[*]	[*]	81.9
MINNTAC TACONITE	[*]	[*]	[*]	[*]	[*]	[*]	178.0	212.6	209.3
NATIONAL TACONITE	[*]	49.7	63.4	91.7	94.1	93.8	104.1	107.9	103.7
HIBBING TACONITE			[*]	[*]	[*]	[*]	95.0	94.7	138.7
INLAND TACONITE			[*]	4.6	36.2	31.6	27.8	38.3	39.3
BLANDIN PAPER	[*]	[*]	[*]	[*]	[*]	[*]	[*]	[*]	[*]
BOISE CASCADE									
TOTAL	0.0	49.7	63.4	138.9	179.4	173.4	452.6	497.3	610.2

CONTRACT MINIMUM	75S	75W	76S	76W	77S	77W	78S	78W	79S
RESERVE TAC/SILVER BAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BUTLER TACONITE	0.0	0.0	0.0	40.2	40.2	40.2	40.2	40.2	40.2
EVELETH TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.3
MINNTAC TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	207.0	207.0	207.0
NATIONAL TACONITE	0.0	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1
HIBBING TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	144.0	144.0	144.0
INLAND TACONITE	0.0	0.0	0.0	37.8	37.8	37.8	37.8	37.8	37.8
BLANDIN PAPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOISE CASCADE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	98.1	98.1	176.1	176.1	176.1	527.1	527.1	601.4

CONTRACT MINIMUM - ACTUAL/ESTIMATED	75S	75W	76S	76W	77S	77W	78S	78W	79S
RESERVE TAC/SILVER BAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BUTLER TACONITE	0.0	0.0	0.0	-2.4	-8.9	-7.8	-7.5	-3.6	2.9
EVELETH TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-7.6
MINNTAC TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	29.0	-5.6	-2.3
NATIONAL TACONITE	0.0	48.4	34.7	6.4	4.0	4.3	-6.0	-9.8	-5.6
HIBBING TACONITE	0.0	0.0	0.0	0.0	0.0	0.0	49.0	49.3	5.3
INLAND TACONITE	0.0	0.0	0.0	33.2	1.6	6.2	10.0	-0.5	-1.5
BLANDIN PAPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOISE CASCADE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	48.4	34.7	37.2	-3.3	2.7	74.5	29.8	-8.8

Note [1]: All data in MW.
[2]: 1975-summer 1986: Actual Peak Data
winter 1986-1987: Est peak data 11/86 Forecast
[3]: Contract minimum calculated as 90% of contract demand in effect as of date of actual peak.
[4]: Butler closed 6/28/85. Remaining contract obligation settled by negotiation. MP may have received payment for some demand charges after 6/85. Contract minimum assumed ended 6/85.
[*]: Actual demand prior to start of contract treated as 0 for this table.
Source: Responses 143 & 148, Harmon testimony Attachment A.

ACTUAL/ESTIMATED PEAK	79W	80S	80W	81S	81W	82S	82W	83S	83W
RESERVE TAC/SILVER BAY			18.9	13.5	6.2	9.4	7.8	6.6	19.5
BUTLER TACONITE	36.0	44.2	45.8	45.0	46.3	37.2	44.3	44.8	4.4
EVELETH TACONITE	64.3	82.9	77.4	81.3	86.3	78.5	47.4	49.6	57.1
MINNTAC TACONITE	217.6	222.8	192.2	189.5	124.8	117.3	97.5	123.2	149.2
NATIONAL TACONITE	104.6	54.2	80.8	65.5	74.0	4.9	62.2	73.3	83.5
HIBBING TACONITE	135.3	144.6	89.0	151.3	141.6	129.6	126.0	134.6	156.2
INLAND TACONITE	31.1	26.8	42.5	33.9	41.6	38.5	32.5	41.2	36.0
BLANDIN PAPER	[*]	[*]	[*]	[*]	33.3	36.8	26.0	26.4	36.0
BOISE CASCADE			22.0	22.7	8.9	21.6	22.4	24.3	23.7
TOTAL	588.9	575.5	568.6	602.7	563.0	473.8	466.1	524.0	565.6

CONTRACT MINIMUM	79W	80S	80W	81S	81W	82S	82W	83S	83W
RESERVE TAC/SILVER BAY	0.0	0.0	18.0	18.0	18.0	18.0	17.1	17.1	17.1
BUTLER TACONITE	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
EVELETH TACONITE	74.3	74.3	74.3	74.3	74.3	74.3	70.5	70.5	70.5
MINNTAC TACONITE	207.0	207.0	207.0	207.0	207.0	207.0	196.7	196.7	196.7
NATIONAL TACONITE	98.1	98.1	98.1	98.1	98.1	98.1	93.2	93.2	93.2
HIBBING TACONITE	144.0	144.0	144.0	144.0	144.0	144.0	136.8	136.8	136.8
INLAND TACONITE	37.8	37.8	37.8	37.8	37.8	37.8	37.4	37.4	37.4
BLANDIN PAPER	0.0	0.0	0.0	0.0	32.4	32.4	30.8	30.8	30.8
BOISE CASCADE	0.0	0.0	21.6	21.6	21.6	21.6	21.6	21.6	21.6
TOTAL	601.4	601.4	641.0	641.0	673.4	673.4	644.2	644.2	644.2

CONTRACT MINIMUM - ACTUAL/ESTIMATED	79W	80S	80W	81S	81W	82S	82W	83S	83W
RESERVE TAC/SILVER BAY	0.0	0.0	-0.9	4.5	11.8	8.6	9.3	10.5	-2.4
BUTLER TACONITE	4.2	-4.0	-5.6	-4.8	-6.1	3.0	-4.1	-4.6	35.8
EVELETH TACONITE	10.0	-8.6	-3.1	-7.0	-12.0	-4.2	23.1	20.9	13.4
MINNTAC TACONITE	-10.6	-15.8	14.8	17.5	82.2	89.7	99.2	73.5	47.5
NATIONAL TACONITE	-6.5	43.9	17.3	32.6	24.1	93.2	31.0	19.9	9.7
HIBBING TACONITE	8.7	-0.6	55.0	-7.3	2.4	14.4	10.8	2.2	-19.4
INLAND TACONITE	6.7	11.0	-4.7	3.9	-3.8	-0.7	4.9	-3.9	1.4
BLANDIN PAPER	0.0	0.0	0.0	0.0	-0.9	-4.4	4.8	4.4	-5.2
BOISE CASCADE	0.0	0.0	-0.4	-1.1	12.7	0.0	-0.8	-2.7	-2.1
TOTAL	12.5	25.9	72.4	38.3	110.4	199.6	178.1	120.2	78.6

TABLE 2.4: LARGE POWER CONTRACT CUSTOMERS: ACTUAL PEAK & CONTRACT MINIMUM: 1975 - 1987

ACTUAL/ESTIMATED PEAK	84S	84W	85S	85W	86S	86W	87S	87W
RESERVE TAC/SILVER BAY	17.5	19.0	17.0	19.0	19.0	2.0	2.0	2.0
BUTLER TACONITE	41.4	46.3	42.0					
EVELETH TACONITE	48.2	66.6	48.0	54.0	47.0	55.0	50.0	50.0
MINNTAC TACONITE	133.2	188.0	160.0	178.0	149.0	158.0	158.0	158.0
NATIONAL TACONITE	73.2	69.4	68.0	82.0	74.0	75.0	75.0	75.0
HIBBING TACONITE	135.4	142.0	151.0	118.0	117.0	109.0	109.0	109.0
INLAND TACONITE	39.6	41.9	41.0	6.0	33.0	38.0	38.0	38.0
BLANDIN PAPER	28.8	37.9	35.0	35.0	34.0	33.0	33.0	33.0
BOISE CASCADE	24.6	24.6	12.0	22.0	24.0	23.0	23.0	23.0
TOTAL	541.9	635.7	574.0	514.0	497.0	493.0	488.0	488.0

CONTRACT MINIMUM								
RESERVE TAC/SILVER BAY	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
BUTLER TACONITE	40.2	40.2	40.2	40.2	0.0	0.0	0.0	0.0
EVELETH TACONITE	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5
MINNTAC TACONITE	196.7	196.7	196.7	159.4	159.4	159.4	159.4	159.4
NATIONAL TACONITE	93.2	93.2	93.2	93.2	93.2	93.2	93.2	78.3
HIBBING TACONITE	136.8	136.8	136.8	110.9	110.9	110.9	110.9	110.9
INLAND TACONITE	37.4	37.4	37.4	30.5	30.5	30.5	30.5	30.5
BLANDIN PAPER	30.8	30.8	30.8	29.3	29.3	29.3	29.3	29.3
BOISE CASCADE	21.6	21.6	21.6	21.6	21.6	21.6	21.6	21.6
TOTAL	644.2	644.2	644.2	572.8	532.6	532.6	532.6	517.7

CONTRACT MINIMUM - ACTUAL/ESTIMATED								
RESERVE TAC/SILVER BAY	-0.4	-1.9	0.1	-1.9	-1.9	15.1	15.1	15.1
BUTLER TACONITE	-1.2	-6.1	-1.8	0.0	0.0	0.0	0.0	0.0
EVELETH TACONITE	22.3	3.9	22.5	16.5	23.5	15.5	20.5	20.5
MINNTAC TACONITE	63.5	8.7	36.7	-18.6	10.4	1.4	1.4	1.4
NATIONAL TACONITE	20.0	23.8	25.2	11.2	19.2	18.2	18.2	3.3
HIBBING TACONITE	1.4	-5.2	-14.2	-7.1	-6.1	1.9	1.9	1.9
INLAND TACONITE	-2.3	-4.5	-3.6	24.5	-2.5	-7.5	-7.5	-7.5
BLANDIN PAPER	2.0	-7.1	-4.2	-5.7	-4.7	-3.7	-3.7	-3.7
BOISE CASCADE	-3.0	-3.0	9.6	-0.4	-2.4	-1.4	-1.4	-1.4
TOTAL	102.3	8.5	70.2	18.6	35.6	39.6	44.6	29.7

	75S	75W	76S	76W	77S	77W	78S	78W	79S
Hydro Subtotal	94	93	106	105	106	105	106	105	108
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	0	0	0	0	0	0	0	0	0
Coyote	0	0	0	0	0	0	0	0	0
Milton R Young	0	0	0	0	340	408	408	408	408
Hibbard 3 and 4	75	75	75	75	75	75	75	75	75
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	882	881	894	893	1234	1301	1302	1301	1304
(1) Seasonal System Demand	688	748	794	903	955	1011	1014	1117	1116
(2) Annual System Demand	691	748	794	903	955	1011	1014	1117	1117
(3) Firm Purchases	0	0	85	275	100	125	100	100	0
(4) Firm Sales	0	0	0	0	0	0	20	0	0
(5) Seasonal Adjusted Net Demand	688	748	709	628	855	886	934	1017	1116
(6) Annual Adjusted Net Demand	691	748	709	628	855	886	934	1017	1117
(6A) Large Power Contract Cust Actual Peak	0	50	63	139	179	173	453	497	610
(6B) Large Power Contract Minimum Demand	0	98	98	176	176	176	527	527	601
(6C) Seasonal Adjusted Net Demand w/ Large Power Contract Cust Class at > of Actual Peak or Contract Minimum	688	796	744	665	855	889	1009	1047	1116
(7) Net Generating Capability	882	881	894	893	1234	1301	1302	1301	1304
(8) Total Participation Purchases	68	76	94	74	0	0	40	70	200
(9) Total Participation Sales	65	50	50	50	50	50	50	50	50
(10) Adjusted Net Capability	885	907	938	917	1184	1251	1292	1321	1454
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	104	119	112	100	128	133	151	157	168
(12) Total Firm Capacity Obligation	792	916	855	765	983	1022	1160	1204	1284
(13) Surplus or Deficit Capacity	93	-9	83	152	201	229	132	117	170
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	173	199	186	166	214	222	252	262	279
(15) Total Firm Capacity Allowance	861	996	930	832	1069	1111	1261	1309	1395
(16) Surplus or Deficit Capacity	24	-89	8	85	115	140	31	12	59
(17) Actual Reserve Margin	28%	14%	26%	38%	38%	41%	28%	26%	30%

	79W	80S	80W	81S	81W	82S	82W	83S	83W
Hydro Subtotal	107	109	108	109	108	109	109	110	109
Erie Interchange	40	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350	350
Boswell 4	0	517	517	517	517	517	517	517	517
Coyote	0	0	0	21	21	21	21	21	21
Milton R Young	408	408	408	408	408	408	408	408	408
Hibbard 3 and 4	75	75	75	75	75	75	75	75	75
Hibbard 1 and 2	50	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25	25
Net Generating Capability	1303	1822	1821	1843	1842	1843	1843	1844	1843
(1) Seasonal System Demand	1144	1041	1156	1092	1080	955	898	1018	1076
(2) Annual System Demand	1144	1041	1156	1156	1092	955	955	1018	1076
(3) Firm Purchases	200	100	0	0	0	0	0	0	0
(4) Firm Sales	0	0	1	0	0	0	0	0	0
(5) Seasonal Adjusted Net Demand	944	941	1157	1092	1080	955	898	1018	1076
(6) Annual Adjusted Net Demand	944	941	1157	1156	1092	955	955	1018	1076
(6A) Large Power Contract Cust Actual Peak	589	576	569	603	563	474	466	524	566
(6B) Large Power Contract Minimum Demand	601	601	641	641	673	673	644	644	644
(6C) Seasonal Adjusted Net Demand w/ Large Power Contract Cust Class at > of Actual Peak or Contract Minimum	957	967	1229	1130	1190	1155	1076	1138	1155
(7) Net Generating Capability	1303	1822	1821	1843	1842	1843	1843	1844	1843
(8) Total Participation Purchases	90	64	0	0	0	0	0	0	0
(9) Total Participation Sales	50	50	20	10	30	10	40	20	40
(10) Adjusted Net Capability	1343	1836	1801	1833	1812	1833	1803	1824	1803
At 15% MAPP minimum Reserves...									
(11) Net Reserve Capacity Obligation	143	145	184	173	179	173	161	171	173
(12) Total Firm Capacity Obligation	1100	1112	1414	1304	1369	1328	1238	1309	1328
(13) Surplus or Deficit Capacity	243	724	387	530	443	505	566	515	475
Allowing 25% Reserves...									
(14) Net Reserve Capacity Allowance	239	242	307	289	298	289	269	285	289
(15) Total Firm Capacity Allowance	1196	1209	1537	1419	1488	1443	1345	1423	1443
(16) Surplus or Deficit Capacity	147	628	264	414	324	390	458	401	360
(17) Actual Reserve Margin	40%	90%	47%	59%	52%	59%	68%	60%	56%

	84S	84W	85S	85W	86S	86W	87S	87W
Hydro Subtotal	110	109	110	109	110	109	110	115
Erie Interchange	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350
Boswell 4	517	517	517	517	517	517	535	535
Coyote	21	21	16	16	11	11	11	11
Milton R Young	408	286	286	293	293	293	293	293
Hibbard 3 and 4	75	75	75	75	75	75	75	46
Hibbard 1 and 2	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25
Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712
(1) Seasonal System Demand	1035	1096	1031	1018	968	1057	1004	1104
(2) Annual System Demand	1076	1096	1096	1031	1018	1057	1057	1104
(3) Firm Purchases	0	0	0	0	0	0	80	0
(4) Firm Sales	0	0	0	0	35	0	0	30
(5) Seasonal Adjusted Net Demand	1035	1096	1031	1018	1003	1057	924	1134
(6) Annual Adjusted Net Demand	1076	1096	1096	1031	1053	1057	977	1134
(6A) Large Power Contract Cust Actual Peak	542	636	574	514	497	493	488	488
(6B) Large Power Contract Minimum Demand	644	644	644	573	533	533	533	518
(6C) Seasonal Adjusted Net Demand w/ Large Power Contract Cust Class at > of Actual Peak or Contract Minimum	1137	1105	1101	1077	1039	1097	969	1164
(7) Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712
(8) Total Participation Purchases	0	0	0	0	0	0	0	0
(9) Total Participation Sales	40	50	130	50	115	100	425	0
(10) Adjusted Net Capability	1804	1671	1587	1673	1603	1617	1311	1712
At 15% MAPP minimum Reserves...								
(11) Net Reserve Capacity Obligation	171	166	165	162	158	164	147	175
(12) Total Firm Capacity Obligation	1308	1270	1266	1238	1197	1261	1115	1338
(13) Surplus or Deficit Capacity	496	400	320	434	407	356	196	374
Allowing 25% Reserves...								
(14) Net Reserve Capacity Allowance	284	276	275	269	263	274	244	291
(15) Total Firm Capacity Allowance	1422	1381	1377	1346	1302	1371	1213	1455
(16) Surplus or Deficit Capacity	383	290	210	327	302	247	99	258
(17) Actual Reserve Margin	59%	51%	44%	55%	52%	47%	34%	47%

Notes: [1] Data for 1975 through Summer 1986 from Response to Question 141, Attachment 1. Data for Winter 1986 from Testimony of G. B. Ostroski, Docket #E002-E015/PA-86-722. Data for 1987 and after from Testimony of G. B. Ostroski, Docket # E-015/GR-87-223.

[2] Formula in Lines 11 and 14 was changed to the reserve margin multiplied by greater of Lines 6 and 6C.

[3] The following changes were made to MP reported capabilities: Laskin was changed to 110 MW from Winter 1983 through Winter 1986; Hibbard 3&4 was changed to 75 MW from Winter 1982 through Summer 1987, and 50 MW in Summer and 46 MW in Winter thereafter; Hibbard 1&2 was changed to 50 MW from Winter 1982 through Summer 1991; Winslow was changed to 25 MW from Winter 1983 to Winter 1986; Erie was added as 40 MW Generating Capacity from Summer 1975 through Winter 1986 & deleted as 40 MW Participation Purchase Summer 1975 through Winter 1982; and Young sale beginning Summer 1989 was noted as reduction in Generating Capacity instead of Participation Sale.

[4] Reserve margin (Line 17) calculated on greater of lines 6 & 6C.

	80S	80W	81S	81W	82S	82W	83S	83W
Hydro Subtotal	109	108	109	108	109	109	110	109
Erie Interchange	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350
Boswell 4	517	517	517	517	517	517	517	517
Coyote	0	0	21	21	21	21	21	21
Milton R Young	408	408	408	408	408	408	408	408
Hibbard 3 and 4	75	75	75	75	75	75	75	75
Hibbard 1 and 2	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25
Net Generating Capability	1822	1821	1843	1842	1843	1843	1844	1843
(1) Seasonal System Demand	1041	1156	1092	1080	955	898	1018	1076
(2) Annual System Demand	1041	1156	1156	1092	955	955	1018	1076
(3) Firm Purchases	100	0	0	0	0	0	0	0
(4) Firm Sales	0	0	0	0	0	0	0	0
(5) Seasonal Adjusted Net Demand	941	1156	1092	1080	955	898	1018	1076
(6) Annual Adjusted Net Demand	941	1156	1156	1092	955	955	1018	1076
(6A) Large Power Contract Cust Actual Peak	576	569	603	563	474	466	524	566
(6B) Large Power Contract Minimum Demand	601	641	641	673	673	644	644	644
(6C) Seasonal Adjusted Net Demand w/ Large Power Contract Cust Class at > of Actual Peak or Contract Minimum	967	1228	1130	1190	1155	1076	1138	1155
(7) Net Generating Capability	1822	1821	1843	1842	1843	1843	1844	1843
(8) Total Participation Purchases	64	0	0	0	0	0	0	0
(9) Total Participation Sales	0	0	0	0	0	0	0	0
(10) Adjusted Net Capability	1886	1821	1843	1842	1843	1843	1844	1843
At 15% MAPP minimum Reserves...								
(11) Net Reserve Capacity Obligation	145	184	173	179	173	161	171	173
(12) Total Firm Capacity Obligation	1112	1413	1304	1369	1328	1238	1309	1328
(13) Surplus or Deficit Capacity	774	408	540	473	515	606	535	515
Allowing 25% Reserves...								
(14) Net Reserve Capacity Allowance	242	307	289	298	289	269	285	289
(15) Total Firm Capacity Allowance	1209	1536	1419	1488	1443	1345	1423	1443
(16) Surplus or Deficit Capacity	678	286	424	354	400	498	421	400
(17) Actual Reserve Margin	95%	48%	59%	55%	60%	71%	62%	60%

Note: [1] All data inputs & formulas from Table 2.5 except lines 3, 4, 8, & 9 set to 0.
[2] 80 MW Firm Purchase (line 3) in summer 1987 set to 0, since it relates to diversity exchanges to repaid in firm sales (line 4): 30 MW winter 1987 & 50 MW winter 1989.

	84S	84W	85S	85W	86S	86W	87S	87W
Hydro Subtotal	110	109	110	109	110	109	110	115
Erie Interchange	40	40	40	40	40	40	40	40
Laskin 1 and 2	110	110	110	110	110	110	110	110
Boswell 1 and 2	138	138	138	138	138	138	138	138
Boswell 3	350	350	350	350	350	350	350	350
Boswell 4	517	517	517	517	517	517	535	535
Coyote	21	21	16	16	11	11	11	11
Milton R Young	408	286	286	293	293	293	293	293
Hibbard 3 and 4	75	75	75	75	75	75	75	46
Hibbard 1 and 2	50	50	50	50	50	50	50	50
Winslow	25	25	25	25	25	25	25	25
Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712
(1) Seasonal System Demand	1035	1096	1031	1018	968	1057	1004	1104
(2) Annual System Demand	1076	1096	1096	1031	1018	1057	1057	1104
(3) Firm Purchases	0	0	0	0	0	0	0	0
(4) Firm Sales	0	0	0	0	0	0	0	0
(5) Seasonal Adjusted Net Demand	1035	1096	1031	1018	968	1057	1004	1104
(6) Annual Adjusted Net Demand	1076	1096	1096	1031	1018	1057	1057	1104
(6A) Large Power Contract Cust Actual Peak	542	636	574	514	497	493	488	488
(6B) Large Power Contract Minimum Demand	644	644	644	573	533	533	533	518
(6C) Seasonal Adjusted Net Demand w/ Large Power Contract Cust Class at > of Actual Peak or Contract Minimum	1137	1105	1101	1077	1004	1097	1049	1134
(7) Net Generating Capability	1844	1721	1717	1723	1718	1717	1736	1712
(8) Total Participation Purchases	0	0	0	0	0	0	0	0
(9) Total Participation Sales	0	0	0	0	0	0	0	0
(10) Adjusted Net Capability	1844	1721	1717	1723	1718	1717	1736	1712
At 15% MAPP minimum Reserves...								
(11) Net Reserve Capacity Obligation	171	166	165	162	153	164	159	170
(12) Total Firm Capacity Obligation	1308	1270	1266	1239	1156	1261	1207	1304
(13) Surplus or Deficit Capacity	536	450	450	484	562	456	529	409
Allowing 25% Reserves...								
(14) Net Reserve Capacity Allowance	284	276	275	269	255	274	264	283
(15) Total Firm Capacity Allowance	1422	1381	1377	1346	1258	1371	1313	1417
(16) Surplus or Deficit Capacity	423	340	340	377	460	347	424	295
(17) Actual Reserve Margin	62%	56%	56%	60%	69%	57%	64%	51%

TABLE 3.1: CONCENTRATION OF SALES TO TACONITE INDUSTRY (MN POWER, 1974-86)

Year	Sales (GWH) Total	Sales (GWH) Retail	Industrial Sales (GWH) Total	Industrial Sales (GWH) Non-Industrial Industrial Sales	Industrial Sales (GWH) Industrial Excluding Non-Industrial Sales	Industrial Sales (GWH) Taconite	Sales Concentration (%) Industrial as % of Total	Sales Concentration (%) Industrial as % of Retail	Sales Concentration (%) Taconites as % of Total	Sales Concentration (%) Taconites as % of Retail
(1)	(2)	(3)	(4)	(5)	(6)=(4)-(5)	(7)	(4)/(2)	(4)/(3)	(7)/(2)	(7)/(3)
1974	5,012	4,304	3,181		3,181	1,992	63%	74%	40%	46%
1975	5,010	4,234	3,066		3,066	1,990	61%	72%	40%	47%
1976	5,637	4,807	3,553		3,553	2,373	63%	74%	42%	49%
1977	6,304	4,755	3,470		3,470	2,276	55%	73%	36%	48%
1978	7,985	6,630	5,281		5,281	4,031	66%	80%	50%	61%
1979	8,354	7,495	6,100		6,100	4,730	73%	81%	57%	63%
1980	8,564	6,814	5,414		5,414	4,143	63%	79%	48%	61%
1981	8,594	7,125	5,656		5,656	4,316	66%	79%	50%	61%
1982	7,033	5,386	3,895		3,895	2,702	55%	72%	38%	50%
1983	7,496	6,075	4,583		4,583	3,305	61%	75%	44%	54%
1984	8,950	7,270	5,739		5,739	4,337	64%	79%	48%	60%
1985	7,947	6,810	5,246	209	5,037	3,987	66%	77%	50%	59%
1986	7,437	6,224	4,619	202	4,417	3,292	62%	74%	44%	53%

Source: Uniform Statistical Reports.

TABLE 3.2: CONCENTRATION OF SALES TO INDUSTRY (1976)

Utility	---Sales (GWH)--- Total	Retail	----Industrial Sales (GWH)---- DOE Total	EEI Total	Non-Industrial Sales in (5)	Industrial excluding Non-Industrial (7)=(5)-(6)	Sales to Largest 2 Digit SIC	Largest 2 Digit SIC
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	
WHEELING ELEC CO	1,818	1,818	1,247	1,247		1,247	951	28
OHIO POWER CO	34,956	23,299	15,637	15,637	154	15,483	9,815	33
NORTHERN INDIANA PS CO	12,572	11,856	9,051	9,051	1,349	7,702	4,825	33
GULF STATES UTIL CO	22,602	21,058	11,901	11,901	941	10,960	7,793	28
POTOMAC EDISON	8,815	7,659	4,170	4,186	238	3,948	2,334	33
LOUISIANA P&L	21,551	14,927	8,068	8,067		8,067	4,069	28
DUKE POWER CO	45,633	38,083	18,417	18,417		18,417	10,242	22
WISCONSIN & MICHIGAN POWER	2,995	2,303	1,115	1,115	66	1,049	608	26
HOUSTON L&P	40,859	38,357	22,244	22,244		22,244	9,804	28
AMERICAN ELEC POWER (HC)	87,018	56,081	30,536	30,536	271	30,265	12,171	33
ARKANSAS P&L	14,390	11,143	5,305	5,304	173	5,131	2,362	33
BANGOR HYDRO-ELECTRIC CO	1,097	1,050	449	446	6	440	216	28
MONTANA POWER CO	6,756	4,661	2,247	2,247		2,247	959	10
CLEVELAND ELEC ILLUM CO	18,070	16,741	8,476	8,476	469	8,007	3,380	33
WEST PENN POWER	13,034	11,652	6,187	6,187	373	5,814	2,337	34
CENT ILL LIGHT	4,226	4,176	2,006	2,006	221	1,785	769	33
DETROIT EDISON	35,328	33,902	17,253	17,253	3,926	13,327	6,211	37
KENTUCKY POWER	4,159	3,169	1,582	1,582	0	1,582	512	33
GULF POWER CO	5,142	4,623	1,435	1,435	551	884	693	28
APPALACHIAN PC	26,037	16,878	7,861	7,861	43	7,818	2,268	11
IOWA-ILLINOIS G&E CO	3,439	3,299	1,292	1,313	99	1,214	433	35
MID-SOUTH (HC)	50,365	36,603	16,124	16,123	692	1,152	4,728	28
GEORGIA POWER CO	41,330	32,068	12,629	12,629	2,522	10,107	3,317	22
KANSAS G&E	6,166	5,341	2,352	2,352	195	2,157	543	28
INDIANAPOLIS P&L CO	7,906	7,829	3,767	3,767	1,639	2,128	769	37
MISSISSIPPI POWER	6,287	4,863	1,936	2,397	510	1,887	476	26
INDIANA & MICHIGAN	20,048	10,917	4,209	4,209	74	4,135	1,038	37
ALABAMA POWER CO	27,597	24,919	11,873	11,873	1,633	10,240	2,330	33
SOUTHERN INDIANA G&E CO	3,457	3,164	1,862	977		977	283	28
NEW ORLEANS PS	4,445	4,244	816	816		816	366	28
BALTIMORE G&E CO	14,758	14,758	6,818	6,818	3,858	2,960	1,140	33
SOUTHERN COMPANY (HC)	80,356	66,472	27,873	28,334	5,216	23,118	4,947	22
UNION ELEC CO	21,423	17,378	9,597	10,577	3,684	6,893	1,185	28
ILLINOIS POWER CO	12,076	11,337	6,416	6,413	2,918	3,495	659	33
NORTHERN STATES POW CO	19,612	16,122	7,566	8,542	4,141	4,401	853	20
MISSISSIPPI P&L	9,979	6,290	1,936	1,936	519	1,417	269	28
COLUMBUS & SOUTH OHIO	8,133	7,660	3,896	1,965		1,965	251	20
LONG ISLAND LIGHT	12,251	11,977	5,229	5,229	4,077	1,152	310	37
MONONGAHELA	7,627	6,671	3,988	NA	NA	NA	NA	NA
PENNSYLVANIA POWER CO	3,035	2,934	1,705	NA	NA	NA	NA	NA
SOUTH WESTERN PS CO	10,117	7,964	4,470	NA	NA	NA	NA	NA
ALLEGHENY POWER SYS (HC)	29,476	25,981	14,344	NA	NA	NA	NA	NA
HAWAIIAN ELEC CO	4,762	4,762	2,403	NA	NA	NA	NA	NA
TUCSON GAS & ELEC	4,297	3,798	1,829	NA	NA	NA	NA	NA
OHIO EDISON	18,167	16,868	7,557	NA	NA	NA	NA	NA
INTERSTATE POWER CO	3,113	2,948	1,269	NA	NA	NA	NA	NA
PUBLIC SERVICE INDIANA	15,532	12,523	5,279	NA	NA	NA	NA	NA

Sources: [2] - [4]: Statistics of Privately Owned Electric Utilities, 1976, DOE/EIA-0044.
[5] - [8]: Uniform Statistical Reports to EEI.
[9]: A sample Uniform Statistical Report from Minnesota Power is attached.

Utility	Industrial/ Total	Industrial/ Retail	Largest SIC/ Total	Largest SIC/ Retail	Holding Company
	Sales Concentration (%)				
(1)	(7)/(2)	(7)/(3)	(8)/(2)	(8)/(3)	
WHEELING ELEC CO	68.6%	68.6%	52.3%	52.3%	AEP
OHIO POWER CO	44.3%	66.5%	28.1%	42.1%	AEP
NORTHERN INDIANA PS CO	61.3%	65.0%	38.4%	40.7%	
GULF STATES UTIL CO	48.5%	52.0%	34.5%	37.0%	
POTOMAC EDISON	44.8%	51.5%	26.5%	30.5%	APS
LOUISIANA P&L	37.4%	54.0%	18.9%	27.3%	MID-SOUTH UTILITIES
DUKE POWER CO	40.4%	48.4%	22.4%	26.9%	
WISCONSIN & MICHIGAN POWER	35.0%	45.5%	20.3%	26.4%	
HOUSTON L&P	54.4%	58.0%	24.0%	25.6%	
AMERICAN ELEC POWER (HC)	34.8%	54.0%	14.0%	21.7%	
ARKANSAS P&L	35.7%	46.0%	16.4%	21.2%	MID-SOUTH UTILITIES
BANGOR HYDRO-ELECTRIC CO	40.1%	41.9%	19.7%	20.6%	
MONTANA POWER CO	33.3%	48.2%	14.2%	20.6%	
CLEVELAND ELEC ILLUM CO	44.3%	47.8%	18.7%	20.2%	
WEST PENN POWER	44.6%	49.9%	17.9%	20.1%	APS
CENT ILL LIGHT	42.2%	42.7%	18.2%	18.4%	
DETROIT EDISON	37.7%	39.3%	17.6%	18.3%	
KENTUCKY POWER	38.0%	49.9%	12.3%	16.2%	AEP
GULF POWER CO	17.2%	19.1%	13.5%	15.0%	SOUTHERN CO
APPALACHIAN PC	30.0%	46.3%	8.7%	13.4%	AEP
IOWA-ILLINOIS G&E CO	35.3%	36.8%	12.6%	13.1%	
MID-SOUTH (HC)	2.3%	3.1%	9.4%	12.9%	
GEORGIA POWER CO	24.5%	31.5%	8.0%	10.3%	SOUTHERN CO
KANSAS G&E	35.0%	40.4%	8.8%	10.2%	
INDIANAPOLIS P&L CO	26.9%	27.2%	9.7%	9.8%	
MISSISSIPPI POWER	30.0%	38.8%	7.6%	9.8%	SOUTHERN CO
INDIANA & MICHIGAN	20.6%	37.9%	5.2%	9.5%	AEP
ALABAMA POWER CO	37.1%	41.1%	8.4%	9.4%	SOUTHERN CO
SOUTHERN INDIANA G&E CO	28.3%	30.9%	8.2%	8.9%	
NEW ORLEANS PS	18.4%	19.2%	8.2%	8.6%	MID-SOUTH UTILITIES
BALTIMORE G&E CO	20.1%	20.1%	7.7%	7.7%	
SOUTHERN COMPANY (HC)	28.8%	34.8%	6.2%	7.4%	
UNION ELEC CO	32.2%	39.7%	5.5%	6.8%	
ILLINOIS POWER CO	28.9%	30.8%	5.5%	5.8%	
NORTHERN STATES POW CO	22.4%	27.3%	4.3%	5.3%	
MISSISSIPPI P&L	14.2%	22.5%	2.7%	4.3%	MID-SOUTH UTILITIES
COLUMBUS & SOUTH OHIO	24.2%	25.7%	3.1%	3.3%	
LONG ISLAND LIGHT	9.4%	9.6%	2.5%	2.6%	
MONONGAHELA	NA	NA	NA	NA	APS
PENNSYLVANIA POWER CO	NA	NA	NA	NA	OHIO EDISON
SOUTH WESTERN PS CO	NA	NA	NA	NA	
ALLEGHENY POWER SYS (HC)	NA	NA	NA	NA	
HAWAIIAN ELEC CO	NA	NA	NA	NA	
TUCSON GAS & ELEC	NA	NA	NA	NA	
OHIO EDISON	NA	NA	NA	NA	OHIO EDISON
INTERSTATE POWER CO	NA	NA	NA	NA	
PUBLIC SERVICE INDIANA	NA	NA	NA	NA	

TABLE 3.2: ATTACHMENT

Company Minnesota Power State of ______ Total System ☒

SCHEDULE XV—CLASSIFICATION OF INDUSTRIAL (OR LARGE LIGHT AND POWER) ENERGY SALES AND REVENUES

Companies operating in more than one state should complete this schedule for each state in which they operate.

State Co-Code

If practical, please give a breakdown of your Industrial (or Large Light & Power) Sales and Revenues by type of industry, preferably by the Major Mining and Manufacturing Groups of the Standard Industrial Classification(a). If not coded strictly by Standard Industrial Classification, please give comparable information by any similar grouping you may have adopted. If you cannot furnish the information on a comprehensive basis, data for your largest industries would be useful (ten if possible).

Where a customer or establishment has operations pertaining to more than one industry, the principal type would determine the classification.

TYPE OF INDUSTRY	S.I.C. NO.(a)		MEGAWATTHOUR SALES	REVENUES (thousands of $)
MINING				
Metal Mining	10	15,1	3,987,520	$ 189,378
Coal Mining	11 & 12	15,2,		
Oil & Gas Extraction	13	15,3,		
Mining & Quarrying of Nonmetallic Min.(except fuels)	14	15,4,		
		15,5,		
Total Mining		15,6,	3,987,520	189,378
MANUFACTURING				
Food and Kindred Products	20	15,7,		
Tobacco Manufacturers	21	15,8,		
Textile Mill Products	22	15,9,		
Apparel & Other Finished Products made from fabrics & similar materials	23	15,10,		
Lumber & Wood Products except furniture	24	15,11,		
Furniture and Fixtures	25	15,12,		
Paper & Allied Products	26	15,13,	637,615	30,026
Printing, Publishing & Allied Industries	27	15,14,		
Chemicals & Allied Products	28	15,15,		
Petroleum Refining and Related Industries	29	15,16,	339,903	14,658
Rubber and Miscellaneous Plastic Products	30	15,17,		
Leather & Leather Products	31	15,18,		
Stone, Clay, Glass and Concrete Products	32	15,19,	12,074	569
Primary Metal Industries	33	15,20,		
Fabricated Metal Products except machinery & transportation equipment	34	15,21,	59,980	3,506
Machinery, except Electrical	35	15,22,		
Electrical and Electronic Machinery, Equipment & Supplies	36	15,23,		
Transportation Equipment	37	15,24,		
Measuring, Analyzing & Controlling Instruments; Photographic, Medical & Optical Goods; Watches & Clocks	38	15,25,		
Miscellaneous Manufacturing Industries	39	15,26,		
		15,27,		
Total Manufacturing		15,28,	1,049,572	48,759
Total Mining and Manufacturing		15,29,	5,037,092	238,137
"Industrial Customers" with demands below____kW		15,30,		
Other "Industrial Customers" not classified		15,31,		
Non-manufacturing "Industrial Customers"		15,32,	209,174	12,137
Adjust. for Differences in SIC Coding(−)(+)		15,33,		
Total Industrial or Large Light & Power(b)		15,34,	5,246,266	$ 250,274

(a) The Standard Industrial Classification is published in manual form by the U.S. Government Printing Office and is available through the Superintendent of Documents. It is used primarily as an aid in securing uniformity and comparability in the presentation of statistical data collected by various agencies of the U.S. Government, State Agencies, Trade Associations, and Private Research Agencies.

(b) Amounts should agree with line 3 (columns 1 and 2) of Schedule XIV—Page E-14.

TABLE 3.3: INDICATORS OF INDUSTRIAL HEALTH

U.S. Steel & Minnesota Taconite (Millions of Tons)

	Total U.S. Steel Consumed ---[1]---	U.S. Shipments of Steel ---[2]---	MN Installed Taconite Capacity: MP Resp. # 144 ---[3]---	MN Installed Taconite Capacity: World Steel Dynamics ---[4]---	MN Taconite Production ---[5]---
1974	119.7	109.5	41.5		41.1
1975	89.0	80.0	41.5		40.3
1976	101.0	89.4	45.1	46.6	39.5
1977	108.4	91.1	56.3	56.3	24.7
1978	116.6	97.9	65.0	62.8	50.2
1979	115.0	100.3	65.0	65.5	55.8
1980	95.3	83.9	62.6	65.5	42.9
1981	105.5	88.5	62.6	63.1	49.0
1982	76.3	61.6	62.6	63.1	22.9
1983	83.5	67.6	62.6	55.3	25.2
1984	98.9	73.7	61.3	52.3	35.9
1985	94.4	73.0	60.7	46.3	33.4
1986	87.7	69.9	58.0	43.1	25.7
1987E	83.3	66.0	55.0/41.0	38.6	

Notes: [1] 1974-1984: From Browne, 1985b, Table A1,
1985-1987: From Kirsis & Kakela, 1987, Ex 4 (Consumption + Inventory addition by users).
[2] 1974-1984: From Browne, 1985b, Table A1,
1985-1987: From Kirsis & Kakela, 1987, Ex 4.
[3] 1974-1987: From Attachment 144.7 of Response 144.
1987: Testimony of Arend Sandbulte, Docket E002-E015/PA-86-722 p 8; 55.0 is capacity "on paper," 41.0 excludes 8.4 million tons at bankrupt Reserve & 6 million tons Minntac oldest unit.
[4] 1976-1986: From Marcus & Kirsis, Ex Z-1-35
1987: From Kirsis & Kakela, 1987, Ex 6.
[5] From Attachment 144.6 of Response 144.

TABLE 3.4: NON-COMMITTED LOAD IN MP FORECASTS

Forecast Produced in Year:	1974	1975	1976	1977	1978	1979	1980	1981
Forecast for:								
79S		15.3	15.3					
79W		39.3	39.3					
80S	37.0	151.3	89.3					
80W	37.0	151.3	126.3					
81S	37.0	151.3	189.3	75.3				
81W	37.0	151.3	189.3	75.3				
82S	37.0	151.3	254.3	119.3				
82W	37.0	151.3	254.3	119.3				
83S	37.0	151.3	254.3	180.3				
83W	37.0	151.3	254.3	216.3				
84S	37.0	151.3	254.3	281.3			4.7	4.0
84W	37.0	151.3	254.3	281.3	86.0		4.7	4.0
85S	53.2	167.5	272.3	362.8	161.0	5.0	4.7	4.0
85W	55.6	169.9	272.3	362.8	196.0	10.0	4.7	4.0
86S	74.1	188.4	291.3	418.8	196.0	10.0	4.7	4.0
86W	74.1	188.4	291.3	418.8	276.0	66.0	51.5	4.0
87S	74.1	188.4	291.3	464.8	276.0	175.0	51.5	4.0
87W	74.1	188.4	291.3	464.8	339.0	191.0	51.5	4.0
88S	74.1	188.4	291.3	464.8	339.0	191.0	51.5	46.0
88W	74.1	188.4	291.3	464.8	339.0	191.0	51.5	46.0
89S	74.1	188.4	291.3	464.8	339.0	191.0	51.5	46.0
89W	74.1	188.4	291.3	464.8	339.0	191.0	113.0	46.0
90S	74.1	188.4	291.3	464.8	339.0	275.0	113.0	46.0
90W	74.1	188.4	291.3	464.8	339.0	275.0	192.5	46.0
91S	74.1	188.4	291.3	464.8	339.0	275.0	192.5	97.2
91W	74.1	188.4	291.3	464.8	339.0	314.0	192.5	97.2
92S	74.1	188.4	291.3	464.8	339.0	314.0	192.5	97.2
92W	74.1	188.4	291.3	464.8	451.0	314.0	192.5	97.2
93S	74.1	188.4	291.3	464.8	451.0	314.0	192.5	97.2
93W	74.1	188.4	291.3	464.8	451.0	371.0	192.5	97.2
94S	74.1	188.4	291.3	464.8	451.0	371.0	192.5	97.2
94W	74.1	188.4	291.3	464.8	451.0	371.0	192.5	97.2
95S	83.4	197.7	291.3	534.8	451.0	371.0	192.5	97.2
95W	83.4	197.7	291.3	534.8	451.0	371.0	192.5	97.2

Notes: [1] Calculated from Discovery Response #143.
[2] Yearly forecasts were dated as follows: 4/29/74, 1/3/75, 1/19/76, 4/19/77, 3/29/78, 5/3/79, 7/80, 7/81.

TABLE 3.5: COMPARISON OF TACONITE SALES TO VARIOUS UTILITY SYSTEM ENERGY REQUIREMENTS

	GWH	MP Sales To Taconites As Percentage Of:
MP Sales to Taconite [1]	3,292	
1986 Energy Requirements [2]:		
MP	7,012	46.9%
NSP	29,687	11.1%
MP & NSP	36,699	9.0%
Minn-Wisc	51,506	6.4%
MAPP	108,923	3.0%

Notes: [1] MP Uniform Statistical Report, 1986.
[2] MAPP 1986 Generating Transmission Report.

TABLE 3.6: TACONITE INVESTMENT PER KILOWATT OF CONTRACT LOAD

Company:	Hibbing	Minntac	National	Eveleth	Inland	Total	Average
1. Late 70's Incremental Investment ($ Million)	100	200	200	150	150	800	
2. Contract KW	160,000	230,000	109,000	82,500	42,000	623,500	
3. Capacity:							
a. Pre-Expansion	5.4	12	2.4	2.4	0	22.2	
b. Expansion	2.7	6.5	3.4	3.7	2.6	18.9	
c. Total	8.1	18.5	5.8	6.1	2.6	41.1	
4. Share of Contract KW to Expansion	53,333	80,811	63,897	50,041	42,000	290,082	
5. $ Invested per KW of Contract	$1,875	$2,475	$3,130	$2,998	$3,571		$2,810

Notes: [1] From Response to MPS Question 151.
[2] From Response to MPS Question 148.
[3a,c] From World Steel Dynamics, Core Report Z, 4/87, page 1-70.
[3b] Line 3c - Line 3a.
[4] Line 2 * Line 3b/Line 3c.
[5] Line 1 / Line 4 * 1000000.

FIGURE 3.1: MP FORECAST HISTORY

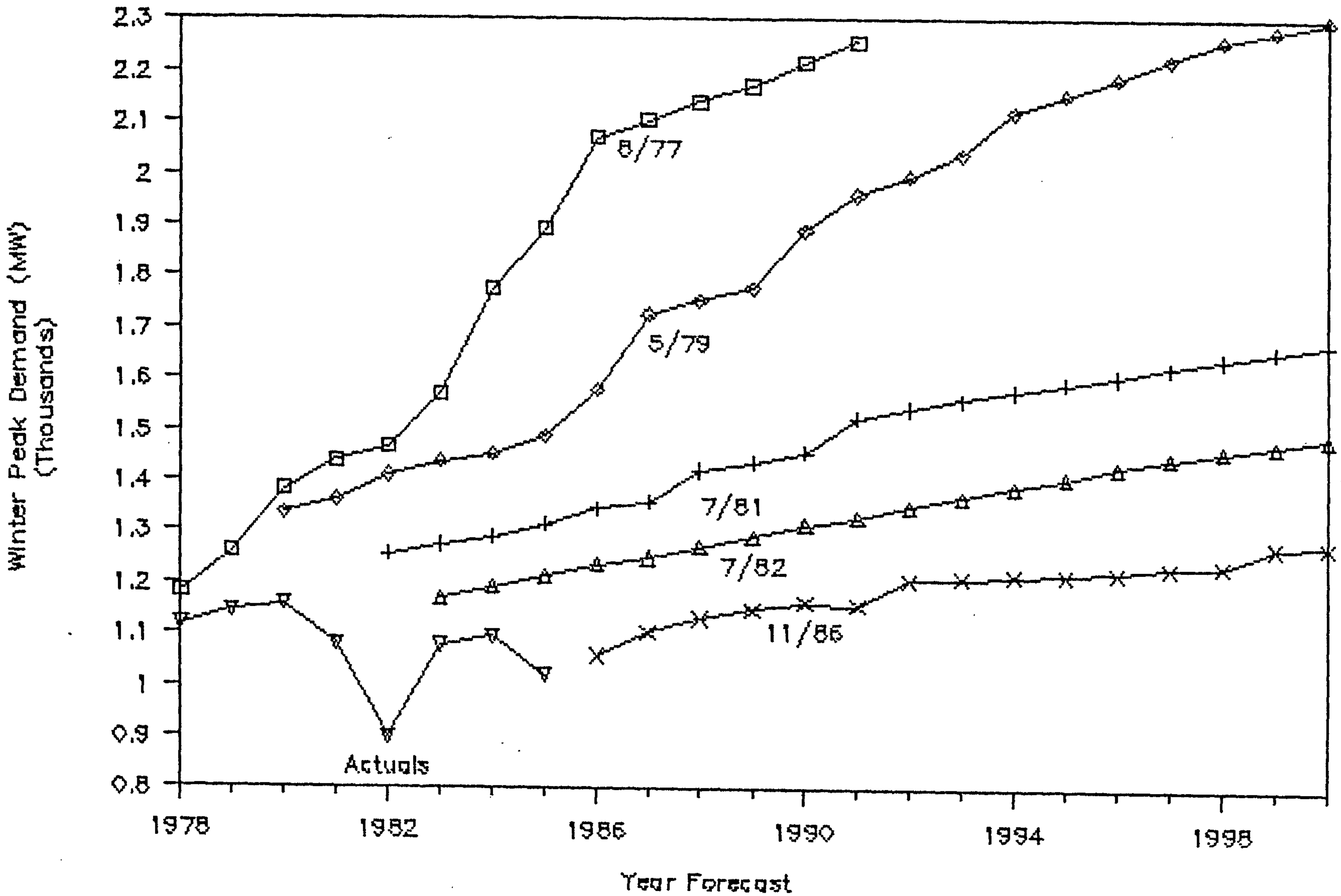
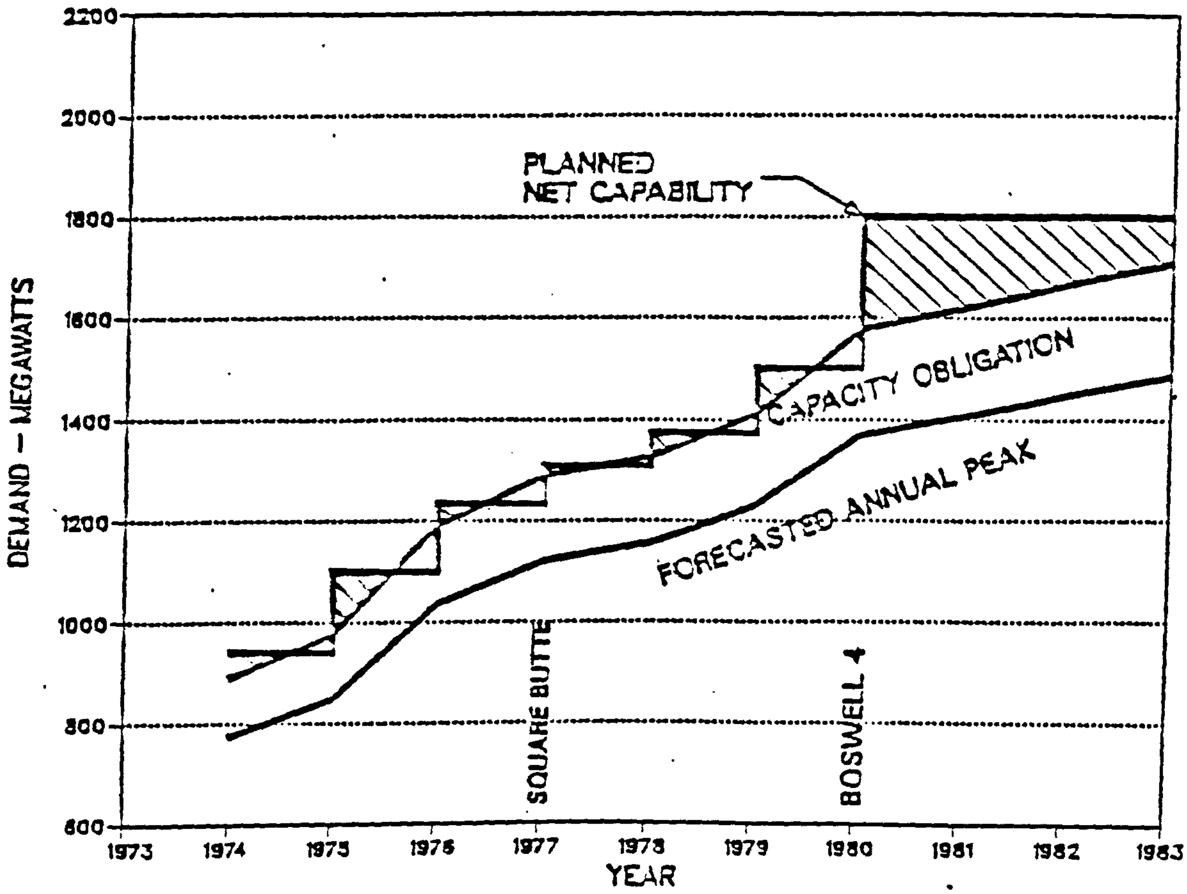


FIGURE 3.2: MP PLANNED SURPLUS, AS OF 1974



From: Rebuttal Testimony

of

Herbert J. Edwards

on behalf of

Minnesota Power & Light Company

Public Utilities Commission of Minnesota
Docket No. E015/GR-81-250

TABLE 4.1: EFFECT ON PRODUCTION COSTS OF A 150 MW SALE OF BOSWELL #4

YEAR	------------Low Load Forecast------------- PEAK (MW) (1)	w/150 MW BOSWELL 4 (Million) (2)	wo/150 MW BOSWELL 4 (Million) (3)	Increase due to sale (Million) (4)=(3)-(2)	------Low Load Forecast Minus 25%------- PEAK (MW) (5)	w/150 MW BOSWELL 4 (Million) (6)	wo/150 MW BOSWELL 4 (Million) (7)	Increase due to sale (Million) (8)=(7)-(6)
1984	1146	$96.6	$96.8	$0.2	1001	$80.4	$80.5	$0.1
1985	1154	$110.4	$110.6	$0.2	1009	$92.3	$92.4	$0.1
1986	1159	$118.9	$119.4	$0.5	1014	$99.6	$99.8	$0.2
1987	1163	$128.6	$131.2	$2.6	1018	$106.9	$108.0	$1.1
1988	1165	$132.3	$134.8	$2.5	1020	$109.9	$111.2	$1.3
1989	1173	$143.3	$147.0	$3.7	1028	$118.8	$120.4	$1.6
1990	1178	$158.1	$163.6	$5.5	1033	$130.9	$133.0	$2.1
1991	1176	$170.3	$176.9	$6.6	1031	$140.6	$143.0	$2.4
1992	1176	$189.2	$199.2	$10.0	1031	$152.8	$156.3	$3.5
1993	1176	$197.7	$206.5	$8.8	1031	$162.7	$165.7	$3.0
1994	1176	$213.0	$222.8	$9.8	1031	$175.3	$178.6	$3.3
1995	1176	$234.5	$246.3	$11.8	1031	$193.2	$196.9	$3.7
1996	1176	$253.6	$266.4	$12.8	1031	$208.9	$213.1	$4.2
1997	1176	$285.9	$306.6	$20.7	1031	$230.0	$236.6	$6.6
1998	1176	$291.8	$306.1	$14.3	1031	$240.7	$245.3	$4.6
1999	1176	$313.2	$327.9	$14.7	1031	$258.5	$263.3	$4.8
2000	1176	$334.9	$349.7	$14.8	1031	$274.1	$281.7	$7.6
2001	1176	$359.1	$374.0	$14.9	1031	$297.5	$302.4	$4.9
2002	1176	$402.7	$425.3	$22.6	1031	$327.7	$334.9	$7.2
2003	1176	$419.4	$438.0	$18.6	1031	$347.0	$355.6	$8.6
PRESENT VALUE 1984-2003		$1,288.6	$1,332.5	$43.9		$1,063.9	$1,079.9	$16.0

Source: Table 1 and 2, "Potential Sale of 150 MW of Boswell Capacity,"
E.R. Norberg November 8, 1982 (Response 169 Attachment 1).

Note: [1] Present Value calculated at 12.00% based on Response 126, Att. 2, pg. 3.
[2] Square Butte 41 MW option 11/89 & 45 MW 11/94.

TABLE 4.2: ESTIMATE OF REVENUE AND INCREASED PRODUCTION COSTS FOR PROPOSED 100 MW SALE OF BOSWELL #4 TO NSP

YEAR	NSP Sale Revenue (Million) (1)	Production Cost Increase (Million) (2)	Net Revenue from sale (Million) (3)=(1)-(2)
1987	$17.4	$2.6	$14.8
1988	$17.4	$2.5	$14.9
1989	$17.4	$3.7	$13.7
1990	$17.4	$5.5	$11.9
1991	$17.4	$6.6	$10.8
1992	$17.4	$10.0	$7.4
1993	$17.4	$8.8	$8.6
1994	$17.4	$9.8	$7.6
1995	$17.4	$11.8	$5.6
1996	$17.4	$12.8	$4.6
1997	$17.4	$20.7	($3.3)
1998	$17.4	$14.3	$3.1
1999	$17.4	$14.7	$2.7
2000	$17.4	$14.8	$2.6
2001	$17.4	$14.9	$2.5
2002	$17.4	$22.6	($5.2)
2003	$17.4	$18.6	($1.2)
2004	$17.4	$24.3	($6.9)
2005	$17.4	$26.1	($8.7)
2006	$17.4	$28.1	($10.7)
2007	$17.4	$30.2	($12.8)
2008	$17.4	$32.4	($15.0)
2009	$17.4	$34.9	($17.5)
2010	$17.4	$37.5	($20.1)
2011	$17.4	$40.3	($22.9)
2012	$17.4	$43.3	($25.9)
2013	$17.4	$46.6	($29.2)
2014	$17.4	$50.1	($32.7)
2015	$17.4	$53.8	($36.4)
2016	$17.4	$57.9	($40.5)
2017	$17.4	$62.2	($44.8)
2018	$17.4	$66.9	($49.5)
2019	$17.4	$71.9	($54.5)
2020	$17.4	$77.3	($59.9)
NET PRESENT VALUE 1987-2020	$141.9	$100.2	$41.7

Source [1]: NSP proposed demand revenue (Response 169, Att. 4) = $14,500/MW-month.
$14,500*12*100 = $17,400,000 annual revenue.
[2]: 1987-2003: Table 4.1 Column (4).
2004-2020: Figure for 2002 escalated at 7.5%.
Note [1]: Net Present Value calculated at 12.00% based on Response 126, Att. 2, pg. 3.

TABLE 4.3: COMPARISON OF YOUNG AND BOSWELL #4 COSTS

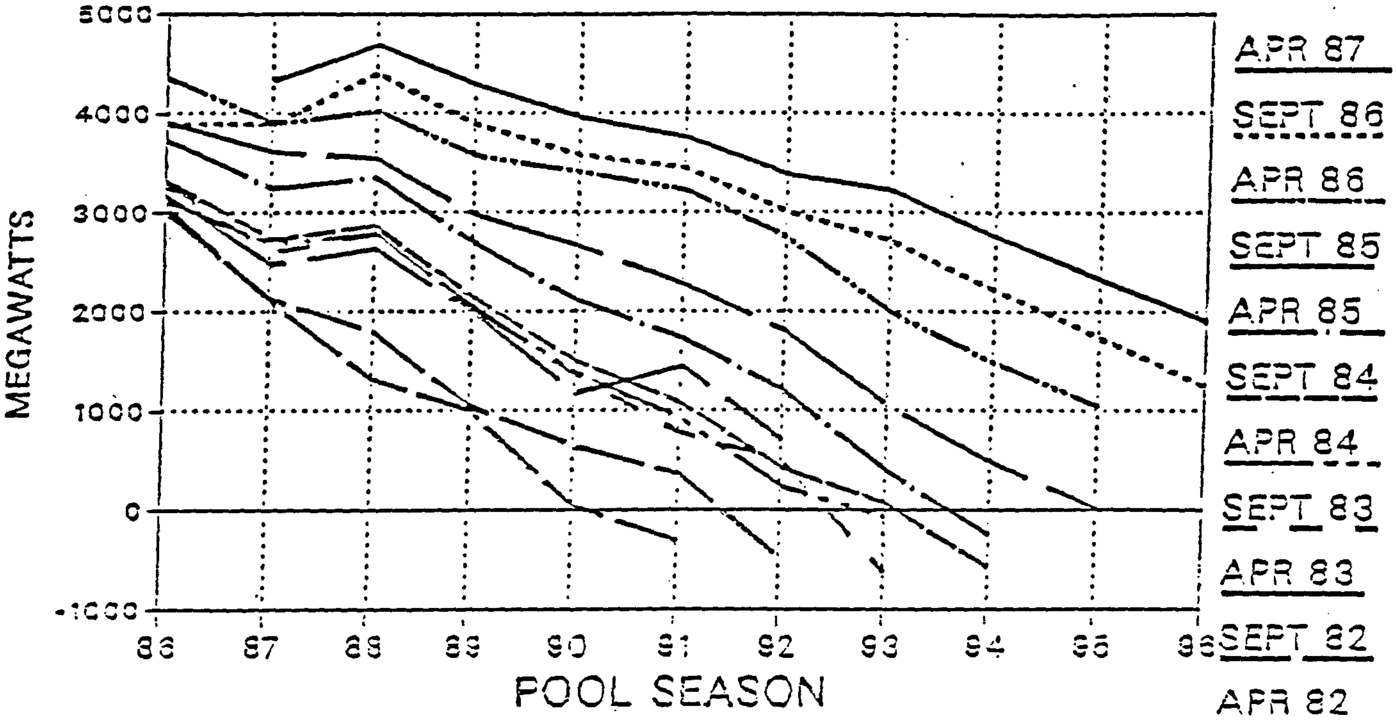
	Young				Boswell #4				Increase in cost		
		TOTAL COST				TOTAL COST			MW basis	Mwh basis	AFPO
YEAR	(MW)	(Million)	$/kw-year	$/mwh	(MW)	(Million)	$/kw-year	$/mwh	(Million)	(Million)	(Million)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1987											$5.7
1988											$11.1
1989	269.8	$48.6	$180.11	$29.4	487.4	$108.7	$223.01	$38.3	$1.0	$1.2	$8.4
1990	235.7	$44.3	$187.95	$30.7	416.1	$96.0	$230.77	$39.6	$2.4	$3.1	$4.7
1991	201.6	$38.3	$190.01	$31.0	344.8	$83.7	$242.75	$41.7	$4.8	$6.0	$1.2
1992	190.2	$37.5	$197.17	$32.2	321.0	$75.2	$234.23	$40.2	$3.8	$5.1	
1993	190.2	$38.8	$204.01	$33.3	321.0	$79.9	$249.05	$42.8	$4.6	$6.0	
1994	190.2	$40.3	$211.89	$34.6	321.0	$82.0	$255.46	$43.9	$4.5	$5.8	
1995	190.2	$42.3	$222.41	$36.3	321.0	$84.3	$262.65	$45.1	$4.1	$5.5	
1996									$4.2	$5.6	
1997									$4.2	$5.6	
1998									$4.2	$5.6	
1999									$4.2	$5.6	
2000									$4.2	$5.6	
2001									$4.2	$5.6	
2002									$4.2	$5.6	
2003									$4.2	$5.6	
2004									$4.2	$5.6	
2005									$4.2	$5.6	
2006									$4.2	$5.6	
2007									$4.2	$5.6	
NET PRESENT VALUE [12]									$21.8	$28.4	$23.6

Source [1]: Unit rating: 70% 418 MW minus transfer to NSP. 1989-1991 prorated for transfer May 1.
[2] & [6]: Response 121.
[3]: (2)/(1)*1000
[4]: (2)/(Mwh)/1000000. (Mwh) = (1)*8760*(CF). CF=70% based on Response 126, Att. 2, pg 3.
[5]: Unit rating @ 535 MW minus sale to NSP. 1989-1991 prorated for transfer May 1.
[7]: (6)/(5)*1000
[8]: (6)/(Mwh)/1000000. (Mwh) = (5)*8760*(CF). CF=66.5% based on 1985-88 data, Response 109.
[9]: 1989-1995: ((7)-(3))*(YNG SLD)/1000. YNG SLD=70% 418 MW - (1).
1996-2007: Extrapolated as average of 1992-1995.
[10]: 1989-1995: ((8)-(4))*(YNG SLD)/1000. YNG SLD=70% 418 MW - (1).
1996-2007: Extrapolated as average of 1992-1995.
[11]: Gartzke testimony, Docket E002-E015/PA-86-722.
[12]: Discount rate of 12.0% based on Response 126, Att. 2, pg 3.

FIGURE 4.1

PROJECTED MAPP SURPLUSES
REFLECTS PAST LOAD & CAPABILITY REPORTS

SUMMER



WINTER

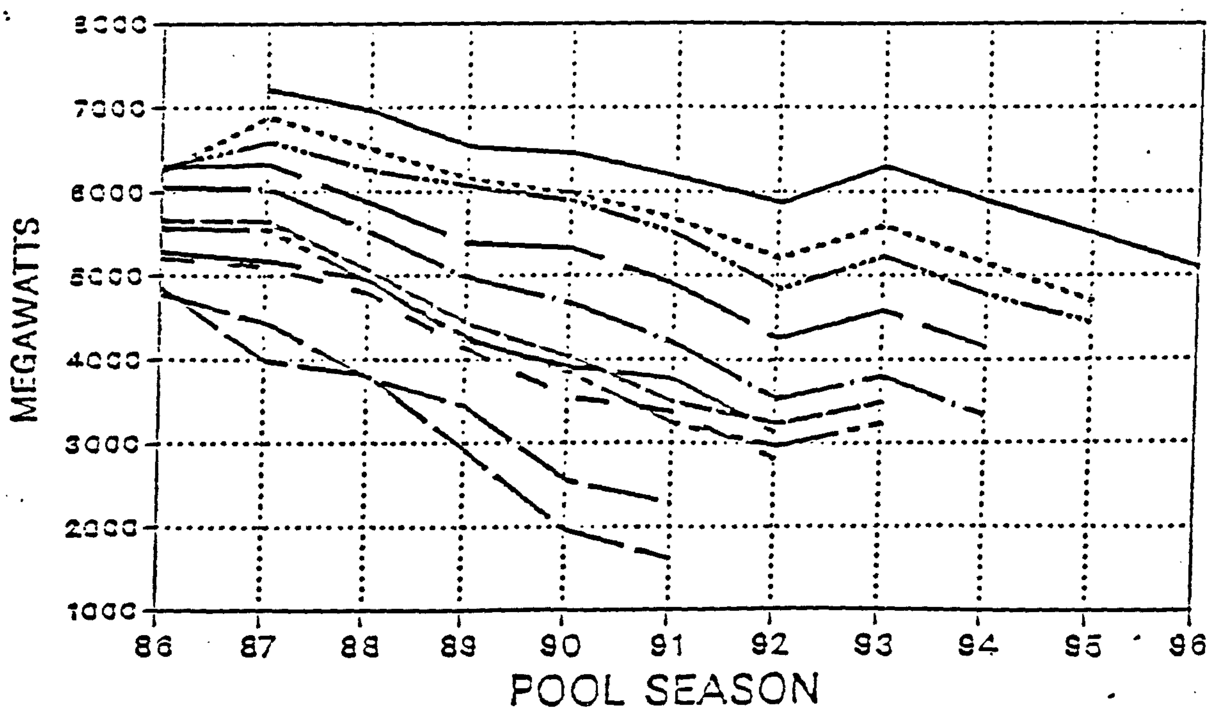


TABLE 5.1: BOSWELL #4 FIXED COSTS TO RATEPAYERS: 1980 - 1987

YEAR	MW	FIXED COSTS (000)	EXCESS CAPACITY (MW)	EXCESS FIXED COSTS (000)
1980	517	$56,539		$0
1981	517	$82,258		$0
1982	517	$78,195	100	$15,125
1983	517	$75,109	200	$29,056
1984	517	$71,551	300	$41,519
1985	517	$68,373	300	$39,675
1986	517	$65,513	300	$38,015
1987	517/535	$57,647	310	$33,451
TOTAL 1980-1986		$497,538		$163,390
TOTAL 1987		$57,647		$33,451
TOTAL 1980-1987		$555,185		$196,840

Note [1]: Excess Capacity assume 100 MW sales 12/31/81,82,83

[2]: Excess Capacity changes 1987, uprating applied proportionally.

Source: Responses 121, 141

TABLE 5.2: COYOTE TOTAL FIXED COSTS TO RATEPAYERS: 1981 - 1987

YEAR	MW	FIXED COSTS (000)
1981	21	$2,570
1982	21	$4,319
1983	21	$4,120
1984	21	$3,894
1985	21/16	$3,454
1986	16/11	$2,112
1987	11	$1,479
TOTAL 1981-1986		$20,469
TOTAL 1987		$1,479
TOTAL 1981-1987		$21,948

Source: Responses 121, 141

TABLE 5.3: FIXED COST OF EXCESS CAPACITY: 1980-1987

YEAR	EXCESS CAPACITY TOTAL MW (1)	------COYOTE------ MW (2)	FIXED COSTS (000) (3)	------BOSWELL #4------- MW (4)=(1)-(2)	FIXED COSTS (000) (5)	TOTAL FIXED COSTS (000) (6)=(3)+(5)
1980	408			408	$44,619	$44,619
1981	473	21	$2,570	452	$71,916	$74,486
1982	515	21	$4,319	494	$74,716	$79,035
1983	515	21	$4,120	494	$71,768	$75,888
1984	450	21	$3,894	429	$59,372	$63,266
1985	450	21/16	$3,454	429	$56,735	$60,189
1986	456	16/11	$2,112	445	$56,389	$58,501
1987	409	11	$1,479	398	$44,378	$45,857
TOTAL 1980-1986			$20,469		$390,896	$411,365
TOTAL 1987			$1,479		$44,378	$45,857
TOTAL 1980-1987			$21,948		$435,275	$457,223

Sources [1]: Table 2.6 (line 13), lesser of summer & winter surplus for each calendar year. It should be noted that MAPP summer and winter seasons do not precisely coincide with calendar years.

[2]-[3]: Table 5.2.

[4]: For 1985 & 1986, calculation based on Coyote capacity in season with less excess capacity see column [1] note.

[5]: Table 5.1 fixed costs prorated by ratio of column [4] & Boswell #4 total MW. 1987 computation based on 517 MW rating.

TABLE 5.4: MP POWER SALES REVENUE 1981 - 1987

NAME	AMOUNT (MW)	MAPP Pool Season	Type of Sale	Sale Demand Rate ($/MW-Mo)	Demand Revenue Year	Total
NSP (LSDP)	10	81 Summer	Boswell #4	$5,329	$319,740	
	30	81 Winter		$5,329	$959,220	
	10	82 Summer		$5,329	$319,740	
	40	82 Winter		$5,329	$1,278,960	
	20	83 Summer		$5,329	$639,480	
	40	83 Winter		$5,329	$1,278,960	
	40	84 Summer		$5,329	$1,278,960	
	50	84 Winter		$5,329	$1,598,700	
	30	85 Summer		$5,329	$959,220	
	50	85 Winter		$5,329	$1,598,700	
	40	86 Summer		$5,329	$1,278,960	
	50	86 Winter		$5,329	$1,598,700	$13,109,340
SMMPA	75	86 Summer	Boswell #4	$9,163	$4,123,350	
	50	86 Winter		$10,491	$3,147,300	
	75	87 Summer		$11,397	$5,128,650	$12,399,300
NSP	N/A	7/15/83-/84	Energy only	N/A	$0	
NSP	100	85 Summer	Laskin/Boswell 1&2	$1,000	$600,000	
NSP	35	86 Summer	Firm Power	$1,000	$210,000	
NSP	350	87 Summer	Boswell #3	$870	$1,827,000	
WPPI	N/A		Energy only	N/A	$0	
TOTAL 1981-1986					$21,189,990	
TOTAL 1987					$6,955,650	
TOTAL 1981-1987					$28,145,640	

Note [1]: Calculated from discovery response 120.

#6 x S

SURREBUTTAL TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

* * *

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

* * *

MINNESOTA POWER COMPANY

E015/GR-87-223

* * *

SEPTEMBER 23, 1987

Q: Please identify yourself.

A: My name is Paul Chernick. My business address is 10 Post Office Square, Boston, Massachusetts.

Q: Are you the same Paul Chernick who filed direct testimony in this docket?

A: Yes.

Q: What are the subjects of your surrebuttal testimony?

A: I will respond in a general fashion to portions of the rebuttal testimony of MP witnesses Sandbulte, Ostroski, Edwards, Harmon, and Landon. Due to the large volume of that testimony, and the short time available for preparation of surrebuttal, I will not respond in detail to many assertions made in the MP rebuttal, on topics which I covered in detail in my direct testimony and the report attached thereto. In many cases, MP's response to my report and testimony consists of repetition of positions which I discussed and debunked in my direct testimony. These issues include:

a. There was clearly a market for Boswell capacity in the early 1980s. NSP projected a need for capacity in the late 1980s, but was interested in purchasing or building ahead of need. NSP has recently purchased Boswell and Young capacity for the late 1980s, some 5 years ahead of need, even following the addition of another major baseload resource (Sherco 3) to its system. In the early 1980s, with less baseload capacity, with the opportunity to defer Sherco 3 construction, with smaller and less persistent surpluses in MAPP, and with the need for additional capacity projected for the late 1980s, the same reasoning would have resulted in an immediate purchase of Boswell capacity. MP's argument that NSP would not have bought Boswell 4 capacity in the early 1980s is illogical and inconsistent with actual experience.

b. I have not proposed any retroactive ratemaking.

c. The used-and-useful standard is reflected in only a small portion of my recommendations, which generally focus on prudence issues. In determining whether MP's excess capacity is used-and-useful, I reviewed a number of factors, including the past duration of the excess, the future duration of the excess, past and future benefits of the excess for ratepayers (through fuel savings, reduced costs of accrediting other capacity, and off-system sales), the amount of excess covered by unused LP contract demand, and the net cost of the excess capacity. Contrary to MP's allegations, I do not simply recommend that all capacity above MP's required reserve be disallowed in each year. Even if I were suggesting this simple reserve test (which I am not) for the current test year, MP's characterization of the disallowance would be unjustified, since MP has already been allowed to recover for over 3200 MW-years of excess capacity since 1980.

d. The problems of the steel industry in the 1980s were clearly anticipated in the 1970s.

e. MP's excess capacity is due to MP's imprudence in the 1970s and 1980s. All of my ratemaking recommendations are consistent with a prudence standard, although some of them could also be applied under a used-and-useful standard, if the Commission does not reach a finding on MP's planning prudence.

f. MP's excess capacity consists of Boswell 4 capacity, imprudently built by MP to serve an excessively risky load, and imprudently retained by MP long after that load collapsed.

g. MP was imprudent in basing its capacity planning on customer representations regarding their future intentions.

h. MP did not attempt to reduce and diversify the risks of serving the taconite loads, beyond the flimsy protection of the LP contracts. The fact that the taconites did not choose to invest in higher efficiency levels, or in cogeneration, or in co-ownership of Boswell 4 (which was never offered to them), or to diversify their power supplies (which MP apparently would have resisted), hardly justifies MP's failure to ursue these options for protecting its customers.

i. Since MP failed to pursue many of its options, we will never know exactly how those might have turned out. MP's failure to explore merger, cooperative power supply arrangements, efficiency improvements and load reductions at the taconites, or sale of Boswell 4 capacity in the early 1980s were imprudent. It is difficult to believe that prudent management would have been unable to achieve any of these options.

j. MP's forecasts in the 1970s and early 1980s relied on (in various combinations) speculative loads and a highly optimistic view of the taconite industry's future. Failure to sell capacity in the early 1980s can not be justified on the basis of these forecasts.

k. MP's high load factor could, <u>in theory</u>, justify a higher reserve margin than is required by reliability considerations. However, MP's own study of this issue indicates that, compared to the <u>cost</u> of Boswell 4 (rather than its current short-term sales value), the fuel savings of a higher reserve margin are not cost-effective.

l. The net cost of carrying the excess Boswell 4 capacity through the 1980s has been much larger than the value of any "gain" MP may have realized by a sale of capacity above book. This is true despite the fact that Boswell 4 is a fairly efficient generating unit.

m. MP repeatedly mischaracterizes my testimony, implying (or even stating) that I predicted the imminent demise of the US steel industry, that I was criticizing MP's current planning process or the sale of Young capacity, and so on.

For any point made in MP's rebuttal testimony that I do not address in this surrebuttal, it is my belief that I have adequately dealt with that point in my report or direct testimony.

Q: Has MP's rebuttal testimony changed any of your basic conclusions?

A: No, not as to any issues which directly affect the test year rate issues. However, MP's rebuttal testimony has caused me to question my assessment of the company's current ability to deal with future risks and uncertainties.

Q: Why is that?

A: The testimony of Mr. Sandbulte suggests that, contrary to my earlier impression, MP has not learned the lessons of its earlier errors.[1] I understand the importance to Mr. Sandbulte of believing that his past decisions were reasonable in the circumstances of the time. However, I am very concerned about MP's attitude, as expressed in Mr. Sandbulte's rebuttal, that those decisions were not errors, even with the benefit of the broader perspectives of the 1980s. Specifically, and in order of increasing importance,

i. Mr. Sandbulte indicates no acceptance of the fact that the predictable problems of the concentration of MP's load in the taconite industry could have been alleviated through a merger, and is inappropriately shocked by the suggestion that a merger could be good for the ratepayers.

ii. He does not acknowledge that mergers are a normal part of the business process, and views a potential merger (either retrospectively or in the future) as a threat to his prerogatives, rather than a risk-management technique.

iii. Despite historical experience which clearly demonstrates that the LP contracts have provided quite limited protection from recession and bankruptcies in the taconite industry, he asserts

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[1] It still appears that at least some of MP's management staff is prepared to deal with the complex environment facing utilities in the late 1980s in a flexible and realistic manner, as evidenced by some of the recent memos I cited in my direct. However, top management most also set an appropriate tone if MP is to adopt a flexible and realistic approach in the future.

that they provided "reasonable protection." This conclusion is clearly counter-factual, and Sandbulte provides no support for it.

iv. Even though MP and its service territory has suffered grievously from MP's mistake in deciding to singlehandedly provide service to the taconites, without any form of risk-sharing, Mr. Sandbulte indicates no regret and implies that MP would have resisted the efforts of any other utility to share those risks.

v. He continues to describe MP's role exclusively in terms of selling electricity to whomever wants it, rather than meeting customer needs in the most appropriate manner, whether that be power sales, conservation, cogeneration, self-generation, or wheeling of power. Mr. Sandbulte appears to be unprepared for the coming era of least-cost planning.

Q: Are there aspects of Mr. Sandbulte's testimony which support your conclusions and recommendations?

A: Yes. Mr. Sandbulte indicates (page 14)[2] that MP's "shareholders invested in [MP], knowing the risks of its service territory." This supports the reasonableness of expecting those shareholders to assume some of the attendant costs, especially when the risks have been exacerbated by the imprudence of the management they selected.

Mr. Sandbulte also indicates that, despite the enormous risks of having MP's sales highly concentrated in the potentially volatile taconite industry, MP did not consider any measures to promote risk sharing, whether through a cooperative arrangement to spread the taconite sales over several utilities, through taconite ownership of generation,

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[2]All references in my surrebuttal are to MP's rebuttal testimony, unless otherwise noted.

through improvements in taconite processing efficiency, or through a merger with another utility. MP's failure to pursue these measures is so clearly imprudent that Mr. Sandbulte's testimony amounts to an admission that the excess Boswell 4 capacity is entirely the fault of MP's management.

Q: Are there any of Mr. Sandbulte's assertions to which you would like to respond?

A: Yes, very briefly. Mr. Sandbulte asserts that the excess capacity on the MP system is due to the older plants, such as Boswell 1&2, Hibbard, and Laskin, rather than Boswell #4. My report demonstrated that, had MP acted prudently, it would have avoided the costs of carrying the excess capacity it now owns in Boswell 4. Under no circumstances would it have been prudent for MP to retire the inexpensive capacity at Laskin, Hibbard, and Boswell 1&2, to replace it with the relatively expensive capacity at Boswell 4. MP's errors have nothing to do with the older plants, and everything to do with Boswell 4.

Mr. Sandbulte makes the surprising assertion (page 8) that NSP "could not have considered" the purchase of Boswell capacity, because it had already made a relatively small investment in Sherco 3 equipment (something less than 10% of the total Sherco 3 cost). It is not clear why he believes that NSP, which had already delayed Sherco's in-service date, and which agreed to a further delay as part of the decision in the Sherco licensing case, would not have done so again if offered economical Boswell capacity. I have seen no evidence of such rigidity on the part of NSP. In any case, an outstanding offer by MP to sell Boswell 4 capacity at any cost below that of Sherco might well have been an insurmountable obstacle to the licensing of Sherco for even a 1988 in-service date.

Mr. Sandbulte claims (page 10), that a sale of Boswell 4 capacity at book value in 1981 or 1982 would have prevented the sale of the remaining excess at a price above book in the late 1980s. He presents no evidence for this claim: it is not clear why the market value of 75 MW of Boswell in 1982 would affect the market value of Boswell in 1989-91. Due to depreciation, the net book value of a kW of Boswell in 1981 would be about 97% of original cost, while in 1990 (ignoring additions and assuming 3% depreciation) it would be 70%: thus, selling Boswell capacity for the 1981 book value in 1990 would give a gain of 39%. Of course, the actual sale price in any year depends on the market value of the capacity, not book values.

Also on page 10, Mr. Sandbulte alleges that a sale of Boswell 4 to NEMMPA would have produced "nonexistent or minimal" benefits to MP's retail customers, since the NEMMPA members were also MP customers. However, NEMMPA was offering to buy a share of Boswell 4, MP's most expensive unit, rather than the cheaper slice of the system assigned to its members by the normal allocation process. NEMMPA was also offering to buy a piece of Boswell 4 that was 40% larger than NEMMPA's load on MP's system (see the two documents in Ex. PLC R-1), so the reduction in revenue requirements should have been much larger than the reduction in sales to NEMMPA. Given NEMMPA's less expensive financing,[3] it should have been possible to lower rates both to MP ratepayers and to NEMMPA ratepayers, by refinancing a portion of Boswell 4 at NEMMPA's lower carrying charges. Mr. Sandbulte does not appear to understand this obvious point, which has been exploited by several utilities, through the transfer of expensive or excess capacity to their wholesale customers.

Q: Is there any of Mr. Landon's rebuttal to which you would like to respond?

A: Yes. In general, Mr. Landon presents very little factual support for his sweeping assertions, and simply contradicts my carefully documented conclusions without adding any substance to the record. I will respond briefly to a few points he raises.

Mr. Landon appears to have the same limited view of utility management's planning role as Mr. Sandbulte. He views that role simply as guessing at future load and

[3]MP tried to get additional price concessions, on the ground that these financing benefits should be passed on from NEMMPA to MP. In fact, the NEMMPA offer appeared to provide MP considerable benefits that were made possible by the financing cost differential.

competently building capacity to meet anticipated future load. He ignores the responsibilities of utilities to provide reliable service at the lowest possible cost, or even to operate in an efficient and cost-effective manner. Mr. Landon's description of utility planning is incompatible with the provision of least-cost energy services.

Mr. Landon also alleges that my recommendations are based on an attempt to shift "market risks" onto the MP shareholders. My report clearly demonstrates that MP's excess capacity results from the kinds of errors Mr. Landon describes as "management risks".

Mr. Landon alleges (page 27) that I have failed to explain how MP would have reached different conclusions. My report discusses the information and options available to MP, which MP improperly either ignored or rejected.

Mr. Landon is correct (page 28) in asserting that I do not dispute the choice of Boswell 4 size or technology, or the prudence of MP's construction management, given MP's error in attempting to serve entire taconite load by itself. Boswell 4 should have been owned by a wider mix of parties (either utilities or the taconites themselves), but the unit appears to be a well-built plant of a reasonable scale. These facts are irrelevant to my discussion of MP's errors.

Mr. Landon asserts that my review of the taconite industry's prospects in the 1970s was "selected," "anecdotal," and "culled". He presents not one iota of conflicting evidence: the general consensus was that steel was facing serious problems and though the industry's future might be bright, it was highly uncertain. More importantly, the fact that there were "conflicting opinions" supports my basic conclusion, that the taconite loads were very risky for a utility of MP's size. Whether the probability of severe problems for the taconites was 25% or 75%, MP was imprudent in tying its fate to that risk.

Mr. Landon suggests that "independently following the steel/taconite industry is a much better planning strategy than the use of . . . mathematical models." I agree. Unfortunately, MP primarily reliance in the late 1970s on customer representations, rather than an independent assessment, resulted in the current overcapacity problem.

Mr. Landon claims that "the large concentration of load in the taconite producers was beyond MP's control." Yet he acknowledges that the PUC could arrange for alternative supplies. Mr. Sandbulte also states (page 11) that MP refused to build capacity for the taconites until the contracts were signed: Mr. Landon does not explain why those contracts could not have included an assignment of a portion of the taconite loads to other utilities,[4] an

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[4]Except for Mr. Sandbulte's hints that MP might have imprudently refused to allow another utility to serve those loads, it is not clear why the taconites would care who supplied power to them. Boswell 4 power would cost about the same amount regardless of whether the share serving a particular portion of a particular taconite's load was owned by MP, by NSP, or by a co-op. (The co-op's debt financing

agreement to limit taconite loads by installing the most efficient available equipment, an agreement to supply a fraction of load through on-site generation or co-generation, or an agreement to participate as owners in Boswell 4. Mr. Landon's hypothetical scenario depends on the assumption that this PUC would have ordered MP to act imprudently, and to serve the taconites by itself, even if MP had attempted to act prudently and share the risk.

Mr. Landon assumes that an investor in a risky venture, such as taconite mining, will make the right level of demand-side investment because they will use "all of the demand-side options that they find economic." Of course, the level of investment which is economic to the taconite producer, whose facilities may not remain in operation very long, is much lower if MP is accepting the capital costs and risks of supplying the extra power required by inefficient equipment. Again, Mr. Landon assumes that MP had no responsibilities or options, other than to supply power whenever and however customer requested it. That was clearly not the case for the taconite expansions.

Mr. Landon provides no evidence that MP could not have required the taconites to provide some of their electric service from non-MP sources, either from on-site generation, from taconite-owned Boswell 4 capacity, or from another

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might have produced slightly lower rates.) If a municipal utility owned a portion of the plant, the power would be less expensive than MP-financed capacity.

utility. Nonetheless, on pages 32-33, he spins a complex fantasy about the discounts which might have been necessary to induce the taconites to accept efficiency improvements or alternative supply arrangements. In addition to the obvious fact that the taconites were in no position to force MP to serve them, Mr. Landon ignores the fact that MP's customers would have been better off with slightly higher costs (unlikely though that might be) to avoid the risk of the excess capacity situation which was a very clear possibility in the 1970s, and which occurred in the 1980s.

If MP had decided to merge with another utility, the delays Mr. Landon hypothesizes might well have occurred.[5] In the meantime, MP should have found it relatively easy to work out an arrangement for sharing the taconite load, or any capacity surpluses or shortfalls, with its merger partner.

Mr. Landon's comments on reserve margin on pages 36-37 confuse the number of customers with the number and size of utility generators. A self-generator with some 30 generating units (roughly the number of units on MP's system, including the Erie capacity), and with large interconnections to other power producers would not need a 50% reserve margin. An isolated system with any number of

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[5]Interestingly, Mr. Landon chooses to discuss a merger involved a registered utility holding company, one of the nation's largest utilities. The merger between NSP and LSDP might be a better model for a potential NSP/MP merger.

customers and with each unit sized to meet peak load would require an enormous reserve margin: such a design would be woefully inefficient for any utility. As far as I can see, Mr. Landon's discussion on this point is either incorrect or irrelevant to the MP system.

On page 15, Mr. Landon alleges that NSP and SMMPA would not have purchased Boswell capacity unless it were supplemented with additional capacity to allow the "long-term" substitution of the combined capacity for Sherco 3. Mr. Landon provides no basis for this statement. Boswell 4 should have been used to defer the Sherco in-service date until Minnesota needed addition power. If the deferral were long enough, a more economical alternative might have emerged in the meantime, and Sherco might never have been built. More likely, Sherco would have become an early-1990s unit. Long-term substitution of Sherco 3 was never a requirement for a Boswell sale: the actual sale of Boswell and Young capacity to NSP is not a long-term substitute for any 800-MW coal plant, although it will defer the in-service date of a future North Dakota plant, under NSP's current plans.

Mr. Landon's major error lies in the assumption that MP had no choices, and no responsibility to review its choices. He is wrong on both counts.

Q: Do you have any response to the points made by Mr. Edwards?

A: Yes. In general, Mr. Edwards repeats the assertions of other MP witnesses, without adding any additional information. He also extensively characterizes Boswell 4 (and the 1970s additions to the MP system as well) as "efficient" or "best" units, as if those characteristics excuse MP's errors which produced the excess capacity problem. Some of his observations (such as that delaying Boswell would have resulted in some extra costs) do not seem to be responsive to any direct testimony. He ignores much of my analysis of MP's alternatives, and simply alleges that, as a utility, MP had no alternatives. Like other MP witnesses, Mr. Edwards denies that MP has any least-cost planning responsibilities. However, Mr. Edwards does make some assertions which are worth discussing.

Mr. Edwards assumes without any documentation that other utilities would have refused to supply non-oil based power to the taconites, even if they were serving those loads as firm loads. Mr. Edwards' assumption is contrary to normal utility practice, which generally prices all firm loads based on average system costs. Since the utilities which picked up the taconite load could also have picked up a corresponding share of Boswell 4, it is difficult to see why they would have chosen to price the sales to the taconites at oil costs. Of course, we will never know what prices other utilities would have offered to the taconites (a very desirable load, if the utility's exposure to industry downturns is small enough), because MP failed to take reasonable actions to protect its ratepayers.

I do not know to what Mr. Edwards is referring when he says that I "view the industry bias against oil-fired capacity as naive in view of current oil prices," (page 11) so I can not respond in any detail. I do not believe that I suggested that MP should have built oil-fired capacity to serve the taconites.

Mr. Edwards includes a lengthy discussion of the possible responses of MP to its excess capacity situation in the early 1980s. He suggests that MP might have found it even more desirable to sell capacity other than Boswell 4: that is possible, in which case the cost of MP's failure to sell was even higher than the estimates presented in my testimony. He also notes that the taconite load continued to be problematical for MP into the 1980s, due to its uncertainty. This is a good point, and suggests that MP might have taken a number of actions in connection with a Boswell sale, which also would have been appropriate in the late 1970s, in the planning process. MP might well have offered to reduce contract demand levels, to reduce the probability of an unanticipated surge of demand from the taconites. It could also have offered to convert portions of the contracts to an interruptible basis, reducing costs to both the taconites and MP.[6] Finally, MP could have

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[6]These are kinds of measures the taconites support in the current proceeding.

offered to transfer some of the right and obligation to serve the taconite load (above some base level) to the purchasers of the Boswell capacity, which would move MP towards the risk-sharing arrangement it should have instituted in the 1970s.

Mr. Edwards discusses the risks of replacement capacity at pages 17-22. This discussion is very general in nature, and requires no specific response. However, I would like to note that MP also clearly faced some risks due to its continuing dependence on Boswell 4 for about a third of its capacity, and a larger fraction of its energy. In addition, the "replacement" capacity for Boswell and Young, whenever that is required, may be a much less expensive source, including purchases from Manitoba Hydro, efficiency improvements (conservation) in MP's service territory, cogeneration, or the refurbishment of the excess capacity at Erie or Reserve.

Q: Do you have any response to the testimony of Mr. Harmon?

A: Yes. He devotes several pages to establishing the fact that <u>some</u> observers of the steel industry expected demand for taconite to be quite solid in the 1980s.[7] This does not contradict my conclusion that MP's projected taconite load was extraordinarily large and extraordinarily risky, and justified extraordinary risk-reduction methods. Contrary to

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[7]Interestingly, Mr. Harmon provides no quotations from the 1970s, when MP was making its most serious errors.

Mr. Harmon's implications, I did not say, and my testimony does not depend on the view that "the end of the steel industry was near" (page 24) or on a prediction of "the demise of the US steel industry." In addition, the observers Mr. Harmon quotes appear to represent a minority view in many respects, as compared to the numerous quotations presented in my testimony.[8] Other quotations (such as that from the New York Times on page 27) appear to refer to year-to-year fluctuations, rather than the important secular trends.

Mr. Harmon discusses the taconite self-generation and cogeneration option, and indicates that MP had convinced US Steel in 1958 not to self-generate. He provides no evidence that MP attempted to encourage cogeneration or self-generation in the 1970s. He also indicates that the taconites preferred to have MP take on the responsibilities of building and operating the generating plants which served them.[9] This is quite likely, especially since MP was willing to assume the attendant risks. Again, MP is arguing

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[8]On page 24, Mr. Harmon quotes a Forbes article, which I also quoted. It is difficult to see how he can read the statement that "the best you can say about [the steel] industry is that it is so far down it has nowhere to go but up" as an optimistic view.

[9]MP could have provided most of the services Mr. Harmon lists on page 14, either by building jointly owned plants at taconite-owned sites, or by allowing the taconites to participate in Boswell 4 ownership. The reliability benefits of the MP transmission grid are available to self-generating customers, such as Erie.

that it had no obligation to plan prudently for its customers' welfare, because each taconite were looking out for its own welfare. Obviously, MP had some responsibilities beyond taking orders from its large customers.

Mr. Harmon misinterprets my "investment per kW of contract load," and incorrectly characterizes it as a "fiction." He does not provide any substantive critique of that analysis, and instead attempts to shift the discussion from whether the taconites could have owned some of their own generation, to whether they wanted to own generation. He continues to confuse MP's planning responsibility with the taconites' planning decision, as in his conclusions that self-generation and co-generation must not have been feasible because the taconites did not install these technologies. Obviously, what each taconite individually wanted to do was not necessarily in the interest of all of MP's ratepayers, or even of all of MP's taconite load.

Mr. Harmon's quotes from Hibbing, Eveleth, and Inland testimony on pages 15-16 support my contention that, while they preferred that MP take the investment risk, the taconites could have supplied their own generation. As Mr. Harmon notes, the taconites and MP should all have relied on one another for reliability and backup support, as MP and Erie have traditionally.

Mr. Harmon also discusses the basic problem of building generation to serve the taconite load: the danger that the power plant will not be utilized by the taconite load, and that its costs will not be covered by the value of taconite production. The magnitude of excess generation capacity at the UP plant is comparable to the excess capacity at Boswell: the difference is that the cost of the excess capacity at Boswell has been borne by MP's other ratepayers (including those taconites which have continued operating), while the excess in Michigan has been absorbed by the mine operator. Mr. Harmon seems to acknowledge the risk to the taconites of owning their own generation, but not the risk to MP.

Mr. Harmon's discussion of cogeneration opportunities at the taconite facilities is, for some reason, concentrated on the use of steam in the taconite kilns and on the recovery of steam from the waste heat from the kilns. I never suggested that the pellets could be dried with direct steam: I recognized that the primary cogeneration opportunity lay in electric generation from the furnace waste heat. By the 1970s, waste heat (bottoming) cogeneration equipment was available which used organic compounds, rather than steam, as working fluids, and which could operate with lower temperature waste heat. Thus, the use of some of the waste heat for other processes did not necessarily imply that no significant cogeneration options remained. The only way to have found out for sure how much cogeneration would have been feasible at the taconite mills would have been to require (or encourage, through higher rates for all-requirements services) the taconites in the 1970s to supply part of their own electricity.

Mr. Harmon seriously confuses my remarks on cogeneration. First, I was not criticizing his forecasts for omission of conservation,[10] but simply pointing out that the taconites might well have reduced their demand per ton, if they had stronger incentives for conservation. For example, the efficiency of motors can usually be improved through the design of the motors, their controls, and the attendant drive equipment.[11] Also, Mr. Fatum has testified in this proceeding on behalf of Hibbing Taconite that the grinding technology employed at Hibbing is much more energy intensive than the grinding process used at the other taconites. The Hibbing Taconite plant requires 25% more electricity per ton than the average taconite operation: Hibbing's choice of technologies might have been made differently if the mill had faced the choice of providing the additional power for the less efficient load.

Mr. Harmon denies that there has been any "clear trend

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[10] Such criticism may be justified, but I have not reviewed MP's forecasts at that level of detail.

[11] Without providing any documentation, Mr. Harmon suggests that conservation at the taconite mills is only possible through computer controls which did not exist in the 1970s. Many conservation measures, especially in efficient motor design, were available long before the 1970s.

of reduced electric consumption per unit of production" (page 22). This testimony contradicts his own discovery response 138, which I cited in my testimony. Mr. Harmon provides no evidence to support his new assertion that the taconites have achieved demand reductions without corresponding energy reductions.[12] In addition, his position is inconsistent with Mr. Fatum's testimony in this case.[13] In any case, Mr. Harmon's data on actual usage per ton is nearly irrelevant in reviewing the conservation potential available in the 1970s, for several reasons:

1. As Mr. Harmon notes, the data he presents reflects little more than the "changes in operating schedules and production mix." Specifically, we would expect the plants to operate at lower efficiencies at partial load and sporadic operating schedules.[14]

2. Given the fixed contract demands, and the low energy rate so long as the plant operates below the demand

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[12]In his rebuttal testimony for MP, Mr. Pace explains that under the existing contracts, the taconites have had no incentive to control their actual demands as long as they were below contract levels. The taconites did have some incentive to reduce energy use, albeit limited given the MP's low energy charges. Thus, the taconites may well have had even less incentive to reduce demand than energy.

[13]At page 14, Mr. Fatum indicates that Hibbing now can produce 9.1 million tons per year utilizing 155 MW, while it previously required 160 MW to produce 8.1 million tons per year.

[14]MP's current load forecast (the 1987 forecast dated November 1986, Attachment A to Mr. Harmon's direct testimony) includes the following under its Expected Scenario Assumptions: "AVERAGE FIRM TACONITE ENERGY REQUIREMENTS PER TON: Conservation and efficiency improvements lower energy per ton from about 124 kwh in 1985 to about 118 kwh in 2010 <u>despite the continuing inefficiencies of most plants operating at less than full capacity.</u>" (Emphasis added, page 6)

level, there is little incentive for conservation investments. This point is made by the taconites in the current and MP's last rate case: see Mr. Fatum's testimony at page 23-24.

3. Given the current uncertainty in the future of the industry, there is even less incentive for efficiency investments.

4. The cost of discarding an existing motor and replacing it with a more efficient one in the 1980s was much higher than the cost of buying a more efficient motor in the first place in the 1970s.

Most importantly, Mr. Harmon's distinctions between load reductions and conservation miss the point: if the taconites had reduced their loads (through conservation or otherwise), MP could have reduced its exposure to taconite load fluctuations.

Finally, Mr. Harmon (pages 11-12) is concerned about my characterization of MP's treatment of diversity. I have completed further review of the 1980 and 1981 forecast documentation and Mr. Ostroski's rebuttal testimony in the 1981 rate case. Based on this review, it appears that an allowance for diversity was included prior to 1980, although it was increased in the 1980 and 1981 forecasts.

Q: Do you have any comments on Mr. Ostroski's rebuttal testimony?

A: Yes. Mr. Ostroski presents the heart of MP's response to my report, since the other MP witnesses offer very little documentation to support their sometime sweeping conclusions. On some subjects, such as the imprudence of MP's decision to own all of Boswell 4 and to serve all of the taconite load itself, or the benefits of a sale to NEMMPA, Mr. Ostroski simply repeats the errors of the other MP witnesses: I will not bother repeating my response to these points. In addition, Mr. Ostroski generally states each of his points several times: I will try to respond only once to each misconception or misrepresentation, regardless of the number of times Mr. Ostroski repeats himself.

Mr. Ostroski's rebuttal testimony also restates a number of MP's previous errors, which I dealt with in my direct testimony and report. For example, he continues to view MP's capacity options as limited to the construction of new central station coal capacity, despite the existence of other options. He also claims that MP used planning techniques, or included options, earlier than they appeared in any available MP documents. Since he does not document his claims (which should be easy, since he would have prepared or received most of the relevant memos), they can be safely ignored. He repeats MP's earlier claim that it needs a 20% reserve margin, which I showed to be contradicted by MP's own study, attached by Mr. Ostroski as Ex. GBO-21. He provides no new support for this discredited allegation.

On page 9, Mr. Ostroski claims that I misrepresented a November 1982 MP study, by "infer[ring] that the study was used as the only support for [MP] decisions in 1982." That is clearly not the point of my report, at pages 68-71. The November 1982 Norberg memo indicated that even when assuming a low load scenario that has proven to be quite accurate, MP was unable to properly balance current savings with future costs. Mr. Ostroski's assertions on pages 10-11 that MP was only concerned with <u>annual</u> costs, and not with comparing <u>total</u> costs for the sale period with the <u>total</u> benefits, confirms my observation that MP's planning process remained "resistant to selling capacity," even when that was in the best interest of MP ratepayers.

Mr. Ostroski suggests repeatedly that the Erie capacity should be excluded from MP's capacity calculation, even though the 40 MW contract backup capacity (and actually much more) is clearly available if it were needed for planning purposes. In recent years, all the Erie capacity has been shut down because it has been cheaper for Erie to purchase power (when it was operating) from MP, but MP has not shown any reason for treating it as unavailable for planning purposes, as needed.[15] Furthermore, MP's contract with Erie does allow MP the choice of purchasing energy from Erie, despite Mr. Ostroski's repeated assertion that the Erie capacity is accompanied by no energy. Response 132 indicates that energy transactions are priced at split savings. In any case, MP's alternative is to repay the

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[15]Obviously, some notice would be necessary to bring the plant back into service. MP achieved this without any reported difficulty in the summer of 1987.

energy it receives from Erie with energy deliveries at other times. Since MP can buy large amounts of pool energy off-peak at low costs, to repay Erie, the Erie contract allows MP to shift off-peak energy purchases onto peak periods. This backup arrangement has been, and can again be, a very valuable addition to MP's power supply.

Mr. Ostroski similarly argues that oil-fired power plants are not real capacity, because they are oil fired. This is a nonsensical argument. Some fraction of peaking and backup capacity is appropriate for any utility. If the oil capacity were not economical, even as peaking and backup capacity, then some of MP's excess Boswell 4 capacity would be justified by the reduction in energy costs. As I demonstrate in my report, this is not the case: the energy benefits of the surplus Boswell 4 capacity are very small compared to the cost of the capacity. MP has not shown that its incorporation of the oil-fired capacity in its capability calculations would produce "unacceptably large consumption of oil" (Ostroski rebuttal, page 23),[16] either in the test year or in any of its planning studies. Mr. Ostroski attaches some 1982 testimony by NSP (Ex. GBO-10), on

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[16]This quotation refers to the status of NSP and SMMPA: the latter's capacity was largely oil-fired, while MP's is approximately 10% oil-fired. Elimination of 300 MW of excess Boswell 4 capacity would bring the oil-fired fraction of MP's capacity to about 12%. This is less than its reserve margin. This is clearly not comparable to the situation of the non-MAPP utilities discussed in Exhibits LRB-1 and 2 to Exhibit GBO-10.

the situation then forecasted for the late 1980s in MAPP, which provides no information on the economics of oil-fired capacity on MAPP's system at any time, let alone MP's system in the test year.

Contrary to Mr. Ostroski's allegation on page 23, I am well aware of the concern with oil dependence in the early 1980s, when I worked for the Attorney General of Massachusetts, a highly oil-dependent state. While all parties to utility regulation wanted to back out uneconomical base-load oil generation, even the Federal government recognized that oil-fired generation was appropriate for backup and peaking purposes. Oil was not bad per se, but only because it was expensive if used in large quantities. I have never seen an MP study which even attempted to demonstrate that it was economical to retain excess Boswell capacity to back out the oil-fired peakers. Mr. Ostroski is correct that "oil-fired capacity [is not] considered a reasonable replacement for coal-fired base load capacity," but it is also true that expensive new coal-fired capacity is not a reasonable replacement for peaking and backup oil-fired capacity.

Mr. Ostroski responds to my observation that MP did not use present value analysis in generation by citing a memo (Ex. GBO-6), which I also mentioned in my report.[17] In that

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[17]He repeats this claim on page 16, in terms of balancing the short and long term needs of the customers.

memo, Mr. Sandbulte alleges that a present value analysis was performed, but no analysis is displayed. Mr. Ostroski does not provide any historical documents to support his claim that MP used present value analysis in generation planning.

In his Ex. GBO-7, Mr. Ostroski purports to correct my analysis of MP's 1984 participation sale option: Mr. Ostroski makes several mistakes in constructing this exhibit. First, he assumes that the sale would have increased Boswell 4 revenue requirements: this is not true. The cost of owning Boswell 4 is independent of whether 100 MW are resold to another utility. The cost of the excess capacity is the same, regardless of whether MP enters into a Participation Power Sale to offset these costs. Thus, column 2 of Ex. GBO-7 should be eliminated: with this correction (even with Mr. Ostroski's other errors), GBO-7 shows a $3 million present value saving from the sale.

Second, Mr. Ostroski assumes that very expensive capacity would be added in the year 2000.[18] Initially, that capacity would cost 5 times the value of the fuel savings from wholesale purchases: given this disparity in costs, it is unlikely that Mr. Ostroski's hypothetical unit would be cost-effective. MP might well be better served by less expensive capacity supplemented by continued pool purchases.

[18]The cost assumptions underlying the enormous cost of the replacement capacity are not documented, so this projection can not be reviewed and should not be given any weight.

Alternatively, MP could have met its load growth (if that occurred) with a combination of efficiency improvements, cogeneration at paper mills, cogeneration at other industrial and commercial facilities, or refurbishment of the surplus capacity at Erie and Reserve.[19] Some of these measures would have lower capacity costs than Mr. Ostroski assumes in his column 4, while others would produce net fuel savings in column 3. Thus, Mr. Ostroski's analysis of replacement energy and capacity costs is close to a worst case.

Third, even in his worst-case planning scenario, the sale would leave MP with an extra 100 MW of youthful replacement capacity in 2015. Due to the depreciation which Mr. Ostroski charges off to the first 15 years of operation, and to inflation between 2000 and 2015, this will be very economical capacity, comparable to Boswell 3 today. MP could use this capacity in 2015, rather than build new capacity to accommodate any load growth or generation retirements, or sell this capacity for more than its cost. Ex. GBO-7 gives no credit for the value of the replacement capacity in 2015.

At the bottom of page 14, Mr. Ostroski denies that NSP was serious in its 1984 proposals on purchases from MP, but offers no documentation for his assertions, beyond the fact

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[19] At page 17, Mr. Ostroski acknowledges that MP knew in the early 1980s that 35MW of Erie capacity, or 35% of the sale under consideration, was available.

that NSP labeled their proposals as "draft proposals for discussion only." So far as I can see, this labeling proves that NSP's legal staff was doing its job, not (as Mr. Ostroski implies) that NSP was less than serious in its negotiations.

On page 15, Mr. Ostroski claims that MP "did act decisively in its power supply planning prior to 1985," and explains that MP decisively did nothing to permanently sell off its excess. Mr. Ostroski's disagreement with my testimony here appears to be simply semantic.

On page 17, Mr. Ostroski suggests that I recommended that MP pursue construction of fuel cells, integrated gasification combined cycle (IGCC) plants, or fluidized bed combustion (FBC) plants. In fact, I was simply noting that economies of scale, which were important for Boswell 4, are not as important for new technologies. It is true that, by the time MP needs additional capacity, such options might be preferable to the high-cost plants MP used in its analyses of Boswell sale opportunities. In addition, contrary to Mr. Ostroski's assertion, IGCC and FBC technologies <u>are</u> clearly commercial, as demonstrated in Exhibits PLC R-2 and R-3. FBC power plants are becoming quite common, and IGCC is the preferred technology for the next baseload plant of some major utilities, including Northeast Utilities and Potomac Electric Power.

Mr. Ostroski claims repeatedly that MP was not imprudent in failing to sell Boswell 4 capacity to NSP or SMMPA, because neither utility had requested such a sale. As in the case of the taconites, MP is once again attempting to shift its planning responsibilities to other parties. Given MP's clearly expressed attitude towards long-term or equity sales of its capacity, it is hardly surprising that neither NSP or SMMPA pursued a purchase.

On page 30, Mr. Ostroski describes MP's slow responses in the 1980s as "an effective strategy." Unfortunately, the major effect was hundreds of millions of dollars of excess costs due to the failure to sell capacity in a timely fashion.

On page 31, Mr. Ostroski confuses the economical date for a 300 MW transfer of an existing plant with the economical date for construction of a new 800 MW plant, at considerably higher cost. Furthermore, prompt action by MP might well have established the Boswell purchase as a prerequisite for the Sherco approval.

If MP had signed a contract in 1982 to transfer some capacity to NSP, and if NSP had for some reason decided not to take possession of the plant until the late 1980s (although this would be inconsistent with NSP's actual policy), the value to NSP of Boswell capacity at the date capacity would be needed and deferring Sherco 3 would have to be <u>greater</u> than the price NSP is actually paying for Boswell some 5 years ahead of need and not deferring any identifiable unit. For some reason, Mr. Ostroski assumes that the price would have been lower, without any documentation. None of the analyses he describes as "Mr. Chernick's plan" or otherwise flowing from my recommendations (see page 32 and GBO-12) are realistic representations of the outcome of prudent management decisions in the period.

Mr. Ostroski's claim that Square Butte is not a more desirable plant than Boswell 4 is belied by the testimony of Mr. Benkusky in the NSP sale case. His analysis also depends on the assertion that Boswell 4 will actually be used at an 85% capacity factor following the NSP sale. Boswell 4 has operated at lower capacity factors, apparently due to the availability of lower-cost energy in the region off peak. Due to the continuing economy interchanges between the utilities in the region, the change in Square Butte and Boswell ownership should not materially change the dispatch of the units. While Square Butte can not operate off-peak at full power because of boiler limitations, Boswell does not operate off-peak because it is uneconomical. The same regional replacement energy supplements the 70% capacity factors for both units, and the appropriate comparison of energy costs is at a 70% capacity factor. In addition, Mr. Ostroski does not dispute my demonstration that Boswell is more expensive per kW-year.

Mr. Ostroski criticizes me for not reviewing every document the MP Planning Department ever produced. Exhibit PLC R-4 provides the questions I asked to explore MP's basis for its planning decisions. No document MP has provided in this case contradicts any of my conclusions. In fact, most of the historical documents Mr. Ostroski attached to his rebuttal testimony were cited in my report.

I am relieved to find (pages 43-44) that MP planners do use present value analysis for transmission planning, as indicated in Exhibit GBO-16. I am still waiting to see a single contemporaneous present-value analysis of MP's decisions to hold onto excess capacity.

Mr. Ostroski asks that some of MP's excess capacity not be counted, on the basis that MP has not recertified the Hibbard capacity. Given the high level of excess, it was probably prudent to avoid some small costs of operating Hibbard for most of the 1980s. It is certainly reasonable to credit these minuscule savings against the cost of the 409 MW of excess Boswell and Coyote.[20] However, as explained in my report, the Commission would be ill advised to allow MP to create a "need" for expensive capacity by deactivating inexpensive capacity. This point is closely related to MP's assertion that Hibbard and Laskin created the surplus, rather than Boswell 4.

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[20]Mr. Ostroski incorrectly states that I concluded that MP has 310 MW of excess capacity in the test year. The correct figure is 409 MW, as stated on Table 5.3 of the report. The 310 MW figure reflects <u>clearly imprudent</u> excess.

Similarly, Mr. Ostroski suggests that there was virtually no excess capacity in the 1987 summer, due to "a beneficial 350 MW short term Participation Power sale" to NSP (page 55). As noted in my testimony and report, the 1987 sale was at a very low price, equivalent to less than 10% of the cost of the Boswell 4 capacity. Obviously, if MP offers a low enough price, it could sell off enough capacity to eliminate any excess, no matter how large. However, when MP creates excess capacity at about $10,000/MW-month, and sells down capacity at $870/MW-month, the ratepayers wind up with enormous excess costs.

Mr. Ostroski notes that I recommend a 25% reserve requirement be used to recognize a reasonable range of <u>short-term</u> imbalances between load and supply. He fails to note that MP has long since used up the five-year interval I recommend for this test, and that even if MP's reserve were only 15% in the test year, the average for the 1980s would still be well over 25%. Hence, the 15% MAPP requirement is a reasonable reserve margin for the purposes of this proceeding, although a 25% margin might have been appropriate in the 1980 rate case. Of course, if MP could document any economic benefits from the excess in the test year, beyond those I identified in my direct testimony, those benefits would appropriately be subtracted from the cost of the imprudent excess in the test year.

Mr. Ostroski suggests that MP's errors in supply planning have been offset by other factors, such as the relatively low cost and (so far) high reliability of Boswell 4, to produce low average rates. Additional factors, such as the high fraction of sales to industrial customers, also help keep down average rates. Nonetheless, if MP can demonstrate truly superior performance (not just prudent, but exceptional) in some area, it has some claim to offset the disallowance for imprudent planning.[21] MP has not demonstrated any such achievement.

Mr. Ostroski complains that Sherco 3 took 11 years to build. The delay in Sherco's schedule was intended to bring Sherco on line when it would be cost-effective, and not before. From the December 1982 approval of the plant, construction has taken less than the five years I recommended as a standard: the terms of the approval did not allow a substantially earlier in-service date.

Mr. Ostroski also argues (pages 69-70) that large extra costs would be required in 1988 if 310 MW of Boswell were eliminated from the MP system, a proposal he attributes to me. I did not recommend physical elimination of the capacity in this docket (I am not even sure what Mr. Ostroski means by that term), only the elimination of a portion of the rate difference between the costs and

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[21]In addition, the size of my proposed disallowance is smaller than it might otherwise be, because Boswell 4 is a fairly inexpensive unit. If Boswell 4 had been a nuclear power plant, the proposed disallowance would have been much larger.

benefits of Boswell 4. Nonetheless, it is interesting to examine the basis of Mr. Ostroski's allegations.

If MP had sold 310 MW of Boswell 4 in the early 1980s, Hibbard could have been restarted by now.[22] Exhibit GBO-20 shows a surplus of 392 MW in the summer of 1988 and 308 MW in the winter, without any Hibbard capacity. (For some reason, Mr. Ostroski states that the sale would have required 50MW of capacity in 1988.) Thus, it might be cheaper to buy capacity for the 12 MW-months[23] necessary to meet MAPP requirements than to recertify Hibbard. Even at Mr. Ostroski's $2000/MW-month, this would cost only $24,000, compared to the $1 million Mr. Ostroski alleges. Since the market value of short-term capacity (including coal-fired capacity) has been more like $1,000/MW-month, assuming that MP's recent sales have accurately reflected market conditions, the actual cost is more realistically $12,000 or less. Mr. Ostroski also claims that changes in energy production would cost $5 million, but provides no documentation. In the discovery phase of this proceeding, MP was unable to provide any calculations of the fuel savings due to Boswell 4 (Response 112), and the Commission

[22]As Mr. Ostroski recognizes (page 75), the restart of Hibbard 3 and 4, even with the coal/wood conversion, will cost only $0.5 to $1.0 million, and will produce energy at $25-30/MWH.

[23]The winter 1988 excess of 308 MW would result in a 2 MW deficit given a 310 MW sale. This 2 MW deficit over the 6 month winter 1988 period results in a total of 12 MW-months.

should give no weight to this new, mysterious, and undocumented cost estimate.

Even if Mr. Ostroski were correct, the net cost of the 310 MW of imprudent excess capacity to MP ratepayers would be $28.2 million, based on net non-fuel costs of $34.2 million, and Mr. Ostroski's fuel and capacity value estimate of $6 million. Using my more realistic approach, Exhibit 3 of my direct shows that the net cost is $28-33 million.

Q: Do you have any corrections or updates to your testimony?

A: Yes. As a result of reviewing Mr. Harmon's second set of supplementary testimony (which I received after my direct testimony was completed), I found that my initial estimates of the benefits to ratepayers of MP's off-system sales, in the past and in the test year, were overstated. This overstatement is due to the fact that a large portion of the off-system sales revenue was credited to the Large Power Contract customers. I noted this effect on direct, but was not able to quantify it. In addition, I am now utilizing MP Workpapers 15-36 which quantify off-system sales net of credits to Large Power Contract customers on a test-year basis. Exhibits R-5 and R-6 correct Table 5.4 of Exhibit PLC-2 and Exhibit PLC-3 from my direct testimony.

The costs of the excess capacity are now approximately $4 million higher than estimated in my direct testimony, due to the lower off-system sales. As derived in Exhibit R-6, my estimate of total excess cost is now $43.1 million (or

$33.1 million including the AFPO credit).

On page 35 of my direct testimony, I describe how the the estimate of excess cost I derived in Exhibit PLC-3 would be applied to a used-and-useful mechanism. Utilizing the methodology from page 35, the $43.1 million in excess costs is equivalent to the cost of Coyote ($1.5 million) and the cost of 386 MW of Boswell 4.[24] The $33.1 million is attributable to Coyote and 293 MW of Boswell 4. As in the case of my direct testimony, Mr. Lusti of the MDPS staff will present a detailed calculation of the rate effect of the return on MP's share of Coyote and of 293-386 MW of Boswell 4.

Q: Does this conclude your testimony?

A: Yes.

[24]The computation is as follows: the ratio of Boswell 4 excess cost ($43.1 million minus $1.5 million for Coyote equals $41.6 million) to Boswell 4 total 1987 fixed costs ($57.6 million as shown in Exhibit PLC-2, Table 5.1) multiplied by Boswell 4 total MW (535 MW).